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 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; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM PURSUANT TO IND. CODE § 8-1-2-42(a) TO (A) TIMELY RECOVER CHARGES AND CREDITS FROM REGIONAL TRANSMISSION ORGANIZATIONS AND NIPSCO'S TRANSMISSION REVENUE REQUIREMENTS; (B) TIMELY RECOVER NIPSCO'S PURCHASED POWER COSTS; AND (C) ALLOCATE NIPSCO'S OFF SYSTEM SALES REVENUES; (6) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS, THE ENVIRONMENTAL COST RECOVERY MECHANISM AND THE ENVIRONMENTAL EXPENSE MECHANISM; (7) APPROVAL OF THE CLASSIFICATION OF NIPSCO'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; AND (8) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1 *ET SEQ.* TO THE EXTENT SUCH RELIEF IS NECESSARY TO EFFECT THE RATEMAKING MECHANISMS PROPOSED BY NIPSCO.	CAUSE NO. 43526 APPROVED: AUG 25 2010

<u>BY THE COMMISSION</u>:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge
Angela Rapp Weber, Administrative Law Judge

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INTRODUCTION

On June 27, 2008, Northern Indiana Public Service Company ("Petitioner," "Company" or "NIPSCO") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") for approval of (1) modifications to its rates and charges for electric utility service; (2) new schedules of rates and charges applicable thereto; (3) revised depreciation accrual rates; (4) inclusion in its basic rates of costs associated with certain previously-approved environmental projects; (5) a rate adjustment mechanism to timely reflect charges and revenues from regional transmission organizations ("RTOs"), purchased power costs, and off-system sales ("OSS") margins; (6) various changes to its electric service tariff; (7) the classification of its facilities as transmission or distribution in accordance with the Seven-Factor Test of the Federal Energy Regulatory Commission ("FERC"); and (8) an alternative regulatory plan pursuant to Ind. Code § 8-1-2.5-1 *et seq.* to the extent such relief is necessary to effect the ratemaking mechanisms proposed by NIPSCO.

Petitions to intervene were filed by NIPSCO Industrial Group ("IG"), Board of Commissioners of LaPorte County ("LaPorte"), City of Hammond ("Hammond"), City of Crown Point, Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Municipal Utilities Group ("MU"), Beta Steel Corporation ("Beta Steel"), Newton County and the United Steelworkers. These petitions were granted, and these entities were made parties to this cause. The Indiana Office of Utility Consumer Counselor ("OUCC" or "Public") also participated in this proceeding as the statutory representative of the consumers.

Pursuant to the Prehearing Conference held on July 29, 2008 and the Prehearing Conference Order dated August 27, 2008, a procedural schedule was established for this proceeding.

The prepared testimony and exhibits constituting NIPSCO's case-in-chief were filed with the Commission on August 29, 2008 and NIPSCO's workpapers were submitted on September 5, 2008. Petitioner's case-in-chief was supplemented by the filing of an inadvertently omitted exhibit on September 5, 2008, a late-filed page and exhibit on September 8, 2008, corrections on September 29, 2008 and supplemental direct testimony concerning NIPSCO's customer notice on October 14, 2008.

On December 18, 2008, the parties filed with the Commission an agreed motion to continue the commencement of the initial evidentiary hearing by one week from January 6, 2009 to January 12, 2009. The motion stated that in accordance with a settlement agreement in Cause No. 43396 S1, a subdocket proceeding concerning NIPSCO's acquisition of the Sugar Creek Generating Station ("Sugar Creek"), and the agreement of the parties, NIPSCO would shortly file revised and supplemental testimony incorporating Sugar Creek into the evidence in this case and addressing a correction of an error in its case-in-chief. The motion stated a short continuance would provide the other parties sufficient time to review NIPSCO's supplemental filing and assist in the efficient and orderly presentation of evidence at the hearing. The Commission initially denied the motion, but after NIPSCO's supplemental filing on December 19, 2008 and a motion for reconsideration by the parties filed on December 22, 2008, the Commission by a docket entry dated December 24, 2008, continued the commencement of the hearing until January 12, 2009. Subsequently, NIPSCO filed additional corrections to its case-in-chief on December 31, 2008, January 6, 2009 and January 9, 2009, and submitted revised case-in-chief workpapers on December 31, 2008. NIPSCO filed supplemental direct testimony and submitted supplemental workpapers relating to the cost of service study on January 26, 2009.

Pursuant to the Prehearing Conference, the Prehearing Conference Order, notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, and the Commission's docket entry dated December 24, 2008, a public hearing in this Cause commenced on January 12, 2009 and continued through February 6, 2009, at which time NIPSCO presented its case-in-chief and its witnesses were made available for cross-examination and questions from the bench.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held on March 3, 2009 in the City of Gary, the largest municipality in Petitioner's service area. At the field hearing, members of the public were afforded the opportunity to make statements on the record to the Commission.

On April 9, 2009, NIPSCO, Beta Steel, Hammond, CAC, MU, LaPorte, IG and the OUCC filed a Joint Motion for Extension of Time requesting an extension of the remaining prefiling and workpaper submission deadlines to allow the parties to analyze and file testimony in response to a corrected version of NIPSCO's cost of service study that was provided by NIPSCO on April 8, 2009, and for which NIPSCO would provided corrected rate design, revenue proof and tariff information on April 10, 2009. In the motion, NIPSCO agreed not to object to other parties making its corrected cost of service study an exhibit in their respective testimonial submissions. This Motion was granted by Docket Entry dated April 14, 2009.

On April 30, 2009, IG filed a Motion for Involuntary Dismissal pursuant to Trial Rule 41(B) contending that the Commission should disallow recovery of charges to NIPSCO for services provided by NiSource Corporate Services Company ("NCS"). NIPSCO filed a response to the motion on May 11, 2009, and the IG filed a reply to NIPSCO's response on May 18, 2009. By Docket Entry dated June 16, 2009, the Presiding Officers determined that the motion would be addressed in this Order.

On May 5, 2009, Beta Steel, MU, LaPorte, IG and the OUCC filed a Joint Submission of Consumer Parties' Joint Exhibits 1 and 2. Joint Exhibit 1 was a copy of the Third Revised Cost of Service Study provided by NIPSCO on April 8, 2009, including correspondence related thereto. Joint Exhibit 2 was a copy of revisions to the Third Revised Cost of Service Study, including correspondence related thereto, that was provided by NIPSCO to the parties on May 1, 2009, which included some additional changes.

On May 7, 2009, the OUCC filed written comments received from consumers since the March 3, 2009 field hearing. The OUCC filed additional consumer comments on August 4, 2009.

On May 8, 2009, the OUCC and Intervenors filed the prepared testimony and exhibits constituting their respective cases-in-chief. Supplements and corrections to IG's case-in-chief were filed on May 11, 2009 and June 23, 2009. LaPorte's case-in-chief was supplemented by the filing of revised testimony on July 17, 2009. On May 15, 2009, the OUCC and Intervenors filed their workpapers. The OUCC submitted corrections to its workpapers on May 22, 2009.

On May 29, 2009, the OUCC, IG and MU filed cross-answering testimony and exhibits responding to each other's prefiled evidence. IG submitted cross-answering workpapers on June 2, 2009.

On June 26, 2009, NIPSCO filed its rebuttal testimony and exhibits. NIPSCO's rebuttal testimony and exhibits were supplemented by the filing of inadvertently omitted and corrected exhibits on June 29, 2009 and July 14, 2009. NIPSCO's rebuttal workpapers were submitted on June 30, 2009 and supplemented on July 1, 2009.

On July 23, 2009, the OUCC filed its Objection and Motion to Strike Testimony of Intervenor's Witness Nicholas Phillips, Jr. IG filed a response to the OUCC's objection and motion on July 24, 2009. After a brief discussion on the record and clarification by IG as to the purpose of the testimony in question, the OUCC withdrew the objection and motion.

Also on July 23, 2009, NIPSCO filed a Motion for Limitation of Cross-Examination by Parties with Similar Interests and Supporting Memorandum. IG filed a response to NIPSCO's motion on July 24, 2009. At the evidentiary hearing, Beta Steel, LaPorte, CAC, MU and the OUCC joined in IG's response to NIPSCO's motion. After a brief discussion on the record, the Commission denied NIPSCO's motion but noted for the record that friendly cross-examination is not permitted.

Pursuant to a docket entry of the Commission dated May 4, 2009 and notice as provided by law, two additional field hearings were held on July 15, 2009 in the City of Michigan City at which time members of the public were afforded the opportunity to make oral and written statements on the record to the Commission.

On July 27, 2009, an evidentiary hearing was commenced at which time the cases-in-chief and cross-answering testimony of the OUCC and Intervenors and NIPSCO's rebuttal evidence were admitted and their witnesses were made available for cross-examination and questions from the bench.

Pursuant to a schedule agreed to at the final hearing, as modified subsequent to the hearing, NIPSCO filed its proposed order on October 15, 2009, the OUCC and Intervenors filed proposed orders and exceptions on December 4, 2009 and cross-answering briefs on December 30, 2009, and NIPSCO filed its reply brief on January 26, 2010.

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 changes in its rates and charges for electric service. Due, legal and timely notices of the Prehearing Conference and 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 46410. NIPSCO 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. NIPSCO also provides gas utility service in northern Indiana. NIPSCO is a wholly-owned subsidiary of NiSource Inc. ("NiSource").

3. **Existing Rates.** Petitioner's existing basic rates and charges for electric utility service (sometimes referred to herein as "base or basic rates") were established pursuant to the Commission's Order dated July 15, 1987 in Cause No. 38045 ("1987 Rate Order"). On September 23, 2002 in Cause No. 41746, the Commission approved a settlement agreement in a proceeding initiated by the Commission to investigate NIPSCO's electric rates ("Rate Investigation"). The settlement agreement provided that the terms of the 1987 Rate Order will remain unchanged as they relate to NIPSCO's basic electric rates and depreciation rates but, among other things, provided for customer bill credits of approximately $55 million per year until the Commission enters a basic rate order approving revisions to NIPSCO's basic electric rates.

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 months ended December 31, 2007. The financial data for this test year, when adjusted for fixed, known and measurable changes as provided in the Prehearing Conference Order, is a proper basis for fixing new rates for Petitioner and testing the effect thereof. The Prehearing Conference Order provided the general rate base cutoff shall reflect used and useful property at the end of the test year. On December 11, 2008, NIPSCO, the OUCC, IG and LaPorte filed a settlement agreement in Cause No. 43396-S1 that provided that Sugar Creek was accepted as an internal designated network resource of NIPSCO by Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") effective December 1, 2008 and that the OUCC, IG and LaPorte would not challenge the inclusion of Sugar Creek in NIPSCO's rate base in this proceeding and the inclusion of reasonable expenses associated with Sugar Creek in NIPSCO's revenue requirement in this proceeding. Accordingly, Sugar Creek was included in NIPSCO's rate base and operating expenses for purposes of this proceeding.

5. **Relief Requested.** In its case-in-chief, NIPSCO proposed that its basic rates and charges be revised to produce annual revenue net of costs for fuel, purchased power and associated taxes ("gross margin" or "margin") of $962,393,192 plus non-trackable fuel expense of $11,669,787, for a total amount of $974,062,979. Miller Direct at 2-3. NIPSCO proposed to remove all of the cost of fuel traditionally recoverable through the fuel adjustment charge ("FAC") from base rates. *Id.* at 2. As discussed hereafter, the determination of the increase in NIPSCO's existing base rates depends upon the manner in which pro forma present rate revenues are adjusted to include or exclude fuel, the bill credits from the Rate Investigation settlement agreement and the discounts provided to certain industrial customers pursuant to Commission-approved customer specific contracts. Under NIPSCO's case-in-chief analysis, its proposed base rates would produce additional gross margin of $85,744,828. NIPSCO asserted its proposed base rates were intended to provide the opportunity to earn net operating income of

$223,095,808. *Id.* at 3. In its rebuttal presentation, NIPSCO reduced its proposed NOI level to $220,900,254. Miller Rebuttal at 7; Petitioner's Ex. LEM-R2, p. 2, l. 83, Col. J. NIPSCO also sought approval of revised depreciation accrual rates; a tracking mechanism for Midwest ISO revenues, Midwest ISO costs, purchased power, and Off System Sales ("OSS"); and reclassifications of transmission and distribution plant pursuant to the Seven-Factor Test.

6. **Overview.** Robert C. Skaggs, Jr., President and Chief Executive Officer of NiSource, provided an overview of NiSource and its corporate structure and explained NiSource's strategic direction. Mr. Skaggs explained that NiSource is a Fortune 500 company headquartered in Merrillville, Indiana, and is organized into three business units: (i) Northern Indiana Energy (which includes NIPSCO, Northern Indiana Fuel & Light Company and Kokomo Gas and Fuel Company), (ii) Gas Distribution, and (iii) Gas Transmission and Storage. Skaggs Direct at 3.

Mr. Skaggs stated that one of his initial priorities upon assuming his current responsibilities was to conduct a strategic review to identify corporate strengths and weaknesses and to define the future strategic direction of NiSource. Mr. Skaggs testified that one of the key findings from that review was that NiSource's core strengths were driven by its regulated infrastructure assets and that the ability to capitalize on those core strengths would require a long-term, investment-driven plan to modernize those core assets and core processes and raise the level of services they support. Skaggs Direct at 4.

Mr. Skaggs stated that, for NIPSCO's electric service, this includes significant increases in vegetation management, additional investments in generating stations and implementation of a contemporary work management system. Skaggs Direct at 6. Mr. Skaggs indicated that investment in NIPSCO's electric system will continue to increase due to environmental compliance, infrastructure growth, public improvements, capacity enhancements and infrastructure replacements. *Id.* In addition to assets and systems, Mr. Skaggs explained that NIPSCO also is addressing the fact that many of its experienced employees will reach retirement age over the next few years. He stated that new positions are being created to ensure NIPSCO has the skills and resources required to execute its business plans. *Id.* at 9. Mr. Skaggs cited NIPSCO's $330 million investment in Sugar Creek as an example of NIPSCO's effort to modernize its generating fleet and improve system reliability. Finally, Mr. Skaggs discussed the importance to NIPSCO and NiSource of credit ratings and the impact of regulatory treatment on those credit ratings. *Id.* at 10-11.

Eileen O'Neill Odum, Executive Vice President and Group Chief Executive Officer for NiSource's Indiana Business Segment and President of NIPSCO, described NIPSCO's mission and focus, provided an overview of its electric system and operations, and briefly summarized the relief requested by NIPSCO in its case-in-chief. Ms. Odum explained that NIPSCO's mission is to provide its customers with safe and reliable electric and gas service at just and reasonable prices. She said NIPSCO maintains a strong focus on all of its stakeholders including customers, employees, communities and regulators. Ms. Odum noted that NIPSCO has recently taken a number of important steps in support of its core mission, including the acquisition of Sugar Creek, a gas-fired combined cycle combustion turbine generating facility and its decision to retire the D.H. Mitchell Generating Station ("Mitchell") and Units 2 and 3 of the Michigan City Generating Station ("Michigan City Units 2 and 3"), which are NIPSCO's oldest coal-fired and retrofitted gas-fired generating facilities. She commented on NIPSCO's increase in security at its key substations, its improvements in customer service, its high quality customer contact center in Merrillville and the upgrading of its system infrastructure. Odum Direct at 2-4.

Ms. Odum also testified as to the recent reorganization of NIPSCO into the Northern Indiana business unit, which Ms. Odum stated provides clear accountability for all aspects of business performance and reinforces NIPSCO's focus on its customer segments. Ms. Odum explained that related to this reorganization was the establishment of 83 positions intended to further NIPSCO's focus on customer satisfaction, system reliability and regulatory transparency. Ms. Odum also highlighted NIPSCO's plan for additional hiring in order to deal with NIPSCO's aging workforce. Odum Direct at 4-5.

Ms. Odum stated that while industrial customers make up less than 1% of NIPSCO's 457,000 electric customers, they consumed more than 53% of the electricity sold during the test year. Odum Direct at 6-7. Ms. Odum also discussed NIPSCO's generation fleet and its plans to retire, demolish and remediate the Mitchell site and to retire and remove the equipment at Michigan City Units 2 and 3. *Id.* at 7-8. She explained that functional control of NIPSCO's transmission system now resides with Midwest ISO which operates under FERC authority as a non-discriminatory open access transmission provider. *Id.* at 7. Ms. Odum testified NIPSCO's generating units are dispatched by Midwest ISO on a security-constrained economic dispatch basis and NIPSCO participates in the Midwest ISO energy markets. *Id.*

Ms. Odum discussed steps NIPSCO has taken to manage escalating costs for operation and maintenance expenses through rigorous budgeting, competitive procurement practices and the implementation of a work management initiative. But she noted there are some costs over which NIPSCO has little control, such as environmental compliance and market prices for materials, equipment and contract labor. Odum Direct at 9-10.

Ms. Odum described the challenges facing NIPSCO in particular and the electric industry in general. Ms. Odum testified that planning for uncertain future changes in environmental regulation, principally carbon emissions, presents a very significant challenge for most electric utilities which, like NIPSCO, depend heavily on coal-fuel generators. Ms. Odum stated that escalating costs, including fuel, transportation and labor costs, pose a severe challenge to the ability of an electric utility to provide service at prices which recover its costs yet remain reasonable for customers. More specific to NIPSCO, Ms. Odum remarked on the substantial changes to NIPSCO's service territory and customer mix that have occurred in the twenty years since its last base rate case. Moreover, the transforming changes have taken place in the industry since then that require new rate mechanisms to deal with a new environment. Ms. Odum noted that NIPSCO's industrial customers represent the economic backbone of its service territory. These customers and their industries have undergone massive restructuring since NIPSCO's base rates were last set, resulting in a consolidation of the number and diversity of customers while the cost to serve them has increased. Ms. Odum testified that the relative cost of providing service has shifted among customer classes resulting in the need to "rebalance" NIPSCO's rate structure. Ms. Odum testified that NIPSCO's proposals in this proceeding represent a platform tailored to address these challenges. Odum Direct at 9-11.

Linda E. Miller, NIPSCO's Executive Director of Rates and Regulatory Finance, testified on NIPSCO's proposed revenue requirement. The adjustments reflected in her accounting exhibits were supported by a number of NIPSCO witnesses discussed in the consideration of the revenue requirement issues that follow.

Frank A. Shambo, NIPSCO's Vice President, Regulatory and Legislative Affairs, testified that when NIPSCO's current base rates were approved in 1987, the increase granted in that case was implemented in an across-the-board fashion. Given the passage of time and changes in circumstances, NIPSCO chose to substantially revise its tariff to reflect a complete assessment of ratemaking principles, cost of service and bill impacts. Shambo Direct at 3-4. Mr. Shambo stated one of the challenges in this proceeding is to balance equity between rate classes because this is the first time in over 20 years that NIPSCO's revenue allocation has been examined in detail. He noted that NIPSCO's industrial customers are subject to global competition and have options as to where they will produce their products. Mr. Shambo also acknowledged that NIPSCO was aware of challenges facing its residential customers. He asserted NIPSCO's proposed cost allocation and rate design takes into consideration the characteristics of all customer classes. *Id.* at 9-10. Mr. Shambo stated that in developing its proposals, NIPSCO considered differences between peak and off-peak usage, understandability, simplification, appropriate price signal and public policies supportive of economic development and energy efficiency. As a result of this review, NIPSCO proposed removing all fuel and purchased power costs from base rates and recovering all trackable fuel costs via the FAC; a Reliability Adjustment tracking mechanism; elimination of declining block rates; changes in its interruptible rates; a reduction in the number of customer rates; an economic development rider; and movement to cost-based rates tempered by gradualism. *Id.* at 9-25.

NIPSCO also presented witnesses on its proposed capital structure and cost of capital, depreciation accrual rates, cost of service study, rates, tariff revisions, tracking mechanisms, Seven-Factor Test reclassifications, and asset valuation.

7. **Petitioner's Rate Base.**

A. Jurisdictional Used and Useful Property. NIPSCO included in its rate base (a) property recorded as electric utility plant in service as of December 31, 2007 less Mitchell, Michigan City Units 2 and 3 and a portion of Unit 17 of the Schahfer Generating Station ("Schahfer 17") that was disallowed by the Commission's Order dated August 9, 1984 in Cause Nos. 37023-S1 and 37458; (b) Sugar Creek; and (c) an allocated share of common plant in service as of December 31, 2007, *i.e.* plant used in common for both electric and gas utility purposes. Miller Direct at 39-41; Petitioner's Ex. LEM-4 (Revised). Although there were issues regarding the valuation of NIPSCO's utility plant in service and the proportion of common plant to be allocated to the electric operation, there was no dispute about the used and useful nature of the utility property included by NIPSCO in its rate base. The Commission finds that such property is used and useful for the convenience of the public in NIPSCO's provision of utility service. Therefore, such property is includible in NIPSCO's rate base.

Mr. Shambo testified that in the test year NIPSCO provided small amounts of FERC-regulated wholesale service to the City of Argos, ancillary services to Indiana Municipal Power Agency and transmission service to Wabash Valley Power Association, Inc. Shambo Direct at 23. Mr. Shambo stated that due to the small size and incidental amount of this business, NIPSCO believes its electric business should be treated as 100% jurisdictional for ratemaking purposes and that revenues from these incidental services should be credited to retail customers. *Id.* No party opposed this proposal and the Commission finds it to be reasonable. Therefore, we shall treat NIPSCO's electric utility operations as 100% jurisdictional, credit the revenues from these incidental services to retail customers and treat the revenues as jurisdictional for purposes of the FAC earnings test. This is consistent with our treatment of Southern Indiana Gas and

Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South") in our Order in Cause No. 43111 dated August 15, 2007 ("Vectren South Order"). See Vectren South Order, p. 6.

B. Original Cost Rate Base. In its case-in-chief, NIPSCO quantified its original cost rate base to be approximately $2.665 billion. Petitioner's Ex. LEM-4 (Revised). The OUCC proposed an original cost rate base of about $2.639 billion. Public's Ex. 2, Sch. TSC-2, p. 2. The only issues regarding NIPSCO's original cost rate base concerned common plant, deferred costs of the Pure Air project, a prepaid pension asset and cash working capital.

(1) Common Plant. Some of NIPSCO's utility plant is used in common for both electric and gas utility service. For purposes of determining NIPSCO's electric rate base, NIPSCO allocated the common plant to its electric operation using common cost allocation ratios described in the direct testimony of Mitchell E. Hershberger, NIPSCO's Controller. Hershberger Direct at 7-10. IG Witness Greg Meyer, a principal in the Brubaker & Associates consulting firm, disputed the appropriateness of NIPSCO's method of allocating NCS charges and internal common costs between NIPSCO's electric and gas operations. Mr. Meyer contended the amount of common plant allocated to electric should be reduced by $25 million based on a PowerPoint document produced by NIPSCO in discovery. Meyer Direct at 44, lines 11-12. This document is dated December 18, 2006 and is based on data from 2005, not the test year. IG Ex. CX-26, pp. 1, 28.

We will discuss Mr. Meyer's position on allocation ratios in detail in connection with our findings on the level of NCS charges to be included in NIPSCO's revenue requirement. Based on our conclusions with respect to allocation ratios, however, we reject Mr. Meyer's proposed $25 million reduction in the amount of common plant included in NIPSCO's electric rate base. In addition, we find Mr. Meyer's recommendation should be given little weight because IG's witnesses themselves could not agree on which original cost rate base to use. For instance, IG Witness Michael Gorman, another Brubaker & Associates consultant, used NIPSCO's proposed original cost rate base of $2,665,421,829 in determining the impact of his cost of capital recommendation on NIPSCO's revenue requirement. IG Ex. MPG-1, p. 1, l. 17 and p. 2, l. 25.

(2) Pure Air Deferred Asset. In its case-in-chief, NIPSCO included in its original cost rate base the unamortized balance at December 31, 2007 of deferred charges relating to the Pure Air flue gas desulfurization system at the Bailly Generation Station. Petitioner's Ex. LEM-4 (Revised), p. 1, l. 11. This deferral was authorized by the Commission in Cause No. 38849-S1. OUCC Witness Thomas S. Catlin, a principal with the Exeter Associates consulting firm, testified the Pure Air project deferred charges should be excluded from rate base because the amortization expired before the end of 2008. Catlin Direct at 7. For this reason, Mr. Catlin stated, NIPSCO Witness Linda E. Miller removed the test year Pure Air amortization expense from NIPSCO's adjusted operating expenses. *Id.* In her rebuttal testimony, Ms. Miller testified that NIPSCO did not object to removal of the Pure Air deferred asset from NIPSCO's rate base. Miller Rebuttal at 53. Therefore, we accept Mr. Catlin's recommendation and find the Pure Air deferred charge asset of $526,218 should not be included in NIPSCO's rate base.

(3) Prepaid Pension Asset. In its case-in-chief, NIPSCO included in its rate base a prepaid pension asset of $25,705,004. Petitioner's Ex. LEM-4 (Revised), p. 1, l. 15. At the hearing on NIPSCO's case-in-chief, Ms. Miller stated that there was a prepaid

pension asset at the end of the test year because the market value of the pension assets was increasing at that time. Tr. at P-55-P-56. However, due to changing market conditions, by December 31, 2008, the prepaid pension asset was down to zero and pension expense was up by tens of millions of dollars. Tr. at P-56. Ms. Miller stated the reduction in the asset value and the increase in the expense were inter-related. *Id.* Ms. Miller sponsored an updated calculation of NIPSCO's pension expense adjustment that reflected a significant increase in NIPSCO's pension expense due to post-test year changes in market conditions. Petitioner's Redirect Ex. 2.

OUCC Witness Catlin recommended that the prepaid pension asset be removed from rate base because it was eliminated in 2008 due to unfavorable market performance. Catlin Direct at 6. Mr. Catlin further testified that the asset does not represent money contributed by NIPSCO to the pension trust in excess of the amount collected from ratepayers, but rather is a calculation made by the plan actuary. *Id.* Mr. Catlin opined that the prepaid pension asset does not constitute investor-supplied capital upon which NIPSCO is entitled to earn a return. *Id.* at 7.

IG Witness Gorman also recommended that NIPSCO's prepaid pension asset be removed from rate base. Gorman Direct at 12. Mr. Gorman asserted that NIPSCO would earn a return on this asset twice if it is included in rates, first by receiving an investment return in the pension trust fund and then a second time from retail customers if the prepaid pension asset is included in the development of retail rates. *Id.* at 89. Mr. Gorman stated that the increased value of the pension asset does not represent the direct investment by NIPSCO that has not been recovered from customers, but rather reflects investment growth of previous cash contributions. *Id.*

In rebuttal, NIPSCO Witness Miller testified that NIPSCO is not opposed to the removal of the prepaid pension asset from rate base, provided that the Commission also reflects the corresponding increase in pension expense. Miller Rebuttal at 51. Ms. Miller stated that the prepaid pension asset on NIPSCO's balance sheet at December 31, 2007 was calculated based on a favorable return on pension plan assets during the test year and that the resulting asset was directly related to the pension credit expense amount reflected in the test year. *Id.* Ms. Miller further stated that at December 31, 2008, the next plan measurement date, unfavorable plan performance in 2008 resulted in elimination of the pension asset and the establishment of increased pension expense to be accrued during 2009. *Id.* She said pension expense accrual amounts are established for the coming year as of the measurement date used for the pension plan valuation. *Id.* Ms. Miller updated NIPSCO's pension expense adjustment to include the new pension expense accrual amount determined as of December 31, 2008. *Id.* at 52; Petitioner's Ex. LEM-R3, Adj. OM-3.

We will discuss the pension expense adjustment *infra*. With respect to NIPSCO's request to include the prepaid pension asset in rate base, the only evidence in Petitioner's case-in-chief purporting to support the inclusion is Ms. Miller's accounting exhibit showing the amount of the prepaid pension asset. A prepaid pension asset could be a voluntary payment by shareholders to supplement the required pension expenses. NIPSCO has presented no justification for including the prepaid pension asset in rate base, and without additional supporting evidence, we decline to include it in NIPSCO's rate base.

(4) Cash Working Capital. IG Witness Meyer testified that because NIPSCO's proposed rate base does not include any amount for cash working capital, NIPSCO is in essence requesting a zero working capital allowance. Meyer Direct at 44. Until last year, Mr. Meyer was employed by the Missouri Public Service Commission. Meyer Direct, Appendix A.

Based on his experience in Missouri, Mr. Meyer believed electric utilities generally have a negative working capital allowance and that a study performed for NIPSCO would likely show the same result. *Id.* Mr. Meyer based his opinion on summaries of lead lag studies performed by the Missouri Commission staff that related to AmerenUE and Kansas City Power & Light Company. IG Ex. GRM-11. Mr. Meyer noted that NIPSCO sells its accounts receivable to a third party, which accelerates the amount of time that NIPSCO receives cash from bills rendered to customers. *Id.* at 44-45. Mr. Meyer did not perform a lead lag study of NIPSCO but instead recommended that the Commission require NIPSCO to perform a lead lag study for inclusion in its next rate case. *Id.* at 47.

In rebuttal, NIPSCO Witness Miller testified that NIPSCO disagreed with Mr. Meyer's contention and it would be premature to ask the Commission to decide in this current rate case what should be done in a future rate case. Miller Rebuttal at 55-56. Further, Ms. Miller stated that Mr. Meyer provided no evidence to indicate that lead lag studies are required in rate cases or that NIPSCO's case is deficient because it does not contain one. *Id.* at 56.

No other major Indiana electric utility submitted a lead lag study in its most recent rate cases. *Ind. Michigan Power Co.*, Cause No. 43306 (March 4, 2009); *S. In Ind. Gas and Elec. Co.*, Cause No. 43111 (Aug. 15, 2007); *PSI Energy, Inc.*, Cause No. 42359 (May 18, 2004). Nor have we ordered those companies to do so in their next rate cases. IG has submitted no evidence explaining why NIPSCO should be treated differently than these other utilities. In comparison, our rules on Minimum Standard Filing Requirements state such studies need be submitted only if the utility is requesting an allowance for cash working capital, which is not the case here. 170 IAC 1-5-12(1). Accordingly, we reject Mr. Meyer's assertion that a lead lag study was required in this Cause.

(5) Quantification of Original Cost Rate Base. Based on the evidence and the findings made above, the Commission determines that the original cost of NIPSCO's property used and useful in the provision of electric utility service is as follows:

Description	Amount
Utility Plant	$ 5,205,578,748
Common Plant Allocated	214,502,540
Less Schahfer 17 Disallowed Plant	(31,733,655)
Total Utility Plant	5,388,347,633
Accumulated Dep. and Amort.	(2,800,380,478)
Sugar Creek Acc. Dep. and Amort.	(5,618,432)
Common Plant Acc. Dep. Allocated	(98,409,168)
Less Disallowed Plant Acc. Dep.	27,399,652
Total Accumulated Dep. and Amort.	(2,877,008,426)
Net Utility Plant	2,511,339,207
Schahfer 17 Deferred Dep. (CN 37129)	542,928
Schahfer 18 Deferred Dep. (CN 37819)	5,206,694
Schahfer 18 Def. Carrying Charges (CN 37819)	16,132,193
Prepaid Pension Asset	$0
Materials & Supplies	46,907,735
Sugar Creek Materials & Supplies	1,495,291
Production Fuel	57,566,559
Total Rate Base	$ 2,639,190,607

Sugar Creek has been included in the original cost rate base at the acquisition cost of approximately $328 million as identified in Ms. Miller's testimony. Miller Direct at 41. Accumulated depreciation and amortization has been increased for depreciation on Sugar Creek from June 1, 2008 through November 30, 2008, the period from its acquisition by NIPSCO through the period before it was a designated network resource in Midwest ISO. *Id.* No parties disagreed with NIPSCO's proposed treatment of the Sugar Creek amounts.

C. **Fair Value of Rate Base.**

(1) Legal Requirements. Ind. Code § 8-1-2-6 provides the Commission "shall value all property of every public utility actually used and useful for the convenience of the public at its fair value, giving such consideration as it deems appropriate in

each case to all bases of valuation which may be presented or which the commission is authorized to consider by the following provisions of this section." The Indiana Supreme Court has held use of fair value reflects not only legislative policy, but also a requirement of the Indiana Constitution. *Pub. Serv. Comm'n of Ind. v. City of Indianapolis*, 235 Ind. 70, 92-93, 131 N.E.2d 308, 317 (Ind. 1956). In determining fair value, the Commission cannot ignore the "commonly known and recognized fact of inflation." *Indianapolis Water Co. v. Pub. Serv. Comm'n of Ind.*, 484 N.E.2d 635, 640 (Ind. Ct. App. 1985). For this reason, "'reproduction cost new less depreciation cannot be disregarded in fixing a valuation for rate making purposes.'" *Id.* (quoting from *Pub. Serv. Comm'n of Ind. v. City of Indianapolis*, 235 Ind. at 108, 131 N.E.2d at 325).

(2) Evidence. In addition to its evidence on the original cost, NIPSCO submitted evidence on the fair value of its property using alternative ways of computing fair value. NIPSCO Witness John P. Kelly, an asset valuation specialist with Concentric Energy Advisors, Inc., determined the value of NIPSCO's electric properties including common plant allocated to the electric operation and excluding Mitchell, Michigan City Units 2 and 3 and Sugar Creek. In his valuation, Mr. Kelly used the replacement cost less depreciation ("RCNLD") approach. Kelly Direct at 3. To the extent the assets would be constructed today in substantially the same form, Mr. Kelly determined the cost to reproduce the property as it exists today. *Id.* at 8. Where assets would be replaced in a different form, he derived the cost for the functionally-equivalent assets that would be constructed today. *Id.* at 8-9.

To determine the reproduction cost of NIPSCO's property, Mr. Kelly applied cost trend factors to the original costs by vintage for each plant account. The trend factors were developed from the Handy-Whitman Index of Public Utility Construction Costs and other indices. Kelly Direct at 9, 12-15. He then made a downward adjustment to reflect loss in service value due to age and condition of property. *Id.* at 9. As part of this adjustment, Mr. Kelly also considered which assets would be replaced today with functionally-equivalent but different assets. *Id.* For production plant, Mr. Kelly used the cost of a new scrubbed coal facility as the replacement for NIPSCO's existing base load and intermediate load units and a new combustion turbine as the replacement for NIPSCO's hydroelectric and peaking units. *Id.* at 19. The construction and operating and maintenance ("O&M") costs of the alternative facilities were used to determine the physical and functional depreciation of the existing generating facilities. *Id.* at 17-18. For transmission, distribution and general plant, Mr. Kelly determined depreciation by reflecting the average service life, estimated remaining useful life and condition percent for each account. The condition percent was derived from the well-accepted Robley Winfrey tables published by Iowa State University. *Id.* at 20-21, 23. These steps resulted in a RCNLD value of $6,864,797,377. *Id.* at 25.

Mr. Kelly then made an additional adjustment to reflect economic depreciation applicable to the production plant. The economic depreciation amount reflected the results of a valuation of NIPSCO's generation facilities using the discounted cash flow ("DCF") method performed by NIPSCO Witness John J. Reed. Kelly Direct at 25-26. Mr. Reed, Chairman and Chief Executive Officer of Concentric Energy Advisors, Inc., determined the value of the generating assets (excluding Mitchell, Michigan City 2 and 3, and Sugar Creek) by discounting to present value the projected after-tax operating cash flows that would be generated during their remaining useful lives. Reed Direct at 7. Mr. Reed's analysis utilized energy price forecasts for each plant that were developed by Ventyx, a leading provider of electricity modeling services, using a detailed production cost model. *Id.* at 9. Mr. Reed stated this method determines the fair market value of the assets in a free, competitive market which is now possible because of the existence of competitive wholesale power markets. *Id.* at 12-13.

Mr. Reed's analysis also considered forecasted fixed and variable costs based on unit-specific heat rates, fuel costs, emission rates, forecasted capital expenditures (including for emissions reduction technology) and demolition costs. *Id.* at 8, 13, 17, 19. Mr. Reed developed a DCF value for the generation assets of $2.270 billion, an average of $819 per kW. *Id.* at 22. Mr. Kelly reflected the difference between his production plant RCNLD values and Mr. Reed's DCF production plant values as economic depreciation. Kelly Direct at 26-27. The resulting RCNLD value for the entire system, including production plant economic depreciation, is $6.33 billion. *Id.* at 27.

Paul R. Moul, Managing Consultant of the P. Moul & Associates consulting firm, also testified on the fair value of NIPSCO's property. Mr. Moul developed a fair value estimate that considered both the original cost less depreciation and replacement cost less depreciation of NIPSCO's property. Moul Direct at 43. Mr. Moul gave 49.94% weight to replacement cost and 50.05% weight to original cost. These are the ratios of the common equity and non-common equity components of NIPSCO's rate setting capital structure. Mr. Moul stated this method is a compromise approach that is intended to make sure that, at a minimum, the Company gets the benefit of the appreciation in value of its assets to the extent they were financed by the common equity investor. *Id.* For the replacement cost, Mr. Moul used Mr. Kelly's RCNLD value adjusted for economic depreciation to which he added Sugar Creek, deferred charges includible in rate base, the pension plan asset, materials and supplies and production fuel as shown on <u>Petitioner's Exhibit LEM-4</u>, p. 1. *Id.* at 43-44. For the original cost value, Mr. Moul used the original cost rate base as computed on the same exhibit. The result of Mr. Moul's weighting approach was a fair value of $4,733,099,690. *Id.* at 44.

LaPorte Witness Reed W. Cearley raised two specific issues regarding Mr. Kelly's RCNLD valuation. Mr. Cearley is an independent contractor retained by LaPorte as a special utility consultant in this proceeding. Cearley Direct at 1.

Mr. Cearley testified that Mr. Kelly's valuation improperly included $26,431,540 for "Intangible Plant" in his electric plant valuation and $63,185,925 for "Miscellaneous Intangible Plant" in his allocated common plant valuation, citing the part of Mr. Kelly's exhibits that included amounts recorded in Accounts 302 and 303 of the FERC Uniform System of Accounts ("USOA"). Mr. Cearley testified that Ind. Code § 8-1-2-6(b) provides all public utility valuations shall be based upon tangible property. Mr. Cearley therefore recommended that Mr. Kelly's valuation be reduced by $89,617,465 to eliminate intangible property from his valuation. Cearley Direct at 15-16.

Mr. Cearley also expressed his concern that the value of NIPSCO's property for ratemaking purposes and for tax purposes is not consistent. Cearley Direct at 16. Mr. Cearley maintained that, pursuant to Ind. Code § 8-1-2-6(a), the assessed value of NIPSCO's property was relevant to the Commission's determination of the fair value of that property for ratemaking purposes. *Id.* at 17. Mr. Cearley testified that the valuation of NIPSCO's property for tax purposes is significantly less than its valuation for ratemaking purposes and that Mr. Kelly improperly valued NIPSCO's real estate at a greater amount than the assessed value of its land exclusive of improvements valued for taxation. *Id.* at 18. Mr. Cearley concluded that the

Commission should consider the assessed value of NIPSCO's property in determining the fair value of NIPSCO's electric plant in service in this case. *Id.* at 19.

In rebuttal, NIPSCO Witness Miller responded that the intangible assets to which Mr. Cearley referred are software assets. Miller Rebuttal at 55. Ms. Miller said that these assets are properly included in the valuation because they are part of the cost of bringing NIPSCO's property to its present state of efficiency. Ms. Miller stated that she unaware of any Commission orders that have excluded software assets from rate base. *Id.*

(3) Fair Value Determination. NIPSCO presented its RCNLD evidence to support its proposed fair value of NIPSCO's utility plant, and with the exception of Mr. Cearley, no evidence was submitted challenging Petitioner's RCNLD study or its fair valuation methodology. However, as Ms. Odom confirmed on the first day of the hearing, NIPSCO was not seeking a revenue requirement based on fair value, but on original cost. Indeed, NIPSCO's evidence and proposed order presented in this Cause contain its net operating income request based on the original cost of NIPSCO's rate base. Further, NIPSCO did not present evidence of an inflation-adjusted fair rate of return to apply to its proposed fair value, but provided its cost of equity evidence in support of a return on its original cost rate base. While NIPSCO did calculate a fair return in its proposed order, its recommended return was merely used as a comparison to fair returns the Commission found for other electric IOUs. However, as NIPSCO failed to provide any evidence concerning an inflation adjustment to its cost of equity evidence, we find this comparison inappropriate and unnecessary.

The Commission is cognizant of its obligation to make a fair value determination under Indiana Code Section 8-1-2-6. However, it is unclear what purpose a fair value determination has in this Cause given NIPSCO's use of original cost in determining its NOI. The Commission does not engage in such decision-making for academic pursuits, and we do not do so here. A fair value determination is the first step to making the ultimate determination of a fair return using a fair rate of return. If the evidence is insufficient to support a subsequent step of the fair value calculation, the Commission need not proceed with any step of the calculation, and must use the evidence available to determine an appropriate revenue requirement.

Accordingly, although we find that NIPSCO presented evidence that the fair value of NIPSCO's utility property used and useful and in the provision of electric utility service is $4,707,000,000, we give no weight to this valuation in this Cause for purposes of calculating NIPSCO's revenue requirement. We must reach this conclusion given NIPSCO's failure to present evidence concerning the inflation-adjusted fair rate of return to apply to its fair value. Instead, as requested by Petitioner, we use Petitioner's original cost valuation for purposes of ratemaking in this proceeding.

8. Rate of Return.

A. Capital Structure.

(1) Evidence. NIPSCO determined its proposed cost of capital using its actual capital structure as of December 31, 2007 adjusted to (a) exclude $1,168,208 of equity representing accumulated Other Comprehensive Income ("OCI") relating to derivative activity; (b) include $160 million of additional long-term debt issued in June 2008; (c) exclude $795,992 of deferred taxes related to the OCI adjustment; and (d) exclude $10,040,730 of cost free capital

relating to post-retirement benefits other than pensions ("OPEBs") to correct for the erroneous inclusion in medical benefits expense of an amount that should have been reflected as a reduction in the OPEBs accrued liability. Miller Direct at 47-48; Petitioner's Ex. LEM-5 (2nd Revised), p. 2. The OCI adjustment was supported by Mr. Moul who agreed that amount should be removed because it represents cash flow hedges that have no impact on NIPSCO's rate base. Moul Direct at 13-14.

Tyler E. Bolinger, the Director of the OUCC's Electric Division, testified that NIPSCO has a strong balance sheet including an equity ratio of over 60% of its investor-provided capital which compares to an average of 43.5% for the Standard & Poor's ("S&P") utility group. Bolinger Direct at 11-12. He said NiSource, on the other hand, is "a highly leveraged firm facing major challenges attributable to its heavy reliance on debt" and "face[s] significantly higher debt costs relative to similar firms with stronger credit ratings and stronger balance sheets (i.e. lower debt ratios and higher equity ratios)." *Id.* at 11. Mr. Bolinger contended that NIPSCO is burdened by NiSource's weak balance sheet and credit ratings despite NIPSCO's stronger stand-alone profile. *Id.* at 12-13. Mr. Bolinger noted that NIPSCO gets its equity capital and some of its debt capital from NiSource. *Id.* He said NIPSCO's 60% equity ratio impacts NIPSCO's revenue requirement because the cost of equity is higher than the cost of debt. *Id.* at 13. Mr. Bolinger opined that it would be unreasonable and not in the public interest to use NIPSCO's actual capital structure in determining its cost of capital because ratepayers will pay the cost of NIPSCO's strong balance sheet and the cost of NiSource's weak balance sheet. *Id.* at 17. Mr. Bolinger concluded that OUCC Witness J. Randall Woolridge would sponsor a proposal to use a different capital structure. *Id.*

OUCC Witness Woolridge testified that NIPSCO's capital structure, consisting of 60.60% common equity and 39.40% long-term debt, was not appropriate for NIPSCO because it "is significantly out of line with the capital structures of electric utility companies" as represented by the average 2008 common equity ratio of his proxy group which is 46.7%. Woolridge Direct at 16-17. Dr. Woolridge further contended that NiSource's equity and debt ratios "are in-line with those of other electric utilities." *Id.* at 17. Dr. Woolridge proposed that for ratemaking purposes the equity and debt in NIPSCO's capital structure should be adjusted to reflect the mix of equity and debt in NiSource's capital structure as of December 31, 2007 which, he stated, was 52.43% equity and 45.57% debt. Public' Ex. JRW-5, p. 2, Panel C, Col. 1 and 3. He asserted NiSource's capitalization is the one that is used by both NiSource and NIPSCO to attract capital. *Id.* at 18. However, for the non-investor-supplied capital components of the ratemaking capital structure–customer deposits, cost-free capital and investment tax credits–Dr. Woolridge used the weights in NIPSCO's capital structure. *Id.* at 19-20; Public's Ex. JRW-5. He said use of this combination of NiSource weights and NIPSCO weights would reduce NIPSCO's revenue requirement by $29.9 million from what would be produced if NIPSCO's actual capital structure were used. *Id.* at 21.

IG Witness Michael Gorman also recommended use of NiSource's equity and debt ratios. Mr. Gorman contended NIPSCO's affiliation with NiSource has negatively affected its credit rating because NIPSCO has stronger "stand-alone metrics." Gorman Direct at 27-28. He described NiSource as "a very highly leveraged company." *Id.* at 27. Mr. Gorman asserted that NIPSCO's proposed capital structure was not reasonable because credit analysts focus on NiSource's capital structure to evaluate NIPSCO's bond ratings and NIPSCO's capital structure was "excessively expensive." *Id.* at 30. Mr. Gorman said NIPSCO's equity ratio exceeded the proxy group average, the average of 2008 major electric and gas rate decisions and the 5-year average of major electric and gas rate decisions. *Id.* at 33. Mr. Gorman maintained that NIPSCO's debt ratio is lower than what would be acceptable for an investment grade bond rating. *Id.* at 34. Mr. Gorman recommended that for ratemaking purposes the Commission use NiSource's capitalization ratios of 42.4% equity and 57.6% debt. *Id.* at 35. Mr. Gorman's NiSource equity ratio is lower and debt ratio is higher than what Dr. Woolridge used because Mr. Gorman's ratios were as of December 31, 2008 instead of December 31, 2007. Also, Mr. Gorman included NiSource debt maturing within twelve months of December 31, 2008.[1] With respect to the other components of the ratemaking capital structure, Mr. Gorman used the weights in NIPSCO's actual capital structure as of December 31, 2007.[2] Mr. Gorman testified that the NiSource debt ratios were within ranges used by S&P for a business and financial risk profile like NIPSCO's and by Moody's for bond ratings of Baa2 or Baa3. *Id.* at 36. He also described his proposed capital structure as "adequate" for NIPSCO to maintain an investment grade credit rating, financial integrity and access to capital. *Id.* at 9.

In rebuttal, NIPSCO Witness Moul responded that the OUCC and IG propose the use of a hypothetical capital structure that would provide a debt return on a significant portion of NIPSCO's capitalization that is actually common equity. He said this would be inappropriate on many levels. Moul Rebuttal at 3. Mr. Moul stated that if the Commission were to adopt the hypothetical capital structures proposed here, NIPSCO would be faced with either (a) earning significantly less than its allowed return on equity or (b) restructuring its capital structure to align it with the one used for rate-setting purposes by issuing very large amounts of new debt and using the proceeds to pay dividends to its parent company. *Id.* Furthermore, Mr. Moul explained that by using the hypothetical debt ratio in the interest synchronization calculation, the OUCC and IG also create a hypothetical interest expense deduction that decreases the income tax expense component of NIPSCO's revenue requirement. In the case of the OUCC proposal, the shortfall in income tax expense is $7.47 million.[3] Because the tax savings from the hypothetical interest is also purely hypothetical, the effect will be an even greater shortfall in NIPSCO's return on equity. *Id.* at 4. Mr. Moul provided an analysis that showed the OUCC's capital structure proposal would have the effect of reducing Dr. Woolridge's recommended 10.00% cost of equity rate to an equity return of only 8.69%. *Id.* at 4-5; Petitioner's Ex. PRM-R2, p. 2. Mr. Moul testified that the negative impact on NIPSCO would be even greater under Mr. Gorman's proposal as he treated an even larger amount of NIPSCO's common equity as if it were debt. *Id.* at 5.

Mr. Moul stated that to restructure its actual capitalization ratios to match the imputed ratios of the OUCC and IG, NIPSCO would have to issue $299.6 million of additional debt in the case of Dr. Woolridge's proposal and $418.3 million of additional debt in the case of Mr. Gorman's proposal. Then NIPSCO would be required to pay an equivalent amount of dividends. Mr. Moul emphasized issuing such large amounts of new debt will change NIPSCO's actual cost

[1] IG Ex. MPG-3, p. 2, calculates NiSource's equity and debt ratios as of December 31, 2008 and cites the NiSource 2008 SEC Form 10-K at pages 83-84 as the source. Mr. Gorman has increased the long-term debt in his calculated 57.6% debt ratio to include $469.3 million of debt which is excluded from long-term debt on page 84 of Form 10-K and instead included under the category "current liabilities" because it is due within one year. We normally treat debt maturing within 365 days as short-term debt, not long-term debt. *See* Ind. Code § 8-1-2-76, -78. Mr. Gorman's adjustment to treat debt maturing within one year as long-term debt has the effect of inflating the NiSource long-term debt ratio and lowering the NiSource equity ratio.

[2] This can be seen by comparing IG Ex. MPG-3, p. 1, lines 4-6, col. 3 and IG Ex. MPG-1, p. 2, lines 4-6, col. 2.

[3] OUCC Witness Thomas S. Catlin quantifies this amount on Schedule TSC-4, Note 1, to his direct testimony.

of debt, which neither Dr. Woolridge nor Mr. Gorman acknowledge. He remarked that due to the turmoil that presently exists in the credit markets, this is a bad time to be issuing large amounts of debt unnecessarily. Moul Rebuttal at 5-6.

Mr. Moul also criticized the OUCC's and IG's proposals because they would impute to NIPSCO large amounts of NiSource debt that played no role in financing NIPSCO's rate base. Mr. Moul stated that at December 31, 2008, there was $1.5 billion of NiSource debt outstanding that was used to finance the acquisition of Columbia Energy Group ("CEG"), $1.0 billion of NiSource debt outstanding that was used to refinance the debentures of CEG, and $48.5 million of debt outstanding at Bay State Gas Company that was issued prior to its acquisition by NiSource. Mr. Moul testified that none of these debt amounts should play any role in the determination of the capital structure ratios for NIPSCO in this case. Moul Rebuttal at 6-7.

NIPSCO Witness Vincent V. Rea, Assistant Treasurer for NiSource, NFC and NIPSCO, also testified in opposition to the OUCC's and IG's capital structure proposals. Mr. Rea disagreed with Mr. Bolinger's opinion that NiSource was "just barely" investment grade and noted S&P had recently upgraded NiSource's outlook from negative to stable. Rea Rebuttal at 2. He further pointed out that while S&P rated NIPSCO BBB- (the same rating it assigns to NiSource), Moody's and Fitch assigned NIPSCO ratings that are higher than their NiSource ratings (Moody's Baa2 and Fitch BBB). According to Mr. Rea, the higher Moody's and Fitch ratings reflect NIPSCO's superior credit profile compared to NiSource. *Id.* Mr. Rea further commented that Moody's has said NIPSCO would be rated only "slightly higher" than its current rating on a stand-alone or independent basis. *Id.* at 3.

Mr. Rea also disagreed with Mr. Bolinger's statement that NIPSCO is "inextricably linked to NiSource" and pointed out that its relationship banks have informed NIPSCO that the marketplace would treat NIPSCO's debt securities as "structurally senior" to NiSource's debt securities and that a 10-year note offering for NIPSCO would be priced approximately 100 to 125 basis points lower than an equivalent offering by NiSource. Mr. Rea stated that when NIPSCO borrows on an intercompany basis through NFC, it receives rates very similar to those available to it in the external debt markets. Mr. Rea further explained that NIPSCO's financing costs are not exclusively dependent on credit ratings because in recent years, capital market participants have completed their own internal credit analyses to supplement and complement the work of rating agencies. He cited the rapid expansion of the use of pricing levels within the credit default swap market as demonstrating the interest of the financial marketplace in alternatives to credit ratings. Rea Rebuttal at 4-5.

Mr. Rea disputed the assertions by Mr. Bolinger, Dr. Woolridge and Mr. Gorman that NIPSCO gets little or no benefit from its strong equity ratio. He noted the information from relationship banks mentioned above shows otherwise. Despite the fact that S&P rates both companies BBB-, NIPSCO would be able to issue debt on more favorable terms than NiSource. According to Mr. Rea, this shows the marketplace clearly acknowledges NIPSCO's superior credit profile. In addition, Moody's and Fitch recognize this fact by giving NIPSCO a higher credit rating than NiSource. Mr. Rea testified that even on an intercompany basis, NIPSCO's borrowing costs are not dependent on NiSource's financial and capitalization profile. Rea Rebuttal at 5-6.

Finally, Mr. Rea noted that both the OUCC and the Commission found NIPSCO's capitalization ratios to be reasonable in NIPSCO's 2008 financing proceeding, Cause No. 43370.

Id. at 7. NIPSCO's pro forma investor-supplied capitalization ratios in that case were 59% equity and 41% debt which is comparable to the ratios in this case of 60.60% equity and 39.40% debt. Mr. Rea attributed the slight increase in the equity ratio to NIPSCO's continuing commitment to a strong capital structure in light of the Sugar Creek purchase and future capital requirements. *Id.* at 8.

(2) Discussion and Findings. NIPSCO proposes that we determine its cost of capital using its actual capital structure.[4] The OUCC and IG propose that we instead recategorize a substantial amount of NIPSCO common equity as lower cost long-term debt in order to replicate in NIPSCO's capital structure the equity and debt ratios in NiSource's capital structure,[5] which would result in a tax savings that they propose be used to reduce NIPSCO's revenue requirement. Dr. Woolridge, citing to the testimony of Mr. Catlin, indicated that the Company's revenue requirement would be reduced by $29.9 million with his capital structure. Woolridge Direct at 21. Mr. Moul indicated the OUCC's proposal would have the effect of reducing NIPSCO's actual return on equity from the 10.0% recommended by Dr. Woolridge to just 8.69% and that the shortfall under Mr. Gorman's proposal would be even greater.

Hypothetical capital structures such as those proposed here by the OUCC and IG have long been held to be contrary to Indiana law. In *Pub. Service Comm'n of Ind. v. Ind. Bell Tel. Co.*, 235 Ind. 1, 130 N.E.2d 467 (Ind. 1955) ("*Indiana Bell*"), the Indiana Supreme Court reviewed a rate order for a telephone utility (Indiana Bell) which had a 100% equity capital structure but was a subsidiary of a holding company (AT&T) that had a 50% equity and 50% debt capital structure. In the case below, the Commission reduced the utility's rate of return to reflect the parent company's cost of capital and imputed to the Indiana utility tax savings that would exist if its capital structure were two-third equity and one-third debt. 235 Ind. At 29, 130 N.E.2d at 480. The Indiana Supreme Court held the Commission's order was unlawful in both respects. Using the parent company's capital raising ability as the measure of a reasonable return was improper because Indiana Bell was "an Indiana corporation having its own separate identity even though a part of the general Bell System." 235 Ind. at 26, 130 N.E.2d at 479. The Court explained:

> Appellee is an Indiana corporation, a separate and distinct utility as defined by statute and it is the duty of the Commission to establish for it a schedule of rates which will produce a fair and non-confiscatory return upon its used and useful intrastate property, whether its stockholders are one or many, and without regard to its relationship to other companies.
>
> The fact that appellee has not used its own credit with which to raise additional capital is immaterial, and its ability to do so cannot be measured by the yardstick of the ability of the parent company to raise additional capital. The intrastate properties and operations of appellee are the ones to be considered in fixing a fair rate of return upon its used and useful property and not those of the

[4] While NIPSCO's witnesses testified that the Commission approved NIPSCO's capital structure in various financing cases, our determinations in those cases were not approvals of the utility's capital structure, but rather findings that the proposed financing was consistent with the capital structure in place at the time of the financing request.

[5] Mr. Gorman quantifies the dollar amount of his proposed shift in IG Ex. MPG-2 and IG Ex. MPG-3. There, he shows NIPSCO's actual common equity balance of $1,395,245,772 being reduced to $976,944,492, with the difference of $418,301,280 being shifted to long-term debt.

entire Bell System.

> The acts of appellants in considering the cost of money to the parent company, A.T. & T., and the "entire Bell System" rather than considering only the properties and operations of appellee is in violation of [Ind. Code § 8-1-2-6] and is unlawful.

235 Ind. at 28-29, 130 N.E.2d at 480. Similarly, the Court held the imputed tax savings adjustment was arbitrary and unlawful because it assumed "a tax saving under a capital structure which did not exist." 235 Ind. at 29-30, 130 N.E.2d at 480.

The *Indiana Bell* case was soon followed by a second capital structure decision. In *Public Service Commission of Indiana v. City of Indianapolis*, 235 Ind. 70, 131 N.E.2d 308 (Ind. 1956) (*"City of Indianapolis"*), the City, an Intervenor, challenged a Commission order granting a rate increase to Indianapolis Water Company. Among other things, the City argued that the company financed expansion of its system excessively with equity and should have issued preferred stock and bonds. In rejecting this position, our Supreme Court stated: "The statute does not permit the fixing of rates on a hypothesis or a situation never in existence." *Id.*, 235 Ind. at 91, 131 N.E.2d at 317. The Court noted that the City could have petitioned the Commission "for an order compelling the Company to engage in this financing," but noted that no such pleading was ever filed and no such order was ever issued. *Id.*, 235 Ind. at 91, 131 N.E.2d at 316.

Many examples exist of Commission Orders rejecting hypothetical capital structures, including those based on parent company capitalization ratios. *E.g.*, *Pub. Serv. Co. of Ind.*, Cause No. 28364, 37 PUR3d 485, 498-499 (Jan. 31, 1961) (rejecting the Intervenor's argument that the utility should have issued more debt as contrary to the *City of Indianapolis* case); *Ind. Bell Tel. Co.*, Cause No. 36732, p. 7, 1982 Ind. PUC LEXIS 191 at *14-15 (Sept. 7, 1982) (rejecting OUCC's proposal to use the more leveraged and less costly consolidated Bell system capital structure because "the capital structure of Petitioner as it actually exists . . . should be used in determining a fair rate of return for Petitioner"); *Indianapolis Water Co.*, Cause No. 37612, p. 17, 1985 Ind. PUC LEXIS 490 at *38 (March 20, 1985) (rejecting the OUCC's proposal to treat equity as debt because "[w]e cannot, as a matter of law, use this hypothetical capital structure to fix rates in this case"); *Hoosier Gas Corp.*, Cause No. 37541, p. 17, 1985 Ind. PUC LEXIS 522 at *34, 65 PUR4th 463, 475-476 (Feb. 28, 1985) (OUCC's proposal to use a more leveraged "typical" gas utility capital structure for cost of capital and tax expense purposes rejected as contrary to the "the statutes we are sworn to administer"); *N. Ind. Public Serv. Co.*, Cause No. 38045, p. 48, 1987 Ind. PUC LEXIS 180 at *122-123, 85 PUR4th 605, 652 (July 15, 1987) (use of pre-Bailly nuclear plant write-off equity ratio rejected as a hypothetical capital structure); *Terre Haute Gas Corp.*, Cause No. 38515, pp. 27-88, 1989 Ind. PUC LEXIS 113 at *76-78 (OUCC proposal to use a cost of equity that would reach the same result as a "proper" capital structure rejected because "[t]his Commission has consistently held in accord with Indiana law stated above that it cannot use a hypothetical capital structure to fix rates"); *Flowing Wells, Inc.*, Cause No. 38719 U, p. 7, 1989 Ind. PUC LEXIS 310 at *19 (Aug. 30, 1989) (use of parent company's debt-equity ratios rejected); *Ind. Cities Water Corp.*, Cause No. 38851, pp. 9-10, 1990 Ind. PUC LEXIS 229 at *15-16, 115 PUR4th 470, 478 (July 5, 1990) (OUCC's proposal to treat equity as debt and preferred stock at parent company's costs rejected because "artificially rais[ing] the utility's percentage of debt or artificially lower[ing] the utility's cost of equity" is inconsistent with the *Indiana Bell* case and "our guidance [from the Court] could not be clearer").

Here, the Commission finds that NIPSCO's actual capital structure shall be used to determine NIPSCO's cost of capital. Therefore, the Commission will use the capital structure set forth in Petitioner's Exhibit LEM-5 (2nd Revised), p. 1, but adjusted to include the long-term debt amount of $906,631,137 shown on Petitioner's Exhibit VVR-2, p. 1. The adjustment reflects the actual terms of the August 25, 2008 bond remarketing, which are discussed below. Rea Direct at 7.

While we approve NIPSCO's actual capital structure for purposes of determining NIPSCO's weighted cost of capital in this Cause, we note that NIPSCO is approaching the edge of what this Commission finds to be a reasonable capital structure for a large investor-owned electric utility. Going forward, we would encourage NIPSCO to take prudent steps to reduce its equity to debt ratio.

B. Cost of Capital.

(1) Petitioner's Evidence. Ms. Miller calculated NIPSCO's weighted cost of capital to be 8.37%, based on NIPSCO's December 31, 2007 actual capital structure, as adjusted, a debt cost rate of 6.56% and a common equity cost rate of 12.00%. Miller Direct at 44; Petitioner's Ex. LEM-5 (2nd Revised), p. 1. The 6.56% debt cost rate included an estimate of the interest rate and transaction costs that would be incurred in remarketing $254 million of Jasper County tax-exempt bonds. Rea Direct at 7. Mr. Rea testified that the remarketing occurred only four days before NIPSCO's case-in-chief was to be filed and NIPSCO did not have time to revise its case-in-chief to incorporate the actual terms. However, he provided a schedule showing the effect on the amount of debt and the weighted cost of debt when the Jasper County debt cost estimates were trued-up to actual. Id. at 7-8; Petitioner's Ex. VVR-2, p. 1. There was only a minor difference, i.e., $906,631,137 instead of $906,997,137 and 6.52% instead of 6.56%. Dr. Woolridge used the estimated 6.56% debt rate. Public's Ex. JRW-1. Mr. Gorman used the actual amount and rate. IG Ex. MPG-1. Although the impact on NIPSCO's cost of capital is very slight, we find the actual amount and rate shown in Petitioner's Exhibit VVR-2, p. 1, should be used in determining NIPSCO's cost of capital.

NIPSCO proposed a cost of common equity rate of 12.00% through the testimony of Mr. Moul. Mr. Moul considered the risk factors that affect electric utilities in general and NIPSCO in particular. He noted that electric utilities, including NIPSCO, face substantial increases in operating and capital costs due to increasingly stringent environmental regulations including future greenhouse gas regulation. He noted environmental investments increase risk without adding to a utility's generating capacity and this risk is aggravated by the "moving target" nature of evolving environmental regulation. He said NIPSCO's risk profile is strongly influenced by the magnitude of its sales to industrial customers that represent 53% of its sales in kWh but are less than 1% of its customers. Mr. Moul testified that NIPSCO's industrial sales far exceed the utility average. He said 64% of NIPSCO's industrial sales are to steel-related industries that face international competition, increased costs and fluctuating demand for their products. Mr. Moul pointed out that the credit rating agencies have cited Indiana's high level of industrial employment and high concentration of steel, chemical, metals, auto parts and refining businesses as creating risks for NIPSCO. According to Mr. Moul, NIPSCO is exposed to significant sales and bad debt risk because of the magnitude of its industrial load and the reliance of its service area on heavy industry. Moul Direct at 7-8. Mr. Moul also discussed NIPSCO's substantial future capital expenditure requirements and stated a fair rate of return will be key to attracting the capital necessary to meet NIPSCO's needs. *Id.* at 9.

Mr. Moul developed a proxy group of publicly traded utility companies ("Electric Group" or "Group") for use in the models he applied to estimate NIPSCO's cost of equity. These companies are all included in Value Line Investment Survey ("Value Line"), have electric utility subsidiaries that are Midwest ISO members or formerly had transmission assets that were transferred to separate Midwest ISO-participating transmission companies, have not recently reduced their common dividend and are not the target of a merger or acquisition. Moul Direct at 4; Petitioner's Ex. PRM-2, p. 7. Mr. Moul then compared NIPSCO and the Group with respect to nine separate risk factors. He concluded that on some counts NIPSCO's risk is higher than the Group and on other counts lower or approximately equal. On balance, he considered the factors to average out so that, in Mr. Moul's opinion, the Group provides a reasonable basis for measuring NIPSCO's cost of equity.

Mr. Moul first applied the discounted cash flow approach. This model considers the cost of equity to be equal to a stock's dividend yield plus expected long-term growth. In applying the model, Mr. Moul used a divided yield of 4.54% based on the average dividend yield for the Electric Group for the six months ended May 2008 adjusted to a forward-looking basis using three generally accepted methods to reflect the prospective nature of dividends. Mr. Moul used a growth rate of 6.50% after analyzing historical and forecasted per share growth in earnings, dividends, book value and cash flow for the members of the Electric Group. Mr. Moul gave the greatest emphasis to projected earnings per share ("EPS") growth because he considered it to be the principal focus of investor expectations. Moul Direct at 18-19.

Mr. Moul said the historical rates were not good measures for the Electric Group because they include many negative rates of change that provide no reliable guide to gauge investor expectation of future growth. He explained rational investors expect positive returns on their investments. Moul Direct at 22. Mr. Moul commented that Professor Myron Gordon, the foremost proponent of the use of the DCF model in rate cases, concluded EPS forecasts were the best measure of the DCF growth rate. *Id.* at 25. Mr. Moul added a flotation cost adjustment of 0.17% to cover issuance expenses. *Id.* at 28; Petitioner's Ex. PRM-1, Appendix E. To support the flotation cost adjustment, Mr. Moul provided issuance expenses in public offerings of electric utility stocks from 2003 to 2007. Petitioner's Ex. PRM-2, p. 14, Sch. 8. The result of Mr. Moul's DCF analysis was a cost of equity rate of 11.21%, i.e., 4.54% + 6.50% + 0.17. *Id.*

Mr. Moul also performed a risk premium analysis. This method determines the cost of equity by adding a premium to corporate bond yields to account for the fact that the equity investor is exposed to greater risk than debt capital. Moul Direct at 28-29. In this approach, Mr. Moul used a 6.00% estimate of the prospective yield on long-term A-rated public utility bonds. The 6.00% yield was based on consensus forecasts of 30-year treasury bond yields reported in Blue Chip Financial Forecasts ("Blue Chip") plus 1.50% representing the spread between returns on utility bonds and treasury bonds during recent three month, six month and twelve month periods. *Id.* at 30. Mr. Moul developed a 5.50% equity risk premium by first comparing the difference in market returns on utility stocks in the S&P Public Utility Index and market returns on utility bonds during four different historical time periods, each of which began with a financial market defining event. Mr. Moul then made a downward adjustment for the risk differences between the S&P Public Utility Index and his Electric Group. *Id.* at 32-33. He then added the 0.17% flotation cost adjustment to derive a risk premium result of 11.67, i.e., 6.00% + 5.50% + 0.17%. Moul Direct at 34.

Mr. Moul also applied the Capital Asset Pricing Model ("CAPM") approach which measures the cost of equity as the yield on a risk-free interest bearing obligation plus an equity risk premium proportional to the non-diversifiable or systematic risk of an investment. Moul Direct at 34; Petitioner's Ex. PRM-1, Appendix H, p. H-1. Mr. Moul used a 4.50% risk-free rate based on recent historical yields on long-term treasury bonds, Blue Chip forecasts and the recent trend. *Id.* at 35-36. In the CAPM, systematic risk is represented by a company's beta which measures how the stock price changes compared to the overall market. Mr. Moul used a beta of 0.85 which is the average of the Value Line betas for the companies in the Electric Group. *Id.* at 35. Mr. Moul selected a market premium of 8.44% by averaging the difference between (a) historical market returns and treasury bond returns (6.5%) and (b) the difference between forecasted market returns and treasury bond returns (10.37%). The historical market premium was derived from data published by Ibbotson Associates in Stocks, Bonds, Bills and Inflation Yearbook ("SBBI") for the period 1926-2007. Mr. Moul said arithmetic mean returns were used because the CAPM is a single period model. He quoted an explanation from SBBI as to why arithmetic returns must be used. Petitioner's Ex. PRM-1, Appendix H, p. H-6. Mr. Moul added a size premium of 0.92% to adjust for the size of the Electric Group. This adjustment reflects the size premium for mid-capitalization stocks published in SBBI. He also added the 0.17% flotation cost adjustment. These inputs produced a CAPM result of 12.76%, i.e., 4.50% + (0.85 × 8.44%) + 0.92% + 0.17%.

Mr. Moul also pointed out that in *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923), the United States Supreme Court held a public utility is entitled to rates that will permit it to earn a return on the value of its property equal to that generally being made on investments in other business undertakings which are attended by corresponding risks. Therefore, Mr. Moul testified, it is important to identify the returns earned by comparable risk companies that compete for capital with the public utility and are subject to competitive marketplace forces. Moul Direct at 38-39. To implement this approach, Mr. Moul applied the following screening criteria to identify non-utility companies followed by Value Line that reflect the risk of the Electric Group – Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Betas and Technical Rank. *Id.* at 39. Mr. Moul considered a ten year business cycle for these firms consisting of five historical years and five projected years. The historical return on equity of 15.4% and the projected return on equity of 16.0% were averaged to produce a Comparable Earnings result of 15.70%. *Id.* at 40-41.

Mr. Moul then considered the results of each of his approaches to analyzing NIPSCO's cost of equity. He recommended that the Commission find a cost of common equity for NIPSCO of 12.00% to be reasonable. He explained that the average of the DCF and CAPM results were 11.99%, the average of the three market models (DCF, CAPM and Risk Premium) was 11.88% and the average of all four methods was 12.84%. Moul Direct at 6. Mr. Moul said his proposed 12.00% cost of equity made no provision for the prospect that the rate of return may not be achieved due to unforeseen events such as unexpected spikes in costs, abrupt changes in customer usage and abnormal weather. *Id.*

(2) OUCC's Evidence. Dr. Woolridge testified in support of the OUCC's recommendation that the Commission find NIPSCO's cost of common equity to be 10.00%. Dr. Woolridge first discussed the effect of the current financial crisis on the difference

in yields on treasury bonds and utility bonds, noting that the differential increased significantly due to tightening credit markets and the flight to quality that drove treasury yields to historic lows. But he stated the differential has declined over the past several months. Woolridge Direct at 7. Dr. Woolridge recognized that the credit market for corporate and utility debt experienced higher rates due to the credit crisis and that the long-term market remains tight, but he said the market has improved in response to unprecedented actions by the federal government. Id. at 10-11. Dr. Woolridge expressed his opinion that the Obama administration is committed to bringing the economy around, utilities are likely to benefit under an Obama administration, the worst of the credit crisis appears to be over and credit spreads, while still high, have declined. Id. at 11-12. Dr. Woolridge asserted his viewpoint that the volatility of stocks relative to bonds has declined recently and relied on an article authored by employees of McKinsey & Co., a consulting firm, expressing the opinion that the financial crisis has not significantly changed McKinsey's long-term estimate of the equity risk premium.[6] Id. at 12-14. Dr. Woolridge also believed utility stocks have held up well compared to the overall market. Id. at 15.

Dr. Woolridge used two market-based models to estimate NIPSCO's cost of equity – a DCF model and a CAPM. To apply these models, he selected a nine member Electric Proxy Group consisting of companies that are listed as an electric utility or combination electric and gas company by AUS Utility Reports, listed as an electric utility by Value Line, have at least 75% regulated electric revenues, have operating revenues less than $10 billion, have a 3-year history of paying dividends with no actual or pending cuts, and have an investment grade bond rating. Woolridge Direct at 15-16.

Before applying his models, Dr. Woolridge testified that in equilibrium the market value of a firm's securities will be equal to book value and that when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of book value. Woolridge Direct at 23-24. In support, he cited a 1988 article by the founder of consulting firm Marakon Associates that said the value of a company is determined by its cash flow which is in turn affected by its return on equity and a 1987 Harvard Business School case study which concluded higher returns on equity provide higher market-to-book ratios. *Id.* 23-24.

Dr. Woolridge said he relies primarily on the DCF model to estimate the cost of equity capital. Woolridge Direct at 29. In his DCF analysis, he used a dividend yield of 5.4% which is the mid-point of the proxy group average for the six months ending April 2009 and the proxy group average in April 2009, adjusted for one-half year of expected growth. *Id.* at 33; Public's Ex. JRW-10, p. 1. Dr. Woolridge selected a growth rate of 5.0% after considering historical growth rates for the proxy companies in EPS, dividends per share ("DPS") and book value per share ("BVPS") as measured by both means and medians. He also considered Value Line's projections of EPS, DPS and BVPS, projected internal growth rates calculated by Dr. Woolridge from Value Line's projected retention rate and return on equity, and analyst EPS growth rate forecasts. *Id.* at 36-38. However, he discounted the analyst forecasts because of his belief that

[6] Dr. Woolridge referred to this document as a study. A review of his workpapers shows he relies upon a 5 ½ page document on a McKinsey website expressing the subjective opinion that "there is no evidence of a substantial increase in the cost of long-term capital" but which acknowledges: "we cannot be certain that its cost will not increase over the next several years as the recession develops," cash flow "uncertainty has increased significantly," and "[i]t is particularly unclear what a normal level of growth and returns on capital will be in the future." *Id.* at pp. 5, 6.

they have an upward bias. *Id.* at 39. His DCF result was a common equity cost rate for NIPSCO of 10.4%, i.e., 5.4% + 5.0%.

In his CAPM, Dr. Woolridge used a risk free rate of 4.00% which was the upper end of the range of yields in 10-year and 20-year treasury bonds that he thought was reasonable for the near future. *Id.* at 43. He used a beta of 0.68 which was his proxy group average. *Id.* at 44; Public's Ex. JRW-11, p. 3. Dr. Woolridge used an equity risk premium of 4.61%. He stated that the "traditional way" to measure the equity risk premium was to use the difference between historical average stock and bond returns. This approach, Dr. Woolridge said, is often called the "Ibbotson approach" after Professor Roger Ibbotson, and usually suggests an equity risk premium of 5%-7% above the long-term treasury bond rate. *Id.* at 45. Dr. Woolridge asserted that some academic studies using "ex ante models" and "puzzle research" compute lower expected returns using market data without regard to historical returns. *Id.* at 46-48. According to Dr. Woolridge, the historical returns are "biased upwards" because "the expected equity risk premium has declined [as] stock prices have risen." *Id.* at 48. Dr. Woolridge's equity risk premium of 4.61% is an average of four different averages: (a) seven historical studies for periods beginning as early as 1872, most with both arithmetic results and geometric results included in the average; (b) 25 ex ante puzzle research studies, many with multiple low, high and midpoint results, published between 1999 and 2009; (c) four surveys of forecasters, Chief Financial Officers and academics; and (d) two estimates using the "building blocks" methodology, one of which was performed by Dr. Woolridge for this case. Public's Ex. JRW-11, p. 5. Dr. Woolridge's building blocks calculation derived an expected equity return for the market of 7.90% by adding a real growth rate of 2.50%, a dividend yield of 3.00% and an inflation rate 2.40%. Public's Ex. JRW-11, p. 7. Dr. Woolridge then deducted a recent 30-year treasury yield rate of 3.83% to derive an equity risk premium of 4.07%. *Id.* at 55-56. However, this is but one of 83 percentages included in the averages and averages of averages used to compute his 4.61% equity risk premium. Public's Ex. JRW-11, p. 5. Using the equity risk premium of 4.61%, Dr. Woolridge computed a CAPM result of 7.1%, i.e., 4.00% + (0.68 × 4.61%).

Although his calculated range was 7.1%-10.4%, Dr. Woolridge recommended an equity cost rate of 10.0% for NIPSCO, stating that the upper end of the range should be used due to the current volatile capital market conditions. Woolridge Direct at 59.

Dr. Woolridge also discussed his disagreements with Mr. Moul's testimony. With respect to the proxy group, Dr. Woolridge said Mr. Moul's Electric Group companies were not particularly good proxies for NIPSCO because five were combination gas and electric companies with an average only 57% of revenues from electric operations. He cited Avista, CMS, Integrys, NiSource and Vectren as companies with substantial gas operations. He also said Mr. Moul's group had lower common equity ratios and higher coefficients of variation of earned returns on common equity than NIPSCO. Woolridge Direct at 63-64.

With respect to Mr. Moul's DCF analysis, Dr. Woolridge criticized Mr. Moul's adjustment to state the dividend yield on a forward-looking basis by compounding quarterly dividends to the end of the year. Dr. Woolridge argued that compounding should not be used because the investor has the option of reinvesting the dividends as he or she chooses. Woolridge Direct at 66. Dr. Woolridge also criticized Mr. Moul's 6.50% growth rate on the ground that it gave too much weight to analysts' forecasts of EPS growth. Dr. Woolridge contended analysts' forecasts are overly optimistic and biased upwards. Dr. Woolridge said this was demonstrated by a comparison he made of forecast and actual EPS growth rates since 1988 for the companies in the I/B/E/S data base. *Id.* at 68. Dr. Woolridge maintained that his findings indicated forecast errors for the long-term estimates were predominately positive which he interpreted as showing upward bias. *Id.* at 69. Although he recognized that analysts' EPS growth rate forecasts have subsided somewhat since 2000 and new regulations against conflicts of interest were adopted in 2003, in Dr. Woolridge's opinion, analysts' forecasts continue to be overly optimistic. *Id.* at 70. In support, he cited two Wall Street Journal articles, one of which reported on Dr. Woolridge's opinions about Wall Street analysts. *Id.* at 70-71; Public's Ex. JRW-13, p. 4. Dr. Woolridge testified that the upward bias is not as pronounced for electric utility companies but, in his opinion, analysts' projected electric growth rates still exceed the actual rates. *Id.* at 71-72. Dr. Woolridge also believes Value Line is upwardly biased which he attributed to its reluctance to forecast negative growth rates. *Id.* at 73.

Dr. Woolridge also opposed Mr. Moul's flotation cost adjustment on a variety of grounds: the Company has not identified any flotation costs; investors are not entitled to flotation costs when market prices exceed book value; underwriting spreads need not be recovered through the regulatory process; and brokerage fees that investors pay in secondary market transaction are not included in the DCF analysis. Woolridge Direct at 73-75.

Dr. Woolridge opposed Mr. Moul's use of a risk premium analysis because utility bonds are subject to interest rate risk and credit risk which do not apply to equity investors. *Id.* at 76. He reiterated his position discussed above that risk premiums based on historical returns are overstated. *Id.* at 77. He also contended historical bond returns were biased downward because of capital losses; geometric means only should be used; investors could not achieve the historical market returns because of transaction costs and without rebalancing their portfolios every month; stock index returns are affected by survivorship bias and the "Peso Problem" (less disruption in U.S. markets than other markets around the world); and market conditions today are different than in the past which has resulted in a decrease in the equity premium over bond yields. *Id.* at 78-87.

With respect to Mr. Moul's CAPM, Dr. Woolridge contended Mr. Moul's risk-free rate was overstated. He objected to the consideration of historic risk premiums for reasons previously mentioned. He also criticized Mr. Moul's prospective risk premium because of its reliance on forecasts of EPS growth by analysts and by Value Line (both of which Dr. Woolridge deems to be upwardly biased), because Mr. Moul considered only dividend-paying stocks and because the stocks are weighted equally. Woolridge Direct at 89-92. He said Mr. Moul's use of an 11.29% growth rate in his calculation of the prospective equity risk premium is excessive because it exceeds the historical nominal growth rate in gross domestic product ("GDP") of 7.20%. *Id.* at 93. Dr. Woolridge also asserted Mr. Moul's size adjustment is inappropriate for regulated electric utilities. *Id.* at 95-96.

Dr. Woolridge disagreed with Mr. Moul's Comparable Earnings analysis on the basis that it did not measure long-term earnings expectations. *Id.* at 97.

(3) IG's Evidence. IG Witness Michael Gorman used multiple methods to estimate NIPSCO's cost of common equity–three different versions of the DCF model, two versions of the Risk Premium model, and the CAPM. In applying his models, he used the same proxy group as Mr. Moul. Mr. Gorman recommended that the Commission find

that NIPSCO's cost of common equity is 10.3% with a capital structure that uses NiSource's capitalization ratios and 9.8% with NIPSCO's actual capital structure.

Mr. Gorman first used a constant growth DCF model with a dividend yield of 5.93% and a growth rate of 6.00% resulting in a cost of equity estimate of 11.77%. The dividend yield was calculated from average stock prices during the 13-week period ended March 13, 2009 and annualized dividends adjusted for next year's growth. Gorman Direct at 40-41. The growth rate came from security analysts' earnings growth forecasts available on March 17, 2009. *Id.* at 42. Mr. Gorman testified that analysts' forecasts have been shown to be more accurate predictors of future returns than growth rates derived from historical data and influence stock observable prices more than historical data. *Id.* at 41-42. The average forecast growth rate for the proxy group was 8.99%. *Id.* at 43. However, Mr. Gorman believed this growth rate was too high and substituted a 6.00% growth rate, which was the median of the proxy group growth rates. He said use of this lower growth rate was appropriate because it excluded the impact of the two highest growth rates (Empire District and Integrys) and was more consistent with consensus projections of GDP growth that he believed should be a "ceiling" on a utility's growth rate. *Id.* at 44. He said economists expect GDP growth over the next five to ten years of no more than 5.1%. *Id.* at 43. In support of his position that there should be a GDP growth ceiling on a utility's growth rate, Mr. Gorman cited the 2007 edition of the Brigham and Houston text, Fundamentals of Financial Management. *Id.* at 45. During cross-examination, Mr. Gorman stated he deleted from the quote in his testimony a statement by the authors on a GDP growth basis one might expect the dividends of an average or normal company to grow at a rate of 5% to 8% a year. Tr. at DD-80. Mr. Gorman said he deleted this statement because it was based on outdated information, and he did not believe the authors would have that same view today. Tr. at DD-80–DD-82.

Mr. Gorman also contended that even after substituting the lower median for the average, the 6.00% growth rate was not sustainable. Therefore, he performed a second DCF calculation using a growth rate of 4.21% which he said was the sustainable growth rate.[7] This rate was based on Value Line projections of returns on equity, payout ratios and earnings retention. *Id.* at 47. The result of the "sustainable growth" DCF model was 10.13%.

Mr. Gorman also performed a third DCF calculation that used decreasing growth rates for (a) the first five-years, (b) the next five-years and (c) year 11 through perpetuity. *Id.* at 48. The rates used in the first stage were the analysts' forecasts described above; the rates used in the second stage represented the difference between the analysts' forecasts and the Blue Chip 5 to 10 year GDP growth projection of 5.1%; and the rate used in the third stage (year 11 forward) was the 5.1% GDP growth estimate. Gorman Direct at 49. The result of the multi-stage DCF model was 11.23%. *Id.* at 50.

For his ultimate DCF recommendation, Mr. Gorman averaged his sustainable growth and multi-stage DCF results (10.13% and 11.23%) and rounded the average up to 10.70%. *Id.* at 50.

In his Risk Premium models, Mr. Gorman calculated the difference between regulatory commission-authorized returns for electric utilities in each year since 1988 as reported by

[7] Mr. Gorman's testimony states that he used a 4.21% sustainable growth rate to derive a 10.13% DCF result. Gorman Direct at 48. However, IG Ex. MPG-13 appears to show that a growth rate of only 3.77% was used in the 10.13% calculation.

Regulatory Research Associates and average yields on treasury bonds and A-rated utility bonds in each of those same years. This method produced an average risk premium over treasury bonds of 5.10% and over A-rated utility bonds of 3.68%. IG Ex. MPG-16; IG Ex. MPG-17. Mr. Gorman then selected ranges of 4.40% to 6.01% for the treasury spread and 3.03% to 4.39% for the utility bond spread by focusing on where most of the annual results fell. Gorman Direct at 52. Mr. Gorman then added the treasury risk premium range to a projected treasury bond yield of 4.30% and the utility bond risk premium range to a current 13-week average yield on A-rated and Baa-rated utility bonds of 7.85%. From these results, Mr. Gorman recommended a 9.91% rate for the treasury bonds analysis (a rate between the mid-point and high end of his range) and a rate of 10.40% for the utility bond analysis (the low end of his range). *Id.* at 54-55. Mr. Gorman said he used the low end of the utility bond range to reflect his belief that yields would decline to more normal levels once economic conditions strengthen. *Id.* at 55.

In his CAPM, Mr. Gorman used a 4.30% risk-free rate based upon a Blue Chip projected treasury bond yield and a beta of 0.73 based on the average of the Value Line proxy group beta estimates. Gorman Direct at 56, 57. Mr. Gorman derived a forward looking market risk premium of 7.00% and a historical market risk premium of 6.50%. *Id.* at 58. The forward looking premium was determined by subtracting the 4.30% risk-free rate from Mr. Gorman's estimate of the expected return on the S&P 500 Index which was calculated by adding an estimated inflation rate of 2.1% to the long-term historical arithmetic average real return on the market as reported in the Valuation Edition of SBBI. Mr. Gorman's CAPM results are 9.05% to 9.41% with a midpoint of 9.20%. *Id.* at 60.

Based on the results of all of his analyses, Mr. Gorman recommended a return on equity range of 9.80% to 10.70% with the low end being the average of his risk Premium and CAPM results and the upper end being his DCF result. Gorman Direct at 61. He testified that if NIPSCO's actual capital structure was used (as proposed by NIPSCO), he recommended 9.80%, the low end of the range, because there is less financial risk. But if his proposed NiSource capital structure is used, he recommended 10.30%, the midpoint of his range. *Id.* Mr. Gorman contended his recommendations would support investment grade credit ratings under S&P's credit metric benchmarks. *Id.* at 62. However, he acknowledged S&P's new credit metrics are not as transparent as its former metrics and do not clearly identify utility-specific credit metric guidance ranges based on its business risk assessment. *Id.* at 62.

Mr. Gorman also commented on Mr. Moul's testimony. He said Mr. Moul's DCF growth rate of 6.50% was too high to be sustainable in the long run. Mr. Gorman asserted academics have found, and investors understand, long-term sustainable growth cannot exceed GDP growth over sustained periods of time. Gorman Direct at 74-75. Mr. Gorman argued the financial risk of a utility is based on book value leverage, not market value leverage, and analysts do not consider market value leverage to be of significance. *Id.* at 71. He said Mr. Moul's flotation cost adjustment was not appropriate because it was not based on NIPSCO's actual expenses. *Id.* at 73.

Mr. Gorman disputed the 5.50% risk premium used by Mr. Moul in the Risk Premium approach on the ground it was not based on observable and verifiable market evidence of NIPSCO's risk as compared to the proxy group. *Id.* at 77.

Mr. Gorman also objected to Mr. Moul's size adjustment in the CAPM. According to Mr. Gorman, a size adjustment is not proper because the SBBI mid-cap deciles used in the adjustment include stocks with an average beta of 1.12 which is higher than the proxy group. *Id.* at 79. Mr. Gorman concurred with Mr. Moul's historical market risk premium of 6.50% but considered his prospective market risk premium of 10.37% to be excessive because the Value Line and S&P growth used by Mr. Moul project growth in excess of GDP growth.

Finally, Mr. Gorman disagreed with Mr. Moul's Comparable Earnings analysis on the grounds that it measures book returns instead of market required returns and includes non-regulated companies not comparable to NIPSCO. *Id.* at 82.

(4) Petitioner's Rebuttal Evidence. Mr. Moul responded to Dr. Woolridge's discussion of the credit crisis. Mr. Moul said that in response to the credit crisis investors have become more risk adverse thereby increasing their required return. He explained that market volatility is much higher than it was prior to the beginning of the financial crisis and yield spreads and debt costs have increased. Mr. Moul testified attracting capital would be more difficult for NIPSCO if the Commission accepted the returns proposed by Dr. Woolridge and Mr. Gorman. Moul Rebuttal at 8-11. Mr. Moul also provided updates of this cost of equity models using the latest information available. His updated results were as follows:

	Direct Testimony	Update
DCF	11.21%	12.62%
RP	11.67%	12.44%
CAPM	12.76%	11.24%
Comparable Earnings	15.70%	14.30%
Average	12.84%	12.65%
Median	12.22%	12.53%
Mid-point	13.46%	12.77%

Id. at 12. He said the DCF and Risk Premium results increased because of increasing dividend yields and widening spreads over treasury yields. The CAPM result declined due to lower betas and a reduction in the market premium. The Comparable Earnings result was lower because of the recession. Because the average of the market-based models is 12.10% and the average of the DCF and CAPM methods is 11.93%, Mr. Moul concluded a rate of return of no less than 12.00% is still reasonable. Id. at 12-13.

Mr. Moul criticized Dr. Woolridge's proxy group because the companies have few characteristics that are comparable to NIPSCO. He said Dr. Woolridge should have considered combination companies and should not have included companies with speculative bond ratings, delivery-only utilities and utilities with significant hydro generation. Moul Rebuttal at 14-15.

Mr. Moul described Dr. Woolridge's criticism of Mr. Moul's quarterly compounding method of determining the dividend yield in the DCF as a "tempest in a teapot" because Dr. Woolridge's method produces precisely the same result. Moul Rebuttal at 16. However, for purposes of his rebuttal, Mr. Moul used Dr. Woolridge's method in his rebuttal updates. Id.

Mr. Moul reaffirmed his position that analysts' forecasts of EPS growth are the best measure of growth in the DCF model and should be given primary weight. He said they are the primary determinant of investor expectations. Moul Rebuttal at 16-17.

Mr. Moul noted that the results of Mr. Gorman's constant growth DCF model (the form previously used by this Commission) and Mr. Gorman's multi-stage model are both well above 11%. Moul Rebuttal at 17-18. He cited eight factors that contribute to investors' expectations of earnings growth that are not considered by Mr. Gorman's "sustainable" or "retention growth" model which only considers book value changes and accretion from the sale of stock. Id. at 18. Mr. Moul asserted BVPS growth, or its surrogate retention growth, does not represent a proper financial variable because utility stocks typically do not trade at book value. Id. at 8-19. Mr. Moul also said Mr. Gorman relies on projections not shown to be sustainable beyond the identified periods and has not provided recognition of transition growth through 2012 and growth beyond 2014. Id. at 19. Further, Mr. Gorman's result is entirely dependent upon his assumed return on equity of 10.15%. According to Mr. Moul, that is like having to know the end result in order to calculate it. Id. at 20.

Mr. Moul testified that Mr. Gorman has been inconsistent in his use of the multi-stage DCF model, citing cases since 2001 where Mr. Gorman used the model and others where he did not. Mr. Moul rejected Mr. Gorman's opinion that analysts' earnings forecasts cannot be reasonable estimates when in excess of current 5 and 10 years forecasts of GDP growth. Mr. Moul said Mr. Gorman has not shown any cause and effect relationship or linkage of these variables. Mr. Moul said one could as easily assume dividend growth and GDP growth understate investors' expectations of proxy group growth, thereby showing the need to use analysts' forecasts. Id. at 19-22.

Mr. Moul testified GDP growth is not the sole determinant of earnings growth. He described GDP as having a "product side" and an "income side," both of which are made up of many components. He contrasted Mr. Gorman's 5.1% GDP growth rate with Value Line's Industrial Composite earnings growth forecast of 6.5% and Blue Chip's forecasts of growth in pre-tax profits of 7.0% for 2011-2015 and 5.5% for 2016-2020. Mr. Moul said this showed future corporate profit growth will exceed GDP growth which has also been true historically. Moul Rebuttal at 22-23. Mr. Moul also pointed out FERC has rejected use of a two-stage DCF model for electric companies because objective measures showed electric companies do not display growth characteristics that fit a multi-stage model. Id. at 23. While FERC does use a two-stage model for natural gas pipelines, Mr. Moul showed that the FERC approach, if followed here, would raise Mr. Gorman's median result to 11.44% and his group average to 13.74%. Id. at 24.

Mr. Moul disputed Dr. Woolridge's contention that analysts' forecasts of EPS growth are biased. He considered Dr. Woolridge's opinions out-of-date because of the 2003 final judgment in the Global Research Analyst Settlement required Wall Street firms to separate their research and investment banking services. Moul Rebuttal at 25. Mr. Moul also considered Dr. Woolridge's position on analyst bias to be inconsistent with his DCF model which uses analysts' forecasts (Public's Ex. JRW-10, pp. 4 and 5) and Dr. Woolridge's reliance on the Claus and Thomas study that measures expected cash flow by using analysts' forecasts (Woolridge Direct at 25-26). Finally, Mr. Moul testified that regardless of what Dr. Woolridge thinks about their accuracy, analysts' forecasts are what investors actually use in their decisions to buy, sell or hold stocks. Id. at 26. Even if there were bias suggesting a downward adjustment might be appropriate, stock prices would likewise require a downward adjustment because the growth rate must be synchronized with the price investors establish when valuing a stock. Id. at 26.

Mr. Moul criticized Dr. Woolridge's use of Value Line DPS forecasts in determining the DCF growth rate. Mr. Moul said the low DPS growth rates are attributable to Value Line's forecast of declining dividend payout ratios for Dr. Woolridge's proxy companies. Moul Rebuttal at 26. With respect to Dr. Woolridge's reliance on historical growth rates, Mr. Moul said analysts consider historical growth rates in the process of developing forecasted growth rates to assess how the future may diverge from historical practices. Id. at 27. Mr. Moul disagreed with the retention ratios of Dr. Woolridge and Mr. Gorman because they did not convert year-end book values to average book values in determining the return on equity. Mr. Moul said this causes an understatement of retention growth and that FERC requires this adjustment. Id. at 28-29. Mr. Moul testified Dr. Woolridge's and Mr. Gorman's retention growth calculations have an additional downward bias because they ignore future growth from external stock financing. Id. at 29.

Mr. Moul testified the analysts' forecasts of EPS growth for Dr. Woolridge's proxy companies average 6.52% and, if this rate of growth is used in Dr. Woolridge's DCF model, the result is an common equity cost rate of 11.99%. Moul Rebuttal at 29-30.

Mr. Moul said a flotation cost adjustment is appropriate because Value Line forecasts show the utilities will be issuing new common stock in the future and that has been historically true. Moul Rebuttal at 30. Mr. Moul stated flotation costs must be considered because only stock sale proceeds net of the underwriting spread and out-of-pocket expenses are available for utility investments. Id.

Mr. Moul criticized Dr. Woolridge for not using the Risk Premium method because it considers a company's own borrowing rate. Moreover, the Risk Premium approach considers additional risk, which is not reflected in the beta measure of systematic risk. Moul Rebuttal at 31. Mr. Moul believed this method was particularly pertinent today because of the credit crisis, which has significantly affected utility debt costs. Id. at 31-32. While Mr. Gorman used the Risk Premium method, his use of regulatory authorized returns to determine the risk premium is of limited usefulness because it reflects an arbitrary time period beginning in 1986. Id. at 32. Mr. Moul showed Mr. Gorman's premiums would be substantially higher if authorized returns since 1999 or 2004 were used. Id. Mr. Moul also said Mr. Gorman's approach was deficient because it mixed book equity returns with market-determined bond yields; does not synchronize the rate orders with the time of the evidentiary record (creating a potential time period mismatch); authorized returns do not necessarily reflect investor-required returns because they can be influenced by policy, political factors and regulatory practices; and past authorized returns do not reflect the risks faced by electric utilities today. Id. at 32-33.

Mr. Moul disagreed with each of the reasons Dr. Woolridge raised against the Risk Premium method. Mr. Moul also elaborated on the justification for using arithmetic means in the Risk Premium method. Moul Rebuttal at 34-38.

With respect to Dr. Woolridge's opinion that the risk return relationship that existed in the past no longer applies today, Mr. Moul provided a graph showing the historical performance of the Chicago Board of Options Exchange Volatility Index ("VIX") since 1990. Moul Rebuttal at 39-40. Because the volatility of the market is higher today (as shown by the VIX), Mr. Moul concluded there has been no shrinkage in the equity risk premium. Id. at 41.

Although Mr. Moul agreed with the historical equity risk premium used by Mr. Gorman in the CAPM, he criticized Mr. Gorman for failing to also consider a prospective premium that reflected expected future market returns. Moul Rebuttal at 41. Mr. Moul criticized both Mr. Gorman and Dr. Woolridge for failing to include a size adjustment in their CAPM calculations. Mr. Moul described Dr. Woolridge's 7.1% CAPM result as "simply not credible" as evidenced by the fact that it is lower than the May 2009 Baa-rated utility bond yield of 7.76%. Id. at 42. He said Dr. Woolridge's CAPM assumes an expected market return of only 7.90% (Woolridge Direct at 54, l. 8), which is totally unrealistic as shown by Value Line's Industrial Composite forecasts. Id. at 43. Because Dr. Woolridge computes a DCF return for his proxy group of 10.4%, Mr. Moul said it is not possible for the total market return to be only 7.9%. Id. at 44.

With respect to the size adjustment, Mr. Moul testified that, contrary to Dr. Woolridge's opinion, the beta of the SBBI mid-cap decile provides no basis to reject the adjustment. He opined the Wong article relied on by Dr. Woolridge is not relevant because it relies on data going back to the 1960s when the utility business was fundamentally different. He cited the famous Fama/French study as identifying size as a separate risk factor not compensated for by the beta. Moul Rebuttal at 44-45.

Mr. Moul defended his Comparable Earnings analysis on the ground that it was supported by the underlying premise of rate regulation and was consistent with the views of the financial community that the regulatory process must consider returns achieved by the non-regulated sector to ensure regulated companies can compete effectively in the capital markets. Moul Rebuttal at 46. He noted investors would not be motivated by an opportunity to earn a 10% return for NIPSCO when they could obtain higher returns on alternative investment opportunities of equal risk. Id. at 46. Mr. Moul disputed Dr. Woolridge's contention that low cost of equity rates can be justified because market-to-book ratios typically exceed 1.0. Id. at 46-47.

(5) Discussion and Findings. The record contains a number of different methods of estimating NIPSCO's cost of common equity. We recognize the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment. Due to this lack of precision, the use of multiple methods is desirable because no single method will produce the most reasonable result under all conditions and circumstances.

In summary, the parties have presented evidence that the cost of equity could be as low as 7.1% and as high as 12.76%, and recommended a cost of common equity between 9.80% and 12.00%. Having considered the evidence of record and giving such weight to the evidence as we deem appropriate, we find that a cost of equity range of 9.90% to 10.50% is reasonable and appropriate for NIPSCO in today's economic climate. This is comparable with our cost of equity findings in Duke Energy Indiana's (formerly PSI Energy, Inc., hereinafter referenced as "PSI") most recent rate case in Cause No. 42359 (finding 10.5% to be appropriate), our approval of the settlement agreement in I&M's rate case in Cause No. 43306 (approving 10.5% as part of the settlement), and our approval of the settlement agreement in Vectren South's rate case in Cause No. 43111 (approving 10.4% as part of the settlement).

Having found an appropriate range, we now turn to determining a specific return to apply to NIPSCO's common equity. In our Order in Cause No. 42359 concerning PSI's rates, we recognized that a utility's operational and financial performance were appropriate considerations in determining a utility's cost of equity. The Commission has previously expressed concerns with the soundness of NIPSCO's managerial and operational decisions. For example, in Cause No. 42194, the Commission analyzed NIPSCO's plan to consolidate and close Local Operating Areas, or maintenance facilities, in its gas and electric service areas. The Commission questioned whether NIPSCO properly and thoroughly evaluated the impact of its plan on NIPSCO's ability to provide reasonably adequate service prior to the plan's implementation. Specifically, the Commission stated, "[T]he lack of any evidence on the part of NISPCO that demonstrates that it undertook a careful and thoughtful review of the [plan] vis-à-vis its possible impact on customers and service quality, has resulted in uncertainties regarding its implementation." *In Re: An Emergency Complaint Against N. Ind. Pub. Serv. Co.*, Cause No. 42194 at 56 (Aug. 10, 2005). As a result, the Commission found that NIPSCO should not implement its plan.

The Commission continues to have concerns regarding NIPSCO's managerial and operational decisions. To illustrate, in the present case, NIPSCO developed new tariff provisions without consulting its industrial customers—the customers who would be most affected by the new provisions and who comprise the majority of NIPSCO's load. While we have seen recent positive efforts by senior management to address customer and operational shortcomings, the Commission will continue to monitor and evaluate managerial efforts, and we will review and revisit those efforts in NIPSCO's next rate case.

Further, in Cause No. 42359, we determined that PSI's reliability and quality customer service warranted some consideration in our ultimate cost of equity determination. The evidence showed that PSI, and its parent Cinergy Corp., scored in the top quartile of the most recent J.D. Power and Associates customer satisfaction studies. In contrast, the evidence presented in this Cause demonstrated that NIPSCO was in the bottom quartile of the J.D. Power studies in 2007 and 2008, and one of the worst-rated utilities in 2009. While we are hesitant to place undue weight on customer surveys, the three-year trend of poor customer satisfaction cannot be ignored.

We must also consider the effect tracking mechanisms have in reducing risk in order to ensure that these reduced risks are properly reflected in NIPSCO's cost of equity. See Order, Cause No. 42359 at 53. NIPSCO has a number of trackers in place currently, and we have approved additional trackers in this Cause. No witness for NIPSCO addressed the effects of trackers on NIPSCO's cost of capital, which could be considered a fatal failing of its analysis.

The Commission has a unique role in regulating its jurisdictional utilities, which at times requires us to send a clear and direct message to utility management concerning the need for improvement in the provision of its utility service. Our determination of the authorized cost of common equity capital can be a very direct means to incent improved service. We anticipate that NIPSCO will respond accordingly and therefore anticipate that such authorized cost of common equity capital will apply for a limited duration as identified below.

Based on the entirety of the evidence at issue, and giving such weight to the evidence as we deem appropriate, we find that NIPSCO's cost of common equity capital shall be 9.9% and NIPSCO's overall weighted cost of capital to be 7.29%, determined as follows:

Description	Amount	Percent	Cost	Weighted Average Cost
Common Equity	$ 1,395,245,772	49.95%	9.90%	4.94%
Long-Term Debt	$ 906,631,137	32.46%	6.52%	2.12%
Customer Deposits	$ 63,684,199	2.28%	6.00%	0.14%
Deferred Income Taxes	$ 294,780,249	10.55%	0.00%	0.00%
Post-Retirement Liability	$ 102,637,766	3.67%	0.00%	0.00%
Post-1970 ITC	$ 30,350,460	1.09%	8.57%	0.09%
Totals	$ 2,793,329,583	100.00%		7.29%[8]

The cost rate we have assigned to the post-1970 investment tax credits is the overall weighted cost of investor-supplied capital determined as follows:

Description	Amount	Percent	Cost	Weighted Average Cost
Common Equity	$ 1,395,245,772	60.61%	9.90%	6.00%
Long-Term Debt	$ 906,631,137	39.39%	6.52%	2.57%
Totals	$ 2,301,876,909	100.00%		8.57%

This is consistent with the methodology adopted by the Commission in Indianapolis Power & Light Co., Cause No. 37837, p. 18 (Aug. 6, 1986). Applying the weighted cost of capital to NIPSCO's original cost rate base, we find a net operating income level for NIPSCO of $192,425,533 is just and reasonable.

The Commission recognizes that a 9.9% return reflects the low end of the range discussed above, and that a higher return may be appropriate if NIPSCO is able to demonstrate improved company performance in its next base rate proceeding. In order for NIPSCO's level of performance to be reevaluated by the Commission, NIPSCO is hereby directed to file a new base rate case with the Commission no later than September 30, 2012.

[8] In comparison, PSI Energy of Indiana's weighted cost of capital in Cause No. 42359 was 7.30%, while I&M's weighted cost of capital, based on settlement approved in Cause No. 43306, was 7.62%, and SIGECO's weighted cost of capital, based on settlement approved in Cause No. 43111, was 7.32%.

9. Operating Income at Present Rates.

A. Undisputed Pro Forma Adjustments. NIPSCO proposed a number of pro forma adjustments to its test year revenues and expenses that were accepted by the other parties. All the undisputed pro forma adjustments proposed by NIPSCO have been fully identified by the parties and are hereby accepted even though they may not be specifically discussed herein. The disputed adjustments are discussed hereinafter.

B. Disputed Pro Forma Revenue Adjustments.

(1) Credits and Discounts.

(a) Evidence. Pursuant to the settlement agreement in Cause No. 41746, NIPSCO's customers have been receiving bill credits of approximately $55 million per year. These bill credits will terminate upon the issuance of an Order by the Commission approving new base rates. Also, during the test year, many of NIPSCO's large industrial customers were receiving discounts pursuant to various Commission-approved special contracts, some of which have expired, others of which will expire six months following the implementation of new base rates in this proceeding, and others of which continue in effect until 2011 or later. Shambo Direct at 5. There was considerable disagreement over whether to adjust pro forma revenues at present rates to reflect the expiration of the bill credits and the expiration and/or imputation of industrial customer discounts. In its case-in-chief, NIPSCO proposed an adjustment to increase revenues at present rates by $80 million for expiring industrial customer discounted contracts. Miller Direct at 8; Shambo Direct at 5. NIPSCO did not make a present rates adjustment for the expiring bill credits in its direct case. However, NIPSCO did reflect this adjustment at present rates in its rebuttal filing.

The OUCC made an upward adjustment to present rate revenues of $55,102,044 to reflect the expiration of the bill credits. Catlin Direct at 7-8. IG made a comparable adjustment but in the amount of $57.8 million.[9] Gorman Direct at 3, 7, and 13. OUCC Witness Bolinger testified that NIPSCO's actual test year revenues fell far short of the amount that would result under full tariff rates such that pro forma revenues at present rates are understated and the calculation of the revenue increase overstated. Bolinger Direct at 5-7. Mr. Gorman took a similar position on behalf of IG. MU Witness Kerry A. Heid disagreed with their adjustments and took the position that the $55 million in bill credits were more appropriately addressed as an adjustment at proposed rates rather than present rates. Heid Cross-Answering at 19-21. The IG also added an additional adjustment to increase revenues by $107 million to reflect additional industrial customer discounts that were not captured by NIPSCO's $80 million adjustment. Gorman Direct at 3, 8, 16; Phillips Direct at 12.

On rebuttal, NIPSCO Witness Miller responded to these various contentions by pointing out that, other than with respect to mitigation, the characterization of these adjustments as adjustments at present or proposed rates makes no difference. She pointed out two facts to demonstrate her position. First, adjustments to revenues at present or proposed rates have no

[9] Mr. Gorman said he obtained this amount from Ms. Miller's proof of revenue. Ms. Miller testified Mr. Gorman's number was not correct and the actual test year bill credits amounted to $55,981,908. Miller Rebuttal at 14, 18. The bill credits actually received in any year will vary depending on customer usage. The settlement agreement in Cause No. 41746 provides that the bill credits actually received will be periodically trued-up to the agreed-upon amount of $55,102,044.

impact on the revenue requirement. The revenue requirement is the sum of the pro forma level of expenses plus the authorized return. Whether an adjustment is made at present or proposed rates only impacts the "starting point" for purposes of calculating the size of the increase/decrease needed to produce the revenue requirement. Miller Rebuttal at 11-12. Second, NIPSCO's proposed rates in this case have been designed to recover the revenue requirement with the assumption there would be no bill credits or contractual discounts in place after the Order in this case. Thus, for any period of time after rates are approved in this case during which contractual discounts remain in place, NIPSCO and not the ratepayers will absorb the shortfall. Ms. Miller demonstrated with an exhibit that the total revenue requirement would not change and the revenues that would be produced by the rates NIPSCO has proposed will remain the same regardless of whether these various adjustments for expiring bill credits and discounted contracts are treated as adjustments at present or proposed rates. *Id.* at 13-17, 20-21; Petitioner's Ex. LEM-R5.

With that background, Ms. Miller explained NIPSCO's rebuttal position with respect to these adjustments. NIPSCO adhered to its position that the proper approach is to treat the $55 million in bill credits as an adjustment at proposed rates because the bill credits will not cease until new rates are placed into effect as a result of this case. Ms. Miller explained, however, that to eliminate confusion associated with the various presentations, NIPSCO has re-presented its accounting schedules showing the adjustment as one at present rates. Miller Rebuttal at 18.

With respect to imputation associated with discounted contracts, Ms. Miller testified that NIPSCO included in its adjustment at present rates those customers whose contracts have expired or which, by their terms, will expire six months from the effective date of new rates in this case. Miller Rebuttal at 19, 24-25. She testified that, again, the only difference the various forms of treatment would make is with respect to mitigation and that, for those customers who will remain on discounted rates for six months after the Order in this proceeding, mitigation has already been built into their contracts via the six month grace period. *Id.* at 12, 24-25. For those customers, NIPSCO's shareholders will bear the shortfall for six months until those contracts expire and NIPSCO can charge them full tariff rates. *Id.* at 20. Mr. Shambo also confirmed there would be no cost shifting of the discounts to other customers under NIPSCO's proposed rates. Shambo Rebuttal at 9-10.

(b) Discussion and Findings. We find the treatment of the bill credits and special contract discounts as an adjustment at present or proposed rates makes no difference in the ultimate revenue requirement to be approved in this case. This is fundamentally true because, as discussed *infra*, we find that an equalized rate of return shall apply to the various rate classes, which elimates the need for any subsidy reduction scheme. While Mr. Phillips argued the present rates adjustment for industrial contract discounts should be increased by $107 million, he agreed his proposal "does not affect the calculation of the revenue requirement." Tr. at KK-21. Thus, the IG's proposed adjustment is not substantive, but does call attention to the magnitude of the benefit the industrial customers have received from their contractual discounts. To minimize differences among the parties, we will accept the $55 million bill credits adjustment as an adjustment at present rates as set forth in Mr. Miller's rebuttal exhibits. With respect to the special contract discounts, we approve NIPSCO's proposed $80 million adjustment at present rates.

(2) Off-System Sales.

(a) Evidence. In the test year, NIPSCO had $50,400,058 in revenue from OSS which, net of fuel costs, produced a margin of $29.1 million. Miller Direct at 9; Miller Rebuttal at 26-28. Consistent with its proposal to exclude OSS from base rates and to track OSS margins in its proposed Reliability Adjustment tracking mechanism ("RA Tracker"), NIPSCO removed the test year OSS revenue from its pro forma present rates revenues. Miller Direct at 11. NIPSCO also removed $21,285,492 of related OSS fuel expense. Miller Direct at 15. OUCC witness Mr. Satchwell stated that he was concerned with NIPSCO's OSS Margin Sharing mechanism because there is no amount built into base rates for OSS margins and recommended an amount of OSS margins be built into base rates, consistent with the Commission's final orders in Cause Nos. 42359 and 43111. Mr. Satchwell recommended that $8,731,000, the smallest margin achieved by NIPSCO for the calendar years 2002 through 2007, be used as the base rate amount because it is a reasonable amount and is not so high as to be unachievable. Satchwell Direct at 17. Mr. Satchwell agreed with Petitioner's recommendation to share above the base rate credit amount all OSS margins (80% with customers and 20% with the company). IG proposed a base rate credit for OSS margins of $15 million if the RA Tracker is not approved and $9 million if the RA Tracker is approved. Gorman Direct at 3, 8, 16; Dauphinais Direct at 3, 11, 19-20. LaPorte Witness Cearley said NIPSCO should include at least $11.9 million of OSS margins in base rates. Cearley Direct at 13.

In rebuttal, Mr. Shambo stated NIPSCO should not be at risk for OSS margins that may or may not be realized because the Midwest ISO now dispatches NIPSCO's generating units based on factors outside NIPSCO's control. He testified that NIPSCO's proposal aligns the interests of NIPSCO and its customers. On the other hand, the position of the OUCC and Intervenors would penalize NIPSCO for participating in the Midwest ISO even though that participation provides centralized dispatch benefits including reduced need for reserve margins, reduced transmission loading relief occurrences and downward pressure on wholesale prices. Shambo Rebuttal at 11-14. Ms. Miller testified the OUCC's and IG's margin adjustment is flawed because it ignores the revenue-based taxes and fees associated with OSS revenues. Miller Rebuttal at 27. She further pointed out OSS margins produced in prior years are not representative of future margin opportunities because of changed circumstances, including purchasing practices. She noted that NIPSCO's OSS margins during the period of January-April 2009 were $618,000 compared to $7.5 million in the same months in 2008. *Id.* at 27-28.

b. Discussion and Findings. We agree with the OUCC and Intervenors that it is appropriate to include an amount of OSS margins as a credit against base rates. In essence, this amount will serve as an offset to the Revenue Requirement otherwise determined in this case. This is consistent with our rulings in the most recent electric base rate cases, Cause Nos. 42359, 43111 and 43306.

With respect to determining an appropriate amount to include as an offset, we are mindful of Mr. Shambo's concerns that the amount of the offset should not be an amount that is not sustainable by NIPSCO. The OUCC recommended that the smallest annual margin amount achieved by NIPSCO during the past five years be used. We find that NIPSCO shall credit base rates by $8,731,000. As discussed *infra*, while we do not approve NIPSCO's proposed RA tracker, we do authorize NIPSCO to track OSS margins above the base rate credit amount with 50% credited to consumers and 50% to NIPSCO. This percentage of margin sharing is more consistent with the other electric IOU's that track OSS. We also find that in tracking such margins, NIPSCO may not apply a net annual margin of less than zero to the tracker, and all OSS net income shall be included as jurisdictional income for purposes of the FAC earnings test.

(3) Emission Allowance Sales.

a. Evidence. NIPSCO made an adjustment to remove $11,790,599 of test year revenue generated through the sale of emission allowances. NIPSCO proposed that in the future when such sales arise, the net proceeds be passed back to customers via NIPSCO's existing Environmental Expense Recovery Mechanism ("EERM"). Miller Direct at 10. Phillip W. Pack, NIPSCO's Director, Generation Support Services and Major Projects, testified NIPSCO proposes to include in the EERM recovery of emission allowance purchase costs and the crediting of revenues from the sale of any emission allowances. Pack Direct at 11.

OUCC Witness Catlin rejected NIPSCO's adjustment and included the allowance sales proceeds in NIPSCO's going level revenues based on the testimony of OUCC Witness Cynthia M. Pruett, who opposed the tracking of emission allowance purchases and sales for reasons we shall discuss later in the section describing changes to the ECRM and EERM trackers. Catlin Direct at 10-11. Ms. Pruett showed that NIPSCO had earned revenues of $10,762,552 in 2006, $11,801,845 in 2007, and $9,607,509 in 2008 from the sale of emission allowances. Prior to 2006, NIPSCO did not appear to sell or purchase any emission allowances. Pruett Direct 8. Ms. Pruett also testified that NIPSCO admitted to selling these allowances to fund the Company's ongoing capital needs. Ms. Pruett argued that NIPSCO sold off a significant number of zero-cost allowances to benefit the company's shareholders when these allowances should have been evaluated for future compliance with environmental regulations. Pruett Direct, 9-10. Because it appeared that NIPSCO acted irresponsibly with regards to selling zero-cost emission allowances, Ms. Pruett recommended Revenue Adjustment 9 (REV-9) be rejected and that the $11.7 million emission allowance revenues be included as part of NIPSCO's test year revenues. Ms. Pruett also said the $11.7 million in allowance sales revenue should be credited in base rates because "NIPSCO has charged ratepayers for its investment in [the environmental] projects" that made the allowance sales possible. Pruett Direct at 11-12.

In rebuttal, Mr. Pack testified NIPSCO is not expecting to make future sales of allowances, among other reasons, because of the impact of the Court decision overturning the Clean Air Interstate Rule ("CAIR") on the market for SO_2 allowances. *See North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008) (per curiam); *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008) (per curiam). He also stated Ms. Pruett was mistaken in believing the projects that gave rise to the sold allowances were included in NIPSCO's environmental tracker. He said the sold allowances resulted from SO_2 projects that have not been included in the tracker and for which NIPSCO is not presently recovering costs or earning a return on investment. Pack Rebuttal at 7-8.

Ms. Miller also testified in rebuttal that the OUCC and IG proposals were unreasonable because the level of emission sales during the test year is not ongoing, recurring or reflective of future operations. Miller Rebuttal at 29. As an alternative, Ms. Miller proposed that NIPSCO amortize the $11.8 million amount as a base rate credit over a 5-year period (*i.e.*, $2.3 million per year). *Id.* She proposed that at the end of the five-year period, NIPSCO will automatically terminate the credit by filing new tariffs, which would eliminate the impact of the amortization. *Id.* Ms. Miller also explained that, under NIPSCO's proposal, 100% of net revenues received from the sale of emission allowances and 100% of the costs associated with the purchase of emission allowances after the implementation of new base rates would flow through its environmental tracker. *Id.*

b. Discussion and Findings. We hereby approve NIPSCO's proposal to track emission allowance expenses and revenues via the EERM. However, rather than not including emission allowance revenues in test year revenues, we find that a portion of these revenues shall be included in test year revenues despite NIPSCO's assertion that future sales are unlikely. During both the test year and the pro forma year, NIPSCO generated a considerable amount of revenues associated with the sale of emission allowances. We cannot say that NIPSCO's interpretation of how CAIR is resolved constitutes a change that is fixed, known and measurable. While we note NIPSCO proposed to amortize its $11.8 million test year revenues over five years in its rebuttal case, we find that a shorter period is more appropriate, and order that NIPSCO shall amortize the $11.8 million in emission allowance revenues over three years as a base rate credit.

(4) Metal Melting Customers. NIPSCO adjusted revenue downward by $804,136 and associated fuel and purchased power expense downward by $628,813 to reflect the fact that during the test year certain customers in the metal melting business operated at levels above contract volumes and that this would not be permitted in the future. Miller Direct at 7-8, 11. OUCC Witness Catlin testified that this adjustment should not be made because these customers had also operated in excess of contract volumes in years prior to the test year. Catlin Direct at 9. Mr. Shambo testified in both direct and rebuttal that while these Rate 825 customers were allowed to exceed the limits on off-peak hours under the current tariff during the 2005-2008 period, that would not be the going-forward practice of the Company under its new tariff. Shambo Direct at 6; Shambo Rebuttal at 11.

The question is not what volumes have existed in the past, but what volumes will exist on a pro forma going forward basis. NIPSCO made the determination, during the test year, that these customers would no longer be permitted to operate in excess of contractual volumes. Accordingly, we find NIPSCO's adjustments to revenue and expense should be approved.

(5) Weather Normalization.

a. Evidence. NIPSCO made an adjustment to reduce revenue by $14,604,146 and fuel and purchased power expense by $3,683,450 to account for warmer than normal weather in the test year. Miller Direct at 7, 13. William Gresham, Manager of Forecasting for NCS, testified in support of NIPSCO's weather normalization adjustment. Mr. Gresham stated the Cooling Degree Days ("CDD") experienced in May through October of 2007 were 17% higher than the 30-year average period ended 2005 and should be normalized to reflect test year consumption under normal weather conditions. Gresham Direct at 3-4. Mr. Gresham noted that weather normalization of electric revenues is not new as NIPSCO has normalized for weather in two prior electric base rate cases (Cause No. 36689 and Cause No. 36394). *Id.* at 3. He used a base load/temperature-sensitive load normalization procedure—the same method accepted in the previous NIPSCO electric base rate cases. This methodology begins by identifying a base load of energy representing consumption for uses such as lighting and water heating, which are not temperature sensitive. The load in excess of the base load is then normalized for weather and added back to the base load to arrive at a normal level of usage. *Id.* at 6-8.

Mr. Gresham selected April as the base load month for most rate classes because April had the least amount of CDDs and the lowest level of kWh usage per customer during the year. Mr. Gresham used November, 2007 as the base month for residential heat pump customers because an unusually hot October during the test year impacted the use of heat pumps for heating and cooling of homes. Mr. Gresham normalized usage above the base load for the test year months of May through October. May and October were included because they each had an unusually high number of CDDs and the kWh usage per customer for those months was significantly above that for the base month. Mr. Gresham's weather normalization adjustment reduced sales volume in five and increased sales volume in one of the six months in the normalized season (May through October) producing a net 2.2% reduction of the annual sales volume. Gresham Direct at 8-10.

The OUCC accepted NIPSCO's weather normalization adjustment.

IG presented the testimony of Greg Meyer, consultant with Brubaker & Associates, Inc. Mr. Meyer accepted the claim that the weather in 2007 was warmer than normal, but believed the reduction to test year revenues should be much less than the level proposed by NIPSCO. IG Ex. 1 at 25. He testified that the May through October time period chosen by NIPSCO to weather normalize revenues for summer usage is too long to properly capture the effects of summer consumption patterns in NIPSCO's service territory and thereby the use of air conditioning. He also testified that the use of April as a base month is inconsistent with prior Commission decisions and is the lowest month of average electric usage for the entire year for some rate classes. *Id.* at 26.

Mr. Meyer testified that one should also look at the Heating Degree Days ("HDD") each month when determining the base month and measuring period. Mr. Meyer presented a comparative table showing the CDDs and HDDs based on a 30-year average of 1971-2000 temperature observations for the weather stations in South Bend, Indiana; Fort Wayne, Indiana; and Indiana Dunes, Indiana. *Id.* at 27. The table reflects that the months of April, May and October are predominantly heating months and are influenced most by heating degree days. The table also indicates that under normal circumstances in the NIPSCO service territory in the month of April, residential consumers are still engaging in home heating behavior indicative of a winter month, and do not begin to engage in summer-like home cooling behavior until May. Similarly, in October customers are typically refocused on heating their homes, and are no longer engaged in significant home cooling behavior. Therefore, Mr. Meyer testifies, NIPSCO is incorrect in assuming that the months of May and October involve temperatures that create air conditioning usage consistent with summer months.

Mr. Meyer also testified that the month of April has historically been the lowest average usage per month per NIPSCO Rate 811 residential customer for many years. IG Ex. 1 at 6. That residential class is the largest customer class of NIPSCO, and has the biggest impact on the use of air conditioning. By using April's low average usage as the base month, NIPSCO greatly increases the amount of variable electric usage attributed to summer weather. Mr. Meyer testified that using April data for determining the base usage understates the true level of base usage that exists in the residential class. *Id.* at 28.

Mr. Meyer provided a number of alternative calculations for comparative purposes to demonstrate that normalization of revenues is highly dependent upon the selection of the base period. IG Ex. 1 at 7. One alternative established a base usage using average consumption in the non-cooling months of January, February, March, November and December 2007, and applied that usage to the months of June through September, when NIPSCO's revenues are most affected by the use of air conditioning. This produced an adjustment which increases total revenues (including base charge for fuel expense) by $354,000. IG Ex. 1 at 1. In another example, Mr. Meyer used May as the base month and weather normalized sales for June through October, resulting in a revenue reduction of $4.1 million. IG Ex. 1 at 2.

In two other examples, Mr. Meyer used the weather normalization methodologies approved by the Commission in Cause Nos. 43111 and 36689. In the former proceeding, Vectren South weather normalized June through October using the average usage in May and October as the base load. This methodology results in a revenue reduction of $2,407,178. IG Ex. 1 at 3. In the latter proceeding, NIPSCO weather normalized June through September using May sales as a base load. This results in a revenue reduction of $1,814,470. IG Ex. 1 at 4. Mr. Meyer recommended that the Commission continue to apply this latter methodology from Cause No. 36689, resulting in an increase in margin revenues of $9.5 million. IG Ex.1. Thus, Mr. Meyer believes NIPSCO's proposed methodology results in an unreasonable and extreme adjustment when compared with previously approved methodologies (i.e. $14 million vs. $2 million).

Mr. Gresham submitted rebuttal testimony defending his use of April 2007 as the base month and his normalizing of May through October. He testified that Mr. Meyer's methodology required the Commission to draw conclusions about the appropriate inputs for weather normalization based on historic averages that mask the hotter than average temperatures actually experienced in May through October of 2007. Mr. Gresham disagreed with Mr. Meyer that April, 2007 could understate the true level of base usage absent some evidence of an event causing customers to not use lighting, water heating or other base load electrical appliances. Gresham Rebuttal at 2-4. No evidence of such an event was cited by Mr. Meyers.

Mr. Gresham also criticized Mr. Meyer's proposal to adopt a weather normalization procedure that blindly used the same base month regardless of the actual weather experienced. He noted that Mr. Meyer acknowledged that the presence of CDDs or HDDs is a factor to consider in establishing a base month. Mr. Gresham testified that May 2007 was much warmer than the average May and resulted in higher usage as evidenced by it having 100 CDDs and average usage of 612 kWh per residential customer compared to an average of 53 CDDs and 550 kWh per customer. Gresham Rebuttal at 4-5. Mr. Gresham testified that his decision to use April, 2007 as the base month was bolstered by Mr. Meyers' own data showing that the residential customer usage in April, 2007 of 548 kWh was more consistent with the average May usage from 2002 through 2006 of 550 kWh.

Mr. Gresham also disagreed with Mr. Meyer that May and October are predominantly heating months. Mr. Gresham stated these months were more aptly described as transition months when customers use both heating and cooling and that cooling has a more significant impact on load. To support this conclusion, Mr. Gresham cited NIPSCO data showing that only 6% of NIPSCO residential customers use electric appliances to heat their homes while 90% use electric appliances to cool their homes. Moreover, a regression analysis conducted by Mr. Gresham demonstrated that CDDs have a much greater impact on electric usage than HDDs during the months of May and October. Based on data for 2007, Mr. Gresham concluded that May and October were heavily influenced by CDDs and should be normalized. Gresham Rebuttal at 7-9.

(b) Discussion and Findings. In evaluating this issue it is helpful to first establish several points of agreement. NIPSCO and the Industrial Group are in agreement that base load consumption is the minimum amount that would occur each month if there was no weather related consumption, and that the base load is observed in the month with the least call for heating and cooling. They are also in agreement that the base load/temperature sensitive load normalization procedure is an appropriate method for adjusting kwh for ratemaking. Finally, both parties agree that 2007 was warmer than normal based on historical weather records.

We are faced, however, with competing interpretations of the effect of test year weather, measured in HDDs and CDDs, on kwh consumption by NISPCO customers. That issue determines the appropriate base month and weather normalization period to use in resolving the $9.5 million difference between NIPSCO's proposal and the adjustment recommended by the Industrial Group. IG Ex. 1 at 8. As a preliminary matter, we are skeptical that the use of 65 degrees as a threshold for measuring CDDs reflects actual consumer behavior.[10] For instance, NIPSCO's adjustment assumes that consumers in northern Indiana react to a 66 degree day in April by turning on their air conditioners. Pet. Ex. WG-1 at 5-6. We doubt that significant numbers of NIPSCO consumers engage in such behavior. Our doubts are supported by NIPSCO's request that those same customers conserve energy by turning down their home *heating* units to between 68 and 72 degrees. IG Ex. CX-50. However, in light of the historic use of 65 degrees as a threshold for establishing CDDs, we will adopt this methodology while giving it the limited evidentiary weight it merits. We would anticipate that in future cases, NIPSCO would present testimony in support of an appropriate threshold; testimony that would reconcile air conditioning use assumptions with energy efficiency program assumptions.

Mr. Gresham cites Exhibit GRM-6 in support of NIPSCO' claim that April had the least amount of weather-affected consumption, and therefore should be used as a base against which summer cooling behavior is measured. Pet. Ex. WG-R1 at 3. That exhibit reflects that April falls slightly below May as the month with the lowest average KWH use for Rate 811 customers. *Id.* Ergo, Mr. Gresham concludes, it had the least weather-related consumption. However, Mr. Gresham agreed that April would understate the true level of base usage if customers reduced electric load in April for reasons unrelated to weather. *Id.* at 3-4.

Based on weather records in NIPSCO's service territory, April 2007 had a combined total of approximately 550 HDDs and CDDs, while May had an approximate total of only 220 HDDs and CDDs. IG Ex. CX-47. That strongly suggests that May had far less weather related consumption than April. Moreover, April 2007 had approximately 540 HDDs compared with only 10 CDDs. *Id.* Thus, we agree with Mr. Meyer's testimony that April continued its historical trend of being a predominantly heating month influenced most by heating days, and under normal circumstances NIPSCO's northern Indiana residential customers are still engaging in home heating behavior indicative of a winter month. We also agree with Mr. Meyer that, based on the test year weather records, NIPSCO customers were not likely to engage in summer-like home cooling behavior until temperatures began to warm in late May. In fact, test year temperatures did not exceed a 65 degree average with any significance or regularity until the later days of May, and May 2007 had more HDDs (i.e. sub 65 degree average days) than CDDs. IG Ex. CX-47. Therefore, when identifying the month when NIPSCO customers are most likely

[10] Alternatively, the historic use of 65 degrees as a threshold for measuring heating behavior, or HDDs appears reasonably designed to reflect customer heating behavior.

to be using neither air conditioning nor heating – i.e. the month with the least "weather related consumption" – the evidence points to the transitional month of May, rather than the much colder month of April when customers are still engaged in winter-like heating behavior.

We agree that flexibility is necessary in selecting a month for base usage to avoid having weather itself impact a normalization adjustment, and that different methodologies must be used depending on the circumstances. However, there is no evidence on the record indicating that test year weather in this case differed in any material way from the test year NIPSCO used in Cause No. 36689, wherein weather was normalized June through September using May sales as a base load. Nor does NIPSCO explain why it is appropriate to use a relatively cooler month (April) to calculate summer base load in *northern* Indiana as compared with Cause No. 43111, in which the Commission approved the use of a warmer month average (May/Oct) to calculate summer base load. Likewise, NIPSCO does not explain why it is appropriate to use a relatively longer measuring period (May-October) in northern Indiana, and a shorter measuring period (June-October) as the measuring period in *southern* Indiana, where the weather is generally acknowledged to be warmer.

Based on the forgoing, we find that the methodology used in Cause No. 36689 remains the proper approach. Therefore, the month of May should be used as the base month because it more closely reflects the true level of base usage during non-summer months, and revenues should be weather normalized for the months of June through September, when air conditioning has the greatest impact. This results in a revenue reduction of $1,814,470, and an expense decrease for fuel of $408,324 as set forth on Exhibit GRM-8.

C. **Depreciation Expense.**

(1) Petitioner's Evidence. John J. Spanos, Vice President, Valuation and Rate Division of Gannett Fleming, Inc., testified in support of Petitioner's proposed new depreciation accrual rates and sponsored the depreciation study that he had conducted. He proposed new depreciation rates for all accounts and plants including common plant and Sugar Creek. Spanos Direct at 6-7. Ms. Miller used Mr. Spanos' proposed depreciation rates to determine NIPSCO's pro forma depreciation expense which resulted in a $21.048 million adjustment above the test year level.[11] Miller Direct at 29-30; Petitioner's Ex. LEM-2 (2nd Revised), p. 1, lines 54-55. Mr. Spanos explained that depreciation refers to the loss in service value that is not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that can be reasonably anticipated or contemplated, against which the company is not protected by insurance. Spanos Direct at 7. Mr. Spanos conducted his study using the straight line remaining life method with the equal life group ("ELG") procedure. This method distributes the unrecovered costs of fixed capital assets over the estimated remaining useful life of each unit or group of assets. *Id.* at 9.

Mr. Spanos developed his proposed depreciation rates by first estimating the service life and net salvage characteristics for each depreciable group. He then calculated the composite remaining lives and annual depreciation accrual rates based on such service life and net salvage estimates. The service life and net salvage estimates were made by compiling historic data from records related to NIPSCO's plant, analyzing data to obtain historic trends of survivor and net

[11] This amount also includes a $227,322 adjustment resulting from a change in the allocation of common plant between the electric and gas operations implemented in the test year. Miller Direct at 29.

salvage characteristics, obtaining supplementary information from management and operating personnel, and interpreting the data. The historic data consisted of NIPSCO's accounting entries for the 72-year period from 1936 through 2007. Mr. Spanos used the retirement rate method for all electric and common accounts. This is an actuarial method of deriving survivor curves using the average rates at which each age group is retired. Mr. Spanos applied this method to each group of property and formed life tables which, when plotted, show original survivor curves for each property group. He then used Iowa-type survivor curves to interpret the original survivor curves. He explained that Iowa-type curves are widely used and are generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. Field reviews were conducted to learn about Company operations, obtain an understanding of the function of the plant and obtain information about the reasons for past retirements and the expected causes of future retirements. Spanos Direct at 9-13.

Mr. Spanos also incorporated net salvage into his analysis. Net salvage is the salvage value received for an asset upon retirement minus the cost to retire the asset. When the cost to retire the asset (cost of removal) exceeds the salvage value, the result is negative net salvage. Because depreciation expense is the loss in service value of an asset during a defined period, it must include a ratable portion of both the original cost and net salvage. For most accounts, Mr. Spanos determined net salvage percentages by analyzing historical data. In the historical analysis, the net salvage, cost of removal and gross salvage amounts are expressed as percents of the original costs retired. Spanos Direct at 14-15.

For production plant, Mr. Spanos used the life span technique. Under this approach, the retirement date of the entire facility is estimated and interim survivor curves are used to describe the rate of retirement related to the replacement of elements of the facility that occur during its life. The estimated retirement dates for the production facilities were based on judgment and considered age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar facilities. Spanos Direct at 12-13.

Mr. Spanos determined the negative net salvage of the steam production plants by using dismantling cost estimates determined by Burns & McDonnell Engineering Co., Inc. ("BMcD") pursuant to site-specific demolition studies.[12] NIPSCO Witness Victor F. Ranalletta, Associate Engineer and Manager of the Energy Division in BMcD's Chicago Regional Office, sponsored the BMcD demolition cost studies for NIPSCO's fossil-fuel fired generating stations. Petitioner's Ex. VFR-2 through Petitioner's Ex. VFR-7. In each of these studies, BMcD estimated the cost of demolishing the power block equipment and site facility and remediating the site. Each report describes the plant, sets forth the general cost assumptions used in the study, identifies costs not included in the study, explains how scrap metal value is determined and provides detailed cost estimates for demolition and remediation to both industrial condition and greenfield condition. Ranalletta Direct at 5. The industrial demolition cost estimates were based upon demolishing each plant down to the surrounding grade elevation, assuming all equipment and materials located above and below grade would be demolished and all below grade foundations would remain. *Id.* at 7. The greenfield estimates include the costs of removing all below grade foundations as well, filling the resulting below grade void, and remediation of ash ponds and coal yards. *Id.* at 8. A 20% contingency factor was included to

[12] The witnesses have used three different terms to refer to the removal of a retired generating unit and the remediation of the site – demolition, dismantlement and decommissioning. For purposes of this Order, we treat these terms as synonymous.

estimate costs that are presently unknown but which are expected to be incurred based upon past experience and uncertainty in the precision of the estimate. Mr. Ranalletta testified a 20% contingency was reasonable for estimating the demolition costs of NIPSCO's generating stations. *Id.* at 10-11. Because NIPSCO proposes to retire Michigan City Units 2 and 3 presently but leave the rest of the plant in service, BMcD prepared one estimate for Units 2 and 3 and a separate estimate for the building, Unit 12 and the balance of the plant.

Mr. Spanos escalated the BMcD industrial condition estimates for inflation at the rate of 3% per year to the anticipated date of final retirement. Because Mitchell and Michigan City Units 2 and 3 are to be retired in the very near future, Mr. Spanos assigned sufficient depreciation reserve to these units to account for the anticipated retirement and negative net salvage for these units so that the net book value will be zero. Spanos Direct at 15-16.

After determining service lives and net salvage characteristics for each group, Mr. Spanos calculated annual rates for each group using the straight line method, using remaining lives weighted consistently with the ELG procedure. Under this procedure, future book accruals for each vintage are divided by the composite remaining life for the surviving original cost of that vintage. For certain general plant accounts representing a very small portion of depreciable plant, Mr. Spanos' proposed depreciation rates were based upon amortization accounting in which the accrual is equal to the original cost multiplied by the ratio of the vintage's age to a defined amortization period. Amortization accounting was used for accounts with a large number of units of low asset value (such as furniture, computer equipment and tools) making it difficult to inventory the account. Spanos Direct at 17; Petitioner's Ex. JJS-2, p. 46-47.

Mr. Pack testified regarding the retirement of Mitchell (which has units that are 38 to 52 years old) and Michigan City Units 2 and 3 (which are 57 to 58 years old). Mr. Pack indicated that NIPSCO no longer intends to operate Mitchell as NIPSCO's 2007 Integrated Resource Plan suggested that restarting Mitchell should be abandoned in lieu of purchasing one or more combined-cycle gas turbines. Mr. Pack testified that NIPSCO intends to retire Mitchell, demolish the facilities and remediate the site to industrial condition. With respect to Michigan City Units 2 and 3, Mr. Pack stated that NIPSCO has determined the units are at the end of their useful lives due to extensive corrosion and wear due to their 50-plus years of service. Mr. Pack further stated that NIPSCO will retire Units 2 and 3 and demolish the facilities as described in the BMcD demolition studies but leave the building shell in place and continue to operate Unit 12. Pack Direct at 6-8.

(2) OUCC's Evidence. Michael J. Majoros, Jr. of Snavely, King, Majoros, O'Connor & Lee, Inc. testified on behalf of the OUCC. He testified that NIPSCO's present depreciation rates were approved in 1987 in Cause No. 38045 and reaffirmed in Cause No. 41746 in September, 2002. Mr. Majoros recommended approval of new depreciation accrual rates providing approximately $58 million less in annual expense than would result from NIPSCO's proposed accrual rates.

Mr. Majoros testified that the Commission should not allow any reflection of terminal decommissioning costs associated with Mitchell or Michigan City Units 2 and 3 in the calculation of depreciation accrual rates. His reasoning was that recovery of these costs forces a highly uneconomic and unnecessary cost onto ratepayers. He asserted that there was no payback associated with such an expenditure and demolition is unnecessary because NIPSCO has no legal obligation to demolish the plants. Majoros Direct at 13.

Mr. Majoros also disagreed with Mr. Spanos' use of the ELG procedure. He explained that the use of ELG in this case is a departure from the method under which NIPSCO's existing depreciation accrual rates were approved in 1987, which used the average life group procedure ("ALG"). Mr. Majoros explained that the ALG procedure applies a single average depreciation rate over the entire life of the account. Mr. Majoros acknowledged that the ELG procedure is more precise and that both ELG and ALG provide for the same full recovery, but he testified that the use of the ELG procedure requires annual depreciation rate changes and is more susceptible to errors resulting from forecasting inaccuracies than the ALG procedure. He then testified that if the ELG procedure is to be approved, it should only be applied prospectively to vintages after the date of Mr. Spanos' study, meaning the first ELG vintage would be 2008 for the purposes of the next depreciation study. Mr. Majoros claimed that to do otherwise would result in retroactive application of ELG. Mr. Majoros testified that this was consistent with application of the ELG procedure at the Federal Communications Commission ("FCC"). He testified that of his $58 million difference with Mr. Spanos, $24.1 million relates to his objection to Mr. Spanos' use of ELG. Majoros Direct at 15-20.

Mr. Majoros also objected to Mr. Spanos' cost of removal assumptions inherent in the net salvage percents. He explained that for generating plant accounts Mr. Spanos inflated the decommissioning estimates to the anticipated date of retirement. For mass property accounts, Mr. Spanos conducted a traditional net salvage analysis to which Mr. Majoros has been objecting for several years. He explained that these traditional methodologies increased the current estimates of future costs by projecting historic inflation into the future. Mr. Majoros restated all estimates of future dismantlement and retirement to present value. Mr. Majoros proposed that the annual depreciation rates should increase every year as the inflation is incurred. He presented an exhibit showing accruals for a single asset which he claimed demonstrated that Mr. Spanos' approach front-loads depreciation expense as compared to Mr. Majoros' approach. He testified that his own approach is more consistent with accrual accounting and matching. Majoros Direct at 21-25. He testified that his present value approach accounted for approximately $26 million of the $58 million difference with Mr. Spanos. Tr. at CC-10–CC-11.

Finally, Mr. Majoros testified that the Commission should "specifically recognize" that NIPSCO has a $892.7 million regulatory liability "for ratemaking and regulatory reporting purposes" of which $413.2 pertains to electric plant. Majoros Direct at 31, n. 38; 40. These amounts correspond to a regulatory liability recorded by NIPSCO for *financial reporting purposes* pursuant to Statement of Financial Accounting Standards No. 143 ("SFAS 143"). SFAS 143 requires that to the extent a public utility recovers through rates depreciation expense associated with future cost of removal that is not an asset retirement obligation ("ARO"), the amount should be recorded as a regulatory liability for financial reporting purposes only. *Id.* at 34-35. An ARO under SFAS 143 is a legal obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. Tr. at CC-18. Mr. Majoros testified that without this treatment, NIPSCO and virtually all other utilities would consider the amounts recovered to be "their" money. He contended that if the Commission does not exercise authority in this area, these amounts would be unprotected and NIPSCO would eventually take these amounts into income, especially if in the future Generally Accepted Accounting Principles ("GAAP") accounting is replaced by international accounting standards. *Id.* at 36-39.

(3) IG's Evidence. James T. Selecky, a consultant with Brubaker & Associates, Inc., testified on behalf of IG. He proposed a number of changes to Mr. Spanos' depreciation study producing, collectively, an annual reduction in depreciation expense of $24.825 million from the level produced by NIPSCO's proposed depreciation rates. Selecky Direct at 4, 38. Unlike Mr. Majoros, he did not object to the use of ELG because this Commission has on several occasions expressed a preference for ELG. Id. at 7. He also did not discount to present value the net salvage assumptions. Id. at 20. Further, he did not propose to reallocate the portion of accumulated depreciation representing accruals of future cost of removal to a regulatory liability account as proposed by Mr. Majoros.

Mr. Selecky's first disagreement with Mr. Spanos' study concerned the 20% contingency factor included in the BMcD dismantling cost estimates. Mr. Selecky testified that NIPSCO did not include any offset to the dismantlement cost for the value of the land after dismantlement which he thought would be valuable to NIPSCO or an independent power producer as a site for a next generation power plant. In Mr. Selecky's opinion, current ratepayers, not future ratepayers, should get the benefit of this land value. Selecky Direct at 10-18. He recommended that the Commission "exclude the contingency factor from the dismantling studies to reflect the potential value of the site." *Id.* at 18. He also opined that the contingency factor does not represent a "real cost" and should have been applied to "direct costs, indirect costs and gross salvage or credits." *Id.* at 18-19.

Mr. Selecky's next change concerned inflation. Mr. Selecky reflected the impact of future inflation on the cost of dismantling the steam production units using a lower inflation rate (2.5% compared to 3% used by Mr. Spanos). He testified that current forecasts of future inflation over the next twenty years are closer to his projection than Mr. Spanos' projection. Finally, Mr. Selecky applied inflation to the net dismantling costs (i.e. net of salvage) and not just the gross dismantling costs. Selecky Direct at 3, 20-21.

Mr. Selecky reduced the accumulated depreciation allocated to Mitchell and Michigan City Units 2 and 3 by the amount of his reduction in the dismantling cost estimate for those facilities. He then allocated that amount to the other steam production units. The effect of this adjustment was to lower his proposed depreciation rates for steam production by $912,000 per year. Selecky Direct at 3, 23-25.

Mr. Selecky also reduced the depreciation reserve allocated to Mitchell by $52.589 million, his estimate of the Mitchell dismantling cost. The effect of this adjustment also was to increase the depreciation reserve allocated to the other plants and thereby reduce the depreciation rates for those plants. Mr. Selecky said he made this adjustment because, in his opinion, Mitchell was "retired prematurely." Mr. Selecky contrasted NIPSCO's proposed 60-year life span for its steam production units with the 53-, 50-, 50- and 39-year life spans of the four Mitchell steam units. He concluded that because the Mitchell units' life spans have been less than the estimated life spans used in the study for the other steam production plants, ratepayers have not received the fair value from the Mitchell plant. Therefore, Mr. Selecky opined, the Commission should exclude the Mitchell dismantlement cost from the Mitchell depreciation reserve. According to Mr. Selecky, his Mitchell adjustment reduces depreciation expense by $2.391 million per year. Selecky Direct at 3-4, 25-27.

Finally, Mr. Selecky objected to Mr. Spanos' net salvage percentages for transmission and distribution plant. He testified that Mr. Spanos' methodology has the effect of projecting past inflation into the future because it determines the net salvage ratio by dividing an annual net salvage expense in current dollars by the associated retirement in original cost dollars. According to Mr. Selecky, past inflation exceeds estimates of future inflation. He cited the same sources utilized for reducing the escalation rate for steam production plant dismantlement costs. He provided a hypothetical example involving a single asset that quantified an amount of removal costs that would be over accrued if future inflation were lower than historic inflation. IG Ex. JTS-8. Mr. Selecky contended that if this were to be true, intergenerational inequities would be created because the excess accrual would reduce future depreciation rates. Mr. Selecky reduced Mr. Spanos' net salvage ratios across-the-board by 30% based on a comparison of historical inflation over the last 30 years and his forecasted inflation rate of 2.5% per year. Mr. Selecky said this change would reduce transmission and distribution depreciation expense by $6.212 million per year. Selecky Direct at 27-38.

IG Witness Phillips concurred with Mr. Selecky that customers should not bear the Mitchell demolition costs in their rates. Mr. Phillips believed Mitchell's shut-down in 2002 resulted in NIPSCO's purchasing significantly more power. He said after the Mitchell shut-down, NIPSCO's FAC has increased 14.152 mills per kWh. Phillips Direct at 39-40. Mr. Phillips acknowledged on cross-examination that the FAC factor increase for Duke Energy, Inc. and Indianapolis Power & Light Co. was comparable to the increase NIPSCO experienced after Mitchell was taken off-line. Tr. at KK-26–KK-30. Mr. Phillips also contended that NIPSCO experienced significant O&M expense savings by ceasing to operate Mitchell which savings were not returned to the customers. Phillips Direct at 41.

(4) Petitioner's Rebuttal Evidence. Mr. Spanos offered rebuttal testimony to both Mr. Majoros and Mr. Selecky. With respect to ELG, Mr. Spanos explained that ELG is superior to ALG because it more correctly matches depreciation to the life of the asset. He explained that historically the use of ELG had been constrained by the large amount of computations that are required, but with advent of modern computer equipment, this constraint has been removed. Mr. Spanos stated that the ELG procedure has always been unquestionably more accurate and has been approved consistently by this Commission. He cited to a number of orders where we have accepted the use of the ELG procedure dating back to the initial approval in 1981 in Cause No. 36361 involving Citizens Gas & Coke Utility. Spanos Rebuttal at 5-10.

Mr. Spanos also disagreed with Mr. Majoros' position that ELG should only be implemented on a prospective basis. He explained that in both his study and Mr. Majoros' ALG presentation, the same amount of future accruals and remaining lives are used for determining annual depreciation. He said the question concerns the time period over which those accruals will be recovered. The use of ELG more accurately recovers future accruals related to each item over its actual remaining life rather than the use of averages for an entire account. Spanos Rebuttal at 11-12.

With respect to net salvage for plant other than steam production, Mr. Spanos explained that Mr. Majoros' proposal to discount net salvage to present value would constitute a radical departure from the accepted way of determining net salvage. He asserted that over the last five years, Mr. Majoros has proposed a variety of different ways to reduce net salvage, always with the same result of reducing depreciation expense. Mr. Spanos defended his approach as equitable, sound, supported by authoritative depreciation texts and well-accepted by regulatory commissions. He described Mr. Majoros' approach as an "annuity" or "sinking fund" method. Mr. Spanos provided an example to demonstrate how Mr. Majoros' approach backloads depreciation expense and leads to intergenerational inequity. According to Mr. Spanos, under Mr. Majoros' proposal depreciation rates would have to be changed every year to assure full recovery. Mr. Spanos explained that his methodology for computing net salvage is precisely the same traditional approach that was accepted by the Commission in the 2004 PSI Energy, Inc. Order in Cause No. 42359. Spanos Rebuttal p. 14-21.

Mr. Spanos responded to Mr. Selecky's proposal to reduce the transmission and distribution plant net salvage ratios by 30%. Mr. Spanos said Mr. Selecky's adjustment was arbitrary and departed from the traditional net salvage approach. He explained that inflation has been around for a long time and there is no reason to believe it will not continue for the foreseeable future. The inflation factor used by Mr. Spanos considers a long historical period containing both high growth years and low growth years, with many cycles. He said it would be inappropriate to disregard historic inflation based upon subjective predictions of future inflation which quite often prove to be incorrect. Mr. Spanos noted that his net salvage ratios are not limited to historical data but also reflect judgment, trends in removal practices and the age of the assets being retired. He emphasized again his net salvage method was precisely the same one approved in the 2004 PSI Order. Spanos Rebuttal at 26-28.

With respect to steam production plant, Mr. Spanos also cited the 2004 PSI Order for the proposition that future inflation should be included in the cost of removal estimate. Spanos Rebuttal at 29. With respect to Mr. Selecky's prediction of future inflation being at a lower rate (2.5%), Mr. Spanos noted that his 3% rate was more closely aligned with historic inflation over a long period and is the same escalation rate approved in the PSI Order. Mr. Spanos testified the 3% rate also is more consistent with construction cost trend indices than a basket of goods inflation index. He also explained that the reason why the escalation should only apply to the gross dismantlement cost (not the net cost) is that, in Mr. Spanos' experience, the cost of labor will continue to increase each year. He does not, however, see a corresponding increase of like magnitude for the value of the scrap that would be used as an offset. *Id.* at 30-31.

Mr. Spanos noted that the use of a contingency factor by Burns & McDonnell is a widely accepted approach and the 20% factor is comparable to that used by Sargent & Lundy in the dismantlement cost studies approved in 2004 PSI Order. As to the value of the site, Mr. Spanos testified that it is assumed the sites are being restored to industrial condition. In order to assume a marketable piece of real estate (for some use other than another production facility), the site would have to be restored to greenfield condition at a much higher cost. He noted that Mr. Selecky cited no orders supporting his position that either the value of the site must be estimated and used as an offset to the cost of removal or the contingency factor must be eliminated. Spanos Rebuttal at 33-35.

Finally, Mr. Spanos responded to the proposals of Mr. Selecky to disallow any recognition of the dismantlement cost of Mitchell and of Mr. Majoros to disregard the dismantlement cost of both Mitchell and Michigan City Units 2 and 3. Mr. Spanos testified that Mitchell was in operation for a very long time and it could not be said Mitchell was retired prematurely. Mr. Selecky's opinion was based solely on the comparison of Mitchell's age to the estimated life spans for other units. Whenever an average is used as comparison, there will be units across the United States shut down after the average number of years and some shut down before the average age. Mr. Spanos said consideration of the cost of removal related to Mitchell and Michigan City Units 2 and 3 is necessary to fulfill the purpose of depreciation rates to systematically and rationally recover the full service value of all of the utility's assets -- both their original cost and negative net salvage. Spanos Rebuttal at 35-36.

Alan Felsenthal, a Certified Public Accountant and a Managing Director of Huron Consulting Group, testified in rebuttal to Mr. Majoros. Mr. Felsenthal objected to Mr. Majoros' proposal to restate future net salvage to present value. He testified that Mr. Majoros' present value approach utilizes what is in effect a sinking fund, annuity or discount approach. Mr. Felsenthal testified that such an approach is contrary to the appropriate, traditional and widely accepted regulatory approach of recovering estimated future cost of removal on a straight line basis through depreciation accruals. Mr. Felsenthal stated Mr. Majoros' discounting methodology would result in ever-increasing annual charges which would back-load recovery to the detriment of future customers. Furthermore, when the rate base impact of Mr. Majoros' proposal is considered, long run revenue requirements are actually greater under Mr. Majoros' present value approach. This is because there is less accumulated depreciation to offset rate base. Felsenthal Rebuttal at 13-17; Petitioner's Ex. ADF-R3.

Mr. Felsenthal rejected Mr. Majoros' position that GAAP does not provide for the recognition of future inflation in current periods. He testified that GAAP requires depreciation over the useful life of the assets in a systematic and rational manner (usually straight line). Depreciation accounting contemplates allocating the net original cost (original cost plus or minus future negative and positive salvage). The regulatory rationale is to promote intergenerational equity and appropriately match the cost to the provision of service. Mr. Felsenthal said NIPSCO's approach to net salvage is used by virtually every enterprise under GAAP. He stated Mr. Majoros' sinking fund or annuity approach, which results in ever-increasing charges for depreciation, is not consistent with GAAP, citing SFAS 92 which states "annuity methods of depreciation are not acceptable under generally accepted accounting principles applicable to enterprises in general." Felsenthal Rebuttal at 9-17.

Mr. Felsenthal also explained why recognition for regulatory purposes of the regulatory liability reflected for financial reporting purposes would be inappropriate and unnecessary. He testified that the showing of accumulated cost of removal as a regulatory liability for financial reporting purposes is a recommendation of the SEC, not a requirement of the Financial Accounting Standards Board ("FASB") or GAAP. Furthermore, no support exists for recording these amounts as a regulatory liability for ratemaking purposes. He explained that under the FERC Uniform System of Accounts ("USOA"), NIPSCO is not permitted (without regulatory approval) to remove amounts previously accrued for removal costs from accumulated depreciation and record them in income or apply them to some other account. He explained that the ARO referenced in SFAS 143 corresponds to retirement obligations for which there exists a present legal obligation (such as those that relate to PCBs and asbestos). Other obligations may arise and become AROs in the future and other removals may never be legally required but are nevertheless implemented for other reasons such as safety. He testified that SFAS 143 does not require that AROs for financial reporting purposes be removed from accumulated depreciation for regulatory purposes. Felsenthal Rebuttal at 20-29. Mr. Felsenthal also testified that in FERC Order No. 631, FERC concluded there was no reason to change regulatory accounting for non-legal costs of removal, although utilities are required to maintain subsidiary records that identify the cost of removal in the depreciation accruals. *Id.* at 40.

NIPSCO Witness Bradley K. Sweet, NIPSCO's Vice President, Strategic Planning and Operations Support, responded to assertions that NIPSCO's depreciation rates should not recover the dismantlement costs for Mitchell and Michigan City Units 2 and 3. Mr. Sweet disagreed with OUCC Witness Majoros' contention that these costs are uneconomic and unnecessary. He also discussed the shutdown, retirement, and demolition of Mitchell.

Mr. Sweet stated the shutdown of Mitchell Units 4, 5, 6 and 11 occurred in January of 2002 because an economic slowdown rendered the energy unnecessary, the cost of maintaining the units was substantial and NIPSCO's remaining generation resources were adequate to satisfy NIPSCO's projected demand through 2003. Sweet Rebuttal at 9. He said NIPSCO intended to restart the Mitchell facility, but the City of Gary, Indiana ("Gary") announced plans to acquire Mitchell in 2004 and initiated a proceeding with the Commission to condemn the facility. Sweet Rebuttal at 7. Mr. Sweet indicated that NIPSCO requested an expedited procedural schedule to quickly resolve Gary's petition because failure to restart Mitchell in 2004 would increase the probability that a new source review permit would be required. However, an expedited schedule was opposed by some parties. *Id.* at 7-8. Because of the potential for Gary to acquire the Mitchell site, Mr. Sweet testified that NIPSCO maintained the facility in a mothballed state rather than incurring the substantial cost of restarting it. Sweet Rebuttal at 9-10. In January, 2006 the Commission rejected a settlement agreement between NIPSCO and Gary. *Id.*

Mr. Sweet described the ensuing stakeholder process used to discuss Mitchell's future. NIPSCO and LaPorte both commissioned studies to evaluate the cost of restarting Mitchell. NIPSCO's study assumed new source review would be required to restart Mitchell and estimated the cost at between $587 million and $758 million. LaPorte's study did not assume new source review and projected a much lower restart cost. Mr. Sweet explained that Indiana Department of Environmental Management ("IDEM") subsequently confirmed new source review would be required. Sweet Rebuttal at 10; Petitioner's Ex. BKS-2. NIPSCO evaluated alternative energy sources and concluded that there were more cost effective options for satisfying its capacity needs.

Mr. Sweet also noted that NIPSCO was not alone in retiring coal plants of Mitchell's vintage. Using data from the Energy Information Administration, he provided a list of more than 40 coal generation units placed into service in the 1950s and 1960s which have been retired. He concluded that changing environmental requirements and system demands have changed the value placed on older, less efficient coal facilities like Mitchell. Sweet Rebuttal at 11-14.

Mr. Sweet said that a utility cannot simply walk away from a facility that is no longer being used to provide service and abandon it in place because this creates other issues. Mr. Sweet explained utilities would continue to incur costs for abandoned facilities to maintain the sites in a safe and secure condition. Mr. Sweet testified that NIPSCO would prefer not to abandon the plant and leave it to deteriorate, especially when the property on which it resides may be used for other purposes. Sweet Rebuttal at 8-9.

Based on this analysis, Mr. Sweet disagreed with Mr. Phillips' assertion that NIPSCO should be required to absorb the cost of demolishing Mitchell. Sweet Rebuttal at 14. Mr. Sweet did not dispute that NIPSCO avoided O&M costs associated with Mitchell, but he noted that these savings freed funds to cover other cost increases and generally did not inure to shareholders as evidenced by the fact that NIPSCO only rarely earned its authorized return. Sweet Rebuttal at 15. He concluded by noting that NIPSCO's customers benefited from many years of service from Mitchell and should pay the cost of demolishing the facility.

(5) Discussion and Findings.

(a) ELG v. ALG. We consider the debate between ELG and ALG to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the ELG procedure.[13] We have heard nothing new in this case to change our view and so approve the use of the ELG procedure in Mr. Spano's depreciation study.

The next issue raised is the application of the ELG procedure to existing vintages. Mr. Majoros contended ELG, if approved, should only apply on a going forward basis to plant not included in the current depreciation study. Mr. Majoros admitted that his position taken in this case is the same position taken by OUCC Witness Sarah J. Mamuska in *Indiana-American Water Co.*, Cause No. 40703 (Dec. 11, 1997). Tr. at CC-10. There we explained her position:

> Ms. Mamuska contended the ELG procedure was front loaded and that application of the ELG procedure to embedded plant would be retroactive ratemaking because it would result in a depreciation shortfall which "must be borne by current and future customers" since it cannot be charged to previous customers. She cited the FCC as having implemented the ELG procedure on a going-forward basis.

Indiana-American, p. 47. In *Indiana-American* we rejected Ms. Mamuska's position (the same position Mr. Majoros takes here), finding:

> We do not agree that application of ELG to embedded plant would be retroactive ratemaking. Under any method the current undepreciated balance of the property in each account would be recovered prospectively. . . . Accordingly, we reject the OUCC's proposal to implement ELG only for property placed in service after 1995. . . . Nor can we agree with the OUCC's contention that the ELG procedure "front loads" depreciation accruals. As we stated in the *Public Service Co.* Order [in Cause Nos. 37414-S2 and 38809], "[t]he ELG procedure remains a straight-line procedure . . . and does not permit the recovery of large amounts of capital of a particular asset in the earlier years of its life." 112 PUR 4th at 146. We explained that "whether the speed of capital recovery under the ELG procedure is quicker or slower than under the ALG procedure is really a function of the life of the asset, as it should be."

Id., pp. 49-50. Mr. Majoros added nothing that we have not already considered concerning the use of the ELG procedure with respect to embedded plant. For the reasons given in *Indiana-American,* we reject Mr. Majoros' arguments.

(b) Future Inflation. OUCC Witness Majoros objects to the inclusion of future inflation associated with costs of removal. On cross-examination Mr. Majoros admitted that both he and Mr. Selecky had testified in *PSI Energy, Inc.*, Cause No. 42359 (May 18, 2004), that future dismantlement costs and net salvage costs should be stated at net present value. Tr. at CC-11. In that case, we found:

[13] *See, e.g., Ind.-Am. Water Co.*, Cause No. 43081, at 2 (Nov. 21, 2006); *PSI Energy, Inc.*, Cause No. 42359, at 72 (May 18, 2004) ("This Commission on numerous occasions has accepted the use of the ELG methodology").

> The final issue regarding dismantlement costs is whether inflation should be factored into the dismantlement cost estimates to be utilized in determining PSI's depreciation rates. Mr. Selecky and Mr. Majoros objected to the use of inflation. Mr. Spanos utilized Mr. Wendorf's dismantlement costs which are stated in 2002 dollars, and factored inflation up to the year of the projected dismantlement as a factor in his consideration, along with his analysis of historical, or interim retirements. We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service, a sound ratemaking principle followed by this Commission. Moreover, current customers receive benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base because of the increased accumulated reserve for depreciation. Accordingly, this Commission finds that accounting for inflation in determining the dismantlement estimates to be used as a part of PSI's depreciation rates is reasonable.

PSI Energy, Inc., p. 71. As with ELG, Mr. Majoros has provided no new or additional evidence suggesting a change from our past practice is warranted. Accordingly, we reject Mr. Majoros' proposal to restate costs of removal at the present value.

The only other objection made about inflation was from Mr. Selecky who objected to the rate of inflation assumed for steam production plant and the net salvage ratios for all other accounts. Based upon projections of future inflation set forth in Annual Energy Outlook and Blue Chip Economic Indicator, Mr. Selecky reduced Mr. Spanos' recommended depreciation accrual rates by assuming that future inflation will be lower than historical inflation.

It is noteworthy that one of the sources upon which Mr. Selecky relies cautions against relying upon such long-range projections of future inflation. Blue Chip Economic Indicator warns: "Apply these projections cautiously. For the most part economic and political forces cannot be evaluated over such long time spans." Petitioner's Ex. CX-3, p. 14. Annual Energy Outlook specifically notes that its 2008 projections relied on by Mr. Selecky predated the federal deficits incurred as a result of the American Recovery and Reinvestment Act of 2009. Petitioner's Ex. CX-4. More recent projections factoring those impacts show higher inflation projections than those on which Mr. Selecky relies. *Id.* Mr. Selecky cites net salvage practices of certain other commissions (Selecky Direct at 29-30), but they do not appear to address the inflation adjustment that Mr. Selecky proposes here. We further note that while Mr. Selecky's colleague at Brubaker & Associates, Mr. Meyer, asks the Commission to rely on lead lag studies prepared by the staff of the Missouri Commission (Meyer Direct at 46-47), that Commission has recently rejected a proposal made by Mr. Selecky to use a forecasted 2.5% inflation rate to determine future net salvage, stating:

> Even more fundamentally, MIEC and Public Counsel have failed to demonstrate any reason to believe their estimates of future inflation are a more reliable predictor of future inflation than the past history used by Staff and AmerenUE in their calculations. Expert predictions of future inflation can be little more than

> guesswork. It is impossible to accurately predict what inflation might occur 30 to 40 years in the future. No doubt if an esteemed panel of experts had been polled in 1960 they never would have predicted the severe inflation of the 1970s and 1980s. Similarly, today's experts cannot possibly foresee whatever inflation may occur in 2023. The Commission finds past history to be a better predictor of future inflation for ratemaking purposes.

Union Elec. Co. d/b/a AmerenUE, 2007 Mo. PSC LEXIS 716 at *153-154, 257 PUR4th 259, 304 (May 22, 2007).

We understand there are different viewpoints on an appropriate rate of future inflation but take comfort in the fact that Mr. Spanos' study relies upon long periods covering multiple business cycles. We note that OUCC Witness Majoros measured future inflation for his present value adjustment based on the historical period of 1984 to 2007, resulting in inflation factors even higher than what Mr. Spanos used. Majoros Direct at 30; Public's Ex. MJM-9, Sch. 3, Col. (3). We find that historical experience is a better indicator of the future than admittedly less reliable projections about future inflation. We therefore reject Mr. Selecky's proposals to modify the depreciation rates using lower estimates of future inflation based upon the hypothesis that long run future inflation will be lower than in the past.

(c) Mitchell and Michigan City Decommissioning Costs. The IG and OUCC both proposed to exclude the cost to dismantle certain facilities from NIPSCO's depreciation rates. The OUCC asserts dismantlement of both Mitchell and the Michigan City Units 2 and 3 should be excluded because dismantlement costs are uneconomical and unnecessary. IG proposes to exclude the Mitchell dismantlement costs because Mitchell was prematurely retired. For the reasons described below, we find that decommissioning costs for these units shall not be included in Petitioner's proposed depreciation expense.

It is axiomatic that only used and useful plant can be depreciated. Once plant is no longer used and useful, that plant is removed from rate base and the accompanying depreciation expense is also eliminated. Here, it is undisputed that Mitchell and Michigan City 2 and 3 were not included by Petitioner in Petitioner's proposed rate base, and as discussed above, the Commission determined the value of rate base excluding those units. Based on that exclusion, we find that those decommissioning costs shall not be included in Petitioner's depreciation rates. Accordingly, we need not address any of the IG or OUCC arguments on this issue. To the extent NIPSCO incurs decommissioning costs for these units in the future, our decision here with respect to depreciation rates does not preclude NIPSCO from seeking to recover those cost in a subsequent rate proceeding.

(d) Remaining Issues. The next issue to be resolved is the use of a contingency in the BMcD dismantlement studies. Mr. Selecky argued either the post-remediation value of the land in industrial condition should be an offset to the dismantlement costs or the contingency should be eliminated as a trade-off for the value of the land. Mr. Selecky did not identify the dollar value of the land after dismantlement. As a result, there is no evidence in the record to guide us in determining whether this would produce a material difference in the depreciation rates or be a reasonable trade-off for the contingency, assuming for the sake of argument it would even be proper to treat a non-depreciable asset like land as salvage. Further, we find it noteworthy that Mr. Selecky is not a licensed real estate appraiser. As a result, the record is devoid of any evidence to judge whether his proposal to equate the value of the land with the contingency is reasonable. We also give weight to the fact that the 20% contingency factor used in the BMcD demolition cost studies is conservative compared to the 25% contingency factor we accepted in PSI Energy, Inc., Cause No. 42359, at 70-71. Also, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. Id. at 70. No evidence was presented that this Commission has ever used the value of land as an offset to an asset's cost of removal. In fact, Mr. Selecky did not identify to us any decision of any regulatory commission accepting his position regarding land and the contingency. Petitioner's Ex. JJS-R5; Petitioner's Ex. JJS-R6. Given that Mr. Selecky's recommendation would be such a departure from our past practice and that we have scant evidence to guide us in this exercise, we reject Mr. Selecky's proposal.

The next issue raised by Mr. Selecky concerns the application of escalation to the gross cost of salvage rather than net cost. As with contingency, Mr. Selecky has not offered the impact that this proposed change would have and whether it would be material. We are persuaded by Mr. Spanos' testimony that the charges most likely to be impacted by future inflation are labor rather than the salvage components. Also, as mentioned above, the contingency factor in the BMcD demolition studies and the industrial condition assumption in Mr. Spanos' depreciation study are conservative. Accordingly, we reject Mr. Selecky's argument.

Finally, there is the issue of SFAS 143 and Mr. Majoros' request that we require the cost of removal reflected in NIPSCO's depreciation reserve to be reclassified as a regulatory liability. First, we see little difference in Mr. Majoros' proposal here and the one he made in the 2004 PSI Energy, Inc. rate case that we did not accept. *PSI Energy, Inc.*, Cause No. 42359 at 62. Second, we are left to ponder why it would be important for us to do as Mr. Majoros recommends. The only basis that we have heard is that without such recognition, NIPSCO will be inclined to move these amounts to income. But NIPSCO cannot unilaterally make that decision. The USOA provides: "The utility is restricted in its use of the accumulated provision for depreciation to the purposes set forth above. It shall not transfer any portion of this account to retained earnings or make any other use thereof without authorization by the Commission." USOA, Electric Plant Account 108(E); 170 I.A.C. 4-2-1.1(a). Accordingly, we find Mr. Majoros' recommendation should not be accepted.

(e) Ultimate Finding. For the foregoing reasons, we find that Mr. Spanos' depreciation study and proposed depreciation accrual rates for electric and common plant as set forth in Petitioner's Exhibit JJS-2, pp. 51-62, are hereby approved, with the exception of decommissioning costs. This results in a total increase in depreciation expense to reflect the new rates, Sugar Creek, and common plant of $17,744,442. As proposed by NIPSCO (Hershberger Direct at 25), NIPSCO shall determine the depreciation and amortization expense associated with Sugar Creek by applying the rates set forth in Petitioner's Exhibit JJS-2, p. 60, to the acquisition price of the plant.

D. Operation and Maintenance Expense.

(1) Labor Cost Adjustments.

(a) Petitioner's Evidence. NIPSCO Witness Eileen O'Neill Odum described the reorganization within NIPSCO intended to improve NIPSCO's focus by providing needed support in a variety of substantive areas including regulatory compliance, system reliability, and customer satisfaction. Odum Direct at 4-5. She testified that she had authorized the creation of 83 new staff positions in 2008 to effectuate that reorganization and the furtherance of NIPSCO's performance. Ms. Miller sponsored proposed Adjustment OM-9 to increase test year operation and maintenance expenses by $6.4 million to reflect the new positions.

NIPSCO also presented testimony from Robert D. Campbell, Senior Vice President of Human Resources for NiSource, Inc., that addressed NIPSCO's compensation and benefits practices in support of NIPSCO's test year labor expense as well as several pro forma adjustments. Mr. Campbell testified that NiSource, NCS, and NIPSCO utilize a "total rewards" compensation philosophy that considers all forms of compensation in order to attract and retain qualified employees. He explained that employee compensation generally consists of three components: base pay, annual incentive opportunity, and benefits. Campbell Direct at 3-4.

Mr. Campbell testified that NCS has regularly retained Hewitt Associates, a global human resources consulting firm, to assist in the setting of competitive salary ranges, establishing a program for administering salary increases, and evaluating and recommending modifications to NIPSCO's wage and benefit plans. He explained that Hewitt is familiar with the NiSource, NCS, and NIPSCO information systems, data, personnel and corporate structure based on its long-term relationship. He testified that Hewitt has helped with the implementation of a base pay management system and has also assisted in the measuring of benefit programs. Mr. Campbell testified that NIPSCO's compensation packages are reasonable and competitive. Campbell Direct at 4-5.

Mr. Campbell explained that the terms of NIPSCO's two collective bargaining agreements determine wages for its union employees and those agreements provide for wage increases of 3.0% effective at the conclusion of the years ending December 31, 2007 and December 31, 2008. He testified that for employees not covered by those contracts, base pay is determined using market data to establish a compensation range of between 75% and 125% of the market median, with specific decisions within that range based on the skill set, experience and performance of the employee. He testified that effective March 1, 2008 an overall average 3.25% pay increase was awarded to NIPSCO's non-union workforce. Campbell Direct at 6-7.

Mr. Campbell detailed NIPSCO's incentive compensation plan in his direct testimony. He testified that the incentive compensation plan is intended to drive the Company's goals through documented performance in four key areas: Customer, Employee, Financial, and Process/Capability. He testified that the potential to earn incentive pay is necessary to attract and retain qualified employees as part of a total compensation package, and noted that by 2007 nearly 90% of U.S. companies had implemented a broad-based variable pay plan. Campbell Direct at 7-8.

Mr. Campbell explained that NIPSCO's incentive levels and ranges are established by placing each employee in a job scope level based upon his or her responsibility in the organization, with an incentive range that corresponds to the assigned job scope. The incentive range defines the opportunity for an incentive payout that begins at a "trigger" level and increases through a "target" level to a maximum "stretch" incentive. Percentages over base pay are then assigned to each of the three levels for each job scope. Mr. Campbell testified that if specific financial goals are met, an incentive pool is created for distribution to employees. For non-exempt employees, the incentive payout is determined by multiplying eligible wages for the employee times the incentive payout percentage. For exempt (non-union) employees, one third of the incentive payout is determined through the same calculation, with the remainder determined through an assessment of the employee's success against defined individual performance objectives. Mr. Campbell testified that payment of incentives is based on whether the established criteria have been met, and that NIPSCO had paid incentives at some level in three of the past four years. Campbell Direct at 8-10.

Mr. Campbell testified that NIPSCO's base salary and total cash compensation are reasonable and competitive. Campbell Direct at 12. Mr. Campbell's conclusion was supported by an analysis that compared base salaries and incentive pay for a sampling of NIPSCO positions to similar external positions based on data provided by Hewitt. *Id.* at 11. The comparison showed that base salary for the NIPSCO positions sampled was 4.6% below the comparable market positions and that total cash compensation was 7.4% below the market. *Id.* at 11-12; Petitioner's Ex. RDC-4. He also testified that similar conditions exist for NCS, with base salaries 3.2% below the market and total cash compensation 3.9% below. *Id.* at 12; Petitioner's Ex. RDC-5.

Mr. Campbell testified that merit increases of 2.5% for its non-exempt, non-union employees and of 3.0% for its exempt employees were below average for both companies within the region and within the utility industry. Campbell Direct at 13; Petitioner's Ex. RDC-6. He explained that the merit increases for non-exempt employees took effect March 1 of each year. Mr. Campbell testified that regular merit increases are important to recognize employee contributions and to attract a high quality workforce and are therefore awarded on a regular basis. *Id.* at 13-14.

Mr. Campbell's testimony also addressed the benefits paid to NIPSCO's employees, including health and welfare plans, a defined benefit plan (pension), a 401k plan as well as paid time off for vacation, holidays and sick days. He testified that pension plans are provided to certain NCS and NIPSCO employees under one of four pension offerings. He explained each of the four offerings (the Account Balance 2011 formula, the Account Balance formula, the salaried/non-exempt Final Average Pay formula, and the bargaining unit Final Average Pay formula) as well as the way benefits are calculated for each. Campbell Direct at 14-16. He also explained that NIPSCO's retirement savings plan and bargaining unit deferred savings plan allow employees to contribute 1% to 50% of eligible compensation on a pre-tax basis, and that contributions are matched by NIPSCO at a rate determined based upon the pension plan in which the employee participates. *Id.* at 16-17.

Mr. Campbell testified that medical plans are provided to employees pursuant to four self-insured plans, and also provided to retirees who meet certain criteria. Campbell Direct at 17. He also explained NIPSCO's three dental coverage options, its vision plan, its three forms of life insurance, its long term disability plan, and its employee assistance program, each of which are available to employees. *Id.* at 18-19. Mr. Campbell testified that NIPSCO's health plans are competitively bid to ensure that both carriers and third-party administrators are able to provide quality service in the most cost-efficient manner. *Id.* at 19. He testified that NCS, on behalf of NIPSCO, is proactive in examining ways to better manage health care costs. He explained that underwriting margins are reduced because primary plans are self-insured. He noted NIPSCO's affiliation with NiSource ensures that NIPSCO is in a position to take advantage of greater purchasing power and a larger risk pool. *Id.* at 20. Mr. Campbell explained that NIPSCO's employees have experienced increases in their contributions toward health plans because they share on a percentage of cost basis.

Mr. Campbell testified that NCS performs periodic studies to compare NIPSCO's benefits to a "market basket" of similar offerings from other energy industry and non-energy industry employers. The total value and the employer-paid portion of the package are rated on a standardized value scale to assess the deviation of the NIPSCO standard benefit offerings from the average of other companies. NCS and Hewitt also conduct ongoing evaluations of marketplace trends in benefits and other ways to reduce the cost of providing the necessary benefits. He testified that Hewitt's most recent study showed that the employer-paid value of its benefits plan was 0.1% higher than the average of the selected industry cohort. He concluded that NIPSCO's benefits are competitive and reasonable when compared with those offered by other similar employers. Campbell Direct at 21-22.

Mr. Campbell testified that the utility industry is faced with a significant challenge posed by the aging of its workforce. He explained that projected retirements over the next five-years will require the filling of certain critical positions ahead of time to allow for formal and on-the-job training. He testified that the median age of all NIPSCO electric-related employees as of the close of the test year was 50.0 years -- considerably higher than the rest of the electric utility industry and the U.S. workforce in general. Campbell Direct at 23-24.

Mr. Campbell testified that the eligible retirement age bracket for NIPSCO begins at 55 years of age as a function of NIPSCO's pension and its collective bargaining contracts, and that at the end of 2007 about 26% of NIPSCO's electric associated workforce was in that age bracket, and 51% of that workforce is over the age of 50. He testified that as a result of those facts, over half of NIPSCO's electric-associated workforce will be eligible for retirement by 2012. Campbell Direct at 24-25.

According to Mr. Campbell, 64% of the 830 electric employees eligible for reduced-benefit or full retirement over the next five-years will choose to retire by the end of 2012, based on statistical projections included in his testimony. Campbell Direct at 25-26. He testified that NIPSCO has identified positions within its bargaining unit employees in generation, transmission, and distribution that are especially critical to safe, reliable and effective day-to-day operations, along with "feeder" positions into those critical jobs. He explained that over the past five-years NIPSCO has focused on the timely filling of retirement vacancies into the critical and feeder positions. *Id.* at 27.

Mr. Campbell testified that NIPSCO has taken steps to manage the acceleration of retirements. He explained the "mega-bid" process used by NIPSCO whereby a job-needs complement is developed for the upcoming year based upon analysis of retirement trends and employee migration. Bids are posted for this projection in January and filled as required by the timing of retirements to streamline the creation of an applicant pool and to allow for certain positions to be filled in advance to allow for extra training. Campbell Direct at 27. He added that succession planning programs have helped accomplish a critical-position focus, and that the hiring of summer interns and use of part-time retirees to help mentor younger engineers has also been employed. Finally, Mr. Campbell testified that through a partnership with Ivy Tech Community College of Indiana, NIPSCO has worked to create curriculum content and otherwise assist in developing training programs that result in capable and interested candidates for utility industry positions. Mr. Campbell also identified the critical positions that are the focus of NIPSCO's efforts into the future for both management and represented (union) positions. *Id.* at 28-30.

Mr. Campbell testified that NIPSCO has stepped up recruiting for critical positions to bring replacements into the workforce six months to a year prior to the retirement of critical employees to allow the replacement workers to be mentored by more experienced employees prior to their retirement. He explained that the identification of replacement needs in advance also allows for the hiring of apprentices for bargaining unit positions to allow for training to take place prior to the occurrence of the vacancy. He also indicated that significant support will be required from the Human Resources Department to identify an optimized blend of new employees and contract workers to provide the most cost-effective solution. Campbell Direct at 30-31.

Mr. Campbell testified that NIPSCO incurs additional costs as part of its early hiring for critical positions primarily due to the temporary double staffing that takes place after a new employee is hired but before the incumbent retires. He indicated that those costs are increased by a multiplier to cover employee benefits, and that capital-related costs are subtracted. He testified that in the case of dual employees working on both the gas and electric sides of the business, an electric allocator is used to identify the electric-only costs. Campbell Direct at 31-32. Mr. Campbell sponsored Petitioner's Exhibit RDC-7 that documented the proposed adjustment over the five-year period from 2008 to 2012. That exhibit contained a five-year cost projection of $19,626,036, with annual projected expenses of between $2,031,703 in 2008 to $6,689,011 in 2010.

Mr. Campbell testified that the adjustment proposed is reasonable because by focusing on critical positions and their backfills, NIPSCO can continue to provide safe and reliable service at a reasonable cost along with a good balance of journeymen to apprentices to enable effective on-the-job training. He added that the incremental cost is a reasonable approach to ensure continuation of local expertise necessary to effective day-to-day operation of NIPSCO's generating stations and its transmission and distribution system. Campbell Direct at 33-34.

Mr. Campbell also presented testimony supporting Adjustment OM-8 sponsored by Petitioner's Witness Miller which concerned positions that were vacant in the test year. He testified that the $5,016,101 adjustment was intended to reflect additional staffing for vacancies that NIPSCO is actively seeking to fill. Mr. Campbell testified that the amount of the adjustment was calculated by using the salary or wage information for each of the 104 vacancies identified by Human Resources, and adding the cost for benefits and incentive compensation, identifying the portion of the vacancies that are electric-associated, and then subtracting the capitalized portion of the expense. Campbell Direct at 34. He explained that the positions not covered by a collective bargaining agreement are posted internally and on an external website. He added that positions covered by a collective bargaining unit are posted on all NIPSCO Union Bulletin Boards and that certain entry-level positions are also posted externally and advertised in local newspapers. *Id.* at 35.

NIPSCO Witness Timothy A. Dehring, NIPSCO's Senior Vice President, Energy Delivery, also submitted direct testimony that addressed specific aspects of the proposed aging workforce adjustment related to NIPSCO's electric transmission and distribution system. He testified that the critical positions identified in those areas were electric lineman, electric metermen, substation electricians, dispatcher operators, first line supervisors, and engineers. He explained that NIPSCO had experienced steady retirements in electric linemen resulting in a rapid growth of apprentices in lineman positions. Dehring Direct at 23. He indicated that NIPSCO had filled additional jobs over and above retirement levels in 2007 and anticipated continuing to do so. He testified that about 50 is the maximum number of apprentice lineman that NIPSCO can support with on the job training from experienced journeymen, and that the growth in the relative number of apprentices has resulted in increases in planned overtime among linemen. *Id.* at 23-24.

Mr. Dehring detailed the circumstances surrounding the need to address losses in experienced electric metermen and substation electricians, and noted that retirement among dispatcher operators was more critical even though the training cycle for those positions was only one year. He testified that about 80% of NIPSCO's dispatcher operators are currently eligible to retire, and that NIPSCO has four to five employees in training at a time in advance of anticipated retirements, and that NIPSCO had hired a dedicated trainer for this position. Dehring Direct at 24. He testified that NIPSCO's current strategy of hiring replacements as soon as retirements occur is inadequate because it has become increasingly difficult to train new hires with fewer first line supervisors and engineers. *Id.* at 25.

Mr. Dehring detailed NIPSCO's more proactive approach to filling jobs in advance of retirement. He testified that NIPSCO had created a five-year staffing plan for each of the critical positions in his area that includes the advance hiring of early replacements beginning in 2007. He testified that the planning process is also intended to reduce planned overtime necessitated by heavy reliance on less experienced workers as senior employees retire. Mr. Dehring sponsored Petitioner's Exhibit TAD-4 that summarized the five-year staffing plan for electric linemen and that showed the calculation of incremental staffing beyond 2007, exclusive of lineman positions specifically targeted for safety. Dehring Direct at 25. Mr. Dehring sponsored similar plans for the other four critical positions identified in Petitioner's Exhibits TAD-5 through Petitioner's Exhibit TAD-8.

(b) OUCC's Evidence. OUCC Witness Barbara A. Smith presented testimony that addressed many of the labor-related adjustments proposed by NIPSCO. Ms. Smith testified that the OUCC did not oppose NIPSCO's proposed Adjustment OM-5 to capture wage increases because the proposed adjustment was fixed, known and measurable. She testified that the OUCC also did not oppose NIPSCO's incentive compensation Adjustment OM-6 based on an analysis of testimony, workpapers and discovery. Smith Direct at 3-4.

Ms. Smith testified in opposition to NIPSCO's proposed aging workforce adjustment. She testified that NIPSCO has not experienced a lower employee count based on retirements in recent years, and that NIPSCO actually employed more workers during the test year than the average for the 2001-2007 time period. Smith Direct at 6. Ms. Smith testified that the number of retirees in 2007 was below the average retirements from 2003 to 2007, and was critical of the proposed adjustment because it was not dependent upon the occurrence of the projected retirements. *Id.* at 7. She testified that a significant downward adjustment was warranted for the removal of retirees' salaries to eliminate the overstatement of labor expense. *Id.* at 9. Ms. Smith also testified that NIPSCO's ability to accurately predict retirees was flawed, and instead recommended a different approach to aging workforce predicated on the actual expenses incurred during the 2008 adjustment period. She testified that NIPSCO could not be blamed for failing to foresee the economic collapse after the filing of its case-in-chief, but testified that the use of the actual 2008 amount would be a better reflection of workforce conditions. She proposed that NIPSCO be allowed recovery of the 2008 expenditures relating to aging workforce replacements of $2,223,128. *Id.* at 10-11.

Ms. Smith also testified on the issue of vacancies in NIPSCO's workforce captured in NIPSCO Adjustment OM-8. She testified that NIPSCO should not be authorized to recover costs associated with positions that do not represent incremental increases in base pay and incentive compensation, and instead proposed that the proposed pro forma adjustment of $5,016,101 be reduced to $2,766,995.[14] Smith Direct at 13. Ms. Smith applied a similar rationale to NIPSCO's proposed Adjustment OM-9 for the filling of the 83 new positions identified by Ms. Odum. She testified that by reducing the proposed adjustment for positions not backfilled, accounting for all new positions filled through March 11, 2009, and eliminating the capitalized portion, the OUCC calculated an appropriate adjustment for NIPSCO's electric operations of $4,637,695. *Id.* at 14-15.

(c) <u>IG's Evidence</u>. IG Witness Meyer testified that NIPSCO's proposed aging workforce adjustment was not reasonable because it is unnecessary in light of NIPSCO's current practices, is highly speculative, and encompasses events beyond the test year and adjustment period. He testified that the extensive evidence offered by NIPSCO established the adequacy of its hiring procedures. He asserted that the mega-bid process, increased training in the test year, and the partnership with Ivy Tech are examples of the adequacy of NIPSCO's existing tools. Meyer Direct at 3.

Mr. Meyer testified that the projected retirements embedded in NIPSCO's proposed adjustment were highly speculative, and that the actual experience in 2008 was proof that the projections were unreliable and the statistics were inflated. He testified that approval of an adjustment based on inflated projections will result in ratepayers overpaying until the adjustment is removed from rates in the next rate case. Meyer Direct at 4-5.

Mr. Meyer expressed his opinion that a utility proposing an adjustment that encompasses a time period beyond the test period should demonstrate the adjustment is required in order for the utility to earn its authorized return during the years the proposed rates are in effect. Meyer Direct at 5-6. He explained that other cost of service changes may occur during the five-year projection period of the adjustment that will not be captured in rates between cases. He testified that one example of such offsetting changes is that the proposed adjustment fails to capture savings associated with lower salaried workers being hired after retirements occur. He testified that the failure to capture those savings in the adjustment should lead the Commission to deny the proposal in its entirety. *Id.* at 6-8.

Mr. Meyer also opposed NIPSCO's proposed adjustment for the filling of test year vacancies. He testified that vacancies are commonplace, and that any adjustment approved should be for less than the full 104 vacancies in recognition of the fact that some vacancies always exist. He recommended that the adjustment be scaled back to recognize only those positions filled as of the close of the adjustment period. He also recommended that the approved adjustment incorporate only the minimum of the salary range for each position filled. He proposed that the adjustment be reduced from $5 million to $2.9 million in recognition of his recommendations. Meyer Direct at 9-11.

Similarly, Mr. Meyer recommended that NIPSCO's proposed adjustment for the addition of positions as part of the change to its organizational structure be reduced to reflect fewer

[14] Ms. Smith corrected her testimony during the evidentiary hearing to reduce her original recommendation from $4,087,646 to $2,766,995 in order to correct a mathematical error.

positions and lower salary. Mr. Meyer testified that in his opinion, some of the services to be provided by the 83 new positions must have been provided during the test year by NCS employees. Mr. Meyer contended that once the new positions were filled, NCS expenses would consequently decrease as services are transitioned to the new employees, so a pro forma adjustment to reduce NCS expenses should have been made. He concluded that only 49 of the 83 positions identified by Ms. Odum had been demonstrated to represent a supported additional employee hire. Mr. Meyer also recommended calculating the adjustment using the low end of the range salary data. Based on his application of the ratio of positions hired through December 31, 2008 to total positions requested, Mr. Meyer proposed a reduction in the proposed adjustment for new positions from $6.4 Million to $3.8 Million. Meyer Direct at 11-14.

Mr. Meyer also criticized NIPSCO's inclusion of incentive compensation dollars associated with the meeting of financial goals in its revenue requirement. He testified that in his view all employee payments under an acceptable incentive plan should be directly related to the achievement of operational performance goals in order to be recoverable in rates. Meyer Direct at 16. Mr. Meyer testified that he was opposed to the use of financial targets or earnings per share as a basis for the award of incentive payments because such targets may cause a reduction in the quality of service to customers. He testified that "it is entirely inappropriate to pass the costs of such profit-driven awards onto the ratepayers." *Id.* at 17. Mr. Meyer cited two Missouri Public Service Commission orders in support of his position, and also discussed the Commission's order in *PSI Energy, Inc.* Cause No. 40003 (Sept. 27, 2006), in support of his proposed standard that would exclude all earnings per share related incentive awards. Mr. Meyer proposed the disallowance of $2.5 million in addition to the proposed reduction in test year incentive payments proposed by NIPSCO to eliminate all incentive payments to union and non-exempt, non-union employees and one-half of the incentive payments made to exempt employees. Meyer Direct at 14-20.

(d) Petitioner's Rebuttal Evidence. In NIPSCO's rebuttal case, Mr. Campbell disagreed with the positions taken by OUCC Witness Smith and IG Witness Meyer opposing NIPSCO's proposed aging workforce adjustment. He explained that contrary to the assertions of Ms. Smith and Mr. Meyer, the difference between the projected and actual retirements for 2008 (the first year of the projection) does not impact the accuracy of the proposed adjustment. He testified that the use of a five-year average in the calculation of the adjustment was intended to account for single year fluctuations because individuals foregoing retirement in the first year would be more likely to retire in the second, and so forth. He explained that the average year approach is intended to smooth out the year-to-year variances in retirements caused by a variety of factors. Campbell Rebuttal at 2-3.

Mr. Campbell was also critical of Mr. Meyer's contention that an aging workforce adjustment was unnecessary based on NIPSCO's demonstrated ability to fill positions in the past. He explained that the Ivy Tech partnership and mega-bid strategy discussed in his direct testimony were beneficial regardless of the rate of retirement, but were not designed as a replacement for on-the-job training for critical employees. He testified that the cost of implementing the new program during the 2007 test year was subtracted from the calculation of costs going forward so as to arrive at a representative average. Mr. Campbell explained that the replacement of retiring workers in the past is not the same as the situation faced in the future because in the case of prior retirements, NIPSCO had a pool of qualified replacements from which to draw. He testified that the cumulative impact of the accelerated loss of experienced personnel will become greater as retirements increase, so it is necessary to work now to ensure that replacements are available when they occur. Campbell Rebuttal at 3-5.

Mr. Campbell testified about the process and analysis used to identify individual workers in critical positions which involved conversations with employees and their supervisors. For critical positions with larger populations of eligible employees (such as lineman and customer service center personnel), NIPSCO used projections based on the previous five-years of electric-related bargaining unit retirements. He testified that the results of that analysis were shown on exhibits sponsored by Mr. Dehring. Mr. Campbell also explained the difference between that analysis and the process used in his testimony to predict retirements of baby boomer generation employees which was intended to demonstrate the challenge faced by NIPSCO in dealing with the upcoming surge in retirements. Campbell Rebuttal at 5-7; Petitioner's Ex. TAD-4. Mr. Campbell clarified that the bar graph contained in his direct testimony was a predictive model for all employees developed from historical data, while the projected retirements among critical employees were determined according to the analysis based on discussions with employees and supervisors. *Id.* at 7.

Mr. Campbell disagreed with Mr. Meyer that the proposed aging workforce adjustment failed to capture savings from lower salaries associated with replacement workers. Mr. Campbell sponsored an exhibit that demonstrated that the aging workforce adjustment captures only the incremental cost during the overlap between the two positions. Campbell Direct at 8; Petitioner's Ex. RDC-R2. This exhibit, he stated, illustrates why the proposed adjustment did not result in a "double count" of costs. Finally, Mr. Campbell disagreed with Ms. Smith's proposal to calculate the adjustment based solely on the 2008 actual data on the ground that the five-year average used by NIPSCO is a more accurate reflection of the anticipated level of ongoing expense. *Id.* at 9.

Mr. Campbell testified that NIPSCO accepted the OUCC's proposed modifications to proposed Adjustments OM-8 and OM-9 to reflect the number of employees actually hired. Campbell Rebuttal at 10, 11. The reduction for Adjustment OM-8 was agreed to be $2,766,995, and for Adjustment OM-9 was agreed to be $4,637,695.[15] Mr. Campbell disagreed with the additional reductions proposed by Mr. Meyer because Mr. Meyer's proposal assumed that all positions would be filled at the minimum salary level. Mr. Campbell said such an assumption is unrealistic and unsupported by market information. In Mr. Campbell's experience, individuals are hired at different points within the salary range based on experience, qualifications and other measurable criteria. He noted that NIPSCO's agreement to the OUCC proposals for Adjustments OM-8 and OM-9 incorporated actual salary data. Campbell Rebuttal at 10-11.

With respect to NIPSCO's incentive compensation plan, Mr. Campbell testified that Mr. Meyer had misunderstood the plan because performance metrics are built into the discretionary portion of NIPSCO's plan. He testified that in order to qualify for the discretionary portion of the incentive plan, metrics for safety, operational and reliability measures, and customer satisfaction would necessarily have been met, thus providing benefits to ratepayers. He also testified that Mr. Meyer had misunderstood the corporate financial measures used in the incentive plan as earnings per share, when the actual metric is *operating* earnings per share that normalizes for weather. Mr. Campbell testified that NIPSCO's proposed adjustment satisfied all

[15] The amount of the adjustments was contained in NIPSCO Witness Miller's rebuttal testimony and exhibits, but Mr. Campbell indicated agreement with the OUCC's calculation.

three legs of the Commission standards set forth in *PSI Energy, Inc.*, Cause No. 42359, for recovery of incentive compensation, including the requirement that shareholders bear responsibility for a portion of the incentive payments. Campbell Rebuttal at 11-13.

(e) Discussion and Findings.

(i) Incentive Compensation. The Commission has long recognized the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. The criteria for the recovery of incentive compensation payments through rates are well settled in Indiana: (1) the incentive compensation plan is not a pure profit sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. *See, e.g.*, *PSI Energy, Inc.*, Cause No. 42359, at 89. IG witness Meyer proposes to disallow all of NIPSCO's incentive compensation plan costs. IG Ex. Exhibit GRM-3. NIPSCO maintains these costs satisfy the criteria for recovery. No party asserts that NIPSCO's incentive compensation plan results in excessive pay levels. We focus on the two remaining criteria to evaluate Mr. Meyer's adjustment.

First, NIPSCO's incentive plan cannot be said to be a pure-profit sharing plan which only incents employees to become more profitable. *Ind.-Am. Water Co.*, Cause No. 42029, at 45 (Nov. 6, 2001). Components of NIPSCO's plan are indisputably based on operational performance metrics of the type we have required to be included in recoverable plans in prior orders. Mr. Meyer proposes to eliminate recovery of all of the costs because he understood the incentive payments are dependent upon NiSource's achievement of a financial trigger for an applicable calendar year rather than operational incentives. Mr. Campbell testified, however, that NIPSCO's incentive plan also incorporates operational performance goals by considering metrics like safety and reliability measures in awarding incentive pay to exempt employees. Basing the incentive pay of these leaders on operational performance metrics gives them an incentive to ensure the employees that report to them, including union and non-exempt non-union employees, focus on service to ratepayers. Mr. Campbell also testified that achievement of financial goals provides benefits to ratepayers and shareholders. We agree a balanced approach to controlling costs and efficiently serving customers can both improve a utility's bottom line and benefit ratepayers in the short- and long-run.

We also believe that Mr. Meyer's adjustment inappropriately allocates the entire incentive pay cost to shareholders. This proposal is inconsistent with our conclusion that NIPSCO's incentive plan includes operational requirements and is not a pure profit sharing plan. Under our criteria, once an incentive compensation plan is found to provide benefits to shareholders and ratepayers and not be excessive, an appropriate level of costs should be recovered from ratepayers who are benefited by these programs. Mr. Campbell explained that NiSource's shareholders are already allocated a portion of the incentive plan costs because NIPSCO's adjustment only includes incentive compensation at the trigger level which is 50% below the target amount, leaving shareholders to cover the target and stretch levels. Thus, NIPSCO's adjustment reduces electric test year incentive compensation expense by $916,264. Miller Direct at 20. NIPSCO's adjustment is consistent with incentive compensation adjustments that we have previously approved for other utilities. *See Ind.-Am. Water Co.*, Cause No. 43187, at 12 (Oct. 10, 2007); *Ind.-Am. Water Co.*, Cause No. 42520, at 88 (Nov. 18, 2004);

PSI Energy, Inc., Cause No. 42359, at 88-89. Because NIPSCO's plan satisfies the general criteria for cost recovery, we accept NIPSCO's incentive compensation adjustment.

(ii) Aging Workforce. This is not the first time that the Commission has been faced with a proposal to address aging in the utility workforce. Both Vectren and I&M have proposed variations on the aging workforce theme. Though each of those proposals ultimately became moot as a result of settlement, we are nonetheless cognizant that the demographic characteristics of the workforce at large are particularly problematic for the utility industry that is highly reliant upon experienced and skilled workers to maintain their critical infrastructure.

In evaluating the adjustment proposed by NIPSCO, we must first evaluate whether the conditions faced by the utility warrant consideration of an adjustment to account for them. We conclude that the evidentiary record here supports the conclusion that such conditions exist. While both OUCC Witness Smith and IG Witness Meyer were critical of the specific mechanics of NIPSCO's proposal, it is undisputed that more than half of NIPSCO's employees in critical positions will be eligible for retirement by 2012. While it is difficult to project how external factors may influence individual retirement decisions, the undeniable reality is that NIPSCO will be faced with the need to replace a large number of its most experienced personnel in the foreseeable future.

Having concluded that NIPSCO is faced with conditions sufficient to warrant consideration of its aging workforce proposal, we must next assess whether existing hiring practices and initiatives are adequate to enable the utility to bridge the gap the proposal is intended to address. Both Mr. Campbell and Mr. Dehring described the range of efforts undertaken to accelerate the hiring and training of new workers in time to develop the experience and expertise to fill the positions that NIPSCO identified as critical. While Mr. Meyer questioned why NIPSCO's existing measures were not adequate to address the aging of its workforce, we note that Mr. Meyer offered no evidence to explain why NIPSCO's current measures were sufficient. Moreover, there was also no evidence disputing that the positions selected were critical to the success of NIPSCO in providing safe and reliable service.

We now turn to an examination of the methodology proposed by NIPSCO for the calculation of its proposed adjustment. Both the OUCC and IG were critical of NIPSCO's proposal as speculative and imprecise because it relies on projections of future retirements rather than on known events. We are concerned that many adjustments based on projections are not representative of an ongoing level of future expense. However, the fact that projected data is used does not in and of itself disqualify a proposed adjustment unless it is clear that the data relied upon or the projection methodology employed is suspect. That is not the case here. The use of a five-year average, when taken in the context of the undisputed evidence about the age of NIPSCO's critical workforce, is reasonable as a technique to smooth expected variations in retirements. This is the case because the projection techniques themselves are sufficiently sophisticated to be reasonable, and because the advanced age of the workforce dictates that predictable retirements will occur sometime within the five-year period. We find Mr. Campbell's rebuttal testimony to be persuasive in that regard because it clearly explained how and why the actual 2008 retirements did not impact the proposed adjustment.

Finally, we find that the proposed adjustment is conservative because it proposes recovery of only the "overlap" dollars for the period when a replacement worker is on the payroll prior to the retirement of the current employee. We disagree with Mr. Meyer's position that the proposed adjustment fails to account for savings associated with the lower paid replacement based on the explanation of the adjustment in Mr. Campbell's rebuttal testimony. We also note that while the OUCC disagreed with NIPSCO's calculation of the aging workforce adjustment, it supported recovery of actual 2008 dollars spent for early replacement of retiring workers, an amount $1.7 million lower than that proposed by NIPSCO.

We find that the aging workforce Adjustment OM-7 of $3,925,207 proposed by NIPSCO is reasonably representative of the actual expenses to be incurred during the life of the rates approved in this proceeding and should be approved. However, as Mr. Campbell testified that its proposed adjustment is based on projected retirements through 2012, we similarly find that the adjustment approved shall apply through 2012—upon the conclusion of 2012, NIPSCO shall file a tariff revision eliminating this adjustment.

(iii) Vacancies and Reorganization. In evaluating adjustments to test year staffing levels and associated expenses proposed by the parties, the question is whether the proposed expense is fixed, known, and measurable and is reasonably representative of ongoing levels of operating expense of the utility. In this case, NIPSCO agreed to the OUCC's proposal for an ongoing expense that captures actual hirings as of a specified date even though that expense level was below that which NIPSCO initially proposed. We find that the test year labor expense, as adjusted by the amount agreed to between NIPSCO and the OUCC, is representative of the ongoing expense NIPSCO is likely to experience during the life of the rates approved in this proceeding and should be approved. In approving that ongoing expense level, we reject Mr. Meyer's proposal to base the adjustment on the assumption that all employees hired to fill vacancies or to staff newly created positions would be filled at the minimum of the applicable salary range, especially because the adjustment we approve is based on actual rather than theoretical salaries.

(2) Pension Expense. In its prefiled case-in-chief, NIPSCO proposed a five-year average for pension expense. During cross-examination and redirect examination of Ms. Miller during the presentation of NIPSCO's case-in-chief, Ms. Miller explained that NIPSCO has experienced a significant increase in pension expense as a result of the market collapse in the fall of 2008. Tr. at P-55–P-57, P-83–P-86, and P-92–P-94. NIPSCO's pension expense for 2009 was determined as of December 31, 2008. She sponsored a redirect exhibit showing a recalculated five-year average including 2009 and dropping out 2004. The updated five-year average increased the pension expense adjustment from $5,762,558 (Petitioner's Ex. LEM-3, Adjustment OM-3) to $10,188,010 (Petitioner's Redirect Ex. 2). Although no party contested this calculation, neither the OUCC nor IG included the updated adjustment in their proposed revenue requirements. On rebuttal, Ms. Miller sponsored an exhibit further updating the adjustment from $10,188,010 to $10,489,229 to reflect a slight change resulting from finalization of the books at the end of 2008. Miller Rebuttal at 51-52; Petitioner's Ex. LEM-R3, Adjustment OM-3.

We find that NIPSCO's original five-year average is appropriate, and accordingly find the pension expense adjustment of $5,762,558 shall be approved.

(3) Variable Production O&M Expense.

(a) Evidence. NIPSCO Witnesses Pack and Sweet supported

Adjustment OM-2, which increased test year operating expenses by $4,001,238 to normalize the variable costs required to operate NIPSCO's generating facilities. Miller Direct at 14. Mr. Pack explained that NIPSCO's generation fleet experienced three unusually long outages in 2007. Unit 7 required two outages totaling 25 weeks to combine maintenance with the installation of environmental control equipment. Unit 10 suffered an equipment failure and delays in obtaining replacement components resulting in an 11-month outage during the test year. Equipment failure also caused Unit 16A to suffer an unusual outage for the last five months of the test year. Mr. Pack noted that these outages were unusual and not expected to occur in the future. Pack Direct at 5. Mr. Sweet explained that test year expenses should be adjusted to include run time by: (1) three months for Unit 7; (2) eleven months for Unit 10; and (3) five months for Unit 16A. Sweet Direct at 11.

OUCC Witness Catlin opposed NIPSCO's adjustment because he believed the PROMOD generating dispatch model run used to calculate the adjustment should be re-run to reflect Sugar Creek's dispatch into the Midwest ISO along with NIPSCO's other units. Mr. Catlin testified that NIPSCO had not prepared such an update of its model and, until such an update was presented, the OUCC opposed the adjustment. Catlin Direct at 12-13.

IG Witness Meyer also opposed NIPSCO's variable production O&M expense adjustment. Mr. Meyer testified NIPSCO's test year production expense (less fuel) was already too high based on historical trends. *Id.* at 21-22. For that reason, he contended that NIPSCO's adjustment should be rejected. Meyer Direct at 20-23.

In rebuttal, NIPSCO Witness Shambo asserted that NIPSCO's proposed adjustment to normalize the effect of unusual outages is reasonable, and pointed out that neither Mr. Catlin nor Mr. Meyer presented any convincing evidence to the contrary. Mr. Shambo testified that the dispatching of NIPSCO's generating stations is dependent upon the economic dispatch determinations of Midwest ISO; and it is Midwest ISO's algorithms, not NIPSCO or NIPSCO's load, that determine the least cost dispatch outcomes. Mr. Shambo concluded that because NIPSCO's coal-fired units are dispatched for energy before Sugar Creek is dispatched, the incorporation of Sugar Creek will not impact the dispatch of NIPSCO's other generating units. Shambo Rebuttal at 17-18. Mr. Shambo noted that NIPSCO is willing to incorporate the position of IG and MU that NIPSCO's non-fuel O&M expense should be treated as 90% fixed and 10% variable which would have a modest impact on the proposed $4,001,238 adjustment. NIPSCO did not anticipate a material difference in the cost of service study results. *Id.* at 20. Mr. Pack similarly refuted the claim that the inclusion of Sugar Creek in the PROMOD model would materially affect the adjustment. He explained the primary driver for the adjustment was the outage at Unit 7, which has a lower operating cost than Sugar Creek. Given those cost relationships, Mr. Pack emphasized, Sugar Creek would not be dispatched by the Midwest ISO unless Unit 7 has already been dispatched. Pack Rebuttal at 9.

(b) Discussion and Findings. No party disputes that NIPSCO experienced lengthy, unusual outages at three of its generation facilities during the test year. NIPSCO does not expect these outages to occur in the future. NIPSCO's proposed methodology was to adjust its variable O&M expenses to reflect a more typical operation year by using 2003 through 2005 data to create a percentage allocator applied to test year costs. This cost was then compared to its PROMOD model, which NIPSCO used to create a hypothetical operation scenario based upon test year inputs. The difference between these two calculations resulted in NIPSCO's proposed adjustment.

NIPSCO's methodology appears to ignore test year variable O&M expense and instead utilize historic data to restate this expense on a going forward basis. While we are cognizant that NIPSCO experienced more outages in the test year than in prior years, NIPSCO has not carried its burden of persuading the Commission that its methodology appropriately reflects an adjustment to this test year expense. Accordingly, we make no adjustment to NIPSCO's variable O&M expense.

(4) Gasoline And Diesel Fuel Expense. NIPSCO Witness Miller sponsored Adjustment OM-15, which increased test year operating expenses in the amount of $799,403 to reflect higher gasoline and diesel fuel costs. Ms. Miller testified that the average cost of bulk gasoline and diesel fuel during the 2007 test year was updated to reflect March 2008 costs. Miller Direct at 25. Ms. Miller also sponsored Adjustment FP-4, which increased test year operating expenses in the amount of $840,335 for the higher cost of diesel fuel used in the fuel handling equipment in the generating stations. Miller Direct at 14-15.

OUCC Witness Catlin testified that the prices used by NIPSCO in developing its adjusted gasoline and diesel fuel costs were too high and not representative of NIPSCO's ongoing costs. Mr. Catlin explained that through discovery NIPSCO indicated that it paid $1.93 per gallon for diesel fuel in January 2009, compared to a price of $4.032 per gallon as of June 2008. For gasoline, NIPSCO reported that it paid $1.92 per gallon in January 2009 versus $4.386 per gallon in June 2008. Mr. Catlin proposed adjusting gasoline and diesel fuel costs to reflect the January 2009 prices paid by NIPSCO. Catlin Direct at 11-12.

IG Witness Meyer recommended that NIPSCO's gasoline and diesel fuel expense adjustments be disallowed, arguing that the projected increase in gasoline and diesel fuel expenses have not materialized. Mr. Meyer opined that the price paid by NIPSCO in January 2009 indicates that no adjustment needs to be made to the test year levels of gasoline and diesel fuel expenses or to NIPSCO's revenue requirement. Meyer Direct at 23-24.

In rebuttal, NIPSCO Witness Miller agreed that the price of gasoline and diesel fuel has declined since June 2008, but noted that prices have recently increased and are expected to fluctuate. Therefore, Ms. Miller proposed as an alternative to use a two-year average (January 2007 – December 2008) of gasoline and diesel fuel prices. Using these averages results in revised adjustments of $185,586 for Adjustment FP-4 and $138,596 for Adjustment OM-15, as reflected in Petitioner's Exhibit LEM-R2, page 1 of 3, lines 21 and 42. Miller Rebuttal at 44.

In recent years, there has been significant volatility in the price of gasoline and diesel fuel. As a result of that volatility, pricing the fuel at any particular spot date is problematic. Accordingly, we find that NIPSCO's rebuttal proposal to use a two-year average is appropriate and should be accepted.

(5) Weather Normalization. Consistent with our finding on the revenue adjustment, we adjust NIPSCO's fuel and purchased power expense by $408,324 to reflect the lower sales volumes reflected in the weather normalization adjustment discussed above.

(6) Service Company Allocations and Allocation of Common Costs.

(a) Petitioner's Evidence. Susanne M. Taylor, Controller for NCS, testified about NCS and the role it serves within NiSource, and provided support for the annualized level of fixed, known and measurable NCS charges applicable to NIPSCO. Ms. Taylor explained that NCS is a subsidiary of NiSource and an affiliate of NIPSCO within the NiSource corporate organization. She testified that NCS provides a range of services to the individual operating companies within NiSource, including NIPSCO, and coordinates the allocation and billing of charges to the operating companies for services provided by both NCS directly and by third-party vendors. Taylor Direct at 3.

Ms. Taylor testified that expenses are billed to operating companies by NCS in two ways: through contract billings and through convenience billings. She explained that contract billings are identified by job order and cover NCS labor and expenses associated with a specific project or cost center/department, and are billed according to the terms of individual Service Agreements with each affiliate. In contrast to contract billings, she testified that convenience billings reflect payments that are routinely made on behalf of affiliates. She cited employee benefits, corporate insurance, leasing, and external auditing as examples of ongoing corporate-wide expenses that are handled through convenience billings as a convenience to the vendor to eliminate the need for individual invoices to each affiliate entity. NCS makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate. Taylor Direct at 4.

Ms. Taylor sponsored a copy of the most recent NCS Service Agreement with NIPSCO and explained that with the exception of the Virginia affiliate, each of the NiSource operating companies has an identical Service Agreement with NCS. She testified that the previous NIPSCO Service Agreement was superseded in 2007, but that the way individual expenses were allocated and billed under the two agreements was the same. Taylor Direct at 5-6. Ms. Taylor also sponsored an exhibit showing the unadjusted total NCS billings to NIPSCO during the test year of $73,988,195 broken down by service category. Petitioner's Ex. SMT-3. Ms. Taylor identified and explained each of the service categories that made up at least 3% of the test year unadjusted total as Information Technology, Operations Support and Planning, Legal, Rate, Employee, Customer Billing, Collection and Contact, Accounting and Statistical, Office Space, Corporate, and Purchasing, Storage and Disposition. *Id.* at 7-11.

Having discussed the structure of the relationship between NIPSCO and NCS, the ways services are billed, and the categories of services provided, Ms. Taylor explained the job order process within NCS that is used to ensure that charges are correctly charged to the right operating company(s) for each project. She explained that NCS creates a job order for each project or related group of projects and that each job order is assigned a ten digit number that captures information about how expenses for the project are to be charged. She explained that job orders that directly bill costs to individual affiliates like NIPSCO are strongly favored, but that some projects necessarily involve more than one affiliate, and in those cases, job orders that allocate costs among the participating affiliates is used. Taylor Direct at 12.

Ms. Taylor testified that when a project is initiated, a decision is made jointly by representatives of the operating company affiliate and NCS about whether the costs could be directly billed to one affiliate or should be allocated among several participating companies. She testified that an allocation code is assigned to each job order that identifies how costs are to be allocated among which operating companies, and that the assigned allocation code remains constant throughout the project, to ensure consistency throughout the project life, unless a change occurs in the identity of the affiliates participating in a specific job order. As a control, she explained that only a few individuals within the NCS accounting department have authority to create or modify job orders to ensure consistency. Taylor Direct at 12-13.

In her direct testimony, Ms. Taylor testified that NCS uses thirteen Bases of Allocation that are filed annually with FERC and that were previously approved by the Securities and Exchange Commission ("SEC"). Taylor Direct at 13. Petitioner's Exhibit SMT-4 described in detail each of those Bases of Allocation. *Id.* at 14. She explained that all services provided to NIPSCO are billed at cost, and that the 2007 Service Agreement provides that charges allocated to NIPSCO may be reviewed and challenged as a matter of right. *Id.* at 15.

Ms. Taylor sponsored two adjustments to the test year allocation of NCS costs to NIPSCO. The first of these adjustments was made to remove one-time, non-recurring charges totaling $5,025,326 from test year NCS allocations. Taylor Direct at 15; Petitioner's Ex. SMT-6. This adjustment was made up of three components. First, Ms. Taylor reduced test year expenses by $3,961,081 to remove NIPSCO's share of costs associated with the restructuring of the NiSource outsourcing contract with IBM, and for the one-time costs associated with the design assessment and configuration of a new Work Management system. Second, Ms. Taylor explained that $990,780 had been adjusted out of test year NCS allocations for a number of miscellaneous costs that were either non-recurring or inappropriate for rate recovery. These adjustments related to the Marble Cliff facility, the sale of mainframe equipment, the sale of certain real estate, and elimination of certain dues, memberships and lobbying expenses. *Id.* at 16-17. Finally, Ms. Taylor explained the elimination of $73,466 of incentive compensation expense to true-up the 2007 expense with a previously recorded accrual. *Id.* at 17.

Ms. Taylor explained that the second pro forma adjustment totaling $2,242,932 was made to reflect ongoing level of NCS expenses. She explained that this second adjustment was made to reflect the impact of payroll and benefit increases made during the adjustment period, a reduction in incentive compensation expense to reflect anticipated lower payout for 2008, and to reflect an increase in annual IBM fixed fees consistent with the escalation provision of the contract with IBM. Taylor Direct at 18. Inclusive of her two downward adjustments netting $2,782,395, Ms. Taylor documented adjusted test year NCS expenses of $71,205,800. Petitioner's Ex. SMT-6. Finally, Ms. Taylor noted an entry was required to test year NCS expenses to reflect the transfer of certain amounts related to capital, stores expenses and certain deferral accounts so that the total ties accurately for cost of service purposes. Taylor Direct at 18-19.

NIPSCO Witness Hershberger presented testimony that addressed how costs billed by NCS are handled within NIPSCO. Mr. Hershberger testified that NIPSCO receives an electronic invoice from NCS on a monthly basis that includes detailed line item charges in a coding structure that allows an understanding of the charge, the internal department responsible, the job order and sub codes applicable to the charge, the allocation basis or direct charge code, along with descriptive information about each charge. Hershberger Direct at 11.

Mr. Hershberger explained that NCS charges billed to NIPSCO are booked based on a mapping process that identifies the department responsible for each charge and then maps the charge to the appropriate NIPSCO gas, electric, or common account. Mr. Hershberger also described how NIPSCO's account mapping is updated manually each time a new NCS Job Order or Sub Code is created. Mr. Hershberger added that effective January 1, 2008, NIPSCO changed its mapping process to accommodate NCS's adoption of FERC Rule 684 requiring that service company charges be correlated to the FERC USOA. Hershberger Direct at 11-12.

Mr. Hershberger described the options available under the Service Agreement with NCS for the review and challenge of charges billed to NIPSCO through NCS. He explained that NIPSCO has ten days from the receipt of the detailed invoice to identify questions and concerns with monthly charges, and testified that issues identified are generally addressed during regular interactions between the two companies. In his direct testimony, Mr. Hershberger noted that NCS costs are billed to NIPSCO on a total company basis, rather than individually to its gas and electric operations. He clarified that common costs associated with functions common to both gas and electric are allocated internally using NIPSCO's common cost allocation ratios that generally replicate the method used by NCS to allocate charges to NIPSCO. Hershberger Direct at 12-13.

Mr. Hershberger sponsored Petitioner's Exhibit MEH-5 that demonstrated the calculation of the impact of Ms. Taylor's proposed pro forma adjustments to test year NCS expenses. Petitioner's Exhibit MEH-5 identified two categories of costs included in Ms. Taylor's proposed $2,782,395 downward adjustment: those costs carrying specific accounts and those "Unidentified" charges without a specific associated account. Mr. Hershberger testified that the total impact to NIPSCO's electric function from Ms. Taylor's proposed adjustments was a decrease to test year electric expenses of $1,215,130 and an increase to electric capital of $97,580. He explained that these calculations were based on the application of NIPSCO's common cost ratios to the charges identified in Ms. Taylor's adjustments. Hershberger Direct at 14-15.

Mr. Hershberger testified that in addition to his determination of the portion of Ms. Taylor's adjustment to test year NCS expenses applicable to NIPSCO's electric business, NIPSCO undertook an additional analysis of third-party vendor invoices to ensure that the proposed level of test year expense was compiled accurately. He explained that NIPSCO focused on third-party invoices because its personnel were more familiar than NCS with the various gas and electric projects, and thus could most readily identify charges that should not be charged to NIPSCO's electric operations. Mr. Hershberger testified that a review of 3,000 of the individual third-party invoices during the test year captured more than 99% of the total vendor costs during the test year, and resulted in four proposed adjustments to test year expenses. Hershberger Direct at 15-16.

Mr. Hershberger explained the four adjustments resulting from the review of individual test year invoices in his direct testimony. The four adjustments were: (a) a reduction in test year expenses of $704,715 to remove costs solely attributable to NIPSCO's gas operation; (b) an increase in test year expenses of $563,795 to reflect reassignment of charges that relate solely to the electric operation that were incorrectly booked to both gas and electric operations; (c) a decrease in test year expenses of $978,561 to eliminate costs not properly included in NIPSCO's regulated electric books; and (d) an increase in test year expenses of $15,840 to adjust the remaining invoices not individually reviewed by the percentage change resulting from specific invoice review. The adjustments were compiled in Petitioner's Exhibit MEH-6 and resulted in an overall reduction in test year expenses of $1,103,641. Hershberger Direct at 16. That amount formed the basis of Adjustment OM-17 sponsored by NIPSCO Witness Miller. Miller Direct at 26. Mr. Hershberger added that the comprehensive review undertaken in the calculation of the test year NCS expense gave rise to an improved, three part protocol for the review and processing of NCS invoices on a prospective basis. Hershberger Direct at 16-17.

Mr. Hershberger's direct testimony also addressed the allocation of common costs between NIPSCO's gas and electric operations. He explained that common costs incurred by both gas and electric operations have historically been allocated based on an allocation study performed by Arthur Anderson in 1968. Hershberger Direct at 8. He testified that the allocation ratios resulting from that study were reviewed beginning in 2006 to determine whether they were still reflective of cost causation. *Id.* Mr. Hershberger explained that it was determined that a majority of the ratios remained accurate, but that some ratios were no longer reflective of current operating conditions, and new ones were required to directly align NIPSCO's allocation with the allocation methodology employed by NCS for certain corporate costs. *Id.* at 8-9.

Mr. Hershberger specifically identified the former Composite Ratio A as no longer accurate and reflective of cost causation. He explained that Ratio A was a basic average of four components including gross utility revenues, transmission and distribution expenses, the number of customers, and gross plant. He testified that Ratio A was inappropriate for current use because utility gross revenues had become highly volatile based on fluctuations in gas and fuel prices, and because it did not account for electric production or gas storage. Hershberger Direct at 9.

Mr. Hershberger testified that former Composite Ratio A was replaced by a new Ratio O&M that is similar to the allocation methodology (Basis 20) used by NCS. Hershberger Direct at 10. Mr. Hershberger sponsored <u>Petitioner's Exhibit MEH-4</u> that detailed the revised common allocation ratios in effect at the close of the test year and forward, and used in the preparation of Adjustment OM-18 sponsored by Ms. Miller. Adjustment OM-18 was an increase to the test year levels of $3,187,121. He explained that the common cost allocation ratios are recalculated twice per year to incorporate current information and are representative of the way common costs are incurred by NIPSCO. *Id.* at 9-10.

(b) <u>IG's Evidence</u>. IG Witness Greg Meyer presented testimony in response to NIPSCO's proposed Adjustment OM-17. He testified that the allocators used by NCS necessarily result in the assignment of more costs to NIPSCO than other NiSource affiliates. Mr. Meyer identified four of the Bases of Allocation identified by Ms. Taylor that he contended were biased toward an assignment of more costs to NIPSCO - Basis 1 (Gross Fixed Assets and Total Operating Expenses), Basis 2 (Gross Fixed Assets), Basis 7 (Gross Depreciable Property and Total Operating Expenses), and Basis 20 (Direct Costs). Meyer Direct at 34-35.

Mr. Meyer was critical of Bases 1, 2, and 7, asserting that the comparatively high production costs associated with NIPSCO's electric operation mathematically skews cost allocations toward NIPSCO in comparison to its less intensively capitalized gas operations. He criticized Basis 20 because of the potential to create a "snowball effect" whereby more and more costs would be allocated to NIPSCO over time because of the comparative magnitude of bills over prior periods. He testified that it was necessary to evaluate the costs assigned to all NiSource affiliates in order to determine whether a bias exists in the allocators used by NCS. Meyer Direct at 34-36.

Mr. Meyer presented a table showing NIPSCO's proportionate share of NCS direct and allocated costs for the period 2005 through 2007, and noted that NIPSCO was billed 15.31% of total NCS direct expenses, and 24.69% of its allocated expenses during the test year. He testified that the bills tendered to NIPSCO by NCS are insufficient to determine how any individual expense was allocated. He testified that in order to track a cost from NCS to NIPSCO, it would be necessary to know the charge code, the job code and the sub code under which the cost was allocated by NCS. Mr. Meyer was also critical of NIPSCO's method for allocating common costs between its gas and electric operations. Mr. Meyer contended that the process is not transparent and that the documentation necessary to enable a full tracking of a cost at NCS through to NIPSCO electric are generally not available. Mr. Meyer agreed that the common cost allocation ratios mirror those used to allocate costs at the NCS level, but voiced the same concerns that those ratios also over allocate costs to NIPSCO's electric operations. Meyer Direct at 36-38.

Mr. Meyer claimed that the adoption of new common cost allocation ratios such as Ratio O&M was undertaken to take advantage of a shift in common costs from NIPSCO's gas to NIPSCO's electric operations in preparation for this proceeding. He disagreed with Mr. Hershberger that Ratio O&M was needed because the former Ratio A captured too much fluctuation in gas prices based on the fact that the previous ratio had resulted in a steady allocation of costs since 1985. He testified that 61.25% of NIPSCO's 2007 NCS charges had been allocated to its electric operations, an increase of about $14 million over the allocation that would have occurred under the previous allocation ratios. He claimed that NIPSCO's Controller was not in a position to protect NIPSCO's electric interests during the allocation process. Meyer Direct at 39-40.

Mr. Meyer also criticized NIPSCO's use of Ratio O&M for the allocation of costs that had been direct billed to NIPSCO by NCS. He testified that those costs made up $11.029 million out of the $17.948 million in test year common costs allocated to NIPSCO electric. He contended that because NCS had identified a way to directly assign those costs to NIPSCO at the corporate level, NIPSCO should also be able to evaluate those costs and individually assign them to gas or electric operations. He concluded that more time should be taken by NIPSCO to examine the proper assignment of costs. Mr. Meyer calculated that the 61%/39% split between electric and gas allocation of common costs was reduced to a 55%/45% split by removing the costs allocated to NIPSCO by NCS, and contended that calculation supported his conclusion that costs to NIPSCO's electric operations had been overstated and that those costs should therefore be eliminated when calculating the common cost allocation percentage. Meyer Direct at 41-43.

Mr. Meyer made four recommendations concerning NCS allocations and the allocation of common costs. First, he recommended that proposed Adjustment OM-18 be disallowed. Second, he recommended that NIPSCO's O&M expenses be adjusted downward by $10.8 million to reflect the application of NIPSCO's previous common cost allocation ratios. Third, he recommended a $25 million reduction in NIPSCO's rate base to reflect the application of NIPSCO's previous common cost allocation methodology to capital accounts. Fourth, he recommended that the Commission open a subdocket to require the filing of a complete allocation study from NCS and NIPSCO, and that any award of NCS costs in this proceeding be made interim and subject to refund pending the outcome of that subdocket. Meyer Direct at 44.

(c) NIPSCO's Rebuttal Evidence. NIPSCO submitted rebuttal evidence from Susanne Taylor that addressed claims made by Mr. Meyer. Ms. Taylor testified that Mr. Meyer's contention that NCS allocates excessive costs to NIPSCO was premised on a misunderstanding of how Bases of Allocation are used by NCS to apportion charges to affiliates, and that his criticisms were unsupported by an examination of the actual charges and their allocations. She explained that Mr. Meyer's position failed to recognize that each project job order delineates specific companies to which costs are allocated. She explained that only 5.1% of the total company NCS charges were allocated using Basis 1, and that those dollars involved either gas-only or Indiana specific projects (in which NIPSCO's exposure to cost allocation was appropriate), or certain IT-related projects appropriately billed under Basis 1. Taylor Rebuttal at 2.

Ms. Taylor explained that Mr. Meyer's criticisms of Basis 2 and Basis 7 were unfounded because Basis 2 had been used for only a single correction entry during the test year, and Basis 7 is used exclusively for the allocation of insurance premiums that are driven directly by gross depreciable property and O&M upon which Basis 7 allocations are made. She also rejected Mr. Meyer's criticism of Basis 20 and testified that cost allocation under Basis 20 actually saves NIPSCO money in comparison to the allocation of common charges using other Bases of Allocation. She noted that the SEC had stated a preference for Basis 20 during its audit of NCS because it most fairly allocates costs among all affiliate companies. Taylor Rebuttal at 2-3.

Ms. Taylor agreed that allocators must be carefully selected to accommodate the fact that NIPSCO is the only electric utility among the NiSource family of companies. However, she disagreed with the hypothetical example of an NCS employee working solely for NIPSCO. She testified that it is NCS's position that such dedicated personnel should be on NIPSCO's payroll, and that NCS personnel typically provide or have the ability to provide service to more than one operating company. Taylor Rebuttal at 3-4.

Ms. Taylor reiterated that NCS is very careful in establishing allocators to ensure that individual affiliates are not billed for inappropriate charges. She noted that NCS is involved in regulatory filings on issues of cost allocation in many of the other states where NiSource utilities provide service and that expense allocations for both contract and convenience billings are routinely subject to regulatory auditing and review. Further, NiSource employs an independent accounting firm, Deloitte and Touche LLP ("Deloitte"), to test NCS's expense allocations for both contract and convenience billings as part of their audit procedures used to support their outside opinions on the financial statements of NIPSCO. None of these reviews have required adjustments related to NCS allocations. Taylor Rebuttal at 4.

Finally, Ms. Taylor disagreed with Mr. Meyer's assertion that NCS contract billing invoices were insufficient to determine how particular expenses had been allocated. She again explained that the Charge Codes that appear for each line item contain information from which the allocation and origin of each charge can be readily identified, and noted that processes exist for the review and challenge of NCS allocations if additional clarification is required. Taylor Rebuttal at 5.

NIPSCO's Accounting Manager Shirley M. Rippy provided rebuttal testimony that explained the process used by NIPSCO to review monthly NCS billings. She explained that NIPSCO receives monthly billing files from NCS that identify invoice numbers and either direct billing codes or corporate allocations used to identify how each item came to be billed to NIPSCO. NIPSCO also has access to the underlying electronic invoices. She testified that the financial analyst responsible for reviewing the invoice automatically prints invoices greater than

$10,000 for review during monthly meetings that involve the Controller, accounting managers and financial analysts. She clarified that each expense is reviewed, and that expenses smaller than $10,000 may also be flagged for further review. She testified that invoices for which questions exist are returned to NCS for clarification and/or adjustment. Rippy Rebuttal at 2-4.

Ms. Rippy also clarified that NCS costs that are not specifically allocated to gas or electric operations are allocated in the same way as other common costs. She echoed Mr. Hershberger's direct testimony by noting that the common cost allocation ratios used to apportion costs between gas and electric operations are updated with more current data twice a year. She testified that in the case of NCS charges, common costs are allocated between gas and electric using allocation ratios that are similar to those used to allocate the charge at the NCS level. Rippy Rebuttal at 4.

(d) IG Motion For Involuntary Dismissal. On April 20, 2009, IG filed its Motion for Involuntary Dismissal of Certain Portions of NIPSCO's Case-in-Chief Relating to Allocated Expenses. On May 11, 2009, NIPSCO filed its Response in Opposition. On May 18, 2009, IG filed its Reply In Support of Motion to Dismiss. By Docket Entry dated June 16, 2009, the presiding officers reserved its decision on the motion to this Order.

Having reviewed NIPSCO's case-in-chief testimony, the Commission finds that Petitioner met its evidentiary burden for including NCS charges in NIPSCO's expenses. The gravamen of IG's argument is that NIPSCO failed to include in its evidence exactly how these allocations were made. However, such level of detail is unnecessary to support inclusion of the purported cost in rates. Indeed, as NIPSCO noted in its Reply Brief, no party to this proceeding presented evidence that NCS charges should be disallowed—in fact, just the opposite is true. Even IG's own witnesses supported the inclusion of some level of NCS charges as part of NIPSCO's O&M expense. Accordingly, the Commission finds that NIPSCO met its burden of proof on this issue, and IG's Motion for Involuntary Dismissal is hereby denied.

(e) IG Appeal to Full Commission and Petition to Reopen Record. During the evidentiary hearing, the presiding officers admitted Petitioner's Redirect Exhibits 3 and 3-C ("Redirect Exhibits") into the record over the objection of IG. Those exhibits consisted of the public and confidential portions of NIPSCO's response to IG Data Request Set 15, Question 1. IG appealed the presiding officers' ruling on the admissibility of those exhibits to the full Commission, contending that the exhibits were beyond the scope of IG's cross-examination. IG also requested that the Commission reopen the record to allow additional cross-examination to occur and additional evidence to be presented. The parties submitted briefs to the Commission addressing their respective views on the admission of the exhibits.

Having considered the evidentiary record and the argument and briefing of counsel, the Commission denies IG's appeal with respect to the admission of Petitioner's Redirect Exhibits. The Commission is ultimately charged with evaluating the evidence in this Cause and giving the evidence of record appropriate weight. As noted above, Petitioner submitted sufficient evidence to meet its burden of having these charges considered by the Commission, and the Commission does not give significant weight to the Redirect Exhibits. The information contained within the Redirect Exhibits merely provides the background information for Ms. Taylor's ultimate opinion on the amount of NCS charges that NIPSCO seeks to recover. This information could more appropriately have been provided as workpapers to Ms. Taylor's testimony and exhibits, but were not. Workpapers are not typically admitted into the record, but we find no error in the inclusion of such evidence.

Moreover, IG had ample opportunity to review the information included in the Redirect Exhibits well before the June 30, 2009 hearing and could have cross-examined Ms. Taylor concerning that information. NIPSCO provided IG the data included in the redirect exhibits on March 17, 2009 and NIPSCO responded to additional questions to IG on April 20, 2009. As discussed above, the evidentiary record was sufficient for the Commission to consider NIPSCO's request to include NCS charges as part of its revenue requirement without the Redirect Exhibits. Any objection to the Presiding Officer's admission of additional evidence on that issue goes to the weight of the evidence and not the admissibility. Accordingly, we deny IG's appeal to the full Commission and its Petition to Reopen the Record.

(f) Discussion and Findings.

(i) NCS Allocators. The Commission has previously addressed the recovery of costs allocated from corporate service companies similar to NCS. The Commission evaluates whether the methodology used to allocate costs to the utility is reasonable and produces allocations representative of future costs to be properly allocated to the utility during the period when the rates requested will be effective. *See, e.g,. PSI Energy, Inc.*, Cause No. 42359, at 77.

In this case, NIPSCO Witness Taylor provided testimony supporting the existence of a long-standing methodology for the allocation of costs through NCS, including evidence of the process used to ensure that costs are allocated consistently. Ms. Taylor proposed adjustments to the test year allocations for non-recurring charges and for expenses not appropriate for rate recovery, and NIPSCO conducted further analysis of more than 99% of test year NCS allocations from third-party vendors to identify a proposed representative level of expense. Petitioner's proposed Adjustment OM-17 captured the results of those analyses. While IG Witness Meyer was critical of certain of the Bases of Allocation used by NCS, he offered no evidence that the adjustments proposed by Ms. Taylor or Mr. Hershberger were inaccurate or inappropriate; nor did he offer specific evidence that any of the charges allocated were improper or that the results were not representative of an ongoing level of expense. We find no reason to modify or reject NIPSCO's proposed treatment of NCS charges.

We reject the position of IG that NIPSCO is required to submit evidence justifying each individual expense incorporated into the test year allocations from its service company as a predicate for rate recovery. In the first place, NIPSCO's books are presumptively correct. *Oaktown Tel. Co. v. Miller*, 194 N.E. 741, 742 (Ind. Ct. App. 1935); *West Ohio Gas Co. v. Public Util. Comm'n of Ohio*, 294 U.S. 63, 67-68, 72-73 (1935); *Ind. Mich. Power Co.*, Cause No. 39314, pp. 4-7 (Nov. 12, 1993). Second, the NCS charges are assessed to NIPSCO pursuant to a service agreement properly on file with the Commission. *City of Terre Haute v. Terre Haute Water Works Corp.*, 133 Ind. App. 232, 180 N.E.2d 110, 114-16 (1962). Third, the Commission is very familiar with shared services agreements like that at issue here because most of the major Indiana investor-owned utilities are subsidiaries of holding companies and receive shared services from affiliated service companies just as NIPSCO does.

We have not in the past required the utilities subject to our jurisdiction to provide the level of detail that IG claims is necessary, and we decline to do so here. A theoretical concern about the allocation methodology employed is not sufficient to overcome substantial evidence that the proposed expense is reasonable. *City of Terre Haute*, 180 N.E.2d at 117 (recognizing that the intervenor had the burden of going forward with the evidence after the utility had presented a prima facie case on service company charges). As we have said before, a petitioner's obligation is to submit "substantial evidence" sufficient for a prima facie case, not to satisfy a "clear and convincing" or "beyond a reasonable doubt" standard. *Ind. Mich. Power Co.* at 5. Nor may parties ask the Commission to "manipulate the burden of proof in order to merely disallow portions of [a utility's] rate request." *Id.* at 7. "[T]here is no authority whatsoever to support our imposition of any greater burden of proof than is provided for in a statutory standard or a duly promulgated rule." *Id.* We conclude that the test year NCS allocations, reflected in proposed Adjustment OM-17 are a reasonable representation of annual allocations and should be approved.

(ii) Common Cost Allocators. Similar to our analysis of allocated service company costs, the threshold issue for our consideration is whether the allocation of common costs proposed by Petitioner results in a representative ongoing level of expense. In analyzing the reasonableness of a common cost allocation, we have previously concluded that,

> . . . it is important that the methodology employed (which includes the use of test year ratios) is equitable, yields a reasonable result over time, and is not subject to constant revisions and change. We believe it is important that parties not have the ability to manipulate the allocation of common costs for their own purposes. We realize any allocation formula for any time period is necessarily subject to change but the Commission must use a methodology which proves reasonable over time.

N. Ind. Pub. Serv. Co. [gas], Cause No. 38380, at 6 (Oct. 26, 1988). Our analysis thus reflects the balance between consistency of methodology and accuracy of results.

The record reflects that NIPSCO allocated common costs using a series of common cost ratios developed beginning in 2006 to replace the ratios that had been used for that purpose since 1968. Proposed Adjustment OM-18 adjusted test year common cost allocations to reflect the adoption of the revised ratios in April of 2007. Mr. Hershberger testified that the revised allocation ratios were representative of cost-causation and representative of the way common costs would be allocated on an ongoing basis.

IG Witness Meyer implied that the revised ratios were prepared to justify an increase in expense for NIPSCO's electric business in this case, rather than in an effort to improve the accuracy of the allocation. We disagree. The electric and natural gas industries have undergone sweeping restructuring since the 1960s, so NIPSCO's re-evaluation of the method for allocating common costs was logical, if not required, in light of those changes. While consistency of methodology is desirable over the long run, the result must be an accurate reflection of ongoing expense levels.

We have previously voiced our concern about the manipulation of common cost allocations by parties for their own purposes. *See* Order in Cause No. 38380. Mr. Meyer's proposal to revert to the previous common cost allocators appears to be driven largely by the reduced cost allocation it produces, not by evidence that NIPSCO's revised allocation ratios are inaccurate or non-representative. As Mr. Shambo pointed out, Mr. Meyer's industrial customer clients would potentially experience little of the common costs shifted to the gas operation. As much as Mr. Meyer voiced theoretical opposition to the calculation of NCS Bases of Allocation, his criticism of NIPSCO's proposed allocation ratios is lacking in specificity. In particular, Mr. Meyer recommends the disallowance of $25 million in rate base, but offers no evidence to support the proposition that NIPSCO's proposed capital allocation is not proper.

Based on the evidence of record, we find that the revised common cost allocation methodology employed by NIPSCO is reasonable, produces results that are reflective of ongoing expense levels and properly balances the interests of NIPSCO electric customers and NIPSCO gas customers. We accordingly approve the adjusted test year expense identified in Adjustment OM-18.

(iii) Subdocket Proposal. Having determined that the allocation of common costs and the adjusted test year NCS allocations are reasonable, we find that the creation of a subdocket to this proceeding as proposed by Mr. Meyer unnecessary.

(7) Superfund Remediation Expense. OUCC Witness Pruett recommended the removal of $417,372 in test year remediation expenses associated with NIPSCO's involvement as a Potentially Responsible Party at two Superfund sites. Ms. Pruett asserted the recovery of these costs is not sufficiently related to the provision of public utility service to current or future customers. Ms. Pruett further contended that ratepayers should not be held accountable for management decisions and contractor actions and that the adjustment was appropriate in light of NIPSCO's receipt of insurance reimbursements for some of these expenses. Pruett Direct at 15-18.

In rebuttal, NIPSCO Witness Miller indicated that because NIPSCO has received insurance reimbursement for the Superfund remediation expenses, it did not oppose the adjustment of $417,372 in this particular case. Miller Rebuttal at 35. Mr. Carmichael, in rebuttal, further stated that NIPSCO's decision not to challenge this adjustment did not reflect NIPSCO's agreement with Ms. Pruett's rationale for excluding these costs. More specifically, Mr. Carmichael noted that NIPSCO incurred these costs as a result of providing public utility service to its customers, and that NIPSCO took reasonable steps in selecting its contractors and the facilities used for disposal of generation by-products. Mr. Carmichael concluded by noting that NIPSCO will bear future costs that exceed the insurance received until it files a subsequent rate case, and that NIPSCO has a strong incentive to minimize such costs. Carmichael Rebuttal at 2-7.

Given that there was no dispute as to the appropriateness of the adjustment, we find that resolution of the rationale for the adjustment is unnecessary and accept the OUCC's proposed adjustment.

(8) Midwest ISO Costs in Base Rates. NIPSCO proposed that all Midwest ISO charges be recovered through the RA Tracker and that none be included in base rates. OUCC Witness Catlin adjusted NIPSCO's O&M expenses upward by $5,326,931 to reflect the recommendation of OUCC Witness Satchwell that this level of Midwest ISO Administrative Fees, Schedule 24 charges and Schedule 26 charges be "built into base rates" and removed from the RA Tracker. Catlin Direct at 14. Mr. Satchwell testified that those charges are non-energy related costs that are consistent enough in nature to be accurately reflected in base rates. We see no reason to treat these administrative expenses any differently than we do

for the other Indiana investor-owned electric utilities in Cause Nos. 42359, 43111 and 43306. Therefore, we accept the OUCC's proposed expense adjustment.

(9) Amortization of Deferred Midwest ISO Costs. In Cause No. 42685, NIPSCO was authorized to defer its non-fuel expenses incurred commencing August 1, 2006, in connection with its participation in Midwest ISO. NIPSCO proposed to amortize the deferred costs over a three-year period. This resulted in a pro forma adjustment for deferred Midwest ISO amortization expense of $8,256,052. Miller Direct at 30-31; Petitioner's Ex. LEM-3, Adjustment DA-3.

OUCC Witness Catlin proposed four changes to NIPSCO's claim for deferred Midwest ISO costs. First, Mr. Catlin updated NIPSCO's projection of the balance as of December 31, 2008 to reflect the actual balance of deferred Midwest ISO costs as of that date. Second, Mr. Catlin proposed to amortize the deferred Midwest ISO balance over four years, rather than the three years proposed by NIPSCO. Mr. Catlin stated that a four year amortization period is consistent with the amortization periods used by the other Midwest ISO member utilities in Indiana for such costs. Third, Mr. Catlin proposed to reduce the balance of FERC Assessment Fees based on the average annual level of FERC Assessment Fees paid in 2002 and 2003. Fourth, Mr. Catlin reduced the balance of Midwest ISO costs to account for non-firm transmission revenues received over the period from August 2006 through December 2008. The effect of these four changes is a reduction of $5,386,708 in annual amortization expense for deferred Midwest ISO costs. Catlin Direct at 15-16.

In rebuttal, NIPSCO Witness Miller indicated that NIPSCO agreed with the four-year amortization period and the use of the actual December 31, 2008 balance. Ms. Miller did not agree, however, with the OUCC's proposed reduction in FERC Assessment fees that are part of the deferred Midwest ISO costs or the offset for non-firm transmission revenues. Ms. Miller noted that NIPSCO was authorized to defer the FERC assessment fees in Cause No. 42685, and that the level of such fees increased dramatically when NIPSCO began paying them to Midwest ISO. *Id.* Ms. Miller testified that none of the other utilities have been required to reduce their deferred balances as proposed by Mr. Catlin. As to Mr. Catlin's recommendation to reduce the amount of deferred costs to be amortized by the non-firm transmission revenues, Ms. Miller stated that this was not consistent with the Commission's Order in Cause No. 42685 or the Commission's Order in Vectren South's rate case proceeding (Cause No. 43111). Miller Rebuttal at 37-38. Curtis L. Crum, NIPSCO's Director, Generation Dispatch and Energy Management, stated that NIPSCO believes that it should receive comparable treatment. In addition, NIPSCO was receiving transmission revenues from point-to-point firm and non-firm transmission service prior to joining the Midwest ISO. He explained that the revenues received from the Midwest ISO for point-to-point transmission service are not a result of being a transmission owning member of the Midwest ISO and therefore should not be netted against Midwest ISO administrative charges. Crum Rebuttal at 5. Ms. Miller indicated that the revised amortization expense is $5,732,141, a reduction of $2,523,911. Miller Rebuttal at 37-38.

We find that NIPSCO's rebuttal position is reasonable and proper, and accept NIPSCO's rebuttal adjustment. The Order in Cause No. 42685 allows the deferral of the Midwest ISO costs with no mention of the reduction proposed now by OUCC Witness Catlin. Consistent with our finding that NIPSCO shall eliminate its aging workforce expense following 2012, we find NIPSCO should likewise adjust its base rates to eliminate the Midwest ISO deferred cost amortization at the end of the amortization period.

(10) Amortization of Sugar Creek Deferred Depreciation. In connection with his testimony regarding depreciation expense, OUCC Witness Majoros explained that NIPSCO is requesting a 5-year amortization of $7.3 million of Sugar Creek depreciation expense. Majoros Direct at p 5. Mr. Majoros recommended that the Commission not approve NIPSCO's request for a depreciation expense increase.

As discussed previously, the Commission approved NIPSCO's proposed treatment of depreciation expense, with the exception of decommissioning costs. Accordingly, the Commission approves NIPSCO's treatment of the amortization of deferred Sugar Creek depreciation expense. At the conclusion of the amortization period, NIPSCO shall file a revised tariff removing this amortization from rates.

(11) Rate Case Expense. OUCC Witness Catlin proposed that NIPSCO's rate case expense be amortized over six years, rather than the three years proposed by NIPSCO. Mr. Catlin stated that a longer amortization period was justified due to NIPSCO's high rate case expenses, the infrequency with which NIPSCO has filed rate cases and the inclusion of costs that are not incurred in every case. Mr. Catlin further recommended that, to the extent NIPSCO voluntarily elects to file another rate case before the costs for this case are fully amortized, NIPSCO be required to write off the unamortized balance. Catlin Direct at 16-18.

On rebuttal, Ms. Miller proposed a five-year amortization period. She opposed the proposal that any unamortized portion be written-off if another base rate case is filed. She explained that the energy sector is in a state of transition, the effects of new energy efficiency initiatives are uncertain, and anticipated federal and state legislation may significantly affect costs as well as energy load. As a result, there is a great deal of uncertainty regarding when another base rate case would be required, and it would be inappropriate and unwarranted to punish NIPSCO for filing another rate case within the shorter time frame when it has a statutory right to do so. She explained that the reason for the higher rate case expense was the length of time since NIPSCO's last rate case. Miller Rebuttal at 44-45.

While the rate case expense was approximately $5.9 million, of which of $1.85 million were for legal expenses and $2.51 million were for expert witnesses, no witness testified that the expenses were excessive or imprudent and no parties proposed that any portion of rate case expense be disallowed. The evidence concerning the proposed level of rate case expense incurred by NIPSCO is unchallenged by the parties. Accordingly, the Commission accepts the proposed level of rate case expense and approves a five-year amortization period. However, the Commission accepts the level of rate case expense with an expectation that future cases will provide a higher level of specific detail supporting NIPSCO's (as well as all utilities') proposed rate case expense. Consistent with our finding on the aging workforce adjustment and Sugar Creek depreciation amortization, we find NIPSCO should adjust its base rates to eliminate the rate case expense amortization at the end of the amortization period.

(12) Interest Synchronization. The issue surrounding interest synchronization is derivative of the issue associated with the hypothetical cost of capital discussed previously. The OUCC and IG calculated the interest deduction for purposes of interest synchronization based on the assumption that NIPSCO has debt in its capital structure which it does not have. For the reasons explained with respect to our rejection of the use of a hypothetical capital structure, we reject this proposal with respect to interest synchronization.

E. Pro Forma Present Rates Income Statement. Based upon the evidence presented and the determinations made above, we find that NIPSCO's adjusted operating results under its present rates and charges for electric utility service are as follows:

Description	Amount
Operating Revenue	$ 1,482,439,820
Fuel, Purch. Power and Related URT[16]	526,936,766
Gross Margin	$ 955,503,054
Operations & Maintenance Expenses	$ 338,056,493
Depreciation Expense	193,989,102
Amortization Expense	27,699,199
Taxes Other Than Income	56,208,081
Income Taxes	114,340,190
Total Operating Expenses	$ 730,293,065
Net Operating Income	$ 225,209,989

In summary, we find that with appropriate adjustments for ratemaking purposes, NIPSCO's annual net operating income under its present rates for electric utility service would be $225,209,989. When compared to the return determined in Section 8(B)(5), *supra*, NIPSCO's pro forma NOI exceeds what is necessary to obtain that return. Accordingly, we find that Petitioner's present rates are unreasonable and unlawful.

10. Authorized Revenue Requirement. On the basis of the evidence presented in these proceedings, we find and order that NIPSCO shall be directed to decrease its rates and charges for electric utility service to produce gross margin of $899,401,890 as follows:

[16] Includes $11,015,038 of non-trackable fuel expense.

Description	Amount
Operating Revenue	$ 1,433,561,560
Fuel, Purch. Power and Related URT[17]	534,159,670
Gross Margin	$ 899,401,890
Operations & Maintenance Expenses	$ 337,862,056
Depreciation Expense	193,989,102
Amortization Expense	27,699,199
Taxes Other Than Income	55,424,442
Income Taxes	92,001,559
Total Operating Expenses	$ 706,976,357
Net Operating Income	$ 192,425,533

11. Revenue Allocation.

A. Retail Cost of Service Study.

(1) Evidence. NIPSCO presented the results of its retail cost of service studies, prepared by Robert D. Greneman of Shaw Consultants International, Inc. (formerly Stone & Webster Management Consultants, Inc.). Mr. Greneman explained that a fully-allocated cost of service study, which apportions the Company's revenue requirement to customer classes, provides a standard industry yardstick to measure the degree to which the revenues produced by each customer class, in comparison with the cost to serve that class, are equitable and non-discriminatory.

He stated that NIPSCO's cost of service study developed a revenue requirement for each customer class based on a target rate of return for that class; developed a fully unbundled pro forma revenue requirement for each defined function (generation, transmission, distribution and billing and collecting) as well as sub-functions within each of these main functions based on the target rate of return for each class; indicated which customer classes are receiving or providing a subsidy to other classes; and developed unit costs by customer class and unbundled function.

Mr. Greneman explained that the cost of service study was developed on a gross margin basis, i.e., net of fuel and purchased power, as the Company is proposing to recover all of its fuel through its FAC and all purchased power costs through its RA Tracker. The cost of service study used the traditional three-step approach that consists of functionalization, classification and allocation. He stated that production plant was separated into fixed and variable components to capture fixed costs associated with generating plant versus non-fuel variable costs such as fuel

[17] Includes $11,015,038 of non-trackable fuel expense.

handling, boiler maintenance and fuel stock. He stated that the breakdown was based on a fixed-variable analysis that was performed by the Company.

Mr. Greneman testified that primary lines, secondary lines and line transformers were classified as 100% demand-related because NIPSCO's property records were not sufficiently detailed as to reliably support a zero-intercept or minimum system analysis. Plant and expenses functionalized to the generation functions were allocated on the basis of the contribution of each class of service to the four-month (June through September) average control area peak (hereinafter referred to as a "4 CP methodology"). Mr. Greneman stated that transmission was allocated among retail customers based on the 12-month average of the Company's coincident control area peak demands (hereinafter referred to as a "12 CP methodology"), which is the most commonly used method before the FERC. He noted that a 12 CP methodology rather than a 4 CP methodology is used by Midwest ISO for cost allocation.

Nicholas Phillips, Jr., a principal in the firm of Brubaker & Associates, Inc., testified on behalf of the IG and made certain recommendations to NIPSCO's cost of service study. He asserted that production and transmission investment should be allocated by the 4 CP methodology because it properly allocates cost responsibility to customer classes and, if implemented properly, would minimize the need for new generating capacity. Mr. Phillips criticized Mr. Greneman's classification of a significant amount of production non-fuel expense as being variable and energy related. He stated that, based on a review of other utilities in Indiana, he recommended that NIPSCO use 90% fixed and 10% variable classifications for production related non-fuel operation and maintenance expense. Phillips Direct at 14-15. Mr. Phillips also expressed a concern regarding direct assignments of costs associated with items such as sales expense and customer information related expense. He admitted on cross-examination, however, that were these costs not directly assigned, they would be borne by other customers. Tr. KK-22-23. Mr. Phillips stated that customers served at 34.5 kV should not be allocated costs associated with standard primary voltage because these customers do not use these lower primary voltage lines and substations. Phillips Direct at 17-18. Mr. Phillips did not agree with NIPSCO's proposal to remove the cost of fuel from its base rates. Phillips Direct at 18.

Dale E. Swan, senior economist and principal with Exeter Associates, Inc., addressed issues involving Petitioner's embedded class cost of service study on behalf of the OUCC. Dr. Swan disagreed with Petitioner's allocation of its generation and transmission plant-related costs. Swan Direct at 3. He disagreed with the way in which generation and transmission capital costs and generation and transmission plant-related O&M costs have been allocated in Petitioner's study, specifically noting that these costs have largely been allocated on a peak demand basis, with no responsibility being assigned to energy. Swan Direct at 5. Dr. Swan disagreed with Petitioner's classification and allocation of production and transmission plant related costs as 100% peak demand related. He stated that a cost study should classify and allocate costs among customer classes on the basis of other factors that caused those costs to be incurred and that Petitioner's total production and transmission plant investment costs have not been caused solely by the peak demand of its customers. Swan Direct at 7. Dr. Swan opined that a significant portion of the investment costs have been directly caused by the need to meet the energy requirements of Petitioner's customers so a commensurate portion of the investments costs and the associated plant-related O&M costs should be allocated on the basis of class energy usage. Swan Direct at 7. Dr. Swan recommended use of the OUCC's Peak and Average Cost of Service

Study as the cost basis for determining the spread of the allowed change in jurisdictional revenues. Swan Direct at 3. He opined that the Peak and Average method allocates a portion of plant and related expenses on the basis of class contributions to the relevant measure of system coincident peak demand, and the remainder on the basis of class energy use at source. Swan Direct at 17. Based on the results of his analysis, Dr. Swan recommended that 65% of production plant and related O&M costs be allocated on class energy use, and the remaining 35% be allocated on each class' contribution to the appropriate measure of peak demand. Swan Direct at 20. As an alternative to the use of the OUCC's Peak and Average study, Dr. Swan recommended use of the 12 CP study that was used in NIPSCO's last rate case rather than use of the Company's proposed 4 CP methodology for production plant. Swan Direct at 32. Dr. Swan opined that the 12 CP methodology is superior to the 4 CP methodology. *Id.*

Kerry A. Heid testified on behalf of Intervenor MU. Mr. Heid provided a comprehensive overview of the history of NIPSCO's rates, including NIPSCO's last base rate proceeding and the Commission investigation into NIPSCO's rates in Cause Nos. 38045 and 41746. Heid Direct at 4.

He explained that the classification of costs as demand, energy or customer-related has significant impact on the allocation of costs. For example, costs classified as energy-related have the most favorable impact on residential customers, while costs classified as customer-related have the least favorable impact on residential customers. Mr. Heid agreed with NIPSCO's 4 CP demand allocation for production plant. He noted that the FERC allocation method states that if the demand curve is relatively flat then use of 12 CP is appropriate and, if there is a pronounced peak, then use of another CP method is supported. He noted that Mr. Greneman utilized the FERC allocation method to conclude that the use of 4 CP was supported. *Id.* at 8. He noted that Vectren South, in Cause No. 43111, used 4 CP production demand allocation and that in PSI's last general rate case, the Commission noted that PSI's demand allocation methodology "is also consistent with the FERC's allocation guidelines." *PSI Energy, Inc.*, Cause No. 42359, at 101.

Mr. Heid disagreed with NIPSCO's fixed-variable analysis and NIPSCO's proposed allocation of production O&M accounts. Mr. Heid recommended that the Commission reject NIPSCO's fixed-variable analysis and suggested that all production expenses should be classified as demand-related, "as they were in previous rate cases." Heid Direct at 9-11.

Mr. Heid explained that line losses are losses that occur in the utility's system between the generating or purchased power sources and the customers' meters. He stated that Mr. Greneman used a 1999 line loss study prepared by NIPSCO Transmission Planning and asserted that there was a subsequent 2001 line loss study. Heid Direct at 12. Mr. Heid recommended that the Commission reject the 1999 line loss estimates and use the line loss percentages that were filed by NIPSCO in Cause Nos. 41746 and 41658.

Mr. Heid also disagreed with Mr. Greneman's assertion that there are inadequate records to perform a zero-intercept analysis, citing the historical use zero intercept analyses in Cause Nos. 41746 and 38045. Mr. Heid noted that the NARUC Electric Utility Cost Allocation Manual supports the appropriateness of classifying a portion of distribution costs as customer-related. He recommended that NIPSCO modify its cost of service study to reflect the minimum distribution system analysis results from Cause No. 41746.

IG Witness Phillips' cross-answering testimony responded to the Peak and Average method proposed by OUCC Witness Swan. He stated that Dr. Swan's proposal inappropriately over-allocates production plant costs to high load factor and off-peak classes, is counter to the Commission's direct findings on this issue, is not based on sound rate making principles and should be rejected. Mr. Phillips concluded the Commission should also reject Dr. Swan's alternative proposal to adopt a 12 CP allocation method for production and transmission fixed costs. He argued that instead, the Commission should adopt the 4 CP methodology proposed by the Company because the latter method more accurately reflects the dominant system peak demands that drive incremental generation investments on the NIPSCO system.

In rebuttal, Mr. Greneman and Mr. Shambo addressed Mr. Phillips' proposed 90% fixed/10% variable allocation of non-fuel O&M expenses and Mr. Heid's proposal that non-fuel O&M expenses be 100% fixed. Mr. Greneman and Mr. Shambo explained that for its rebuttal position, NIPSCO would support the 90% fixed/10% variable allocation of non-fuel O&M expenses as recommended by Mr. Phillips. Mr. Greneman asserted that Mr. Heid had not presented any technical evidence to discredit the line loss percentages calculated from the 1999 loss study, and he recommended that the loss percentages used in the cost of service study in this proceeding should stand. With respect to Mr. Phillips' contention that NIPSCO over-assigned sales expenses and customer service and informational expenses to industrial customers, Mr. Greneman noted that NIPSCO has one of the largest industrial bases of any utility in the country and has individuals dedicated to providing needed billing, sales and customer service and informational expenses for these industrial customers. He explained that, if the industrial class is not directly allocated these dedicated costs, then other classes, such as residential, will be asked to provide a subsidy to industrial customers, which is not in accordance with cost causation principles.

(2) Discussion and Findings. Witnesses Heid and Phillips agreed with and relied upon Mr. Greneman's application of the FERC guidelines to determine that a 4 CP method is the appropriate basis for allocating production plant costs among NIPSCO's customer classes. We find this reliance is misplaced. While we are not bound to directly apply the FERC Allocation Method Tests for retail ratemaking in Indiana, we find the guidelines useful information for determining the appropriate production cost allocation methodology. In *Golden Spread Elec. Coop. v. Sw. Pub. Serv. Co.*, 123 F.E.R.C. p .61,047 at 61,249, FERC stated,

> Historically, the Commission has considered three tests in determining whether a system is better characterized as 3 CP or 12 CP. First, the Commission compares the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak -- the On and Off Peak test. *Generally, the Commission has held that a nineteen percentage point or less difference between these two figures supports using the 12 CP method.* The second test, the Low-to-Annual Peak test, involves the lowest monthly peak as a percentage of the annual peak. *The Commission considers a range of sixty-six percent or higher as indicative of a 12 CP system.* The third test is the Average to Annual Peak test, and it computes the average of the twelve monthly peaks as a percentage of annual peak. *Generally, the range for a utility to be considered 12 CP is eighty-one percent or higher.*

(Emphasis added, internal citations omitted.)

The results for NIPSCO appearing in Petitioner's Exhibit No. RDG-2, Schedule 1.0, page 3 of 3 for Test 1 are 19% and 16% for 2007 and 2006, respectively; a six-year average 68.5% for Test 2; and a 6-year average of 81.0% in the last test. We therefore find that application of the FERC Allocation Method Test could reasonably support a finding that a 12 CP method is more appropriate for NIPSCO system load characteristics, rather than the 4 CP method determined by Mr. Greneman. Moreover, this Commission previously has found that the "12 CP method is often utilized to reflect the full range of operating realities throughout the year including system demand, scheduled maintenance, and reserve requirements." Cause No. 39314, at 171. In the most recently contested electric utility rate proceeding, we noted in our Order that "a change in cost allocation methodology can have significant impacts on customer classes, and, thus, such a change should not be lightly undertaken, especially where, as here, so much of PSI's plant was in service at the time of its last rate case and costs were assigned using the 12-CP methodology in that case." Cause No. 42359 at 102. Here, the record indicates that NIPSCO's current rates reflect a 12 CP methodology as approved in Cause No. 37023, and adjusted across-the-board in Cause No. 38045, and any departure can have significant impacts and should not be undertaken lightly. We note the complete absence of any analysis of other operating realities, such as loss of load probabilities, reserve requirements, and scheduled maintenance by the proponents of a change to 4 CP method that would provide sufficient evidence to justify a change in allocation method.

After considering the evidence, we find that allocation of these costs shall be based on the 12 CP methodology. Much of the capital investment costs at issue were, in fact, incurred to meet NIPSCO's energy requirements at lower costs thereby minimizing the total cost of service. This is consistent with the evidence that NIPSCO's system was designed, planned, and built in material part to serve the loads of its energy intensive industrial customers. Moreover, we note that the most recent capacity addition to the NIPSCO system was the intermediate/baseload combined cycle Sugar Creek facility, and not a "peaker" generating plant.

This Commission has a long and consistent practice of allocating generation and transmission costs on some measure of coincident peak and precedent must factor into our final decision. Given that our last Order found the 12 CP methodology appropriate, and the FERC tests demonstrate the 12 CP is marginally still appropriate, we find no reason to move to a different allocation methodology in this Cause. Moreover, our preference is to utilize the previously approved allocation methodology, given sufficient evidence, unless system operating characteristics are demonstrated to have changed since the last approved cost of service study allocation methodology.[18] Accordingly, we direct NIPSCO to utilize a 12 CP study as the initial basis on which to determine class revenue responsibilities.

We also find that NIPSCO's initial proposal to split non-fuel Production O&M expenses as 60 percent variable and 40 percent fixed will result in a superior reflection of the costs of serving the several customer classes. We are particularly persuaded by the fact that this split is consistent with both the FERC and the NARUC methodologies. Thus, despite the Company's willingness to revise its study to comport with Mr. Phillips proposed 90%/10% split, we order NIPSCO to utilize its initially proposed 60%/40% split for non-fuel Production O&M expenses.

[18] *See, Ind. Mich. Power Co.*, Cause No. 39314, at 171-72 (Nov. 12, 1993).

With regard to NIPSCO's line loss study, while we find it troubling that Mr. Greneman was unable to explain the differences from the 1999 line loss study and the results submitted into evidence in Cause No. 41746, the only evidence that we have in this proceeding are the 1999 results, and therefore we find that those results are sufficient for purposes of this proceeding. With regard to Mr. Heid's recommendation that NIPSCO modify its cost of service study to reflect the minimum distribution system analysis results from Cause No. 41746, the Commission would note that those results are not in evidence in this case; the preparers of that analysis were not subject to cross-examination; and we must base our decisions upon substantial evidence in the record. Based upon those factors, and the arguments raised by Dr. Swan against the use of a minimum system approach, the Commission finds that NIPSCO need not modify its cost of service study to reflect the minimum distribution system analysis.

With regard to Mr. Phillips' contention that NIPSCO over-assigned sales expenses and customer service and informational expenses to industrial customers, we find that it would be inappropriate to allocate those direct expenses to other rate classes, and we therefore find that NIPSCO's direct allocation of those costs is appropriate.

While various witnesses questioned NIPSCO's billing determinants, in rebuttal, Mr. Greneman explained that NIPSCO prepared an analysis of its present rates under pro forma billing determinants that produce pro forma revenues, before NIPSCO's proposed rate increase. He noted that neither Mr. Phillips nor Mr. Heid contested NIPSCO's reconciliation of demand billing determinants on technical grounds.

In conclusion, the Commission finds that NIPSCO should rerun its cost of service study at the allowed total jurisdictional revenue requirement based on a 12 CP allocation of both generation and transmission costs and reflecting the original 60/40 variable/fixed split of non-fuel production O&M expenses, and the results of that cost of service study should be utilized as the starting point from which to recover from the several customer classes the revenue requirement found above. NIPSCO shall file the results of the cost of service study as a component of its compliance filing ordered *infra*.

B. Reduction in Subsidy/Excess Revenues.

(1) Evidence. In its direct case, NIPSCO's proposed moderation plan impacted all classes that were increasing, including its residential customers and inter-departmental sales. As discussed earlier in this Order, much testimony was presented concerning the appropriate level of pro forma operating revenues at present rates. As found hereinabove, NIPSCO's rebuttal presentation of the revenue credit ($55 million at present rates) and expiring special contracts ($80 million at present rates) was approved. Mr. Shambo, in rebuttal, discussed the issue of how pro forma revenues at current rates impacts NIPSCO's proposed rates due to its moderation plan, which proposed to limit the subsidy reduction to any customer class to 25%. Mr. Heid noted that NIPSCO proposed elimination of only 25% of the interdepartmental sales subsidies. Heid Direct at 31. He recommended that the Commission order NIPSCO to eliminate 100% of the NIPSCO inter-departmental subsidies. On rebuttal, NIPSCO concurred with Mr. Heid's recommendation.

Mr. Phillips asserted that NIPSCO's rate moderation plan did not take into account increases to its largest customers due to the elimination of special contracts. Phillips Direct at 34. Mr. Phillips recommended that the large industrial rates be based on parity or without subsidies and, to the extent other classes can be moved to cost of service, he recommended that be accomplished to the extent practicable. Phillips Direct at 34-35. Mr. Shambo responded in rebuttal that Mr. Phillips' comments regarding a lack of moderation to special contract customers ignored that under the terms of the special contracts, any rates approved in this proceeding would not become effective for these customers until six months after a Commission order in this proceeding. In other words, Mr. Shambo argued that these customers anticipated and contractually agreed to the method of instituting a grace period between the effective date of a Commission order in the rate case and the impact of those new rates on them. Thus, Mr. Shambo concluded that these customers will receive the benefit of their contractual moderation plan.

(2) Discussion and Findings. All parties in this proceeding have a vested interest in how to allocate the revenue requirement across the customer segments. We initially note that our decision to use a 12 CP cost allocation methodology serves to assign more costs to the energy intensive industrial customers than the company's proposed 4 CP methodology would have allocated. As such the use of the 12 CP cost allocation methodology can be viewed as a moderating step to the rates that will be borne by low energy intensive customers. We are also cognizant that NIPSCO's managerial decision to discontinue the use of special contracts effectively imposes an increase in rates on some of its energy intensive industrial customers and that any proposed subsidy moderation scheme will further increase their rates. These factors lead to a conclusion that basing rate class revenue requirements on a 12 CP allocation methodology and an equalized, or parity, rate of return balances the regulatory principles of gradualism and rates based to the extent practical on the cost to serve customers. Accordingly, based upon the evidence presented, we find that NIPSCO's proposed 25% moderation plan is not approved and rates shall be designed on a parity return basis.

12. Rate Design.

A. Tracking Mechanisms.

(1) Fuel Adjustment Charge.

(a) Evidence. NIPSCO proposed to remove fuel-related costs from its basic rates. Mr. Shambo noted that this Commission has repeatedly encouraged electric utilities to purchase power from neighboring utilities when such power was less expensive than that of the utility's own internal generating units.[19] He explained that in this proceeding NIPSCO proposed to remove all fuel costs,[20] including purchased power costs, from its base rates for two reasons: (1) fuel is a variable cost by nature and should not be collected in a fixed component on the bill; and (2) to simplify its tariff structure. As discussed later in this Order, NIPSCO also proposed to remove purchased power and related Midwest ISO costs from the FAC and recover these costs through the RA mechanism.

OUCC witnesses Michael Eckert, Satchwell, Cearley and IG witness James Dauphinais all opposed NIPSCO's removal of all fuel costs from base rates. Mr. Dauphinais testified, for

[19] *N. Ind. Pub. Serv. Co.*, Cause No. 37343, at 4-5 (Dec. 27, 1983). (The Commission found that "it is imperative that [NIPSCO] . . . commence a program directed toward reducing fuel costs by supplementing internal coal generation of electricity with the purchase of less expensive supplies of electricity from neighboring utilities whenever operating conditions will permit this without adversely affecting the reliability of electrical services.")
[20] Except for non-trackable fuel expense of $11,015,038.

example, that NIPSCO had not shown that it is reasonable to move the recovery of purchased energy costs from base rates and its FAC to its proposed RA Tracker. Dauphinais Direct at 7. Mr. Phillips recommended that NIPSCO's rates maintain the test year fuel cost as the base cost of fuel in the approved rate structure and that the FAC should be modified to more accurately adjust fuel cost by class with different FAC adjustments for each class reflective of fuel cost. Mr. Phillips proposed that the Commission adopt the FAC allocator methodology proposed in Cause No. 43618 in this proceeding. Phillips Direct at 31. In its cross-answering testimony, the OUCC opposed this recommendation. Swan Cross-Answering at 10-11.

In rebuttal, Mr. Shambo responded to Mr. Phillips' suggestion that NIPSCO incorporate its FAC allocator proposal from its pending DSM proceeding (Cause No. 43618) into this proceeding by acknowledging that while NIPSCO continued to support the FAC allocator proposal, it had agreed with the other parties in Cause No. 43618 to stay the consideration of that proposal. Mr. Shambo stated that NIPSCO understood that parties have raised certain questions regarding the application of a voltage differentiated line loss factor, and NIPSCO agreed that some methodology should be used to recognize the differences in fuel cost to the customer segments based upon the voltage level of service. Therefore, Mr. Shambo articulated NIPSCO's agreement to apply the 1999 line loss factors used by Mr. Greneman in this proceeding in its FAC filings subsequent to an order in this proceeding.

(b) Discussion and Findings. The non-NIPSCO parties in this proceeding opposed NIPSCO's proposal to remove all fuel costs from its base rates. They articulated two sound reasons for this opposition: (1) NIPSCO's proposal is different than the traditional treatment of electric utility fuel costs at the Commission and would result in treatment different from all the other electric utilities in the State of Indiana; and (2) NIPSCO's proposal does not consider differences in line losses at various voltage levels. Whether or not NIPSCO can address the second concern by applying the line loss factors in the subsequent FAC filings, the present record lacks sufficient evidence to support how this would be accomplished. Further, as noted above, we are troubled by the line loss study presented herein and are not convinced such a study can reasonably and cost-effectively reach the level of detail needed for application to a monthly fuel cost allocation.

As for the traditional treatment of fuel costs, the Commission would note that fuel is an integral component of electricity production and is appropriate to establish in base rates at the same time all the other costs of electricity production are established. The Commission would further note that the Indiana statutory construct does not mandate or support fuel costs embedded into base rates; rather, it provides for the ability of electric generating utilities to track the changes in fuel costs. Under this construct, absent the tracking of changes from base rates, fuel costs would remain statically embedded in base rates. While providing accurate price signals to one's customers is a laudable goal, nothing in NIPSCO's proposal to recover all trackable fuel costs in its FAC provides a different price signal to customers because total bills would remain identical in either approach. Based upon the evidence presented, the Commission finds that fuel costs should be included in NIPSCO's base rates and its FACs should recover changes in trackable fuel costs. This treatment takes into account different customer classes' voltage levels to the extent historically practical.

(2) Petitioner's Proposed RA Tracker.

(a) NIPSCO's Evidence. Mr. Crum discussed certain aspects of NIPSCO's RA Tracker, which was requested pursuant to Ind. Code § 8-1-2-42(a). NIPSCO Witness Miller described the proposed timing for RA filings and pro forma schedules for processing the RA Tracker.

Mr. Crum testified that the RA Tracker provides for the timely recovery of: (1) charges and credits assessed by RTOs, including costs associated with transmission upgrades constructed by others ("RTO Costs"); (2) NIPSCO's purchased power costs; (3) NIPSCO's capacity costs; and (4) the allocation of revenues from NIPSCO's OSS. Mr. Crum described the Midwest ISO-related costs incurred by NIPSCO. He stated NIPSCO's Midwest ISO-related costs can be grouped into three categories: (1) non-fuel charges assessed by the Midwest ISO pursuant to its tariff that has been accepted for filing by FERC; (2) fuel-related costs incurred due to participation in the Midwest ISO pursuant to its tariff that has been accepted for filing by FERC; and (3) transmission costs accessed through Attachment FF and other transmission costs pursuant to rate schedules that have been accepted for filing by FERC.

He stated the current RTO Costs that would be included in the RA include: (1) Midwest ISO administrative costs billed under Schedule 10 (ISO Cost Recovery Adder), a successor provision (including Schedule 10-FERC), or any successor tariff of the Midwest ISO; (2) Midwest ISO administrative costs billed under Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder), or any successor tariff of the Midwest ISO; (3) Midwest ISO costs associated with purchased power such as Non-Asset and certain Asset Energy Amounts; (4) Midwest ISO administrative costs billed under Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder), or any successor tariff of the Midwest ISO; (5) Midwest ISO costs and revenues that are "socialized," which are often referred to as "uplift costs," such as the Real-Time Revenue Neutrality Uplift Amount; (6) certain Midwest ISO transmission costs assigned to NIPSCO pursuant to the Midwest ISO's Open Access Transmission and Energy Markets Tariff ("TEMT") including, but not limited to, Schedule 24 and Schedule 26; (7) fuel-related Midwest ISO amounts related to Revenue Sufficiency including (i) Day-Ahead Revenue Sufficiency Guarantee Distribution Amount; (ii) Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount; and (iii) revenue sufficiency make whole payments; (8) transmission revenues from Midwest ISO Schedules 7 and 8 and the revenues from Midwest ISO Schedules 1 and 2 associated with Schedules 7 and 8; (9) costs and revenues from transmission adjustments captured in the Midwest ISO Schedule 11; and (10) any other amounts billed pursuant to the Midwest ISO's tariff that have been approved for filing at FERC and that are not included in NIPSCO's FAC proceedings.

Mr. Crum explained the recovery of Midwest ISO costs in the RA Tracker should be approved for the following reasons: (1) the Midwest ISO charges and credits to be recovered under the RA Tracker are assessed pursuant to the Midwest ISO's tariffs and are a necessary cost as NIPSCO continues to provide safe, adequate, and reliable service to its customers; (2) the costs associated with purchased power are reasonable and necessary for the provision of safe, adequate, and reliable service to the Company's customers; (3) the RTO Costs and purchased power costs are variable in amount from year to year and quarter to quarter; (4) the timing of these charges and credits is also variable; (5) the RTO Costs are also substantial in the aggregate and in individual amounts; and (6) the ability to timely recover Midwest ISO charges on an ongoing basis is important to NIPSCO's financial well being and to the accuracy of price signals sent to the Company's customers.

Mr. Crum explained NIPSCO's proposed recovery of purchased power costs. Mr. Crum stated that in the past purchased power costs have been recoverable in the FAC, subject to a "benchmark," which was utilized as a surrogate for the fuel component of the costs. In this proceeding NIPSCO proposed to include its purchased power costs in its RA Tracker, subject to a benchmark.

Mr. Crum described NIPSCO's proposed Purchased Power Benchmark. He explained that each day a "Benchmark" would be established based upon a generic Gas Turbine ("GT"), using an effective GT heat rate of 12,500 btu/kWh and a fuel cost based on the day ahead natural gas prices for the New York Mercantile Exchange Chicago City Gate, plus a \$.17/ mmbtu gas transport charge. Purchases made in the course of the Midwest ISO's economic dispatch regime to meet jurisdictional retail load are a reasonable expense and are fully recoverable up to their actual cost or the Benchmark, whichever is lower. In each individual hour that purchased power costs exceed the Benchmark, purchases made under the following conditions would be recoverable: (1) If NIPSCO has generating units available to the Midwest ISO that were offered into the Midwest ISO market at expected cost and which were not selected by the Midwest ISO and the utility purchased power over the benchmark, 100% of the purchase power costs are recoverable; (2) if the sum of unplanned full forced outages, qualifying environmental derates, partial outages, and qualifying scheduled maintenance outages total 11% or more of NIPSCO's seasonal generating fleet capacity, 100% of purchase costs over the Benchmark for purchases made to account for such outage level are recoverable; (3) if purchases were made to account for qualifying environmental derates, 100% of the purchase costs over the Benchmark for such purchases are recoverable up to the amount of the derated capacity; (4) for purchases not subject to 100% recovery as described in the above parameters, 85% of the purchase costs over the Benchmark for such purchases are recoverable up to the FERC approved Midwest ISO definition of scarcity pricing. Mr. Crum explained that the Midwest ISO makes the decision which NIPSCO generating resources are to be dispatched and at what level. Depending on the specific conditions, the Midwest ISO's directive may be for NIPSCO to purchase power from the market rather than the Midwest ISO calling for NIPSCO's internal generation. As a result, NIPSCO may, on occasion, be directed by the Midwest ISO to make economy purchases at what may appear to be a higher cost than NIPSCO's own resources. Those Midwest ISO directed purchases can even be at levels above the Benchmark. Mr. Crum testified the Benchmark mechanism is in the public interest. He stated use of a daily Benchmark captures the variability of fuel prices over time. In addition, the Benchmark addresses the recoverability of costs incurred when the Midwest ISO elects to utilize other more cost efficient generation in the footprint in lieu of starting higher cost NIPSCO generation, benefiting NIPSCO's jurisdictional retail customers.

Mr. Shambo testified that excluding purchased power costs from the FAC is consistent with the logic of the Revised Purchased Power Benchmark approved in NIPSCO's FAC71 sub-docket, which allowed for recovery of certain purchased power costs via a tracker mechanism approved pursuant to Ind. Code § 8-1-2-42(a).

NIPSCO also proposed to recover prudently-incurred capacity costs, which were described by NIPSCO Witness Sweet. Mr. Sweet testified that he was familiar with the evolution of the Midwest ISO's long-term Resource Adequacy Plan. He stated that when FERC conditionally approved TEMT on August 6, 2004, it also approved the proposed Module E of the TEMT as a "short-term transition mechanism" to help ensure reliability throughout the Midwest

ISO footprint. In the same order, FERC directed the Midwest ISO to work toward a long-term resource adequacy plan through its stakeholder process. In response to that directive, on December 28, 2007, the Midwest ISO filed its long-term resource adequacy proposal, which contained mandatory requirements for any market participant serving load in the Midwest ISO region to have and maintain access to sufficient planning resources. Under the proposal, the Midwest ISO would establish a Planning Reserve Margin for each Load-Serving Entity ("LSE"), which then must demonstrate that it has sufficient resources to meet the forecast requirements plus the applicable Planning Reserve Margin requirements. Mr. Sweet explained that NIPSCO is an LSE and, therefore, must comply with these requirements.

The first planning year under the Resource Adequacy Plan started June 1, 2009. Mr. Sweet testified that NIPSCO is a member of the Midwest Planning Reserve Sharing Group ("PRSG"), which is a voluntary group of LSEs. He explained that the PRSG was established to study the collective resources of the group and to determine a minimum level of planning reserve requirements. He stated that the Midwest PRSG approved a planning reserve target margin for the 2008-2009 planning year of 14.3% for the Central Zone, of which NIPSCO is a member. He testified that NIPSCO purchased 800 MWs of capacity for the period June 1, 2008 through May 31, 2009 and entered into seven contracts of between 50 and 200 MWs each for a total price of under $14,000,000. He stated that NIPSCO proposed to recover its 2009 capacity costs through the RA Tracker.

The final item included in the RA Tracker is the gross margin from OSS. As discussed earlier herein, NIPSCO proposed that 100% of future OSS margins up to $15 million annually will be passed back to the ratepayers through its proposed RA Tracker.

(b) OUCC's Evidence. OUCC Witnesses Satchwell and Eckert opined that purchased power costs and fuel-related Midwest ISO charge types should be tracked in the FAC. Mr. Eckert recommended that the Day-Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amount and the Real-Time RSG First Pass Distribution Amount charge types remain in the FAC and that Day-Ahead and Real-Time RSG Distribution Amounts associated with native load be included in the FAC and charges associated with non-native load should be included in the OUCC's proposed RTO Tracker. Mr. Eckert also recommended that only Revenue Sufficiency Guarantee Make Whole Payments ("MWP") Amounts associated with native load be recovered through the FAC. RSG MWP Amounts associated with non-native load should be recovered through the OUCC's proposed RTO Tracker where OSS margins are recovered. They agreed that NIPSCO's purchased power costs should be subject to NIPSCO's proposed benchmark as revised by Mr. Eckert. Mr. Eckert recommended that NIPSCO continue to proactively track RSG amounts above the benchmark and provide support for proposed recovery of such charges as a narrative in its testimony filed in each of NIPSCO's future FAC and/or RTO tracker filings. He also asked the Commission to require NIPSCO to include a narrative in testimony providing evidence of the reasonableness of Contestable RSG amounts.

Mr. Satchwell acknowledged that the OUCC generally supports participation in RTOs as they are supposed to provide benefits to customers. He asserted that utilities must balance benefits with costs. Satchwell Direct at 3-4. He stated that the OUCC is concerned that NIPSCO is proposing open-ended approval of all current and future Midwest ISO costs and revenues. Satchwell Direct at 4. He asserted that it is unclear how NIPSCO proposes to recover any future modified or new Midwest ISO charge types and concluded that these changes should be reviewed and a new determination of appropriate recovery made. Satchwell Direct at 4-5. He testified that NIPSCO should include the test year amount of Midwest ISO charges and credits under Schedules 10, 10-FERC, 16, and 17 in base rates ($6,502,782) and track variances through the RA. Satchwell Direct at 6. He also suggested that NIPSCO should build test year amount of Schedule 24 (load-balancing authority) charges and credits in base rates ($1,287,485) and track variances through the RA Tracker. Satchwell Direct at 7. He further concluded that NIPSCO should include pro forma period amount of Schedule 26 charges ($111,634) into base rates and track the variance through an RTO tracker. Satchwell Direct at 8. He stated that the OUCC accepted NIPSCO's proposal to include non-Regional Expansion Criteria and Benefits transmission revenues as an offset in base rates without tracking variances. Satchwell Direct at 8.

With regards to recovery of purchased capacity costs, Mr. Satchwell testified that NIPSCO should be allowed to recover prudently-incurred capacity costs through a tracker, subject to prudency reviews at each tracker filing. He recommended that NIPSCO should be required to justify any capacity purchases that yield a planning reserve margin greater than Midwest ISO's. Satchwell Direct at 13-14. He stated that Midwest ISO's 12.69% planning reserve margin varies greatly from NIPSCO Witness Sweet's statement of a 15% margin and that NIPSCO's planning reserve margin should be clarified so as to avoid incurring Module E penalties. Satchwell Direct at 13. He also recommended that Module E penalty charges should not be recoverable in the RA Tracker.

Mr. Satchwell expressed two additional concerns regarding the RA. First he testified that quarterly filing would present many challenges for review and auditing and second, he observed that the RA Tracker appears to be a "catch-all" for recovery of many costs and revenues which may significantly decrease transparency and lead to inaccurate price signals. Satchwell Direct at 19. To address these concerns, Mr. Satchwell proposed that Midwest ISO costs and revenues and the OSS sharing be included in one tracking mechanism that he designated the RTO Tracker and that purchased capacity costs should be combined into a separate tracking mechanism that he designated as the Resource Adequacy Tracker. He recommended that the RTO Tracker should be a semi-annual tracking mechanism, coordinated with FAC audit process and that the OUCC and Intervenors should have 60 days to audit and that the Resource Adequacy Tracker should also be a semi-annual tracker, subject to 60-day audit. Satchwell Direct at 19-20.

(c) LaPorte County/Hammond's Evidence. Mr. Cearley disagreed with NIPSCO's proposal to implement its proposed Purchased Power Benchmark mechanism. Mr. Shambo in rebuttal stated that Mr. Cearley's position is a situation whereby NIPSCO is unreasonably penalized for adhering to economic dispatch, which is within the control of the Midwest ISO. Mr. Shambo asserted that Mr. Cearley ignored Commission precedent and treatment of purchased power costs for other electric utilities.

(d) IG's Evidence. Mr. Dauphinais recommended NIPSCO's proposed RA Tracker should either be rejected or substantially modified. Mr. Dauphinais opined that in general, rate tracking mechanisms should be avoided except when the magnitude, volatility and unpredictability of the costs and revenues in question could threaten the financial integrity of the utility. Dauphinais Direct at 8. Mr. Dauphinais also suggested that certain Midwest ISO charges should be allocated on the basis of demand rather than energy. Dauphinais Direct at 9.

(e) NIPSCO's Rebuttal Evidence. Mr. Shambo testified that a common theme among the OUCC and Intervenors is a concern that NIPSCO has requested pre-approval or pre-determination of prudence for recovery of certain costs through NIPSCO's tracker proposals. He noted that Mr. Satchwell suggested this notion in regard to the RA Tracker. Mr. Shambo explained that NIPSCO was not proposing pre-approval of specific charges but simply proposing that the Commission approve the tracking mechanism in NIPSCO's requested form to permit the appropriate "vehicles" for future consideration of such cost items to avoid any unnecessary litigation and administrative efforts in the future because the appropriate recovery mechanism is already in existence. Mr. Shambo also testified that NIPSCO agreed to Mr. Eckert's suggested modifications to the Purchased Power Benchmark mechanism, i.e., making it consistent with that approved in Cause No. 43414. In response to Mr. Eckert's recommendation that NIPSCO include the recovery of purchased power costs that are subject to the Purchased Power Benchmark mechanism in its FAC, Mr. Shambo restated NIPSCO's position that purchased power costs are more appropriately handled through the RA Tracker is unchanged.

Mr. Shambo stated that NIPSCO was willing to incorporate the OUCC's suggested changes, with slight modification, in regard to the following items: (i) inclusion of asset/non-asset energy in FAC; (ii) inclusion of ancillary service market energy-related charges as defined by the Commission in Cause No. 43426; and (iii) if and to the extent Midwest ISO develops new charge types or modifies its charge types, NIPSCO would seek authorization from the Commission to include them in the RA Tracker.

Mr. Shambo stated that, in terms of other items proposed by Mr. Satchwell and Mr. Eckert, NIPSCO opposed the suggestion of introducing an RTO Tracker and a Resource Adequacy Tracker. He asserted that NIPSCO's proposed RA Tracker is sufficient to address the various items proposed for inclusion, and NIPSCO is willing to supply the necessary information to the OUCC and Intervenors supporting future recovery under these proposed trackers.

On rebuttal, Mr. Crum testified that the costs and revenues proposed in the RA Tracker involve large, volatile and unpredictable costs and revenues that warrant a rate tracking mechanism. He stated the Midwest ISO charge types proposed to be recovered in the RA Tracker have varied in magnitude over time and many of the charge types have been resettled several times. He also noted that the Commission has approved similar tracking mechanisms for the same Midwest ISO charge types for Vectren South and Duke. In addition, I&M recently received authority to recover similar PJM RTO costs through a functionally equivalent tracking mechanism. Mr. Crum also disagreed with IG's proposed change to the allocation of certain Midwest ISO charge types proposed in the RA Tracker to be on a demand basis. He stated IG did not provide any justification for its proposed allocation. He explained that these costs are allocated by the Midwest ISO to market participants, such as NIPSCO, on an energy basis with the exception of Schedule 26 charges and revenues. He stated that NIPSCO, likewise, has proposed to allocate these Midwest ISO charge types, with the exception of Schedule 26, to its customers on an energy basis.

(f) Discussion and Findings. We find the best practice would be for the Midwest ISO non-fuel costs and revenues and the OSS sharing to be included in one tracking mechanism designated as the RTO Tracker. We further agree with the OUCC that purchased power costs and fuel-related Midwest ISO charge types shall be tracked in the FAC. Therefore, we find that the OUCC's proposal to track Midwest ISO-related costs and revenues and OSS margins through its RTO Tracker and to track purchased power costs and fuel-related Midwest ISO charge types in the FAC is reasonable.

We further find that the OUCC's proposal for a purchase capacity tracker, referred to as the Resource Adequacy Tracker, is approved. This tracker shall be a semi-annual tracking mechanism, coordinated with the FAC audit process. Later in this Order we discuss NIPSCO's proposal to include a credit of $40.5 million, which is projected to be credited to their interruptible customers, in its cost of service study. To the extent that NIPSCO does not have 500 MWs of interruptible load, and therefore has less than $40.5 million of credits to its interruptible customers, this difference should be used to offset any capacity costs recoverable through the Resource Adequacy Tracker. In this way, NIPSCO's customers are protected from paying rates designed to recover higher credits, while at the same time NIPSCO is protected from having reasonably incurred costs not being recovered through its rates and charges.

Finally, NIPSCO's proposed purchased power benchmark, as modified by the OUCC is consistent with the benchmarks we have approved for IPL and Vectren South, and the Commission finds that its use in the FAC tracker is appropriate. The parties should note that pursuant to the Commission's Interim Order in Cause No. 43706 FAC 80 S2, the Commission is conducting a review of the FAC process generally based on two recent refunds of $40.5 million to ratepayers in order to determine whether further modifications of the FAC process would be appropriate.

(3) <u>Modifications to ECRM and EERM.</u>

(a) <u>NIPSCO's Evidence</u>. NIPSCO proposed to clarify that compliance costs for current and anticipated air regulations are eligible for recovery on a semi-annual basis through its ECRM and EERM. Mr. Pack explained that NIPSCO sought to recover emission allowance purchase costs and credit revenues from the sales of emissions allowances to customers. Pack Direct at 11. Mr. Shambo explained that the proposal was designed to promote symmetry such that costs and gains associated with emissions allowances were shared equally with NIPSCO customers. Shambo Direct at 8. Ms. Miller and Mr. Pack further explained that NIPSCO seeks approval to file the EERM on a semi-annual, as opposed to annual, basis. Miller Direct at 49.

(b) <u>OUCC's Evidence</u>. OUCC Witness Pruett did not object to NIPSCO's proposal to file its EERM on a semi-annual, rather than an annual, basis. Pruett Direct at 11. However, Ms. Pruett objected to NIPSCO's proposal to track emission allowance purchase costs and revenues through the EERM. While Ms. Pruett agreed that NIPSCO faces current and future air regulations that may impact the need for allowances, she believed NIPSCO failed to demonstrate two of the three conditions to track emissions allowance costs were satisfied. Pruett Direct at 6. First, she testified that NIPSCO's admission that it did not forecast the purchase or sale of SO2 or NOx emissions allowances in the near future indicated the anticipated costs involved were small. Pruett Direct at 7. Second, she believed that emissions allowance expenses are within a utility's control because it can choose the most cost-effective path to comply with environmental cap and trade regulations. Pruett Direct at 6-7. She claimed a utility would need to show either that it must rely on the emission allowance market for compliance or that such reliance is the least cost environmental compliance strategy before being authorized to track emissions allowance purchase costs. Ms. Pruett was also concerned that NIPSCO had mismanaged its emissions allowances by selling allowances that otherwise could have been used as a low-cost option for future regulatory compliance. Pruett Direct at 9. She asserted allowing NIPSCO to track emissions allowance expenses could give NIPSCO even less incentive to manage allowances in a cost-effective manner.

(c) IG's Evidence. IG Witness Dauphinais opposed NIPSCO's proposal to modify its EERM to the extent that modification allowed NIPSCO to recover emissions allowance costs for substances not currently authorized by Indiana's statutes. Dauphinais Direct at 20. Mr. Dauphinais believed NIPSCO should wait until carbon or other regulations are enacted and then make proposals to recover allowance costs associated with those new regulations. Dauphinais Direct at 20-21.

(d) NIPSCO's Rebuttal Evidence. Mr. Pack continued to believe in the appropriateness of tracking emissions allowance costs and revenues through the EERM. He noted that NIPSCO's proposal is not a break from traditional regulatory practice in Indiana because most of the other investor owned electric utilities are authorized to track emission allowance costs. Pack Rebuttal at 2-3. Mr. Pack testified that the Commission's prior authorization for other electric utilities to track emissions allowance costs demonstrates tracking such costs is consistent with Commission requirements. Pack Rebuttal at 3.

Disagreeing with Ms. Pruett, Mr. Pack concluded that emissions allowance costs satisfied the criteria for tracking. He testified that while NIPSCO currently does not have an estimate of its future costs for emissions allowances, the general consensus in the industry is that the potential cost is significant. He explained that the reason NIPSCO currently has no estimates is due to the uncertainty over legal challenges to current regulations and the form future regulation will take. Pack Rebuttal at 3-4. Mr. Pack also disagreed with Ms. Pruett's belief that emissions allowance costs are within the control of the utility. While Ms. Pruett focused on the utility's freedom to select control technology to mitigate its need for emissions allowances, Mr. Pack believed a more appropriate focus was on the actual costs for necessary emissions allowances, which are set by the market and not within the control of the utility. Pack Rebuttal at 4. He also noted that there was no assurance control technology would be available before potential CO_2 caps are placed into effect.

Mr. Pack also took issue with Ms. Pruett's assertion that NIPSCO's failure to manage its emissions allowances could result in greater future costs for NIPSCO electric customers. He explained that the Clean Air Act Title IV emissions allowances ("Allowances") NIPSCO had previously sold would not likely be available for future compliance based upon the CAIR remand to the Environmental Protection Agency ("EPA"). The remand decision questioned the EPA's authority to utilize historic allowances for future compliance requirements. Based on the Court decision, Mr. Pack believed it is improbable that the allowances will be available for use in future compliance requirements to defer investment in emissions compliance equipment. Pack Rebuttal at 5. Mr. Pack noted NIPSCO's management efforts will include providing information about its plans to manage emissions allowances in its EERM including: (1) regulatory updates on the CAIR remand and CO_2 as they evolve; (2) least-cost compliance options including use of technology and purchase/sale of allowances; and (3) progress of approved projects and purchases/sales allowances.

Mr. Pack also disagreed with Mr. Dauphinais' proposal to declare that the EERM could not include emissions allowance costs to comply with future air emissions regulations. He noted that NIPSCO proposes to use the allowance tracker when needed to result in the most cost-effective path to comply with State/Federal environmental regulations in effect at the time cost recovery is sought. NIPSCO will justify the sale/purchase of any allowances in the EERM filings. The amounts would not be recovered until the Commission (and other parties) has had an opportunity to review the costs and compliance proposals and until the Commission approves recovery of these costs. Pack Rebuttal at 5-6.

(e) Discussion and Findings. NIPSCO has made two proposals relating to its EERM in this proceeding. First, NIPSCO has proposed to file its EERM on a semi-annual basis. While no party opposed this proposal and a semi-annual filing would be consistent with the frequency with which other electric utilities file similar tracking mechanisms, the Commission is concerned with the amount of time and resources tracker review entails in order to have a meaningful review and audit by consumer parties and the Commission. Accordingly, we find that NIPSCO shall file its EERM on an annual basis.

NIPSCO's second proposal is to clarify that its EERM can track emissions allowance costs and revenues. We begin by noting that the environmental tracking mechanisms approved for several other electric utilities in Indiana authorize the recovery of emissions allowance costs and a mechanism for sharing revenues from sales. *See e.g., Ind. Mich. Power Co.*, Cause No. 43306, at 29-30 and 53 (approving a settlement under which utility will implement an environmental tracking mechanism allowing tracking of net emissions costs); *PSI Energy, Inc.*, Cause No. 42359, at 118 (approving a tracking mechanism to recover expenses to purchase NO_x emissions allowance credits and return net proceeds associated with any sales of jurisdictional NO_x sales).

We also find that, with respect to NIPSCO, Mr. Pack has demonstrated that the conditions to track allowance costs have been satisfied. The costs associated with emissions allowances can be substantial. Ms. Pruett's contrary conclusion was based on NIPSCO's indication it did not forecast the purchase or sale of SO_2 or NO_x allowances, but Mr. Pack explained that NIPSCO's inability to quantify that cost resulted from the uncertainty surrounding the regulation of air emissions. This does not mean the cost of acquiring any necessary allowances once the regulatory uncertainty is resolved will not be substantial. Mr. Pack notes that few in the industry dispute that future air emissions regulations, including potential CO_2 regulations, could pose a significant costs for electric utilities. While Ms. Pruett is correct that a utility may have some control over the degree to which it relies on emissions allowance costs, this does not mean that the utility has control over the price it must pay for the emissions allowances. Emission allowances pricing is set by the market, not by the utility. Electric utilities have long been authorized to track fuel costs even though they have some control over the type of fuel that powers its generation equipment. No party disputes that these prices are volatile and this conclusion is bolstered by Mr. Pack's testimony of the significant increase in SO_2 emissions allowances during portions of 2005. For the foregoing reasons, we find that NIPSCO shall be authorized to seek recovery of prudently incurred emissions allowance costs and to credit customers emissions allowances revenues through its EERM. We note that this finding shall not be construed as pre-approving recovery of any such costs, and such specific costs shall be reviewed in the context of its EERM filings.

We also reject Mr. Dauphinais' proposal to limit the recovery of emissions allowances only to air emissions currently eligible for recovery under Indiana statutes. We have already authorized a utility to recover allowances for a pollutant that was expected to be regulated in the future. *See S. Ind. Gas & Elec. Co.*, Cause No. 43111, at 21 (Aug. 15, 2007) (approving the tracking of costs to comply with mercury control regulations when they become effective). While we clarify that NIPSCO should not seek recovery of allowance costs associated with pollutants that are not subject to Federal or State regulation at the time they are purchased, there is no need to require NIPSCO to seek future modification of the EERM to allow recovery of the cost to comply with the regulation of pollutants that become subject to regulation in the future.

The Commission notes that in Attachment CMP-5 to Ms. Pruett's testimony, NIPSCO responded to OUCC Data Request 29-18 and stated its EERM will include 7 months (Jan-Apr & Oct-Dec) of expenses due to annual operation of its U8, 12, and 14 SCRs, and that all other EERM expenses proposed for inclusion in base rates will no longer be tracked in the EERM. However, since the SCR projects are being placed into rate base, all O&M costs for QPCP projects that have been placed into base rates should no longer be tracked. To the extent NIPSCO incurs an increase in O&M expense for those units placed in rate base, those increases may be appropriate for recovery in NIPSCO's next rate case.

Ms. Pruett also recommended that NIPSCO file its progress report on the status of qualified pollution control projects tracked in the Environmental Cost Recovery Mechanism ("ECRM") as part of its ECRM filing. NIPSCO accepted this recommendation and we find NIPSCO should submit this progress report as part of its environmental cost recovery filing.

B. Tariff Rate Class Proposals.

(1) Evidence. Mr. Shambo testified NIPSCO had three overall policy objectives in the development of the rates proposed in this proceeding: (1) the charge for any service rendered is reasonable and just; (2) to the extent possible, the rates should be easy to understand and administer; and (3) the final rates need to consider broader public policy objectives.

With regard to the first objective, he stated that there are two underlying goals: (1) an appropriate balance between the desire of customers for reasonable rates and NIPSCO's responsibility to its shareholders to design rates that give the Company an opportunity to earn a reasonable return on its investment, which ultimately is also in the customer's best interest; and (2) a reasonable level of equity between customer classes in the final rate design. Mr. Shambo stated obtaining a fair return for investors, in turn, requires that rates be designed based on an appropriate revenue requirement level and that the rate structure provide NIPSCO with a reasonable opportunity to recover that revenue requirement. He explained that NIPSCO's industrial customers represent an unusually high percentage of annual load when compared to other utilities, accounting for more than 50% of annual energy usage on NIPSCO's system. He asserted that NIPSCO's proposed cost allocation and rate design takes into consideration the characteristics of all customer classes.

Mr. Shambo stated that NIPSCO is also addressing in its proposed rate design the difference between "peak" and "off-peak" usage. He explained that the advent of the Midwest ISO marketplace has provided much clearer signals on the relative value of electricity for all hours. He asserted that NIPSCO's rate design policy should provide more encouragement for customers to move from peak hours to off-peak hours. He explained that this is a benefit to all customers in three ways: (1) NIPSCO can reduce production from less efficient units; (2) NIPSCO can reduce purchases from the market that by design reflect the dispatch of higher cost units across the Midwest ISO's footprint as demand rises; and/or (3) NIPSCO can make OSS into the Midwest ISO marketplace at the Locational Marginal Prices ("LMP") (with the vast majority of these OSS margins proposed to be passed back to customers through the RA mechanism).

Mr. Shambo testified that NIPSCO does not anticipate that the expiring special contracts will be replaced by new special contracts. He stated that NIPSCO's cost allocation and rate design in this proceeding are more reflective of the actual cost to serve these customers. This better alignment of rates should eliminate the need for special contract rates for these customers.

Mr. Shambo testified that all customers want safe and reliable service priced at rates that are easy to understand. To promote rates that are easy to understand and administer, NIPSCO proposed to reduce the number of rate schedules in its proposed tariff. Mr. Shambo stated that NIPSCO is proposing to reduce the number of customer Rates from 42 to 13. Determining the appropriate number of customer rates is a balance between seeking equitable cost allocation among customers with different characteristics and the simplicity and administrative feasibility of fewer rate offerings with some embedded riders. He stated that NIPSCO has decided to move in the direction of simplicity and administrative feasibility in this proceeding, and testified that, while many of NIPSCO's customers have diverse usage characteristics, NIPSCO's proposed rate restructuring is now able to better align customer load profile with the Company's underlying cost structure.

Mr. Shambo identified key rate development decisions made by NIPSCO and their relation to the Company's objectives including: (1) production costs are allocated based upon 4 Coincident Peaks ("4 CP"); (2) fuel costs are removed from base rates to permit recovery of all fuel costs in the FAC; (3) declining block rates are eliminated; (4) certain billing determinants for demand charges have been developed to recognize the difference between peak and off-peak; (5) rates are constructed that encourage lowering peak demand (Rates 526 and 527); (6) the use of Interval Demand Recording ("IDR") meters will be increased for customers served under Rates 523 and 533; (7) interruptible service is continued and expanded; (8) the total number of rate schedules is reduced and the service offerings are simplified so that customers and stakeholders will better understand the options available; (9) the customer charges were increased to better reflect the cost to serve; (10) a new structure was developed for the Economic Development Rider; and (11) NIPSCO's rate design was adjusted to provide a measured progress toward full cost based rates for certain customer classes in order to avoid rate shock.

Mr. Shambo also explained that NIPSCO eliminated declining block rates because this rate structure encourages customers to increase energy usage. He stated that given current policies in favor of promoting energy efficiency, NIPSCO proposed to eliminate declining block rates.

Mr. Shambo described the reclassification process used in defining the tariff categories. He stated that there are a number of schedules in the commercial/small industrial classes that will be collapsed into just three rate schedules (Rates 521, 523 and 533). He explained that Rate 521 is designed for small commercial customers that do not have demand meters. He testified that these customers are not likely to have as much energy acquisition sophistication as larger customers. He stated that the rate structure is similar to the residential rates with a customer charge and a volumetric per kWh charge.

Curt A. Westerhausen, Manager of Rates and Contracts for NIPSCO, described NIPSCO's proposed Tariff, including the Schedules of Rates, Riders and General Rules and Regulations ("Rules") and explained how the proposed Tariff differs from NIPSCO's current Tariff. Mr. Westerhausen testified NIPSCO's current electric Tariff was developed from NIPSCO's last base rate case dating back to the mid-1980s. In the ensuing years, a number of additional tariff changes, as well as adjustments and updates to existing Rates have been made. In addition, NIPSCO entered into contracts with certain individual customers. He noted that NIPSCO's residential basic rates have remained constant for more than twenty years.

Mr. Westerhausen testified the development of a new electric rate structure will provide customers with a simplified structured approach. This approach was used in all phases of the ratemaking process in order to reflect current conditions and with an eye toward future changes. Mr. Westerhausen summarized NIPSCO's proposed electric Rates and Riders. Mr. Westerhausen sponsored Petitioner's Exhibit CAW-3 that summarized the charges, terms, and applicable Riders for each Rate. He also sponsored Petitioner's Exhibit CAW-2 (Revised), which provided specific details, terms and conditions, rules, etc., applicable to each Rate.

Various witnesses stated concerns regarding the timing and impact of NIPSCO's rate increase, including a discussion of the state of the steel industry and how NIPSCO has communicated its proposals in this proceeding to its customers. For example, Beta Steel offered the testimony of Jeffry Pollock, an energy advisor. Mr. Pollock's testimony focused on issues specific to Beta Steel, including the impact of NIPSCO's proposed rates on Beta Steel, the current state of the steel industry, and specific class cost of service study and rate design issues. Pollock Direct at 5. Mr. Pollock stated that, with the expiration of Beta Steel's special contract, NIPSCO's proposed rates would increase Beta Steel's electricity costs by $9.3 million per year. Mr. Pollock testified that, in light of the current economic conditions facing Beta Steel and other similar companies, NIPSCO's proposed rate increase could create enormous disruption on its large industrial customers. Pollock Direct at 15-16.

David R. Christian, President and Chief Executive Officer of AMPCOR II, d/b/a American Metal Products, Inc., testified regarding the challenges facing smaller manufacturing firms and the potential impact from any increase in electric rates. Mr. Christian stated his belief that NIPSCO's current electric rates have depressed local economic activity and have dissuaded new, energy-intensive companies from locating to LaPorte County. Mr. Christian testified that the LaPorte Manufacturer's Association and the Greater LaPorte Chamber of Commerce are both opposed to NIPSCO's proposed rate increase. Mr. Christian concluded that having access to reliable, affordable electricity is critical for many businesses. Christian Direct at 2-3.

In rebuttal, Mr. Shambo noted that as a result of the passage of time since its last rate case, NIPSCO's presentation included a comprehensive proposal reflecting its proposed revenue requirement and the need to make fundamental changes to its rate design. Mr. Shambo stated the Company proposed steps to improve the offerings available in its tariff and to adjust its offerings to the dynamics of the current wholesale marketplace. He testified it was important to recognize the interrelated nature of NIPSCO's proposed cost allocation and rate design. He emphasized NIPSCO's rate structure is not a series of independently interchangeable parts. Shambo Rebuttal at 2-3.

Mr. Shambo asserted that NIPSCO's opportunity to earn a fair return will be materially affected by the outcome of rate design in this case. He stated there are a significant number of exogenous factors that will have a detrimental impact on NIPSCO if not correctly addressed in the rate design portion of this proceeding. These include, but are not limited to, the ongoing recession, the increased interest and emphasis on energy efficiency programs, and the impact that climate change legislation could have on the rate design and service structure. Shambo Rebuttal at 5.

Mr. Shambo stated that NIPSCO recognizes that there is virtually no good time for a rate increase from the customer's point of view. This concern is magnified by the current recession, regardless if the customer is residential, commercial or industrial. However, the timing of this rate case was mandated by a Settlement Agreement in Cause No. 42824, which was executed by the OUCC and certain customers contained within IG. Mr. Shambo explained that NIPSCO had no alternative but to file this rate case by the date required. Shambo Rebuttal at 6, 40-41.

(a) Rate 511 – Rate for Electric Service, Residential ("RS"). Mr. Westerhausen explained that NIPSCO has three residential Rates in the 800 Series and has created one residential Rate in the 500 Series available to residential and farm customers. Residential electric heating, including electric heat pumps, will be covered by Rider 575 "Electric Spaceheating Rider to Residential Service." Mr. Shambo stated that most residential customers will map easily from Rate 811 to the new Rate 511 schedules. He explained that NIPSCO is converting two additional residential rates into riders for Rate 511. Mr. Shambo explained Rider 575, which is applicable to residential space heating customers. He explained that NIPSCO's current tariff includes three separate space heating rates. Consistent with NIPSCO's effort to simplify its tariff, the three existing rate schedules have been transitioned to one rider, Rider 575. He testified that Rider 575, Electric Spaceheating Rider to Residential Service ("ES") increases the threshold for the discount applicable to the Energy Charge for residential space heating customers to 700 kWh during October through April based upon a review of space heating customer usage. Mr. Westerhausen explained that ES is applicable to Residential Customers that currently have permanently installed electric space heating or electric heat pumps.

Mr. Shambo explained that upon completion of the class embedded cost study, it was apparent that a substantial cost shift was occurring among the three major customer classes. Because existing rates date back to the early 1980s, Mr. Shambo noted that there are many possible explanations for the changes, including fundamental shifts in demand in the commercial class that has moved from smaller units to big box operations during this period, and changing residential usage patterns with the major changes in electrical appliances over this period. Mr. Shambo explained that NIPSCO sought to move toward rates that rely on cost-based allocations with limited inter-class rate subsidies. He explained, however, that moving to cost-based allocations in one step (after 20 years) would result in a 31.4% increase in basic rates for residential customers. He stated that NIPSCO is therefore proposing that only one-third of the full cost-based rate increase to the residential Rate be implemented in this proceeding, yielding an average 16.73% increase in basic rates to residential customers. Shambo Direct at 22.

Mr. Swan asserted that any increase in the customer charge in Rate 511 should be limited to 20% on the basis of rate continuity concerns. He suggested that, if no jurisdictional increase or a reduction is ordered, no change should be made.

NIPSCO disagreed with Mr. Swan's suggestion that NIPSCO should implement a moderation plan regarding its proposed increase to the customer charge. Mr. Shambo stated there does not need to be any moderation of the customer charge as suggested by Mr. Swan. He noted that Mr. Swan did not provide any evidence supporting his suggestion other than the fact that the claimed increase in one aspect of the rate schedule is too much, which misapplies the moderation plan. Mr. Shambo concluded that NIPSCO's proposed customer charge of $10.50 per month is reasonable and fair given the high customer-related fixed costs for this class.

(b) Rates 521 and 523 – Rates for Electric Service, General Service ("GS") Small (521) and Medium (523). Mr. Westerhausen described NIPSCO's General Service rates: Rate 521 – GS Small ("GSS"), and Rate 523 – GS Medium ("GSM"). He stated that GSS is an energy only rate and is available to customers with a rolling twelve month average energy consumption less than 5,000 kWh per month. He explained that GSM is a demand and energy metered rate and is available to customers with demand greater than 10 kilowatts ("kW") but less than 300 kW. NIPSCO Witness Dehring described the Company's efforts to ensure that all GSM customers will have appropriately installed demand meters. Mr. Westerhausen testified that a transitional energy only rate will be used to bill these customers during the interim period.

Mr. Swan asserted that any increase in the customer charge in Rate 521 should be limited to 20% on the basis of rate continuity concerns. He suggested that if no jurisdictional increase or a reduction is ordered, no change should be made.

On rebuttal, Mr. Shambo stated there does not need to be any moderation of the customer charge as suggested by Mr. Swan. He noted that Mr. Swan did not provide any evidence supporting his suggestion other than the fact that the claimed increase in one aspect of the rate schedule is too much, which misapplies the moderation plan. Mr. Shambo stated that NIPSCO's fixed cost incurrence greatly exceeds the revenue that will be generated by the proposed fixed charges. Thus, under Mr. Swan's proposal, NIPSCO would be placed in a position of even greater risk of recovery of its incurred costs. To illustrate this point, Mr. Shambo noted that Mr. Swan is proposing the lowest fixed to variable cost percentage regarding production O&M (*i.e.*, 35% fixed and 65% variable). Mr. Shambo explained that NIPSCO's proposed $10.50 customer charge (in the context of an average monthly bill of $72.13 excluding fuel and trackers) would provide fixed cost recovery much lower than any party's quantification of NIPSCO's fixed production O&M expenses. Therefore, Mr. Shambo concluded, the appropriate application of the moderation plan is to the class as a whole, not to specific charges within the rate class. Shambo Rebuttal at 32-33.

Mr. Shambo testified that proposed Rate 523 contains a broad grouping of customers, estimated at 11,500, that receive power from the distribution system. He explained that this is the first rate schedule that provides a demand charge, and customers were mapped into this rate schedule from Rates 821, 823 and 824 based upon a combination of the assets used to serve these customers, demand data from those customers with permanent demand meters and sampling demand meters. He stated that this is a difficult grouping because of the variety of loads within this class. In recognition of this difficulty, he stated that NIPSCO is planning to expand the use of IDR meters within this group. He also explained that NIPSCO is also providing a number of riders that can be used to better fit customer needs in this Rate.

(c) Rate 526 -- Rate for Electric Service, Off-peak Service ("OPS"). Mr. Shambo explained the nature of Rate 526 and NIPSCO's proposed rate design. He stated that Rate 526 is specifically identified as off-peak Service and was proposed to encourage off-peak usage. He stated that this Rate encourages off-peak service by setting Billing Demand equal to either 100% of On-Peak hours for the past 12 months or 50% of off-peak hours for the past 24 months. On-Peak hours for Rate 526 are defined as 11 AM to 7 PM from April 1 through September 30 and 1 PM to 9 PM from October 1 to March 31, excluding weekends and holidays. Customers with high load during On-Peak hours would pay more on this Rate than under Rate 533 because under Rate 533 only 90% of Peak is used to determine Billing Demand, rather than 100%. By contrast, a Customer whose demand could be migrated to off-peak hours would be encouraged to do so because their Billing Demand would be set at 50%, as compared to 80% under Rate 533. Mr. Westerhausen explained that customers that have demands greater than 300 kW can benefit by shifting their demand from on-peak to off-peak periods by utilizing NIPSCO's proposed OPS. The customer's billing demands are based on the greater of 100% on-peak demand within the last 12 months up, to and including the current month or 50% off-peak demand within the last 24 months, up to and including the current month. A three-year contract is required for service under OPS.

Mr. Phillips noted that NIPSCO proposed to change the definition of billing demand to raise the amount of off-peak demand that counts toward monthly billing demand from 30% to 50%. Mr. Phillips asserted that changing the demand ratchet from 30% to 50% of on-peak load would incent increasing load during on-peak. He noted that NIPSCO changed its billing determinants to coincide with its proposed change in the definition of billing demand under the assumption that "customers will conform usage to rate." Phillips Direct at 22. He asserted that an increase in billing demand units should result in a decrease in the demand charge. Mr. Phillips additionally noted that NIPSCO also proposed to ratchet billing demands to include demands created during the previous 24 months. He asserted that proposed Rate 526 included an increase in the number of on-peak hours from the number NIPSCO has been applying under Rate 825, the requirement of a three-year contract, a new customer charge, and an elimination of the flexibility to deal with unusual circumstances. Mr. Dauphinais also expressed concern that NIPSCO's contracts would be imposed without Commission review or approval. Dauphinais Direct at 28-29.

John Hiler, President of Accurate Castings, Inc., testified about the impact of NIPSCO's proposed Rate 526 on his company. Mr. Hiler described the communications between his company and NIPSCO regarding NIPSCO's proposed rates, and stated his concern that NIPSCO's proposed tariff changes would have a substantial financial and operational impact on his company. Mr. Hiler expressed his concerns regarding NIPSCO's proposed billing demand calculation under Rate 526, the proposed ratchet and the proposed demand change in the number of peak hours.

Mr. Hiler testified that the proposed terms of Rate 526 would have significant financial and operational impacts on his company. Mr. Hiler also expressed his disagreement with NIPSCO's proposed three-year contract term, and stated his belief that NIPSCO should not be permitted to impose any conditions in a new contract that exceed those in the current one-year contract between NIPSCO and his company. Mr. Hiler testified that the proposed Rate 526 would not encourage metal melters to move to off-peak hours and may increase on-peak demand. Mr. Hiler explained that customers currently receiving service under Rate 825 may seek to increase their on-peak load to utilize new demand they would be obligated to purchase under Rate 526, and that Rate 526 ultimately punishes those Rate 825 customers who have modified their operations by moving load to off-peak hours to respond to that rate's price signals. Mr. Hiler then offered some possible ideas to encourage additional load to move from peak to off-peak. Mr. Hiler concluded by recommending that: (a) the monthly billing demand be revised to reflect the criteria in Rate 825; (b) any new contract for existing customers be for a one-year duration, and have the current termination provisions; (c) the peak hours be retained at five as they have been for many years; (d) the customer charge be reduced; (e) language added to provide NIPSCO with the ability to make available additional off-peak hours of service; and (f) the 12/24 month demand ratchet be eliminated, especially retroactively.

Gary R. Connor, Manager of Facility Engineering at Weil-McLain, testified regarding the impact of NIPSCO's proposed Rate 526 on Weil-McLain. Mr. Connor testified that he reviewed Mr. Hiler's testimony and agreed with his objections to the proposed rate increase and rate design of Rate 526. Mr. Connor recommended that the Commission adopt Mr. Hiler's recommendations.

In response to Mr. Hiler's concerns relating to NIPSCO's proposed Rate 526, Mr. Shambo stated that NIPSCO understood his concern with the calculation of a monthly billing demand. Mr. Shambo testified that NIPSCO was willing to define the monthly billing demand using 30% of off-peak demand; however, NIPSCO's allocation of costs to this rate class did not change. Therefore, a shift in the calculation of the billing demand changes the rate determinants, and in the case of reducing it to 30%, the effect is to increase the proposed demand charge to this rate class. Mr. Greneman provided additional detail regarding the effect of reverting to the 30% billing demand determination, and the changes were also reflected in the revised charges contained within Rate 526 as supported by Mr. Westerhausen's rebuttal testimony.

Responding to Mr. Hiler's proposal regarding a 25% level of off-peak demand for purposes of determining billing demand, Mr. Shambo stated NIPSCO had not examined its effect, but it would simply increase the proposed rate to the rate class because it would further reduce the level of billing determinants.

As to Mr. Hiler's statements regarding the Company's proposed monthly customer charge for Rate 526, Mr. Shambo stated NIPSCO's proposed fixed cost recovery is lower than its fixed cost incurrence. He stated that NIPSCO's proposed customer charges are not unreasonable in light of its actual cost structure.

Mr. Shambo also testified that Mr. Hiler's proposal to reduce the number of hours that are considered on-peak under Rate 526 is not appropriate. Lastly, Mr. Shambo addressed Mr. Hiler's concern with NIPSCO's proposal regarding the flexibility of determining on-peak hours; Mr. Shambo stated NIPSCO is maintaining its proposal.

(d) <u>Rate 527 - Rate for Electric Service, Limited Production Large ("LPL")</u>. Mr. Shambo testified that like Rate 526, Rate 527 was proposed to encourage off-peak usage and offered lower costs to any customer willing to limit operation during peak hours to two out of five business days. Mr. Shambo stated that this provision would encourage customers to move demand to off-peak periods, which in turn benefits all customers by more efficiently using NIPSCO's system and reducing the need for additional capacity. NIPSCO expected that some customers would be at the beginning of the week (Monday and Tuesday) and others at the end of the week (Thursday and Friday), further diversifying NIPSCO's demand requirements. NIPSCO included specific provisions for situations when these customers need additional power during periods outside of the hours provided in the Rate.

Mr. Westerhausen stated that proposed rate LPL would be available to customers that have the ability to creatively manage their production in both an on- and off-peak and days-of-the-week fashion. This Rate is available to customers with demands greater than 20,000 kW and the flexibility to utilize the system predominately in the off-peak. He explained that the energy used during non-production hours must be less than 2.5% of the energy used during production hours. If a customer defaults on this condition, the customer will be moved to an appropriate rate. A three-year contract is required for service under LPL.

Mr. Pollock discussed Beta Steel's objection to Rate 527, which Mr. Pollock stated would limit Beta Steel's operating flexibility and would impose burdensome restrictions on Beta Steel's ability to meet its designed production level. Pollock Direct at 17. Mr. Pollock proposed that Beta Steel be moved to the Rate 534 class, and explained how Beta Steel's load could be incorporated into a "combined" Rate 527/534 customer class. *Id.* at 24-26. Mr. Pollock further proposed that the Commission apply the principle of gradualism to this combined class and set rates that will reflect only the actual cost to provide service to these customers. *Id.* at 30. Mr. Pollock also recommended that the Commission adopt the recommendations of IG Witnesses Dauphinais and Phillips. *Id.* at 6.

Mr. Phillips recommended combining Rates 527 and 534 because the one customer mapped to Rate 527 could not operate under the constraints of Rate 527. Phillips Direct at 18.

In response to concerns with NIPSCO's proposed Rate 527, Mr. Shambo stated that, in its rebuttal filing, NIPSCO eliminated Rate 527 from its proposal and reclassified Beta Steel to Rate 534.

(e) <u>Rates 533 and 534 Rate for Electric Service, General Service Large ("GSL") and Rate for Electric Service, Industrial Service Large ("ISL")</u>. Mr. Shambo testified that proposed Rate 533 contains a smaller group of customers, estimated at 900 plus, that take service at the distribution and transmission levels. These customers, by and large, have had demand meters for some time. He stated that customers were mapped into this rate schedule from 817, 820, 821, 823, 824, 826, 832 and 833 based upon a combination of the assets used to serve these customers and demand data from the existing demand meters. He stated that NIPSCO will be replacing existing Demand Indicating meters with IDR meters, in this group for better understanding of load characteristics.

Mr. Shambo explained NIPSCO's rationale for the billing determinants for demand charges used in Rates 533 and 534. He stated that in light of public policy objectives and the goal of providing more cost-reflective price signals within classes, NIPSCO is seeking to create greater awareness of seasonal peak versus off-peak usage in the rates proposed in this proceeding. NIPSCO is proposing that the billing determinants for Rates 533 and 534 be set at the higher of 90% of peak usage, defined as the eight-hour period from 11 AM to 7 PM, Monday through Friday, excluding holidays, during the four summer months of June through September, or 80% of all other hours. The billing determinants for a given month will be the highest of the previous 24 months using the rule described above. NIPSCO chose a 90% threshold, instead of 100%, to avoid overly penalizing a customer that may have had just a handful of high hours during that period. Using 80% of the off-peak period clearly encourages customers to move higher demand into off-peak hours. This billing determinant approach is also consistent with the use of 4 CP for allocating production costs.

Mr. Westerhausen explained that GSL is for customers with demands between 300 kW and 10,000 kW. All customers taking service under GSL would be required to have IDR meters. This is a seasonal rate where all hours outside of the four summer months (June through September) are considered off-peak for demand billing purposes. A customer's monthly billing demand will be based on the higher of 90% of the highest demand during the summer on-peak period within the last 24 months up to and including the current month or 80% of the highest demand at any other time within the last 24 months up to and including the current month.

Mr. Westerhausen explained that ISL is for customers with demands greater than 10,000 kW. This is also a seasonal rate where all hours outside of the four summer months (June through September) are considered off-peak for demand billing purposes. A three-year contract is required for service under ISL. He stated that a customer's monthly billing demand would be based on the higher of 90% of the highest demand during the summer on-peak period within the last 24 months up to and including the current month or 80% of the highest demand at any other time within the last 24 months up to and including the current month or 80% of the contract demand.

Mr. Phillips noted that NIPSCO's proposed demands of 90% of Maximum Summer Peak Hour Demand, 80% of the Maximum Non-Summer Peak Hour Demand, or 80% of Contract Demand are an increase from current Rate 833. Phillips Direct at 25-26. He stated that the requirement of a three-year contract to receive firm service pursuant to a tariff is unreasonable. *Id.* at 28.

In response to Mr. Phillips' concern regarding NIPSCO's proposed three year contracting requirement in its industrial tariffs, Mr. Shambo articulated NIPSCO's need to require a new three-year contract to promote stability and support the Company's planning efforts. Mr. Westerhausen testified that NIPSCO is not seeking discretionary authority to redefine the terms and conditions under which it will provide service through a variety of new customer contract requirements. The standard contract template was admitted into evidence as <u>Petitioner's Exhibit CAW-R3</u>.

(f) <u>Demand Ratchet/Billing Determinants</u>. The tariffs sponsored by Mr. Westerhausen in NIPSCO's direct case included a 24-month demand ratchet for customers on Rates 526, 533 and 534.

Mr. Pollock made some recommendations regarding NIPSCO's proposed change from an 11-month to a 24-month billing demand ratchet. Mr. Pollock testified that a 24-month would be a dramatic change that is not consistent with the practices of other Indiana electric utilities. Pollock Direct at 36-37. Mr. Pollock recommended that the Commission approve a 12-month demand ratchet. *Id.* at 37.

Messrs. Phillips and Hiler proposed that NIPSCO should not be allowed to use a 24-month ratchet provision for development of rate determinants. Mr. Hiler testified that under Rate 825, the monthly demand is the greater of the maximum on-peak half-hour demand, 30% of maximum off-peak half-hour demand, 75% of highest billing demand for the prior 11 months, or

500 kW. He explained that his company operated its facilities so as to keep its on-peak usage at 30% of peak usage, which is the price signal sent by Rate 825. Hiler Direct at 6. He testified that his company had made investments to keep on-peak within 30% of off-peak. *Id.* at 7.

Mr. Phillips opined that use of 24-month look back for the demand ratchet penalizes those with higher billing demand for responding to previous rate. Phillips Direct at 24. He recommended that the new demand ratchet start at zero.

In rebuttal, Mr. Greneman explained that NIPSCO must establish rate determinants to calculate rates. To the extent that rate determinants, for a given rate, are higher than billing determinants for that rate, NIPSCO will under collect its revenue requirement allocated to that rate. He stated that the 24-month ratchet provision is NIPSCO's method for defining billing demand that is appropriate for reasons of equity, an opportunity to earn its authorized return, revenue stability and supporting NIPSCO's long-term capital investment decisions and associated financing. NIPSCO's proposal defines the demand billing determinant for each Rate 533 and 534 customer based upon the greater of 90% of their summer on-peak demand or 80% of any other hour over the preceding 24 months. He testified that NIPSCO's proposed rate determinants were developed under the same rules using 2007 test year data, noting that there is consistency between NIPSCO's proposed rate determinants and billing determinants that will be applied to those rates.

NIPSCO Witness James A. Heidell addressed in rebuttal NIPSCO's need for an appropriate method for recovering demand costs allocated to the industrial customers in light of the significant drop in industrial customer loads compared to the 2007 test-year levels. Mr. Heidell testified that the Company's average monthly peak loads of industrial customers for the third quarter of 2008 were approximately 22% below those in the test year. Heidell Rebuttal at 1-2.

Mr. Heidell explained that NIPSCO's proposed 24-month demand ratchet is an appropriate method to use for Rates 526, 533 and 534 given NIPSCO's unique conditions and the decrease in peak demand since the test year. He stated that NIPSCO has significant fixed costs associated with generation, transmission and sub-transmission plant installed to serve its industrial customers and its industrial load is a much larger share of total load than most utilities. Mr. Heidell testified that NIPSCO's industrial load is over 50% of its total sales volume, and therefore a large share of the Company's total costs are allocated to industrial classes in the ratemaking process. He explained that this unusually high percentage of industrial load creates particular risk to the Company to the extent its cost recovery is dependent on industrial customers' electricity demand in each discrete billing month with no ratchet adjustment. Mr. Heidell explained that NIPSCO stands to significantly under-collect the rate of return the Commission finds reasonable in this case unless industrial customer demands are reflective of the computation of the rate determinants used to compute the demand charges. Heidell Rebuttal at 5.

Mr. Heidell stated that NIPSCO's proposal for a 24-month backward looking ratchet for defining billing demand is a reasonable approach for dealing with the high reliance on demand charges to recover fixed costs. Mr. Heidell testified under NIPSCO's proposal, billing demand for Rate 526, 533 and 534 customers would be defined as their highest monthly demand in the past 24 months. He explained that use of a 24-month period to determine billing demands would help preserve NIPSCO's ability to recover the fixed costs incurred to meet industrial load. Heidell Rebuttal at 6.

Mr. Heidell testified that two primary rate design principles that support NIPSCO's proposal to implement a 24-month historical ratchet are (1) equity and (2) that rates should be designed to provide a reasonable opportunity to earn the allowed rate of return. He stated that along with these two primary principles, rate design involves balancing multiple additional objectives including economic efficiency, understandability, and administrative feasibility. Heidell Rebuttal at 6.

Mr. Heidell explained that it is equitable to apply a 24-month ratchet to customers on Rates 526, 533 and 534 because the Company has invested in generation, transmission, and sub-transmission to serve these customers. These costs are fixed in the short- and medium-terms. He stated the proposed ratchet is similar to the concept of a facilities charge, in which customers pay on a fixed monthly basis (rather than on the basis of usage in a particular month) for facilities installed to accommodate their demand. Mr. Heidell explained that basing a portion of large customers' bills on their demands over the past 24 months compensates the Company fairly for the investment made to ensure adequate resources to meet their load requirements. Heidell Rebuttal at 6.

He explained this approach is also fair to other customer classes, which might, under other cost allocation procedures, have to absorb costs not recovered from the industrial customers. Mr. Heidell testified that, in order for the industrial customers to pay their fair share of the system costs, a ratchet (or a facilities charge or some other fixed demand charge approach) is not just appropriate but in this case essential, given the difference between the test-year demands and the anticipated rate-year customer demands. Heidell Rebuttal at 7.

Mr. Heidell testified that, while the use of 24-month ratchets may not be commonplace, whether it is an appropriate method should be considered in light of a particular utility's specific circumstances. He explained that unless taken into account in the rate-setting process, this decrease will impair the Company's ability to earn a fair rate of return on facilities that were largely built to serve the loads of the industrial customers. He stated that although the 24-month ratchet may not be sufficient to allow NIPSCO to indefinitely earn its full allowed rate of return, due to the rolling 24-month calculation of customer billing demands, this method will limit the revenue shortfall compared to a 12-month ratchet or, as the industrial customers propose, a ratchet starting at zero. Heidell Rebuttal at 7.

Mr. Heidell testified that should the Commission reject the 24-month ratchet and accept IG's proposal for rate structures with no ratchets, then the use of annualized fourth quarter 2008 peak demands to compute the demand charges for Rates 526, 533 and 534 is an appropriate approach that will largely offset the otherwise highly negative impact on NIPSCO's ability to recover its allowed rate of return. Mr. Heidell stated that, if the Commission were to adopt IG's proposal that the new demand ratchet start at zero, NIPSCO's revenues would fluctuate much more than those of other electric utilities that have demand ratchets. He explained that the average of NIPSCO industrial customers' peak demands in the last three months of 2008 was approximately 22% below these customer's average monthly peak demands in the test year and that NIPSCO does not expect industrial activity in NIPSCO's service territory to recover to pre-recession levels for some time. Mr. Heidell testified that NIPSCO will have little possibility of earning the rate of return that the Commission finds reasonable in this case unless the reduction in industrial loads is taken into account either in the definition of billing demand incorporated in the tariff structure, or in the rate determinants used to calculate the demand charges. Heidell Rebuttal at 5.

(g) Rate 536 – Rate for Electric Service, Interruptible Industrial Service ("IIS")/Rider 581. Mr. Shambo described proposed Rate 536 for interruptible service and the Company's rationale for its design and the expected volumes used to create the rate schedule. He stated that interruptible load that conforms to the Midwest ISO interruption requirements would benefit all customers by allowing NIPSCO to avoid building new facilities or paying for capacity to meet reliability standards. He asserted that NIPSCO's proposed Rate 536 conformed to the Midwest ISO interruption requirements. He explained that NIPSCO allocated only 50% of the capacity costs to this rate schedule because of its ability to interrupt service on short notice.

He stated that NIPSCO evaluated the load characteristics of the customers eligible for this tariff to determine the billing determinants used in the proposed rates. This determination was based on those customers that (a) currently are on interruptible service or (b) have self-generation options.

Mr. Shambo explained that the counterpart to Rate 536 in NIPSCO's current rates and charges (Rate 836) limits the rate's availability to 110 MW. NIPSCO estimated that the total load of current customers who would benefit from this Rate at 250 MW.

Mr. Westerhausen explained that IIS is for Customers who have the ability to interrupt and/or curtail electric demand with 10 minute notice. Interruptions would be requested on an economic basis while curtailment would be requested in regard to bulk electric system reliability. He stated that a customer may continue to receive service upon being interrupted, but will be billed at the Midwest ISO LMP at the NIPSCO load node. A three-year contract is required for service under IIS. A customer's monthly billing demand will be based on the contract demand.

Mr. Dauphinais asserted that certain elements of NIPSCO's proposed Rate 536 were unreasonable including the "transmission" customer requirement; the 250 MW cap on customer participation; the 10 minute notice requirement; the curtailment and interruption limitations; the mandatory participation in the economic interruption provisions of Rate 536; the "buy through" rate for economic interruptions; and the additional $2,200 per month customer charge. Mr. Dauphinais also suggested that NIPSCO clarify that 'first through the meter' means that a customer can only be required to interrupt down to their firm Rate 533 or 534 demand. (Page 50.) Mr. Phillips recommended a 75% credit rather than 50% credit in billing demand charges for Rate 536 customers. He asserted that NIPSCO will interrupt load more frequently in the future than in the past based on economic considerations. He noted that a 75% credit was accepted in NIPSCO's last base rate case.

In response to Messrs. Phillips' and Dauphinais' concerns with and changes to NIPSCO's proposed Rate 536, Mr. Shambo explained that NIPSCO's proposed structure for Rate 536 was based upon the proposed allocation of costs while also taking into consideration other factors such as the proposed moderation plan and the OSS margin proposal. Mr. Shambo testified that NIPSCO agreed that Mr. Dauphinais' demand credit of $6.75/kW-month is a reasonable amount of credit based upon the avoided amortized cost of a combustion turbine, and has determined that the applicable credit to the rate class is $40,500,000. He stated that, to the extent the parties desire changes to the rate structure, it was necessary to re-calculate the rates based upon those changes to assure that the allocation of costs remains consistent among customers within the rate class and in comparison to other classes and that NIPSCO retains the opportunity to achieve its revenue requirement.

Mr. Shambo testified that NIPSCO was also willing to incorporate IG's proposal to increase the MW limit under Rate 536 and to permit 34 kV primary customers to participate under that rate schedule and to eliminate the customer charge. Because of these changes, however, NIPSCO proposed that Rate 536 become Rider 581 to Rates 533 and 534. Mr. Shambo asserted that this change would simplify the understanding of the interruptible tariff option in concert with the applicable underlying rate schedules. Therefore, NIPSCO re-calculated the effect of some of the changes proposed by IG.

Mr. Shambo stated that NIPSCO was not willing to remove the ability to economically interrupt customers under Rider 581. He noted that Mr. Dauphinais seems to promote a situation whereby Rider 581 customers are paying at interruptible rates for firm service. He explained that these interruptible customers will be provided an opportunity to receive power at coal-based, variable prices for much of the time with a credit to their demand charge. He stated that a fundamental tenet of NIPSCO's proposed interruptible rider is the ability to interrupt customers when market pricing signals dictate a situation that benefits non-interruptible customers. He asserted that economic interruptions will benefit the vast majority of customers who do not subscribe to the interruptible rider. Because the amount of the credits to interruptible customers is shifted to NIPSCO's non-interruptible customers in the cost of service study and included in their rates, it is only reasonable that those other customers receive the opportunity (and benefit from it) through NIPSCO's interruption of Rider 581 customers when it can otherwise save costs. It is NIPSCO's intent to preserve the opportunity to economically interrupt customers under Rider 581 when the wholesale market pricing supports such interruption, including situations of facilitating OSS or purchases for non-interruptible customers. This is the benefit of the bargain for non-interruptible customers paying for the credit under Rider 581. Thus, Mr. Shambo asserted NIPSCO must retain the ability to economically interrupt Rider 581 customers.

(h) Rate 541 – Rate for Electric Service, Water Pumping ("WP"). Mr. Westerhausen explained that WP is available on a metered basis to Municipalities, the Indiana Department of Natural Resources, Corporations or Persons operating under an exclusive franchise in furnishing water service at retail, and on an unmetered basis to applicable residential and small commercial customers pumping sewage water and waste. Energy consumption on the non-metered pumps was estimated for the purposes of allocating applicable Riders.

(i) Rate 544 – Rate for Electric Service, Railroad Power Service ("RR"). Mr. Westerhausen stated that RR is available only to existing railroads or to a non-profit commuter transportation district operating said railroads. Electricity will be supplied for the operation of trains on a continuous electrified right-of-way of the customer.

(j) Rate 550 – Rate for Electric Service, Street Lighting ("SL"). Mr. Westerhausen explained that SL is available for street, highway and billboard lighting service. Twenty separate lighting rates from the 800 Series are combined into SL. Billing is based upon type, ownership and responsible maintaining party of the lighting fixture. New to SL is the applicability of various Riders to pre-allocated amounts of electric usage based on specific light fixture sizes and types. He also stated that Rate SL eliminates the geographic-specific billing metric.

(k) Rate 555 – Rate for Electric Service, Traffic and Directive Lighting ("TDL"). Mr. Westerhausen stated that TDL will be closely related to existing Rate 895, Traffic and Directive Lighting of the 800 Series and is applicable to traffic, directive, and similar lighting.

(l) Rate 560 – Rate for Electric Service, Dusk to Dawn Area Lighting ("DDAL"). Mr. Westerhausen testified that DDAL is similar to SL. Customers taking service under DDAL would be billed based on estimated energy usage by type of fixture. Also, DDAL will be subject to the same various Riders as SL. He stated that a one-year contract is required for service under DDAL.

(m) Rider 574 – Adjustment of Charges for Power Factor ("PF"). Mr. Westerhausen stated that the PF Rider is applicable to on-peak demands in the proposed electric Rates and incents the customer's efficient use of service. The 800 Series rates had four separate metrics for determining power factor charges. The proposed 500 Series Rider standardizes these different calculations into a single method. Mr. Greneman also discussed the new power factor adjustment calculation.

Mr. Pollock recommended that the proposed Power Factor charge be based on the embedded costs of capacitors, not current costs. Pollock Direct at 39. Mr. Pollock also proposed to lower the reference level to 85% lagging. Mr. Pollock concluded that while some increase in the power factor charge is justified, the Commission should set the Power Factor charge to reflect NIPSCO's actual embedded costs. Pollock Direct at 8, 39.

In rebuttal, Mr. Greneman stated that with regard to the level of the power factor, NIPSCO proposed that customers be charged for power factor correction below a reference level of 95% lagging, which is consistent with the reference power factor in present Rate 845. Mr. Greneman explained that, if NIPSCO were to lower the reference level to 85% lagging (the level recommended by Mr. Pollock), the result would be to penalize those customers that have already made the needed efforts to correct their power factor to above 85%. He noted that NIPSCO based the charge on its current cost to add capacitor banks, arguing that pricing should be based on embedded costs, as current costs are at odds with cost of service, which uses embedded cost principles. Mr. Greneman testified that NIPSCO has not used current costs for capacitors in the cost of service study, rather only in the design of the power factor rates. He described the purpose of the power factor charge, which is to provide an incentive to customers to correct their power factor. He explained that current costs provide the appropriate economic signal to customers to decide whether to continue to run their equipment at a lower power factor or to invest in equipment to raise their power factor and lower their overall costs.

(n) Rider 575 – Electric Spaceheating Rider to Residential Service ("ES"). Mr. Westerhausen explained that ES is applicable to Residential Customers that currently have permanently installed electric space heating or electric heat pumps. Rider ES offers a reduced charge for monthly energy consumption over 700 kWh during the months from October through April.

(o) Rider 576 – Thermal Storage Rider ("TS"). Rider TS is applicable to current customers with thermal storage equipment capable of meeting 40% of the total btu requirements for their air-conditioned space during the on-peak daily demand. The discount has been modified from a discount of off-peak energy and demand to a straight 5% discount of the non-fuel portion of the customer's thermal storage bill.

(p) Rider 577 – Purchases From Cogeneration and Small Power Production Facilities. Mr. Westerhausen testified that Rider 577 is available to a Qualifying Facility, as defined in the Rules. A contract is required between the Company and each Qualifying Facility, setting forth all terms and conditions governing the purchase electric power. Availability of back-up and maintenance power is also addressed in Rider 577.

(q) Rider 578 – Interconnection Standards. Mr. Westerhausen explained that Rider 578 is provided in accordance with the applicable standards, rules and regulations of the Commission's Rules as specified in the Indiana Administrative Code.

(r) Rider 579 – Net Metering. Mr. Westerhausen stated that Similar to Rider 578, Rider 579 is provided in accordance with the applicable standards, rules and regulations of the Commission's Rules as specified in the Indiana Administrative Code.

(s) Rider 580 – Economic Development Rider ("EDR"). Mr. Westerhausen testified that the EDR is available to non-residential Customers upon demonstrating the fulfillment of certain new production, increased load and other economic-related characteristics that would otherwise have not occurred absent the availability of this EDR. Mr. Shambo stated that it is in the best interest of NIPSCO and its customers that NIPSCO promote its service territory as a viable location for new businesses. He explained that benefits to NIPSCO customers include an increased tax base from the investment and potential new employment with related income tax, sales tax and property tax benefits.

Mr. Westerhausen testified NIPSCO is proposing discounts to non-fuel rates to avoid shifting the burden to other customers. NIPSCO will also assure that the rate will be above the incremental cost to provide service to a new customer. NIPSCO sought the ability to discount the non-fuel rate for up to five years and by up to 50% in the first year declining to 10% by year five. NIPSCO will evaluate a number of key variables prior to offering the discount, including whether the facility is located in a "brownfield" area. Mr. Shambo explained that NIPSCO has a number of areas where existing transmission and distribution facilities are not at capacity and locating new facilities in those areas can be done at the lowest incremental cost.

(t) Rider 582 (Off-Summer Peaking Rider for Proposed Rates 523 and 533). On rebuttal, Mr. Greneman explained that, at the field hearing held in this Cause, it was brought to the Company's attention that its proposed rate structure would: have a detrimental effect on a group of customers that are currently on energy-only Rate 821; are sufficiently large in terms of annual kWh as to be mapped to proposed Rates 523 and 533; but with the inclusion of the demand charge on these rates, would experience an inordinate increase as compared to their bills under present Rate 821. These customers share in common diminished summer use as compared with non-summer use. There are approximately 550 such customers compared with 12,504 customers on proposed Rates 523 and 533 combined. Mr. Greneman stated that to acknowledge these customers usage patterns, the Company is proposing to provide a 50% credit to the generation portion of the demand charge in both rates for the 550 customers.

In doing so, the class revenue requirement would remain the same, but the revenue shortfall would be compensated by increasing the generation portion of the demand charge for the remaining customers in each rate. Mr. Greneman explained that to be eligible for Rider 582, customers must take service under proposed Rate 523 or 533 and have 12 months of billing activity. Customers must also have an average daily usage for the four summer months (June to September) that is less than 75% of their average daily usage for the eight non-summer months. Customers taking service under Interruptible Industrial Rider 581 are not also eligible for this rider.

(2) Discussion and Findings. The Commission notes at the outset that no party proposed maintaining the current 800 Series rates, terms and conditions. Therefore, our findings will relate to NIPSCO's proposed 500 Series rates, terms and conditions. Several 500 Series rate classes and riders were not opposed by any Party, including Rates 523, 541, 544, 550, 555, 560 and Riders 575, 576, 577, 578, 579, 580, and 582. Based upon the evidence of record, the uncontested proposal for these Rate Classes and Riders is approved as proposed by NIPSCO. With regard to the other rate classes and Riders, we will address each issue individually.

Rate 511. Aside from the moderation plan, which was addressed above, the only contested issue regarding Rate 511 was the level of the customer charge. As noted by Mr. Shambo, NIPSCO presented sufficient evidence to support the charge, and Mr. Swan even agreed with that assessment. His only opposition was premised on the concept of moderation. Regarding that issue, the Commission agrees with Mr. Shambo that the goal of rate design should be to assure adherence to cost-causation principles. Mr. Swan did not contest that the residential class customer charge was not cost based, but rather that anything above a 20% increase was too high. He also acknowledged on cross-examination that if the residential class did not pay this cost, then some other class would be required to pay more than their fully allocated costs. Tr. at DD-32. Based upon the evidence of record, the Commission finds that Rate 511 as proposed by NIPSCO, including the customer charge, shall be approved.

Rate 521. The only contested issue regarding Rate 521 was the level of the customer charge. As noted by Mr. Shambo, NIPSCO's customer charge does not approach recovery of its fixed costs. Any change in the customer charge would not change the costs assigned to Rate 521, but only their allocation. Based upon the evidence of record as discussed above, the Commission finds that Rate 521 as proposed by NIPSCO, including the customer charge should be approved.

Industrial Rates 526, 533 and 534. Various parties raised concerns relating to NIPSCO's proposed Industrial Rates 526, 533 and 534. The first concern was use of 50% vs. 30% off-peak billing demand for Rate 526. We agree with Messrs. Hiler and Phillips that changing the current billing demand ratchet of 30% off-peak to a 50% off-peak demand ratchet would incent increased on-peak usage. Such a result is not what NIPSCO has testified they intended, and on rebuttal they agreed to modify their tariff accordingly (including incorporating the effect into its cost of service study results). Mr. Hiler proposed a 25% level of off-peak demand for purposes of determining billing demand for Rate 526, but Mr. Shambo stated NIPSCO had not examined its effect. As noted by Mr. Shambo, such a modification would simply increase the proposed rate to the rate class because it would further reduce the level of billing determinants. Based upon the concerns, and the willingness of NIPSCO to revise its filing, we find that NIPSCO's billing demand ratchet for Rate 526 should be set at 30%. We approve this modification while recognizing that a shift in the calculation of the billing demand changes the rate determinants and, in the case of reducing it to 30%, the effect will be to increase the proposed demand charge to this rate class.

As to Mr. Hiler's statements regarding the Company's proposed monthly customer charge for Rate 526, NIPSCO's cost of service study illustrates that its proposed fixed cost recovery is lower than its fixed cost incurrence. Therefore, we find that NIPSCO's proposed customer charges are reasonable in light of its actual cost structure.

While the Commission understands Mr. Hiler's proposal to reduce the number of hours that are considered on-peak and his proposal to give NIPSCO flexibility to determine on-peak hours, given the evidence that NIPSCO presented, we find that Mr. Hiler's proposals are not appropriate.

As to Messrs. Hiler's and Phillips' concern regarding the requirement that customers in Rates 526 and 534 execute three year contracts, the Commission understands the need of an energy utility to plan for its projected load and to have a reasonable opportunity to earn its authorized return. Such planning is made easier and more accurate when required pursuant to a contract. We find that the contract contained in Petitioner's Exhibit CAW-R3 is sufficient in detail to serve the needs of NIPSCO, while at the same time addressing the concerns of the various industrial witnesses concerning a requirement of a contract for a customer receiving service pursuant to a tariff.

With regard to the demand ratchet, the evidence is uncontested that NIPSCO's industrial load is over 50% of its total sales volume, and therefore a large share of the Company's total costs are allocated to industrial classes in the ratemaking process. Mr. Heidell explained why NIPSCO's proposed 24-month demand ratchet is an appropriate method to use for Rates 526, 533 and 534 given the unique conditions of NIPSCO. NIPSCO has significant fixed costs associated with generation, transmission and sub-transmission plant installed to serve its industrial customers, but its industrial load is a larger share of total load than most utilities. It is further not the Commission's intent to place NIPSCO in a position that its new rates and charges will be established upon conditions that are not fully representative of current volumes. NIPSCO presented evidence regarding its 4th quarter of 2008 level of volumes, which is appropriately considered in this proceeding because it falls within twelve months of its 2007 test year. On the other hand several witness testified that a 24-month ratchet provision was excessive and beyond the standard length of such ratchet provisions. After considering all of these factors, we direct the Company to revise the ratchet provision to 12 months.

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 Ms. Odom'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.

Rate 527. Rate 527 was proposed to encourage off-peak usage and offered lower costs to any customer willing to limit operation during peak hours to two out of five business days. Mr. Phillips and Mr. Pollock testified that no party would take service under the proposed rate. Given this testimony, NIPSCO made a determination to withdraw Rate 527 from its tariff proposal. The Commission, therefore, will not consider any modifications to Rate 527, but rather will consider any relevant issue in its consideration of Rate 536 and Rider 581.

Rate 536/Rider 581. Various parties assailed the following elements of NIPSCO's proposed Rate 536: (1) the "transmission" customer requirement; (2) the 250 MW cap on customer participation; (3) the 10 minute notice requirement; (4) the curtailment and interruption limitations; (5) the mandatory participation in the economic interruption provisions of Rate 536; (6) the "buy through" rate for economic interruptions; (7) the additional $2,200 per month customer charge; and (8) the 50% credit in billing demand charges vs. the 75% credit that was approved in NIPSCO's last base rate case. In response, NIPSCO agreed that customers served by a 34.5 kV distribution line would be considered sub-transmission customers and eligible for various rates and riders. NIPSCO also agreed to increase the cap on interruptible participation to 500 MW. NIPSCO agreed to modify the ten-minute notice requirement to four hours. NIPSCO Witness Westerhausen explained that many of the revisions in NIPSCO's proposed Rules were designed to address "NIPSCO becoming a member of, and maintaining operation compliance with, the Midwest ISO." Westerhausen Rebuttal at 17. In rebuttal NIPSCO proposed elimination of Rate 536 and implementation of Rider 581. Given that the interruptible provisions of the tariff are now in a rider, there is no additional customer charge associated with it. In rebuttal NIPSCO also agreed that Mr. Dauphinais' demand credit of $6.75/kW-month is a reasonable amount of credit based upon the avoided amortized cost of a combustion turbine. Thus, the remaining contested issues are: (1) the mandatory participation in the economic interruption provision; and (2) the "buy through" rate for economic interruptions.

With regards to the ability to economically interrupt, the Commission agrees with NIPSCO that IG promoted a construct whereby Rider 581 customers are paying at interruptible rates for nearly firm service. These interruptible customers will receive power at coal-based, variable prices for much of the time with a credit to their demand charge. The purpose of an interruptible tariff provision is to give the utility the ability to interrupt customers when market pricing signals dictate a situation that benefits non-interruptible customers. Such economic interruptions will benefit customers who do not subscribe to the interruptible rider because it provides for a reduction to demand that would otherwise be needed; furthermore, it is equitable because NIPSCO's non-interruptible customers are allocated additional costs, and it is only reasonable that those other customers receive the opportunity (and benefit from it) through NIPSCO's economic interruption of Rider 581 customers. The ability to economically interrupt customers under Rider 581 when the wholesale market pricing supports such interruption, including situations of facilitating OSS or reducing purchases for non-interruptible customers, is reasonable. This is the benefit of the bargain for non-interruptible customers subsidizing the credit under Rider 581. Therefore, the Commission finds that these provisions of Rider 581 are reasonable and shall be approved.

Rider 574. NIPSCO's proposed PF Rider is applicable to on-peak demands in the proposed electric Rates. Mr. Pollock recommended that the proposed Power Factor charge be based on the embedded costs of capacitors, not current costs and proposed to lower the reference level to 85% lagging. NIPSCO's proposed Rider standardizes the Power Factor calculations currently found in NIPSCO's tariff into a single method and is designed to encourage the customer's efficient use of service.

NIPSCO's proposal that customers be charged for power factor corrections below a reference level of 95% lagging is consistent with the reference power factor in present Rate 845. If NIPSCO were to lower the reference level to 85% lagging, the result would be to penalize those customers who have already made the needed efforts to correct their power factor to above 85%. The purpose of the power factor charge is to provide an incentive to customers to correct their power factor. Use of current costs provides the appropriate economic signal to customers to decide whether to continue to run their equipment at a lower power factor or to invest in equipment to raise their power factor and lower their overall costs. Based upon the evidence presented, the Commission finds that NIPSCO's proposed PF Rider shall be approved as proposed.

13. Demand Response.

A. Evidence. Mr. Dauphinais proposed that NIPSCO be required to institute a demand response tariff. On cross-examination, Mr. Dauphinais admitted that the Midwest ISO business rules concerning demand response had not been finalized. He also admitted that he was unaware of whether any of the members of IG were prepared to offer demand response resources. Tr. at GG-29.

In response to Mr. Dauphinais' testimony, Mr. Shambo noted that the Commission presently has an open investigation into demand response in Cause No. 43566. Mr. Shambo stated that NIPSCO stands ready to develop reasonable rules with its customers to facilitate such offerings, but this is dependent upon the finalization of the rules at the Midwest ISO level. Mr. Shambo stated that because there is an ongoing Commission proceeding and the Midwest ISO rules are not yet finalized regarding demand response, it is inappropriate to propose such tariffs at this time.

B. Discussion and Findings. While the Commission recognizes the desire of the industrial customers to have available demand response tariffs, the Commission notes that on July 28, 2010, the Commission issued its Order in Cause No. 43566 the Commission issued its Order in Cause No. 43566 requiring utilities to develop and file tariffs or riders authorizing the participation of its retail customers in Midwest ISO demand response programs within 90 days from the date of the Order, and the Midwest ISO rules are not yet finalized regarding demand response. Therefore, the Commission finds that it is not appropriate to order such tariffs through this Cause.

14. Rules.

A. Evidence.

(1) Rule 1 – Definitions. Mr. Westerhausen explained that the definition section in Rule 1 is new and is intended to assist customers in fully understanding the terms used in the proposed Rates, Riders and Rules. It also contains the definitions of the new seasonal On-Peak and Off-peak Hours that are utilized in the proposed Rates and Riders.

(2) Rule 2 – Rates, Rules and Regulations. Mr. Westerhausen testified that proposed Rule 2 revises current Rule 1 to clarify that if there are conflicts with the language between Contracts, Rates, Riders and Rules, which will prevail. Mr. Dauphinais stated that Rule 2.2 (as well as Rules 4.1, 4.3, 5.8 and 6.5) would explicitly give priority to contract terms over all the terms that are reviewed and approved by the Commission thereby giving NIPSCO new authority to decide what terms to impose by contract on customers unable to seek service from competing suppliers, and the contract terms imposed by NIPSCO would have priority over the terms set forth in the Commission-approved tariff. Dauphinais Direct as 30-31. In rebuttal, Mr. Westerhausen explained that NIPSCO's Proposed Rule 2 provides a hierarchy of which will prevail when considering Rates, Riders, Rules and Contracts. Mr. Westerhausen testified this prioritization of interpretation order sequence is an important part of the Company's efforts to simplify and clarify its existing rules. Experience working within the terms and conditions of its existing rules has shown that some confusion and conflict has occurred when interpreting and applying the terms and conditions of the tariffs, riders and other service rules and regulations. He asserted that providing an ordered sequence of interpretation to standard contract terms of service–as reviewed by the Commission–will help achieve the twin goals of simplification and clarification of service and operation.

Mr. Westerhausen described the Company's intent of proposed Rule 2.1. He acknowledged that existing tariffs cannot be superseded by any new tariff unless and until the new tariff is properly approved and implemented in accordance with the appropriate Commission rules and regulations governing the implementation of such new tariffs.

He also explained that with its proposed changes to the existing rules, NIPSCO was not seeking discretionary authority to redefine the terms and conditions under which it will provide service through a variety of new customer contract requirements. He stated that NIPSCO has no intention to undermine Commission oversight, facilitate deviations from the Commission-approved provisions of NIPSCO's filed tariffs, provide the potential for discrimination in service, and/or codify activity in any way that could possibly result in the denial of service to customers. Mr. Westerhausen testified NIPSCO's proposed changes will not erode in any way its duty as a public utility to provide reliable service and meet demand within its assigned territory.

Mr. Westerhausen disagreed with Mr. Dauphinais that NIPSCO's contracts will be imposed without Commission review or approval and that NIPSCO will have sweeping authority to establish its "right" to require contracts for service. He stated that NIPSCO takes its obligation to serve very seriously. Mr. Westerhausen stated it is not NIPSCO's intention to have the Commission review each of the individual contracts. Currently the Commission does not approve the individual contracts. He opined that if the Commission approves the standard contract, there is no reason for each of the contracts to be reviewed. He asserted that NIPSCO intends to submit its standard contract template for service for review by the Commission. In this way, complete Commission oversight and review is maintained. The standard contract template was admitted into evidence as Petitioner's Exhibit CAW-R3.

Mr. Westerhausen stated that NIPSCO is proposing to utilize a three year standard form contract for customers taking service under Rates 526, 534, Rider 581 – Interruptible Industrial Service, and any Rate 533 customers that are also taking interruptible service under Rider 581.

Mr. Westerhausen testified the signing of a contract is among the conditions of accepting service under the following current rates: (1) Rate 824 – General Service – Large Use; (2) Rate 825 – Metal Melting Service; (3) Rate 826 – Off Peak Service; (4) Rate 832 – Industrial Power Service; (5) Rate 833 – Industrial Power Service; (6) Rate 836 – Interruptible Industrial Power Service for Air Separation Processes; and (7) Rate 845 – Industrial Firm Incremental Power Service. He stated that inclusion of a signed contract for service requirement in the select 500 series rates is an extension of the requirement of a signed contract under the approved 800 series rates. He stated that the standard contract will define the rate the customer is taking service under, the electric service voltage, the voltage that the customer is being metered, and the contract demand.

(3) Rule 3 – Character of Service. Mr. Westerhausen stated that Rule 3.1 is a new rule to clarify the standard Company installations to provide service. Rule 3.2 revises current Rule 3.7 to reflect the proposed change of defining 34 kV as a primary service voltage pursuant to the FERC Seven-Factor Test.

(4) Rule 4 – Application, Service Request or Contract. Mr. Westerhausen explained that proposed Rule 4 is a combination of current Rules 2, 3 and 21. He stated that there were no significant changes made to these rules. Mr. Dauphinais expressed the same concerns with Rules 4.1 and 4.3 as he expressed with regard to Rule 2.2. Mr. Westerhausen described the Company's intent of proposed Rule 4.3, which is to make its rules simpler and easier to facilitate. He stated that disclosing that any promise, agreement or representation made between NIPSCO and a customer will not be binding unless incorporated into a Commission-approved contract, eliminates any possibility of misunderstanding or confusion associated with a contract. He noted that this rule was designed to protect both the customer and NIPSCO in a way that the responsibilities and expectations of all parties are properly recorded and understood with a clear record signifying such.

(5) Rule 5 – Prediction of Rate Schedule Selection. Mr. Westerhausen described proposed Rule 5 as a combination of current Rules 10, 11 and 12. He stated that there were no significant changes made to these rules.

(6) Rule 6 – Service Extensions and Modification. Mr. Westerhausen stated that proposed Rule 6 is a combination of current Rules 22, 30, 33, 41 and 42. This new rule includes the proposed modifications to NIPSCO's method of determining the amount of contributions and guaranteed minimums required from customers when NIPSCO extends basic service facilities to provide standard electric service. These proposed modifications will also be used to determine the amount of advances required to be paid by builders and developers prior to their sites receiving service. Mr. Dauphinais expressed concerns regarding Rule 6.5, which requires a contract. Dauphinais Direct at 34. In rebuttal, Mr. Westerhausen described in more detail NIPSCO's proposed Rule 6. He stated that the sizing and design of transmission facilities is unique to each customer regarding, among other things, expected loading, wire size, tower and sub-station design, breaker installation and preferred disconnect and lock-out strategy. NIPSCO's proposed Rule 6.2 provides in advance, the opportunity to analyze each request for new, or extension of existing, transmission service. To that end, he testified that proposed Rule 6.2 is another example of NIPSCO's attempt to insure procedures are in place that allow for the optimization of the design and installation of its capital assets in meeting these new transmission load requirements.

(7) Rule 7 – Customer Installation. Mr. Westerhausen testified that proposed Rule 7 is a combination of current Rules 23 and 32 and stated that there were no significant changes to these rules.

(8) Rule 8 – Company Equipment on Customer's Premises. Mr. Westerhausen stated that proposed Rule 8 is a combination of current Rules 4, 5, 17, 24, 28 and 36, and testified that there were no significant changes to these rules.

(9) Rule 9 – Metering. Mr. Westerhausen explained that the proposed Rule 9 is a combination of current Rules 16, 25 and 26. He stated that Rule 9.4 was added for additional clarification.

(10) Rule 10 – Customer Service Deposits. Mr. Westerhausen testified that proposed Rule 10 is a combination of current Rules 9A and 9B and stated that there were no significant changes to these rules. Mr. Dauphinais asserted that proposed rule 10.2 allows for NIPSCO to ask for deposits to Commercial & Industrial customers whenever they want, which is excessive. (Page 39, lines 21-24).

(11) Rule 11 – Rendering and Payments of Bills. Mr. Westerhausen stated that proposed Rule 11 is a combination of current Rules 6A, 6B and 7. He noted that the Senior Citizen Payment Plan was expanded to include the legally disabled and people receiving social security benefits and is now the Social Security Payment Plan. If the customer meets the criteria, their due date could be extended up to ten calendar days.

(12) Rule 12 – Disconnection and Reconnection of Service. Mr. Westerhausen stated that proposed Rule 12 is a combination of current Rules 8, 15 and 19 and there were no significant changes to these rules. Mr. Dauphinais expressed concerns with the disconnection rules, but admitted in cross-examination that they were consistent with the Commission's current rules. Tr. at GG-46.

(13) Rule 13 – Service Interruptions and Curtailments. Mr. Westerhausen testified that proposed Rule 13 is a combination of current Rules 34 and 35, and has been modified to incorporate the changes to NIPSCO's Curtailment and Interruption procedures as a result of being a member of the Midwest ISO. Mr. Dauphinais also raised issues with the limitation of liability provision (Rule 13.1). He stated that the proposed rules alter the extent to which NIPSCO is relieved of liability for service failures. Mr. Dauphinais also noted that interruptions for the purpose of non-emergency repairs used to receive tem days notice, and now that time has been shortened to only 48 hours. Dauphinais Direct at 42.

In rebuttal, Mr. Westerhausen described the Company's proposed Rules as they pertain to NIPSCO's membership in the Midwest ISO. He stated that a number of NIPSCO's proposed Rules have been updated to account for changes in the operation of the bulk electric system and NIPSCO's participation as a member of the Midwest ISO. The proposals in Rule 13 are consistent with the intent of Proposed Rule 6.2, for example, which identifies a contract requirement for new customers taking service at transmission level voltages. This is included to allow NIPSCO to model, and coordinate in advance with the Midwest ISO, any effect these new transmission loads brought on-line by a new customer will have on the safe and reliable operation of the bulk electric system. Mr. Westerhausen explained that knowing these effects in advance will allow NIPSCO to optimize its asset management efforts in meeting these new load requirements in the most reliable, cost effective manner.

(14) Rule 14 – Miscellaneous and Non-reoccurring Charges. Mr. Westerhausen stated that proposed Rule 14 includes (1) reconnection fees and (2) a charge to reimburse the Company for non-sufficient and returned payment fees. Reconnection fees are calculated to cover the cost of reconnection of service and vary depending on when the service is provided (during normal working hours, after normal working hours or holidays), as well as whether the reconnection is done at the meter or at the pole. The distinction between where the reconnection is done is an expansion of the existing rule. The current rule also changes the former non-sufficient funds fees to encompass both paper and electronic payment transactions. He stated that Rule 14 (Miscellaneous and Non-reoccurring Charges) reflects an increase in the charges for reconnection service based on the Company's analysis of actual costs incurred to perform such services.

Mr. Swan suggested that reconnection charge increases should be limited to 20% if the Commission grants a total increase close to what the Company has requested, and if no increase or a significant reduction in jurisdictional revenues is approved, the charges for reconnection at the meter should not change, but modest increases could be applied to reconnections at the pole.

In rebuttal, Mr. Shambo responded to Mr. Swan's concerns with the proposed increases to the reconnection charges. He noted that NIPSCO had presented evidence of the cost-based nature of these services, and noted that Mr. Swan further acknowledged that NIPSCO had provided such evidence. Mr. Shambo reiterated that it is appropriate to moderate these charges and doing so would introduce a cross-subsidy.

B. Discussion and Findings. We would note at the outset that proposed rules 1 3, 7, 9, and 11 were unopposed by the other parties to this proceeding. Based upon the evidence of record, the uncontested rules are approved as proposed by NIPSCO. With regard to the other proposed rules, we will address each issue individually.

(1) Rule 2 – Rates, Rules and Regulations. The Industrial Group raised concerns with the language in 2.1 because it is ambiguous as to whether the language, if approved, would allow a tariff to become effective upon the issuance of a Commission order approving it, but prior to the tariff being filed with the Commission. The Commission recognizes the Industrial Group's concern and agrees that the proposed language is ambiguous. As proposed, the rule reads "the Tariff, or any part thereof, may be revised, amended, or otherwise changed from time to time and any such changes when approved by the IURC, will supersede the present Tariff." This language could be read to make a tariff's change effective upon the approval of the Commission, even if the tariff has not been filed with the Commission, which would violate the filed rate doctrine. The Company's Reply brief noted its concurrence with the OUCC and IG suggested changes. Therefore, we find that proposed Rule 2.1 shall be changed to read "the Tariff, or any such part thereof, may be revised, amended or otherwise changed from time to time and any such change when approved by the IURC and filed with the Commission will supersede the present tariff.

As to proposed Rule 2.2, the Industrial Group raised concerns because, as proposed, the Company "shall have the right to execute contracts for service under any rate schedule or rider." The first provision of proposed rule 2.2 then sets up the interpretation hierarchy such that in the event of a conflict between any provision of a contract, rate schedule, a rider and/or the rules, the contract would take first priority as to interpretation. The Commission agrees that when these two provisions are taken together, the Company would have the authority to require a contract from a customer under any rate tariff and every contract would trump the tariff language. This result would essentially allow NIPSCO to alter the terms and conditions of an approved tariff by requiring a contract that would not be subject to the Commission's review. NIPSCO's witness, Mr. Westerhausen essentially confirmed that during cross-examination. Tr. PP-114 -115. The Company's Reply brief noted its concurrence with the OUCC and IG suggested changes. The Commission finds that Rule 2.2 should be revised to limit the Company's right to execute contracts for service under only those rate schedules or riders that specifically require a contract for service. Once that revision is made, the second sentence of the paragraph need not be changed.

(2) Rule 4 – Application, Service Request or Contract. The Industrial Group raised concerns with several portions of Rule 4 to the extent that it may allow NIPSCO to require a contract for the provision of service even in the absence of a contract requirement in the tariff and to the extent it relieves NIPSCO of its duty to serve its captive customers. This concern is similar to the problem we found in Rule 2.2 and shall be addressed in a consistent manner.

There are essentially two primary types of contracts that a utility may enter into with its customers. The first is one that simply fleshes out customer specific requirements but is governed by an existing tariff. The second type is those contracts that must be approved pursuant to I.C. 8-1-2-24 and 25. The point of demarcation between these two types lies ultimately with the Commission.

In light of these considerations, we find that Rule 4 is unclear and shall be revised consistent with Rule 2.2.

(3) Rule 5 -- Prediction of Rate Schedule Selection. The Industrial Group challenged the language in proposed Rule 5.8 regarding the default provision. Under proposed Rule 5.8, if a large volume industrial consumer has not entered into a contract under proposed Rates 526, 527, 534 and 536, the default tariff would be Rate 533. While this provision alone may not be troublesome, when taken with other proposed provisions that purport to give NIPSCO very broad discretion in what contract terms will be required, this Commission agrees with Mr. Dauphinais' point that Rule 5.8 could provide NIPSCO with additional leverage when dealing with customers who would be eligible for service under Rates 526, 527, 534 and 536/Rider 581. As discussed previously, any contract requirement under a published tariff shall be limited in nature as to what terms are to be included. To the extent that the contents of the required contract are left open ended, proposed Rule 5 would once again blur the line between those contracts that simply enable a customer to become eligible under a specific tariff rate and contracts that fall under Sections 24 and 25 requiring Commission approval. Accordingly, we find that Rule 5.8 shall be revised consistent with Rule 2.2.

(4) Rule 6 – Service Extensions and Modification. The only disputed issue under Rule 6 concerns the contract requirement under Rule 6.5. Given the planning and expense that are involved in service extensions, the Commission is not persuaded that the contract requirement proposed in Rule 6.5 is unreasonable and accordingly, we find that the rule as proposed shall be approved.

(5) Rule 8 – Company Equipment on Customer's Premises. While the OUCC and IG raised concerns in their respective proposed orders suggesting the proposed Rule 8.3 inappropriately shifts the duty to acquire easements from NIPSCO to the customer and that the language in proposed Rule 8.5 is overly broad regarding the phrase "unauthorized use of electricity" when disconnection is at issue (the third sentence of Rule 8.5), the Commission finds no evidence supporting such a suggestion. Accordingly, we find proposed Rule 8 is reasonable and that the rule as proposed shall be approved.

(6) Rule 10 – Customer Service Deposits. In proposed Rule 10.2, NIPSCO would be granted broad discretion in requiring both new and existing large volume customers to provide deposits or letters of credit as security for service without the ability to appeal or rebut a deposit determination. We agree with the Industrial Group that NIPSCO's proposed Rule 10.2 deviates from the foundation established by the Commission's regulations on deposit and would discriminate against large users. To the extent that such regulations (170 IAC 4-1-15) may not apply to non-residential customers, we believe that equity, absent a showing of need to reasonably discriminate, dictates that such company specific rules as proposed herein should be fundamentally the same. In short, non-residential customers are entitled to an equitable and non-discriminatory method of determining credit worthiness and similar earnings on any equivalently held deposit and to the ability to appeal a deposit determination. We find that Rule 10.2 must provide non-discriminatory treatment to its commercial and industrial customers and provide a clearly defined process by which such customers may appeal a deposit determination. Absent such a revision, the Commission rejects Rule 10.2 as proposed.

(7) Rule 12 – Disconnection and Reconnection of Service. We agree with the Industrial Group that Rule 12.3 grants too much discretion to NIPSCO for disconnection. NIPSCO's proposed rules must be reviewed in the context of the whole rules. See Pet. Ex. CAW-R1 at 17. When NIPSCO's proposed rules are taken as a whole, proposed Rule 12.3 provides excessive authority to NIPSCO. Under the rules as a whole, failure to post a deposit would be sufficient reason for disconnection under Rule 12.3, which would provide additional leverage for NIPSCO to require deposits from its large customers. It also would allow disconnection if a customer challenged a contract requirement. This provision, when coupled with NIPSCO's attempt to acquire open ended authority on imposing contract terms would be an impediment to a customer's ability to challenge a contract requirement. In addition, the lack of supply will not always justify disconnection at the customer's peril. This provision when considered in light of NIPSCO's attempt to change its standard of care for liability to gross negligence grants too much power to NIPSCO. Therefore, we reject proposed Rules 12.3 (a), (b) and (d).

The Commission recognizes the concerns expressed by the IG but is not persuaded that the disconnection authority proposed in the remainder of Rule 12.3 coupled with the other rule revisions directed herein is unreasonable and accordingly, we find that the rule as modified shall be approved.

(8) Rule 13 – Service Interruptions and Curtailments. Some of the concerns the Industrial Group raised with Rule 13 have been addressed by NIPSCO's rebuttal testimony wherein NIPSCO acknowledged that it did not intend to use the defined term "Interruption" in Rule 13 but rather the lower case term. Pet. Ex. CAW-R1 at 14.

NIPSCO's rebuttal did not address the Industrial Group's concerns regarding the standard of care for liability from "fault, neglect or culpability," which is currently in Rule 18, to the gross negligent standard proposed by NIPSCO. NIPSCO presented no testimony to justify this changed standard. Consequently, we reject NIPSCO's proposed change and find that NIPSCO shall retain its original "fault, neglect or culpability" language from Rule 18.

NIPSCO also proposed to change the reduction in the length of notice it would provide for service interruptions for non-emergency repairs. NIPSCO's current industrial tariffs provide that industrial customers would have at least ten days notice of any service interruptions for non-emergency repairs. NIPSCO has proposed to shorten the notice to 48 hours for all customers. Although NIPSCO attempted to justify the change in its rebuttal testimony, the Commission finds no valid reason to reduce the notice time from ten days to two days. Consequently, the Commission finds that the notice to all customers for non-emergency interruptions should be ten days.

(9) Rule 14 – Miscellaneous and Non-reoccurring Charges. As we have stated previously the Commission desires for charges for a service to be based on the cost of providing that service to the extent practical. We also recognize the significant charge increases proposed by NIPSCO as discussed by OUCC Witness Swan and are cognizant of particular impact such charges may have on the smallest and poorest customers who can least afford it. However, non-recurring charge types are inherently different from recurring charge types and therefore the foundation for application of the gradualism principal is reduced. Based on the totality of the evidence of record, the Commission approves the Rule 14 charges proposed by the Company.

15. FERC Seven-Factor Test.

A. Evidence. NIPSCO Witness Greneman explained that in Order 888, the FERC asserted jurisdiction over all unbundled transmission and left distribution regulation to the states. The FERC Order issued the Seven-Factor Test guidelines to help utilities and State regulators delineate its transmission and distribution facilities between what is under the FERC jurisdiction and subject to open access rules versus what is under state jurisdiction and not subject to open access. Mr. Greneman stated that each state is authorized to approve proposed separation of transmission and distribution functions using the Seven-Factor Test, with FERC retaining authority to review and make a final determination on treatment of assets. In this proceeding, NIPSCO is seeking approval to revise its segregation between transmission and distribution facilities to be consistent with orders from FERC.

Mr. Greneman stated that NIPSCO formed a working group and retained expert consultants in 2003 to systematically catalog and classify its facilities and to make recommendations with respect to the guidelines. Mr. Greneman testified that the NIPSCO 345 kV and 138 kV systems are the major bulk power carriers for the Company. All 345 kV and 138 kV lines are classified as transmission under the application of the Seven-Factor Test. The 69 kV was classified as transmission. He stated that virtually all of the 69 kV system is networkable and capable of performing a transmission function. The 34 kV lines, which were classified as distribution in the Seven-Factor Test, were the Company's older sub-transmission voltage lines that were originally used where 69 kV was not available. He explained that over the years, sub-transmission voltages such as 34 kV and 25 kV (in other utilities) tended to operate as distribution as is the case with NIPSCO's older 34 kV system. The technical characteristics and function of the 12.5 kV and below type of facility matches the definition of local distribution under the FERC's Seven-Factor Test.

Mr. Greneman explained that at the conclusion of the Seven-Factor Test a set of rules was developed in the form of an algorithm to be used to reclassify existing transmission and distribution assets in accordance with the results of the Seven-Factor Test. This would also be used as the guideline for booking future plant additions to FERC primary accounts. The procedures were set forth in Exhibit No. RDG-2, Schedule 4.0 of Mr. Greneman's testimony.

NIPSCO Witnesses Hershberger and Dehring testified regarding NIPSCO's implementation of the FERC Seven-Factor Test and the resulting classifications of NIPSCO's facilities as transmission or distribution. Mr. Dehring testified that as a result of joining the Midwest ISO, NIPSCO must implement FERC's Seven-Factor Test set forth in FERC Order No. 888. Mr. Dehring explained that the Seven-Factor Test analyzes the electric delivery system under seven different views to determine how the various components of the electric delivery system should be classified between transmission or distribution. Mr. Dehring stated that NIPSCO retained Stone & Webster Consultants, Inc. to assist in performing the Seven-Factor Test, and that based on the results of that analysis NIPSCO made several changes to how its transmission and distribution assets were classified.

More specifically, Mr. Dehring testified that after reviewing the results of the Stone & Webster study, NIPSCO determined that all of NIPSCO's electric delivery system facilities rated 69 kV and above, networked or operated as radial, should be classified as transmission. All of NIPSCO's electric delivery system facilities rated below 69 kV should be classified as distribution. Mr. Dehring stated that this resulted in $108,644,289 of transmission assets being reclassified as distribution assets and $14,599,077 of distribution assets being reclassified as transmission. Dehring Direct at 6.

Although the actual transfers were not made to NIPSCO's plant and reserve accounts until the beginning of 2008, they were incorporated in the cost of service study as a functional reclassification among primary accounts.

NIPSCO Witness Hershberger described other adjustments to NIPSCO's test year utility plant in service resulting from NIPSCO's implementation of the FERC Seven-Factor Test and other account reclassifications. He explained that other equipment transfers were needed to correct the original classification of the equipment, as shown on Petitioner's Exhibit MEH-8.

B. Discussion and Findings. No party contested these classifications or objected to NIPSCO's Seven-Factor Test in this proceeding. As discussed earlier in this Order, parties raised concerns regarding the allocation of costs to customers served by 34.5 kV facilities, but these concerns were addressed by the creation of a sub-transmission category for purposes of the cost of service study. We find that NIPSCO properly implemented the test and has appropriately determined which of its facilities should be classified as transmission facilities and which should be classified as distribution facilities for purposes of the Seven-Factor Test.

16. Ring Fencing.

A. Evidence. LaPorte and Hammond jointly submitted the testimony of Dr. John Wilson, a consulting economist, who testified regarding potential "ring fencing" conditions for NIPSCO that could be implemented by the Commission. Dr. Wilson defined ring fencing as a package of "distancing mechanisms" designed to insulate a utility company's credit risks from the financial and business risks of a parent corporation. Dr. Wilson explained that ring fencing is intended to ensure the financial stability of the regulated utility and the reliability of its service. Wilson Direct at 4.

Dr. Wilson outlined the specific ring fencing provisions that he recommended the Commission adopt for NIPSCO, including: (1) separate books of accounts and accounting systems; (2) separate credit and debt; (3) limitations on NIPSCO's ability to provide dividends to NiSource; (4) certain notice and preapproval requirements; and (5) specific financing guidelines. Wilson Direct at 13-17. Dr. Wilson concluded that these provisions, if adopted by the Commission, would provide a formal structure for ring fencing and would provide NIPSCO's ratepayers with specific regulatory protections. Wilson Direct at 17.

Petitioner submitted rebuttal testimony of David J. Vajda to respond to Dr. Wilson's recommendation that the Commission impose certain ring fencing conditions on NIPSCO in its Order in this proceeding. Mr. Vajda is Vice President, Treasurer and Chief Risk Office of NiSource and Vice President and Treasurer for its subsidiaries, including NIPSCO. Mr. Vajda testified why Dr. Wilson's recommendations are unnecessary and inappropriate and, in some cases, unduly burdensome.

Specifically, Mr. Vajda explained that the Commission already has access to the records of NIPSCO and records of affiliates that have transactions with NIPSCO related to joint or general expenses. Mr. Vajda added that many affiliate agreements between NIPSCO and NiSource companies are required to be filed with the Commission. Based on the foregoing, Mr. Vajda concluded that Dr. Wilson's recommendation (a) that "[t]he Commission or its agents may audit the accounts of NIPSCO, its parent (NiSource) and its affiliates which are the bases for charges to or transfers from NIPSCO," recommendation (b) that "NIPSCO and its parent (NiSource) shall provide the Commission access to all books of account, as well as all documents, data and records of their affiliated interests, which pertain to transactions between NIPSCO and its affiliated interests," and the part of recommendation (c) providing that "[a]ll NIPSCO financial books and records and those of its parent and affiliates shall be completely and immediately accessible in Indiana" are unnecessary.

Mr. Vajda went on to explain that the part of Dr. Wilson's recommendation (c) that provides that "NIPSCO shall maintain its own accounting system, separate from its parent's and its affiliates' accounting systems" reflects Dr. Wilson's misunderstanding of NIPSCO's accounting structure. As Mr. Vajda stated, NIPSCO maintains its Walker General Ledger system to maintain its financial books in accordance with the USOA and this system is already maintained by NIPSCO separate and distinct from the systems used by other NiSource entities. NIPSCO prepares its own financial statements for regulatory filings required by the Commission and FERC. NIPSCO also submits its financial results for each accounting period to NiSource Consolidation Accounting for the purpose of preparing the consolidated financial statements needed for NiSource's filings with the SEC. The consolidated financial statements are also used to allow management reporting in a consistent format throughout NiSource.

Mr. Vajda testified that it would be inappropriate and an unnecessary expense for the Commission to require that NIPSCO maintain separate credit ratings from its parent and affiliates as recommended by Dr. Wilson given the possibility that in the future, NIPSCO may not have debt outstanding to third parties.

With respect to Dr. Wilson's recommendation (e) that: "[e]xcept as may be expressly authorized by the Commission, NIPSCO will not extend credit or make loans to, or pledge its public utility assets as collateral for the benefit of, its parent or any of its affiliates and will not guarantee any debt of its parent or any of its affiliates" and recommendation (l) requiring approval of a "cash management plan incorporating best practices for insulating NIPSCO's credit from the risks associated with participating in a shared money pool with such affiliates," Mr. Vajda responded that NIPSCO already must obtain Commission approval for issuance of long-term debt and pledges of NIPSCO's public utility property, so the recommended conditions are unnecessary in the context of those transactions. To the extent Dr. Wilson's recommended conditions would apply to NIPSCO's participation in the NiSource money pool to invest surplus funds and borrow on a short-term basis, Mr. Vajda stated the recommendations should be rejected as they would have a detrimental effect on the NiSource money pool program which is very beneficial to NIPSCO and its customers. Mr. Vajda described the NiSource money pool in which NIPSCO and its affiliates may invest surplus funds on a daily basis and borrow funds on a short-term basis on terms that are more advantageous than participants in the money pool would be able to obtain on their own.

Mr. Vajda testified that Dr. Wilson's recommended restrictions on dividends and distributions from NIPSCO to its parent or any subsidiaries or affiliates are unnecessary, inappropriate and unduly burdensome. Imposing this requirement on NIPSCO, explained Mr. Vajda, could create a negative impression in the investment community and cause rating agency and investor uncertainty that could have adverse consequences in the current economic market.

Mr. Vajda testified that NIPSCO's most current agreement with NCS is on file with the Commission and affiliate charges are further reviewed and subjected to scrutiny in the context of rate cases. Accordingly, Mr. Vajda stated that Dr. Wilson's recommendation (i) providing that specific Commission authorization be required for expenses allocated or directly charged to NIPSCO by its parent and affiliates is unnecessary, inappropriate and unduly burdensome.

Finally, Mr. Vajda stated that no justification had been shown for requiring specific Commission authorization for certain transfers and other dispositions or NIPSCO's use of debt proceeds as is recommended by Dr. Wilson in recommendations (j) and (k).

NIPSCO also submitted rebuttal testimony of Steven M. Fetter, President of Regulation UnFettered, responding to the "ring fencing" conditions recommended by Dr. Wilson. Prior to founding his energy advisory firm, Mr. Fetter was head of the utility ratings practice at Fitch, Inc. and before that served as Chairman of the Michigan Public Service Commission. Mr. Fetter began by stating that the majority of major ring fencing efforts among U.S. regulators relate to particular unquantifiable risks in the context of acquisitions, mergers and spin-offs involving complex fact patterns. Mr. Fetter therefore disagreed with Dr. Wilson's testimony describing the financial circumstances of NIPSCO within the NiSource holding company structure as a "classic case" for ring fencing. Mr. Fetter said it would be very unusual for a regulatory commission to impose ring fencing conditions on a utility as part of a general rate case such as this proceeding. Mr. Fetter further explained that the concerns related to the mixing of regulated and unregulated activities within the same consolidated parent corporation–which Dr. Wilson cites as the impetus behind what he calls a growing interest in ring fencing for public utilities–are absent in the case of NIPSCO, because almost all of NiSource's subsidiaries are involved in traditionally-regulated utility and interstate pipeline businesses. Fetter Rebuttal at 9.

Mr. Fetter testified that Dr. Wilson's ring fencing recommendations in this proceeding come at a particularly inopportune time, given the current state of the U.S. capital markets. The recent economic turmoil made it difficult for some utilities to easily access the capital markets. According to Mr. Fetter, actions by a regulator creating the perception that the regulator is asserting control over a utility's dividend policy and retained earnings, matters normally within the discretion of management, is not a reasonable strategy in the current economic environment. In Mr. Fetter's rebuttal, he stated his belief that actions that would establish a perception that the regulator is creating barriers to the realization of efficiencies and economies of scale from a utility's participation in a normal holding company structure could cause additional concern and uncertainty for the investment community. Fetter Rebuttal at 13.

Mr. Fetter disagreed with Dr. Wilson that ring fencing should be implemented in order for NIPSCO to receive an improved credit rating. In Mr. Fetter's view, substantially limiting interaction between NiSource and its regulated Indiana subsidiary to possibly improve NIPSCO's credit ratings by a notch would increase investor uncertainty and diminish benefits flowing from shared managerial expertise and economies of scale. Mr. Fetter also pointed out that NiSource's businesses, being almost 100% regulated, are subject to constant scrutiny by regulators with authority to protect consumers and prevent abuses.

Mr. Fetter then offered his views with regard to some of the specific ring fencing conditions proposed by Dr. Wilson. Mr. Fetter cautioned against allowing regulatory access to information to be used so broadly as to allow regulators to prospect through the books and records underlying the proprietary activities of the utility's holding company or other affiliates. Mr. Fetter also warned that, with respect to the proposed conditions related to financial relationships and transactions between NIPSCO and its affiliates, it is important that regulators not create unnecessary barriers to the achievement of efficiencies and economies of scale that can be derived from being part of a holding company structure, including the benefits of NIPSCO being able to finance through its financing affiliate and participate in the NiSource money pool. Mr. Fetter disagreed with Dr. Wilson's proposed conditions that would interfere with or restrict distributions and dividends from NIPSCO to NiSource. He explained that investors rely upon a utility management's expected dividend policy, particularly within the utility sector. Interference with those policies by regulators would cause investor concern and render the maintenance of a certain equity level much more difficult during times of market stress. Finally, based on his experience as head of the utility ratings practice at Fitch, Mr. Fetter strongly disagreed with Dr. Wilson's proposed recommendation (g), which would grant regulators special access to non-public information supplied to credit rating agencies. As Mr. Fetter explains, rating agency personnel are expressly permitted to receive and analyze the most highly confidential and sensitive company information by the SEC's Regulation FD. Dr. Wilson's proposal would lead issuers to be less forthcoming to rating agencies regarding information that might be relevant to a rating agency's determination of the appropriate rating. Mr. Fetter discussed the difficulty of tracking confidential information, citing a recent news report of two SEC staff attorneys who mishandled confidential information made available to the agency during SEC investigations of certain issuers.

B. <u>Discussion and Findings</u>. LaPorte has presented evidence supporting its ring fencing proposal, while the other parties presented evidence that ring fencing was unnecessary. LaPorte describes how ring fencing would serve to protect NIPSCO from the financial and business risks of its parent corporation and affiliates. In contrast, the remaining parties that presented evidence on this issue argued that ring fencing is not necessary, and may actually harm NIPSCO's ratepayers by creating uncertainty among the investment community, ultimately making financing more expensive for NIPSCO and resulting in higher rates for its customers.

In Cause No. 42292, we addressed concerns that AES, Indianapolis Power & Light Co.'s parent corporation, could potentially affect IPL's capital structure and creditworthiness. *Petition of Indianapolis Power & Light*, Cause No. 42292, 2003 Ind. PUC LEXIS 110 (February 12, 2003). The Commission discussed our concerns over the relationship between IPL and AES as follows:

> As a regulatory agency charged with overseeing utilities, the Commission is attuned to factors that affect all utilities in general and individual utilities as well. With regard to IPL and its ultimate parent AES, the Commission is aware of considerable media attention to the recent financial difficulties of AES. To ignore such reports would be a dereliction of our responsibility to exercise our statutory authority in an informed manner. In the case at hand, the OUCC's witness Mr. Robertson testified that IPL's ultimate parent, AES, has experienced significant financial pressure in the market, and that the financial troubles with IPL's parent companies may lead to cash outflows from IPL that might result in insufficient cash to provide reasonably adequate service, or result in an inappropriate debt to equity ratio. IPL's witness Ms. Horwitz testified that "IPL's credit rating was dropped by the Standard & Poor's rating agency solely because of a practice that Standard & Poor's has on linking a subsidiary to a much lower rated parent." She further conceded that implicit in the rating drop is a concern by the investment community that IPL's parent companies might extract cash from IPL in an amount that would leave IPL in a difficult situation. The evidence presented supports a finding, and we find, that the poor financial condition of AES has created a situation that could endanger the financial health of IPL.
>
> At this time, IPL has a reasonable capital structure, and based on a snapshot of IPL's financial condition, the Commission has approved IPL's financing request. However, faced with an ultimate parent, AES, that is in financial distress, there is a risk that IPL may need to surrender dividends in such an amount that a factor critical to the Commission's approval of a financing request -- the utility's capital structure -- could be substantially changed. If the flow of cash dividends from IPL to its unregulated parent companies were unrestricted, such cash flows could lower the amount of equity retained in IPL to a level that the additional debt financing proposed herein might become imprudent. In addition, as a company increases the percentage of debt in its capital structure, both its cost of equity and its cost of debt increase -- a burden that eventually would fall on ratepayers.

Id. at *22-*24.

Some of the concerns we discussed are present here, but some are not. For instance, unlike IPL, NIPSCO's capitalization is not debt-heavy, which relieves some of the concern over dividend transfers negatively affecting NIPSCO's ability to obtain financing. This Commission seeks to use restraint in creating obstacles that may be viewed by the investment community as over-regulation. Therefore, we do not adopt Dr. Wilson's ring fencing recommendations. However, as discussed previously in this Order, NIPSCO faces ongoing challenges with respect to service quality, and will need to make expenditures to deal with those issues. As we noted in Cause No. 42292, "The Commission's duty to protect the public interest requires that it look beyond the interests of any single constituency, so that a proper balance can be found between a diversity of interests." Id. at *25. We find that the conditions on dividend transfers instituted in Cause No. 42292 would be appropriate for NIPSCO.

Accordingly, the Commission finds that NIPSCO, before declaring or paying any dividend, shall file with the Commission a report detailing (1) the amount of the proposed distribution, (2) the amount of dividends distributed during the prior twelve months, (3) an income statement for the same twelve-month period, (4) the most recent balance sheet, and (5) NIPSCOs capitalization as of the close of the preceding month, as well as a pro forma capitalization giving effect to the proposed dividend, with sufficient detail to indicate the amount of unappropriated retained earnings. If within twenty (20) calendar days the Commission does not initiate a proceeding to further explore the implications of the proposed dividend, the proposed dividend shall be deemed approved. The Commission finds that the preceding approval process shall continue in effect through December 31, 2014, or further Order of the Commission, whichever occurs first.

17. <u>Customer Surveys</u>. Throughout the hearing, LaPorte's counsel asked questions of NIPSCO's witnesses regarding surveys of utility customers. LaPorte Witness Barbara Huston, a LaPorte County Commissioner, testified that NIPSCO should have to earn a rate increase based upon survey results, and hoped that the Commission would apply a "discount" or "deduction" to NIPSCO's authorized rate of return to reflect NIPSCO's low results in customer satisfaction surveys. Huston Direct at 2-3. In rebuttal, NIPSCO Witness Shambo testified that while perception surveys provide important input to utilities, he did not believe that a utility's return should be based upon such surveys. Shambo Rebuttal at 41. During cross-examination of Mr. Skaggs and Ms. Odum, several questions were asked regarding NIPSCO's rankings in various perception surveys and the degree to which NIPSCO was working to improve those rankings. Both Mr. Skaggs and Ms. Odum acknowledged that NIPSCO's rankings can be improved and discussed the steps NIPSCO is taking to improve customer perceptions. Ms. Odum testified about the results of two internal surveys conducted by an outside firm engaged by NIPSCO, which included 17,000 and 21,000 respondents, respectively (as compared to a J.D. Power survey that would include at most 500 customers), have reached significantly different results from the J.D. Power surveys. Tr. at D-28–D-30. Ms. Odum noted that NIPSCO received positive ratings on a number of questions, including a 73% level of agreement that NIPSCO is a positive member of the community, a 91% favorable rating in terms of reliability of service, and a 72% agreement that customers receive good value for the electric services provided. Tr. at E-67–E-68. Ms. Odum stated that these results provide various points of information for NIPSCO to consider as it works to improve customer satisfaction.

The Commission agrees that customer satisfaction is important and customer perception surveys are a useful tool in evaluating customer satisfaction, and we have assigned appropriate weight to this evidence in determining NIPSCO's cost of equity.

As NIPSCO's witnesses discussed during cross-examination on this issue, perception surveys are one data point, among many, in evaluating customers' views towards their utility and the service they are receiving. As Mr. Skaggs stated during cross-examination regarding NIPSCO's efforts to improve customer perceptions of the Company:

> I think that we continually work with our peers and look at their best practices, and I think you can look at that in our contact center, storm response activities, generation of management activities, external affairs activities. We are constantly looking at those standards through industry associations, through our peer relationships, and I'd go a step further, we certainly try to look beyond our peers. The process to make improvement is not a day process, a week process, a month process. It is like our relationship. It takes literally months, years, to rebuild that and to overcome what appears here as eight years-plus of problematic perceptions. It is going to take us a lot of time to rebuild that, and it is not going to be over just one dimension. It is going to be answering the phones; it is going to be participating in the community; it is going to be dealing with the price issue. I can assure you, myself and the team, we've worked night and day to begin moving these numbers and our own numbers.

Tr. at B-41–B-42. Likewise, Ms. Odum discussed during her cross-examination how NIPSCO has expanded its commitment to survey research and has conducted several internal surveys to better identify and understand opportunities to improve the level of customer satisfaction with NIPSCO's service. Tr. at E-27; E-66–E-68. The Commission encourages NIPSCO to continue to actively address the customer perception and satisfaction issues.

18. Confidentiality. NIPSCO filed six motions for protective orders and NIPSCO and the OUCC filed one joint motion for a protective order, all 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 and, in the case of the information subject to the joint motion, that the information was also confidential infrastructure information within the scope of Ind. Code § 5-14-3-4(b). The Presiding Officers issued docket entries and made rulings from the bench finding such information to be preliminarily confidential, after which such information was submitted under seal. NIPSCO also filed a seventh motion for protective order relating to confidential information contained in Petitioner's Redirect Ex. 3-C, which was granted from the bench without objection. Tr. at KK-48–KK-49. 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 continue to be held confidential by the Commission.

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

1. Petitioner Northern Indiana Public Service Company shall be and hereby is authorized to revise its basic rates and charges for electric utility service to provide annual gross margin revenue of $899,401,890 plus non-trackable fuel expense of $11,015,038 which on the

basis of annual electric operating expenses of $706,976,357 (net of revenues and expenses relating to trackable and non-trackable fuel and purchased power and related Utility Receipts Tax) are estimated to provide net operating income of $192,425,533. For purposes of computing the authorized net operating income for Ind. Code § 8-1-2-42(d)(3), the decrease in Petitioner's return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order.

2. Petitioner shall file a new schedule of rates and charges and "proof of revenues" with the Commission's Electricity Division within thirty (30) days of this Order. That "proof of revenues" filing shall include the billing determinants and the allocation of the revenue increase as found appropriate within this Order. At such time, NIPSCO shall also file a revised cost of service study demonstrating that the new rates are consistent with the findings made herein. Copies of same shall be served upon all parties of record. Any party contesting the derivation of the rates and charges shall file its notice within ten (10) business days of the filing of the new rate schedules, proof of revenues and cost of service study. In the event any party files such a notice, the Commission shall then establish a procedural schedule regarding the compliance filing. The new schedule of rates and charges shall be effective upon filing with and approval by the Electricity Division or by Order of the Commission.

3. NIPSCO shall also file with the Electricity Division revised FAC factors in accordance with the findings herein, and such changes shall be effective simultaneously with the change in base rates authorized herein.

4. NIPSCO shall also file with the Electricity Division revised ECRM and EERM factors that eliminate costs that are being rolled into the base rate approved herein which changes shall be effective simultaneously with the new base rates.

5. Subject to adjustment to reflect the rate levels approved herein, NIPSCO's proposed Electric Tariff, revised to conform to Petitioner's Exhibit CAW-R1, including but not limited to the General Rule and Regulations set forth therein, as modified in this Order, shall be and hereby is approved to be effective simultaneously with the new base rates approved herein.

6. NIPSCO's standard form template agreement for service under Rates 526, 533 and 534 in the form of Petitioner's Exhibit CAW-R3 shall be and hereby is approved.

7. NIPSCO shall adjust its base rates to eliminate the aging workforce adjustment, emission allowance sale amortization, rate case expense amortization, the amortization of Sugar Creek deferred depreciation, and the Midwest ISO deferred cost amortization at the end of the respective adjustment or amortization periods approved herein by filing revised rate schedules with the Commission's Electricity Division.

8. NIPSCO's proposed depreciation accrual rates for electric plant and common plant as set forth in Petitioner's Exhibit JJS-2, pages 51-62, are hereby approved and authorized as modified herein. NIPSCO's depreciation rates shall not include decommissioning costs as addressed in this Order.

9. NIPSCO shall be and hereby is approved and authorized to implement an RTO Tracker and Resource Adequacy Tracker as described herein.

10. NIPSCO's proposed reclassification of electric plant as transmission or distribution pursuant to FERC's Seven-Factor Test is hereby approved.

11. 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.

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

HARDY, ATTERHOLT, MAYS, AND ZIEGNER CONCUR; LANDIS ABSENT:
APPROVED: AUG 25 2010

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