STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH – ELECTRIC") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) INCLUSION IN ITS BASE RATES OF COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; (4) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN CERTAIN COSTS AND REVENUES RELATING TO ITS GENERATING FACILITIES; (5) AUTHORITY TO IMPLEMENT A RATE ADJUSTMENT MECHANISM TO TRACK INCREMENTAL CHANGES IN NON-FUEL RELATED MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC. ("MISO") CHARGES AND PETITIONER'S TRANSMISSION REVENUE REQUIREMENT; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS FUEL ADJUSTMENT CHARGE PROCEEDINGS; (7) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (8) APPROVAL OF THE CLASSIFICATION OF PETITIONER'S FACILITIES AS TRANSMISSION OR DISTRIBUTION IN ACCORDANCE WITH THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN FACTOR TEST; AND (9) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR ELECTRIC SERVICE INCLUDING NEW INTERRUPTIBLE AND ECONOMIC DEVELOPMENT RIDERS.	)	FILED SEP 15 2006 INDIANA UTILITY REGULATORY COMMISSION **CAUSE NO. 43111**

Prepared Direct Testimony and Exhibits
Of
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – ELECTRIC)

Book 4 of 4

WS Seelye, KA Heid, WR Hopkins, JL Ulrey

September 15, 2006

FILED

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INDIANA UTILITY REGULATORY COMMISSION

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SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH-ELECTRIC)

IURC CAUSE NO. 43111

DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

ON THE PROPOSED

MISO COST AND REVENUE ADJUSTMENT (MCRA)

SPONSORING PETITIONER'S EXHIBITS WSS-1 THROUGH WSS-7

Direct Testimony of William Steven Seelye

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and fuel and power procurement.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying for Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or "Company"), which provides electric utility service in southwestern Indiana.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PRIOR WORK EXPERIENCE.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company. From May 1979 until December, 1990, I held various positions within the Rate Department of Louisville Gas and Electric Company. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left Louisville Gas and Electric Company in July 1996 to form The Prime Group, LLC.

Since leaving Louisville Gas and Electric Company, I have performed cost of service and rate studies for over 100 investor-owned utilities, rural electric cooperatives, and municipal utilities. I have also developed transmission rates and transmission delivery charges for a number of electric utilities. A more detailed description of my qualifications is included in Petitioner's Exhibit No. WSS-2.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, on a number of occasions. A listing of my testimony is included in Petitioner's Exhibit No. WSS-2.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will present Vectren South's proposed MISO Cost and Revenue Adjustment ("MCRA") which will provide for the recovery or refund of incremental changes in Vectren South's non-fuel MISO charges and will provide for the recovery or refund of incremental changes in the revenue requirement determined in The Midwest Independent System Operator's ("MISO") Attachment O for Vectren South, which is approved by the Federal Energy Regulatory Commission ("FERC"). The direct testimony of Petitioner's Witnesses William S. Doty and Jerome A. Benkert also address MISO matters and the need for a MISO Charges tracker. The direct testimony of Petitioner's Witness Michael W. Chambliss addresses Vectren South's Transmission investments and the underlying need for a MISO Transmission Cost tracker.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. To foster a more competitive and efficient power market, the Commission has determined that it is important to encourage utility membership in MISO. In furtherance of those goals, Vectren South is proposing a MISO Cost and Revenue Adjustment to recover incremental changes in the costs associated with the company's membership in MISO. Vectren South's proposed MISO Cost and Revenue Adjustment would allow for the timely recovery of incremental MISO charges and incremental MISO transmission costs. Specifically, Vectren South is proposing to recover, on a quarterly basis, incremental changes in the non-fuel related charges assessed by MISO and incremental changes in the key cost and revenue components of Vectren South's transmission revenue requirements determined through the application of the FERC-approved Attachment O calculations.

When it allowed Vectren South and other utilities in Indiana to transfer operational control of their transmission assets to MISO, the Commission determined that membership in MISO is in the public interest and will ultimately benefit retail customers through the creation of a more efficient power market. Then, in support of participation in MISO's Day One and Day Two markets, the Commission authorized Vectren to defer non-fuel costs related to that market. To further those objectives, the Commission has allowed Duke Indiana-PSI to implement a cost recovery clause similar to the adjustment mechanism proposed by Vectren South. In approving Duke Indiana-PSI's Standard Contract Rider No. 68, MISO Management Cost and Revenue Adjustment, the Commission evaluated the appropriateness of the tariff by considering the following criteria: Were the costs the result of decisions by the FERC? Were the costs variable in amount from year to year? Were the costs variable as to timing? Were the costs substantial in individual and aggregate amounts? Were they outside the control of the utility? As discussed in my testimony, the costs to be recovered through Vectren South's proposed MISO Cost and Revenue Adjustment meet these same criteria.

Furthermore, as a public policy matter, it is important that participation in MISO continue to be supported and that utilities are also encouraged to make capital investments to upgrade their transmission systems so that the benefits of participation in MISO are fully realized. Section 1241 of Energy Policy Act of 2005 directed the FERC to adopt rules that will promote capital investments in transmission facilities. In response to that directive, the FERC approved in its Order No. 679, Promoting Transmission Investment through Pricing Reform, a framework for encouraging utilities, which own the vast majority of transmission facilities, to make investments in transmission facilities, including allowing utilities to recover a return on such investment on a timely basis, as well as earn an incentive rate of return on transmission investments (which would be higher than the standard MISO rate of return of 12.38% without the incentive). However, unless the timely recovery of a return authorized by the FERC is also authorized by state regulatory commissions, the FERC rulemaking will have no impact on addressing the urgent need for utilities to upgrade their transmission facilities. This is true because utilities still use these systems to provide retail service, and therefore, most of these costs are allocated to retail customers.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is divided into the following sections: (I) Introduction and Qualifications, (II) Overview of FERC Regulation and MISO Costs, and (III) MISO Cost and Revenue Adjustment.

II. OVERVIEW OF FERC REGULATION AND MISO COSTS

Q. HAVE FERC REGULATION AND THE FORMATION OF MISO FUNDAMENTALLY ALTERED THE PLANNING, OPERATION AND COST STRUCTURE OF ELECTRIC UTILITIES IN THE MIDWEST?

A. Yes, they have. Transmission policy in the U.S. has been in a constant state of change since the enactment of the Energy Policy Act of 1992 which initiated utility industry reform that allowed and encouraged more competition between established utilities and independent power producers in the wholesale power market. On April 24, 1996, the FERC issued its Order 888, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities," and Order 889, "Open Access Same-Time Information Systems." Order 888 required transmission owners to file open access transmission tariffs pro-formed to a standard format. Order 889, which was issued concurrently with Order 888, required public utilities that own, control, or operate transmission facilities to create or participate in an Open Access Same-Time Information System ("OASIS"). The principal reason that the FERC issued Order 888 and Order 889 was to create an environment for the provision of transmission service that facilitated or even encouraged competitive power markets. Following the enactment of the Energy Policy Act of 1992, the FERC liberalized the regulation of power transactions, and, as a result, the amount of power being transmitted across utility control areas increased dramatically.

In order to comply with Order 888 and Order 889, integrated utilities began to voluntarily form Independent System Operators soon after the orders were issued. Discussions on the formation of MISO began shortly after Order

888 and Order 889 were issued, culminating in a FERC filing asking for approval of the organization in January 1998. MISO received conditional approval from the FERC on September 16, 1998, and the first employee was hired in August 1999.

In December 1999, the FERC issued Order 2000 which established a new set of regulations designed to resolve what it viewed as problems created by the balkanized control of transmission systems. The goal of Order 2000 was to expand on the impetus that the FERC provided in Order 888 for utilities to form regional transmission organizations to support competitive wholesale markets and to provide additional detail about the functions that these regional transmission organizations must perform. Among other things, Order 2000 mandated the implementation of real-time energy imbalance services and a market-based congestion management system. On March 31, 2004, MISO filed with the FERC in Docket No.04-691-000 an Open Access Transmission and Energy Market Tariff ("TEMT") which set forth rates, charges, terms, and conditions for the implementation of a centralized security-constrained economic platform for the dispatch of power within MISO supported by a day-ahead and real-time energy market design, including locational marginal pricing and financial transmission rights within the MISO footprint. This platform, which is referred to as the "Day 2 Energy Market," or simply the "Midwest Energy Market," was launched on April 1, 2005.

All of these changes in the industry – including the liberalization of the FERC's regulatory oversight of power transactions in the early 1990s, FERC mandated open transmission access, the formation of MISO as a regional transmission operator, and the Midwest Energy Market being launched by MISO – have transformed the planning, operation and cost structure of transmission service in the Midwest. In an effort to create a more efficient power market, the planning and operation of individual utility transmission systems have been shifted from individual utilities to a central organization. Consequently, the planning and operation of transmission facilities within a utility's geographic service area are no longer under the control of the individual utility, but under the control and oversight of MISO. Furthermore, the cost structure of a utility's transmission service function has been fundamentally altered. Not only are there administrative costs associated with managing MISO's transmission support operations and its energy market platform, but there are also newly required capital investments related to constructing new transmission capacity needed to support the increased power flows associated with the Midwest Energy Market. For the market to function regionally as envisioned, upgraded infrastructure is required. Vectren South Witness Chambliss describes these projects.

Q. PLEASE DESCRIBE THE MISO-RELATED COSTS INCURRED BY VECTREN SOUTH.

A. Vectren South's MISO related costs can be grouped into following three categories: (1) Non-fuel charges assessed by MISO pursuant to rate schedules that have been approved by the FERC; (2) fuel costs related to the participation in the Day 2 Energy Market; and (3) transmission costs included in MISO's FERC-approved Attachment O formula rate for Vectren South.

A. <u>NON-FUEL CHARGES ASSESSED BY MISO</u>

Q. WHAT ARE THE NON-FUEL CHARGES ASSESSED BY MISO?

A. MISO currently assesses the following non-fuel charges to Vectren South:

(1) **Schedule 10 and Schedule 10-FERC – ISO Cost Recovery Adder and FERC Annual Charges Recovery**. These schedules provide for the recovery by MISO of the cost of building and operating MISO's control center, coordinated regional transmission planning, administering the TEMT, any deferred pre-operating costs and recovery of the annual assessments paid to the FERC by MISO.

(2) **Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder**. This schedule provides for the recovery of Day 2 Market costs related to bilateral trading coordination, FTR administration, FTR software tools, simultaneous feasibility analysis, revenue distribution, and FTR administration.

(3) **Schedule 17 – Energy Market Support Cost Recovery Adder**. This schedule provides for the recovery of Day 2 Market costs related to market modeling and scheduling, market bidding, locational marginal pricing coordination, market settlements and billing, market monitoring functions, and the economic dispatch of generating resources to serve load in the

MISO footprint while establishing a spot energy market.

(4) **Schedule 24 – Control Area Operator Cost Recovery.** This schedule provides for the recovery of control area or "balancing authority" cost incurred by transmission owning members of MISO as a result of implementing the Day 2 Market.

Q. HAS THE COMMISSION ALLOWED ANY UTILITIES IN INDIANA TO RECOVER THESE COSTS THROUGH A MISO TRACKER?

A. Yes. In its Order in Cause No. 42359 approved May 18, 2004, which was an order in a general rate case proceeding, the Commission permitted Duke Indiana-PSI to track these non-fuel MISO charges through Standard Contract Rider No. 68, MISO Management Cost and Revenue Adjustment. In approving the PSI's adjustment rider, the Commission stated as follows:

> We find reasonable PSI's proposal to track Midwest ISO related costs and revenues, including costs that are: (1) the result of decisions by the FERC; (2) variable in amount from year to year; (3) variable as to timing; (4) substantial in individual and aggregate amounts; and (5) outside the control of PSI. PSI's proposal is balanced and designed to flow through to customers Midwest ISO-related transmission revenues received by PSI. Therefore, we find that PSI's proposal to track Midwest ISO related costs should be approved. (Cause No. 42359, Order dated May 18, 2004, at p. 120.)

In accordance with Standard Contract Rider No. 68, PSI submits quarterly filings with the Commission detailing the costs recovered though the tracker. PSI's most recent filing for the recovery of non-fuel MISO charges was submitted on July 5, 2006, in Cause No. 42736-RTO 7.

In Cause No. 42685, Vectren South proposed to implement a MISO tracker similar to PSI Energy's Standard Contract Rider No. 68. In its order in Cause No. 42685, dated June 1, 2005, the Commission rejected Vectren South's MISO tracker on the ground that the tracker should be considered in the context of a rate case.

However, Vectren South was allowed to defer the recovery of its non-fuel MISO charges until the company's next base rate case proceeding. In its Order, the Commission stated that, "We believe that the approach taken with respect to our approval of PSI's MISO tracker (in the context of a rate case) is sound, as it allowed us to fully review all costs and costs savings prior to reaching a final determination on the issue." (Cause No. 42685, Order dated June 1, 2005, at p. 39.)

Q. ARE THERE OTHER NON-FUEL CHARGES THAT VECTREN SOUTH WILL INCUR UNDER THE MISO TARIFF?

A. Yes. Vectren South will be assessed charges for ***reliability upgrades*** to the MISO transmission system pursuant to Attachment FF – Transmission Expansion Planning Protocol and Attachment GG – Network Upgrade Charge of the TEMT, which are recoverable through the FERC-approved Schedule 26 – Network Upgrade Charge from Transmission Expansion Plan of the TEMT. Reliability upgrades would include generator interconnection projects and transmission delivery service projects identified in the MISO Transmission Expansion Plan (MTEP) required to maintain the reliability of the system. The cost of these upgrades would not be borne solely by the transmission owner constructing the upgrade, but would be shared among transmission owners according to a formula. Thus, Vectren South and all other transmission owners will be allocated some of the cost of reliability upgrades that are constructed by other transmission owners. The cost of the transmission upgrades that MISO directs Vectren South to construct would be recovered through Vectren South's Attachment O of the MISO TEMT unless a portion of the costs are socialized to other MISO participants. Vectren South will need a mechanism to recover these increased costs flowing through Attachment O as well as the costs that it is allocated from transmission projects that MISO directs transmission owners to construct in other areas.

Attachments FF and GG of the TEMT and Schedule 26 were approved by the FERC in its order in Docket No. ER06-18-000 dated February 3, 2006. Attachment FF is the core cost allocation policy document which details the process to be used by MISO to evaluate and develop expansion projects for the MTEP, in addition to the allocation and recovery of costs of transmission expansion projects. Attachment GG sets forth the methodology for calculating charges associated with the network upgrades developed pursuant to Attachment FF. The charges calculated under Attachment GG will be collected under Schedule 26. Attachment FF will allocate costs of transmission projects in other areas to Vectren only for new upgrades that are identified in Transmission Expansion Plans subsequent to MTEP 2005. Therefore, Attachment FF will only include upgrades identified in MTEP 2006 and subsequent MTEPs that are not included in MTEP 2005. Consequently, the network upgrades that are charged to Vectren South using Schedule 26 will not begin until after MTEP 2006 is approved and filed with the FERC later this year.

At some later date, Vectren South will also be assessed charges for ***economic upgrades*** to the MISO transmission system that are built by other transmission owning members of MISO. Economic upgrades are those network upgrades that are beneficial to one or more market participants, but are not necessary to meet NERC reliability criteria during the planning horizon that is used in MTEP. MISO must make a filing with the FERC on September 1, 2006, detailing the methodology to be used for identifying qualifying economic upgrades and the methodology to be used for recovering those costs. Although the exact method for allocating the costs of economic upgrades has not yet been determined, it is certain that there will be some form of regional cost sharing for these projects which is likely to result in some of these costs being allocated and charged to Vectren South.

At some point in the future, Vectren South could also be assessed charges for reactive power service provided by generators in Vectren South's control area. Under current FERC policy, independent generators may file a rate schedule with the FERC for recovery of reactive power costs incurred by the generator. Such charges would be recovered through Schedule 2 – Reactive Power Service of MISO's TEMT.

Q. HOW IS VECTREN SOUTH PROPOSING TO RECOVER THESE NON-FUEL MISO CHARGES ON AN ONGOING BASIS?

A. As will be discussed in greater detail later in my testimony, Vectren South is proposing to recover current and future non-fuel MISO charges through the MISO charge component of the MISO Cost and Revenue Adjustment.

B. FUEL COSTS ASSOCIATED WITH THE MISO DAY 2 ENERGY MARKET

Q. PLEASE DESCRIBE THE FUEL COSTS RELATED TO THE DAY 2 ENERGY MARKET?

A. As explained earlier, on March 31, 2004, MISO filed its TEMT which set forth rates, charges, terms, and conditions for implementing its energy market platform. Under this platform MISO directs the dispatch of all of the MISO members' generating units on a security constrained, regional economic dispatch basis considering the economics of the generation offers into the MISO market. The following fuel-related charges or credits can be incurred or received by Vectren: (a) FTR congestion costs; (b) FTR congestion credits; (c) FTR auction settlements; (d) Virtual Bids and Offers in the Day-Ahead Market used for hedging jurisdictional load; (e) Day-Ahead recovery of Unit Commitment Costs; (f) Excess Congestions Charge Fund Credits; (h) RAC Recovery of Unit Commitment Costs; (i) Marginal Losses Surplus Credit; (j) Inadvertent Energy Charges or Credits; (k) Uninstructed Deviation Penalties; and (l) Revenue from Uninstructed Deviation Penalties. In its Order in Cause No. 42685, dated June 1, 2005, the Commission determined that these items represented components of the cost of fuel and are thus subject to recovery through Vectren South's fuel adjustment clause ("FAC") in accordance with IC 8-1-2-42(d)(1) and IC 8-1-2-42(d)(4). The Commission also ruled in Cause No. 42962 that revenue sufficiency guarantees were recoverable through the FAC.

C. TRANSMISSION COSTS INCLUDED IN MISO'S FERC APPROVED ATTACMENT O FORMULA RATE

Q. PLEASE DESCRIBE MISO ATTACHMENT O?

A. MISO Attachment O is used to determine the transmission service rates under the TEMT for loads that sink into Vectren's control area. Attachment O, which is updated annually, is used to determine the annual transmission revenue requirements for each transmission owner in MISO. For an investor owned utility, revenue requirements are determined based on plant and expense data from the utility's FERC Form 1 and include the following components: (i) operating expenses, including operation and maintenance expenses, taxes other than income tax, and depreciation expenses, (ii) return on transmission net investment grossed up for income taxes, less (ii) transmission revenue credits.

A copy of the most recent Attachment O for Vectren South is shown in Petitioner's Exhibit No. WSS-3. As can be seen from the most recent Attachment O for Vectren South, net revenue requirements are shown on page 1, line 7. Operating Expenses consist of (a) total operation and maintenance expenses shown on page 3, line 8, (b) depreciation expenses shown on page 3, line 12, and (c) taxes other than income taxes shown on page 3, line 20. The return on transmission net investment is shown on page 3, line 28, and the income tax gross up is shown on page 3, line 22. Transmission net plant is shown on page 2, line 18, and adjustments to rate base are shown on line 24.

Q. IS ATTACHMENT O A FERC-APPROVED RATE SCHEDULE?

A. Yes, it is. The revenue requirement set forth in MISO's Attachment O for Vectren South is applicable to all loads sinking in Vectren South's control area, including retail load. Therefore, in a strict sense, Schedule 9 – Network Integration Service of MISO's TEMT is the "filed rate" applicable to loads that sink in Vectren South's control area.

Q. PLEASE DESCRIBE THE TRANSMISSION COSTS INCLUDED IN MISO'S FERC-APPROVED ATTACHMENT O FORMULA RATE?

A. Schedule 7 – Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service, Schedule 8 – Non-Firm Point-to-Point Transmission Service, and Schedule 9 – Network Integration Service of MISO's TEMT are assessed for any loads sinking in a transmission owner's control area. The charges collected under these schedules are based on the rate formula contained in Attachment O of the TEMT. The rate formula corresponds to a revenue requirement calculation that is performed annually by each MISO transmission owner. The revenue requirements include operating expenses and a return on transmission net investment grossed up for income taxes, less transmission revenues (revenue credits) collected pursuant to the Schedule 7, 8, and 9 of the TEMT are allocated to the transmission owner. The costs included in MISO Attachment O are internal costs incurred by Vectren South, the transmission owner; however, because of its membership in MISO, Vectren South is no longer in direct control of transmission facilities. Attachment O is a FERC-approved formula rate that is used to determine the transmission owner's transmission-related revenue requirements based on costs for the most-recent calendar year. As an example, unless a portion of the costs are socialized to other MISO participants any new transmission facilities that MISO directs Vectren South to construct as a result of the MTEP process would be recovered by Vectren South using Attachment O, which is a FERC-approved tariff. As detailed later in my testimony, they are also variable in amount from year to year, variable as to timing, and are substantial in individual and aggregate amounts.

Q. HOW IS VECTREN SOUTH PROPOSING TO RECOVER THESE ATTACHMENT O COSTS ON AN ONGOING BASIS?

A. Vectren South is proposing to recover test-year levels of transmission costs identified in Attachment O through base rates. As will be described in detail later in my testimony, Vectren South is proposing to recover the incremental costs above those reflected in base rates through the MISO transmission component of the MISO Cost and Revenue Adjustment. In so doing, the need to invest in infrastructure emphasized by FERC, and necessary to have import capability for Vectren South's customers, is supported by a cost recovery approach much like that already in place for new generation and environmental investments.

III. <u>MISO COST AND REVENUE ADJUSMENT</u>

Q. PLEASE DESCRIBE VECTREN SOUTH'S PROPOSED MISO COST AND REVENUE ADJUSTMENT?

A. Appendix I – MISO Cost and Revenue Adjustment of Vectren South's Tariff for Electric Service, which is included as <u>Petitioner's Exhibit No. WSS-4</u>, is largely modeled after PSI's Standard Contract Rider No. 68. Under its proposed MISO tracker, Vectren South would make quarterly filings with the Commission to recover non-fuel charges assessed by MISO and MISO transmission costs from Vectren

South's annual Attachment O calculations. The MISO Cost and Revenue Adjustment ("MCRA") would be calculated quarterly by applying the following formula:

$$MCRA = \frac{[(MCC + MTC)\ x\ Rate\ Schedule\ Allocation\ Percentages]}{Rate\ Schedule\ Sales\ Quantities}$$

Where

MCC is the MISO Charges Component;

MTC is the MISO Transmission Component;

Rate Schedule Allocation Percentage is the proportion of the annual MTC amount applicable to each rate schedule.

Rate Schedule Quantities are the quarterly kWh sales quantities for each rate schedule.

According to this formula, the sum of the MISO Charges Component and MISO Transmission Component would be determined quarterly, multiplied by the Rate Schedule Allocation Percentage and then divided by the Rate Schedule Quantities for the quarter to derive the MCRA for each rate schedule. In addition to the MCC and MTC components of the MCRA, any difference between the deferred balance of MISO charges authorized for deferral by the Commission in this proceeding and the deferred amount as of the effective date of new rates would be included as a charge or credit in the MCRA, as described in the testimony of Petitioner's Witness Jerrold L. Ulrey.

Q. WHAT IS THE PURPOSE OF MULTIPLYING THE SUM OF THE MCC AND MTC COMPONENTS BY THE RATE SCHEDULE ALLOCATION PERCENTAGE?

A. The Rate Schedule Allocation Percentage is applied as an allocation factor to the sum of the MCC and MTC components in order to determine the portion of costs to be allocated each rate schedule. These percentages would correspond to the allocation factors used to allocate transmission costs in the electric cost of service study submitted by Vectren South in the current proceeding. As described in Petitioner's Witness Kerry A. Heid's testimony, transmission costs are allocated to the rate classes using a 12-CP allocator, which is consistent with the way that these costs are allocated and billed to Vectren South by MISO. After the sum of MCC and MTC have been allocated to each rate class, the allocated costs would then be divided by projected quarterly kWh sales.

Q. HOW WILL THE MISO CHARGES COMPONENT (MCC) BE DETERMINED?

A. MCC will be calculated by subtracting 25% of the MISO charges included in base rates in the current proceeding from the MISO charges for the three-month period. The charges to be included are: (a) MISO Schedule 10 and Schedule 10-FERC Administrative Costs, or successor provisions, of the MISO TEMT; (b) MISO Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder, or any successor schedule for MISO; (c) MISO Schedule 17 – Energy Market Support Cost Recovery Adder; (d) Schedule 24 – Control Area Operator Cost Recovery; (e) Schedule 26 – Network Upgrade Charge from Transmission Expansion Plan; (f) Schedule 2 – Reactive Power Service billed by generators in Vectren South's Control Area; and (g) Costs, including Real Time Revenue Neutrality Uplift Amount, Real Time Miscellaneous Amount, and Real Time Uninstructed Deviation Amount, that are not otherwise recovered by MISO through other charges and are socialized for recovery from all market participants including Vectren South. The base level of charges reflected in revenue requirements in this proceeding is \$5,882,956; therefore, 25% of \$5,882,956 (or \$1,470,739) will be subtracted from the MISO charges for the 3-month period. A breakdown of the base level of MISO charges is shown in Petitioner's Exhibit No. WSS-5.

Q. ARE THE COSTS TO BE RECOVERED THROUGH THE MCC COMPONENT LIKELY TO CHANGE OVER TIME?

A. Yes. All of the MISO schedules are subject to change over time. MISO Schedules 10, 16, and 17 are subject to change because of new or additional services provided by MISO or required by the FERC; because of additional payments to other transmission operators; because of changes in MISO's expenses for any reason; and because of changes in the load, amount of generation or the membership of MISO. Schedule 24 socializes balancing authority costs over the entire MISO footprint and can change because of additional costs incurred by other transmission owners which are completely outside of Vectren South's control. Currently, there are no charges under Schedule 26; however, beginning in 2007, charges will likely be included in Schedule 26, reflecting the allocation of costs under Attachment GG based on differences between the MTEP 2005 and the MTEP 2006 identified using the procedure described in Attachment FF of the TEMT.

Q. WHAT COST WOULD BE RECOVERED THROUGH THE MISO TRANSMISSION COMPONENT (MTC)?

A. The MTC component would provide for the recovery of incremental transmission costs identified in MISO's FERC-approved Attachment O formula rate for Vectren South. The purpose of the MTC component is to provide a mechanism for the recovery of incremental (or decremental) transmission costs above (or below) the amount to be reflected in base rates in this proceeding. The MTC component would be calculated quarterly by comparing the transmission revenue and cost components from Vectren South's Attachment O filings with the FERC to 25 % of the corresponding levels of these components reflected in base rates. Specifically, the MTC component would provide for recovery or refund of the following components of revenue requirements: (i) the incremental operating expenses identified in future Attachment O calculations less the transmission operating expenses included in revenue requirements in Vectren South's current rate case, (ii) the return and associated income taxes on the difference between the transmission net investment included in future Attachment O calculations and the transmission net investment included in the current rate case, and (iii) the difference between the transmission-related revenues from future Attachment O calculations and the transmission-related revenues included in revenue requirements in the current rate case.

Q. PLEASE EXPLAIN HOW INCREMENTAL OR DECREMENTAL OPERATING EXPENSES WILL BE CALCULATED.

A. The incremental or decremental operating expenses will be calculated by subtracting the transmission operating expenses included in Vectren South's revenue requirements in the current base rate proceeding from the operating expenses determined from future Attachment O filings. Attachment O is recalculated by MISO in May of each year based on the previous calendar year's FERC Form 1 data for each transmission owning member. The new Attachment O becomes effective on June 1 of each year. The transmission operating expenses included in test-year operating results in this proceeding will then be subtracted from the operating expenses determined from the Attachment O for the year that is calculated by MISO.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE CALCULATION OF TRANSMISSION OPERATING EXPENSES INCLUDED IN TEST YEAR REVENUE REQUIREMENTS IN THIS PROCEEDING?

A. Yes. Test-year transmission operating expenses are shown on page 1 of Petitioner's Exhibit No. WSS-6. Joint costs, such as A&G expenses, common operation and maintenance expenses, general plant depreciation, and common plant depreciation, are functionally assigned using the same allocation methodology as used in Attachment O. The transmission operating expenses for the test year are $11,653,602, which includes transmission operations and maintenance expenses, depreciation expenses, and taxes other than income taxes.

Q. PLEASE EXPLAIN HOW THE INCREMENTAL OR DECREMENTAL RETURN COMPONENT WILL BE CALCULATED.

A. The incremental or decremental return component will be calculated by subtracting transmission rate base at the end of the test year in the current proceeding from the transmission net investment (which includes net plant in service *less* the adjustments to rate base prescribed by the FERC formula rate) determined from future Attachment O filings. The rate of return authorized by the FERC will then be applied to this difference, grossed up for income taxes. In other words, the return component will be calculated by applying the rate of return authorized by the FERC, grossed up for income taxes, to the increase or decrease in rate base shown in future Attachment O filings. In determining transmission net investment, the rate base adjustments prescribed by the FERC formula rate (accumulated deferred income taxes) are subtracted from transmission plant in service, which is an alternative methodology for reflecting these adjustments as components of "cost-free capital" in a utility's capital structure. It should be emphasized that Vectren South is only proposing to collect (or provide) the FERC approved rate of return on *incremental* changes in net transmission investment and not on its *entire* net transmission investment.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE CALCULATION OF TRANSMISSION NET INVESTMENT AS OF THE END OF THE TEST YEAR IN THIS PROCEEDING?

A. Yes. Transmission net investment as of March 31, 2006, is shown on page 2 of Petitioner's Exhibit No. WSS-6. Again, joint costs, such as common plant and general plant, are functionally assigned using the same allocation methodology as used in Attachment O. The transmission net investment projected as of the expected rate base cut off date was $229,998,667.

Q. WHY IS IT APPROPRIATE FOR VECTREN TO COLLECT THE RATE OF RETURN AUTHORIZED BY THE FERC ON INCREMENTAL TRANSMISSION INVESTMENT RATHER THAN THE RATE OF RETURN AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. In its Order in Docket No. ER02-2458-000 dated March 5, 2004, the FERC found that a 12.38% return on equity, which was the proxy group's ROE midpoint, should be used by all participating transmission owners of MISO in calculating the appropriate return element in Attachment O. In that proceeding, the FERC authorized a return on equity for transmission owners that have joined MISO that it found to be sufficient to encourage the coordination of transmission operations and planning and to encourage utilities to make investments in transmission plant. From 1975 to 1998 there was a clearly evident trend showing a decline in transmission investments by integrated and stand-alone transmission companies. According to the *EEI Survey of Transmission Investment* published by the Edison

Electric Institute in May 2005, the investment in transmission plant by transmission owners had decreased from around $5,000 billion to approximately $2,200 billion in real dollars, in spite of the fact that the amount of power being traded in the market had increased significantly during this period. In the FERC's view, transmission planning had become "balkanized," with individual integrated utilities and standalone transmission companies planning their own transmission system upgrades without considering the need for the additional transmission capacity necessary to handle the increased parallel flows created by the increased amount of power being traded in the market.

The Energy Policy Act of 2005 also addressed the issue of encouraging transmission investments. Section 1241 of the Energy Policy Act of 2005 amended the Federal Power Act by adding a new section directing the FERC to establish a rule to promote "capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities" and to "provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies)." In response to this directive, on November 18, 2005, the FERC issued a Notice of Proposed Rulemaking in Docket No. RM06-4-000 for *Promoting Transmission Investment through Pricing Reform*. On July 20, 2006, the FERC issued its Final Rule in that proceeding to bolster investment in the country's aging transmission system and to promote electric power reliability. In connection with the FERC Rule, Chairman Joseph T. Kelliher stated that, "There has been a sustained period of underinvestment in the transmission system. Notwithstanding, use of the nation's grid has more than doubled in recent years. It is clear that we need to strengthen the system to meet consumer demand and today's rule takes a significant turn in that direction." Statement of Chairman Joseph T. Kelliher, July 20, 2006.

The public policy challenge that we face is how can the objectives that are clearly articulated in the Energy Policy Act of 2005 and by the FERC of encouraging new investment in transmission facilities be accomplished unless state regulatory commissions – who have regulatory jurisdiction over retail rates and thus have jurisdiction over the recovery of costs associated with much of the transmission investment in the U.S. – allow the returns on transmission investment that are authorized by the FERC to be carried forward into the cost of service to retail customers. In the case of Vectren South, which has very little load that sinks in its control area other than retail load, the rate of return authorized by the FERC is basically meaningless and can provide no incentive unless the Commission allows that return to be included in retail revenue requirements on incremental transmission investments.

In its proposed MISO Cost and Revenue Adjustment, and in future rate case filings, Vectren South is asking the Commission to allow it to use the MISO rate of return, which is currently 12.38% for incremental investment in transmission plant made after the expected rate base cut off date in the current proceeding. This would be consistent from a public policy perspective with the goal articulated in the Energy Policy Act of 2005 of providing an incentive rate of return on transmission investment.

While FERC has been highly vocal on this issue, the Indiana Legislature has voiced similar support for necessary transmission investment. In Indiana Code 8-1-8.8-1, the Legislature explicitly stated that it supports enhancement of Indiana's energy security and reliability, including ensuring that the "electric transmission system within Indiana is upgraded to distribute additional amounts of electricity more efficiently."

Q. PLEASE EXPLAIN HOW THE INCREMENTAL OR DECREMENTAL TRANSMISSION REVENUE COMPONENT WILL BE CALCULATED.

A. The incremental or decremental revenue will be calculated by subtracting the transmission revenues included in Vectren South's revenue requirements in the current proceeding from the transmission revenues shown on page 4, line 35 of future Attachment O filings.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE CALCULATION OF TRANSMISSION REVENUE INCLUDED IN TEST YEAR REVENUE REQUIREMENTS IN THIS PROCEEDING?

A. Yes. Test-year transmission revenues are shown on page 1 of Petitioner's Exhibit No. WSS-6. The transmission revenues during the test year were $4,361,245. This amount includes both the revenue credits of $3,193,974 which would be identified in the Attachment O calculations filed with the FERC and the transmission revenues of $1,167,271 from municipal customer's within Vectren South's control area taking transmission service under the MISO TEMT.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE FORM OF THE FILING SCHEDULES THAT VECTREN PROPOSES TO SUBMIT IN CONJUNCTION WITH QUARTERLY FILINGS OF THE MCRA?

A. Yes. Vectren South's proposed filing schedules are included in Petitioner's Exhibit No. WSS-7. Although the figures shown in these pro-forma filing schedules are purely hypothetical, they serve to illustrate how the components of the MCRA will be calculated.

Q. ARE THE INCREMENTAL COSTS RECOVERD THROUGH THE MTC COMPONENT OUTSIDE OF VECTREN'S CONTROL?

A. Yes. As a member of MISO, Vectren South is ultimately not responsible for transmission planning. While Vectren South certainly assists in the effort, MISO has ultimate responsibility for transmission planning in the MISO footprint. Each year MISO prepares an MTEP detailing the upgrades needed for the system. The Planning Subcommittee and, to a lesser degree, the Reliability Subcommittee of MISO have responsibility for the transmission planning process. The mission statement for the Planning Subcommittee is as follows:

> The Planning Subcommittee (PS) draws upon the collective knowledge of its Transmission Owner and Transmission Customer participants to advise, guide, and provide recommendations to MISO staff with the goal to better enable MISO to execute its planning responsibilities, in an efficient and timely manner, as set forth in the MISO Tariff, MISO/Transmission Owner Agreement, FERC Order 2000 and other applicable documents. Reporting to the Planning Subcommittee are the MISO Expansion Plan Working Group and the MISO Model Building Working Group.

Each year, consistent with FERC directives, MISO is exercising greater control over the transmission planning function. Although Vectren South will continue to play a significant role in the planning process, particularly in an advisory capacity, it is MISO that has ultimate responsibility in this area.

Q. ARE THE INCREMENTAL COSTS TO BE RECOVERED THROUGH THE MTC VARIABLE IN AMOUNT FROM YEAR TO YEAR, VARIABLE AS TO TIMING, AND SUBSTANTIAL IN INDIVIDUAL AND AGGREGATE AMOUNTS?

A. Yes, they are. In its MTEP 2005, MISO determined that Vectren South and International Transmission Company did not have enough import capability to satisfy MISO's reliability criteria. (MTEP 2005, page 131.) Nothing within Vectren South's control area has fundamentally changed the need for import capacity. What is driving the need for additional capacity is not the result of growth in Vectren South's control area, which is relatively modest, but the presence of parallel flows created from the increased level of traffic in the wholesale power market. The transmission investment and associated revenue requirements necessary to increase Vectren South's import capability will be substantial. Vectren Witness Chambliss describes the proposed projects, in the near term to address this issue. The plan, once it is finalized, will take several years to complete and will thus be variable in amount from year to year and variable as to timing, since MISO has not approved the final plans for the MTEP.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT THE COMMISSION SHOULD APPROVE VECTREN SOUTH'S PROPOSED MISO COST AND REVENUE ADJUSTMENT.

A. The criteria used in Cause No. 42359 to evaluate the reasonableness of PSI's Standard Contract Rider No. 68 were:

(1) Were the costs the result of decisions by the FERC?
(2) Were the costs variable in amount from year to year?
(3) Were the costs variable as to timing?
(4) Were the costs substantial in individual and aggregate amounts?
(5) Were the costs outside the control of PSI?

As discussed above, the costs that would be recovered through the MISO Cost and Revenue Adjustment meet all five of these criteria. Both the MCC and MTC that would be recovered through Vectren South's proposed MISO Cost and Revenue Adjustment are the result of decisions by MISO which have been or will be approved by the FERC, variable in amount from year to year, variable as to timing, substantial in individual and aggregate amounts, and outside the control of PSI. Furthermore, the costs incurred by Vectren as a result of its participation in MISO are just, reasonable, necessary, and in the public interest. Without the MISO Cost and Revenue Adjustment, the changes in these costs would not be offset by a corresponding change in the revenues collected by Vectren South.

Moreover, there are broader public policy issues at stake with the MISO Cost and Revenue Adjustment. As a public policy matter, membership in MISO should continue to be encouraged and Vectren South should be provided an opportunity for the timely recovery of the costs related to its membership in MISO. In addition, Vectren South and other MISO members should be encouraged to invest capital in upgrading the transmission system to accommodate a more competitive power market while maintaining system reliability. Allowing Vectren South to recover its incremental transmission costs and earn the rate of return authorized by the FERC on the incremental transmission investments would serve to further the goal of creating an efficient power market.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

WILLIAM STEVEN SEELYE

Summary of Qualifications

Bachelor of Science degree in Mathematics; completed 54 hours of graduate level course work in Industrial Engineering and Physics. Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting and educational services in areas of utility marketing, regulatory analysis, revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Prepared and filed Order No. 888 and 889 compliance filings at the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities. Prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Various Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education
Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Testified in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment. Testified in Case No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Testified in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Testified in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies and rate design.

Kansas: Testifed in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings. Testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates. Testified in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan and in Case No. 99-176 concerning cost of service, rate design and expense adjustments in connection with Delta's rate case. In Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses. Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program. Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings. Testified on behalf of Louisville Gas and Electric Company in Case No. 2003-00433 and on behalf of Kentucky Utilities Company in Case No. 2003-00434 regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design. Testified on behalf of Delta Natural Gas Company in Case No. 2004-00067 regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design. Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Nevada: Testified on behalf of Nevada Power Company in Case No. 03-10001 regarding cash working capital and rate base adjustments. Testified on behalf of Sierra Pacific Power Company in Case No. 03-12002 regarding cash working capital. Testified on behalf of Sierra Pacific Power Company in Case No. 05-10003 regarding cash working capital for an electric general rate case. Testified on behalf of Sierra Pacific Power Company in Case No. 05-10005 regarding cash working capital for a gas general rate case.

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

First Revised Sheet No. 1318

Attachment O
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

VECTREN

Line No.			Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 29)					$ 17,452,941
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34)	0	TP	0.95855	0
3	Account No. 456	(page 4, line 37)	1,939,319	TP	0.95855	1,858,931
4	Revenues from Grandfathered Interzonal Transactions		0	TP	0.95855	0
5	Revenues from service provided by the ISO at a discount		0	TP	0.95855	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					1,858,931
7	NET REVENUE REQUIREMENT (line 1 minus line 6)					$ 15,594,010
	DIVISOR					
8	Average of 12 coincident system peaks for requirements (RQ) service				(Note A)	1,028,167
9	Plus 12 CP of firm bundled sales over one year not in line 8				(Note B)	0
10	Plus 12 CP of Network Load not in line 8				(Note C)	0
11	Less 12 CP of firm P-T-P over one year (enter negative)				(Note D)	0
12	Plus Contract Demand of firm P-T-P over one year					0
13	Less Contract Demand from Grandfathered Interzonal Transactions over one year (enter negative) (Note S)					0
14	Less Contract Demands from service over one year provided by ISO at a discount (enter negative)					0
15	Divisor (sum lines 8-14)					1,028,167
16	Annual Cost ($/kW/Yr)	(line 7 / line 15)	15.167			
17	Network & P-to-P Rate ($/kW/Mo)	(line 16 / 12)	1.264			

Line No.			Peak Rate		Off-Peak Rate	
18	Point-To-Point Rate ($/kW/Wk)	(line 16 / 52; line 16 / 52)	0.292		$0.292	
19	Point-To-Point Rate ($/kW/Day)	(line 18 / 5; line 18 / 7)	0.058	Capped at weekly rate	$0.042	
20	Point-To-Point Rate ($/MWh)	(line 19 / 16; line 19 / 24 times 1,000)	3.646	Capped at weekly and daily rates	$1.736	
21	FERC Annual Charge($/MWh)	(Note E)	$0.000	Short Term	$0.000	Short Term
22			$0.000	Long Term	$0.000	Long Term

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

VECTREN

Line No.	(1) RATE BASE:	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	207.46.g	1,099,872,904	NA		
2	Transmission	207.58.g	155,181,243	TP	0.95855	148,748,730
3	Distribution	207.75.g	331,278,404	NA		
4	General & Intangible	205.5.g & 207.90.g	21,090,534	W/S	0.04875	1,028,260
5	Common	356.1	40,665,670	CE	0.04284	1,742,034
6	TOTAL GROSS PLANT (sum lines 1-5)		1,648,088,755	GP=	9.194%	151,519,025
	ACCUMULATED DEPRECIATION					
7	Production	219.20-24.c	526,135,897	NA		
8	Transmission	219.25.c	74,895,120	TP	0.95855	71,790,597
9	Distribution	219.26.c	139,988,721	NA		
10	General & Intangible	219.27.c	12,650,306	W/S	0.04875	616,761
11	Common	356.1	17,542,081	CE	0.04284	751,467
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		771,212,125			73,158,824
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	573,737,007			
14	Transmission	(line 2- line 8)	80,286,123			76,958,134
15	Distribution	(line 3 - line 9)	191,289,683			
16	General & Intangible	(line 4 - line 10)	8,440,228			411,500
17	Common	(line 5 - line 11)	23,123,589			990,567
18	TOTAL NET PLANT (sum lines 13-17)		876,876,630	NP=	8.936%	78,360,201
	ADJUSTMENTS TO RATE BASE	(Note F)				
19	Account No. 281 (enter negative)	273.8.k	0	NA	zero	0
20	Account No. 282 (enter negative)	275.2.k	-133,840,488	NP	0.08936	-11,960,368
21	Account No. 283 (enter negative)	277.9.k	-19,508,587	NP	0.08936	-1,743,343
22	Account No. 190	234.8.c	27,381,618	NP	0.08936	2,446,900
23	Account No. 255 (enter negative)	267.8.h	-8,659,747	NP	0.08936	-773,860
24	TOTAL ADJUSTMENTS (sum lines 19- 23)		-134,627,204			-12,030,672
25	LAND HELD FOR FUTURE USE	214.x.d (Note G)	1,131,167	TP	0.95855	1,084,278
	WORKING CAPITAL (Note H)					
26	CWC	calculated	3,983,418			319,978
27	Materials & Supplies (Note G)	227.8.c & .15.c	4,493,354	TE	0.44348	1,992,729
28	Prepayments (Account 165)	111.57.c	1,411,074	GP	0.09194	129,729
29	TOTAL WORKING CAPITAL (sum lines 26 - 28)		9,887,846			2,442,436
30	RATE BASE (sum lines 18, 24, 25, & 29)		753,268,438			69,856,243

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

VECTREN

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.100.b	2,548,944	TE	0.44348	1,130,415
2	Less Account 565	321.88.b	0		1.00000	0
3	A&G	323.168.b	29,684,539	W/S	0.04875	1,447,258
4	Less FERC Annual Fees		0	W/S	0.04875	0
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		366,142	W/S	0.04875	17,851
5a	Plus Transmission Related Reg. Comm. Exp. (Note I)		0	TE	0.44348	0
6	Common	356.1	0	CE	0.04284	0
7	Transmission Lease Payments		0		1.00000	0
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)		31,867,341			2,559,822
	DEPRECIATION EXPENSE					
9	Transmission	336.7.b	3,887,176	TP	0.95855	3,726,046
10	General	336.9.b	677,608	W/S	0.04875	33,037
11	Common	336.10.b	772,353	CE	0.04284	33,086
12	TOTAL DEPRECIATION (Sum lines 9 - 11)		5,337,137			3,792,169
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
13	Payroll	263.i	0	W/S	0.04875	0
14	Highway and vehicle	263.i	0	W/S	0.04875	0
15	PLANT RELATED					
16	Property	263.i	6,979,584	GP	0.09194	641,676
17	Gross Receipts	263.i	4,887,326	NA	zero	0
18	Other	263.i	44	GP	0.09194	4
19	Payments in lieu of taxes		0	GP	0.09194	0
20	TOTAL OTHER TAXES (sum lines 13 - 19)		11,866,954			641,681
	INCOME TAXES	(Note K)				
21	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.53%			
22	CIT=(T/1-T) * (1-(WCLTD/R)) =		47.92%			
	where WCLTD=(page 4, line 27) and R= (page 4, line30) and FIT, SIT & p are as given in footnote K.					
23	1 / (1 - T) = (from line 21)		1.6814			
24	Amortized Investment Tax Credit (266.8f) (enter negative)		-1,117,560			
25	Income Tax Calculation = line 22 * line 28		37,124,437	NA		3,442,828
26	ITC adjustment (line 23 * line 24)		-1,879,025	NP	0.08936	-167,915
27	Total Income Taxes	(line 25 plus line 26)	35,245,412			3,274,913
28	RETURN [Rate Base (page 2, line 30) * Rate of Return (page 4, line 30)]		77,469,803	NA		7,184,357
29	REV. REQUIREMENT (sum lines 8, 12, 20, 27, 28)		161,786,647			17,452,941

Midwest ISO
FERC Electric Tariff, Third Revised Volume No. 1

Third Revised Sheet No. 1321

Attachment O
page 4 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

VECTREN
SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN ISO RATES		
1	Total transmission plant (page 2, line 2, column 3)		155,181,243
2	Less transmission plant excluded from ISO rates (Note M)		0
3	Less transmission plant included in OATT Ancillary Services (Note N)		6,432,513
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)		148,748,730
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)	TP=	0.95855
	TRANSMISSION EXPENSES		
6	Total transmission expenses (page 3, line 1, column 3)		2,548,944
7	Less transmission expenses included in OATT Ancillary Services (Note L)		1,369,645
8	Included transmission expenses (line 6 less line 7)		1,179,299
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.46266
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.95855
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.44348

WAGES & SALARY ALLOCATOR (W&S)

Line No.		Form 1 Reference	$	TP	Allocation		W&S Allocator ($ / Allocation)	
12	Production	354.18.b	13,076,653	0.00	0			
13	Transmission	354.19.b	963,477	0.96	923,539			
14	Distribution	354.20.b	3,437,720	0.00	0			
15	Other	354.21,22,23.b	1,464,862	0.00	0			
16	Total (sum lines 12-15)		18,942,612		923,539	=	0.04875	= WS

COMMON PLANT ALLOCATOR (CE) (Note O)

Line No.			$	% Electric (line 17 / line 20)		W&S Allocator (line 16)		CE
17	Electric	200.3.c	1,245,277,903					
18	Gas	201.3.d	171,993,738	0.87864	*	0.04875	=	0.04284
19	Water	201.3.e	0					
20	Total (sum lines 17 - 19)		1,417,271,641					

RETURN (R)

Line No.			$
21	Long Term Interest (117, sum of 62.c through 67.c)		$27,657,465
22	Preferred Dividends (118.29c) (positive number)		$ 3,956
	Development of Common Stock:		
23	Proprietary Capital (112.16.c)		529,552,293
24	Less Preferred Stock (line 28)		0
25	Less Account 216.1 (112.12.c) (enter negative)		0
26	Common Stock	(sum lines 23-25)	529,552,293

Line No.		$	%	Cost (Note P)	Weighted	
27	Long Term Debt (112, sum of 18.c through 21.c)	376,822,802	42%	0.0734	0.0305	=WCLTD
28	Preferred Stock (112.3.c)	0	0%	0.0000	0.0000	
29	Common Stock (line 26)	529,552,293	58%	0.1238	0.0723	
30	Total (sum lines 27-29)	906,375,095			0.1028	=R

REVENUE CREDITS

Line No.				Load
	ACCOUNT 447 (SALES FOR RESALE)	(310-311)	(Note Q)	
31	a. Bundled Non-RQ Sales for Resale (311.x.h)			73,420
32	b. Bundled Sales for Resale included in Divisor on page 1			73,420
33	Total of (a)-(b)			0
34	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			$0
	ACCOUNT 456 (OTHER ELECTRIC REVENUES) (Note U) (330.x.n)			
35	a. Transmission charges for all transmission transactions			$3,122,930
36	b. Transmission charges for all transmission transactions included in Divisor on Page 1			$1,183,611
37	Total of (a)-(b)			$1,939,319

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/05

VECTREN

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Peak as would be reported on page 401, column d of Form 1 at the time of the ISO coincident monthly peaks.
B	Labeled LF, LU, IF, IU on pages 310-311 of Form 1at the time of the ISO coincident monthly peaks.
C	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
D	Labeled LF on page 328 of Form 1 at the time of the ISO coincident monthly peaks.
E	The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff.
F	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111 line 57 in the Form 1.
I	Line 5 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26).

Inputs Required:	FIT =	35.00%	
	SIT=	8.50%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = long-term interest (line 21) / long term debt (line 27). Preferred cost rate = preferred dividends (line 22) / preferred outstanding (line 28). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.
T	The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.
U	Account 456 entry shall be the annual total of the quarterly values reported at Form 1, 330.x.n.

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT

APPLICABILITY

The MISO Cost and Revenue Adjustment (MCRA) shall be applicable to all Rate Schedules as reflected in the MCRA Rates section below.

DESCRIPTION

The MCRA shall be calculated quarterly for each Rate Schedule as follows:

$$MCRA = \frac{[(MCC + MTC)\ x\ Rate\ Schedule\ Allocation\ Percentages}{Rate\ Schedule\ Sales\ Quantities}$$

Where:

MCC is the MISO Charges Component described below.

MTC is the MISO Transmission Component described below.

Rate Schedule Allocation Percentage is the proportion of the annual MTC amount applicable to each Rate Schedule. The percentage for each Rate Schedule is shown in the MCRA Rate section below.

Rate Schedule Quantities are the quarterly estimated quantities of Energy Sales for each Rate Schedule.

The calculated MCRA shall be further modified to allow the recovery of the Indiana Utility Receipts Tax and other similar revenue-based tax charges.

The actual MCRA amounts passed back to or recovered from customers for each quarter shall be reconciled with MCRA amounts intended for pass back to or recovery from customers for such quarter, with any variance reflected in a subsequent MCRA quarterly filing.

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT
(Continued)

where:

MISO CHARGES COMPONENT (MCC)

The MISO Charges Component shall be calculated quarterly for each Rate Schedule as follows:

$$MCC = MISO\ Charges - 25\%\ of\ Base\ Rate\ Amount$$

MISO Charges is the estimated quarterly amount of the recoverable MISO costs, as billed to Company, calculated as follows:

(a) Schedule 10 – ISO Cost Recovery Adder and Schedule 10-FERC – FERC Annual Charges Recovery, or successor provisions, of the Midwest OATT, or successor tariff for the MISO; plus

(b) Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder, or a successor provision, of the MISO OATT, or any successor tariff for the MISO; plus

(c) Schedule 17 - Energy Market Support Cost Recovery Adder, or a successor provision of the MISO OATT, or any successor tariff for the MISO;

(d) Schedule 24 – Control Area Operator Cost Recovery, or a successor provision of the MISO OATT, or any successor tariff for the MISO;

(e) Schedule 26 – Network Upgrade Charge from Transmission Expansion Plan;

(f) Schedule 2 – Reactive Power costs charged by independent generators in Vectren's control area; plus

(g) Costs that are not otherwise recovered by MISO through other charges and are socialized for recovery from all market participants including Company ("uplift costs"), including the Real Time Revenue Neutrality Uplift Amount, Real Time Miscellaneous Amount, and Real Time Uninstructed Deviation Amount billed by MISO.

25% of Base Rate Amount is one-fourth of the base rate amount of $5,882,956 included in base rates for the MISO Charges.

Effective:

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT
(Continued)

MISO TRANSMISSION COMPONENT (MTC)

The MISO Charges Component shall be calculated annually for each Rate Schedule as follows:

$$MTC = (MISOOE + MISORET - MISOREV)\ x\ 25\%$$

where:

MISOOE is the operating expenses from the most recent MISO Attachment O calculation for Company less the corresponding transmission operating expenses of $11,653,602 from Company's last rate case.

MISORET is the product of (a) the transmission net investment less transmission rate base adjustments from the most recent MISO Attachment O calculation for Company less the corresponding transmission net investment of $229,998,667 from Company's last rate case, and (b) the rate of return from the most recent MISO Attachment O calculation for Company grossed-up for income taxes.

MISOREV is the transmission revenue credits from the most recent MISO Attachment O calculation for Company less the corresponding transmission revenue credits of $3,193,974 from Company's last rate case, plus the transmission revenues received from the application of MISO's transmission rates to wholesale loads that sink within Company's control area less the corresponding transmission revenues of $1,167,271 from Company's last rate case.

Effective:

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT
(Continued)

MCRA RATES

Rate Schedule	Allocation Percentage	MCRA Rate ($ per KWh)
A	24.7261%	$0.0000
EH	10.0642%	$0.0000
B	0.2462%	$0.0000
SGS	0.8508%	$0.0000
DGS	26.4253%	$0.0000
OSS	2.2867%	$0.0000
LP	20.5950%	$0.0000
HLF	14.7020%	$0.0000
SL	0.0580%	$0.0000
OL	0.0457%	$0.0000
	100.0000%	

Vectren South

MISO Charges for the 12 Months Ended March 31, 2006

Schedule		Test-Year Amount
Sched 10 Market Admin	$	1,012,802.20
Sched 10 FERC	$	576,745.94
Sched 17 DA Market Admin		878,738.57
Sched 17 RT Market Admin		90,305.98
Sched 16 FTR Market Admin		168,897.99
RT Revenue Neutrality Uplift		3,276,762.41
RT Misc. Amount		25,987.01
Total	$	6,030,240.10
1/4 of Total	$	1,507,560.03

VECTREN SOUTH
Transmission Operating Expenses and Revenue Credits

12 Months Ended March 31, 2006

Line No.	Description	Actual Per Books	Adjustments	7-Factor Reclassification	Total	Allocator		Transmission
	O&M							
1	Transmission	$ 2,485,608	$ 4,104,884		$ 6,590,492	TE	0.76547	$ 5,044,807
2	Less Account 565							-
3	A&G	28,951,655	4,924,172		33,875,827	W/S	0.04994	1,691,716
4	Less FERC Annual Fees					W/S	0.04994	-
5	Less EPRI & Reg. Comm. Exp. & Non-safety Ad.	380,245			380,245	W/S	0.04994	18,989
5a	Plus Transmission Related Reg. Comm. Exp.					TE	0.76547	-
6	Common					CE	0.04391	-
7	Transmission Lease Payments							
8	TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 2, 4, 5)	$ 31,057,018	$ 9,029,056	$ -	$ 40,086,074			$ 6,717,534
	DEPRECIATION EXPENSE							
9	Transmission	$ 4,174,274			$ 4,174,274	TP	0.96317	$ 4,020,524
10	General	978,256			978,256	W/S	0.04994	48,853
11	Common	1,383,939			1,383,939	CE	0.04391	60,767
12	TOTAL DEPRECIATION (Sum lines 9 - 11)	$ 6,536,469	$ -	$ -	$ 6,536,469			$ 4,130,144
	TAXES OTHER THAN INCOME TAXES							
	LABOR RELATED							
13	Payroll							
14	Highway and vehicle							
15	PLANT RELATED							
16	Property	$ 7,240,584	$ 933,537		$ 8,174,121	GP	0.09859	$ 805,921
17	Other	35			35	GP	0.09859	3
18	TOTAL OTHER TAXES (sum lines 13 - 17)	$ 7,240,619	$ 933,537	$ -	$ 8,174,156			$ 805,925
19	Total Transmission Operating Expenses							$ 11,653,602
	ACCOUNT 456 (OTHER ELECTRIC REVENUES)							
20	All transmission transactions	$ 4,528,024			$ 4,528,024		0.96317	$ 4,361,245
21	Transmission transactions billed by MISO under Attachment O	$ 1,211,909			1,211,909		0.96317	$ 1,167,271
22	Revenue Credit Amount for Attachment O (line 19 less line 20)	$ 3,316,115			$ 3,316,115	TP	0.96317	$ 3,193,974

VECTREN SOUTH
Transmission Net Plant and Deferred Income Taxes

As of March 31, 2006

Line No.	Description	Actual Per Books	Adjustments	7-Factor Reclassification	Total	Allocator		Transmission
	GROSS PLANT IN SERVICE							
1	Production	$ 1,107,717,279	$ 49,000,000		$ 1,156,717,279	NA		$ -
2	Transmission	157,664,009	16,977,000		174,641,009	TP	0.96317	168,208,496
3	Distribution	341,418,139			341,418,139	NA		-
4	General & Intangible	17,081,151			17,081,151	W/S	0.04994	853,011
5	Common	44,825,254			44,825,254	CE	0.04391	1,968,210
6	TOTAL GROSS PLANT (sum lines 1-5)	$ 1,668,705,831	$ 65,977,000	$ -	$ 1,734,682,831	GP=	0.09859	$ 171,029,717
	ACCUMULATED DEPRECIATION							
7	Production	$ (536,879,538)			$ (536,879,538)	NA		$ -
8	Transmission	(73,373,433)			(73,373,433)	TP	0.96317	(70,670,886)
9	Distribution	(145,681,811)			(145,681,811)	NA		-
10	General & Intangible	(9,366,946)			(9,366,946)	W/S	0.04994	(467,773)
11	Common	(18,744,226)			(18,744,226)	CE	0.04391	(823,031)
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)	$ (784,045,954)	$ -	$ -	$ (784,045,954)			$ (71,961,690)
	NET PLANT IN SERVICE							
13	Production	$ 1,644,596,817	$ 49,000,000	$ -	$ 1,693,596,817			$ -
14	Transmission	231,037,442	16,977,000	-	248,014,442			238,879,382
15	Distribution	487,099,950	-	-	487,099,950			-
16	General & Intangible	26,448,097	-	-	26,448,097			1,320,784
17	Common	63,569,480	-	-	63,569,480			2,791,241
18	TOTAL NET PLANT (sum lines 13-17)	$ 2,452,751,786	$ 65,977,000	$ -	$ 2,518,728,786	NP=	0.09647	$ 242,991,407
	ADJUSTMENTS TO RATE BASE							
19	Account No. 281	$ -			$ -	NA		$ -
20	Account No. 282	(137,645,902)			(137,645,902)	NP	0.09647	(13,279,227)
21	Account No. 283	(16,466,359)			(16,466,359)	NP	0.09647	(1,588,573)
22	Account No. 190	28,095,689			28,095,689	NP	0.09647	2,710,499
23	Account No. 255	(8,659,747)			(8,659,747)	NP	0.09647	(835,439)
24	TOTAL ADJUSTMENTS (sum lines 19- 23)	$ (134,676,319)			$ (134,676,319)			$ (12,992,740)
25	Plant in Service Net of Deferred Income Taxes							$ 229,998,667

VECTREN SOUTH
Transmission Cost Allocation Factors

For the 12 Months Ended March 31, 2006

Line	Description		$	TP	Allocation				
	TRANSMISSION PLANT ALLOCATOR (TP)								
1	Total transmission plant		$ 174,641,009						
2	Less transmission plant included in OATT Ancillary Services		6,432,513						
3	Transmission plant included in ISO rates		168,208,496						
4	Percentage of transmission plant included in ISO Rates (line 3 divided by line 1)	TP=	0.96317						
	TRANSMISSION EXPENSES ALLOCATOR (TE)								
6	Total transmission expenses		6,590,492						
7	Less transmission expenses included in OATT Ancillary Services		1,352,765						
8	Included transmission expenses (line 6 less line 7)		5,237,727						
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)		0.79474						
10	Percentage of transmission plant included in ISO Rates (line 5)	TP	0.96317						
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)	TE=	0.76547						
	WAGES & SALARY ALLOCATOR (W&S)		$	TP	Allocation				
12	Production		$ 19,459,170	0.0000	0				
13	Transmission		1,514,251	0.9632	1,458,477				
14	Distribution		5,762,163	0.0000	0		W&S Allocator		
15	Other		2,469,752	0.0000	0		($ / Allocation)		
16	Total (sum lines 12-15)		29,205,336		1,458,477	=	0.04994	=	WS
	COMMON PLANT ALLOCATOR (CE)		$						
17	Electric		1,288,574,106		% Electric		W&S Allocator		CE
18	Gas		176,967,759		0.87925	*	0.04994	=	0.04391
19	Water		0						
20	Total (sum lines 17 - 19)		1,465,541,865						

VECTREN SOUTH
Rate of Return Authorized by the FERC
Grossed Up for Income Taxes

Line No.	Description	Grossed-Up ROR
1	Rate of Return Authorized by the FERC (Attachment O, Page 4, line 30)	10.28%
2	Income Tax Gross-up Factor (Attachment O, Page 3, line 22)	47.92%
3	Rate of Return Authorized by the FERC Grossed Up for Income Taxes (Line 1 x 2)	15.21%

Schedule 1
(Pro forma)

VECTREN SOUTH
Determination of MCRA
For Month A, Month B and Month C

Line No.	Estimated Retail Sales (kWh)	Total	Rate A	Rate EH	Rate B	Rate SGS	Rate DGS	Rate OSS	Rate LP	Rate HLF	Rate OL	Rate SL
1	Month A	486,875,781	90,816,599	24,515,130	894,104	55,234,710	55,234,710	7,839,843	164,564,685	79,776,000	5,000,000	3,000,000
2	Month B	460,846,273	69,849,488	29,359,843	1,013,303	50,409,500	50,409,500	8,451,610	156,137,029	87,216,000	5,000,000	3,000,000
3	Month C	480,097,448	71,573,723	44,289,676	1,126,886	49,937,127	49,937,127	10,892,224	164,564,685	79,776,000	5,000,000	3,000,000
4	Total	1,427,819,502	232,239,810	98,164,649	3,034,293	155,581,337	155,581,337	27,183,677	485,266,399	246,768,000	15,000,000	9,000,000
5	MCRA Allocation Percentages (Sch 2)	100.0000%	24.7261%	10.0642%	0.2462%	0.8508%	26.4253%	2.2867%	20.5950%	14.7020%	0.0457%	0.0580%
6	*Incremental MCRA Amounts* (From Sch 3, Page 2 X Line 5)	$ (279,387)	$ (69,082)	$ (28,118)	$ (688)	$ (2,377)	$ (73,829)	$ (6,389)	$ (57,540)	$ (41,075)	$ (128)	$ (162)
7	Variance (Sum Sch 4, Line 5 X Line 5)	$ 60,402	$ 14,935	$ 6,079	$ 149	$ 514	$ 15,961	$ 1,381	$ 12,440	$ 8,880	$ 28	$ 35
8	MCRA Amount plus Variance *(Line 6 + Line 7)*	$ *(218,985)*	$ *(54,146)*	$ (22,039)	$ (539)	$ (1,863)	$ (57,867)	$ (5,008)	$ (45,100)	$ (32,195)	$ (100)	$ (127)
9	MCRA per kWh Excl. Utility Receipts Tax (L8/L5)	$ (0.000153)	$ (0.000233)	$ (0.000225)	$ (0.000178)	$ (0.000012)	$ (0.000372)	$ (0.000184)	$ (0.000093)	$ (0.000130)	$ (0.000007)	$ (0.000014)
10	MCRA per kWh Incl. Utility Receipts Tax	$ (0.000155)	$ (0.000237)	$ (0.000228)	$ (0.000181)	$ (0.000012)	$ (0.000378)	$ (0.000187)	$ (0.000094)	$ (0.000132)	$ (0.000007)	$ (0.000014)

Petitioner's Exhibit No. WSS-7
Vectren South-Electric
Page 1 of 9

Schedule 2
(Pro forma)

VECTREN SOUTH
MISO Cost and Revenue Adjustment (MCRA)

MCRA Allocation Percentages

Line No.	Rate Schedule		Allocation Percentages Cause No. 43111
1	A	Residential	24.7261%
2	EH	Residential Electric Heating	10.0642%
3	B	Water Heating	0.2462%
4	SGS	Small General Service	0.8508%
5	DGS	Large General Service	26.4253%
6	OSS	Off-Season Service	2.2867%
7	LP	Large Power	20.5950%
8	HLF	Transmission Power	14.7020%
9	OL	Outdoor Lighting	0.0457%
10	SL	Street Lighting	0.0580%
11	**TOTAL**		**100.0000%**

Schedule 3
Page 1 of 3
(Pro forma)

VECTREN SOUTH
MISO Cost and Revenue Adjustment (MCRA)
Determination of MISO Charge Component (MCC)
To Be Recovered or Credited through MCRA

Line No.	Description	Formula Reference (A)	Amount (B)
	Schedule 10-FERC-FERC Assessment Fees for the Months of:		
1	Month 1		$ 40,000
2	Month 2		40,000
3	Month 3		40,000
4	Total Schedule 10-FERC		120,000
	Schedule 10-ISO Cost Recovery Adder Charges for the Months of:		
5	Month 1		130,000
6	Month 2		163,500
7	Month 3		245,000
8	Total Schedule 10		538,500
9	Total Schedule 10 and 10-FERC		658,500
	Schedule 16 - Financial Transmission Rights Administrative Service Cost Recovery Adder Charges for the Months of:		
10	Month 1		13,000
11	Month 2		26,000
12	Month 3		11,000
13	Total Schedule 16		50,000
	Schedule 17- Energy Market Support Administrative Service Cost Recovery Adder Charges for the Months of:		
14	Month 1		82,625
15	Month 2		79,522
16	Month 3		92,000
17	Total Schedule 17		254,147
	Schedule 24- Control Area Operator Cost Recovery Cost Recovery Adder Charges for the Months of:		
18	Month 1		-
19	Month 2		-
20	Month 3		-
21	Total Schedule 24		-
	Schedule 26- Network Upgrade Charge from Transmission Expansion Plan Cost Recovery Adder Charges for the Months of:		
22	Month 1		-
23	Month 2		-
24	Month 3		-
25	Total Schedule 26		-
	Other Midwest ISO Standard Market Design and/or Other Gov't Mandated Costs for the Months of:		
26	Month 1		41,000
27	Month 2		41,000
28	Month 3		41,000
29	Total Other Midwest ISO Costs		123,000
30	Total MISO Charges to be Collected from Customers	Lines 9+13+17+21+25+29	$ 1,085,647
31	25% of Amount Included in Base Rates as Authorized in Cause No. 43111		$ 1,470,739
32	**MISO Charges Component (MCC)**	**Line 30 - 31**	**$ (385,092)**

VECTREN SOUTH
MISO Cost and Revenue Adjustment (MCRA)
Determination of MISO Transmission Component (MTC)
To Be Recovered or Credited through MCRA

Line No.	Description	Formula Reference	Amount
	Tranmission Operating Expenses (MISOOE)	(A)	(B)
1	Tranmission Operating Expenses from Attachment O (Attachment O, page 3, lines 8 + 12 + 20)		$ 11,770,139
	Less:		
2	Transmission Operating Expenses from Most Recent Rate Case		11,653,602
3	MISO Operating Expense Adjustment [Lines 1 - 2]		116,536
	Transmission Return (MISORET)		
4	Transmission Net Plant less Deferred Income Taxes from Attachment O (Attachment O, page 2, lines 18 - 24)		$ 232,298,654
	Less:		
5	Transmission Rate Base from Most Recent Rate Case		229,998,667
6	Difference in Transmission Rate Base		2,299,987
7	Rate of Return from Attachment O, grossed up for income taxes		15.21%
8	MISO Return Adjustment [Lines 6 x 7]		349,896
	Transmission Revenues (MISOREV)		
9	Tranmission Revenue from Attachment O (Attachment O, page 4, line 35)		$ 4,404,857
	Less:		
10	Transmission Revenue from Most Recent Rate Case		4,361,245
11	MISO Revenue Adjustment [Lines 9 - 10]		43,612
12	MISOOE + MISORET - MISOREV [(Lines 3 + 8 - 11)]		422,820
13	**MISO Transmission Component (MTC) [25% x Line 12]**		105,705
14	**MCC + MTC [(Sch 3, Page 1 of 3, Line 32 + Line 13)**		**$ (279,387)**

Schedule 3
Page 3 of 3
(Pro forma)

VECTREN SOUTH
MISO Cost and Revenue Adjustment (MCRA)
Determination of MISO Charge Component (MCC)
To Be Recovered or Credited through MCRA

Line No.	Description	Month 1	Month 2	Month 3	Total
	Other Midwest ISO Standard Market Design Costs and/or Other Gov't Mandated Transmission Costs by Month Category:	(A)	(B)	(C)	(D)=(A)+(B)+(C)
1	Real Time Miscellaneous Amount (RT_MISC)	1,000	1,000	1,000	3,000
2	Real Time Revenue Neutrality Uplift Amount (RT_RNU)	40,000	40,000	40,000	120,000
3	Real Time Uninstructed Deviation Amount (RT_UD)	-	-	-	-
4	Total Other Midwest ISO Costs	**$ 41,000**	**41,000**	**41,000**	**$ 123,000**

VECTREN SOUTH
MISO COST AND REVENUE ADJUSTMENT
Determination of MCRA Variance
Month 1

Line No.		Rate A	EH	B	SGS	DGS	OSS	LP	HLF	TOTAL
1	Total kWh Sales (Actual)	80,356,125	54,476,063	1,460,401	25,353,200	63,900,627	9,570,917	119,658,492	89,199,733	443,975,558
2	Applicable MCRA Rate ($/kWh)									
2a	Including Indiana Utility Receipts Tax	$ 0.000350	$ 0.000050	$ -	$ 0.000535	$ 0.001090	$ 0.000450	$ 0.000630	$ 0.000030	
2b	Excluding Indiana Utility Receipts Tax	$ 0.000345	$ 0.000049	$ -	$ 0.000527	$ 0.001073	$ 0.000443	$ 0.000620	$ 0.000030	
3	MCRA Billed									
3a	Including Indiana Utility Receipts Tax	$ 28,125	$ 2,724	$ -	$ 13,564	$ 69,652	$ 4,307	$ 75,385	$ 2,676	$ 196,433
3b	Excluding Indiana Utility Receipts Tax	$ 27,723	$ 2,669	$ -	$ 13,361	$ 68,565	$ 4,240	$ 74,188	$ 2,676	$ 193,422
4	MCRA Intended to be Billed (Excluding IURT)	$ 20,000	$ 3,000	$ 150	$ 25,000	$ 75,000	$ 9,000	$ 85,000	$ 6,500	$ 223,650
5	Under (Over) Recovery Variance (Line 4 - Line 3b)									$ 30,228

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
Determination of GCRA Variance
Month 2

Line No.		Rate A	EH	B	SGS	DGS	OSS	LP	HLF	TOTAL
1	Total kWh Sales (Actual)	84,373,800	57,199,810	1,533,400	26,620,650	6,709,988	10,048,510	125,640,926	93,660,136	405,787,220
2	Applicable MCRA Rate ($/kWh)									
2a	Including Indiana Utility Receipts Tax	$ 0.000350	$ 0.000050	$ -	$ 0.000535	$ 0.001090	$ 0.000450	$ 0.000630	$ 0.000030	
2b	Excluding Indiana Utility Receipts Tax	$ 0.000345	$ 0.000049	$ -	$ 0.000527	$ 0.001073	$ 0.000443	$ 0.000620	$ 0.000030	
3	MCRA Billed									
3a	Including Indiana Utility Receipts Tax	$ 29,531	$ 2,860	$ -	$ 14,242	$ 7,314	$ 4,522	$ 79,154	$ 2,810	$ 140,433
3b	Excluding Indiana Utility Receipts Tax	$ 29,109	$ 2,803	$ -	$ 14,029	$ 7,200	$ 4,451	$ 77,897	$ 2,810	$ 138,299
4	MCRA Intended to be Billed (Excluding IURT)	$ 24,000	$ 2,900	$ 500	$ 15,000	$ 8,000	$ 5,000	$ 75,000	$ 3,000	$ 133,400
5	Under (Over) Recovery Variance (Line 4 - Line 3b)									$ (4,899)

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
Determination of GCRA Variance
Month 3

Line No.		Rate A	EH	B	SGS	DGS	OSS	LP	HLF	TOTAL
1	Total kWh Sales (Actual)	76,338,239	51,752,201	1,387,813	24,085,351	60,705,497	9,091,553	113,675,198	84,739,832	421,775,684
2	Applicable MCRA Rate ($/kWh)									
2a	Including Indiana Utility Receipts Tax	$ 0.000350	$ 0.000050	$ -	$ 0.000535	$ 0.001090	$ 0.000450	$ 0.000630	$ 0.000030	
2b	Excluding Indiana Utility Receipts Tax	$ 0.000345	$ 0.000049	$ -	$ 0.000527	$ 0.001073	$ 0.000443	$ 0.000620	$ 0.000030	
3	MCRA Billed									
3a	Including Indiana Utility Receipts Tax	$ 26,718	$ 2,588	$ -	$ 12,886	$ 66,169	$ 4,091	$ 71,615	$ 2,542	$ 186,609
3b	Excluding Indiana Utility Receipts Tax	$ 26,337	$ 2,536	$ -	$ 12,693	$ 65,137	$ 4,028	$ 70,479	$ 2,542	$ 183,752
4	MCRA Intended to be Billed (Excluding IURT)	$ 35,000	$ 3,500	$ 275	$ 12,000	$ 80,000	$ 8,550	$ 75,000	$ 4,500	$ 218,825
5	Under (Over) Recovery Variance (Line 4 - Line 3b)									$ 35,073

Schedule 5
(Pro forma)

VECTREN SOUTH
MISO Cost and Revenue Adjustment (MCRA)
Comparison of the effect of a Change in MISO Cost and Revenue Adjustment (MCRA) on the Bill of a Typical Residential Customer using 1000 kWhs

Line No.	Descriptions	MISO Management Costs and Revenue Adjustment (MCRA)	Base Bill for Typical Residential Customer (1)	MCRA Adjustment for 1000 kWh	Total Bill including MCRA (2)	Increase/(Decrease) In Total Base Bill	% Increase In Total Base Bill Base Bill
		(A)	(B)	(C)	(D)	(E)	(F)
1	Proposed	$ (0.000237)	$ 75.20	$ (0.24)	$ 74.96	$ (1.41)	-1.8%
2	Last Approved	$ 0.001166	$ 75.20	$ 1.17	$ 76.37	na	na

(1) Reflects rates approved in Cause No. 43111
(2) Excludes costs recovered via Vectren's various rate adjustment riders.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – ELECTRIC)

IURC CAUSE NO. 43111

DIRECT TESTIMONY
OF
KERRY A. HEID

ON

COST OF SERVICE STUDY

SPONSORING PETITIONER'S EXHIBITS NO. KAH-1 THROUGH KAH-5

DIRECT TESTIMONY OF KERRY A. HEID

I. INTRODUCTION AND OVERVIEW

Q. Please state your name and business address.

A. My name is Kerry A. Heid. My address is 3212 Brookfield Drive, Newburgh, IN 47630.

Q. What is your occupation?

A. I am an independent rate consultant. I have been engaged by Petitioner, Southern Indiana Gas and Electric Company. d/b/a/ Vectren Energy Delivery of Indiana, Inc. – South ("Vectren South" or "Company"), to prepare a cost of service study in this proceeding.

Q. What is your educational background?

A. In 1973 I graduated from Purdue University with a Bachelor of Science degree in Civil Engineering. In 1985 I graduated from Indiana University with a Master of Business Administration degree, majoring in Finance.

Q. Please describe your business experience.

A. In May 1989 I was employed by Indiana Gas Company, Inc. as Manager of Rates. In October 1992 I was promoted to Director of Rates for Indiana Gas Company. In April 2000 I became Director of Rates and Regulation with Vectren Energy, formed by the merger of Indiana Energy, Inc. (parent of Indiana Gas Company) and SIGCORP, Inc. (parent of Southern Indiana Gas & Electric Company). Prior to my employment with Vectren Energy, I was employed for seven years by the Indiana Utility Regulatory Commission and its predecessor, the Public Service Commission of Indiana, where I held positions in the Engineering Division and as Special Projects Analyst/Assistant to the Director of Utilities. I was also previously employed in the Management Services Division of Black & Veatch Consulting Engineers and in the Finance Department of Florida Power and Light Company. In May 2002 I resigned my position with Vectren Energy to become an independent rate consultant.

Q. Do you hold any professional accreditations?

A. Yes. I have been a registered Professional Engineer in the State of Indiana since 1977.

Q. Have you previously testified before this Commission?

A. Yes. I have testified on numerous occasions before this Commission on cost-of-service allocation, rate design and other matters.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present evidence on:

(1) Vectren South's cost of service study; and

(2) Vectren South's proposed revenue distribution among rate schedules.

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

I. Introduction and Overview of Presentation;

II. Cost of Service Study; and

III. Proposed Revenue Distribution Among Rate Schedules

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

KAH-1		Prefiled Direct Testimony of Kerry A. Heid
KAH-2		Cost of Service Study
	Sch. 1	Functional Cost Allocation Factors
	Sch. 2	Functionalization of Costs
	Sch. 3	Customer Class Allocation Factors
	Sch. 4	Allocation of Rate Base
	Sch. 5	Allocation of Depreciation and Amortization Expenses
	Sch. 6	Allocation of Operation and Maintenance Expenses
	Sch. 7	Allocation of Taxes Other Than Income
	Sch. 8	Allocation of Miscellaneous Revenues
	Sch. 9	Calculation of Income Taxes and Indiana Utility Receipts Taxes
	Sch. 10	Summary of Cost of Service Study Results
	Sch. 11	Calculation of Unit Costs

KAH-3,	Sch. 1	Statement of Operating Income Based Upon Proforma A[1] at Present Rates of Return
	Sch. 2	Statement of Operating Income Based Upon Proforma A at Equal Rates of Return
	Sch. 3	Statement of Operating Income Based Upon Proforma B at Equal Rates of Return
	Sch. 4	Statement of Operating Income Based Upon Proforma B at Proposed Rates of Return
KAH-4,	Sch. 1	Comparison of Proforma Operating Revenues and Dollar Subsidy Levels
	Sch. 2	Comparison of Earnings Indices at Present and Proposed Rates
KAH-5		Summary of Comparison of Proforma Revenues from Electric Sales at Present and Proposed Rates

II. COST OF SERVICE STUDY

Q. Please provide an overview of your testimony as it relates to your cost of service study.

A. The purpose of my testimony is to sponsor a fully allocated cost of service study based on Vectren South's embedded cost of providing electric service. Working with Vectren South's management, accounting and rate staffs, I prepared an embedded cost of service study based on Vectren South's accounting costs per books, adjusted for known and measurable changes to test year operating results, for the twelve months ended March 31, 2006. The cost of service study corresponds to the proforma financial exhibits included in the exhibits of Vectren South's witness M. Susan Hardwick, Petitioner's Exhibit No. MSH-2. My objective in performing the cost of service study was to determine the rate of return on rate base that Vectren South is earning from each rate schedule, which provides an indication as to whether its rates reflect the cost of providing service to each rate schedule.

I provided the results of my cost of service study to Petitioner's witness William R. Hopkins for use in rate design.

Q. Where did you obtain the data used to perform the cost of service study?

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[1] The designation "Proforma A" represents results at present revenue levels, whereas the designation "Proforma B" represents results at proposed revenue levels.

A. Investment cost data was taken from detailed accounting information, which formed the basis for the utility rate base shown in Petitioners' Exhibit No. MSH-3, Adjustment A65, Page 2 of 3, sponsored by Vectren South's witness Hardwick. The cost of service data was obtained from accounting information which formed the basis for the Proforma Statement of Operating Income shown in Petitioners' Exhibit No. MSH-2 sponsored by Vectren South's witness Hardwick. Data used to derive allocation factors in the allocation of rate base and cost of service came from various sources, including special studies, Vectren South's books and records, and from previously allocated items.

Q. Please list the rate classes to which you allocated costs in your cost of service study.

A. The rate classes to which I allocated costs are listed below. All rate classes correspond to proposed rate schedules, as more fully described by Vectren South witness William R. Hopkins.

Rate A - Residential Service
Rate EH - Electric Home Heating Service
Rate B - Water Heating Service
Rate SGS - Small General Service
Rate DGS - Demand General Service
Rate LP - Large Power Service
Rate HLF - Transmission Power Service
Rate SL - Street Lighting Service
Rate OL - Outdoor Lighting Service

Q. What were the general allocation procedures employed in the development of the cost of service study?

A. I used the traditional cost of service approach of cost functionalization, classification, and allocation to customer classes. They are described in the following paragraphs.

Cost Functionalization and Classification

Cost functionalization involves assigning plant and the associated operation and maintenance, depreciation and tax expense to the function performed. The principal functions used in the study were (1) production-demand; (2) production-energy; (3) transmission, which refers to facilities operating at 138 kV; (4) sub-transmission, which includes facilities operating at 69 kV; (5) primary distribution (2.4 kV – 12 kV); and (6) secondary distribution. Additional cost functions were utilized as well.

Classification of costs separates the functionalized cost groups into demand, energy and customer components based on the predominant factor for cost causation.

Costs that are related to the quantity of kilowatt hours produced or sold are classified as energy-related cost. These costs are allocated based on kWh usage.

Demand-related costs are those associated with maximum rates of use of energy, or demand. Most capital costs are demand-related because the investment in facilities is related to the size of the facility, and facilities are sized to provide service under peak load conditions. These costs are allocated based on peak demands.

Customer-related costs are those that are associated with serving customers irrespective of either the amount of energy used or the maximum demand. For example, every customer has a meter and a service, and the carrying costs associated with these facilities, along with the cost of meter reading and billing have been classified as customer-related. These costs are allocable on factors that are related to the number of customers.

Not all costs can be directly functionalized and classified. For example, general plant has been functionalized and classified based on functionalized and classified labor ratios.

Q. How did you functionalize and classify the company's transmission and distribution system in your study?

A. The assignment of costs to each function will generally follow the accounting categories defined in the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"). However, the FERC USOA does not distinguish between transmission and subtransmission, nor does it distinguish between primary and secondary distribution. Therefore, utility plant was allocated to these functions based in part on a prior analysis, and in part on judgment made by the company's engineering personnel involved with distribution lines and substations.

Q. Did the cost functionalization reflect the results of the FERC Seven-Factor Test, as discussed by Vectren South witness Michael W. Chambliss?

A. Yes. Vectren South reclassified its Utility Plant in Service based on the results of the FERC Seven-Factor Test, and I used the reclassified account amounts.

Allocation to Rate Schedules

Q. Please describe the cost allocation process.

A. Cost allocation is the process of cost assignment to rate schedules by which each class of service receives a proportionate cost responsibility for each of the functionalized and classified cost groups. This was generally accomplished by means of allocation factors, which are based on the ratio of the amount of energy sold, demand, or number of customers for each class of service to the company total. In addition to the use of allocation factors, some costs may be directly assigned to a particular customer class.

Q. Please describe Petitioner's Exhibit No. KAH-2.

A. Petitioner's Exhibit No. KAH-2, Schedules 1 through 10, present the cost of service study I prepared in this proceeding. Schedule 1 presents a table of the functional cost allocation factors used in the cost functionalization process. Schedule 2 presents the results of the cost functionalization process. Schedule 3 presents a table of the rate schedule allocation factors used in the cost allocation process. Schedule 4 presents the results of the allocation of Vectren South's original cost utility rate base among its various rate schedules. Schedule 5 presents the results of the allocation of depreciation and amortization expenses among the various rate schedules. Schedule 6, pages 1 and 2, present the results of the allocation of operation and maintenance expenses ("O&M") among the various rate schedules at Proforma A and Proforma B revenue levels, respectively. Schedule 7 presents the results of the allocation of taxes other than income among the various rate schedules. Schedule 8 presents the results of the allocation of miscellaneous revenues to the various rate schedules. Schedule 9 reflects the rate schedule-by-rate schedule calculation of federal and state income taxes and the Indiana utility receipts tax. Schedule 10 reflects the summarized results of the preceding cost of service allocations. Schedule 11 reflects the calculation of the unit cost to serve by function for each of the rate schedules. These unit costs, which are expressed in \$/kW and \$/kWh of billing demand; \$/kWh of energy cost; and \$/customer/month of customer cost, serve as a guide in designing cost-based rates for each proposed customer class.

Q. How were the major allocation factors developed?

A. The determination of the energy and customer allocation factors were made from the company's records of the sales and number of customers by rate as adjusted for pro forma entries. The determination of the demand allocation factors utilized data available from the company's load research program, as well as actual demand data of customers who are demand metered.

Q. Have the kWh energy sales and kW/kVa demands been adjusted for line losses?

A. Yes. All kWh energy sales and kW/kVa demands have been adjusted for line losses on the basis of a line loss study prepared on behalf of the Company for this proceeding.

Q. Please discuss the basis and use of the demand allocation factors.

A. The coincident demand allocation factor, used for the assignment of production plant, was based on a four-month average of the highest system peaks, which occurred in June, July, August, and September during the test year (4 Coincidental Peak, or 4 CP Method). Use of this factor gives appropriate recognition to the system's peak season, as an examination of the historical relationships of seasonal loads shows that this four-month period is consistently and significantly higher in load than the loads during the balance of the year, and that this period represents the planning peak season of the Petitioner.

Transmission plant, which represent the Company's investment in 138 kV lines and related facilities, and Subtransmission plant, which represents the company's investment in 69 kV lines and related facilities, were allocated to customer classes based on 12 Coincidental Peak, or 12 CP, demand. The use of 12 CP demand was required to be consistent with the Federal Energy Regulatory Commission's use of 12 CP for transmission costs in MISO's FERC-approved Attachment O formula rate for Vectren South, as discussed by Vectren South witness W. Steven Seelye.

To further recognize the decreasing levels of diversity experienced with lower voltage levels on cost incurrence, primary distribution lines were allocated based on an average of the ratios for each class of: (1) the class 4 CP demand at the primary distribution level; and (2) the arithmetic sum of each customer's maximum non-coincidental demand reflected for losses to the primary level.

Secondary distribution lines and transformers were allocated based on the arithmetic sum of each secondary customer's maximum metered demand.

III. PROPOSED REVENUE DISTRIBUTION AMONG RATE SCHEDULES

Q. Have you used the results of the cost of service study in developing your proposed revenue allocations by rate schedule?

A. Yes. My cost of service study served as the foundation for determining the revenue distributions I am proposing. My cost of service study provided the allocation of total original cost rate base for Vectren South to the various rate schedules. The study was structured to provide revenue and operating income amounts and associated taxes to compute the rate of return on rate base for each rate schedule at both present and proposed rates.

Q. Please describe your general approach to reducing the current subsidies.

A. In its Order in SIGECO-Electric's Cause No. 37803 approved February 5, 1986, the Commission stated:

> The Commission does note, however, that in future electric base rate proceedings the Petitioner should be required to reduce any subsidy between classes to the extent of at least 25% until such time as the Commission finds that any such subsidy has been sufficiently reduced or eliminated.

Accordingly, Petitioner has proposed a 25% subsidy reduction in this proceeding.

Q. Please identify the rates of return by rate schedule under Vectren South's present rates.

A. Petitioner's Exhibit No. KAH-3, Schedule 1, contains the Statement of Operating Income at present rates of return (Proforma A) by rate schedule. Line 13 of that schedule reflects the current rate of return for each rate schedule. Line 14 reflects the Earnings Index comparing the current class rates of return to the current overall Company rate of return.

Q. Please identify the total operating revenues by rate schedule that would result from equal rates of return at the present revenue level.

A. Petitioner's Exhibit No. KAH-3, Schedule 2, contains the Statement of Operating Income at equal rates of return at the present revenue levels (Proforma A).

Q. Please identify the total operating revenues by rate schedule that would result from equal rates of return at the proposed revenue requirement.

A. Petitioner's Exhibit No. KAH-3, Schedule 3, contains the Statement of Operating Income at equal rates of return at the proposed revenue requirement (Proforma B).

Q. Please identify the rates of return by rate schedule under Vectren South's proposed rates.

A. Petitioner's Exhibit No. KAH-3, Schedule 4, contains the Statement of Operating Income at proposed rates by rate schedule. The proposed rate schedule rates of return and the relative Earnings Indices are shown on Lines 13 and 14, respectively.

Q. Please identify the subsidy level for each rate schedule at present and proposed rates and the change in each subsidy level reflected in the proposed revenue allocations.

A. Petitioner's Exhibit No. KAH-4, Schedule 1, reflects the current and proposed dollar subsidy levels for each rate schedule at present and proposed rates. Petitioner's Exhibit No. KAH-4, Schedule 2, summarizes the Earnings Indices at present and proposed rates, and shows the relative movement in the Earnings Indices toward equal rates of return.

Q. Does this conclude your prepared direct testimony?

A. Yes, at the present time.

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONAL ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

NO.	ALLOCATORS	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand
	Not Applicable	0	0	0	0	0	0	0	0	0	0
F000		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Production Demand	1	0	0	0	0	0	0	0	0	0
F001		100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Production Energy	0	1	0	0	0	0	0	0	0	0
F002		0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Transmission Demand	0	0	0	1	0	0	0	0	0	0
F003		0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Sub-Transmission Demand	0	0	0	0	1	0	0	0	0	0
F004		0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Primary Distribution Demand	0	0	0	0	0	1	0	0	0	0
F005		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Line Transformers Demand	0	0	0	0	0	0	0	0	0	1
F009		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Services	0	0	0	0	0	0	0	0	0	0
F011		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Meters	0	0	0	0	0	0	0	0	0	0
F012		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Outdoor Lighting	0	0	0	0	0	0	0	0	0	0
F013		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Street Lighting	0	0	0	0	0	0	0	0	0	0
F014		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Customer Accounts-Related	0	0	0	0	0	0	0	0	0	0
F015		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	DSM-Related	0	0	0	0	0	0	0	0	0	0
F016		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONAL ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

NO.	ALLOCATORS	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel	Total Company
	Not Applicable	0	0	0	0	0	0	0	0	0	0
F000		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Production Demand	0	0	0	0	0	0	0	0	0	1
F001		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Production Energy	0	0	0	0	0	0	0	0	0	1
F002		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Transmission Demand	0	0	0	0	0	0	0	0	0	1
F003		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Sub-Transmission Demand	0	0	0	0	0	0	0	0	0	1
F004		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Primary Distribution Demand	0	0	0	0	0	0	0	0	0	1
F005		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Line Transformers Demand	0	0	0	0	0	0	0	0	0	1
F009		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Services	0	1	0	0	0	0	0	0	0	1
F011		0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Meters	0	0	1	0	0	0	0	0	0	1
F012		0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Outdoor Lighting	0	0	0	1	0	0	0	0	0	1
F013		0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Street Lighting	0	0	0	0	1	0	0	0	0	1
F014		0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Customer Accounts-Related	0	0	0	0	0	1	0	0	0	1
F015		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	DSM-Related	0	0	0	0	0	0	1	0	0	1
F016		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONAL ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

NO.	ALLOCATORS	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand
	Non-FAC Fuel	0	0	0	0	0	0	0	0	0	0
F017		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	FAC Fuel	0	0	1	0	0	0	0	0	0	0
F018		0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Line Transformer Zero Intercept Analysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,877,459
F019		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	50.1009%
	Trans Plant Structures & Impr Analysis	$391,273	$0	$0	$356,796	$403,624	$514,422	$0	$0	$0	$0
F020		23.4842%	0.0000%	0.0000%	21.4148%	24.2255%	30.8755%	0.0000%	0.0000%	0.0000%	0.0000%
	Trans Station Equipment Special Analysis	$0	$0	$0	$8,139,171	$58,639,558	$0	$0	$0	$0	$0
F021		0.0000%	0.0000%	0.0000%	12.1883%	87.8117%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Transmission Towers Analysis	$0	$0	$0	$3,846,430	$618,901	$0	$0	$0	$0	$0
F022		0.0000%	0.0000%	0.0000%	86.1399%	13.8601%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Transmission Poles Analysis	$0	$0	$0	$13,347,593	$13,944,261	$0	$0	$0	$0	$0
F023		0.0000%	0.0000%	0.0000%	48.9069%	51.0931%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Trans Overhead Conductors Analysis	$0	$0	$0	$12,668,103	$13,994,529	$0	$0	$0	$0	$0
F024		0.0000%	0.0000%	0.0000%	47.5126%	52.4874%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	75% Primary / 25% Secondary Distribution	0	0	0	0	0	0.75	0	0.25	0	0
F025		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	75.0000%	0.0000%	25.0000%	0.0000%	0.0000%
	90% Primary / 10% Secondary Distribution	0	0	0	0	0	0.90	0	0.10	0	0
F026		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	90.0000%	0.0000%	10.0000%	0.0000%	0.0000%
	88.94% Primary / 11.06% Secondary Distr.	0	0	0	0	0	0.8894	0	0.1106	0	0
F027		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	88.9400%	0.0000%	11.0600%	0.0000%	0.0000%
	Unused	0	0	0	0	0	0	0	0	0	0
F028		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	WPM Fuel	0	0	0	0	0	0	0	0	0	0
F030		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONAL ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

NO.	ALLOCATORS	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel	Total Company
	Non-FAC Fuel	0	0	0	0	0	0	0	1	0	1
F017		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
	FAC Fuel	0	0	0	0	0	0	0	0	0	1
F018		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Line Transformer Zero Intercept Analysis	$25,773,235	$0	$0	$0	$0	$0	$0	$0	$0	$51,650,694
F019		49.8991%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Trans Plant Structures & Impr Analysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,666,114
F020		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Trans Station Equipment Special Analysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$66,778,729
F021		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Transmission Towers Analysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,465,332
F022		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Transmission Poles Analysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,291,854
F023		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Trans Overhead Conductors Analysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26,662,632
F024		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	75% Primary / 25% Secondary Distribution	0	0	0	0	0	0	0	0	0	1
F025		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	90% Primary / 10% Secondary Distribution	0	0	0	0	0	0	0	0	0	1
F026		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	88.94% Primary / 11.06% Secondary Distr.	0	0	0	0	0	0	0	0	0	1
F027		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Unused	0	0	0	0	0	0	0	0	0	1
F028		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	WPM Fuel	0	0	0	0	0	0	0	0	1	1
F030		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	100.0000%

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

NO.	ALLOCATORS	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand
INTERNALLY-GENERATED ALLOCATION FACTORS											
	Subtotal Trans. O&M Operation	$0	$0	$0	$4,937,540	$188,529	$0	$0	$0	$0	$0
F101		0.0000%	0.0000%	0.0000%	96.3221%	3.6779%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Plant in Service	$1,195,020,736	$0	$0	$59,846,532	$123,244,713	$193,901,870	$0	$23,641,255	$0	$27,692,763
F103		68.8899%	0.0000%	0.0000%	3.4500%	7.1047%	11.1779%	0.0000%	1.3629%	0.0000%	1.5964%
	T&D Overhead Conductors	$0	$0	$0	$16,608,103	$18,347,070	$47,088,367	$0	$5,232,041	$0	$0
F104		0.0000%	0.0000%	0.0000%	19.0295%	21.0220%	53.9537%	0.0000%	5.9949%	0.0000%	0.0000%
	Subtotal Transmission Plant	$393,320	$0	$0	$53,318,777	$112,134,658	$517,112	$0	$0	$0	$0
F105		0.2364%	0.0000%	0.0000%	32.0495%	67.4033%	0.3108%	0.0000%	0.0000%	0.0000%	0.0000%
	Plant in Service Excluding G&I	$1,157,130,169	$0	$0	$55,971,559	$117,713,721	$193,791,116	$0	$23,641,255	$0	$26,597,698
F107		69.1742%	0.0000%	0.0000%	3.3460%	7.0370%	11.5850%	0.0000%	1.4133%	0.0000%	1.5900%
	Subtotal Distribution Plant	$0	$0	$0	$0	$0	$192,622,230	$0	$23,564,667	$0	$26,511,532
F113		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	56.6016%	0.0000%	6.9244%	0.0000%	7.7904%
	Prod/Tran/Dist Plant	$1,157,130,169	$0	$0	$55,971,559	$117,713,721	$193,791,116	$0	$23,641,255	$0	$26,597,698
F115		69.1742%	0.0000%	0.0000%	3.3460%	7.0370%	11.5850%	0.0000%	1.4133%	0.0000%	1.5900%
	T&D O&M	$6,367	$0	$0	$9,265,451	$9,496,011	$644,868	$0	$0	$0	$1,222,422
F117		0.0269%	0.0000%	0.0000%	39.1443%	40.1183%	2.7244%	0.0000%	0.0000%	0.0000%	5.1644%
	Total Depreciation Expense	$44,330,644	$0	$0	$1,297,322	$2,469,500	$5,794,453	$0	$774,633	$0	$693,454
F119		68.7351%	0.0000%	0.0000%	2.0115%	3.8290%	8.9844%	0.0000%	1.2011%	0.0000%	1.0752%
	Subtotal Poles & Towers	0	0	0	27,203,776	24,934,752	35,040,581	0	11,680,194	0	0
F120		0.0000%	0.0000%	0.0000%	27.5177%	25.2225%	35.4449%	0.0000%	11.8150%	0.0000%	0.0000%
	Rate Base	$657,024,485	$13,495,550	$0	$34,249,046	$74,548,544	$122,466,847	$0	$14,790,175	$0	$15,382,479
F125		64.5559%	1.3260%	0.0000%	3.3651%	7.3248%	12.0330%	0.0000%	1.4532%	0.0000%	1.5114%
	50% Plant / 50% Labor	67.7649%	0.0000%	0.0000%	5.1325%	8.4162%	5.6864%	0.0000%	0.6814%	0.0000%	1.7612%
F126		67.7649%	0.0000%	0.0000%	5.1325%	8.4162%	5.6864%	0.0000%	0.6814%	0.0000%	1.7612%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONAL ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

INTERNALLY-GENERATED ALLOCATI

NO.	ALLOCATORS	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel	Total Company
	Subtotal Trans. O&M Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,126,069
F101		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Plant in Service	$27,581,227	$42,827,253	$17,490,959	$2,832,594	$10,746,999	$4,808,264	$5,047,665	$0	$0	$1,734,682,832
F103		1.5900%	2.4689%	1.0083%	0.1633%	0.6195%	0.2772%	0.2910%	0.0000%	0.0000%	100.0000%
	T&D Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$87,275,581
F104		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Subtotal Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$166,363,866
F105		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Plant in Service Excluding G&I	$26,490,573	$42,827,253	$15,566,568	$2,832,594	$10,213,921	$0	$0	$0	$0	$1,672,776,429
F107		1.5836%	2.5602%	0.9306%	0.1693%	0.6106%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Subtotal Distribution Plant	$26,404,755	$42,688,510	$15,516,139	$2,823,418	$10,180,832	$0	$0	$0	$0	$340,312,083
F113		7.7590%	12.5439%	4.5594%	0.8297%	2.9916%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Prod/Tran/Dist Plant	$26,490,573	$42,827,253	$15,566,568	$2,832,594	$10,213,921	$0	$0	$0	$0	$1,672,776,429
F115		1.5836%	2.5602%	0.9306%	0.1693%	0.6106%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	T&D O&M	$1,217,498	$0	$1,373,769	$0	$443,617	$0	$0	$0	$0	$23,670,004
F117		5.1436%	0.0000%	5.8038%	0.0000%	1.8742%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Total Depreciation Expense	$690,661	$1,400,196	$514,709	$122,255	$303,045	$134,612	$5,969,398	$0	$0	$64,494,881
F119		1.0709%	2.1710%	0.7981%	0.1896%	0.4699%	0.2087%	9.2556%	0.0000%	0.0000%	100.0000%
	Subtotal Poles & Towers	0	0	0	0	0	0	0	0	0	98,859,303
F120		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Rate Base	$15,320,525	$17,951,683	$9,966,064	$941,916	$5,574,510	$2,431,041	$33,617,027	$0	$0	$1,017,759,890
F125		1.5053%	1.7638%	0.9792%	0.0925%	0.5477%	0.2389%	3.3030%	0.0000%	0.0000%	100.0000%
	50% Plant / 50% Labor	1.7541%	1.2344%	2.1964%	0.0816%	0.7785%	4.3668%	0.1455%	0.0000%	0.0000%	100.0000%
F126		1.7541%	1.2344%	2.1964%	0.0816%	0.7785%	4.3668%	0.1455%	0.0000%	0.0000%	100.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONAL ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

NO.	ALLOCATORS	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand
	Asset Charge Study	4,786,234	0	0	533,201	781,091	593,023	0	69,921	0	148,185
F127		53.3396%	0.0000%	0.0000%	5.9422%	8.7048%	6.6089%	0.0000%	0.7792%	0.0000%	1.6514%
	Total Labor	$19,462,387	$0	$0	$1,990,370	$2,840,979	$56,888	$0	$0	$0	$562,477
F134		66.6398%	0.0000%	0.0000%	6.8151%	9.7276%	0.1948%	0.0000%	0.0000%	0.0000%	1.9259%
	Subtotal Transmission Maintenance O&M	6,234	0	0	386,347	1,005,189	8,196	0	0	0	0
F136		0.4434%	0.0000%	0.0000%	27.4791%	71.4945%	0.5830%	0.0000%	0.0000%	0.0000%	0.0000%
	Transmission Plant	$412,889	$0	$0	$55,971,559	$117,713,721	$542,840	$0	$0	$0	$0
F137		0.2364%	0.0000%	0.0000%	32.0495%	67.4033%	0.3108%	0.0000%	0.0000%	0.0000%	0.0000%
	Subtotal Distribution Maintenance O&M	$0	$0	$0	$3,152,721	$5,069,925	$575,275	$0	$0	$0	$201,477
F138		0.0000%	0.0000%	0.0000%	34.2685%	55.1075%	6.2529%	0.0000%	0.0000%	0.0000%	2.1899%
	Subtotal Distribution Operation O&M	$0	$0	$0	$164,890	$1,054,205	$0	$0	$0	$0	$394,591
F139		0.0000%	0.0000%	0.0000%	6.4473%	41.2198%	0.0000%	0.0000%	0.0000%	0.0000%	15.4286%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONAL ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 1

NO.	ALLOCATORS	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel	Total Company
	Asset Charge Study	147,588	126,665	153,718	8,378	60,321	1,549,880	14,929	0	0	8,973,132
F127		1.6448%	1.4116%	1.7131%	0.0934%	0.6722%	17.2725%	0.1664%	0.0000%	0.0000%	100.0000%
	Total Labor	$560,211	$0	$988,458	$0	$273,814	$2,469,752	$0	$0	$0	$29,205,336
F134		1.9182%	0.0000%	3.3845%	0.0000%	0.9375%	8.4565%	0.0000%	0.0000%	0.0000%	100.0000%
	Subtotal Transmission Maintenance O&M	0	0	0	0	0	0	0	0	0	1,405,967
F136		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$174,641,009
F137		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Subtotal Distribution Maintenance O&M	$200,665	$0	$0	$0	$0	$0	$0	$0	$0	$9,200,063
F138		2.1811%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Subtotal Distribution Operation O&M	$393,001	$0	$522,804	$0	$28,029	$0	$0	$0	$0	$2,557,520
F139		15.3665%	0.0000%	20.4418%	0.0000%	1.0960%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

UTILITY PLANT IN SERVICE (Page 1 of 2)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Steam Production Plant											
310	Land and Land Rights	F001	Production Demand	$3,349,97C	$3,349,97C	$0	$0	$0	$0	$0	$0
311	Structures and Improvements	F001	Production Demand	$71,703,817	$71,703,817	$0	$0	$0	$0	$0	$0
312	Boiler Plant Equipment	F001	Production Demand	$797,867,99E	$797,867,99E	$0	$0	$0	$0	$0	$0
313	Engines and Engine Driven Generators	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
314	Turbogenerator Units	F001	Production Demand	$152,318,054	$152,318,054	$0	$0	$0	$0	$0	$0
315	Accessory Electric Equipment	F001	Production Demand	$34,912,08S	$34,912,08S	$0	$0	$0	$0	$0	$0
316	Miscellaneous Power Plant Equipment	F001	Production Demand	$12,829,117	$12,829,117	$0	$0	$0	$0	$0	$0
317	Asset Retirement Costs for Steam Production	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Steam Production Plant			$1,072,981,04E	$1,072,981,04E	$0	$0	$0	$0	$0	$0
Hydraulic and Pumped Storage Production Plant											
330	Land and Land Rights	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
331	Structures and Improvements	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
332	Reservoirs, Dams and Waterways	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
333	Water Wheels, Turbines and Generators	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
334	Accessory Electric Equipment	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
335	Miscellaneous Power Plant Equipment	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
336	Roads, Railroads and Bridges	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
337	Asset Retirement Costs for Hydraulic Production	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic and Pumped Storage Production Plant			$0	$0	$0	$0	$0	$0	$0	$0
Other Production Plant											
340	Land and Land Rights	F001	Production Demand	$79,288	$79,288	$0	$0	$0	$0	$0	$0
341	Structures and Improvements	F001	Production Demand	$1,762,15S	$1,762,15S	$0	$0	$0	$0	$0	$0
342	Fuel Holders, Producers and Accessories	F001	Production Demand	$4,992,331	$4,992,331	$0	$0	$0	$0	$0	$0
343	Prime Movers	F001	Production Demand	$50,609,84S	$50,609,84S	$0	$0	$0	$0	$0	$0
344	Generators	F001	Production Demand	$20,363,651	$20,363,651	$0	$0	$0	$0	$0	$0
345	Accessory Electric Equipment	F001	Production Demand	$4,288,75S	$4,288,75S	$0	$0	$0	$0	$0	$0
346	Miscellaneous Power Plant Equipment	F001	Production Demand	$1,640,19E	$1,640,19E	$0	$0	$0	$0	$0	$0
347	Asset Retirement Costs for Other Production	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Other Production Plant			$83,736,23E	$83,736,23E	$0	$0	$0	$0	$0	$0
Transmission Plant											
350	Land and Land Rights	F105	Subtotal Transmission Plant	$8,277,14C	$19,569	$0	$0	$2,652,782	$5,579,064	$25,728	$0
352	Structures and Improvements	F020	Trans Plant Structures & Impr Analysis	$1,674,82E	$393,32C	$0	$0	$358,662	$405,73E	$517,112	$0
353	Station Equipment	F021	Trans Station Equipment Special Analysis	$75,057,717	$0	$0	$0	$9,148,23E	$65,909,481	$0	$0
354	Towers and Fixtures	F022	Transmission Towers Analysis	$4,577,79S	$0	$0	$0	$3,943,31C	$634,48S	$0	$0
355	Poles and Fixtures	F023	Transmission Poles Analysis	$47,560,72S	$0	$0	$0	$23,260,46E	$24,300,26C	$0	$0
356	Overhead Conductors and Devices	F024	Trans Overhead Conductors Analysis	$34,955,17C	$0	$0	$0	$16,608,10C	$18,347,07C	$0	$0
357	Underground Conduit	F004	Sub-Transmission Demand	$1,180,974	$0	$0	$0	$0	$1,180,974	$0	$0
358	Underground Conductors and Devices	F004	Sub-Transmission Demand	$1,356,64E	$0	$0	$0	$0	$1,356,64E	$0	$0
359	Road and Trails	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
359.1	Regulatory Assets-MISO Day 2 Capital Component	F105	Subtotal Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Plant			$174,641,00S	$412,88S	$0	$0	$55,971,55S	$117,713,721	$542,84C	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

UTILITY PLANT IN SERVICE (Page 1 of 2)

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
Steam Production Plant													
310	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
311	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
312	Boiler Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
313	Engines and Engine Driven Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
314	Turbogenerator Units	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
315	Accessory Electric Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
316	Miscellaneous Power Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
317	Asset Retirement Costs for Steam Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Steam Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Hydraulic and Pumped Storage Production Plant													
330	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
331	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
332	Reservoirs, Dams and Waterways	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
333	Water Wheels, Turbines and Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
334	Accessory Electric Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
335	Miscellaneous Power Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
336	Roads, Railroads and Bridges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
337	Asset Retirement Costs for Hydraulic Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic and Pumped Storage Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Production Plant													
340	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
341	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
342	Fuel Holders, Producers and Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
343	Prime Movers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
344	Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
345	Accessory Electric Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
346	Miscellaneous Power Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
347	Asset Retirement Costs for Other Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Other Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant													
350	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
352	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
353	Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
354	Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
355	Poles and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
356	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
357	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
358	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
359	Road and Trails	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
359.1	Regulatory Assets-MISO Day 2 Capital Component	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

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TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

UTILITY PLANT IN SERVICE (Page 2 of 2)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Distribution Plant											
360	Land and Land Rights	F113	Subtotal Distribution Plant	$1,106,057	$0	$0	$0	$0	$0	$626,046	$0
361	Structures and Improvements	F005	Primary Distribution Demand	$659,763	$0	$0	$0	$0	$0	$659,763	$0
362	Station Equipment	F005	Primary Distribution Demand	$56,337,374	$0	$0	$0	$0	$0	$56,337,374	$0
363	Storage Battery Equipment	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
364	Poles, Towers and Fixtures	F025	75% Primary / 25% Secondary Distribution	$46,720,775	$0	$0	$0	$0	$0	$35,040,581	$0
365	Overhead Conductors and Devices	F026	90% Primary / 10% Secondary Distribution	$52,320,408	$0	$0	$0	$0	$0	$47,088,367	$0
366	Underground Conduit	F027	88.94% Primary / 11.06% Secondary Distr	$17,484,982	$0	$0	$0	$0	$0	$15,551,143	$0
367	Underground Conductors and Devices	F027	88.94% Primary / 11.06% Secondary Distr	$42,663,595	$0	$0	$0	$0	$0	$37,945,001	$0
368	Line Transformers	F019	Line Transformer Zero Intercept Analysis	$52,916,287	$0	$0	$0	$0	$0	$0	$0
369	Services	F011	Services	$42,688,510	$0	$0	$0	$0	$0	$0	$0
370	Meters	F012	Meters	$15,516,139	$0	$0	$0	$0	$0	$0	$0
371	Installation on Customers' Premises	F013	Outdoor Lighting	$2,823,418	$0	$0	$0	$0	$0	$0	$0
372	Leased Property on Customers' Premises	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
373	Street Lighting and Signal Systems	F014	Street Lighting	$10,180,832	$0	$0	$0	$0	$0	$0	$0
374	Asset Retirement Costs for Distribution Plant	F113	Subtotal Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Plant			$341,418,140	$0	$0	$0	$0	$0	$193,248,276	$0
Plant in Service Excluding General and Intangible Plant				$1,672,776,429	$1,157,130,169	$0	$0	$55,971,559	$117,713,721	$193,791,116	$0
General and Intangible Plant											
301	Organization	F134	Total Labor	$12,151	$8,097	$0	$0	$828	$1,182	$24	$0
302	Franchises and Consents	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
303	Miscellaneous Intangible Plant	F134	Total Labor	$483,986	$322,528	$0	$0	$32,984	$47,080	$943	$0
389	Land and Land Rights	F134	Total Labor	$2,609,902	$1,739,235	$0	$0	$177,867	$253,881	$5,084	$0
390	Structures and Improvements	F134	Total Labor	$29,634,137	$19,748,139	$0	$0	$2,019,593	$2,882,691	$57,724	$0
391	Office Furniture and Equipment	F134	Total Labor	$5,471,522	$3,646,213	$0	$0	$372,889	$532,248	$10,658	$0
392	Transportation Equipment	F134	Total Labor	$10,544,972	$7,027,152	$0	$0	$718,649	$1,025,773	$20,540	$0
393	Stores Equipment	F134	Total Labor	$504,425	$336,148	$0	$0	$34,377	$49,068	$983	$0
394	Tools, Shop and Garage Equipment	F134	Total Labor	$1,219,264	$812,516	$0	$0	$83,094	$118,605	$2,375	$0
395	Laboratory Equipment	F134	Total Labor	$1,480,618	$986,681	$0	$0	$100,905	$144,029	$2,884	$0
396	Power Operated Equipment	F134	Total Labor	$1,175,411	$783,292	$0	$0	$80,105	$114,339	$2,290	$0
397	Communication Equipment	F134	Total Labor	$3,305,983	$2,203,102	$0	$0	$225,306	$321,593	$6,440	$0
398	Miscellaneous Equipment	F134	Total Labor	$416,365	$277,465	$0	$0	$28,376	$40,502	$811	$0
398	Miscellaneous Equipment-DLC	F016	DSM-Related	$5,047,665	$0	$0	$0	$0	$0	$0	$0
399	Other Tangible Property	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
399.1	Asset Retirement Costs for General Plant	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
	Total General and Intangible Plant			$61,906,403	$37,890,568	$0	$0	$3,874,973	$5,530,991	$110,754	$0
Total Utility Plant In Service				**$1,734,682,832**	**$1,195,020,736**	**$0**	**$0**	**$59,846,532**	**$123,244,713**	**$193,901,870**	**$0**

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
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DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

UTILITY PLANT IN SERVICE (Page 2 of 2)

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
Distribution Plant													
360	Land and Land Rights	$76,588	$0	$86,166	$85,819	$138,743	$50,429	$9,176	$33,089	$0	$0	$0	$0
361	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
362	Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
363	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
364	Poles, Towers and Fixtures	$11,680,194	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
365	Overhead Conductors and Devices	$5,232,041	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
366	Underground Conduit	$1,933,839	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
367	Underground Conductors and Devices	$4,718,594	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368	Line Transformers	$0	$0	$26,511,532	$26,404,755	$0	$0	$0	$0	$0	$0	$0	$0
369	Services	$0	$0	$0	$0	$42,688,510	$0	$0	$0	$0	$0	$0	$0
370	Meters	$0	$0	$0	$0	$0	$15,516,139	$0	$0	$0	$0	$0	$0
371	Installation on Customers' Premises	$0	$0	$0	$0	$0	$0	$2,823,418	$0	$0	$0	$0	$0
372	Leased Property on Customers' Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
373	Street Lighting and Signal Systems	$0	$0	$0	$0	$0	$0	$0	$10,180,832	$0	$0	$0	$0
374	Asset Retirement Costs for Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Plant	$23,641,255	$0	$26,597,698	$26,490,573	$42,827,253	$15,566,568	$2,832,594	$10,213,921	$0	$0	$0	$0
	Plant in Service Excluding General and Intangible Plant	$23,641,255	$0	$26,597,698	$26,490,573	$42,827,253	$15,566,568	$2,832,594	$10,213,921	$0	$0	$0	$0
General and Intangible Plant													
301	Organization	$0	$0	$234	$233	$0	$411	$0	$114	$1,028	$0	$0	$0
302	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303	Miscellaneous Intangible Plant	$0	$0	$9,321	$9,284	$0	$16,381	$0	$4,538	$40,928	$0	$0	$0
389	Land and Land Rights	$0	$0	$50,265	$50,063	$0	$88,332	$0	$24,469	$220,707	$0	$0	$0
390	Structures and Improvements	$0	$0	$570,735	$568,437	$0	$1,002,971	$0	$277,834	$2,506,014	$0	$0	$0
391	Office Furniture and Equipment	$0	$0	$105,378	$104,954	$0	$185,184	$0	$51,298	$462,700	$0	$0	$0
392	Transportation Equipment	$0	$0	$203,090	$202,272	$0	$356,896	$0	$98,864	$891,737	$0	$0	$0
393	Stores Equipment	$0	$0	$9,715	$9,676	$0	$17,072	$0	$4,729	$42,657	$0	$0	$0
394	Tools, Shop and Garage Equipment	$0	$0	$23,482	$23,388	$0	$41,266	$0	$11,431	$103,107	$0	$0	$0
395	Laboratory Equipment	$0	$0	$28,516	$28,401	$0	$50,112	$0	$13,882	$125,209	$0	$0	$0
396	Power Operated Equipment	$0	$0	$22,638	$22,547	$0	$39,782	$0	$11,020	$99,399	$0	$0	$0
397	Communication Equipment	$0	$0	$63,671	$63,415	$0	$111,891	$0	$30,995	$279,571	$0	$0	$0
398	Miscellaneous Equipment	$0	$0	$8,019	$7,987	$0	$14,092	$0	$3,904	$35,210	$0	$0	$0
398	Miscellaneous Equipment-DLC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,047,665	$0	$0
399	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
399.1	Asset Retirement Costs for General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total General and Intangible Plant	$0	$0	$1,095,064	$1,090,654	$0	$1,924,391	$0	$533,078	$4,808,264	$5,047,665	$0	$0
	Total Utility Plant in Service	**$23,641,255**	**$0**	**$27,692,763**	**$27,581,227**	**$42,827,253**	**$17,490,959**	**$2,832,594**	**$10,746,999**	**$4,808,264**	**$5,047,665**	**$0**	**$0**

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
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DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

	Description	Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
	DEPRECIATION RESERVE (Page 1 of 2)	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
		F001	Production Demand	$46,152,202	$46,152,202	$0	$0	$0	$0	$0	$0
	Steam Production Depreciation Reserve	F001	Production Demand	$336,345,364	$336,345,364	$0	$0	$0	$0	$0	$0
310	Land and Land Rights	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
311	Structures and Improvements	F001	Production Demand	$83,032,652	$83,032,652	$0	$0	$0	$0	$0	$0
312	Boiler Plant Equipment	F001	Production Demand	$22,977,776	$22,977,776	$0	$0	$0	$0	$0	$0
313	Engines and Engine Driven Generators	F001	Production Demand	$6,015,472	$6,015,472	$0	$0	$0	$0	$0	$0
314	Turbogenerator Units			$494,523,466	$494,523,466	$0	$0	$0	$0	$0	$0
315	Accessory Electric Equipment										
316	Miscellaneous Power Plant Equipment										
	Total Steam Production Depreciation Reserve	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
		F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Hydraulic and Pumped Storage Production Plant Depreciation Rese	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
330	Land and Land Rights	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
331	Structures and Improvements	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
332	Reservoirs, Dams and Waterways	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
333	Water Wheels, Turbines and Generators	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
334	Accessory Electric Equipment			$0	$0	$0	$0	$0	$0	$0	$0
335	Miscellaneous Power Plant Equipment										
336	Roads, Railroads and Bridges										
	Total Hydraulic & Pumped Storage Prod. Plant Depr. Re	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
		F001	Production Demand	$926,526	$926,526	$0	$0	$0	$0	$0	$0
	Other Production Plant Depreciation Reserve	F001	Production Demand	$2,859,841	$2,859,841	$0	$0	$0	$0	$0	$0
340	Land and Land Rights	F001	Production Demand	$27,904,969	$27,904,969	$0	$0	$0	$0	$0	$0
341	Structures and Improvements	F001	Production Demand	$7,976,263	$7,976,263	$0	$0	$0	$0	$0	$0
342	Fuel Holders, Producers and Accessories	F001	Production Demand	$2,513,106	$2,513,106	$0	$0	$0	$0	$0	$0
343	Prime Movers	F001	Production Demand	$175,367	$175,367	$0	$0	$0	$0	$0	$0
344	Generators			$42,356,072	$42,356,072	$0	$0	$0	$0	$0	$0
345	Accessory Electric Equipment										
346	Miscellaneous Power Plant Equipment										
	Total Other Production Plant Depreciation Reserve	F105	Subtotal Transmission Plant	$1,417,223	$3,351	$0	$0	$454,213	$955,254	$4,405	$0
		F020	Trans Plant Structures & Impr Analysis	$943,750	$221,632	$0	$0	$202,102	$228,628	$291,388	$0
	Transmission Plant	F021	Trans Station Equipment Special Analysis	$30,482,252	$0	$0	$0	$3,715,259	$26,766,993	$0	$0
350	Land and Land Rights	F022	Transmission Towers Analysis	$4,106,161	$0	$0	$0	$3,537,041	$569,120	$0	$0
352	Structures and Improvements	F023	Transmission Poles Analysis	$21,715,088	$0	$0	$0	$10,620,171	$11,094,917	$0	$0
353	Station Equipment	F024	Trans Overhead Conductors Analysis	$13,723,811	$0	$0	$0	$6,520,536	$7,203,275	$0	$0
354	Towers and Fixtures	F004	Sub-Transmission Demand	$512,627	$0	$0	$0	$0	$512,627	$0	$0
355	Poles and Fixtures	F004	Sub-Transmission Demand	$472,521	$0	$0	$0	$0	$472,521	$0	$0
356	Overhead Conductors and Devices	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
357	Underground Conduit			$73,373,433	$224,983	$0	$0	$25,049,322	$47,803,335	$295,793	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	DEPRECIATION RESERVE (Page 1 of 2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Steam Production Depreciation Reserve	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
310	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
311	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
312	Boiler Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
313	Engines and Engine Driven Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
314	Turbogenerator Units	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
315	Accessory Electric Equipment												
316	Miscellaneous Power Plant Equipment												
	Total Steam Production Depreciation Reserve	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Hydraulic and Pumped Storage Production Plant Depreciation Rese	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
330	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
331	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
332	Reservoirs, Dams and Waterways	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
333	Water Wheels, Turbines and Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
334	Accessory Electric Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
335	Miscellaneous Power Plant Equipment												
336	Roads, Railroads and Bridges												
	Total Hydraulic & Pumped Storage Prod. Plant Depr. Re	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Other Production Plant Depreciation Reserve	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
340	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
341	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
342	Fuel Holders, Producers and Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
343	Prime Movers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
344	Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
345	Accessory Electric Equipment												
346	Miscellaneous Power Plant Equipment												
	Total Other Production Plant Depreciation Reserve	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
350	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
352	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
353	Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
354	Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
355	Poles and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
356	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
357	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

DEPRECIATION RESERVE (Page 2 of 2)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Distribution Plant Depreciation Reserve											
360	Land and Land Rights	F113	Subtotal Distribution Plant	$50	$0	$0	$0	$0	$0	$28	$0
361	Structures and Improvements	F005	Primary Distribution Demand	$249,867	$0	$0	$0	$0	$0	$249,867	$0
362	Station Equipment	F005	Primary Distribution Demand	$21,830,57C	$0	$0	$0	$0	$0	$21,830,57C	$0
363	Storage Battery Equipment	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
364	Poles, Towers and Fixtures	F025	75% Primary / 25% Secondary Distributior	$18,914,19E	$0	$0	$0	$0	$0	$14,185,64E	$0
365	Overhead Conductors and Devices	F026	90% Primary / 10% Secondary Distributior	$20,758,84C	$0	$0	$0	$0	$0	$18,682,95E	$0
366	Underground Conduit	F027	88.94% Primary / 11.06% Secondary Distr	$6,061,05E	$0	$0	$0	$0	$0	$5,390,702	$0
367	Underground Conductors and Devices	F027	88.94% Primary / 11.06% Secondary Distr	$15,858,48E	$0	$0	$0	$0	$0	$14,104,53E	$0
368	Line Transformers	F019	Line Transformer Zero Intercept Analysis	$23,605,35E	$0	$0	$0	$0	$0	$0	$0
369	Services	F011	Services	$24,968,33E	$0	$0	$0	$0	$0	$0	$0
370	Meters	F012	Meters	$6,607,18E	$0	$0	$0	$0	$0	$0	$0
371	Installation on Customers' Premises	F013	Outdoor Lighting	$1,896,814	$0	$0	$0	$0	$0	$0	$0
372	Leased Property on Customers' Premises	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
373	Street Lighting and Signal Systems	F014	Street Lighting	$4,931,05E	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Plant Depreciation Reserve			$145,681,811	$0	$0	$0	$0	$0	$74,444,30E	$0
General and Intangible Plant Depreciation Reserve											
301	Organization	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
302	Franchises and Consents	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
303	Miscellaneous Intangible Plan	F134	Total Labor	$23,505	$15,663	$0	$0	$1,602	$2,286	$46	$0
389	Land and Land Rights	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
390	Structures and Improvements	F134	Total Labor	$11,575,977	$7,714,212	$0	$0	$788,91E	$1,126,06E	$22,549	$0
391	Office Furniture and Equipment	F134	Total Labor	$1,969,552	$1,312,50E	$0	$0	$134,227	$191,59C	$3,836	$0
392	Transportation Equipment	F134	Total Labor	$4,237,47E	$2,823,84E	$0	$0	$288,78E	$412,20E	$8,254	$0
393	Stores Equipment	F134	Total Labor	$422,301	$281,421	$0	$0	$28,780	$41,080	$823	$0
394	Tools, Shop and Garage Equipment	F134	Total Labor	$906,09E	$603,822	$0	$0	$61,751	$88,142	$1,765	$0
395	Laboratory Equipment	F134	Total Labor	$1,080,15E	$719,814	$0	$0	$73,614	$105,07E	$2,104	$0
396	Power Operated Equipment	F134	Total Labor	$477,874	$318,454	$0	$0	$32,568	$46,486	$931	$0
397	Communication Equipment	F134	Total Labor	$2,608,692	$1,738,42E	$0	$0	$177,78E	$253,76E	$5,081	$0
398	Miscellaneous Equipment	F134	Total Labor	$4,809,53E	$3,205,06E	$0	$0	$327,774	$467,85E	$9,368	$0
399	Other Tangible Property	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
	General and Intangible Plant Depreciation Reserve			$28,111,172	$18,733,23E	$0	$0	$1,915,801	$2,734,54E	$54,757	$0
Total Depreciation Reserve				$784,045,954	$555,837,75E	$0	$0	$26,965,124	$50,537,87E	$74,794,85E	$0
NET UTILITY PLANT IN SERVICE				**$950,636,878**	**$639,182,978**	**$0**	**$0**	**$32,881,409**	**$72,706,835**	**$119,107,015**	**$0**

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

DEPRECIATION RESERVE (Page 2 of 2)

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
Distribution Plant Depreciation Reserve													
360	Land and Land Rights	$3	$0	$4	$4	$6	$2	$0	$1	$0	$0	$0	$0
361	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
362	Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
363	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
364	Poles, Towers and Fixtures	$4,728,549	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
365	Overhead Conductors and Devices	$2,075,884	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
366	Underground Conduit	$670,353	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
367	Underground Conductors and Devices	$1,753,948	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368	Line Transformers	$0	$0	$11,826,493	$11,778,860	$0	$0	$0	$0	$0	$0	$0	$0
369	Services	$0	$0	$0	$0	$24,968,338	$0	$0	$0	$0	$0	$0	$0
370	Meters	$0	$0	$0	$0	$0	$6,607,188	$0	$0	$0	$0	$0	$0
371	Installation on Customers' Premises	$0	$0	$0	$0	$0	$0	$1,896,814	$0	$0	$0	$0	$0
372	Leased Property on Customers' Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
373	Street Lighting and Signal Systems	$0	$0	$0	$0	$0	$0	$0	$4,931,058	$0	$0	$0	$0
	Total Distribution Plant Depreciation Reserve	$9,228,737	$0	$11,826,497	$11,778,864	$24,968,344	$6,607,190	$1,896,814	$4,931,059	$0	$0	$0	$0
General and Intangible Plant Depreciation Reserve													
301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
302	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303	Miscellaneous Intangible Plant	$0	$0	$453	$451	$0	$796	$0	$220	$1,988	$0	$0	$0
389	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
390	Structures and Improvements	$0	$0	$222,946	$222,048	$0	$391,790	$0	$108,530	$978,924	$0	$0	$0
391	Office Furniture and Equipment	$0	$0	$37,932	$37,780	$0	$66,660	$0	$18,466	$166,555	$0	$0	$0
392	Transportation Equipment	$0	$0	$81,611	$81,283	$0	$143,418	$0	$39,728	$358,343	$0	$0	$0
393	Stores Equipment	$0	$0	$8,133	$8,101	$0	$14,293	$0	$3,959	$35,712	$0	$0	$0
394	Tools, Shop and Garage Equipment	$0	$0	$17,451	$17,381	$0	$30,667	$0	$8,495	$76,624	$0	$0	$0
395	Laboratory Equipment	$0	$0	$20,803	$20,719	$0	$36,558	$0	$10,127	$91,343	$0	$0	$0
396	Power Operated Equipment	$0	$0	$9,204	$9,166	$0	$16,174	$0	$4,480	$40,411	$0	$0	$0
397	Communication Equipment	$0	$0	$50,242	$50,039	$0	$88,292	$0	$24,458	$220,604	$0	$0	$0
398	Miscellaneous Equipment	$0	$0	$92,629	$92,256	$0	$162,779	$0	$45,092	$406,719	$0	$0	$0
399	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	General and Intangible Plant Depreciation Reserve	$0	$0	$541,404	$539,223	$0	$951,426	$0	$263,556	$2,377,224	$0	$0	$0
Total Depreciation Reserve		$9,228,737	$0	$12,367,900	$12,318,088	$24,968,344	$7,558,616	$1,896,814	$5,194,615	$2,377,224	$0	$0	$0
NET UTILITY PLANT IN SERVICE		**$14,412,518**	**$0**	**$15,324,862**	**$15,263,140**	**$17,858,909**	**$9,932,343**	**$935,780**	**$5,552,384**	**$2,431,041**	**$5,047,665**	**$0**	**$0**

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

Description	Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
OTHER RATE BASE COMPONENTS										
Fuel Stock & Expense	F002	Production Energy	$13,495,550	$0	$13,495,550	$0	$0	$0	$0	$0
Materials and Supplies (Generation Inventory	F001	Production Demand	$15,149,364	$15,149,364	$0	$0	$0	$0	$0	$0
Stores	F107	Plant in Service Excluding G&	$3,623,633	$2,506,620	$0	$0	$121,248	$254,996	$419,798	$0
Poles Towers & Fixtures	F120	Subtotal Poles & Towers	$0	$0	$0	$0	$0	$0	$0	$0
T&D Inventory	F104	T&D Overhead Conductors	$5,445,406	$0	$0	$0	$1,036,233	$1,144,733	$2,937,996	$0
Allowance Inventory	F001	Production Demand	$183,973	$183,973	$0	$0	$0	$0	$0	$0
Demand-Side Management	F016	DSM-Related	$28,569,362	$0	$0	$0	$0	$0	$0	$0
MISO Day 2 Startup Costs	F137	Transmission Plant	$655,724	$1,550	$0	$0	$210,156	$441,980	$2,038	$0
Other	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Rate Base Components			$67,123,013	$17,841,508	$13,495,550	$0	$1,367,637	$1,841,709	$3,359,832	$0
TOTAL RATE BASE										
Total Utility Plant in Service			$1,734,682,832	$1,195,020,736	$0	$0	$59,846,532	$123,244,713	$193,901,870	$0
Less: Depreciation Reserve			($784,045,954)	($555,837,759)	$0	$0	($26,965,124)	($50,537,878)	($74,794,855)	$0
Plus: Other Rate Base Components			$67,123,013	$17,841,508	$13,495,550	$0	$1,367,637	$1,841,709	$3,359,832	$0
Total Rate Base			**$1,017,759,890**	**$657,024,486**	**$13,495,550**	**$0**	**$34,249,046**	**$74,548,544**	**$122,466,847**	**$0**

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
OTHER RATE BASE COMPONENTS												
Fuel Stock & Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Materials and Supplies (Generation Inventory)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Stores	$51,213	$0	$57,617	$57,385	$92,774	$33,721	$6,136	$22,126	$0	$0	$0	$0
Poles Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
T&D Inventory	$326,444	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demand-Side Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,569,362	$0	$0
MISO Day 2 Startup Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Rate Base Components	$377,657	$0	$57,617	$57,385	$92,774	$33,721	$6,136	$22,126	$0	$28,569,362	$0	$0
TOTAL RATE BASE												
Total Utility Plant in Service	$23,641,255	$0	$27,692,763	$27,581,227	$42,827,253	$17,490,959	$2,832,594	$10,746,999	$4,808,264	$5,047,665	$0	$0
Less: Depreciation Reserve	($9,228,737)	$0	($12,367,900)	($12,318,088)	($24,968,344)	($7,558,616)	($1,896,814)	($5,194,615)	($2,377,224)	$0	$0	$0
Plus: Other Rate Base Components	$377,657	$0	$57,617	$57,385	$92,774	$33,721	$6,136	$22,126	$0	$28,569,362	$0	$0
Total Rate Base	**$14,790,175**	**$0**	**$15,382,479**	**$15,320,525**	**$17,951,683**	**$9,966,064**	**$941,916**	**$5,574,510**	**$2,431,041**	**$33,617,027**	**$0**	**$0**

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

OPERATION AND MAINTENANCE EXPENSES (Page 1 of 5)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Steam Power Generation Expenses											
Operation											
500	Operation Supervision and Engineering	F001	Production Demand	$3,639,362	$3,639,362	$0	$0	$0	$0	$0	$0
501	*Retail (FAC) Fuel*	F018	FAC Fuel	$127,995,233	$0	$0	$127,995,233	$0	$0	$0	$0
501	Non-FAC Fuel	F017	Non-FAC Fuel	$19,045,083	$0	$0	$0	$0	$0	$0	$0
502	WPM Fuel	F030	WPM Fuel	$16,295,008	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses	F001	Production Demand	$9,478,392	$9,478,392	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	F001	Production Demand	$2,008,391	$2,008,391	$0	$0	$0	$0	$0	$0
502	Chemicals - SO2 Equipment	F001	Production Demand	$14,561,531	$14,561,531	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	F001	Production Demand	$750,462	$750,462	$0	$0	$0	$0	$0	$0
502	Steam Expenses-Scrubber Byproducts	F001	Production Demand	($443,439)	($443,439)	$0	$0	$0	$0	$0	$0
503	*Steam from Other Sources*	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
504	Steam Transferred - Cr.	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
505	Electric Expenses	F001	Production Demand	$2,624,704	$2,624,704	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	F001	Production Demand	$4,216,969	$4,216,969	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	F001	Production Demand	$999,966	$999,966	$0	$0	$0	$0	$0	$0
507	Rents	F001	Production Demand	$1,286,826	$1,286,826	$0	$0	$0	$0	$0	$0
	Total Operation Expenses			$202,458,488	$39,123,164	$0	$127,995,233	$0	$0	$0	$0
Maintenance											
510	Maintenance Supervision and Engineering	F001	Production Demand	$127,259	$127,259	$0	$0	$0	$0	$0	$0
511	Maintenance of Structures	F001	Production Demand	$29,033	$29,033	$0	$0	$0	$0	$0	$0
512	Maintenance of Boiler Plan	F001	Production Demand	$15,362,748	$15,362,748	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipment	F001	Production Demand	$3,853,992	$3,853,992	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipment	F001	Production Demand	$570,559	$570,559	$0	$0	$0	$0	$0	$0
513	Maintenance of Electric Plan	F001	Production Demand	$5,741,285	$5,741,285	$0	$0	$0	$0	$0	$0
514	Maintenance of Miscellaneous Steam Plan	F001	Production Demand	$1,196,171	$1,196,171	$0	$0	$0	$0	$0	$0
	Total Maintenance Expenses			$26,881,046	$26,881,046	$0	$0	$0	$0	$0	$0
Total Steam Power Generation Expenses				$229,339,534	$66,004,210	$0	$127,995,233	$0	$0	$0	$0
Hydraulic and Pumped Storage Power Generation Expenses											
Operation											
535	Operation Supervision and Engineering	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
536	*Water for Power*	*F000*	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
537	Hydraulic and Pumped Storage Expenses	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
538	Electric Expenses	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
539	Misc. Hydraulic & Pumped Storage Power Generation Expe	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
540	Rents	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Expenses			$0	$0	$0	$0	$0	$0	$0	$0
Total Hydraulic and Pumped Storage Power Generation Expenses				$0	$0	$0	$0	$0	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	OPERATION AND MAINTENANCE EXPENSES (												
	Steam Power Generation Expenses												
	Operation												
500	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
501	Retail (FAC) Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
501	Non-FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,045,083	$0
502	WPM Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,295,008
502	Steam Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Chemicals - SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses-Scrubber Byproducts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
503	Steam from Other Sources	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
504	Steam Transferred - Cr.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
505	Electric Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
507	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,045,083	$16,295,008
	Maintenance												
510	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
511	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512	Maintenance of Boiler Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
513	Maintenance of Electric Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
514	Maintenance of Miscellaneous Steam Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Steam Power Generation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,045,083	$16,295,008
	Hydraulic and Pumped Storage Power Generation Expenses												
	Operation												
535	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
536	Water for Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537	Hydraulic and Pumped Storage Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538	Electric Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539	Misc. Hydraulic & Pumped Storage Power Generation Expe	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
540	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic and Pumped Storage Power Generation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

OPERATION AND MAINTENANCE EXPENSES (Page 2 of 5)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Other Power Generation Expenses											
Operation											
546	Operations Supervision and Engineering	F001	Production Demand	$173	$173	$0	$0	$0	$0	$0	$0
546	Operations Supervision and Engineering	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
547	Fuel - Cost of Gas Delivered	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
547	Fuel - Cost of Oil Delivered	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
547	Fuel - All Other Expenses	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
548	Generation Expenses	F001	Production Demand	$4,158	$4,158	$0	$0	$0	$0	$0	$0
548	Generation Expenses	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Generation Expense:	F001	Production Demand	$3,992	$3,992	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Generation Expense:	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Power Expenses - Operation of Al..	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Gen. Expenses - Air Mon..	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
550	Rents	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Expenses			$8,323	$8,323	$0	$0	$0	$0	$0	$0
Maintenance											
551	Maintenance Supervision and Engineering	F001	Production Demand	$2,311,803	$2,311,803	$0	$0	$0	$0	$0	$0
551	Mngt & Supv - Mtce Other Power Production	F001	Production Demand	$24,762	$24,762	$0	$0	$0	$0	$0	$0
552	Maintenance of Structures	F001	Production Demand	$1,437,124	$1,437,124	$0	$0	$0	$0	$0	$0
552	Maintenance of Structures-Other Power Production	F001	Production Demand	$10,015	$10,015	$0	$0	$0	$0	$0	$0
553	Maintenance of Generating and Electric Plan	F001	Production Demand	$489,407	$489,407	$0	$0	$0	$0	$0	$0
553	Maintenance of Generating and Electric Plan	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
554	Maintenance of Miscellaneous Other Power Generation Pla	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Expense			$4,273,112	$4,273,112	$0	$0	$0	$0	$0	$0
Total Other Power Generation Expense				$4,281,435	$4,281,435	$0	$0	$0	$0	$0	$0
Other Power Supply Expenses											
Operation											
556	System Control and Load Dispatching	F001	Production Demand	$1,511,693	$1,511,693	$0	$0	$0	$0	$0	$0
556	Transmission of Electricity by Others	F001	Production Demand	$8,751	$8,751	$0	$0	$0	$0	$0	$0
557	Unrealized Gain/Loss on Derivative	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
557	Realized Gain/Loss on Derivative	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
557	Operations Supervision	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
557	All Other Expenses	F001	Production Demand	$2,156	$2,156	$0	$0	$0	$0	$0	$0
557	Allowance Expense	F001	Production Demand	$117,025	$117,025	$0	$0	$0	$0	$0	$0
557	NOx Allowance Expense	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Supply Expenses				$1,639,624	$1,639,624	$0	$0	$0	$0	$0	$0
Total Production Expenses				$235,260,593	$71,925,269	$0	$127,995,233	$0	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

OPERATION AND MAINTENANCE EXPENSES (

Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
Other Power Generation Expenses												
Operation												
546 Operations Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
546 Operations Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
547 Fuel - Cost of Gas Delivered	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
547 Fuel - Cost of Oil Delivered	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
547 Fuel - All Other Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548 Generation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548 Generation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549 Miscellaneous Other Power Generation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549 Miscellaneous Other Power Generation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549 Miscellaneous Power Expenses - Operation of Ai..	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549 Miscellaneous Other Power Gen. Expenses - Air Mon..	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
550 Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Operation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance												
551 Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
551 Mngt & Supv - Mtce Other Power Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
552 Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
552 Maintenance of Structures-Other Power Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
553 Maintenance of Generating and Electric Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
553 Maintenance of Generating and Electric Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
554 Maintenance of Miscellaneous Other Power Generation Pla	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Generation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Power Supply Expenses												
Operation												
556 System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
556 Transmission of Electricity by Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557 Unrealized Gain/Loss on Derivative	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557 Realized Gain/Loss on Derivative	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557 Operations Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557 All Other Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557 Allowance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557 NOx Allowance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Supply Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,045,083	$16,295,008

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

OPERATION AND MAINTENANCE EXPENSES (Page 3 of 5)

	Description	Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Transmission Expenses											
Operation											
560	Operation Supervision and Engineering	F101	Subtotal Trans. O&M Operation	$28,456	$0	$0	$0	$27,409	$1,047	$0	$0
561	Load Dispatching	F003	Transmission Demand	$4,644,724	$0	$0	$0	$4,644,724	$0	$0	$0
562	Station Expenses	F021	Trans Station Equipment Special Analysis	$122,017	$0	$0	$0	$14,872	$107,145	$0	$0
563	Overhead Line Expenses	F024	Trans Overhead Conductors Analysis	$155,055	$0	$0	$0	$73,671	$81,384	$0	$0
564	Underground Line Expenses	F004	Sub-Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
566	Miscellaneous Transmission Expenses	F003	Transmission Demand	$200,052	$0	$0	$0	$200,052	$0	$0	$0
567	Rents	F003	Transmission Demand	$4,222	$0	$0	$0	$4,222	$0	$0	$0
	MISO Day 1 Costs	F003	Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
	MISO Day 2 Costs	F137	Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0
	MISO Day 1 Administrative Costs	F003	Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
	FERC Schedule 10	F003	Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Operation Expenses			$5,154,525	$0	$0	$0	$4,964,949	$189,576	$0	$0
Maintenance											
568	Maintenance Supervision and Engineering	F136	Subtotal Transmission Maintenance O&M	$30,000	$133	$0	$0	$8,244	$21,448	$175	$0
569	Maintenance of Structures	F020	Trans Plant Structures & Impr Analysis	$26,546	$6,234	$0	$0	$5,685	$6,431	$8,196	$0
570	Maintenance of Station Equipment	F021	Trans Station Equipment Special Analysis	$777,754	$0	$0	$0	$94,795	$682,959	$0	$0
571	Maintenance of Overhead Lines	F024	Trans Overhead Conductors Analysis	$58,863	$0	$0	$0	$27,967	$30,896	$0	$0
571	Maintenance of Overhead Lines-Tree Cutting	F024	Trans Overhead Conductors Analysis	$542,804	$0	$0	$0	$257,900	$284,904	$0	$0
572	Maintenance of Underground Lines	F004	Sub-Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
573	Maintenance of Miscellaneous Transmission Plant	F136	Subtotal Transmission Maintenance O&M	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Maintenance Expense			$1,435,967	$6,367	$0	$0	$394,591	$1,026,638	$8,371	$0
Total Transmission Expenses				$6,590,492	$6,367	$0	$0	$5,359,540	$1,216,214	$8,371	$0
Distribution Expenses											
Operation											
580	Operation Supervision and Engineering	F139	Subtotal Distribution Operation O&M	$632,285	$0	$0	$0	$40,765	$260,627	$0	$0
581	Load Dispatching	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
582	Station Expenses	F021	Trans Station Equipment Special Analysis	$144,431	$0	$0	$0	$17,604	$126,827	$0	$0
583	Removing & Resetting Line Transformers	F019	Line Transformer Zero Intercept Analysis	$787,592	$0	$0	$0	$0	$0	$0	$0
583	Overhead Line Expenses	F024	Trans Overhead Conductors Analysis	$309,994	$0	$0	$0	$147,286	$162,708	$0	$0
584	Underground Line Expenses	F004	Sub-Transmission Demand	$243,699	$0	$0	$0	$0	$243,699	$0	$0
584	Locating Lines, Mains-Distribution	F004	Sub-Transmission Demand	$520,971	$0	$0	$0	$0	$520,971	$0	$0
585	Street Lighting and Signal System Expenses	F014	Street Lighting	$28,029	$0	$0	$0	$0	$0	$0	$0
586	Removing and Resetting Meters	F012	Meters	$241,851	$0	$0	$0	$0	$0	$0	$0
586	Meter Testing - Distribution	F012	Meters	$280,953	$0	$0	$0	$0	$0	$0	$0
587	Customer Installations Expenses	F139	Subtotal Distribution Operation O&M	$1,408,950	$0	$0	$0	$90,839	$580,766	$0	$0
588	Miscellaneous Distribution Expenses	F139	Subtotal Distribution Operation O&M	$1,875,582	$0	$0	$0	$120,924	$773,112	$0	$0
588	Miscellaneous Expenses - Distribution	F139	Subtotal Distribution Operation O&M	$3,840	$0	$0	$0	$248	$1,583	$0	$0
589	Rents	F139	Subtotal Distribution Operation O&M	$55	$0	$0	$0	$4	$23	$0	$0
	Total Distribution Operations Expense			$6,478,231	$0	$0	$0	$417,668	$2,670,315	$0	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

Description		Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
OPERATION AND MAINTENANCE EXPENSES (													
Transmission Expenses													
Operation													
560	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
561	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
562	Station Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
563	Overhead Line Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
564	Underground Line Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
566	Miscellaneous Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
567	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	MISO Day 1 Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	MISO Day 2 Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	MISO Day 1 Administrative Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	FERC Schedule 10	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Operation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance													
568	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
569	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
570	Maintenance of Station Equipmen	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
571	Maintenance of Overhead Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
571	Maintenance of Overhead Lines-Tree Cutting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
572	Maintenance of Underground Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
573	Maintenance of Miscellaneous Transmission Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Maintenance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Transmission Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Expenses													
Operation													
580	Operation Supervision and Engineering	$0	$0	$97,553	$97,160	$0	$129,250	$0	$6,930	$0	$0	$0	$0
581	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
582	Station Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
583	Removing & Resetting Line Transformers	$0	$0	$394,591	$393,001	$0	$0	$0	$0	$0	$0	$0	$0
583	*Overhead Line Expenses*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
584	Underground Line Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
584	Locating Lines, Mains-Distributior	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
585	Street Lighting and Signal System Expenses	$0	$0	$0	$0	$0	$0	$0	$28,029	$0	$0	$0	$0
586	Removing and Resetting Meters	$0	$0	$0	$0	$0	$241,851	$0	$0	$0	$0	$0	$0
586	Meter Testing - Distribution	$0	$0	$0	$0	$0	$280,953	$0	$0	$0	$0	$0	$0
587	Customer Installations Expenses	$0	$0	$217,382	$216,506	$0	$288,015	$0	$15,442	$0	$0	$0	$0
588	Miscellaneous Distribution Expenses	$0	$0	$289,377	$288,211	$0	$383,403	$0	$20,556	$0	$0	$0	$0
588	Miscellaneous Expenses - Distributior	$0	$0	$592	$590	$0	$785	$0	$42	$0	$0	$0	$0
589	Rents	$0	$0	$8	$8	$0	$11	$0	$1	$0	$0	$0	$0
	Total Distribution Operations Expense	$0	$0	$999,503	$995,478	$0	$1,324,268	$0	$70,999	$0	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

OPERATION AND MAINTENANCE EXPENSES (Page 4 of 5)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Maintenance											
590	Maintenance Supervision and Engineering	F138	Subtotal Distribution Maintenance O&M	$700,683	$0	$0	$0	$240,113	$386,129	$43,813	$0
591	Maintenance of Structures	F005	Primary Distribution Demand	$575,275	$0	$0	$0	$0	$0	$575,275	$0
592	Maintenance of Station Equipmen	F021	Trans Station Equipment Special Analysis	$412,370	$0	$0	$0	$50,261	$362,109	$0	$0
593	Tree and Brush Clearing	F024	Trans Overhead Conductors Analysis	$1,349,233	$0	$0	$0	$641,055	$708,177	$0	$0
593	Maintenance of Overhead Lines	F024	Trans Overhead Conductors Analysis	$5,180,534	$0	$0	$0	$2,461,405	$2,719,129	$0	$0
594	Maintenance of Underground Lines	F004	Sub-Transmission Demand	$1,280,510	$0	$0	$0	$0	$1,280,510	$0	$0
595	Maintenance of Line Transformers	F019	Line Transformer Zero Intercept Analysis	$402,142	$0	$0	$0	$0	$0	$0	$0
596	Maintenance of Street Lighting and Signal Systems	F014	Street Lighting	$372,618	$0	$0	$0	$0	$0	$0	$0
597	Maintenance of Meters	F012	Meters	$49,501	$0	$0	$0	$0	$0	$0	$0
598	Maintenance of Miscellaneous Distribution Plan	F138	Subtotal Distribution Maintenance O&M	$278,416	$0	$0	$0	$95,409	$153,428	$17,409	$0
	Total Distribution Maintenance Expenses			$10,601,281	$0	$0	$0	$3,488,243	$5,609,482	$636,497	$0
Total Distribution Expenses				$17,079,512	$0	$0	$0	$3,905,911	$8,279,797	$636,497	$0
Customer Accounts Expense											
901	Supervision	F015	Customer Accounts-Related	$249,916	$0	$0	$0	$0	$0	$0	$0
902	Meter Reading Expenses	F015	Customer Accounts-Related	$1,438,613	$0	$0	$0	$0	$0	$0	$0
903	Customer Billing and Accounting	F015	Customer Accounts-Related	$2,903,248	$0	$0	$0	$0	$0	$0	$0
904	Uncollectible Accounts	F015	Customer Accounts-Related	$1,568,107	$0	$0	$0	$0	$0	$0	$0
905	Misc. Customer Accounts Expenses	F015	Customer Accounts-Related	$130,576	$0	$0	$0	$0	$0	$0	$0
Total Customer Accounts Expense				$6,290,460	$0	$0	$0	$0	$0	$0	$0
Customer Service and Informational Expenses											
907	Supervision	F015	Customer Accounts-Related	($1)	$0	$0	$0	$0	$0	$0	$0
908	Residential Assistance	F015	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
908	Commercial Assistance	F015	Customer Accounts-Related	$12,199	$0	$0	$0	$0	$0	$0	$0
908	Industrial Assistance	F015	Customer Accounts-Related	$123,138	$0	$0	$0	$0	$0	$0	$0
908	All Other Customer Assistance	F015	Customer Accounts-Related	$158,216	$0	$0	$0	$0	$0	$0	$0
909	Informational and Instructional Advertising	F015	Customer Accounts-Related	$430,898	$0	$0	$0	$0	$0	$0	$0
910	Miscellaneous Customer Service and Informationa	F015	Customer Accounts-Related	$634,571	$0	$0	$0	$0	$0	$0	$0
Total Customer Service Expenses				$1,359,019	$0	$0	$0	$0	$0	$0	$0
Sales Expenses											
911	Supervision	F015	Customer Accounts-Related	$50,841	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating and Selling Expenses-Residential Solicitatio	F015	Customer Accounts-Related	$4,225	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating and Selling Expenses-Commercial Solicitati	F015	Customer Accounts-Related	$2,496	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating and Selling Expenses-Industrial Solicitatior	F015	Customer Accounts-Related	$2,541	$0	$0	$0	$0	$0	$0	$0
912	Selling Expenses - Area Development	F015	Customer Accounts-Related	$10,100	$0	$0	$0	$0	$0	$0	$0
912	Selling Expenses - Other	F015	Customer Accounts-Related	$155,874	$0	$0	$0	$0	$0	$0	$0
912	Sales Expenses	F015	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
913	Advertising - Salaries and Expenses	F015	Customer Accounts-Related	$599	$0	$0	$0	$0	$0	$0	$0
913	Promotional Advertising Expenses	F015	Customer Accounts-Related	$394	$0	$0	$0	$0	$0	$0	$0
916	Miscellaneous Sales Expenses	F015	Customer Accounts-Related	$8,860	$0	$0	$0	$0	$0	$0	$0
912	DSM Expenses	F015	Customer Accounts-Related	$1,076,740	$0	$0	$0	$0	$0	$0	$0
Total Sales Expenses				$1,312,670	$0	$0	$0	$0	$0	$0	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	OPERATION AND MAINTENANCE EXPENSES (												
	Maintenance												
590	Maintenance Supervision and Engineering	$0	$0	$15,345	$15,283	$0	$0	$0	$0	$0	$0	$0	$0
591	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
592	Maintenance of Station Equipmen	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
593	Tree and Brush Clearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
593	Maintenance of Overhead Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
594	Maintenance of Underground Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
595	Maintenance of Line Transformers	$0	$0	$201,477	$200,665	$0	$0	$0	$0	$0	$0	$0	$0
596	Maintenance of Street Lighting and Signal Systems	$0	$0	$0	$0	$0	$0	$0	$372,618	$0	$0	$0	$0
597	Maintenance of Meters	$0	$0	$0	$0	$0	$49,501	$0	$0	$0	$0	$0	$0
598	Maintenance of Miscellaneous Distribution Plan	$0	$0	$6,097	$6,073	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Maintenance Expenses	$0	$0	$222,919	$222,021	$0	$49,501	$0	$372,618	$0	$0	$0	$0
	Total Distribution Expenses	$0	$0	$1,222,422	$1,217,498	$0	$1,373,769	$0	$443,617	$0	$0	$0	$0
	Customer Accounts Expense												
901	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$249,916	$0	$0	$0
902	Meter Reading Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$1,438,613	$0	$0	$0
903	Customer Billing and Accounting	$0	$0	$0	$0	$0	$0	$0	$0	$2,903,248	$0	$0	$0
904	Uncollectible Accounts	$0	$0	$0	$0	$0	$0	$0	$0	$1,568,107	$0	$0	$0
905	Misc. Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$130,576	$0	$0	$0
	Total Customer Accounts Expense	$0	$0	$0	$0	$0	$0	$0	$0	$6,290,460	$0	$0	$0
	Customer Service and Informational Expenses												
907	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	($1)	$0	$0	$0
908	Residential Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
908	Commercial Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$12,199	$0	$0	$0
908	Industrial Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$123,138	$0	$0	$0
908	All Other Customer Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$158,216	$0	$0	$0
909	Informational and Instructional Advertising	$0	$0	$0	$0	$0	$0	$0	$0	$430,896	$0	$0	$0
910	Miscellaneous Customer Service and Informationa	$0	$0	$0	$0	$0	$0	$0	$0	$634,571	$0	$0	$0
	Total Customer Service Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$1,359,019	$0	$0	$0
	Sales Expenses												
911	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$50,841	$0	$0	$0
912	Demonstrating and Selling Expenses-Residential Solicitation	$0	$0	$0	$0	$0	$0	$0	$0	$4,225	$0	$0	$0
912	Demonstrating and Selling Expenses-Commercial Solicitatio	$0	$0	$0	$0	$0	$0	$0	$0	$2,496	$0	$0	$0
912	Demonstrating and Selling Expenses-Industrial Solicitation	$0	$0	$0	$0	$0	$0	$0	$0	$2,541	$0	$0	$0
912	Selling Expenses - Area Development	$0	$0	$0	$0	$0	$0	$0	$0	$10,100	$0	$0	$0
912	Selling Expenses - Other	$0	$0	$0	$0	$0	$0	$0	$0	$155,874	$0	$0	$0
912	Sales Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
913	Advertising - Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$599	$0	$0	$0
913	Promotional Advertising Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$394	$0	$0	$0
916	Miscellaneous Sales Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$8,860	$0	$0	$0
912	DSM Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$1,076,740	$0	$0	$0
	Total Sales Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$1,312,670	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

OPERATION AND MAINTENANCE EXPENSES (Page 5 of 5)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Administrative & General											
920	Administrative and General Salaries	F134	Total Labor	$11,201,818	$7,464,873	$0	$0	$763,414	$1,089,668	$21,820	$0
921	Expenses of General Officers, Executives & Other Ger	F134	Total Labor	$23,200	$15,461	$0	$0	$1,581	$2,257	$45	$0
921	All Other Expenses	F134	Total Labor	$3,929,819	$2,618,825	$0	$0	$267,821	$382,277	$7,655	$0
921	Bank Charges	F134	Total Labor	$579,962	$386,486	$0	$0	$39,525	$56,416	$1,130	$0
921	Travel	F134	Total Labor	$6,551	$4,365	$0	$0	$446	$637	$13	$0
921	Meals & Entertainment	F134	Total Labor	$8	$5	$0	$0	$1	$1	$0	$0
921	Telephone	F134	Total Labor	$336	$224	$0	$0	$23	$33	$1	$0
921	Office Supplies	F134	Total Labor	$860	$573	$0	$0	$59	$84	$2	$0
922	Administrative Expenses Transferred - Credit	F134	Total Labor	($1,335,276)	($889,826)	$0	$0	($91,000)	($129,890)	($2,601)	$0
923	Corporate Administrative Expenses (Asset Charge)	F127	Asset Charge Study	$8,973,132	$4,786,233	$0	$0	$533,201	$781,091	$593,023	$0
923	Outside Services Employed - Legal	F126	50% Plant / 50% Labor	$2,022,401	$1,370,477	$0	$0	$103,801	$170,209	$115,001	$0
923	Outside Services Employed - Other Special Services	F126	50% Plant / 50% Labor	$1,798,499	$1,218,750	$0	$0	$92,309	$151,365	$102,269	$0
923	Outside Services Employed - Consulting Fees	F126	50% Plant / 50% Labor	$4,880	$3,307	$0	$0	$250	$411	$277	$0
924	Property Insurance	F103	Plant in Service	$1,455,365	$1,002,599	$0	$0	$50,210	$103,400	$162,680	$0
925	Injuries and Damages	F134	Total Labor	$2,116,440	$1,410,392	$0	$0	$144,237	$205,879	$4,123	$0
926	Employee Pensions	F134	Total Labor	$46,260	$30,828	$0	$0	$3,153	$4,500	$90	$0
926	All Other Employee Benefits	F134	Total Labor	$26,625	$17,743	$0	$0	$1,815	$2,590	$52	$0
927	Franchise Requirement	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
928	Regulatory Commission Expenses	F125	Rate Base	$831,259	$536,627	$11,023	$0	$27,973	$60,888	$100,025	$0
930.2	Industry Association Dues & Assessments	F134	Total Labor	$238,225	$158,753	$0	$0	$16,235	$23,174	$464	$0
929	Duplicate Charges - Credit	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
930.1	Institutional or Goodwill Advertising Expense	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
930.2	Miscellaneous General Expense	F134	Total Labor	$250,758	$167,105	$0	$0	$17,089	$24,393	$488	$0
930.2	Amortization of Restricted Stock	F134	Total Labor	$1,245,739	$830,158	$0	$0	$84,898	$121,180	$2,427	$0
931	Rents	F134	Total Labor	$49,279	$32,840	$0	$0	$3,358	$4,794	$96	$0
935	Maintenance of General Plant - Structures	F134	Total Labor	$322,842	$215,141	$0	$0	$22,002	$31,405	$629	$0
935	Maintenance of General Plant - All Othe	F134	Total Labor	$86,846	$57,874	$0	$0	$5,919	$8,448	$169	$0
Total Administrative and General Expenses				$33,875,827	$21,439,812	$11,023	$0	$2,088,319	$3,095,207	$1,109,877	$0
Total Operation & Maintenance Expense - Proforma A				$301,768,572	$93,371,448	$11,023	$127,995,233	$11,353,770	$12,591,218	$1,754,745	$0
Proforma B Adjustments											
	Going Level Uncollectible Accounts	F015	Customer Accounts-Related	$343,557	$0	$0	$0	$0	$0	$0	$0
	IURC Fee	F125	Rate Base	$99,451	$64,202	$1,319	$0	$3,347	$7,285	$11,967	$0
	Total			$443,008	$64,202	$1,319	$0	$3,347	$7,285	$11,967	$0
Total Operation & Maintenance Expense - Proforma B				$302,211,580	$93,435,650	$12,341	$127,995,233	$11,357,117	$12,598,502	$1,766,712	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	OPERATION AND MAINTENANCE EXPENSES (												
	Administrative & General												
920	Administrative and General Salaries	$0	$0	$215,74C	$214,871	$0	$379,127	$0	$105,022	$947,283	$0	$0	$0
921	Expenses of General Officers, Executives & Other Ger	$0	$0	$447	$445	$0	$785	$0	$218	$1,962	$0	$0	$0
921	All Other Expenses	$0	$0	$75,686	$75,381	$0	$133,005	$0	$36,844	$332,326	$0	$0	$0
921	Bank Charges	$0	$0	$11,170	$11,125	$0	$19,629	$0	$5,437	$49,045	$0	$0	$0
921	Travel	$0	$0	$126	$126	$0	$222	$0	$61	$554	$0	$0	$0
921	Meals & Entertainment	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0
921	Telephone	$0	$0	$6	$6	$0	$11	$0	$3	$28	$0	$0	$0
921	Office Supplies	$0	$0	$17	$16	$0	$29	$0	$8	$73	$0	$0	$0
922	Administrative Expenses Transferred - Credit	$0	$0	($25,717)	($25,613)	$0	($45,193)	$0	($12,519)	($112,918)	$0	$0	$0
923	Corporate Administrative Expenses (Asset Charge)	$69,921	$0	$148,185	$147,588	$126,665	$153,718	$8,378	$60,321	$1,549,88C	$14,929	$0	$0
923	Outside Services Employed - Legal	$13,781	$0	$35,618	$35,475	$24,965	$44,420	$1,651	$15,745	$88,315	$2,942	$0	$0
923	Outside Services Employed - Other Special Services	$12,255	$0	$31,675	$31,547	$22,201	$39,502	$1,468	$14,002	$78,538	$2,617	$0	$0
923	Outside Services Employed - Consulting Fees	$33	$0	$86	$86	$60	$107	$4	$38	$213	$7	$0	$0
924	Property Insurance	$19,835	$0	$23,234	$23,140	$35,931	$14,675	$2,376	$9,017	$4,034	$4,235	$0	$0
925	Injuries and Damages	$0	$0	$40,761	$40,597	$0	$71,631	$0	$19,843	$178,977	$0	$0	$0
926	Employee Pensions	$0	$0	$891	$887	$0	$1,566	$0	$434	$3,912	$0	$0	$0
926	All Other Employee Benefits	$0	$0	$513	$511	$0	$901	$0	$250	$2,252	$0	$0	$0
927	Franchise Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
928	Regulatory Commission Expenses	$12,080	$0	$12,564	$12,513	$14,662	$8,140	$769	$4,553	$1,986	$27,457	$0	$0
930.2	Industry Association Dues & Assessments	$0	$0	$4,588	$4,570	$0	$8,063	$0	$2,233	$20,145	$0	$0	$0
929	Duplicate Charges - Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.1	Institutional or Goodwill Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
930.2	Miscellaneous General Expense	$0	$0	$4,829	$4,810	$0	$8,487	$0	$2,351	$21,205	$0	$0	$0
930.2	Amortization of Restricted Stock	$0	$0	$23,992	$23,896	$0	$42,162	$0	$11,679	$105,346	$0	$0	$0
931	Rents	$0	$0	$949	$945	$0	$1,668	$0	$462	$4,167	$0	$0	$0
935	Maintenance of General Plant - Structures	$0	$0	$6,218	$6,193	$0	$10,927	$0	$3,027	$27,301	$0	$0	$0
935	Maintenance of General Plant - All Othe	$0	$0	$1,673	$1,666	$0	$2,939	$0	$814	$7,344	$0	$0	$0
	Total Administrative and General Expenses	$127,906	$0	$613,25C	$610,781	$224,486	$896,521	$14,647	$279,844	$3,311,968	$52,187	$0	$0
	Total Operation & Maintenance Expense - Proforma /	$127,906	$0	$1,835,672	$1,828,279	$224,486	$2,270,291	$14,647	$723,461	$12,274,117	$52,187	$19,045,083	$16,295,008
	Proforma B Adjustments												
	Going Level Uncollectible Accounts	$0	$0	$0	$0	$0	$0	$0	$0	$343,557	$0	$0	$0
	IURC Fee	$1,445	$0	$1,503	$1,497	$1,754	$974	$92	$545	$238	$3,285	$0	$0
	Total	$1,445	$0	$1,503	$1,497	$1,754	$974	$92	$545	$343,795	$3,285	$0	$0
	Total Operation & Maintenance Expense - Proforma E	$129,351	$0	$1,837,175	$1,829,776	$226,24C	$2,271,265	$14,739	$724,005	$12,617,911	$55,472	$19,045,083	$16,295,008

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

DEPRECIATION AND AMORTIZATION EXPENSES (Page 1 of 2)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Steam Production Plant											
310	Land and Land Rights	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
311	Structures and Improvements	F001	Production Demand	$1,500,614	$1,500,614	$0	$0	$0	$0	$0	$0
312	Boiler Plant Equipment	F001	Production Demand	$33,417,764	$33,417,764	$0	$0	$0	$0	$0	$0
313	Engines and Engine Driven Generators	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
314	Turbogenerator Units	F001	Production Demand	$5,269,602	$5,269,602	$0	$0	$0	$0	$0	$0
315	Accessory Electric Equipment	F001	Production Demand	$593,676	$593,676	$0	$0	$0	$0	$0	$0
316	Miscellaneous Power Plant Equipment	F001	Production Demand	$392,107	$392,107	$0	$0	$0	$0	$0	$0
	Total Steam Production Plant			$41,173,763	$41,173,763	$0	$0	$0	$0	$0	$0
Hydraulic and Pumped Storage Production Plant											
330	Land and Land Rights	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
331	Structures and Improvements	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
332	Reservoirs, Dams and Waterways	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
333	Water Wheels, Turbines and Generators	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
334	Accessory Electric Equipment	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
335	Miscellaneous Power Plant Equipment	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
336	Roads, Railroads and Bridges	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic and Pumped Storage Production Plant			$0	$0	$0	$0	$0	$0	$0	$0
Other Production Plant											
340	Land and Land Rights	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
341	Structures and Improvements	F001	Production Demand	$57,052	$57,052	$0	$0	$0	$0	$0	$0
342	Fuel Holders, Producers and Accessories	F001	Production Demand	$137,005	$137,005	$0	$0	$0	$0	$0	$0
343	Prime Movers	F001	Production Demand	$1,255,664	$1,255,664	$0	$0	$0	$0	$0	$0
344	Generators	F001	Production Demand	$525,077	$525,077	$0	$0	$0	$0	$0	$0
345	Accessory Electric Equipment	F001	Production Demand	$77,249	$77,249	$0	$0	$0	$0	$0	$0
346	Miscellaneous Power Plant Equipment	F001	Production Demand	$36,919	$36,919	$0	$0	$0	$0	$0	$0
	Total Other Production Plant			$2,088,965	$2,088,965	$0	$0	$0	$0	$0	$0
Transmission Plant											
350	Land and Land Rights (Should be F105)	F105	Subtotal Transmission Plant	$105,189	$249	$0	$0	$33,713	$70,901	$327	$0
352	Structures and Improvements	F020	Trans Plant Structures & Impr Analysis	$29,309	$6,883	$0	$0	$6,277	$7,100	$9,049	$0
353	Station Equipment	F021	Trans Station Equipment Special Analysis	$1,336,027	$0	$0	$0	$162,839	$1,173,189	$0	$0
354	Towers and Fixtures	F022	Transmission Towers Analysis	$65,463	$0	$0	$0	$56,389	$9,073	$0	$0
355	Poles and Fixtures	F023	Transmission Poles Analysis	$1,208,043	$0	$0	$0	$590,816	$617,227	$0	$0
356	Overhead Conductors and Devices	F024	Trans Overhead Conductors Analysis	$713,086	$0	$0	$0	$338,805	$374,280	$0	$0
357	Underground Conduit	F004	Sub-Transmission Demand	$22,320	$0	$0	$0	$0	$22,320	$0	$0
358	Underground Conductors and Devices	F004	Sub-Transmission Demand	$40,564	$0	$0	$0	$0	$40,564	$0	$0
359	Road and Trails	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Plant			$3,520,001	$7,132	$0	$0	$1,188,838	$2,314,654	$9,376	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

Description		Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
DEPRECIATION AND AMORTIZATION EXPENS													
Steam Production Plant													
310	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
311	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
312	Boiler Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
313	Engines and Engine Driven Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
314	Turbogenerator Units	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
315	Accessory Electric Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
316	Miscellaneous Power Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Steam Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Hydraulic and Pumped Storage Production Plant													
330	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
331	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
332	Reservoirs, Dams and Waterways	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
333	Water Wheels, Turbines and Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
334	Accessory Electric Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
335	Miscellaneous Power Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
336	Roads, Railroads and Bridges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic and Pumped Storage Production Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Production Plant													
340	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
341	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
342	Fuel Holders, Producers and Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
343	Prime Movers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
344	Generators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
345	Accessory Electric Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
346	Miscellaneous Power Plant Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Other Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant													
350	Land and Land Rights (Should be F105)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
352	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
353	Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
354	Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
355	Poles and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
356	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
357	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
358	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
359	Road and Trails	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

DEPRECIATION AND AMORTIZATION EXPENSES (Page 2 of 2)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Distribution Plant											
360	Land and Land Rights	F113	Subtotal Distribution Plant	$101	$0	$0	$0	$0	$0	$57	$0
361	Structures and Improvements	F005	Primary Distribution Demand	$20,783	$0	$0	$0	$0	$0	$20,783	$0
362	Station Equipment	F005	Primary Distribution Demand	$1,425,336	$0	$0	$0	$0	$0	$1,425,336	$0
363	Storage Battery Equipment	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
364	Poles, Towers and Fixtures	F025	75% Primary / 25% Secondary Distribution	$1,639,899	$0	$0	$0	$0	$0	$1,229,924	$0
365	Overhead Conductors and Devices	F026	90% Primary / 10% Secondary Distribution	$1,810,286	$0	$0	$0	$0	$0	$1,629,258	$0
366	Underground Conduit	F027	88.94% Primary / 11.06% Secondary Distr	$452,861	$0	$0	$0	$0	$0	$402,775	$0
367	Underground Conductors and Devices	F027	88.94% Primary / 11.06% Secondary Distr	$1,207,380	$0	$0	$0	$0	$0	$1,073,844	$0
368	Line Transformers	F019	Line Transformer Zero Intercept Analysis	$1,322,907	$0	$0	$0	$0	$0	$0	$0
369	Services	F011	Services	$1,400,183	$0	$0	$0	$0	$0	$0	$0
370	Meters	F012	Meters	$460,829	$0	$0	$0	$0	$0	$0	$0
371	Installation on Customers' Premises	F013	Outdoor Lighting	$122,254	$0	$0	$0	$0	$0	$0	$0
372	Leased Property on Customers' Premises	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
373	Street Lighting and Signal Systems	F014	Street Lighting	$288,118	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Plant			$10,150,937	$0	$0	$0	$0	$0	$5,781,975	$0
General and Intangible Plant											
301	Organization	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
302	Franchises and Consents	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
303	Miscellaneous Intangible Plant	F134	Total Labor	$48,399	$32,253	$0	$0	$3,298	$4,708	$94	$0
389	Land and Land Rights	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
390	Structures and Improvements	F134	Total Labor	$705,705	$470,281	$0	$0	$48,094	$68,648	$1,375	$0
391	Office Furniture and Equipment	F134	Total Labor	$454,705	$303,015	$0	$0	$30,989	$44,232	$886	$0
392	Transportation Equipment	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
393	Stores Equipment	F134	Total Labor	$5,403	$3,600	$0	$0	$368	$526	$11	$0
394	Tools, Shop and Garage Equipment	F134	Total Labor	$15,417	$10,274	$0	$0	$1,051	$1,500	$30	$0
395	Laboratory Equipment	F134	Total Labor	$36,571	$24,371	$0	$0	$2,492	$3,558	$71	$0
396	Power Operated Equipment	F134	Total Labor	$56,477	$37,636	$0	$0	$3,849	$5,494	$110	$0
397	Communication Equipment	F134	Total Labor	$60,380	$40,237	$0	$0	$4,115	$5,874	$118	$0
398	Miscellaneous Equipment	F134	Total Labor	$208,761	$139,118	$0	$0	$14,227	$20,307	$407	$0
399	Other Tangible Property	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
	Other	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
	Total General and Intangible Plant			$1,591,818	$1,060,785	$0	$0	$108,484	$154,846	$3,101	$0
Total Depreciation Expense				$58,525,483	$44,330,644	$0	$0	$1,297,322	$2,469,500	$5,794,453	$0
Amortization Expenses											
	Amortization of DSM	F016	DSM-Related	$5,969,398	$0	$0	$0	$0	$0	$0	$0
	Amortization of Other1	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
	Amortization of Other2	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
				$5,969,398	$0	$0	$0	$0	$0	$0	$0
Total Depreciation and Amortization Expenses				$64,494,881	$44,330,644	$0	$0	$1,297,322	$2,469,500	$5,794,453	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	DEPRECIATION AND AMORTIZATION EXPENSI												
	Distribution Plant												
360	Land and Land Rights	$7	$0	$8	$8	$13	$5	$1	$3	$0	$0	$0	$0
361	Structures and Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
362	Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
363	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
364	Poles, Towers and Fixtures	$409,975	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
365	Overhead Conductors and Devices	$181,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
366	Underground Conduit	$50,086	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
367	Underground Conductors and Devices	$133,536	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
368	Line Transformers	$0	$0	$662,788	$660,119	$0	$0	$0	$0	$0	$0	$0	$0
369	Services	$0	$0	$0	$0	$1,400,183	$0	$0	$0	$0	$0	$0	$0
370	Meters	$0	$0	$0	$0	$0	$460,829	$0	$0	$0	$0	$0	$0
371	Installation on Customers' Premises	$0	$0	$0	$0	$0	$0	$122,254	$0	$0	$0	$0	$0
372	Leased Property on Customers' Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
373	Street Lighting and Signal Systems	$0	$0	$0	$0	$0	$0	$0	$288,118	$0	$0	$0	$0
	Total Distribution Plant	$774,633	$0	$662,796	$660,127	$1,400,196	$460,834	$122,255	$288,121	$0	$0	$0	$0
	General and Intangible Plant												
301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
302	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
303	Miscellaneous Intangible Plan	$0	$0	$932	$928	$0	$1,638	$0	$454	$4,093	$0	$0	$0
389	Land and Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
390	Structures and Improvements	$0	$0	$13,591	$13,537	$0	$23,885	$0	$6,616	$59,678	$0	$0	$0
391	Office Furniture and Equipment	$0	$0	$8,757	$8,722	$0	$15,390	$0	$4,263	$38,452	$0	$0	$0
392	Transportation Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
393	Stores Equipment	$0	$0	$104	$104	$0	$183	$0	$51	$457	$0	$0	$0
394	Tools, Shop and Garage Equipment	$0	$0	$297	$296	$0	$522	$0	$145	$1,304	$0	$0	$0
395	Laboratory Equipment	$0	$0	$704	$702	$0	$1,238	$0	$343	$3,093	$0	$0	$0
396	Power Operated Equipment	$0	$0	$1,088	$1,083	$0	$1,911	$0	$530	$4,776	$0	$0	$0
397	Communication Equipment	$0	$0	$1,163	$1,158	$0	$2,044	$0	$566	$5,106	$0	$0	$0
398	Miscellaneous Equipment	$0	$0	$4,021	$4,004	$0	$7,066	$0	$1,957	$17,654	$0	$0	$0
399	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total General and Intangible Plan	$0	$0	$30,657	$30,534	$0	$53,875	$0	$14,924	$134,612	$0	$0	$0
	Total Depreciation Expense	$774,633	$0	$693,454	$690,661	$1,400,196	$514,709	$122,255	$303,045	$134,612	$0	$0	$0
	Amortization Expenses												
	Amortization of DSM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,969,398	$0	$0
	Amortization of Other1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Amortization of Other2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,969,398	$0	$0
	Total Depreciation and Amortization Expenses	$774,633	$0	$693,454	$690,661	$1,400,196	$514,709	$122,255	$303,045	$134,612	$5,969,398	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

Description	Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
TAXES OTHER THAN INCOME TAXES (EXCLUDING IURT)										
Indiana State and Local Taxes										
Real Estate and Persona	F103	Plant in Service	$8,174,121	$5,631,141	$0	$0	$282,007	$580,75C	$913,69S	$0
Gross Income	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
Unemployment	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
Public Utility Fee	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
Sales and Use	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
Excise	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
Total Indiana State and Local Taxe:			$8,174,121	$5,631,141	$0	$0	$282,007	$580,75C	$913,69S	$0
Kentucky State and Local Taxes										
License Tax	F103	Plant in Service	$175	$121	$0	$0	$6	$12	$20	$0
Deferred Coal Tax	F001	Production Demand	($95,857)	($95,857)	$0	$0	$0	$0	$0	$0
Total Kentucky State and Local Taxe:			($95,682)	($95,736)	$0	$0	$6	$12	$20	$0
Federal Taxes Other Than Income										
Unemployment	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
FICA	F134	Total Labor	$0	$0	$0	$0	$0	$0	$0	$0
Excise	F103	Plant in Service	$35	$24	$0	$0	$1	$2	$4	$0
			$35	$24	$0	$0	$1	$2	$4	$0
Total Taxes Other Than Income Taxes (Excluding IURT)			$8,078,474	$5,535,42S	$0	$0	$282,014	$580,76E	$913,722	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
TAXES OTHER THAN INCOME TAXES (EXCLUI												
Indiana State and Local Taxes												
Real Estate and Persona	$111,402	$0	$130,493	$129,967	$201,809	$82,420	$13,348	$50,642	$22,657	$23,785	$0	$0
Gross Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unemployment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Public Utility Fee	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sales and Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Excise	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Indiana State and Local Taxe:	$111,402	$0	$130,493	$129,967	$201,809	$82,420	$13,348	$50,642	$22,657	$23,785	$0	$0
Kentucky State and Local Taxes												
License Tax	$2	$0	$3	$3	$4	$2	$0	$1	$0	$1	$0	$0
Deferred Coal Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Kentucky State and Local Taxe	$2	$0	$3	$3	$4	$2	$0	$1	$0	$1	$0	$0
Federal Taxes Other Than Income												
Unemployment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
FICA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Excise	$0	$0	$1	$1	$1	$0	$0	$0	$0	$0	$0	$0
	$0	$0	$1	$1	$1	$0	$0	$0	$0	$0	$0	$0
Total Taxes Other Than Income Taxes (Excluding IURT)	$111,404	$0	$130,496	$129,971	$201,814	$82,422	$13,348	$50,643	$22,658	$23,786	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

ASSET CHARGE (Page 1 of 2)

ASSET CHARGE DETAIL

Description	Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Electronic Equipment (non OVS)	F134	Total Labor	$4,827,049	$3,216,737	$0	$0	$328,968	$469,556	$9,402	$0
Transportation Equipment - Light Trucks	F134	Total Labor	$37,207	$24,795	$0	$0	$2,536	$3,619	$72	$0
Electronic Equipment (OVS)	F134	Total Labor	$1,463,780	$975,461	$0	$0	$99,758	$142,391	$2,851	$0
Noetix	F134	Total Labor	$106,099	$70,704	$0	$0	$7,231	$10,321	$207	$0
Enterprise Storage	F134	Total Labor	$109,596	$73,035	$0	$0	$7,469	$10,661	$213	$0
404 Compliance Software	F134	Total Labor	$134,365	$89,541	$0	$0	$9,157	$13,070	$262	$0
MCR Budget Tool	F134	Total Labor	$142,123	$94,711	$0	$0	$9,686	$13,825	$277	$0
Meter Management System	F012	Meters	$167,022	$0	$0	$0	$0	$0	$0	$0
Optimain Integration	F134	Total Labor	$176,382	$117,541	$0	$0	$12,021	$17,158	$344	$0
NPMS - Build - ED	F134	Total Labor	$184,444	$122,913	$0	$0	$12,570	$17,942	$359	$0
Facility Damage Reporting	F134	Total Labor	$195,032	$129,969	$0	$0	$13,292	$18,972	$380	$0
Enterprise Data Backup	F134	Total Labor	$201,931	$134,566	$0	$0	$13,762	$19,643	$393	$0
Oracle 11i (Phase 1)	F134	Total Labor	$214,498	$142,941	$0	$0	$14,618	$20,866	$418	$0
Vectren Intranet	F134	Total Labor	$233,206	$155,408	$0	$0	$15,893	$22,685	$454	$0
Cook Hulbert Software	F134	Total Labor	$237,686	$158,394	$0	$0	$16,199	$23,121	$463	$0
Records System Software	F134	Total Labor	$242,474	$161,584	$0	$0	$16,525	$23,587	$472	$0
Tape Drives Software	F134	Total Labor	$249,574	$166,316	$0	$0	$17,009	$24,278	$486	$0
Virtual Hold	F134	Total Labor	$268,954	$179,230	$0	$0	$18,329	$26,163	$524	$0
Enhance Tactical Support	F134	Total Labor	$285,198	$190,055	$0	$0	$19,436	$27,743	$556	$0
Advantis	F134	Total Labor	$329,057	$219,283	$0	$0	$22,426	$32,009	$641	$0
Interactive Voice System	F015	Customer Accounts-Related	$368,615	$0	$0	$0	$0	$0	$0	$0
Forecasting Model	F134	Total Labor	$382,913	$255,173	$0	$0	$26,096	$37,248	$746	$0
Oracle Cash Management	F134	Total Labor	$454,305	$302,748	$0	$0	$30,961	$44,193	$885	$0
170 Systems	F134	Total Labor	$514,981	$343,182	$0	$0	$35,096	$50,095	$1,003	$0
Microsoft	F134	Total Labor	$534,849	$356,422	$0	$0	$36,450	$52,028	$1,042	$0
Timberline	F134	Total Labor	$568,802	$379,049	$0	$0	$38,764	$55,331	$1,108	$0
EBIZ Systems	F134	Total Labor	$590,698	$393,639	$0	$0	$40,256	$57,461	$1,151	$0
Management Office 2	F134	Total Labor	$649,417	$432,770	$0	$0	$44,258	$63,173	$1,265	$0
Bill Print Outsource	F015	Customer Accounts-Related	$714,376	$0	$0	$0	$0	$0	$0	$0
Billgen	F015	Customer Accounts-Related	$747,111	$0	$0	$0	$0	$0	$0	$0
Fixed Asset System (IntelliPlant)	F103	Plant in Service	$794,941	$547,634	$0	$0	$27,425	$56,478	$88,858	$0
Customer Care	F015	Customer Accounts-Related	$816,134	$0	$0	$0	$0	$0	$0	$0
Desktop Tools	F134	Total Labor	$1,178,061	$785,058	$0	$0	$80,286	$114,597	$2,295	$0
IT Infrastructure Upgrade	F134	Total Labor	$1,301,082	$867,039	$0	$0	$88,670	$126,564	$2,534	$0
Enerlink	F134	Total Labor	$1,469,446	$979,236	$0	$0	$100,144	$142,942	$2,862	$0
HR Payroll	F134	Total Labor	$1,660,441	$1,106,515	$0	$0	$113,161	$161,521	$3,234	$0
Customer Business Intelligence	F134	Total Labor	$1,703,867	$1,135,454	$0	$0	$116,120	$165,745	$3,319	$0
E Business	F134	Total Labor	$1,728,234	$1,151,692	$0	$0	$117,781	$168,116	$3,366	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

ASSET CHARGE (Page 1 of 2)

Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
ASSET CHARGE DETAIL												
Electronic Equipment (non OVS)	$0	$0	$92,966	$92,592	$0	$163,372	$0	$45,256	$408,200	$0	$0	$0
Transportation Equipment - Light Trucks	$0	$0	$717	$714	$0	$1,259	$0	$349	$3,146	$0	$0	$0
Electronic Equipment (OVS)	$0	$0	$28,192	$28,078	$0	$49,542	$0	$13,724	$123,785	$0	$0	$0
Noetix	$0	$0	$2,043	$2,035	$0	$3,591	$0	$995	$8,972	$0	$0	$0
Enterprise Storage	$0	$0	$2,111	$2,102	$0	$3,709	$0	$1,028	$9,268	$0	$0	$0
404 Compliance Software	$0	$0	$2,588	$2,577	$0	$4,548	$0	$1,260	$11,363	$0	$0	$0
MCR Budget Tool	$0	$0	$2,737	$2,726	$0	$4,810	$0	$1,332	$12,019	$0	$0	$0
Meter Management System	$0	$0	$0	$0	$0	$167,022	$0	$0	$0	$0	$0	$0
Optimain Integration	$0	$0	$3,397	$3,383	$0	$5,970	$0	$1,654	$14,916	$0	$0	$0
NPMS - Build - ED	$0	$0	$3,552	$3,538	$0	$6,243	$0	$1,729	$15,598	$0	$0	$0
Facility Damage Reporting	$0	$0	$3,756	$3,741	$0	$6,601	$0	$1,829	$16,493	$0	$0	$0
Enterprise Data Backup	$0	$0	$3,889	$3,873	$0	$6,834	$0	$1,893	$17,076	$0	$0	$0
Oracle 11i (Phase 1)	$0	$0	$4,131	$4,114	$0	$7,260	$0	$2,011	$18,139	$0	$0	$0
Vectren Intranet	$0	$0	$4,491	$4,473	$0	$7,893	$0	$2,186	$19,721	$0	$0	$0
Cook Hulbert Software	$0	$0	$4,578	$4,559	$0	$8,045	$0	$2,228	$20,100	$0	$0	$0
Records System Software	$0	$0	$4,670	$4,651	$0	$8,207	$0	$2,273	$20,505	$0	$0	$0
Tape Drives Software	$0	$0	$4,807	$4,787	$0	$8,447	$0	$2,340	$21,105	$0	$0	$0
Virtual Hold	$0	$0	$5,180	$5,159	$0	$9,103	$0	$2,522	$22,744	$0	$0	$0
Enhance Tactical Support	$0	$0	$5,493	$5,471	$0	$9,653	$0	$2,674	$24,118	$0	$0	$0
Advantis	$0	$0	$6,337	$6,312	$0	$11,137	$0	$3,085	$27,827	$0	$0	$0
Interactive Voice System	$0	$0	$0	$0	$0	$0	$0	$0	$368,615	$0	$0	$0
Forecasting Model	$0	$0	$7,375	$7,345	$0	$12,960	$0	$3,590	$32,381	$0	$0	$0
Oracle Cash Management	$0	$0	$8,750	$8,714	$0	$15,376	$0	$4,259	$38,418	$0	$0	$0
170 Systems	$0	$0	$9,918	$9,878	$0	$17,430	$0	$4,828	$43,549	$0	$0	$0
Microsoft	$0	$0	$10,301	$10,259	$0	$18,102	$0	$5,014	$45,230	$0	$0	$0
Timberline	$0	$0	$10,955	$10,911	$0	$19,251	$0	$5,333	$48,101	$0	$0	$0
EBIZ Systems	$0	$0	$11,376	$11,331	$0	$19,992	$0	$5,538	$49,952	$0	$0	$0
Management Office 2	$0	$0	$12,507	$12,457	$0	$21,980	$0	$6,089	$54,918	$0	$0	$0
Bill Print Outsource	$0	$0	$0	$0	$0	$0	$0	$0	$714,376	$0	$0	$0
Billgen	$0	$0	$0	$0	$0	$0	$0	$0	$747,111	$0	$0	$0
Fixed Asset System (IntelliPlant)	$10,834	$0	$12,691	$12,639	$19,626	$8,015	$1,298	$4,925	$2,203	$2,313	$0	$0
Customer Care	$0	$0	$0	$0	$0	$0	$0	$0	$816,134	$0	$0	$0
Desktop Tools	$0	$0	$22,689	$22,597	$0	$39,872	$0	$11,045	$99,623	$0	$0	$0
IT Infrastructure Upgrade	$0	$0	$25,058	$24,957	$0	$44,035	$0	$12,198	$110,026	$0	$0	$0
Enerlink	$0	$0	$28,301	$28,187	$0	$49,734	$0	$13,777	$124,264	$0	$0	$0
HR Payroll	$0	$0	$31,979	$31,850	$0	$56,198	$0	$15,567	$140,415	$0	$0	$0
Customer Business Intelligence	$0	$0	$32,815	$32,683	$0	$57,668	$0	$15,975	$144,088	$0	$0	$0
E Business	$0	$0	$33,285	$33,151	$0	$58,492	$0	$16,203	$146,148	$0	$0	$0

ASSET CHARGE (Page 2 of 2)

ASSET CHARGE DETAIL

Description	Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
e-Enablement	F015	Customer Accounts-Related	$2,069,717	$0	$0	$0	$0	$0	$0	$0
Miscellaneous Software under $100,000	F134	Total Labor	$1,431,523	$953,965	$0	$0	$97,560	$139,253	$2,788	$0
Mobile Data Dispatch	F117	T&D O&M	$3,884,118	$1,045	$0	$0	$1,520,410	$1,558,243	$105,819	$0
ED Workforce Scheduling	F117	T&D O&M	$3,953,348	$1,063	$0	$0	$1,547,509	$1,586,017	$107,705	$0
FIS System (Oracle)	F134	Total Labor	$10,414,590	$6,940,265	$0	$0	$709,764	$1,013,090	$20,286	$0
GIS	F117	T&D O&M	$10,654,740	$2,866	$0	$0	$4,170,721	$4,274,504	$290,279	$0
Banner	F015	Customer Accounts-Related	$33,573,680	$0	$0	$0	$0	$0	$0	$0
Communication Equipment	F117	T&D O&M	$2,758,868	$742	$0	$0	$1,079,939	$1,106,812	$75,163	$0
Furniture & Fixtures (OVS)	F134	Total Labor	$3,447,415	$2,297,352	$0	$0	$234,944	$335,351	$6,715	$0
Furniture & Fixtures (non OVS)	F134	Total Labor	$3,797,958	$2,530,953	$0	$0	$258,834	$369,450	$7,398	$0
SSC Building	F015	Customer Accounts-Related	$8,498,436	$0	$0	$0	$0	$0	$0	$0
OVS Building	F134	Total Labor	$20,012,194	$13,336,093	$0	$0	$1,363,849	$1,946,707	$38,981	$0
SSC Land	F015	Customer Accounts-Related	$3,403,075	$0	$0	$0	$0	$0	$0	$0
OVS Land	F134	Total Labor	$6,992,826	$4,660,008	$0	$0	$476,567	$680,234	$13,621	$0
Total			$140,876,436	$46,183,146	$0	$0	$13,012,449	$15,242,763	$801,200	$0
VUHI Cost of Capital Grossed Up for Income Taxes			11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%
Asset Cost - Return and Income Taxes			$16,806,559	$5,509,649	$0	$0	$1,552,385	$1,818,462	$95,583	$0
Depreciation Expense	F103	Plant in Service	$21,148,656	$14,569,281	$0	$0	$729,628	$1,502,557	$2,363,985	$0
Property Taxes	F103	Plant in Service	$1,069,000	$736,433	$0	$0	$36,880	$75,950	$119,492	$0
Total Vectren Proforma Asset Charge			$39,024,215	$20,815,364	$0	$0	$2,318,894	$3,396,968	$2,579,060	$0
SIG-Electric Corporate Allocation Factor			22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%
Total SIG-Electric Proforma Asset Charge			$8,973,132	$4,786,234	$0	$0	$533,201	$781,091	$593,023	$0

ASSET CHARGE (Page 2 of 2)

ASSET CHARGE DETAIL

Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
e-Enablement	$0	$0	$0	$0	$0	$0	$0	$0	$2,069,717	$0	$0	$0
Miscellaneous Software under $100,000	$0	$0	$27,570	$27,459	$0	$48,450	$0	$13,421	$121,057	$0	$0	$0
Mobile Data Dispatch	$0	$0	$200,593	$199,785	$0	$225,428	$0	$72,795	$0	$0	$0	$0
ED Workforce Scheduling	$0	$0	$204,168	$203,346	$0	$229,446	$0	$74,093	$0	$0	$0	$0
FIS System (Oracle)	$0	$0	$200,579	$199,771	$0	$352,483	$0	$97,642	$880,711	$0	$0	$0
GIS	$0	$0	$550,257	$548,041	$0	$618,384	$0	$199,688	$0	$0	$0	$0
Banner	$0	$0	$0	$0	$0	$0	$0	$0	$33,573,680	$0	$0	$0
Communication Equipment	$0	$0	$142,480	$141,908	$0	$160,120	$0	$51,706	$0	$0	$0	$0
Furniture & Fixtures (OVS)	$0	$0	$66,395	$66,128	$0	$116,678	$0	$32,321	$291,531	$0	$0	$0
Furniture & Fixtures (non OVS)	$0	$0	$73,146	$72,852	$0	$128,542	$0	$35,608	$321,175	$0	$0	$0
SSC Building	$0	$0	$0	$0	$0	$0	$0	$0	$8,498,436	$0	$0	$0
OVS Building	$0	$0	$385,423	$383,870	$0	$677,315	$0	$187,624	$1,692,333	$0	$0	$0
SSC Land	$0	$0	$0	$0	$0	$0	$0	$0	$3,403,075	$0	$0	$0
OVS Land	$0	$0	$134,678	$134,135	$0	$236,673	$0	$65,561	$591,349	$0	$0	$0
Total	$10,834	$0	$2,428,922	$2,419,139	$19,626	$3,725,868	$1,298	$1,045,168	$55,983,710	$2,313	$0	$0
VUHI Cost of Capital Grossed Up for Income Taxes	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%	11.93%
Asset Cost - Return and Income Taxes	$1,292	$0	$289,770	$288,603	$2,341	$444,496	$155	$124,688	$6,678,857	$276	$0	$0
Depreciation Expense	$288,226	$0	$337,621	$336,261	$522,135	$213,244	$34,534	$131,024	$58,621	$61,539	$0	$0
Property Taxes	$14,569	$0	$17,066	$16,997	$26,392	$10,779	$1,746	$6,623	$2,963	$3,111	$0	$0
Total Vectren Proforma Asset Charge	$304,087	$0	$644,457	$641,861	$550,869	$668,519	$36,434	$262,335	$6,740,440	$64,926	$0	$0
SIG-Electric Corporate Allocation Factor	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%	22.99%
Total SIG-Electric Proforma Asset Charge	$69,921	$0	$148,185	$147,588	$126,665	$153,718	$8,378	$60,321	$1,549,880	$14,929	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

LABOR EXPENSES (Page 1 of 5)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Steam Power Generation Labor											
Operation Labor											
500	Operation Supervision and Engineering	F001	Production Demand	$2,223,735	$2,223,735	$0	$0	$0	$0	$0	$0
501	Retail (FAC) Fuel	F018	FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses	F001	Production Demand	$3,418,230	$3,418,230	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	F001	Production Demand	$1,675,751	$1,675,751	$0	$0	$0	$0	$0	$0
502	Chemicals - SO2 Equipment	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	F001	Production Demand	$690,465	$690,465	$0	$0	$0	$0	$0	$0
502	Steam Expenses-Scrubber Byproducts	F001	Production Demand	$100,375	$100,375	$0	$0	$0	$0	$0	$0
503	Steam from Other Sources	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
504	Steam Transferred - Cr.	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
505	Electric Expenses	F001	Production Demand	$2,026,836	$2,026,836	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	F001	Production Demand	$988,026	$988,026	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	F001	Production Demand	$2,732	$2,732	$0	$0	$0	$0	$0	$0
507	Rents	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor			$11,126,150	$11,126,150	$0	$0	$0	$0	$0	$0
Maintenance Labor											
510	Maintenance Supervision and Engineering	F001	Production Demand	$1,548,631	$1,548,631	$0	$0	$0	$0	$0	$0
511	Maintenance of Structures	F001	Production Demand	$353,813	$353,813	$0	$0	$0	$0	$0	$0
512	Maintenance of Boiler Plan	F001	Production Demand	$2,965,802	$2,965,802	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipmen	F001	Production Demand	$995,488	$995,488	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipmen	F001	Production Demand	$17,137	$17,137	$0	$0	$0	$0	$0	$0
513	Maintenance of Electric Plan	F001	Production Demand	$577,157	$577,157	$0	$0	$0	$0	$0	$0
514	Maintenance of Miscellaneous Steam Plan	F001	Production Demand	$110,942	$110,942	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor			$6,568,970	$6,568,970	$0	$0	$0	$0	$0	$0
Total Steam Power Generation Labor				$17,695,121	$17,695,121	$0	$0	$0	$0	$0	$0
Hydraulic and Pumped Storage Power Generation Labor											
Operation Labor											
535	Operation Supervision and Engineering	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
537	Hydraulic and Pumped Storage Expenses	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
538	Electric Expenses	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
539	Misc. Hydraulic & Pumped Storage Power Generation Expe	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
540	Rents	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor			$0	$0	$0	$0	$0	$0	$0	$0
Maintenance Labor											
541	Maintenance Supervision and Engineering	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
542	Maintenance of Structures	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
543	Maintenance of Reservoirs, Dams and Waterways	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
544	Maintenance of Electric Plan	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
545	Maintenance of Misc. Hydraulic and Pumped Storage Plan	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor			$0	$0	$0	$0	$0	$0	$0	$0
Total Hydraulic and Pumped Storage Power Generation Labo				$0	$0	$0	$0	$0	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

LABOR EXPENSES (Page 1 of 5)

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	Steam Power Generation Labor												
	Operation Labor												
500	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
501	Retail (FAC) Fuel	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Chemicals - SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses-SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
502	Steam Expenses-Scrubber Byproducts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
503	Steam from Other Sources	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
504	Steam Transferred - Cr.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
505	Electric Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
506	Miscellaneous Steam Power Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
507	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Maintenance Labor												
510	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
511	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512	Maintenance of Boiler Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
512	Maintenance of SO2 Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
513	Maintenance of Electric Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
514	Maintenance of Miscellaneous Steam Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Steam Power Generation Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Hydraulic and Pumped Storage Power Generation Labor												
	Operation Labor												
535	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
537	Hydraulic and Pumped Storage Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
538	Electric Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
539	Misc. Hydraulic & Pumped Storage Power Generation Expe	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
540	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Maintenance Labor												
541	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
542	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
543	Maintenance of Reservoirs, Dams and Waterways	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
544	Maintenance of Electric Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
545	Maintenance of Misc. Hydraulic and Pumped Storage Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Hydraulic and Pumped Storage Power Generation Labo	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

LABOR EXPENSES (Page 2 of 5)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Other Power Generation Labor											
Operation Labor											
546	Operations Supervision and Engineering	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
546	Operations Supervision and Engineering	F001	Production Demand	$2,113	$2,113	$0	$0	$0	$0	$0	$0
547	Fuel - Cost of Gas Delivered	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
548	Generation Expenses	F001	Production Demand	$50,831	$50,831	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Generation Expense	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Generation Expense	F001	Production Demand	$47,878	$47,878	$0	$0	$0	$0	$0	$0
549	Miscellaneous Power Expenses - Operation of Ai..	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Gen. Expenses - Air Mon..	F001	Production Demand	$791	$791	$0	$0	$0	$0	$0	$0
550	Rents	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor			$101,613	$101,613	$0	$0	$0	$0	$0	$0
Maintenance Labor											
551	Maintenance Supervision and Engineering	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
551	Mngt & Supv - Mtce Other Power Production	F001	Production Demand	$20,694	$20,694	$0	$0	$0	$0	$0	$0
552	Maintenance of Structures	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
552	Maintenance of Structures-Other Power Production	F001	Production Demand	$899	$899	$0	$0	$0	$0	$0	$0
553	Maintenance of Generating and Electric Plan	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
553	Maintenance of Generating and Electric Plan	F001	Production Demand	$221,301	$221,301	$0	$0	$0	$0	$0	$0
554	Maintenance of Miscellaneous Other Power Generation Pla	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor			$242,894	$242,894	$0	$0	$0	$0	$0	$0
Total Other Power Generation Labor				$344,507	$344,507	$0	$0	$0	$0	$0	$0
Other Power Supply Labor											
Operation Labor											
555	Purchased Power	F002	Production Energy	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power Options	F002	Production Energy	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power Brokerage Fees	F002	Production Energy	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power - MISO Transmission Expenses	F003	Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power - MISO Transmission Expenses	F003	Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
556	System Control and Load Dispatching	F001	Production Demand	$1,418,709	$1,418,709	$0	$0	$0	$0	$0	$0
556	Transmission of Electricity by Others	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
557	Unrealized Gain/Loss on Derivative	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
557	Realized Gain/Loss on Derivative	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
557	Operations Supervision	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
557	All Other Expenses	F001	Production Demand	$833	$833	$0	$0	$0	$0	$0	$0
557	Allowance Expense	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
557	NOx Allowance Expense	F001	Production Demand	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Supply Labor				$1,419,542	$1,419,542	$0	$0	$0	$0	$0	$0
Total Production Labor											

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

LABOR EXPENSES (Page 2 of 5)

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
Other Power Generation Labor													
Operation Labor													
546	Operations Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
546	Operations Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
547	Fuel - Cost of Gas Delivered	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
548	Generation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Generation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Generation Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Power Expenses - Operation of Ai..	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
549	Miscellaneous Other Power Gen. Expenses - Air Mon..	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
550	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance Labor													
551	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
551	Mngt & Supv - Mtce Other Power Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
552	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
552	Maintenance of Structures-Other Power Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
553	Maintenance of Generating and Electric Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
553	Maintenance of Generating and Electric Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
554	Maintenance of Miscellaneous Other Power Generation Pla	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Generation Labor		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Power Supply Labor													
Operation Labor													
555	Purchased Power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power Options	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power Brokerage Fees	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power - MISO Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
555	Purchased Power - MISO Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
556	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
556	Transmission of Electricity by Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557	Unrealized Gain/Loss on Derivative	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557	Realized Gain/Loss on Derivative	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557	Operations Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557	All Other Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557	Allowance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
557	NOx Allowance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Power Supply Labor		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Production Labor													

	Description	Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
LABOR EXPENSES (Page 3 of 5)											
Transmission Labor											
Operation Labor											
560	Operation Supervision and Engineering	F101	Subtotal Trans. O&M Operation	$0	$0	$0	$0	$0	$0	$0	$0
561	Load Dispatching	F003	Transmission Demand	$939,873	$0	$0	$0	$939,873	$0	$0	$0
562	Station Expenses	F021	Trans Station Equipment Special Analysis	$62,481	$0	$0	$0	$7,615	$54,866	$0	$0
563	Overhead Line Expenses	F024	Trans Overhead Conductors Analysis	$19,237	$0	$0	$0	$9,140	$10,097	$0	$0
564	Underground Line Expenses	F004	Sub-Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
566	Miscellaneous Transmission Expenses	F003	Transmission Demand	$161,882	$0	$0	$0	$161,882	$0	$0	$0
567	Rents	F003	Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor			$1,183,473	$0	$0	$0	$1,118,510	$64,963	$0	$0
Maintenance Labor											
568	*Maintenance Supervision and Engineering*	F136	Subtotal Transmission Maintenance O&M	$0	$0	$0	$0	$0	$0	$0	$0
569	Maintenance of Structures	F020	Trans Plant Structures & Impr Analysis	$13,700	$3,217	$0	$0	$2,934	$3,319	$4,230	$0
570	Maintenance of Station Equipment	F021	Trans Station Equipment Special Analysis	$232,424	$0	$0	$0	$28,328	$204,096	$0	$0
571	Maintenance of Overhead Lines	F024	Trans Overhead Conductors Analysis	$67,072	$0	$0	$0	$31,867	$35,204	$0	$0
571	Maintenance of Overhead Lines-Tree Cutting	F024	Trans Overhead Conductors Analysis	$17,582	$0	$0	$0	$8,354	$9,228	$0	$0
572	Maintenance of Underground Lines	F004	Sub-Transmission Demand	$0	$0	$0	$0	$0	$0	$0	$0
573	*Maintenance of Miscellaneous Transmission Plant*	F136	*Subtotal Transmission Maintenance O&M*	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor			$330,778	$3,217	$0	$0	$71,483	$251,847	$4,230	$0
Total Transmission Labor				$1,514,251	$3,217	$0	$0	$1,189,994	$316,810	$4,230	$0
Distribution Labor											
Operation Labor											
580	Operation Supervision and Engineering	F139	Subtotal Distribution Operation O&M	$395,586	$0	$0	$0	$25,504	$163,060	$0	$0
581	Load Dispatching	F000	Not Applicable	$0	$0	$0	$0	$0	$0	$0	$0
582	Station Expenses	F021	Trans Station Equipment Special Analysis	$78,479	$0	$0	$0	$9,565	$68,914	$0	$0
583	*Removing & Resetting Line Transformers*	F019	Line Transformer Zero Intercept Analysis	$98,401	$0	$0	$0	$0	$0	$0	$0
583	Overhead Line Expenses	F024	Trans Overhead Conductors Analysis	$50,276	$0	$0	$0	$23,888	$26,389	$0	$0
584	Underground Line Expenses	F004	Sub-Transmission Demand	$164	$0	$0	$0	$0	$164	$0	$0
584	Locating Lines, Mains-Distribution	F004	Sub-Transmission Demand	$25,114	$0	$0	$0	$0	$25,114	$0	$0
585	Street Lighting and Signal System Expenses	F014	Street Lighting	$21,273	$0	$0	$0	$0	$0	$0	$0
586	Removing and Resetting Meters	F012	Meters	$103,855	$0	$0	$0	$0	$0	$0	$0
586	*Meter Testing - Distribution*	F012	Meters	$256,824	$0	$0	$0	$0	$0	$0	$0
587	Customer Installations Expenses	F139	Subtotal Distribution Operation O&M	$1,161,282	$0	$0	$0	$74,871	$478,678	$0	$0
588	Miscellaneous Distribution Expenses	F139	Subtotal Distribution Operation O&M	$1,320,218	$0	$0	$0	$85,118	$544,191	$0	$0
588	Miscellaneous Expenses - Distribution	F139	Subtotal Distribution Operation O&M	$0	$0	$0	$0	$0	$0	$0	$0
589	Rents	F139	Subtotal Distribution Operation O&M	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Operations Labor			$3,511,472	$0	$0	$0	$218,946	$1,306,510	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

LABOR EXPENSES (Page 3 of 5)

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	Transmission Labor												
	Operation Labor												
560	Operation Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
561	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
562	Station Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
563	Overhead Line Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
564	Underground Line Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
566	Miscellaneous Transmission Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
567	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Operation Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Maintenance Labor												
568	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
569	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
570	Maintenance of Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
571	Maintenance of Overhead Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
571	Maintenance of Overhead Lines-Tree Cutting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
572	Maintenance of Underground Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
573	Maintenance of Miscellaneous Transmission Plan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Maintenance Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Transmission Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Distribution Labor												
	Operation Labor												
580	Operation Supervision and Engineering	$0	$0	$61,034	$60,788	$0	$80,865	$0	$4,335	$0	$0	$0	$0
581	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
582	Station Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
583	Removing & Resetting Line Transformers	$0	$0	$49,300	$49,101	$0	$0	$0	$0	$0	$0	$0	$0
583	Overhead Line Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
584	Underground Line Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
584	Locating Lines, Mains-Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
585	Street Lighting and Signal System Expenses	$0	$0	$0	$0	$0	$0	$0	$21,273	$0	$0	$0	$0
586	Removing and Resetting Meters	$0	$0	$0	$0	$0	$103,855	$0	$0	$0	$0	$0	$0
586	Meter Testing - Distribution	$0	$0	$0	$0	$0	$256,824	$0	$0	$0	$0	$0	$0
587	Customer Installations Expenses	$0	$0	$179,170	$178,448	$0	$237,387	$0	$12,727	$0	$0	$0	$0
588	Miscellaneous Distribution Expenses	$0	$0	$203,692	$202,871	$0	$269,876	$0	$14,469	$0	$0	$0	$0
588	Miscellaneous Expenses - Distribution	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
589	Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Operations Labor	$0	$0	$493,195	$491,209	$0	$948,808	$0	$52,804	$0	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
FUNCTIONALIZATION OF COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

LABOR EXPENSES (Page 4 of 5)

Description		Allocator		Total Company Proforma	Production Demand	Production Energy	FAC Fuel	Transmission Demand	Sub-Transmission Demand	Primary Distribution Demand	Primary Distribution Customer
Maintenance Labor											
590	Maintenance Supervision and Engineering	F138	Subtotal Distribution Maintenance O&M	$443,509	$0	$0	$0	$151,984	$244,407	$27,732	$0
591	Maintenance of Structures	F005	Primary Distribution Demand	$11,550	$0	$0	$0	$0	$0	$11,550	$0
592	Maintenance of Station Equipment	F021	Trans Station Equipment Special Analysis	$93,577	$0	$0	$0	$11,405	$82,171	$0	$0
593	Tree and Brush Clearing	F024	Trans Overhead Conductors Analysis	$102,417	$0	$0	$0	$48,661	$53,756	$0	$0
593	Maintenance of Overhead Lines	F024	Trans Overhead Conductors Analysis	$623,152	$0	$0	$0	$296,076	$327,076	$0	$0
594	Maintenance of Underground Lines	F004	Sub-Transmission Demand	$392,367	$0	$0	$0	$0	$392,367	$0	$0
595	Maintenance of Line Transformers	F019	Line Transformer Zero Intercept Analysis	$109,548	$0	$0	$0	$0	$0	$0	$0
596	Maintenance of Street Lighting and Signal Systems	F014	Street Lighting	$221,010	$0	$0	$0	$0	$0	$0	$0
597	Maintenance of Meters	F012	Meters	$39,650	$0	$0	$0	$0	$0	$0	$0
598	Maintenance of Miscellaneous Distribution Plant	F138	Subtotal Distribution Maintenance O&M	$213,911	$0	$0	$0	$73,304	$117,881	$13,376	$0
	Total Distribution Maintenance Labor			$2,250,691	$0	$0	$0	$581,430	$1,217,659	$52,658	$0
Total Distribution Labor				$5,762,163	$0	$0	$0	$800,376	$2,524,169	$52,658	$0
Customer Accounts Labor											
901	Supervision	F015	Customer Accounts-Related	$228,758	$0	$0	$0	$0	$0	$0	$0
902	Meter Reading Expenses	F015	Customer Accounts-Related	$644,935	$0	$0	$0	$0	$0	$0	$0
903	Customer Billing and Accounting	F015	Customer Accounts-Related	$1,218,700	$0	$0	$0	$0	$0	$0	$0
904	Uncollectible Accounts	F015	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
905	Misc. Customer Accounts Expenses	F015	Customer Accounts-Related	$72,282	$0	$0	$0	$0	$0	$0	$0
Total Customer Accounts Labor				$2,164,675	$0	$0	$0	$0	$0	$0	$0
Customer Service Labor											
907	Supervision	F015	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
908	Residential Assistance	F015	Customer Accounts-Related	$12,199	$0	$0	$0	$0	$0	$0	$0
908	Commercial Assistance	F015	Customer Accounts-Related	$122,889	$0	$0	$0	$0	$0	$0	$0
908	Industrial Assistance	F015	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
908	All Other Customer Assistance	F015	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
909	Informational and Instructional Advertising	F015	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
910	Miscellaneous Customer Service and Informational	F015	Customer Accounts-Related	$103,415	$0	$0	$0	$0	$0	$0	$0
Total Customer Service Labor				$238,502	$0	$0	$0	$0	$0	$0	$0
Sales Promotion Labor											
911	Supervision	F015	Customer Accounts-Related	$46,995	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating and Selling Expenses-Residential Solicitation	F015	Customer Accounts-Related	$2,442	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating and Selling Expenses-Commercial Solicitation	F015	Customer Accounts-Related	$3,182	$0	$0	$0	$0	$0	$0	$0
912	Demonstrating and Selling Expenses-Industrial Solicitation	F015	Customer Accounts-Related	$3,594	$0	$0	$0	$0	$0	$0	$0
912	Selling Expenses - Area Development	F015	Customer Accounts-Related	$10,361	$0	$0	$0	$0	$0	$0	$0
Total Sales Labor				$66,575	$0	$0	$0	$0	$0	$0	$0
Total Labor Expenses				$29,205,336	$19,462,387	$0	$0	$1,990,370	$2,840,979	$56,888	$0

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE NO. 2

LABOR EXPENSES (Page 4 of 5)

	Description	Secondary Distribution Demand	Secondary Distribution Customer	Line Transformers Demand	Line Transformers Customer	Services	Meters	Outdoor Lighting	Street Lighting	Customer Accounts-Related	DSM-Related	Non-FAC Fuel	WPM Fuel
	Maintenance Labor												
590	Maintenance Supervision and Engineering	$0	$0	$9,713	$9,674	$0	$0	$0	$0	$0	$0	$0	$0
591	Maintenance of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
592	Maintenance of Station Equipmen	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
593	Tree and Brush Clearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
593	Maintenance of Overhead Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
594	Maintenance of Underground Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
595	Maintenance of Line Transformers	$0	$0	$54,885	$54,664	$0	$0	$0	$0	$0	$0	$0	$0
596	Maintenance of Street Lighting and Signal Systems	$0	$0	$0	$0	$0	$0	$0	$221,010	$0	$0	$0	$0
597	Maintenance of Meters	$0	$0	$0	$0	$0	$39,650	$0	$0	$0	$0	$0	$0
598	Maintenance of Miscellaneous Distribution Plan	$0	$0	$4,685	$4,666	$0	$0	$0	$0	$0	$0	$0	$0
	Total Distribution Maintenance Labo	$0	$0	$69,282	$69,003	$0	$39,650	$0	$221,010	$0	$0	$0	$0
	Total Distribution Labor	$0	$0	$562,477	$560,211	$0	$988,458	$0	$273,814	$0	$0	$0	$0
	Customer Accounts Labor												
901	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$228,758	$0	$0	$0
902	Meter Reading Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$644,935	$0	$0	$0
903	Customer Billing and Accounting	$0	$0	$0	$0	$0	$0	$0	$0	$1,218,700	$0	$0	$0
904	*Uncollectible Accounts*	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
905	Misc. Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$72,282	$0	$0	$0
	Total Customer Accounts Labor	$0	$0	$0	$0	$0	$0	$0	$0	$2,164,675	$0	$0	$0
	Customer Service Labor												
907	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
908	Residential Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$12,199	$0	$0	$0
908	Commercial Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$122,889	$0	$0	$0
908	Industrial Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
908	All Other Customer Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
909	Informational and Instructional Advertising	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
910	Miscellaneous Customer Service and Informationa	$0	$0	$0	$0	$0	$0	$0	$0	$103,415	$0	$0	$0
	Total Customer Service Labor	$0	$0	$0	$0	$0	$0	$0	$0	$238,502	$0	$0	$0
	Sales Promotion Labor												
911	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$46,995	$0	$0	$0
912	Demonstrating and Selling Expenses-Residential Solicitatio	$0	$0	$0	$0	$0	$0	$0	$0	$2,442	$0	$0	$0
912	Demonstrating and Selling Expenses-Commercial Solicitati	$0	$0	$0	$0	$0	$0	$0	$0	$3,182	$0	$0	$0
912	Demonstrating and Selling Expenses-Industrial Solicitatior	$0	$0	$0	$0	$0	$0	$0	$0	$3,594	$0	$0	$0
912	Selling Expenses - Area Development	$0	$0	$0	$0	$0	$0	$0	$0	$10,361	$0	$0	$0
	Total Sales Labor	$0	$0	$0	$0	$0	$0	$0	$0	$66,575	$0	$0	$0
	Total Labor Expenses	$0	$0	$562,477	$560,211	$0	$988,458	$0	$273,814	$2,469,752	$0	$0	$0

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	Input Allocators						
	Energy at Generation (mWh)	1,179,737,213	491,450,467	15,597,510	63,767,059	1,298,261,408	114,687,404
1		20.9634%	8.7329%	0.2772%	1.1331%	23.0695%	2.0379%
	Energy at Generation - Firm Sales (mWh)	1,179,737,213	491,450,467	15,597,510	63,767,059	1,298,261,408	114,687,404
2		20.9634%	8.7329%	0.2772%	1.1331%	23.0695%	2.0379%
	Average Customers	94,147	26,746	5,591	9,497	8,407	860
3		60.4416%	17.1707%	3.5893%	6.0972%	5.3974%	0.5522%
	4 CP Demand at Generation (kW)	327,250	78,151	1,496	8,265	295,655	21,752
4		30.9625%	7.3942%	0.1415%	0.7820%	27.9731%	2.0581%
	Average Customers Excl. Rate B	94,147	26,746	0	9,497	8,407	860
5		62.6918%	17.8099%	0.0000%	6.3242%	5.5983%	0.5727%
	P/F A Normal Rev. w/o Misc. Rev.	$91,872,794	$29,154,071	$1,010,433	$5,982,248	$77,768,636	$6,164,062
6		28.3043%	8.9818%	0.3113%	1.8430%	23.9591%	1.8990%
		36.21%	16.16%	0.41%	0.77%	27.60%	2.63%
	Class NCP Demand at Primary (kW)	378,079	168,696	4,252	8,014	288,211	27,472
	Individual NCP Demand at Primary (kW)	680,293	308,804	4,252	8,014	410,088	40,113
	50% Class and 50% Indiv. Cust. NCP Demand at Primary (	529,186	238,750	4,252	8,014	349,150	33,793
7		39.4177%	17.7839%	0.3167%	0.5969%	26.0072%	2.5171%
	Services Study	94,147.17	37,034.76	0.00	15,222.80	17,630.52	1,803.65
8		56.7703%	22.3318%	0.0000%	9.1793%	10.6311%	1.0876%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)	TOTAL
	Input Allocators					
	Energy at Generation (mWh)	1,402,184,142	1,041,500,645	7,204,284	13,211,888	5,627,602,020
1		24.9162%	18.5070%	0.1280%	0.2348%	100.0000%
	Energy at Generation - Firm Sales (mWh)	1,402,184,142	1,041,500,645	7,204,284	13,211,888	5,627,602,020
2		24.9162%	18.5070%	0.1280%	0.2348%	100.0000%
	Average Customers	105	2	8,863	1,547	155,766
3		0.0674%	0.0013%	5.6900%	0.9931%	100.0000%
	4 CP Demand at Generation (kW)	194,933	129,423	0	0	1,056,925
4		18.4434%	12.2453%	0.0000%	0.0000%	100.0000%
	Average Customers Excl. Rate B	105	2	8,863	1,547	150,175
5		0.0699%	0.0013%	5.9018%	1.0301%	100.0000%
	P/F A Normal Rev. w/o Misc. Rev.	$65,858,104	$43,803,418	$938,716	$2,037,132	$324,589,615
6		20.2897%	13.4950%	0.2892%	0.6276%	100.0000%
		15.76%	0.00%	0.19%	0.27%	0
	Class NCP Demand at Primary (kW)	164,530	0	2,006	2,799	1,044,059
	Individual NCP Demand at Primary (kW)	184,592	0	2,006	2,799	1,640,961
	50% Class and 50% Indiv. Cust. NCP Demand at Primary (	174,561	0	2,006	2,799	1,342,510
7		13.0026%	0.0000%	0.1494%	0.2085%	100.0000%
	Services Study	0.00	0.00	0.00	0.00	165,838.89
8		0.0000%	0.0000%	0.0000%	0.0000%	100.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
9	Meters Study	94,147 37.1008%	35,064 13.8176%	4,029 1.5878%	25,202 9.9313%	71,731 28.2673%	7,338 2.8918%
10	Average Retail Customers	94,147 60.4416%	26,746 17.1707%	5,591 3.5893%	9,497 6.0972%	8,407 5.3974%	860 0.5522%
11	12 CP Demand at Transmission (kW)	211,329 24.7282%	86,017 10.0651%	2,104 0.2462%	7,271 0.8509%	225,848 26.4273%	19,544 2.2869%
15	Direct to Street Lighting	0 0.0000%	0 0.0000%	0 0.0000%	0 0.0000%	0 0.0000%	0 0.0000%
17	Meter Reading Study	$935,463 65.0719%	$265,753 18.4861%	$18,332 1.2752%	$94,367 6.5643%	$87,692 6.1000%	$8,973 0.6242%
18	Customer Records & Collection Study	$1,846,729 63.6091%	$524,632 18.0705%	$54,833 1.8887%	$186,293 6.4167%	$187,118 6.4451%	$19,775 0.6812%
19	Customer Class NCP Demand at Subtransmission (kW)	385,616 31.1918%	172,059 13.9176%	4,337 0.3508%	8,173 0.6611%	293,957 23.7776%	28,020 2.2665%
20	Individual Customer NCP Demand at Secondary (kW)	656,740 47.4507%	298,112 21.5392%	4,105 0.2966%	7,736 0.5590%	373,991 27.0216%	38,724 2.7979%
21	Direct to Outdoor Lighting	0 0.0000%	0 0.0000%	0 0.0000%	0 0.0000%	0 0.0000%	0 0.0000%
22	Customer O&M Accounts 901-918	$7,626,674 62.1362%	$2,102,253 17.1275%	$304,729 2.4827%	$687,284 5.5995%	$879,739 7.1674%	$66,419 0.5411%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)	TOTAL
	Meters Study	15,924	326	0	0	253,761
9		6.2751%	0.1284%	0.0000%	0.0000%	100.0000%
	Average Retail Customers	105	2	8,863	1,547	155,766
10		0.0674%	0.0013%	5.6900%	0.9931%	100.0000%
	12 CP Demand at Transmission (kW)	175,979	125,626	390	495	854,604
11		20.5919%	14.6999%	0.0457%	0.0580%	100.0000%
	Direct to Street Lighting	0	0	0	1	1
15		0.0000%	0.0000%	0.0000%	100.0000%	100.0000%
	Meter Reading Study	$26,591	$412	$0	$0	$1,437,583
17		1.8497%	0.0286%	0.0000%	0.0000%	100.0000%
	Customer Records & Collection Study	$10,022	$39	$43,463	$30,343	$2,903,248
18		0.3452%	0.0014%	1.4970%	1.0452%	100.0000%
	Customer Class NCP Demand at Subtransmission (kW)	205,787	133,425	2,046	2,855	1,236,275
19		16.6457%	10.7925%	0.1655%	0.2309%	100.0000%
	Individual Customer NCP Demand at Secondary (kW)	0	0	1,937	2,702	1,384,047
20		0.0000%	0.0000%	0.1399%	0.1952%	100.0000%
	Direct to Outdoor Lighting	0	0	1	0	1.00
21		0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
	Customer O&M Accounts 901-918	$109,525	$541	$399,536	$97,416	$12,274,117
22		0.8923%	0.0044%	3.2551%	0.7937%	100.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	Bad Debts Analysis	$ 711,745.39	$ 156,986.05	$ 4,221.86	$ 14,167.20	$ 184,172.19	$ 1,828.41
23		63.3237%	13.9670%	0.3756%	1.2605%	16.3857%	0.1627%
	Sales to Customers (MWH)	1,081,881,362	450,686,046	14,303,741	58,477,763	1,190,584,262	105,174,409
26		20.5687%	8.5684%	0.2719%	1.1118%	22.6354%	1.9996%
	Average Customers at Secondary	94,147	26,746	5,591	9,497	95	860
27		63.8952%	18.1518%	3.7944%	6.4456%	0.0644%	0.5837%
	Test Year CAAA Credits	(834,065)	(188,015)	(8,378)	(23,262)	(478,325)	(51,759)
28		39.2000%	8.8365%	0.3938%	1.0933%	22.4807%	2.4326%
	Test Year DSM Revenues	197,682	31,880	0	48,807	1,003,615	121,569
29		9.7161%	1.5669%	0.0000%	2.3989%	49.3276%	5.9751%
	Test Year QPCP-CC Revenues	5,610,432	1,329,758	58,282	158,879	3,267,011	359,703
30		37.9710%	8.9997%	0.3944%	1.0753%	22.1109%	2.4344%
	Test Year QPCP-OE Revenues	9,433,127	1,959,074	93,493	263,732	5,423,107	570,622
31		37.9335%	7.8780%	0.3760%	1.0605%	21.8080%	2.2946%
	Test Year IP-2 Credits	0	0	0	0	(5,538)	0
32		0.0000%	0.0000%	0.0000%	0.0000%	0.4915%	0.0000%
	Test Year LP-1 Credits	0	0	0	0	0	0
33		0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	NSF Analysis	57,287	16,275	0	1,906	1,687	173

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)	TOTAL
	Bad Debts Analysis	$ 47,697.38	$0	$ 29.10	$ 3,131.27	$1,123,979
23		4.2436%	0.0000%	0.0026%	0.2786%	100.0000%
	Sales to Customers (MWH)	1,320,758,678	1,019,247,677	6,606,709	12,115,999	5,259,836,647
26		25.1103%	19.3779%	0.1256%	0.2303%	100.0000%
	Average Customers at Secondary	0	0	8,863	1,547	147,346
27		0.0000%	0.0000%	6.0151%	1.0499%	100.0000%
	Test Year CAAA Credits	(294,261)	(249,654)	0	0	(2,127,719)
28		13.8299%	11.7334%	0.0000%	0.0000%	100.0000%
	Test Year DSM Revenues	563,171	67,867	0	0	2,034,590
29		27.6798%	3.3357%	0.0000%	0.0000%	100.0000%
	Test Year QPCP-CC Revenues	2,172,536	1,818,967	0	0	14,775,568
30		14.7036%	12.3106%	0.0000%	0.0000%	100.0000%
	Test Year QPCP-OE Revenues	4,172,034	2,952,327	0	0	24,867,516
31		16.7770%	11.8722%	0.0000%	0.0000%	100.0000%
	Test Year IP-2 Credits	(131,611)	(989,526)	0	0	(1,126,676)
32		11.6814%	87.8271%	0.0000%	0.0000%	100.0000%
	Test Year LP-1 Credits	(516,131)	0	0	0	(516,131)
33		100.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	NSF Analysis	0	0	0	0	77,327

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
34		74.0846%	21.0465%	0.0000%	2.4643%	2.1815%	0.2232%
	Forfeited Discounts Analysis	1,216,010	385,878	0	53,046	689,595	54,658
35		44.0484%	13.9779%	0.0000%	1.9215%	24.9797%	1.9799%
	Reconnect Charge Analysis	123,632	39,232	0	550	7,155	567
36		72.2419%	22.9246%	0.0000%	0.3216%	4.1806%	0.3314%
	Direct to Residential	1	0	0	0	0	0
37		100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
	Unbilled Analysis	$928,248	$597,848	$22,363	$78,850	$1,025,038	$103,964
38		10.7761%	6.9405%	0.2596%	0.9154%	11.8998%	1.2069%

Internally-Generated Allocators

NO.	ALLOCATORS	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	Gross Plant	$569,049,116	$170,514,345	$4,358,896	$20,102,151	$458,241,733	$36,361,181
100		32.8042%	9.8297%	0.2513%	1.1588%	26.4165%	2.0961%
	Original Cost Rate Base	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986
102		32.5569%	9.8312%	0.2515%	1.0946%	26.5261%	2.1115%
	Subtotal Customer-Related O&M	$5,624,868	$1,533,565	$185,854	$485,347	$700,980	$48,132
103		62.7625%	17.1116%	2.0738%	5.4155%	7.8216%	0.5371%
	Subtotal Customer Accounts O&M	$7,471,386	$2,059,448	$298,524	$673,290	$861,826	$65,067
104		62.1362%	17.1275%	2.4827%	5.5995%	7.1674%	0.5411%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)	TOTAL
34		0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Forfeited Discounts Analysis	361,436	0	0	0	2,760,625
35		13.0925%	0.0000%	0.0000%	0.0000%	100.0000%
	Reconnect Charge Analysis	0	0	0	0	171,136
36		0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Direct to Residential	0	0	0	0	1
37		0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
	Unbilled Analysis	$2,982,457	$2,866,980	$2,582	$5,602	$8,613,932
38		34.6236%	33.2831%	0.0300%	0.0650%	100.0000%

Internally-Generated Allocators

NO.	ALLOCATORS	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)	TOTAL
	Gross Plant	$285,388,369	$173,888,294	$5,093,391	$11,685,355	$1,734,682,831
100		16.4519%	10.0242%	0.2936%	0.6736%	100.0000%
	Original Cost Rate Base	$169,714,918	$103,074,452	$2,234,810	$6,163,643	$1,017,759,890
102		16.6753%	10.1276%	0.2196%	0.6056%	100.0000%
	Subtotal Customer-Related O&M	$107,295	$498	$211,086	$64,525	$8,962,148
103		1.1972%	0.0056%	2.3553%	0.7200%	100.0000%
	Subtotal Customer Accounts O&M	$107,295	$530	$391,401	$95,433	$12,024,200
104		0.8923%	0.0044%	3.2551%	0.7937%	100.0000%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	O&M Without Fuel Costs (P/F A)	$43,363,246	$12,036,011	$442,895	$1,718,345	$34,830,811	$2,687,673
115		32.4196%	8.9985%	0.3311%	1.2847%	26.0405%	2.0094%
	O&M Without Fuel Costs (P/F B)	$43,611,961	$12,093,474	$444,422	$1,723,719	$34,912,629	$2,690,263
117		32.4987%	9.0118%	0.3312%	1.2845%	26.0162%	2.0047%
	Total Depreciation Expenses	$20,997,055	$5,977,321	$140,878	$699,894	$17,274,070	$1,343,162
120		32.5562%	9.2679%	0.2184%	1.0852%	26.7836%	2.0826%
	P/F A Normal Rev. w/ Misc. Rev.	$121,207,380	$36,409,958	$1,255,111	$6,985,175	$99,570,813	$8,148,173
121		29.3722%	8.8232%	0.3042%	1.6927%	24.1290%	1.9745%
	P/F A Equalized Rev. w/ Misc. Rev.	117,904,239	37,368,236	1,300,249	5,012,282	103,056,609	8,363,219
122		28.5718%	9.0555%	0.3151%	1.2146%	24.9737%	2.0267%
	P/F B Equalized Rev. w/ Misc. Rev.	147,073,700	46,162,241	1,484,643	5,938,324	127,278,407	10,284,784
123		29.2353%	9.1761%	0.2951%	1.1804%	25.3004%	2.0444%
	P/F B Normal Rev. w/ Misc. Rev.	149,551,055	45,443,532	1,450,789	7,417,995	124,664,059	10,123,500
124		29.7277%	9.0332%	0.2884%	1.4745%	24.7807%	2.0123%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SCHEDULE OF CUSTOMER CLASS ALLOCATION FACTORS

DATA: 12 MONTHS ENDED MARCH 31, 2005
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 3

NO.	ALLOCATORS	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)	TOTAL
	O&M Without Fuel Costs (P/F A)	$22,632,629	$14,958,916	$271,393	$814,505	$133,756,423
115		16.9208%	11.1837%	0.2029%	0.6089%	100.0000%
	O&M Without Fuel Costs (P/F B)	$22,663,185	$14,968,586	$271,607	$816,062	$134,195,908
117		16.8881%	11.1543%	0.2024%	0.6081%	100.0000%
	Total Depreciation Expenses	$10,839,638	$6,713,753	$180,615	$328,495	$64,494,881
120		16.8070%	10.4097%	0.2800%	0.5093%	100.0000%
	P/F A Normal Rev. w/ Misc. Rev.	$81,548,168	$54,428,787	$980,437	$2,125,808	$412,659,810
121		19.7616%	13.1897%	0.2376%	0.5151%	100.0000%
	P/F A Equalized Rev. w/ Misc. Rev.	81,040,752	55,795,250	1,010,228	1,808,745	$412,659,809
122		19.6386%	13.5209%	0.2448%	0.4383%	100.0000%
	P/F B Equalized Rev. w/ Misc. Rev.	96,297,751	65,064,918	1,134,842	2,350,001	$503,069,610
123		19.1420%	12.9336%	0.2256%	0.4671%	100.0000%
	P/F B Normal Rev. w/ Misc. Rev.	96,678,313	64,040,070	1,112,499	2,587,798	$503,069,611
124		19.2177%	12.7299%	0.2211%	0.5144%	100.0000%

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)
	PLANT IN SERVICE					
(1)	Production Demand	4	4 CP Demand at Generation (kW)	$1,195,020,736	$370,007,896	$88,361,705
(2)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(3)	FAC Fuel	1	Energy at Generation (mWh)	$0	$0	$0
(4)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$59,846,532	$14,798,997	$6,023,616
(5)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$123,244,713	$30,476,255	$12,404,709
(6)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Demand at Primary (KW)	$193,901,870	$76,431,569	$34,483,227
(7)	Primary Distribution Customer	0	Not Applicable	$0	$0	$0
(8)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Secondary (kW)	$23,641,255	$11,217,936	$5,092,130
(9)	Secondary Distribution Customer	0	Not Applicable	$0	$0	$0
(10)	Line Transformers Demand	20	Individual Customer NCP Demand at Secondary (kW)	$27,692,763	$13,140,403	$5,964,791
(11)	Line Transformers Customer	27	Average Customers at Secondary	$27,581,227	$17,623,078	$5,006,490
(12)	Services	8	Services Study	$42,827,253	$24,313,143	$9,564,083
(13)	Meters	9	Meters Study	$17,490,959	$6,489,283	$2,416,826
(14)	Outdoor Lighting	21	Direct to Outdoor Lighting	$2,832,594	$0	$0
(15)	Street Lighting	15	Direct to Street Lighting	$10,746,999	$0	$0
(16)	Customer Accounts-Related	22	Customer O&M Accounts 901-918	$4,808,264	$2,987,675	$823,537
(17)	DSM-Related	4	4 CP Demand at Generation (kW)	$5,047,665	$1,562,882	$373,232
(18)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(19)	WPM Fuel	4	4 CP Demand at Generation (kW)	$0	$0	$0
(20)	Unused	0	Not Applicable	$0	$0	$0
(21)	Total Gross Plant			$1,734,682,832	$569,049,116	$170,514,345

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PLANT IN SERVICE								
(1)	Production Demand	$1,691,036	$9,345,153	$334,284,378	$24,594,495	$220,402,742	$146,333,330	$0	$0
(2)	Production Energy	$0	$0	$0	$0	$0	$0	$0	$0
(3)	FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(4)	Transmission Demand	$147,334	$509,211	$15,815,794	$1,368,656	$12,323,528	$8,797,366	$27,336	$34,694
(5)	Sub-Transmission Demand	$303,411	$1,048,642	$32,570,192	$2,818,537	$25,378,407	$18,116,820	$56,294	$71,446
(6)	Primary Distribution Demand	$614,113	$1,157,428	$50,428,494	$4,880,732	$25,212,256	$0	$289,781	$404,271
(7)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(8)	Secondary Distribution Demand	$70,113	$132,144	$6,388,236	$661,456	$0	$0	$33,084	$46,156
(9)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(10)	Line Transformers Demand	$82,129	$154,790	$7,483,017	$774,813	$0	$0	$38,754	$54,066
(11)	Line Transformers Customer	$1,046,528	$1,777,773	$17,767	$160,996	$0	$0	$1,659,034	$289,562
(12)	Services	$0	$3,931,228	$4,553,014	$465,785	$0	$0	$0	$0
(13)	Meters	$277,714	$1,737,072	$4,944,223	$505,807	$1,097,567	$22,467	$0	$0
(14)	Outdoor Lighting	$0	$0	$0	$0	$0	$0	$2,832,594	$0
(15)	Street Lighting	$0	$0	$0	$0	$0	$0	$0	$10,746,999
(16)	Customer Accounts-Related	$119,375	$269,237	$344,629	$26,019	$42,905	$212	$156,514	$38,162
(17)	DSM-Related	$7,143	$39,473	$1,411,989	$103,885	$930,962	$618,099	$0	$0
(18)	Non-FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(19)	WPM Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(20)	Unused	$0	$0	$0	$0	$0	$0	$0	$0
(21)	Total Gross Plant	$4,358,896	$20,102,151	$458,241,733	$36,361,181	$285,388,369	$173,888,294	$5,093,391	$11,685,355

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)
	PLANT IN SERVICE					
(22)	Production Demand	4	4 CP Demand at Generation (kW)	$555,837,759	$172,101,080	$41,099,514
(23)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(24)	FAC Fuel	1	Energy at Generation (mWh)	$0	$0	$0
(25)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$26,965,124	$6,668,002	$2,714,068
(26)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$50,537,878	$12,497,130	$5,086,690
(27)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Demand at Primary (KW)	$74,794,855	$29,482,377	$13,301,408
(28)	Primary Distribution Customer	0	Not Applicable	$0	$0	$0
(29)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Secondary (kW)	$9,228,737	$4,379,098	$1,987,793
(30)	Secondary Distribution Customer	0	Not Applicable	$0	$0	$0
(31)	Line Transformers Demand	20	Individual Customer NCP Demand at Secondary (kW)	$12,367,900	$5,868,653	$2,663,943
(32)	Line Transformers Customer	27	Average Customers at Secondary	$12,318,088	$7,870,666	$2,235,955
(33)	Services	8	Services Study	$24,968,344	$14,174,594	$5,575,873
(34)	Meters	9	Meters Study	$7,558,616	$2,804,306	$1,044,417
(35)	Outdoor Lighting	21	Direct to Outdoor Lighting	$1,896,814	$0	$0
(36)	Street Lighting	15	Direct to Street Lighting	$5,194,615	$0	$0
(37)	Customer Accounts-Related	22	Customer O&M Accounts 901-918	$2,377,224	$1,477,117	$407,160
(38)	DSM-Related	4	4 CP Demand at Generation (kW)	$0	$0	$0
(39)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(40)	WPM Fuel	4	4 CP Demand at Generation (kW)	$0	$0	$0
(41)	Unused	0	Not Applicable	$0	$0	$0
(42)	Total Depreciation Reserve			$784,045,954	$257,323,023	$76,116,822

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PLANT IN SERVICE								
(22)	Production Demand	$786,548	$4,346,694	$155,485,067	$11,439,591	$102,515,515	$68,063,748	$0	$0
(23)	Production Energy	$0	$0	$0	$0	$0	$0	$0	$0
(24)	FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(25)	*Transmission Demand*	$66,384	$229,436	$7,126,141	$616,677	$5,552,627	$3,963,840	$12,317	$15,632
(26)	Sub-Transmission Demand	$124,417	$430,007	$13,355,773	$1,155,773	$10,406,701	$7,429,005	$23,084	$29,297
(27)	Primary Distribution Demand	$236,885	$446,461	$19,452,066	$1,882,672	$9,725,265	$0	$111,779	$155,942
(28)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(29)	Secondary Distribution Demand	$27,370	$51,584	$2,493,749	$258,210	$0	$0	$12,915	$18,018
(30)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(31)	Line Transformers Demand	$36,680	$69,131	$3,342,000	$346,040	$0	$0	$17,308	$24,146
(32)	Line Transformers Customer	$467,391	$793,973	$7,935	$71,903	$0	$0	$740,943	$129,322
(33)	Services	$0	$2,291,911	$2,654,413	$271,553	$0	$0	$0	$0
(34)	Meters	$120,013	$750,666	$2,136,617	$218,581	$474,307	$9,709	$0	$0
(35)	Outdoor Lighting	$0	$0	$0	$0	$0	$0	$1,896,814	$0
(36)	Street Lighting	$0	$0	$0	$0	$0	$0	$0	$5,194,615
(37)	Customer Accounts-Related	$59,019	$133,112	$170,386	$12,864	$21,213	$105	$77,381	$18,867
(38)	DSM-Related	$0	$0	$0	$0	$0	$0	$0	$0
(39)	Non-FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(40)	WPM Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(41)	Unused	$0	$0	$0	$0	$0	$0	$0	$0
(42)	Total Depreciation Reserve	$1,924,708	$9,542,975	$206,224,147	$16,273,864	$128,695,628	$79,466,407	$2,892,541	$5,585,839

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)
	PLANT IN SERVICE					
(43)	Production Demand	4	4 CP Demand at Generation (kW)	$17,841,508	$5,524,171	$1,319,229
(44)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$13,495,550	$2,829,127	$1,178,547
(45)	FAC Fuel	1	Energy at Generation (mWh)	$0	$0	$0
(46)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$1,367,637	$338,193	$137,654
(47)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$1,841,709	$455,422	$185,370
(48)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Demand at Primary (KW)	$3,359,832	$1,324,367	$597,508
(49)	Primary Distribution Customer	0	Not Applicable	$0	$0	$0
(50)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Secondary (kW)	$377,657	$179,201	$81,344
(51)	Secondary Distribution Customer	0	Not Applicable	$0	$0	$0
(52)	Line Transformers Demand	20	Individual Customer NCP Demand at Secondary (kW)	$57,617	$27,340	$12,410
(53)	Line Transformers Customer	27	Average Customers at Secondary	$57,385	$36,666	$10,416
(54)	Services	8	Services Study	$92,774	$52,668	$20,718
(55)	Meters	9	Meters Study	$33,721	$12,511	$4,659
(56)	Outdoor Lighting	21	Direct to Outdoor Lighting	$6,136	$0	$0
(57)	Street Lighting	15	Direct to Street Lighting	$22,126	$0	$0
(58)	Customer Accounts-Related	22	Customer O&M Accounts 901-918	$0	$0	$0
(59)	DSM-Related	4	4 CP Demand at Generation (kW)	$28,569,362	$8,845,779	$2,112,463
(60)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(61)	WPM Fuel	4	4 CP Demand at Generation (kW)	$0	$0	$0
(62)	Unused	0	Not Applicable	$0	$0	$0
(63)	Total Other Rate Base Components			$67,123,013	$19,625,444	$5,660,319
(64)	Total Rate Base			$1,017,759,890	$331,351,537	$100,057,843

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PLANT IN SERVICE								
(43)	Production Demand	$25,247	$139,522	$4,990,823	$367,193	$3,290,585	$2,184,738	$0	$0
(44)	Production Energy	$37,404	$152,920	$3,113,360	$275,032	$3,362,577	$2,497,622	$17,277	$31,683
(45)	FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(46)	Transmission Demand	$3,367	$11,637	$361,429	$31,277	$281,622	$201,041	$625	$793
(47)	Sub-Transmission Demand	$4,534	$15,670	$486,713	$42,119	$379,243	$270,729	$841	$1,068
(48)	Primary Distribution Demand	$10,641	$20,055	$873,799	$84,571	$436,865	$0	$5,021	$7,005
(49)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(50)	Secondary Distribution Demand	$1,120	$2,111	$102,049	$10,566	$0	$0	$529	$737
(51)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(52)	Line Transformers Demand	$171	$322	$15,569	$1,612	$0	$0	$81	$112
(53)	Line Transformers Customer	$2,177	$3,699	$37	$335	$0	$0	$3,452	$602
(54)	Services	$0	$8,516	$9,863	$1,009	$0	$0	$0	$0
(55)	Meters	$535	$3,349	$9,532	$975	$2,116	$43	$0	$0
(56)	Outdoor Lighting	$0	$0	$0	$0	$0	$0	$6,136	$0
(57)	Street Lighting	$0	$0	$0	$0	$0	$0	$0	$22,126
(58)	Customer Accounts-Related	$0	$0	$0	$0	$0	$0	$0	$0
(59)	DSM-Related	$40,428	$223,415	$7,991,737	$587,981	$5,269,169	$3,498,391	$0	$0
(60)	Non-FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(61)	WPM Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(62)	Unused	$0	$0	$0	$0	$0	$0	$0	$0
(63)	Total Other Rate Base Components	$125,625	$581,215	$17,954,911	$1,402,669	$13,022,177	$8,652,565	$33,961	$64,127
(64)	Total Rate Base	$2,559,813	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)
	PLANT IN SERVICE					
(65)	Production Demand	4	4 CP Demand at Generation (kW)	$657,024,485	$203,430,987	$48,581,419
(66)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$13,495,550	$2,829,127	$1,178,547
(67)	FAC Fuel	1	Energy at Generation (mWh)	$0	$0	$0
(68)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$34,249,046	$8,469,188	$3,447,202
(69)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$74,548,544	$18,434,547	$7,503,389
(70)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Demand at Primary (KW)	$122,466,847	$48,273,558	$21,779,326
(71)	Primary Distribution Customer	0	Not Applicable	$0	$0	$0
(72)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Secondary (kW)	$14,790,175	$7,018,038	$3,185,681
(73)	Secondary Distribution Customer	0	Not Applicable	$0	$0	$0
(74)	Line Transformers Demand	20	Individual Customer NCP Demand at Secondary (kW)	$15,382,479	$7,299,090	$3,313,258
(75)	Line Transformers Customer	27	Average Customers at Secondary	$15,320,525	$9,789,078	$2,780,951
(76)	Services	8	Services Study	$17,951,683	$10,191,217	$4,008,928
(77)	Meters	9	Meters Study	$9,966,064	$3,697,488	$1,377,068
(78)	Outdoor Lighting	21	Direct to Outdoor Lighting	$941,916	$0	$0
(79)	Street Lighting	15	Direct to Street Lighting	$5,574,510	$0	$0
(80)	Customer Accounts-Related	22	Customer O&M Accounts 901-918	$2,431,041	$1,510,557	$416,377
(81)	DSM-Related	4	4 CP Demand at Generation (kW)	$33,617,027	$10,408,661	$2,485,696
(82)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(83)	WPM Fuel	4	4 CP Demand at Generation (kW)	$0	$0	$0
(84)	Unused	0	Not Applicable	$0	$0	$0
(85)	Total Rate Base			$1,017,759,890	$331,351,537	$100,057,843

VECTRN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF RATE BASE

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 4

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PLANT IN SERVICE								
(65)	Production Demand	$929,734	$5,137,981	$183,790,134	$13,522,096	$121,177,812	$80,454,320	$0	$0
(66)	Production Energy	$37,404	$152,920	$3,113,360	$275,032	$3,362,577	$2,497,622	$17,277	$31,683
(67)	FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(68)	Transmission Demand	$84,316	$291,412	$9,051,082	$783,256	$7,052,524	$5,034,567	$15,644	$19,855
(69)	Sub-Transmission Demand	$183,528	$634,305	$19,701,132	$1,704,883	$15,350,949	$10,958,543	$34,051	$43,217
(70)	Primary Distribution Demand	$387,869	$731,022	$31,850,228	$3,082,630	$15,923,856	$0	$183,023	$255,334
(71)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(72)	Secondary Distribution Demand	$43,864	$82,670	$3,996,536	$413,813	$0	$0	$20,698	$28,875
(73)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(74)	Line Transformers Demand	$45,620	$85,981	$4,156,586	$430,385	$0	$0	$21,527	$30,032
(75)	Line Transformers Customer	$581,314	$987,498	$9,869	$89,428	$0	$0	$921,542	$160,843
(76)	Services	$0	$1,647,833	$1,908,464	$195,241	$0	$0	$0	$0
(77)	Meters	$158,237	$989,755	$2,817,138	$288,200	$625,376	$12,801	$0	$0
(78)	Outdoor Lighting	$0	$0	$0	$0	$0	$0	$941,916	$0
(79)	*Street Lighting*	$0	$0	$0	$0	$0	$0	$0	$5,574,510
(80)	Customer Accounts-Related	$60,355	$136,125	$174,243	$13,155	$21,693	$107	$79,133	$19,294
(81)	DSM-Related	$47,570	$262,888	$9,403,726	$691,866	$6,200,131	$4,116,491	$0	$0
(82)	Non-FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(83)	WPM Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(84)	Unused	$0	$0	$0	$0	$0	$0	$0	$0
(85)	Total Rate Base	$2,559,813	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF DEPRECIATION EXPENSE

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 5

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)
	DEPRECIATION AND AMORTIZATION EXPENSES					
(1)	Production Demand	4	4 CP Demand at Generation (kW)	$44,330,644	$13,725,861	$3,277,877
(2)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(3)	FAC Fuel	1	Energy at Generation (mWh)	$0	$0	$0
(3)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$1,297,322	$320,805	$130,577
(4)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$2,469,500	$610,664	$248,558
(5)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Demand at Primary (KW)	$5,794,453	$2,284,037	$1,030,477
(6)	Primary Distribution Customer	0	Not Applicable	$0	$0	$0
(7)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Secondary (kW)	$774,633	$367,569	$166,850
(8)	Secondary Distribution Customer	0	Not Applicable	$0	$0	$0
(9)	Line Transformers Demand	20	Individual Customer NCP Demand at Secondary (kW)	$693,454	$329,048	$149,364
(10)	Line Transformers Customer	27	Average Customers at Secondary	$690,661	$441,299	$125,367
(11)	Services	8	Services Study	$1,400,196	$794,895	$312,688
(12)	Meters	9	Meters Study	$514,709	$190,961	$71,120
(13)	Outdoor Lighting	21	Direct to Outdoor Lighting	$122,255	$0	$0
(14)	Street Lighting	15	Direct to Street Lighting	$303,045	$0	$0
(15)	Customer Accounts-Related	22	Customer O&M Accounts 901-918	$134,612	$83,643	$23,056
(16)	DSM-Related	4	4 CP Demand at Generation (kW)	$5,969,398	$1,848,273	$441,387
(17)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0
(18)	WPM Fuel	4	4 CP Demand at Generation (kW)	$0	$0	$0
(19)	Unused	0	Not Applicable	$0		
(20)	Total Depreciation and Amortization Expense			$64,494,881	$20,997,055	$5,977,321

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF DEPRECIATION EXPENSE

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 5

		Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	DEPRECIATION AND AMORTIZATION								
(1)	Production Demand	$62,731	$346,669	$12,400,657	$912,361	$8,176,089	$5,428,400	$0	$0
(2)	Production Energy	$0	$0	$0	$0	$0	$0	$0	$0
(3)	FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(3)	Transmission Demand	$3,194	$11,038	$342,847	$29,669	$267,143	$190,705	$593	$752
(4)	Sub-Transmission Demand	$6,080	$21,012	$652,621	$56,476	$508,517	$363,013	$1,128	$1,432
(5)	Primary Distribution Demand	$18,352	$34,588	$1,506,976	$145,853	$753,429	$0	$8,660	$12,081
(6)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(7)	Secondary Distribution Demand	$2,297	$4,330	$209,318	$21,673	$0	$0	$1,084	$1,512
(8)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(9)	Line Transformers Demand	$2,057	$3,876	$187,382	$19,402	$0	$0	$970	$1,354
(10)	Line Transformers Customer	$26,206	$44,517	$445	$4,031	$0	$0	$41,544	$7,251
(11)	Services	$0	$128,528	$148,856	$15,228	$0	$0	$0	$0
(12)	Meters	$8,172	$51,117	$145,494	$14,884	$32,298	$661	$0	$0
(13)	Outdoor Lighting	$0	$0	$0	$0	$0	$0	$122,255	$0
(14)	Street Lighting	$0	$0	$0	$0	$0	$0	$0	$303,045
(15)	Customer Accounts-Related	$3,342	$7,538	$9,648	$728	$1,201	$6	$4,382	$1,068
(16)	DSM-Related	$8,447	$46,681	$1,669,826	$122,855	$1,100,961	$730,968	$0	$0
(17)	Non-FAC Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(18)	WPM Fuel	$0	$0	$0	$0	$0	$0	$0	$0
(19)	Unused								
(20)	Total Depreciation and Amortization Exp	$140,878	$699,894	$17,274,070	$1,343,162	$10,839,638	$6,713,753	$180,615	$328,495

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF OPERATION MAINTENANCE EXPENSES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 6

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)
	PROFORMA A OPERATING EXPENSES					
(1)	Production Demand	4	4 CP Demand at Generation (kW)	$93,371,448	$28,910,103	$6,904,031
(2)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$11,023	$2,311	$963
(3)	FAC Fuel	1	Energy at Generation (mWh)	$127,995,233	$26,832,164	$11,177,641
(4)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$11,353,770	$2,807,588	$1,142,769
(5)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$12,591,218	$3,113,587	$1,267,319
(6)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Demand at Primary (KW)	$1,754,745	$691,679	$312,061
(7)	Primary Distribution Customer	3	Average Customers	$0	$0	$0
(8)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Secondary (kW)	$127,906	$60,692	$27,550
(9)	Secondary Distribution Customer	3	Average Customers	$0	$0	$0
(10)	Line Transformers Demand	20	Individual Customer NCP Demand at Secondary (kW)	$1,835,672	$871,039	$395,389
(11)	Line Transformers Customer	3	Average Customers	$1,828,279	$1,105,041	$313,928
(12)	Services	8	Services Study	$224,486	$127,441	$50,132
(13)	Meters	9	Meters Study	$2,270,291	$842,296	$313,699
(14)	Outdoor Lighting	21	Direct to Outdoor Lighting	$14,647	$0	$0
(15)	Street Lighting	15	Direct to Street Lighting	$723,461	$0	$0
	Customer Accounts-Related					
(16)	Supervision	104	Subtotal Customer Accounts O&M	$249,916	$155,289	$42,804
(17)	Meter Reading Expenses	17	Meter Reading Study	$1,438,613	$936,133	$265,943
(18)	Customer Billing and Accounting	18	Customer Records & Collection Study	$2,903,248	$1,846,729	$524,632
(19)	Uncollectible Accounts	23	Bad Debts Analysis	$1,568,107	$992,984	$219,017
(20)	Misc. Customer Accounts Expenses	10	Average Retail Customers	$130,576	$78,922	$22,421
(21)	Cust. Service & Info. Expenses	10	Average Retail Customers	$1,359,019	$821,413	$233,353
(22)	Sales Expenses	10	Average Retail Customers	$1,312,670	$793,399	$225,394
(23)	Customer-Related A&G	10	Average Retail Customers	$3,311,968	$2,001,807	$568,688
(24)	DSM-Related	4	4 CP Demand at Generation (kW)	$52,187	$16,158	$3,859
(25)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$19,045,083	$3,992,499	$1,663,180
(26)	WPM Fuel	4	4 CP Demand at Generation (kW)	$16,295,008	$5,045,336	$1,204,878
(27)	Total Proforma A Operating Cost:			$301,768,572	$82,044,609	$26,879,651
(28)	Total Depreciation and Amortization Expense			$64,494,881	$20,997,055	$5,977,321
(29)	Total Proforma A Operating and Maintenance Expenses Before Tax			$366,263,453	$103,041,664	$32,856,972

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF OPERATION MAINTENANCE EXPENSES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 6

		Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PROFORMA A OPERATING EXPENSE								
(1)	Production Demand	$132,127	$730,172	$26,118,891	$1,921,660	$17,220,892	$11,433,571	$0	$0
(2)	Production Energy	$31	$125	$2,543	$225	$2,746	$2,040	$14	$26
(3)	FAC Fuel	$354,753	$1,450,330	$29,527,900	$2,608,472	$31,891,538	$23,688,085	$163,856	$300,494
(4)	Transmission Demand	$27,951	$96,605	$3,000,490	$259,654	$2,337,955	$1,668,990	$5,186	$6,582
(5)	Sub-Transmission Demand	$30,998	$107,134	$3,327,513	$287,954	$2,592,769	$1,850,893	$5,751	$7,299
(6)	Primary Distribution Demand	$5,558	$10,474	$456,361	$44,169	$228,162	$0	$2,622	$3,659
(7)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(8)	Secondary Distribution Demand	$379	$715	$34,562	$3,579	$0	$0	$179	$250
(9)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0
(10)	Line Transformers Demand	$5,444	$10,261	$496,027	$51,360	$0	$0	$2,569	$3,584
(11)	Line Transformers Customer	$65,622	$111,474	$98,679	$10,095	$1,231	$23	$104,028	$18,157
(12)	Services	$0	$20,606	$23,865	$2,441	$0	$0	$0	$0
(13)	Meters	$36,047	$225,468	$641,750	$65,653	$142,462	$2,916	$0	$0
(14)	Outdoor Lighting	$0	$0	$0	$0	$0	$0	$14,647	$0
(15)	Street Lighting	$0	$0	$0	$0	$0	$0	$0	$723,461
	Customer Accounts-Related								
(16)	Supervision	$6,205	$13,994	$17,913	$1,352	$2,230	$11	$8,135	$1,984
(17)	Meter Reading Expenses	$18,345	$94,435	$87,755	$8,980	$26,610	$412	$0	$0
(18)	Customer Billing and Accounting	$54,833	$186,293	$187,118	$19,775	$10,022	$39	$43,463	$30,343
(19)	Uncollectible Accounts	$5,890	$19,765	$256,946	$2,551	$66,544	$0	$41	$4,369
(20)	Misc. Customer Accounts Expenses	$4,687	$7,961	$7,048	$721	$88	$2	$7,430	$1,297
(21)	Cust. Service & Info. Expenses	$48,779	$82,862	$73,351	$7,504	$915	$17	$77,328	$13,496
(22)	Sales Expenses	$47,115	$80,036	$70,850	$7,248	$884	$17	$74,690	$13,036
(23)	Customer-Related A&G	$118,875	$201,937	$178,759	$18,288	$2,231	$43	$188,450	$32,891
(24)	DSM-Related	$74	$408	$14,598	$1,074	$9,625	$6,390	$0	$0
(25)	Non-FAC Fuel	$52,786	$215,802	$4,393,611	$388,128	$4,745,310	$3,524,675	$24,381	$44,712
(26)	WPM Fuel	$23,059	$127,428	$4,558,219	$335,364	$3,005,357	$1,995,365	$0	$0
(27)	Total Proforma A Operating Cost:	$1,039,556	$3,794,286	$73,574,749	$6,046,248	$62,287,574	$44,173,491	$722,769	$1,205,638
(28)	Total Depreciation and Amortization Exp	$140,878	$699,894	$17,274,070	$1,343,162	$10,839,638	$6,713,753	$180,615	$328,495
(29)	Total Proforma A Operating and Mainten	$1,180,433	$4,494,180	$90,848,819	$7,389,410	$73,127,212	$50,887,244	$903,385	$1,534,133

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF OPERATION MAINTENANCE EXPENSES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 6

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	PROFORMA B OPERATING EXPENSES						
(30)	Production Demand	4	4 CP Demand at Generation (kW)	$93,435,650	$28,929,982	$6,908,778	$132,218
(31)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$12,341	$2,587	$1,078	$34
(32)	FAC Fuel	1	Energy at Generation (mWh)	$127,995,233	$26,832,164	$11,177,641	$354,753
(33)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$11,357,117	$2,808,416	$1,143,106	$27,960
(34)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$12,598,502	$3,115,389	$1,268,052	$31,016
(35)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Demand at Primary (KW)	$1,766,712	$696,396	$314,190	$5,595
(36)	Primary Distribution Customer	3	Average Customers	$0	$0	$0	$0
(37)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Secondary (kW)	$129,351	$61,378	$27,861	$384
(38)	Secondary Distribution Customer	3	Average Customers	$0	$0	$0	$0
(39)	Line Transformers Demand	20	Individual Customer NCP Demand at Secondary (kW)	$1,837,175	$871,752	$395,712	$5,449
(40)	Line Transformers Customer	3	Average Customers	$1,829,776	$1,105,946	$314,185	$65,675
(41)	Services	8	Services Study	$226,240	$128,437	$50,523	$0
(42)	Meters	9	Meters Study	$2,271,265	$842,657	$313,834	$36,062
(43)	Outdoor Lighting	21	Direct to Outdoor Lighting	$14,739	$0	$0	$0
(44)	Street Lighting	15	Direct to Street Lighting	$724,005	$0	$0	$0
	Customer Accounts-Related						
(45)	Supervision	104	Subtotal Customer Accounts O&M	$249,916	$155,289	$42,804	$6,205
(46)	Meter Reading Expenses	17	Meter Reading Study	$1,438,613	$936,133	$265,943	$18,345
(47)	Customer Billing and Accounting	18	Customer Records & Collection Study	$2,903,248	$1,846,729	$524,632	$54,833
(48)	Uncollectible Accounts	23	Bad Debts Analysis	$1,911,664	$1,210,537	$267,002	$7,181
(49)	Misc. Customer Accounts Expense	10	Average Retail Customers	$130,576	$78,922	$22,421	$4,687
(50)	Cust. Service & Info. Expenses	10	Average Retail Customers	$1,359,019	$821,413	$233,353	$48,779
(51)	Sales Expenses	117	O&M Without Fuel Costs (P/F B)	$1,312,670	$426,601	$118,295	$4,347
(52)	Customer-Related A&G	10	Average Retail Customers	$3,312,206	$2,001,950	$568,728	$118,884
(53)	DSM-Related	4	4 CP Demand at Generation (kW)	$55,472	$17,175	$4,102	$78
(54)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$19,045,083	$3,992,499	$1,663,180	$52,786
(55)	WPM Fuel	4	4 CP Demand at Generation (kW)	$16,295,008	$5,045,336	$1,204,878	$23,059
(56)	Total Proforma B Operating Costs			$302,211,580	$81,927,687	$26,830,299	$998,328
(57)	Total Depreciation and Amortization Expense			$64,494,881	$20,997,055	$5,977,321	$140,878
(58)	Total Proforma B Operating and Maintenance Expenses Before Tax			$366,706,461	$102,924,742	$32,807,620	$1,139,205

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF OPERATION MAINTENANCE EXPENSES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 6

		Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PROFORMA B OPERATING EXPENSE							
(30)	Production Demand	$730,674	$26,136,850	$1,922,981	$17,232,733	$11,441,433	$0	$0
(31)	Production Energy	$140	$2,847	$252	$3,075	$2,284	$16	$29
(32)	FAC Fuel	$1,450,330	$29,527,900	$2,608,472	$31,891,538	$23,688,085	$163,856	$300,494
(33)	Transmission Demand	$96,633	$3,001,374	$259,731	$2,338,644	$1,669,482	$5,187	$6,584
(34)	Sub-Transmission Demand	$107,196	$3,329,438	$288,121	$2,594,269	$1,851,964	$5,755	$7,303
(35)	Primary Distribution Demand	$10,546	$459,473	$44,470	$229,718	$0	$2,640	$3,683
(36)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(37)	Secondary Distribution Demand	$723	$34,953	$3,619	$0	$0	$181	$253
(38)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(39)	Line Transformers Demand	$10,269	$496,433	$51,402	$0	$0	$2,571	$3,587
(40)	Line Transformers Customer	$111,565	$98,760	$10,103	$1,232	$23	$104,114	$18,172
(41)	Services	$20,767	$24,052	$2,461	$0	$0	$0	$0
(42)	Meters	$225,565	$642,025	$65,681	$142,523	$2,917	$0	$0
(43)	Outdoor Lighting	$0	$0	$0	$0	$0	$14,739	$0
(44)	Street Lighting	$0	$0	$0	$0	$0	$0	$724,005
	Customer Accounts-Related							
(45)	Supervision	$13,994	$17,913	$1,352	$2,230	$11	$8,135	$1,984
(46)	Meter Reading Expenses	$94,435	$87,755	$8,980	$26,610	$412	$0	$0
(47)	Customer Billing and Accounting	$186,293	$187,118	$19,775	$10,022	$39	$43,463	$30,343
(48)	Uncollectible Accounts	$24,096	$313,240	$3,110	$81,124	$0	$49	$5,326
(49)	Misc. Customer Accounts Expense	$7,961	$7,048	$721	$88	$2	$7,430	$1,297
(50)	Cust. Service & Info. Expenses	$82,862	$73,351	$7,504	$915	$17	$77,328	$13,496
(51)	Sales Expenses	$16,861	$341,506	$26,315	$221,685	$146,419	$2,657	$7,983
(52)	Customer-Related A&G	$201,952	$178,772	$18,289	$2,231	$43	$188,463	$32,894
(53)	DSM-Related	$434	$15,517	$1,142	$10,231	$6,793	$0	$0
(54)	Non-FAC Fuel	$215,802	$4,393,611	$388,128	$4,745,310	$3,524,675	$24,381	$44,712
(55)	WPM Fuel	$127,428	$4,558,219	$335,364	$3,005,357	$1,995,365	$0	$0
(56)	Total Proforma B Operating Costs	$3,736,526	$73,928,156	$6,067,973	$62,539,537	$44,329,965	$650,964	$1,202,144
(57)	Total Depreciation and Amortization Expe	$699,894	$17,274,070	$1,343,162	$10,839,638	$6,713,753	$180,615	$328,495
(58)	Total Proforma B Operating and Mainten	$4,436,420	$91,202,226	$7,411,135	$73,379,175	$51,043,718	$831,579	$1,530,638

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF TAXES OTHER THAN INCOME

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 7

		No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	TAXES OTHER THAN INCOME						
(1)	Production Demand	4	4 CP Demand at Generation (kW)	$5,535,429	$1,713,905	$409,298	$7,833
(2)	Production Energy	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0	$0
(3)	FAC Fuel	1	Energy at Generation (mWh)	$0	$0	$0	$0
(3)	Transmission Demand	11	12 CP Demand at Transmission (kW)	$282,014	$69,737	$28,385	$694
(4)	Sub-Transmission Demand	11	12 CP Demand at Transmission (kW)	$580,765	$143,613	$58,455	$1,430
(5)	Primary Distribution Demand	7	50% Class and 50% Indiv. Cust. NCP Dem	$913,722	$360,168	$162,495	$2,894
(6)	Primary Distribution Customer	0	Not Applicable	$0	$0	$0	$0
(7)	Secondary Distribution Demand	20	Individual Customer NCP Demand at Seco	$111,404	$52,862	$23,996	$330
(8)	Secondary Distribution Customer	0	Not Applicable	$0	$0	$0	$0
(9)	Line Transformers Demand	20	Individual Customer NCP Demand at Seco	$130,496	$61,921	$28,108	$387
(10)	Line Transformers Customer	27	Average Customers at Secondary	$129,971	$83,045	$23,592	$4,932
(11)	Services	8	Services Study	$201,814	$114,571	$45,069	$0
(12)	Meters	9	Meters Study	$82,422	$30,579	$11,389	$1,309
(13)	Outdoor Lighting	21	Direct to Outdoor Lighting	$13,348	$0	$0	$0
(14)	Street Lighting	15	Direct to Street Lighting	$50,643	$0	$0	$0
(15)	Customer Accounts-Related	22	Customer O&M Accounts 901-918	$22,658	$14,079	$3,881	$563
(16)	DSM-Related	4	4 CP Demand at Generation (kW)	$23,786	$7,365	$1,759	$34
(17)	Non-FAC Fuel	2	Energy at Generation - Firm Sales (mWh)	$0	$0	$0	$0
(18)	WPM Fuel	4	4 CP Demand at Generation (kW)	$0	$0	$0	$0
(19)	Unused	0	Not Applicable	$0			
(20)	Total Taxes Other Than Income			$8,078,474	$2,651,846	$796,425	$20,405

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF TAXES OTHER THAN INCOME

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 7

		Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	TAXES OTHER THAN INCOME							
(1)	Production Demand	$43,287	$1,548,431	$113,924	$1,020,923	$677,827	$0	$0
(2)	Production Energy	$0	$0	$0	$0	$0	$0	$0
(3)	FAC Fuel	$0	$0	$0	$0	$0	$0	$0
(3)	Transmission Demand	$2,400	$74,529	$6,450	$58,072	$41,456	$129	$163
(4)	Sub-Transmission Demand	$4,942	$153,480	$13,282	$119,590	$85,372	$265	$337
(5)	Primary Distribution Demand	$5,454	$237,634	$22,999	$118,807	$0	$1,366	$1,905
(6)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(7)	Secondary Distribution Demand	$623	$30,103	$3,117	$0	$0	$156	$217
(8)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(9)	Line Transformers Demand	$729	$35,262	$3,651	$0	$0	$183	$255
(10)	Line Transformers Customer	$8,377	$84	$759	$0	$0	$7,818	$1,365
(11)	Services	$18,525	$21,455	$2,195	$0	$0	$0	$0
(12)	Meters	$8,186	$23,299	$2,384	$5,172	$106	$0	$0
(13)	Outdoor Lighting	$0	$0	$0	$0	$0	$13,348	$0
(14)	Street Lighting	$0	$0	$0	$0	$0	$0	$50,643
(15)	Customer Accounts-Related	$1,269	$1,624	$123	$202	$1	$738	$180
(16)	DSM-Related	$186	$6,654	$490	$4,387	$2,913	$0	$0
(17)	Non-FAC Fuel	$0	$0	$0	$0	$0	$0	$0
(18)	WPM Fuel	$0	$0	$0	$0	$0	$0	$0
(19)	Unused							
(20)	Total Taxes Other Than Income	$93,978	$2,132,554	$169,372	$1,327,154	$807,674	$24,002	$55,065

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

			Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	PROFORMA A NORMALIZED MISCELLANEOUS REVENUES						
(1)	CAAA	28	Test Year CAAA Credits	$80,872	$31,702	$7,146	$318
(2)	DSM	29	Test Year DSM Revenues	$1,976,220	$192,011	$30,965	$0
(3)	QPCP-CC	30	Test Year QPCP-CC Revenues	$14,775,568	$5,610,432	$1,329,758	$58,282
(4)	QPCP-OE	31	Test Year QPCP-OE Revenues	$25,502,335	$9,673,936	$2,009,085	$95,880
(5)	IP-2 Credits	4	4 CP Demand at Generation (kW)	($1,126,676)	($348,847)	($83,308)	($1,594)
(6)	LP-1 Credits	4	4 CP Demand at Generation (kW)	($516,131)	($159,807)	($38,164)	($730)
(7)	TSO Revenue	11	12 CP Demand at Transmission (kW)	$4,528,023	$1,119,701	$455,750	$11,147
(8)	WPM	4	4 CP Demand at Generation (kW)	$26,814,396	$8,302,398	$1,982,698	$37,944
(9)	Interdepartmental Revenue	6	P/F A Normal Rev. w/o Misc. Rev.	$90,160	$25,519	$8,098	$281
(10)	Unbilled	38	Unbilled Analysis	$329,468	$35,504	$22,867	$855
	Miscellaneous Revenue						
(11)	Reconnect Fees	36	Reconnect Charge Analysis	$250,585	$181,027	$57,446	$0
(12)	*Diversion Fees*	37	*Direct to Residential*	$20,625	$20,625	$0	$0
(13)	Forfeited discounts	35	Forfeited Discounts Analysis	$1,655,974	$729,429	$231,470	$0
(14)	After Hours Charges	36	Reconnect Charge Analysis	$14,085	$10,175	$3,229	$0
(15)	Insufficient Funds Fee	34	NSF Analysis	$87,931	$65,143	$18,506	$0
(16)	Other - Pole rental, AK Steel Agreem	6	P/F A Normal Rev. w/o Misc. Rev.	$1,316,502	$372,627	$118,246	$4,098
(17)	Special Contract Revenues	6	P/F A Normal Rev. w/o Misc. Rev.	$12,270,258	$3,473,010	$1,102,093	$38,197
(18)	Total Miscellaneous Revenue:			$88,070,195	$29,334,586	$7,255,887	$244,678

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

		Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PROFORMA A NORMALIZED MISCELI							
(1)	CAAA	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(2)	DSM	$47,407	$974,823	$118,081	$547,014	$65,920	$0	$0
(3)	QPCP-CC	$158,879	$3,267,011	$359,703	$2,172,536	$1,818,967	$0	$0
(4)	QPCP-OE	$270,464	$5,561,548	$585,188	$4,278,538	$3,027,694	$0	$0
(5)	IP-2 Credits	($8,811)	($315,166)	($23,188)	($207,798)	($137,964)	$0	$0
(6)	LP-1 Credits	($4,036)	($144,378)	($10,622)	($95,192)	($63,202)	$0	$0
(7)	TSO Revenue	$38,527	$1,196,632	$103,553	$932,405	$665,614	$2,068	$2,625
(8)	WPM	$209,691	$7,500,819	$551,862	$4,945,493	$3,283,491	$0	$0
(9)	Interdepartmental Revenue	$1,662	$21,601	$1,712	$18,293	$12,167	$261	$566
(10)	Unbilled	$3,016	$39,206	$3,976	$114,074	$109,657	$99	$214
	Miscellaneous Revenue							
(11)	Reconnect Fees	$806	$10,476	$830	$0	$0	$0	$0
(12)	Diversion Fees	$0	$0	$0	$0	$0	$0	$0
(13)	Forfeited discounts	$31,820	$413,657	$32,787	$216,809	$0	$0	$0
(14)	After Hours Charges	$45	$589	$47	$0	$0	$0	$0
(15)	Insufficient Funds Fee	$2,167	$1,918	$196	$0	$0	$0	$0
(16)	Other - Pole rental, AK Steel Agreem	$24,263	$315,422	$25,001	$267,114	$177,662	$3,807	$8,262
(17)	Special Contract Revenues	$226,143	$2,939,839	$233,016	$2,489,593	$1,655,873	$35,486	$77,008
(18)	Total Miscellaneous Revenue:	$1,002,927	$21,802,178	$1,984,110	$15,690,064	$10,625,368	$41,721	$88,676

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

			Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	PROFORMA A EQUALIZED MISCELLANEOUS REVENUES						
(19)	CAAA	28	Test Year CAAA Credits	$80,872	$31,702	$7,146	$318
(20)	DSM	29	Test Year DSM Revenues	$1,976,220	$192,011	$30,965	$0
(21)	QPCP-CC	30	Test Year QPCP-CC Revenues	$14,775,568	$5,610,432	$1,329,758	$58,282
(22)	QPCP-OE	31	Test Year QPCP-OE Revenues	$25,502,335	$9,673,936	$2,009,085	$95,880
(23)	IP-2 Credits	4	4 CP Demand at Generation (kW)	($1,126,676)	($348,847)	($83,308)	($1,594)
(24)	LP-1 Credits	4	4 CP Demand at Generation (kW)	($516,131)	($159,807)	($38,164)	($730)
(25)	TSO Revenue	11	12 CP Demand at Transmission (kW)	$4,528,023	$1,119,701	$455,750	$11,147
(26)	WPM	4	4 CP Demand at Generation (kW)	$26,814,396	$8,302,398	$1,982,698	$37,944
(27)	Interdepartmental Revenue	122	P/F A Equalized Rev. w/ Misc. Rev.	$90,160	$25,760	$8,164	$284
(28)	Unbilled	38	Unbilled Analysis	$329,468	$35,504	$22,867	$855
	Miscellaneous Revenue						
(29)	Reconnect Fees	36	Reconnect Charge Analysis	$250,585	$181,027	$57,446	$0
(30)	Diversion Fees	37	Direct to Residential	$20,625	$20,625	$0	$0
(31)	Forfeited discounts	35	Forfeited Discounts Analysis	$1,655,974	$729,429	$231,470	$0
(32)	After Hours Charges	36	Reconnect Charge Analysis	$14,085	$10,175	$3,229	$0
(33)	Insufficient Funds Fee	34	NSF Analysis	$87,931	$65,143	$18,506	$0
(34)	Other - Pole rental, AK Steel Agreem	122	P/F A Equalized Rev. w/ Misc. Rev.	$1,316,502	$376,148	$119,215	$4,148
(35)	Special Contract Revenues	122	P/F A Equalized Rev. w/ Misc. Rev.	$12,270,258	$3,505,831	$1,111,128	$38,662
(36)	Total Miscellaneous Revenue:			$88,070,195	$29,371,169	$7,265,958	$245,197

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

		Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PROFORMA A EQUALIZED MISCELLA							
(19)	CAAA	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(20)	DSM	$47,407	$974,823	$118,081	$547,014	$65,920	$0	$0
(21)	QPCP-CC	$158,879	$3,267,011	$359,703	$2,172,536	$1,818,967	$0	$0
(22)	QPCP-OE	$270,464	$5,561,548	$585,188	$4,278,538	$3,027,694	$0	$0
(23)	IP-2 Credits	($8,811)	($315,166)	($23,188)	($207,798)	($137,964)	$0	$0
(24)	LP-1 Credits	($4,036)	($144,378)	($10,622)	($95,192)	($63,202)	$0	$0
(25)	TSO Revenue	$38,527	$1,196,632	$103,553	$932,405	$665,614	$2,068	$2,625
(26)	WPM	$209,691	$7,500,819	$551,862	$4,945,493	$3,283,491	$0	$0
(27)	Interdepartmental Revenue	$1,095	$22,516	$1,827	$17,706	$12,190	$221	$395
(28)	Unbilled	$3,016	$39,206	$3,976	$114,074	$109,657	$99	$214
	Miscellaneous Revenue							
(29)	Reconnect Fees	$806	$10,476	$830	$0	$0	$0	$0
(30)	Diversion Fees	$0	$0	$0	$0	$0	$0	$0
(31)	Forfeited discounts	$31,820	$413,657	$32,787	$216,809	$0	$0	$0
(32)	After Hours Charges	$45	$589	$47	$0	$0	$0	$0
(33)	Insufficient Funds Fee	$2,167	$1,918	$196	$0	$0	$0	$0
(34)	Other - Pole rental, AK Steel Agreem	$15,991	$328,780	$26,681	$258,543	$178,003	$3,223	$5,770
(35)	Special Contract Revenues	$149,038	$3,064,343	$248,677	$2,409,711	$1,659,047	$30,039	$53,782
(36)	Total Miscellaneous Revenue:	$916,982	$21,940,955	$2,001,566	$15,601,025	$10,628,906	$35,649	$62,787

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

			Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	PROFORMA B EQUALIZED MISCELLANEOUS REVENUES						
(37)	CAAA	28	Test Year CAAA Credits	$80,872	$31,702	$7,146	$318
(38)	DSM	29	Test Year DSM Revenues	$0	$0	$0	$0
(39)	QPCP-CC	30	Test Year QPCP-CC Revenues	$0	$0	$0	$0
(40)	QPCP-OE	31	Test Year QPCP-OE Revenues	$0	$0	$0	$0
(41)	IP-2 Credits	4	4 CP Demand at Generation (kW)	($1,126,676)	($348,847)	($83,308)	($1,594)
(42)	LP-1 Credits	4	4 CP Demand at Generation (kW)	($516,131)	($159,807)	($38,164)	($730)
(43)	TSO Revenue	11	12 CP Demand at Transmission (kW)	$4,528,023	$1,119,701	$455,750	$11,147
(44)	WPM	4	4 CP Demand at Generation (kW)	$26,814,396	$8,302,398	$1,982,698	$37,944
(45)	Interdepartmental Revenue	123	P/F B Equalized Rev. w/ Misc. Rev.	$90,160	$26,359	$8,273	$266
(46)	Unbilled	38	Unbilled Analysis	$329,468	$35,504	$22,867	$855
	Miscellaneous Revenue						
(47)	Reconnect Fees	36	Reconnect Charge Analysis	$250,585	$181,027	$57,446	$0
(48)	Diversion Fees	37	Direct to Residential	$20,625	$20,625	$0	$0
(49)	Forfeited discounts	35	Forfeited Discounts Analysis	$1,655,974	$729,429	$231,470	$0
(50)	After Hours Charges	36	Reconnect Charge Analysis	$14,085	$10,175	$3,229	$0
(51)	Insufficient Funds Fee	34	NSF Analysis	$87,931	$65,143	$18,506	$0
(52)	Other - Pole rental, AK Steel Agreem	123	P/F B Equalized Rev. w/ Misc. Rev.	$1,316,502	$384,883	$120,804	$3,885
(53)	Special Contract Revenues	123	P/F B Equalized Rev. w/ Misc. Rev.	$12,270,258	$3,587,242	$1,125,933	$36,212
(54)	Total Miscellaneous Revenue:			$45,816,072	$13,985,534	$3,912,651	$88,304

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

		Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PROFORMA B EQUALIZED MISCELLA							
(37)	CAAA	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(38)	DSM	$0	$0	$0	$0	$0	$0	$0
(39)	QPCP-CC	$0	$0	$0	$0	$0	$0	$0
(40)	QPCP-OE	$0	$0	$0	$0	$0	$0	$0
(41)	IP-2 Credits	($8,811)	($315,166)	($23,188)	($207,798)	($137,964)	$0	$0
(42)	LP-1 Credits	($4,036)	($144,378)	($10,622)	($95,192)	($63,202)	$0	$0
(43)	TSO Revenue	$38,527	$1,196,632	$103,553	$932,405	$665,614	$2,068	$2,625
(44)	WPM	$209,691	$7,500,819	$551,862	$4,945,493	$3,283,491	$0	$0
(45)	Interdepartmental Revenue	$1,064	$22,811	$1,843	$17,258	$11,661	$203	$421
(46)	Unbilled	$3,016	$39,206	$3,976	$114,074	$109,657	$99	$214
	Miscellaneous Revenue							
(47)	Reconnect Fees	$806	$10,476	$830	$0	$0	$0	$0
(48)	Diversion Fees	$0	$0	$0	$0	$0	$0	$0
(49)	Forfeited discounts	$31,820	$413,657	$32,787	$216,809	$0	$0	$0
(50)	After Hours Charges	$45	$589	$47	$0	$0	$0	$0
(51)	Insufficient Funds Fee	$2,167	$1,918	$196	$0	$0	$0	$0
(52)	Other - Pole rental, AK Steel Agreem	$15,540	$333,080	$26,915	$252,005	$170,271	$2,970	$6,150
(53)	Special Contract Revenues	$144,840	$3,104,419	$250,854	$2,348,777	$1,586,984	$27,680	$57,318
(54)	Total Miscellaneous Revenue	$435,554	$12,182,243	$941,021	$8,535,016	$5,636,001	$33,020	$66,729

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

			Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	PROFORMA B NORMALIZED MISCELLANEOUS REVENUES						
(55)	CAAA	28	Test Year CAAA Credits	$80,872	$31,702	$7,146	$318
(56)	DSM	29	Test Year DSM Revenues	$0	$0	$0	$0
(57)	QPCP-CC	30	Test Year QPCP-CC Revenues	$0	$0	$0	$0
(58)	QPCP-OE	31	Test Year QPCP-OE Revenues	$0	$0	$0	$0
(59)	IP-2 Credits	4	4 CP Demand at Generation (kW)	($1,126,676)	($348,847)	($83,308)	($1,594)
(60)	LP-1 Credits	4	4 CP Demand at Generation (kW)	($516,131)	($159,807)	($38,164)	($730)
(61)	TSO Revenue	11	12 CP Demand at Transmission (kW)	$4,528,023	$1,119,701	$455,750	$11,147
(62)	WPM	4	4 CP Demand at Generation (kW)	$26,814,396	$8,302,398	$1,982,698	$37,944
(63)	Interdepartmental Revenue	124	P/F B Normal Rev. w/ Misc. Rev.	$90,160	$26,802	$8,144	$260
(64)	Unbilled	38	Unbilled Analysis	$329,468	$35,504	$22,867	$855
	Miscellaneous Revenue						
(65)	Reconnect Fees	36	Reconnect Charge Analysis	$250,585	$181,027	$57,446	$0
(66)	Diversion Fees	37	Direct to Residential	$20,625	$20,625	$0	$0
(67)	Forfeited discounts	35	Forfeited Discounts Analysis	$1,655,974	$729,429	$231,470	$0
(68)	After Hours Charges	36	Reconnect Charge Analysis	$14,085	$10,175	$3,229	$0
(69)	Insufficient Funds Fee	34	NSF Analysis	$87,931	$65,143	$18,506	$0
(70)	Other - Pole rental, AK Steel Agreem	124	P/F B Normal Rev. w/ Misc. Rev.	$1,316,502	$391,366	$118,923	$3,797
(71)	Special Contract Revenues	124	P/F B Normal Rev. w/ Misc. Rev.	$12,270,258	$3,647,666	$1,108,403	$35,386
(72)	Total Miscellaneous Revenue:			$45,816,072	$14,052,886	$3,893,111	$87,383

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
ALLOCATION OF MISCELLANEOUS REVENUES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 8

		Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	PROFORMA B NORMALIZED MISCELL							
(55)	CAAA	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(56)	DSM	$0	$0	$0	$0	$0	$0	$0
(57)	QPCP-CC	$0	$0	$0	$0	$0	$0	$0
(58)	QPCP-OE	$0	$0	$0	$0	$0	$0	$0
(59)	IP-2 Credits	($8,811)	($315,166)	($23,188)	($207,798)	($137,964)	$0	$0
(60)	LP-1 Credits	($4,036)	($144,378)	($10,622)	($95,192)	($63,202)	$0	$0
(61)	TSO Revenue	$38,527	$1,196,632	$103,553	$932,405	$665,614	$2,068	$2,625
(62)	WPM	$209,691	$7,500,819	$551,862	$4,945,493	$3,283,491	$0	$0
(63)	Interdepartmental Revenue	$1,329	$22,342	$1,814	$17,327	$11,477	$199	$464
(64)	Unbilled	$3,016	$39,206	$3,976	$114,074	$109,657	$99	$214
	Miscellaneous Revenue							
(65)	Reconnect Fees	$806	$10,476	$830	$0	$0	$0	$0
(66)	Diversion Fees	$0	$0	$0	$0	$0	$0	$0
(67)	Forfeited discounts	$31,820	$413,657	$32,787	$216,809	$0	$0	$0
(68)	After Hours Charges	$45	$589	$47	$0	$0	$0	$0
(69)	Insufficient Funds Fee	$2,167	$1,918	$196	$0	$0	$0	$0
(70)	Other - Pole rental, AK Steel Agreem	$19,412	$326,238	$26,493	$253,001	$167,589	$2,911	$6,772
(71)	Special Contract Revenues	$180,931	$3,040,653	$246,920	$2,358,059	$1,561,987	$27,135	$63,118
(72)	Total Miscellaneous Revenue	$475,782	$12,111,167	$936,636	$8,545,362	$5,608,138	$32,412	$73,194

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A NORMALIZED TAXES	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
(1)	Proforma A Normalized Margins. w/o Misc. Rev.			$177,549,298	$61,048,132	$16,313,250	$602,895
(2)	Proforma A Fuel Cost Revenues	1	Energy at Generation (mWh)	147,040,317	$30,824,663	$12,840,821	$407,538
(3)	Proforma A Normalized Miscellaneous Revenues			88,070,195	29,334,586	7,255,887	244,678
(4)	Proforma A Normalized Rev. w/Misc. Revenue			$412,659,810	$121,207,380	$36,409,958	$1,255,111
	Indiana Utility Receipts Taxes						
(5)	Total Proforma A Normalized Revenues w/ Misc. Rev.			$412,659,810	$121,207,380	$36,409,958	$1,255,111
(6)	Less: Uncollectible Expense	10	Average Retail Customers	(1,568,107)	($947,789)	($269,255)	($56,283)
(7)	Less: Statutory Exemption	121	P/F A Normal Rev. w/ Misc. Rev.	(1,000)	($294)	($88)	($3)
(8)	Income for Utility Receipts Tax			$411,090,703	$120,259,297	$36,140,615	$1,198,825
(9)	Utility Receipts Tax Rate			1.40%	1.40%	1.40%	1.40%
(10)	Utility Receipts Tax			$5,755,270	$1,683,630	$505,969	$16,784
	State Income Taxes						
(11)	Total Proforma A Normalized Revenues			$412,659,810	$121,207,380	$36,409,958	$1,255,111
(12)	Less: Operation and Maintenance Expenses (Excl. Fuel)			(173,773,339)	(55,212,445)	(15,702,010)	(684,803)
(13)	Less: Fuel Costs			(127,995,233)	(26,832,164)	(11,177,641)	(354,753)
(14)	Less: Depreciation			(64,494,881)	(20,997,055)	(5,977,321)	(140,878)
(15)	Less: Property Taxes	100	Gross Plant	(8,174,121)	($2,681,456)	($803,493)	($20,540)
(16)	Less: Other Taxes	115	O&M Without Fuel Costs (P/F A)	95,822	$31,065	$8,622	$317
(17)	Less: Utility Receipts Tax			0	0	0	0
(18)	Less: Interest Expense	102	Original Cost Rate Base	(24,528,013)	($7,985,572)	($2,411,394)	($61,691)
(19)	Plus: Non-Deductible Expenses	102	Original Cost Rate Base	1,799,249	$585,780	$176,887	$4,525
(20)	Income for State Income Taxes			$15,589,294	$8,115,533	$523,609	($2,711)
(21)	State Income Tax Rate			8.50%	8.50%	8.50%	8.50%
(22)	State Income Taxes			$1,325,090	$689,820	$44,507	($230)
(23)	Less: Deferred State Tax Flowback	120	Total Depreciation Expenses	0	$0	$0	$0
(24)	Total State Tax Liabilit			$1,325,090	$689,820	$44,507	($230)

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A NORMALIZED TAXES	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
(1)	Proforma A Normalized Margins. w/o Misc. Rev.	$4,316,116	$43,847,124	$3,167,462	$29,221,256	$16,590,658	$750,480	$1,691,926
(2)	Proforma A Fuel Cost Revenues	$1,666,132	$33,921,512	$2,996,600	$36,636,848	$27,212,760	$188,236	$345,206
(3)	Proforma A Normalized Miscellaneous Revenues	1,002,927	21,802,178	1,984,110	15,690,064	10,625,368	41,721	88,676
(4)	Proforma A Normalized Rev. w/Misc. Revenue	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
	Indiana Utility Receipts Taxes							
(5)	Total Proforma A Normalized Revenues w/ Misc. Rev.	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
(6)	Less: Uncollectible Expense	($95,611)	($84,637)	($8,659)	($1,056)	($20)	($89,225)	($15,573)
(7)	Less: Statutory Exemption	($17)	($241)	($20)	($198)	($132)	($2)	($5)
(8)	Income for Utility Receipts Tax	$6,889,548	$99,485,935	$8,139,494	$81,546,914	$54,428,635	$891,210	$2,110,230
(9)	Utility Receipts Tax Rate	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%
(10)	Utility Receipts Tax	$96,454	$1,392,803	$113,953	$1,141,657	$762,001	$12,477	$29,543
	State Income Taxes							
(11)	Total Proforma A Normalized Revenues	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
(12)	Less: Operation and Maintenance Expenses (Excl. Fuel)	(2,343,956)	(44,046,849)	(3,437,776)	(30,396,036)	(20,485,406)	(558,914)	(905,145)
(13)	Less: Fuel Costs	(1,450,330)	(29,527,900)	(2,608,472)	(31,891,538)	(23,688,085)	(163,856)	(300,494)
(14)	Less: Depreciation	(699,894)	(17,274,070)	(1,343,162)	(10,839,638)	(6,713,753)	(180,615)	(328,495)
(15)	Less: Property Taxes	($94,725)	($2,159,313)	($171,340)	($1,344,799)	($819,391)	($24,001)	($55,063)
(16)	Less: Other Taxes	$1,231	$24,953	$1,925	$16,214	$10,716	$194	$584
(17)	Less: Utility Receipts Tax	0	0	0	0	0	0	0
(18)	Less: Interest Expense	($268,483)	($6,506,337)	($517,909)	($4,090,129)	($2,484,094)	($53,859)	($148,544)
(19)	Plus: Non-Deductible Expenses	$19,695	$477,271	$37,991	$300,031	$182,220	$3,951	$10,896
(20)	Income for State Income Taxes	$2,148,712	$558,567	$109,431	$3,302,273	$430,993	$3,338	$399,548
(21)	State Income Tax Rate	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
(22)	State Income Taxes	$182,641	$47,478	$9,302	$280,693	$36,634	$284	$33,962
(23)	Less: Deferred State Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(24)	Total State Tax Liabilit	$182,641	$47,478	$9,302	$280,693	$36,635	$284	$33,962

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A NORMALIZED TAXES (cont.)	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	Federal Income Taxes						
(25)	Total Proforma A Normalized Revenues			$412,659,810	$121,207,380	$36,409,958	$1,255,111
(26)	Less: Operation and Maintenance Expenses (Excl. Fuel)			(173,773,339)	(55,212,445)	(15,702,010)	(684,803)
(27)	Less: Fuel Costs			(127,995,233)	(26,832,164)	(11,177,641)	(354,753)
(28)	Less: Depreciation			(64,494,881)	(20,997,055)	(5,977,321)	(140,878)
(29)	Less: Property Taxes			(8,174,121)	(2,681,456)	(803,493)	(20,540)
(30)	Less: Other Taxes			95,822	31,065	8,622	317
(31)	Less: Utility Receipts Tax			(5,755,270)	(1,683,630)	(505,969)	(16,784)
(32)	Less: Interest Expense			(24,528,013)	(7,985,572)	(2,411,394)	(61,691)
(33)	Plus: Non-Deductible Expenses	102	Original Cost Rate Base	1,286,735	$418,922	$126,501	$3,236
(34)	Less: State Income taxes			(1,325,090)	(689,820)	(44,507)	230
(35)	Less: Kentucky Taxes	100	Gross Plant	(175)	(57)	(17)	(0)
(36)	Income for Federal Income Taxes			$7,996,245	$5,575,166	($77,270)	($20,554)
(37)	Federal Income Tax Rate			35.00%	35.00%	35.00%	35.00%
(38)	Federal Income Taxes			$2,798,686	$1,951,308	($27,044)	($7,194)
(39)	Less: Investment Tax Credit	100	Gross Plant	(1,111,141)	(364,501)	(109,222)	(2,792)
(40)	Less: Deferred Federal Tax Flowback	120	Total Depreciation Expenses	0	$0	$0	$0
(41)	Total Federal Tax Liabilit			$1,687,545	$1,586,807	($136,266)	($9,986)
	Net Operating Income						
(42)	Total Proforma A Normalized Margins			$412,659,810	$121,207,380	$36,409,958	$1,255,111
(43)	Less: Operation and Maintenance Expenses (Excl. Fuel)			(173,773,339)	(55,212,445)	(15,702,010)	(684,803)
(44)	Less: Fuel Costs			(127,995,233)	(26,832,164)	(11,177,641)	(354,753)
(45)	Less: Depreciation			(64,494,881)	(20,997,055)	(5,977,321)	(140,878)
(46)	Less: Other Taxes			95,822	31,065	8,622	317
(47)	Less: Utility Receipts Tax			(5,755,270)	(1,683,630)	(505,969)	(16,784)
(48)	Less: Property Taxes			(8,174,121)	(2,681,456)	(803,493)	(20,540)
(49)	Less: State Income Taxes			(1,325,090)	(689,820)	(44,507)	230
(50)	Less: Kentucky Taxes			(175)	(57)	(17)	(0)
(51)	Less: Total Federal Income tax Liability			(1,687,545)	(1,586,807)	136,266	9,986
(52)	Net Operating Income			$29,549,979	$11,555,010	$2,343,889	$47,887
(53)	Total Rate Base			$1,017,759,890	$331,351,537	$100,057,843	$2,559,813
(54)	Rate of Return			2.90%	3.49%	2.34%	1.87%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A NORMALIZED TAXES (cont.)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	Federal Income Taxes							
(25)	Total Proforma A Normalized Revenues	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
(26)	Less: Operation and Maintenance Expenses (Excl. Fuel)	(2,343,956)	(44,046,849)	(3,437,776)	(30,396,036)	(20,485,406)	(558,914)	(905,145)
(27)	Less: Fuel Costs	(1,450,330)	(29,527,900)	(2,608,472)	(31,891,538)	(23,688,085)	(163,856)	(300,494)
(28)	Less: Depreciation	(699,894)	(17,274,070)	(1,343,162)	(10,839,638)	(6,713,753)	(180,615)	(328,495)
(29)	Less: Property Taxes	(94,725)	(2,159,313)	(171,340)	(1,344,799)	(819,391)	(24,001)	(55,063)
(30)	Less: Other Taxes	1,231	24,953	1,925	16,214	10,716	194	584
(31)	Less: Utility Receipts Tax	(96,454)	(1,392,803)	(113,953)	(1,141,657)	(762,001)	(12,477)	(29,543)
(32)	Less: Interest Expense	(268,483)	(6,506,337)	(517,909)	(4,090,129)	(2,484,094)	(53,859)	(148,544)
(33)	Plus: Non-Deductible Expenses	$14,085	$341,321	$27,169	$214,567	$130,315	$2,825	$7,793
(34)	Less: State Income taxes	(182,641)	(47,478)	(9,302)	(280,693)	(36,635)	(284)	(33,962)
(35)	Less: Kentucky Taxes	(2)	(46)	(4)	(29)	(18)	(1)	(1)
(36)	Income for Federal Income Taxes	$1,864,006	($1,017,710)	($24,649)	$1,794,431	($419,565)	($10,549)	$332,938
(37)	Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
(38)	Federal Income Taxes	$652,402	($356,199)	($8,627)	$628,051	($146,848)	($3,692)	$116,528
(39)	Less: Investment Tax Credit	(12,876)	(293,524)	(23,291)	(182,804)	(111,383)	(3,263)	(7,485)
(40)	Less: Deferred Federal Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(41)	Total Federal Tax Liabilit	$639,526	($649,723)	($31,918)	$445,247	($258,231)	($6,955)	$109,043
	Net Operating Income							
(42)	Total Proforma A Normalized Margins	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
(43)	Less: Operation and Maintenance Expenses (Excl. Fuel)	(2,343,956)	(44,046,849)	(3,437,776)	(30,396,036)	(20,485,406)	(558,914)	(905,145)
(44)	Less: Fuel Costs	(1,450,330)	(29,527,900)	(2,608,472)	(31,891,538)	(23,688,085)	(163,856)	(300,494)
(45)	Less: Depreciation	(699,894)	(17,274,070)	(1,343,162)	(10,839,638)	(6,713,753)	(180,615)	(328,495)
(46)	Less: Other Taxes	1,231	24,953	1,925	16,214	10,716	194	584
(47)	Less: Utility Receipts Tax	(96,454)	(1,392,803)	(113,953)	(1,141,657)	(762,001)	(12,477)	(29,543)
(48)	Less: Property Taxes	(94,725)	(2,159,313)	(171,340)	(1,344,799)	(819,391)	(24,001)	(55,063)
(49)	Less: State Income Taxes	(182,641)	(47,478)	(9,302)	(280,693)	(36,635)	(284)	(33,962)
(50)	Less: Kentucky Taxes	(2)	(46)	(4)	(29)	(18)	(1)	(1)
(51)	Less: Total Federal Income tax Liability	(639,526)	649,723	31,918	(445,247)	258,231	6,955	(109,043)
(52)	Net Operating Income	$1,478,879	$5,797,028	$498,008	$5,224,746	$2,192,445	$47,439	$364,646
(53)	Total Rate Base	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(54)	Rate of Return	13.27%	2.15%	2.32%	3.08%	2.13%	2.12%	5.92%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A EQUALIZED TAXES	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
(1)	Rate Base			$1,017,759,890	$331,351,537	$100,057,843	$2,559,813
(2)	Allowed Rate of Return			2.9034%	2.9034%	2.9034%	2.9034%
(3)	Allowed Net Operating Incom			$29,549,978	$9,620,570	$2,905,113	$74,322
	Federal Income Taxes						
(4)	Net Operating Income			$29,549,978	$9,620,570	$2,905,113	$74,322
(5)	Less: Interest Expense	102	Original Cost Rate Base	(24,528,013)	($7,985,572)	($2,411,394)	($61,691)
(6)	Plus: Non-Deductible Expenses			1,286,735	418,922	126,501	3,236
(7)	Plus: Investment Tax Credit	100	Gross Plant	(1,111,141)	($364,501)	($109,222)	($2,792)
(8)	Less: Deferred Federal Tax Flowback	120	Total Depreciation Expenses	0	$0	$0	$0
(9)	Total Amount to Calculate Federal Taxes			$5,197,559	$1,689,419	$510,998	$13,075
(10)	Federal Tax Factor (Tax Rate/(1-Tax Rate))			53.8462%	53.8462%	53.8462%	53.8462%
(11)	Federal Income Taxes Before Flowback			$2,798,686	$909,687	$275,153	$7,041
(12)	Less: Deferred Federal Tax Flowback			0	0	0	0
(13)	Less: Investment Tax Credit			(1,111,141)	(364,501)	(109,222)	(2,792)
(14)	Federal Income taxes After Flowback			$1,687,545	$545,186	$165,931	$4,248
	State Income Taxes						
(15)	Net Operating Income			$29,549,978	$9,620,570	$2,905,113	$74,322
(16)	Less: Interest Expense			(24,528,013)	(7,985,572)	(2,411,394)	(61,691)
(17)	Plus: Non-Deductible Expenses			1,799,249	585,780	176,887	4,525
(18)	Plus: Utility Receipts Tax			$5,755,270	$1,637,385	$519,384	$17,415
(19)	Plus: Investment Tax Credit			0	0	0	0
(20)	Plus: Federal Income Taxes			1,687,545	545,186	165,931	4,248
(21)	Plus: Property Taxes	100	Gross Plant	0	$0	$0	$0
(22)	Plus: Kentucky Taxes			175	57	17	0
(23)	Less: Deferred State Tax Flowback	102	Original Cost Rate Base	0	$0	$0	$0
(24)	Total Amount to Calculate State Taxes			$14,264,203	$4,403,408	$1,355,938	$38,821
(25)	State Tax Factor (Tax Rate/(1-Tax Rate))			9.2896%	9.2896%	9.2896%	9.2896%
(26)	State Income Taxes-Current and Deferred			$1,325,090	$409,060	$125,961	$3,606
(27)	Less: Deferred State Tax Flowback			$0	$0	$0	$0
(28)	State Income Tax After Flowback			$1,325,090	$409,060	$125,961	$3,606

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A EQUALIZED TAXES	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
(1)	Rate Base	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(2)	Allowed Rate of Return	2.9034%	2.9034%	2.9034%	2.9034%	2.9034%	2.9034%	2.9034%
(3)	Allowed Net Operating Incom	$323,454	$7,838,471	$623,947	$4,927,559	$2,992,698	$64,886	$178,957
	Federal Income Taxes							
(4)	Net Operating Income	$323,454	$7,838,471	$623,947	$4,927,559	$2,992,698	$64,886	$178,957
(5)	Less: Interest Expense	($268,483)	($6,506,337)	($517,909)	($4,090,129)	($2,484,094)	($53,859)	($148,544)
(6)	Plus: Non-Deductible Expenses	14,085	341,321	27,169	214,567	130,315	2,825	7,793
(7)	Plus: Investment Tax Credit	($12,876)	($293,524)	($23,291)	($182,804)	($111,383)	($3,263)	($7,485)
(8)	Less: Deferred Federal Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(9)	Total Amount to Calculate Federal Taxes	$56,179	$1,379,931	$109,917	$869,193	$527,536	$10,590	$30,721
(10)	*Federal Tax Factor (Tax Rate/(1-Tax Rate))*	53.8462%	53.8462%	53.8462%	53.8462%	53.8462%	53.8462%	53.8462%
(11)	Federal Income Taxes Before Flowback	$30,250	$743,040	$59,186	$468,027	$284,058	$5,702	$16,542
(12)	Less: Deferred Federal Tax Flowback	0	0	0	0	0	0	0
(13)	Less: Investment Tax Credit	(12,876)	(293,524)	(23,291)	(182,804)	(111,383)	(3,263)	(7,485)
(14)	Federal Income taxes After Flowback	$17,374	$449,516	$35,895	$285,223	$172,674	$2,440	$9,057
	State Income Taxes							
(15)	*Net Operating Income*	$323,454	$7,838,471	$623,947	$4,927,559	$2,992,698	$64,886	$178,957
(16)	Less: Interest Expense	(268,483)	(6,506,337)	(517,909)	(4,090,129)	(2,484,094)	(53,859)	(148,544)
(17)	Plus: Non-Deductible Expenses	19,695	477,271	37,991	300,031	182,220	3,951	10,896
(18)	Plus: Utility Receipts Tax	$68,833	$1,441,604	$116,964	$1,134,553	$781,131	$12,894	$25,104
(19)	Plus: Investment Tax Credit	0	0	0	0	0	0	0
(20)	Plus: Federal Income Taxes	17,374	449,516	35,895	285,223	172,674	2,440	9,057
(21)	Plus: Property Taxes	$0	$0	$0	$0	$0	$0	$0
(22)	Plus: Kentucky Taxes	2	46	4	29	18	1	1
(23)	Less: Deferred State Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(24)	Total Amount to Calculate State Taxes	$160,874	$3,700,571	$296,892	$2,557,265	$1,644,647	$30,312	$75,472
(25)	State Tax Factor (Tax Rate/(1-Tax Rate))	9.2896%	9.2896%	9.2896%	9.2896%	9.2896%	9.2896%	9.2896%
(26)	State Income Taxes-Current and Deferred	$14,945	$343,769	$27,580	$237,560	$152,781	$2,816	$7,011
(27)	Less: Deferred State Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(28)	State Income Tax After Flowback	$14,945	$343,769	$27,580	$237,560	$152,781	$2,816	$7,011

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A EQUALIZED TAXES (cont.)	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	Utility Receipts Taxes						
(29)	Net Operating Income			29,549,978	9,620,570	2,905,113	74,322
(30)	Plus: Operating & Maintenance Expenses (Excl. Fuel)			$173,773,339	$55,212,445	$15,702,010	$684,803
(31)	Plus: Fuel Costs			$127,995,233	$26,832,164	$11,177,641	$354,753
(32)	Plus: Depreciation and Amortization Expenses			$64,494,881	$20,997,055	$5,977,321	$140,878
(33)	Plus: Investment Tax Credit			0	0	0	0
(34)	Plus: Federal Income Taxes			1,687,545	545,186	165,931	4,248
(35)	Plus: State Income Taxes			1,325,090	409,060	125,961	3,606
(36)	Plus: Kentucky Taxes			175	57	17	0
(37)	Plus: Property Taxes			8,174,121	2,681,456	803,493	20,540
(38)	Plus: Other Taxes	117	O&M Without Fuel Costs (P/F B)	(95,822)	($31,141)	($8,635)	($317)
(39)	Less: Uncollectible Expense	10	Average Retail Customers	(1,568,107)	($947,789)	($269,255)	($56,283)
(40)	Less: Statutory Exemption	121	P/F A Normal Rev. w/ Misc. Rev.	(1,000)	($294)	($88)	($3)
(41)	Total Amount to Calculate Utility Receipts Taxes			$405,335,432	$115,318,770	$36,579,509	$1,226,547
(42)	*Utility Receipts Tax Factor (Tax Rate/(1-Tax Rate))*			1.4199%	1.4199%	1.4199%	1.4199%
(43)	Utility Receipts Taxes			$5,755,270	$1,637,386	$519,385	$17,415
	Derivation of Proforma A Equalized Revenues						
(44)	Net Operating Income			29,549,978	9,620,570	2,905,113	74,322
(45)	Plus: Operating & Maintenance Expenses (Excl. Fuel)			$173,773,339	$55,212,445	$15,702,010	$684,803
(46)	Plus: Fuel Costs			127,995,233	26,832,164	11,177,641	354,753
(47)	Plus: Depreciation and Amortization Expenses			$64,494,881	$20,997,055	$5,977,321	$140,878
(48)	Plus: Federal Income Taxes			1,687,545	545,186	165,931	4,248
(49)	Plus: State Income Taxes			1,325,090	409,060	125,961	3,606
(50)	Plus: Kentucky Taxes			175	57	17	0
(51)	Plus: Gross Income Taxes			5,755,270	1,637,386	519,385	17,415
(52)	Plus: Property Taxes			8,174,121	2,681,456	803,493	20,540
(53)	Plus: Other Taxes			(95,822)	(31,141)	(8,635)	(317)
(54)	Plus: Investment Tax Credit			0	0	0	0
(55)	Proforma A Equalized Revenues w/Misc. Re\			$412,659,809	$117,904,239	$37,368,236	$1,300,249

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA A EQUALIZED TAXES (cont.)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	Utility Receipts Taxes							
(29)	Net Operating Income	323,454	7,838,471	623,947	4,927,559	2,992,698	64,886	178,957
(30)	Plus: Operating & Maintenance Expenses (Excl. Fuel)	$2,343,956	$44,046,849	$3,437,776	$30,396,036	$20,485,406	$558,914	$905,145
(31)	Plus: Fuel Costs	$1,450,330	$29,527,900	$2,608,472	$31,891,538	$23,688,085	$163,856	$300,494
(32)	Plus: Depreciation and Amortization Expenses	$699,894	$17,274,070	$1,343,162	$10,839,638	$6,713,753	$180,615	$328,495
(33)	Plus: Investment Tax Credit	0	0	0	0	0	0	0
(34)	Plus: Federal Income Taxes	17,374	449,516	35,895	285,223	172,674	2,440	9,057
(35)	Plus: State Income Taxes	14,945	343,769	27,580	237,560	152,781	2,816	7,011
(36)	Plus: Kentucky Taxes	2	46	4	29	18	1	1
(37)	Plus: Property Taxes	94,725	2,159,313	171,340	1,344,799	819,391	24,001	55,063
(38)	Plus: Other Taxes	($1,231)	($24,929)	($1,921)	($16,183)	($10,688)	($194)	($583)
(39)	Less: Uncollectible Expense	($95,611)	($84,637)	($8,659)	($1,056)	($20)	($89,225)	($15,573)
(40)	Less: Statutory Exemption	($17)	($241)	($20)	($198)	($132)	($2)	($5)
(41)	Total Amount to Calculate Utility Receipts Taxes	$4,847,821	$101,530,127	$8,237,577	$79,904,946	$55,013,967	$908,107	$1,768,062
(42)	Utility Receipts Tax Factor (Tax Rate/(1-Tax Rate))	1.4199%	1.4199%	1.4199%	1.4199%	1.4199%	1.4199%	1.4199%
(43)	Utility Receipts Taxes	$68,833	$1,441,604	$116,964	$1,134,553	$781,131	$12,894	$25,104
	Derivation of Proforma A Equalized Revenues							
(44)	Net Operating Income	323,454	7,838,471	623,947	4,927,559	2,992,698	64,886	178,957
(45)	Plus: Operating & Maintenance Expenses (Excl. Fuel)	$2,343,956	$44,046,849	$3,437,776	$30,396,036	$20,485,406	$558,914	$905,145
(46)	Plus: Fuel Costs	1,450,330	29,527,900	2,608,472	31,891,538	23,688,085	163,856	300,494
(47)	Plus: Depreciation and Amortization Expenses	$699,894	$17,274,070	$1,343,162	$10,839,638	$6,713,753	$180,615	$328,495
(48)	Plus: Federal Income Taxes	17,374	449,516	35,895	285,223	172,674	2,440	9,057
(49)	Plus: State Income Taxes	14,945	343,769	27,580	237,560	152,781	2,816	7,011
(50)	Plus: Kentucky Taxes	2	46	4	29	18	1	1
(51)	Plus: Gross Income Taxes	68,833	1,441,604	116,964	1,134,553	781,131	12,894	25,104
(52)	Plus: Property Taxes	94,725	2,159,313	171,340	1,344,799	819,391	24,001	55,063
(53)	Plus: Other Taxes	(1,231)	(24,929)	(1,921)	(16,183)	(10,688)	(194)	(583)
(54)	Plus: Investment Tax Credit	0	0	0	0	0	0	0
(55)	Proforma A Equalized Revenues w/Misc. Re	$5,012,282	$103,056,609	$8,363,219	$81,040,752	$55,795,250	$1,010,228	$1,808,745

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B EQUALIZED TAXES	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
(1)	Rate Base			$1,017,759,890	$331,351,537	$100,057,843	$2,559,813
(2)	Allowed Rate of Return			8.0800%	8.0800%	8.0800%	8.0800%
(3)	Allowed Net Operating Incom			$82,234,999	$26,773,204	$8,084,674	$206,833
	Federal Income Taxes						
(4)	Net Operating Income			$82,234,999	$26,773,204	$8,084,674	$206,833
(5)	Less: Interest Expense	102	Original Cost Rate Base	(24,528,013)	($7,985,572)	($2,411,394)	($61,691)
(6)	Plus: Non-Deductible Expenses			1,286,735	418,922	126,501	3,236
(7)	Plus: Investment Tax Credit	100	Gross Plant	(1,111,141)	($364,501)	($109,222)	($2,792)
(8)	Less: Deferred Federal Tax Flowback	120	Total Depreciation Expenses	0	$0	$0	$0
(9)	Total Amount to Calculate Federal Taxes			$57,882,580	$18,842,053	$5,690,559	$145,586
(10)	Federal Tax Factor (Tax Rate/(1-Tax Rate))			53.8462%	53.8462%	53.8462%	53.8462%
(11)	Federal Income Taxes Before Flowback and ITC			$31,167,543	$10,145,721	$3,064,147	$78,392
(12)	Less: Deferred Federal Tax Flowback			0	0	0	0
(13)	Less: Investment Tax Credit			(1,111,141)	(364,501)	(109,222)	(2,792)
(14)	Federal Income Tax Liability			$30,056,402	$9,781,220	$2,954,925	$75,600
	State Income Taxes						
(15)	Net Operating Income			$82,234,999	$26,773,204	$8,084,674	$206,833
(16)	Less: Interest Expense			(24,528,013)	(7,985,572)	(2,411,394)	(61,691)
(17)	Plus: Non-Deductible Expenses			1,799,249	585,780	176,887	4,525
(18)	Plus: Utility Receipts Tax			$7,021,007	$2,045,759	$642,501	$19,997
(19)	Plus: Investment Tax Credit			0	0	0	0
(20)	Plus: Federal Income Taxes			30,056,402	9,781,220	2,954,925	75,600
(21)	Plus: Kentucky Taxes	100	Gross Plant	175	57	17	0
(22)	Plus: Property Taxes	100	Gross Plant	$0	$0	$0	$0
(23)	Less: Deferred State Tax Flowback			$0	$0	$0	$0
(24)	Total Amount to Calculate State Taxes			$96,583,819	$31,200,448	$9,447,610	$245,264
(25)	State Tax Factor (Tax Rate/(1-Tax Rate)			9.2896%	9.2896%	9.2896%	9.2896%
(26)	State Income Taxes-Current and Deferre			$8,972,267	$2,898,402	$877,647	$22,784
(27)	Less: Deferred State Tax Flowbac			$0	$0	$0	$0
(28)	State Income Tax Liabilit			$8,972,267	$2,898,402	$877,647	$22,784

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B EQUALIZED TAXES	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
(1)	Rate Base	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(2)	Allowed Rate of Return	8.0800%	8.0800%	8.0800%	8.0800%	8.0800%	8.0800%	8.0800%
(3)	Allowed Net Operating Incom	$900,144	$21,813,778	$1,736,391	$13,712,965	$8,328,416	$180,573	$498,022
	Federal Income Taxes							
(4)	Net Operating Income	$900,144	$21,813,778	$1,736,391	$13,712,965	$8,328,416	$180,573	$498,022
(5)	Less: Interest Expense	($268,483)	($6,506,337)	($517,909)	($4,090,129)	($2,484,094)	($53,859)	($148,544)
(6)	Plus: Non-Deductible Expenses	14,085	341,321	27,169	214,567	130,315	2,825	7,793
(7)	Plus: Investment Tax Credit	($12,876)	($293,524)	($23,291)	($182,804)	($111,383)	($3,263)	($7,485)
(8)	Less: Deferred Federal Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(9)	Total Amount to Calculate Federal Taxes	$632,868	$15,355,238	$1,222,361	$9,654,599	$5,863,253	$126,277	$349,786
(10)	Federal Tax Factor (Tax Rate/(1-Tax Rate))	53.8462%	53.8462%	53.8462%	53.8462%	53.8462%	53.8462%	53.8462%
(11)	Federal Income Taxes Before Flowback and ITC	$340,775	$8,268,205	$658,194	$5,198,630	$3,157,136	$67,995	$188,346
(12)	Less: Deferred Federal Tax Flowback	0	0	0	0	0	0	0
(13)	Less: Investment Tax Credit	(12,876)	(293,524)	(23,291)	(182,804)	(111,383)	(3,263)	(7,485)
(14)	Federal Income Tax Liability	$327,899	$7,974,681	$634,903	$5,015,827	$3,045,753	$64,733	$180,861
	State Income Taxes							
(15)	Net Operating Income	$900,144	$21,813,778	$1,736,391	$13,712,965	$8,328,416	$180,573	$498,022
(16)	Less: Interest Expense	(268,483)	(6,506,337)	(517,909)	(4,090,129)	(2,484,094)	(53,859)	(148,544)
(17)	Plus: Non-Deductible Expenses	19,695	477,271	37,991	300,031	182,220	3,951	10,896
(18)	Plus: Utility Receipts Tax	$81,798	$1,780,709	$143,865	$1,348,151	$910,907	$14,639	$32,682
(19)	Plus: Investment Tax Credit	0	0	0	0	0	0	0
(20)	Plus: Federal Income Taxes	327,899	7,974,681	634,903	5,015,827	3,045,753	64,733	180,861
(21)	Plus: Kentucky Taxes	2	46	4	29	18	1	1
(22)	Plus: Property Taxes	$0	$0	$0	$0	$0	$0	$0
(23)	Less: Deferred State Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(24)	Total Amount to Calculate State Taxes	$1,061,054	$25,540,148	$2,035,246	$16,286,873	$9,983,219	$210,036	$573,919
(25)	State Tax Factor (Tax Rate/(1-Tax Rate)	9.2896%	9.2896%	9.2896%	9.2896%	9.2896%	9.2896%	9.2896%
(26)	State Income Taxes-Current and Deferre	$98,568	$2,372,582	$189,067	$1,512,988	$927,403	$19,512	$53,315
(27)	Less: Deferred State Tax Flowbac	$0	$0	$0	$0	$0	$0	$0
(28)	State Income Tax Liabilit	$98,568	$2,372,582	$189,067	$1,512,988	$927,403	$19,512	$53,315

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B EQUALIZED TAXES (cont.)	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	Utility Receipts Tax						
(29)	Net Operating Income			82,234,999	26,773,204	8,084,674	206,833
(30)	Plus: Operating & Maintenance Expenses (Excl. Fue			$174,216,347	$55,095,523	$15,652,658	$643,575
(31)	Plus: Fuel Costs			$127,995,233	$26,832,164	$11,177,641	$354,753
(32)	Plus: Depreciation and Amortization Expense			$64,494,881	$20,997,055	$5,977,321	$140,878
(33)	Plus: Investment Tax Credi	100	Gross Plant	$0	$0	$0	$0
(34)	Plus: Federal Income Taxe:			$30,056,402	$9,781,220	$2,954,925	$75,600
(35)	Plus: Property Taxes			$8,174,121	$2,681,456	$803,493	$20,540
(36)	Plus: Kentucky Taxes			$175	$57	$17	$0
(37)	Plus: State Income Taxes			$8,972,267	$2,898,402	$877,647	$22,784
(38)	Plus: Other Taxes	117	O&M Without Fuel Costs (P/F B)	($95,822)	($31,141)	($8,635)	($317)
(39)	Less: Uncollectible Expense	10	Average Retail Customer:	($1,568,107)	($947,789)	($269,255)	($56,283)
(40)	Less: Statutory Exemptio	122	P/F A Equalized Rev. w/ Misc. Rev	(1,000)	($286)	($91)	($3)
(41)	Total Amount to Calculate Utility Receipts Tax			$494,479,496	$144,079,866	$45,250,395	$1,408,359
(42)	Utility Receipts Tax Factor (Tax Rate/(1-Tax Rate))			1.4199%	1.4199%	1.4199%	1.4199%
(43)	Utility Receipts Taxes			$7,021,007	$2,045,759	$642,501	$19,997
	DERIVATION OF PROFORMA B EQUALIZED REVENUES						
(44)	Net Operating Income			82,234,999	26,773,204	8,084,674	206,833
(45)	Plus: Operating & Maintenance Expenses (Excl. Fuel)			$174,216,347	$55,095,523	$15,652,658	$643,575
(46)	Plus: Fuel Costs			127,995,233	26,832,164	11,177,641	354,753
(47)	Plus: Depreciation and Amortization Expenses			$64,494,881	$20,997,055	$5,977,321	$140,878
(48)	Plus: Federal Income Taxes			30,056,402	9,781,220	2,954,925	75,600
(49)	Plus: State Income Taxes			8,972,267	2,898,402	877,647	22,784
(50)	Plus: Kentucky Taxes			175	57	17	0
(51)	Plus: Utility Receipts Taxes			7,021,007	2,045,759	642,501	19,997
(52)	Plus: Property Taxes			8,174,121	2,681,456	803,493	20,540
(53)	Plus Other Taxes			(95,822)	(31,141)	(8,635)	(317)
(54)	Plus: Investment Tax Credit			0	0	0	0
(55)	Proforma B Equalized Revenues w/Misc. Re\			$503,069,610	$147,073,700	$46,162,241	$1,484,643

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B EQUALIZED TAXES (cont.)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	Utility Receipts Tax							
(29)	Net Operating Income	900,144	21,813,778	1,736,391	13,712,965	8,328,416	180,573	498,022
(30)	Plus: Operating & Maintenance Expenses (Excl. Fue	$2,286,196	$44,400,256	$3,459,501	$30,647,999	$20,641,880	$487,108	$901,650
(31)	Plus: Fuel Costs	$1,450,330	$29,527,900	$2,608,472	$31,891,538	$23,688,085	$163,856	$300,494
(32)	Plus: Depreciation and Amortization Expense	$699,894	$17,274,070	$1,343,162	$10,839,638	$6,713,753	$180,615	$328,495
(33)	Plus: Investment Tax Credi	$0	$0	$0	$0	$0	$0	$0
(34)	Plus: Federal Income Taxe:	$327,899	$7,974,681	$634,903	$5,015,827	$3,045,753	$64,733	$180,861
(35)	Plus: Property Taxe:	$94,725	$2,159,313	$171,340	$1,344,799	$819,391	$24,001	$55,063
(36)	Plus: Kentucky Taxe:	$2	$46	$4	$29	$18	$1	$1
(37)	Plus: State Income Taxe:	$98,568	$2,372,582	$189,067	$1,512,988	$927,403	$19,512	$53,315
(38)	Plus: Other Taxes	($1,231)	($24,929)	($1,921)	($16,183)	($10,688)	($194)	($583)
(39)	Less: Uncollectible Expens	($95,611)	($84,637)	($8,659)	($1,056)	($20)	($89,225)	($15,573)
(40)	Less: Statutory Exemptio	($12)	($250)	($20)	($196)	($135)	($2)	($4)
(41)	Total Amount to Calculate Utility Receipts Tax	$5,760,904	$125,412,811	$10,132,240	$94,948,348	$64,153,856	$1,030,976	$2,301,742
(42)	Utility Receipts Tax Factor (Tax Rate/(1-Tax Rate))	1.4199%	1.4199%	1.4199%	1.4199%	1.4199%	1.4199%	1.4199%
(43)	Utility Receipts Taxes	$81,798	$1,780,709	$143,865	$1,348,151	$910,907	$14,639	$32,682
	DERIVATION OF PROFORMA B EQUALIZED REVENUE							
(44)	Net Operating Income	900,144	21,813,778	1,736,391	13,712,965	8,328,416	180,573	498,022
(45)	Plus: Operating & Maintenance Expenses (Excl. Fuel)	$2,286,196	$44,400,256	$3,459,501	$30,647,999	$20,641,880	$487,108	$901,650
(46)	Plus: Fuel Costs	1,450,330	29,527,900	2,608,472	31,891,538	23,688,085	163,856	300,494
(47)	Plus: Depreciation and Amortization Expenses	$699,894	$17,274,070	$1,343,162	$10,839,638	$6,713,753	$180,615	$328,495
(48)	Plus: Federal Income Taxes	327,899	7,974,681	634,903	5,015,827	3,045,753	64,733	180,861
(49)	Plus: State Income Taxes	98,568	2,372,582	189,067	1,512,988	927,403	19,512	53,315
(50)	Plus: Kentucky Taxes	2	46	4	29	18	1	1
(51)	Plus: Utility Receipts Taxes	81,798	1,780,709	143,865	1,348,151	910,907	14,639	32,682
(52)	Plus: Property Taxes	94,725	2,159,313	171,340	1,344,799	819,391	24,001	55,063
(53)	Plus Other Taxes	(1,231)	(24,929)	(1,921)	(16,183)	(10,688)	(194)	(583)
(54)	Plus: Investment Tax Credit	0	0	0	0	0	0	0
(55)	Proforma B Equalized Revenues w/Misc. Re	$5,938,324	$127,278,407	$10,284,784	$96,297,751	$65,064,918	$1,134,842	$2,350,001

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B NORMALIZED TAXES	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	SUBSIDY REDUCTION						
(1)	Proforma A Normalized Margins w/Misc. Rev.			$265,619,494	$90,382,718	$23,569,136	$847,573
(2)	Proforma A Fuel Cost Revenues			$147,040,317	$30,824,663	$12,840,821	$407,538
(3)	Less: Proforma A Equalized Revenues w/Misc. Rev.			412,659,809	117,904,239	37,368,236	1,300,249
(4)	Proforma A Subsidy			$1	$3,303,141	($958,278)	($45,138)
(5)	Proposed Subsidy Reduction Percentage				25.00%	25.00%	25.00%
(6)	Proforma B Subsidy			$1	$2,477,356	($718,709)	($33,853)
(7)	Proforma B Equalized Revenues w/Misc. Rev.			$503,069,610	$147,073,700	$46,162,241	$1,484,643
(8)	Proforma B Normalized Revenues w/Misc. Re\			$503,069,611	$149,551,055	$45,443,532	$1,450,789
	TAX CALCULATIONS						
	Utility Receipts Taxes						
(9)	Total Proforma B Normal Revenues			$503,069,611	$149,551,055	$45,443,532	$1,450,789
(10)	Less: Uncollectible Expense	10	Average Retail Customers	(1,568,107)	($947,789)	($269,255)	($56,283)
(11)	Less: Statutory Exemption	124	P/F B Normal Rev. w/ Misc. Rev.	(1,000)	($297)	($90)	($3)
(12)	Income for Utility Receipts Taxes			$501,500,504	$148,602,969	$45,174,187	$1,394,503
(13)	Utility Receipts Tax Rate			1.40%	1.40%	1.40%	1.40%
(14)	Utility Receipts Taxes			$7,021,007	$2,080,442	$632,439	$19,523
	State Income Taxes						
(15)	Total Proforma B Normal Revenues			$503,069,611	$149,551,055	$45,443,532	$1,450,789
(16)	Less: Operation and Maintenance Expenses (Excl. Fuel)			(174,216,347)	(55,095,523)	(15,652,658)	(643,575)
(17)	Less: Fuel Costs			(127,995,233)	(26,832,164)	(11,177,641)	(354,753)
(18)	Less: Depreciation Expense			(64,494,881)	(20,997,055)	(5,977,321)	(140,878)
(19)	Less: Property Taxes			(8,174,121)	(2,681,456)	(803,493)	(20,540)
(20)	Less: Other Taxes	117	O&M Without Fuel Costs (P/F B)	95,822	$31,141	$8,635	$317
(21)	Less: Utility Receipts Tax			0	0	0	0
(22)	Less: Interest Expense	102	Original Cost Rate Base	(24,528,013)	($7,985,572)	($2,411,394)	($61,691)
(23)	Less: Non-Deductible Expenses			1,799,249	585,780	176,887	4,525
(24)	Income for State Income Taxes			$105,556,087	$36,576,206	$9,606,548	$234,195
(25)	State Income Tax Rate			8.50%	8.50%	8.50%	8.50%
(26)	State Income Taxes Before Flowback			$8,972,267	$3,108,978	$816,557	$19,907
(27)	Less: Deferred State Tax Flowback			$0	$0	$0	$0
(28)	Total State Income Tax Liability			$8,972,267	$3,108,978	$816,557	$19,907

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B NORMALIZED TAXES	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	SUBSIDY REDUCTION							
(1)	Proforma A Normalized Margins w/Misc. Rev.	$5,319,043	$65,649,301	$5,151,573	$44,911,320	$27,216,026	$792,200	$1,780,602
(2)	Proforma A Fuel Cost Revenues	$1,666,132	$33,921,512	$2,996,600	$36,636,848	$27,212,760	$188,236	$345,206
(3)	Less: Proforma A Equalized Revenues w/Misc. Rev.	5,012,282	103,056,609	8,363,219	81,040,752	55,795,250	1,010,228	1,808,745
(4)	Proforma A Subsidy	$1,972,894	($3,485,796)	($215,046)	$507,416	($1,366,464)	($29,791)	$317,063
(5)	Proposed Subsidy Reduction Percentage	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
(6)	Proforma B Subsidy	$1,479,670	($2,614,347)	($161,284)	$380,562	($1,024,848)	($22,343)	$237,797
(7)	Proforma B Equalized Revenues w/Misc. Rev.	$5,938,324	$127,278,407	$10,284,784	$96,297,751	$65,064,918	$1,134,842	$2,350,001
(8)	Proforma B Normalized Revenues w/Misc. Re\	$7,417,995	$124,664,059	$10,123,500	$96,678,313	$64,040,070	$1,112,499	$2,587,798
	TAX CALCULATIONS							
	Utility Receipts Taxes							
(9)	Total Proforma B Normal Revenues	$7,417,995	$124,664,059	$10,123,500	$96,678,313	$64,040,070	$1,112,499	$2,587,798
(10)	Less: Uncollectible Expense	($95,611)	($84,637)	($8,659)	($1,056)	($20)	($89,225)	($15,573)
(11)	Less: Statutory Exemption	($15)	($248)	($20)	($192)	($127)	($2)	($5)
(12)	Income for Utility Receipts Taxes	$7,322,369	$124,579,175	$10,114,821	$96,677,065	$64,039,923	$1,023,272	$2,572,220
(13)	Utility Receipts Tax Rate	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%	1.40%
(14)	Utility Receipts Taxes	$102,513	$1,744,108	$141,607	$1,353,479	$896,559	$14,326	$36,011
	State Income Taxes							
(15)	Total Proforma B Normal Revenues	$7,417,995	$124,664,059	$10,123,500	$96,678,313	$64,040,070	$1,112,499	$2,587,798
(16)	Less: Operation and Maintenance Expenses (Excl. Fuel)	(2,286,196)	(44,400,256)	(3,459,501)	(30,647,999)	(20,641,880)	(487,108)	(901,650)
(17)	Less: Fuel Costs	(1,450,330)	(29,527,900)	(2,608,472)	(31,891,538)	(23,688,085)	(163,856)	(300,494)
(18)	Less: Depreciation Expense	(699,894)	(17,274,070)	(1,343,162)	(10,839,638)	(6,713,753)	(180,615)	(328,495)
(19)	Less: Property Taxes	(94,725)	(2,159,313)	(171,340)	(1,344,799)	(819,391)	(24,001)	(55,063)
(20)	Less: Other Taxes	$1,231	$24,929	$1,921	$16,183	$10,688	$194	$583
(21)	Less: Utility Receipts Tax	0	0	0	0	0	0	0
(22)	Less: Interest Expense	($268,483)	($6,506,337)	($517,909)	($4,090,129)	($2,484,094)	($53,859)	($148,544)
(23)	Less: Non-Deductible Expenses	19,695	477,271	37,991	300,031	182,220	3,951	10,896
(24)	Income for State Income Taxes	$2,639,292	$25,298,383	$2,063,028	$18,180,423	$9,885,775	$207,204	$865,032
(25)	State Income Tax Rate	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
(26)	State Income Taxes Before Flowback	$224,340	$2,150,363	$175,357	$1,545,336	$840,291	$17,612	$73,528
(27)	Less: Deferred State Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(28)	Total State Income Tax Liability	$224,340	$2,150,363	$175,357	$1,545,336	$840,291	$17,612	$73,528

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B NORMALIZED TAXES (cont.)	No.	Allocation Method	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
	Federal Income taxes						
(29)	Total Proforma B Normal Revenues			$503,069,611	$149,551,055	$45,443,532	$1,450,789
(30)	Less: Operation and Maintenance Expenses (Excl. Fuel)			(174,216,347)	(55,095,523)	(15,652,658)	(643,575)
(31)	Less: Fuel Costs			(127,995,233)	(26,832,164)	(11,177,641)	(354,753)
(32)	Less: Depreciation Expense			(64,494,881)	(20,997,055)	(5,977,321)	(140,878)
(33)	Less: Other Taxes			95,822	31,141	8,635	317
(34)	Less: Property Taxes	100	Gross Plant	(8,174,121)	($2,681,456)	($803,493)	($20,540)
(35)	Less: Utility Receipts Taxes			(7,021,007)	(2,080,442)	(632,439)	(19,523)
(36)	Less: Interest Expense	102	Original Cost Rate Base	(24,528,013)	($7,985,572)	($2,411,394)	($61,691)
(37)	Less: Non-Deductible Expenses			1,286,735	418,922	126,501	3,236
(38)	Less: State Income taxes			(8,972,267)	(3,108,978)	(816,557)	(19,907)
(39)	Less: Kentucky Taxes			(175)	(57)	(17)	(0)
(40)	Income for Federal Income Taxes			$89,050,124	$31,219,871	$8,107,150	$193,476
(41)	Federal Income Tax Rate			35.00%	35.00%	35.00%	35.00%
(42)	Federal Income Taxes			$31,167,543	$10,926,955	$2,837,502	$67,717
(43)	Less: Investment Tax Credit	100	Gross Plant	(1,111,141)	($364,501)	($109,222)	($2,792)
(44)	Less Deferred Federal Tax Flowback	120	Total Depreciation Expenses	0	$0	$0	$0
(45)	Total Federal Income Tax Liability			$30,056,402	$10,562,454	$2,728,280	$64,925
	Net Operating Income						
(46)	Total Proforma B Normal Revenues w/Misc. Rev.			$503,069,611	$149,551,055	$45,443,532	$1,450,789
(47)	Less: Operation and Maintenance Expenses (Excl. Fuel)			(174,216,347)	(55,095,523)	(15,652,658)	(643,575)
(48)	Less: Fuel Costs			(127,995,233)	(26,832,164)	(11,177,641)	(354,753)
(49)	Less: Depreciation Expense			(64,494,881)	(20,997,055)	(5,977,321)	(140,878)
(50)	Less: Other Taxes			95,822	31,141	8,635	317
(51)	Less: Utility Receipts Taxes			(7,021,007)	(2,080,442)	(632,439)	(19,523)
(52)	Less: Property Taxes			(8,174,121)	(2,681,456)	(803,493)	(20,540)
(53)	Less: State Income Taxes			(8,972,267)	(3,108,978)	(816,557)	(19,907)
(54)	Less: Kentucky Taxes			(175)	(57)	(17)	(0)
(55)	Less: Total Federal Income Tax Liability			(30,056,402)	(10,562,454)	(2,728,280)	(64,925)
(56)	Net Operating Income			$82,235,000	$28,224,068	$7,663,762	$187,007
(57)	Total Rate Base			$1,017,759,890	$331,351,537	$100,057,843	$2,559,813
(58)	Rate of Return			8.08%	8.52%	7.66%	7.31%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	PROFORMA B NORMALIZED TAXES (cont.)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	Federal Income taxes							
(29)	Total Proforma B Normal Revenues	$7,417,995	$124,664,059	$10,123,500	$96,678,313	$64,040,070	$1,112,499	$2,587,798
(30)	Less: Operation and Maintenance Expenses (Excl. Fuel)	(2,286,196)	(44,400,256)	(3,459,501)	(30,647,999)	(20,641,880)	(487,108)	(901,650)
(31)	Less: Fuel Costs	(1,450,330)	(29,527,900)	(2,608,472)	(31,891,538)	(23,688,085)	(163,856)	(300,494)
(32)	Less: Depreciation Expense	(699,894)	(17,274,070)	(1,343,162)	(10,839,638)	(6,713,753)	(180,615)	(328,495)
(33)	Less: Other Taxes	1,231	24,929	1,921	16,183	10,688	194	583
(34)	Less: Property Taxes	($94,725)	($2,159,313)	($171,340)	($1,344,799)	($819,391)	($24,001)	($55,063)
(35)	Less: Utility Receipts Taxes	(102,513)	(1,744,108)	(141,607)	(1,353,479)	(896,559)	(14,326)	(36,011)
(36)	Less: Interest Expense	($268,483)	($6,506,337)	($517,909)	($4,090,129)	($2,484,094)	($53,859)	($148,544)
(37)	Less: Non-Deductible Expenses	14,085	341,321	27,169	214,567	130,315	2,825	7,793
(38)	Less: State Income taxes	(224,340)	(2,150,363)	(175,357)	(1,545,336)	(840,291)	(17,612)	(73,528)
(39)	Less: Kentucky Taxes	(2)	(46)	(4)	(29)	(18)	(1)	(1)
(40)	Income for Federal Income Taxes	$2,306,827	$21,267,916	$1,735,238	$15,196,116	$8,097,002	$174,140	$752,388
(41)	Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%
(42)	Federal Income Taxes	$807,389	$7,443,771	$607,333	$5,318,641	$2,833,951	$60,949	$263,336
(43)	Less: Investment Tax Credit	($12,876)	($293,524)	($23,291)	($182,804)	($111,383)	($3,263)	($7,485)
(44)	Less Deferred Federal Tax Flowback	$0	$0	$0	$0	$0	$0	$0
(45)	Total Federal Income Tax Liability	$794,513	$7,150,246	$584,042	$5,135,837	$2,722,568	$57,687	$255,851
	Net Operating Income							
(46)	Total Proforma B Normal Revenues w/Misc. Rev.	$7,417,995	$124,664,059	$10,123,500	$96,678,313	$64,040,070	$1,112,499	$2,587,798
(47)	Less: Operation and Maintenance Expenses (Excl. Fuel)	(2,286,196)	(44,400,256)	(3,459,501)	(30,647,999)	(20,641,880)	(487,108)	(901,650)
(48)	Less: Fuel Costs	(1,450,330)	(29,527,900)	(2,608,472)	(31,891,538)	(23,688,085)	(163,856)	(300,494)
(49)	Less: Depreciation Expense	(699,894)	(17,274,070)	(1,343,162)	(10,839,638)	(6,713,753)	(180,615)	(328,495)
(50)	Less: Other Taxes	1,231	24,929	1,921	16,183	10,688	194	583
(51)	Less: Utility Receipts Taxes	(102,513)	(1,744,108)	(141,607)	(1,353,479)	(896,559)	(14,326)	(36,011)
(52)	Less: Property Taxes	(94,725)	(2,159,313)	(171,340)	(1,344,799)	(819,391)	(24,001)	(55,063)
(53)	Less: State Income Taxes	(224,340)	(2,150,363)	(175,357)	(1,545,336)	(840,291)	(17,612)	(73,528)
(54)	Less: Kentucky Taxes	(2)	(46)	(4)	(29)	(18)	(1)	(1)
(55)	Less: Total Federal Income Tax Liability	(794,513)	(7,150,246)	(584,042)	(5,135,837)	(2,722,568)	(57,687)	(255,851)
(56)	Net Operating Income	$1,766,712	$20,282,685	$1,641,935	$13,935,841	$7,728,214	$167,487	$637,288
(57)	Total Rate Base	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(58)	Rate of Return	15.86%	7.51%	7.64%	8.21%	7.50%	7.49%	10.34%

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

	Proforma A Normalized Revenues	NO.	ALLOCATION METHOD	TOTAL	Residential (A)	Electric Home Heating (EH)	Water Heating (B)
(1)	Proforma A Normalized Revenues w/o Misc. Rev.			$324,589,615	$91,872,794	$29,154,071	$1,010,433
(2)	Proforma A Rider Revenues			$42,334,996	$15,508,081	$3,376,955	$154,480
(3)	Proforma A Normalized Miscellaneous Revenues			45,735,200	13,826,505	3,878,932	90,198
(4)	Total Proforma A Normalized Revenues w/Misc. Re			$412,659,810	$121,207,380	$36,409,958	$1,255,111
	Proforma A Equalized Revenues						
(5)	Proforma A Equalized Revenues w/o Misc. Rev.			$324,589,614	$88,533,070	$30,102,278	$1,055,052
(6)	Proforma A Rider Revenues			$42,334,996	$15,508,081	$3,376,955	$154,480
(7)	Proforma A Equalized Miscellaneous Revenues			45,735,200	13,863,089	3,889,003	90,717
(8)	Total Proforma A Equalized Revenues w/Misc. Re			$412,659,809	$117,904,239	$37,368,236	$1,300,249
	Proforma B Equalized Revenues						
(9)	Proforma B Equalized Revenues w/o Misc. Rev.			$457,253,539	$133,088,165	$42,249,590	$1,396,339
(10)	Proforma B Rider Revenues			$80,872	$31,702	$7,146	$318
(11)	Proforma B Equalized Miscellaneous Revenues			45,735,200	13,953,833	3,905,505	87,985
(12)	Total Proforma B Equalized Revenues w/Misc. Re			$503,069,610	$147,073,700	$46,162,241	$1,484,643
	Proforma B Normalized Revenues						
(13)	Proforma B Normalized Revenues w/o Misc. Rev.			$457,253,540	$135,498,169	$41,550,421	$1,363,406
(14)	Proforma B Rider Revenues			$80,872	$31,702	$7,146	$318
(15)	Proforma B Normalized Miscellaneous Revenues			45,735,200	14,021,184	3,885,965	87,065
(16)	Total Proforma B Normalized Revenues w/Misc. Re			$503,069,611	$149,551,055	$45,443,532	$1,450,789

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF INCOME TAXES AND INDIANA UTILITY RECEIPTS TAX

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. 2
SCHEDULE 9

		Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	Proforma A Normalized Revenues							
(1)	Proforma A Normalized Revenues w/o Misc. Rev.	$5,982,248	$77,768,636	$6,164,062	$65,858,104	$43,803,418	$938,716	$2,037,132
(2)	Proforma A Rider Revenues	$477,634	$9,821,563	$1,064,940	$7,009,273	$4,922,070	$0	$0
(3)	Proforma A Normalized Miscellaneous Revenues	525,293	11,980,615	919,171	8,680,791	5,703,298	41,721	88,676
(4)	Total Proforma A Normalized Revenues w/Misc. Re	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
	Proforma A Equalized Revenues							
(5)	Proforma A Equalized Revenues w/o Misc. Rev.	$4,095,299	$81,115,655	$6,361,652	$65,439,728	$45,166,344	$974,579	$1,745,958
(6)	Proforma A Rider Revenues	$477,634	$9,821,563	$1,064,940	$7,009,273	$4,922,070	$0	$0
(7)	Proforma A Equalized Miscellaneous Revenues	439,349	12,119,392	936,627	8,591,751	5,706,836	35,649	62,787
(8)	Total Proforma A Equalized Revenues w/Misc. Re	$5,012,282	$103,056,609	$8,363,219	$81,040,752	$55,795,250	$1,010,228	$1,808,745
	Proforma B Equalized Revenues							
(9)	Proforma B Equalized Revenues w/o Misc. Rev.	$5,502,771	$115,096,164	$9,343,763	$87,762,735	$59,428,917	$1,101,822	$2,283,272
(10)	Proforma B Rider Revenues	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(11)	Proforma B Equalized Miscellaneous Revenues	434,670	12,164,062	939,054	8,523,832	5,626,511	33,020	66,729
(12)	Total Proforma B Equalized Revenues w/Misc. Re	$5,938,324	$127,278,407	$10,284,784	$96,297,751	$65,064,918	$1,134,842	$2,350,001
	Proforma B Normalized Revenues							
(13)	Proforma B Normalized Revenues w/o Misc. Rev.	$6,942,213	$112,552,893	$9,186,864	$88,132,951	$58,431,932	$1,080,086	$2,514,605
(14)	Proforma B Rider Revenues	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(15)	Proforma B Normalized Miscellaneous Revenues	474,897	12,092,986	934,669	8,534,178	5,598,649	32,412	73,194
(16)	Total Proforma B Normalized Revenues w/Misc. Re	$7,417,995	$124,664,059	$10,123,500	$96,678,313	$64,040,070	$1,112,499	$2,587,798

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

NORMALIZED COST OF SERVICE AT PRESENT RATES

		TOTAL	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	OPERATING REVENUES:							
(1)	Revenue from Gas Sales	$324,589,615	$91,872,794	$29,154,071	$1,010,433	$5,982,248	$77,768,636	$6,164,062
(2)	Revenues from Riders	$42,334,996	$15,508,081	$3,376,955	$154,480	$477,634	$9,821,563	$1,064,940
(3)	Miscellaneous Revenues	$45,735,200	$13,826,505	$3,878,932	$90,198	$525,293	$11,980,615	$919,171
(4)	Total Operating Revenues	$412,659,810	$121,207,380	$36,409,958	$1,255,111	$6,985,175	$99,570,813	$8,148,173
			$107,380,875	$32,531,026	$1,164,913	$6,459,882	$87,590,198	$7,229,002
	OPERATING EXPENSES							
(5)	Production Demand	$93,371,448	$28,910,103	$6,904,031	$132,127	$730,172	$26,118,891	$1,921,660
(6)	Production Energy	$11,023	$2,311	$963	$31	$125	$2,543	$225
(7)	FAC Fuel	$127,995,233	$26,832,164	$11,177,641	$354,753	$1,450,330	$29,527,900	$2,608,472
(8)	Transmission Demand	$11,353,770	$2,807,588	$1,142,769	$27,951	$96,605	$3,000,490	$259,654
(9)	Sub-Transmission Demand	$12,591,218	$3,113,587	$1,267,319	$30,998	$107,134	$3,327,513	$287,954
(10)	Primary Distribution Demand	$1,754,745	$691,679	$312,061	$5,558	$10,474	$456,361	$44,169
(11)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$127,906	$60,692	$27,550	$379	$715	$34,562	$3,579
(13)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(14)	Line Transformers Demand	$1,835,672	$871,039	$395,389	$5,444	$10,261	$496,027	$51,360
(15)	Line Transformers Customer	$1,828,279	$1,105,041	$313,928	$65,622	$111,474	$98,679	$10,095
(16)	Services	$224,486	$127,441	$50,132	$0	$20,606	$23,865	$2,441
(17)	Meters	$2,270,291	$842,296	$313,699	$36,047	$225,468	$641,750	$65,653
(18)	Outdoor Lighting	$14,647	$0	$0	$0	$0	$0	$0
(19)	Street Lighting	$723,461	$0	$0	$0	$0	$0	$0
(20)	Customer Accounts-Related	$12,274,117	$7,626,674	$2,102,253	$304,729	$687,284	$879,739	$66,419
(21)	DSM-Related	$52,187	$16,158	$3,859	$74	$408	$14,598	$1,074
(22)	Non-FAC Fuel	$19,045,083	$3,992,499	$1,663,180	$52,786	$215,802	$4,393,611	$388,128
(23)	WPM Fuel	$16,295,008	$5,045,336	$1,204,878	$23,059	$127,428	$4,558,219	$335,364
(24)	Total Proforma A Operating Costs	$301,768,572	$82,044,609	$26,879,651	$1,039,556	$3,794,286	$73,574,749	$6,046,248
(25)	Total Depreciation and Amortization Expens	$64,494,881	$20,997,055	$5,977,321	$140,878	$699,894	$17,274,070	$1,343,162

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

NORMALIZED COST OF SERVICE AT PRESENT RATES

		Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	OPERATING REVENUES:				
(1)	Revenue from Gas Sales	$65,858,104	$43,803,418	$938,716	$2,037,132
(2)	Revenues from Riders	$7,009,273	$4,922,070	$0	$0
(3)	Miscellaneous Revenues	$8,680,791	$5,703,298	$41,721	$88,676
(4)	Total Operating Revenues	~~$81,548,168~~	~~$54,428,787~~	~~$980,437~~	~~$2,125,808~~
		$72,867,378	$48,725,488	$938,716	$2,037,132
	OPERATING EXPENSES				
(5)	Production Demand	$17,220,892	$11,433,571	$0	$0
(6)	Production Energy	$2,746	$2,040	$14	$26
(7)	FAC Fuel	$31,891,538	$23,688,085	$163,856	$300,494
(8)	Transmission Demand	$2,337,955	$1,668,990	$5,186	$6,582
(9)	Sub-Transmission Demand	$2,592,769	$1,850,893	$5,751	$7,299
(10)	Primary Distribution Demand	$228,162	$0	$2,622	$3,659
(11)	Primary Distribution Customer	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$0	$0	$179	$250
(13)	Secondary Distribution Customer	$0	$0	$0	$0
(14)	Line Transformers Demand	$0	$0	$2,569	$3,584
(15)	Line Transformers Customer	$1,231	$23	$104,028	$18,157
(16)	Services	$0	$0	$0	$0
(17)	Meters	$142,462	$2,916	$0	$0
(18)	Outdoor Lighting	$0	$0	$14,647	$0
(19)	Street Lighting	$0	$0	$0	$723,461
(20)	Customer Accounts-Related	$109,525	$541	$399,536	$97,416
(21)	DSM-Related	$9,625	$6,390	$0	$0
(22)	Non-FAC Fuel	$4,745,310	$3,524,675	$24,381	$44,712
(23)	WPM Fuel	$3,005,357	$1,995,365	$0	$0
(24)	Total Proforma A Operating Costs	$62,287,574	$44,173,491	$722,769	$1,205,638
(25)	Total Depreciation and Amortization Expense	$10,839,638	$6,713,753	$180,615	$328,495

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	(95,822)	(31,065)	(8,622)	(317)	(1,231)	(24,953)	(1,925)
(27)	Property Taxes	8,174,121	2,681,456	803,493	20,540	94,725	2,159,313	171,340
(28)	Utility Receipts Taxes	5,755,270	1,683,630	505,969	16,784	96,454	1,392,803	113,953
(29)	State Income Taxes	1,325,265	689,878	44,524	(230)	182,643	47,525	9,305
(30)	Federal Income Taxes	1,687,545	1,586,807	(136,266)	(9,986)	639,526	(649,723)	(31,918)
(31)	Total Operating Expenses	$383,109,832	$109,652,371	$34,066,069	$1,207,224	$5,506,296	$93,773,785	$7,650,164
(32)	Net Operating Income	$29,549,979	$11,555,010	$2,343,889	$47,887	$1,478,879	$5,797,028	$498,008
(33)	Total Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986
(34)	Rate of Return	2.90%	3.49%	2.34%	1.87%	13.27%	2.15%	2.32%
(35)	Index	1.00	1.20	0.81	0.64	4.57	0.74	0.80

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	(16,214)	(10,716)	(194)	(584)
(27)	Property Taxes	1,344,799	819,391	24,001	55,063
(28)	Utility Receipts Taxes	1,141,657	762,001	12,477	29,543
(29)	State Income Taxes	280,722	36,652	284	33,963
(30)	Federal Income Taxes	445,247	(258,231)	(6,955)	109,043
(31)	Total Operating Expenses	$76,323,422	$52,236,341	$932,998	$1,761,162
(32)	Net Operating Income	$5,224,746	$2,192,445	$47,439	$364,646
(33)	Total Rate Base	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(34)	Rate of Return	3.08%	2.13%	2.12%	5.92%
(35)	Index	1.06	0.73	0.73	2.04

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

EQUALIZED COST OF SERVICE AT PRESENT RATES

		TOTAL	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	OPERATING REVENUES:							
(1)	Revenue from Gas Sales	$324,589,614	$88,533,070	$30,102,278	$1,055,052	$4,095,299	$81,115,655	$6,361,652
(2)	Revenues from Riders	$42,334,996	$15,508,081	$3,376,955	$154,480	$477,634	$9,821,563	$1,064,940
(3)	Miscellaneous Revenues	$45,735,200	$13,863,089	$3,889,003	$90,717	$439,349	$12,119,392	$936,627
(4)	Total Operating Revenues	$412,659,809	$117,904,239	$37,368,236	$1,300,249	$5,012,282	$103,056,609	$8,363,219
	OPERATING EXPENSES							
(5)	Production Demand	$93,371,448	$28,910,103	$6,904,031	$132,127	$730,172	$26,118,891	$1,921,660
(6)	Production Energy	$11,023	$2,311	$963	$31	$125	$2,543	$225
(7)	FAC Fuel	$127,995,233	$26,832,164	$11,177,641	$354,753	$1,450,330	$29,527,900	$2,608,472
(8)	Transmission Demand	$11,353,770	$2,807,588	$1,142,769	$27,951	$96,605	$3,000,490	$259,654
(9)	Sub-Transmission Demand	$12,591,218	$3,113,587	$1,267,319	$30,998	$107,134	$3,327,513	$287,954
(10)	Primary Distribution Demand	$1,754,745	$691,679	$312,061	$5,558	$10,474	$456,361	$44,169
(11)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$127,906	$60,692	$27,550	$379	$715	$34,562	$3,579
(13)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(14)	Line Transformers Demand	$1,835,672	$871,039	$395,389	$5,444	$10,261	$496,027	$51,360
(15)	Line Transformers Customer	$1,828,279	$1,105,041	$313,928	$65,622	$111,474	$98,679	$10,095
(16)	Services	$224,486	$127,441	$50,132	$0	$20,606	$23,865	$2,441
(17)	Meters	$2,270,291	$842,296	$313,699	$36,047	$225,468	$641,750	$65,653
(18)	Outdoor Lighting	$14,647	$0	$0	$0	$0	$0	$0
(19)	Street Lighting	$723,461	$0	$0	$0	$0	$0	$0
(20)	Customer Accounts-Related	$12,274,117	$7,626,674	$2,102,253	$304,729	$687,284	$879,739	$66,419
(21)	DSM-Related	$52,187	$16,158	$3,859	$74	$408	$14,598	$1,074
(22)	Non-FAC Fuel	$19,045,083	$3,992,499	$1,663,180	$52,786	$215,802	$4,393,611	$388,128
(23)	WPM Fuel	$16,295,008	$5,045,336	$1,204,878	$23,059	$127,428	$4,558,219	$335,364
(24)	Total Proforma A Operating Costs	$301,768,572	$82,044,609	$26,879,651	$1,039,556	$3,794,286	$73,574,749	$6,046,248
(25)	Total Depreciation and Amortization Expens	$64,494,881	$20,997,055	$5,977,321	$140,878	$699,894	$17,274,070	$1,343,162

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

EQUALIZED COST OF SERVICE AT PRESENT RATES

		Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	OPERATING REVENUES:				
(1)	Revenue from Gas Sales	$65,439,728	$45,166,344	$974,579	$1,745,958
(2)	Revenues from Riders	$7,009,273	$4,922,070	$0	$0
(3)	Miscellaneous Revenues	$8,591,751	$5,706,836	$35,649	$62,787
(4)	Total Operating Revenues	$81,040,752	$55,795,250	$1,010,228	$1,808,745
	OPERATING EXPENSES				
(5)	Production Demand	$17,220,892	$11,433,571	$0	$0
(6)	Production Energy	$2,746	$2,040	$14	$26
(7)	FAC Fuel	$31,891,538	$23,688,085	$163,856	$300,494
(8)	Transmission Demand	$2,337,955	$1,668,990	$5,186	$6,582
(9)	Sub-Transmission Demand	$2,592,769	$1,850,893	$5,751	$7,299
(10)	Primary Distribution Demand	$228,162	$0	$2,622	$3,659
(11)	Primary Distribution Customer	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$0	$0	$179	$250
(13)	Secondary Distribution Customer	$0	$0	$0	$0
(14)	Line Transformers Demand	$0	$0	$2,569	$3,584
(15)	Line Transformers Customer	$1,231	$23	$104,028	$18,157
(16)	Services	$0	$0	$0	$0
(17)	Meters	$142,462	$2,916	$0	$0
(18)	Outdoor Lighting	$0	$0	$14,647	$0
(19)	Street Lighting	$0	$0	$0	$723,461
(20)	Customer Accounts-Related	$109,525	$541	$399,536	$97,416
(21)	DSM-Related	$9,625	$6,390	$0	$0
(22)	Non-FAC Fuel	$4,745,310	$3,524,675	$24,381	$44,712
(23)	WPM Fuel	$3,005,357	$1,995,365	$0	$0
(24)	Total Proforma A Operating Costs	$62,287,574	$44,173,491	$722,769	$1,205,638
(25)	Total Depreciation and Amortization Expense	$10,839,638	$6,713,753	$180,615	$328,495

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	($95,822)	($31,141)	($8,635)	($317)	($1,231)	($24,929)	($1,921)
(27)	Property Taxes	$8,174,121	$2,681,456	$803,493	$20,540	$94,725	$2,159,313	$171,340
(28)	Utility Receipts Taxes	$5,755,270	$1,637,386	$519,385	$17,415	$68,833	$1,441,604	$116,964
(29)	State Income Taxes	$1,325,265	$409,117	$125,979	$3,607	$14,947	$343,815	$27,584
(30)	Federal Income Taxes	$1,687,545	$545,186	$165,931	$4,248	$17,374	$449,516	$35,895
(31)	Total Operating Expenses	$383,109,831	$108,283,669	$34,463,123	$1,225,926	$4,688,828	$95,218,138	$7,739,271
(32)	Net Operating Income	$29,549,978	$9,620,570	$2,905,113	$74,322	$323,454	$7,838,471	$623,947
(33)	Total Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986
(34)	Rate of Return	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
(35)	Index	1.00	1.00	1.00	1.00	1.00	1.00	1.00

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	($16,183)	($10,688)	($194)	($583)
(27)	Property Taxes	$1,344,799	$819,391	$24,001	$55,063
(28)	Utility Receipts Taxes	$1,134,553	$781,131	$12,894	$25,104
(29)	State Income Taxes	$237,589	$152,799	$2,816	$7,012
(30)	Federal Income Taxes	$285,223	$172,674	$2,440	$9,057
(31)	Total Operating Expenses	$76,113,193	$52,802,552	$945,342	$1,629,788
(32)	Net Operating Income	$4,927,559	$2,992,698	$64,886	$178,957
(33)	Total Rate Base	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(34)	Rate of Return	2.90%	2.90%	2.90%	2.90%
(35)	Index	1.00	1.00	1.00	1.00

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

EQUALIZED COST OF SERVICE AT PROPOSED RATES

		TOTAL	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	OPERATING REVENUES:							
(1)	Revenue from Gas Sales	$457,253,539	$133,088,165	$42,249,590	$1,396,339	$5,502,771	$115,096,164	$9,343,763
(2)	Revenues from Riders	$80,872	$31,702	$7,146	$318	$884	$18,181	$1,967
(3)	Miscellaneous Revenues	$45,735,200	$13,953,833	$3,905,505	$87,985	$434,670	$12,164,062	$939,054
(4)	Total Operating Revenues	$503,069,610	$147,073,700	$46,162,241	$1,484,643	$5,938,324	$127,278,407	$10,284,784
	OPERATING EXPENSES							
(5)	Production Demand	$93,435,650	$28,929,982	$6,908,778	$132,218	$730,674	$26,136,850	$1,922,981
(6)	Production Energy	$12,341	$2,587	$1,078	$34	$140	$2,847	$252
(7)	FAC Fuel	$127,995,233	$26,832,164	$11,177,641	$354,753	$1,450,330	$29,527,900	$2,608,472
(8)	Transmission Demand	$11,357,117	$2,808,416	$1,143,106	$27,960	$96,633	$3,001,374	$259,731
(9)	Sub-Transmission Demand	$12,598,502	$3,115,389	$1,268,052	$31,016	$107,196	$3,329,438	$288,121
(10)	Primary Distribution Demand	$1,766,712	$696,396	$314,190	$5,595	$10,546	$459,473	$44,470
(11)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$129,351	$61,378	$27,861	$384	$723	$34,953	$3,619
(13)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(14)	Line Transformers Demand	$1,837,175	$871,752	$395,712	$5,449	$10,269	$496,433	$51,402
(15)	Line Transformers Customer	$1,829,776	$1,105,946	$314,185	$65,675	$111,565	$98,760	$10,103
(16)	Services	$226,240	$128,437	$50,523	$0	$20,767	$24,052	$2,461
(17)	Meters	$2,271,265	$842,657	$313,834	$36,062	$225,565	$642,025	$65,681
(18)	Outdoor Lighting	$14,739	$0	$0	$0	$0	$0	$0
(19)	Street Lighting	$724,005	$0	$0	$0	$0	$0	$0
(20)	Customer Accounts-Related	$12,617,911	$7,477,573	$2,043,179	$263,260	$628,454	$1,206,703	$86,047
(21)	DSM-Related	$55,472	$17,175	$4,102	$78	$434	$15,517	$1,142
(22)	Non-FAC Fuel	$19,045,083	$3,992,499	$1,663,180	$52,786	$215,802	$4,393,611	$388,128
(23)	WPM Fuel	$16,295,008	$5,045,336	$1,204,878	$23,059	$127,428	$4,558,219	$335,364
(24)	Total Proforma B Operating Costs	$302,211,580	$81,927,687	$26,830,299	$998,328	$3,736,526	$73,928,156	$6,067,973
(25)	Total Depreciation and Amortization Expens	$64,494,881	$20,997,055	$5,977,321	$140,878	$699,894	$17,274,070	$1,343,162

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

EQUALIZED COST OF SERVICE AT PROPOSED RATES

		Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	OPERATING REVENUES:				
(1)	Revenue from Gas Sales	$87,762,735	$59,428,917	$1,101,822	$2,283,272
(2)	Revenues from Riders	$11,184	$9,489	$0	$0
(3)	Miscellaneous Revenues	$8,523,832	$5,626,511	$33,020	$66,729
(4)	Total Operating Revenues	$96,297,751	$65,064,918	$1,134,842	$2,350,001
	OPERATING EXPENSES				
(5)	Production Demand	$17,232,733	$11,441,433	$0	$0
(6)	Production Energy	$3,075	$2,284	$16	$29
(7)	FAC Fuel	$31,891,538	$23,688,085	$163,856	$300,494
(8)	Transmission Demand	$2,338,644	$1,669,482	$5,187	$6,584
(9)	Sub-Transmission Demand	$2,594,269	$1,851,964	$5,755	$7,303
(10)	Primary Distribution Demand	$229,718	$0	$2,640	$3,683
(11)	Primary Distribution Customer	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$0	$0	$181	$253
(13)	Secondary Distribution Customer	$0	$0	$0	$0
(14)	Line Transformers Demand	$0	$0	$2,571	$3,587
(15)	Line Transformers Customer	$1,232	$23	$104,114	$18,172
(16)	Services	$0	$0	$0	$0
(17)	Meters	$142,523	$2,917	$0	$0
(18)	Outdoor Lighting	$0	$0	$14,739	$0
(19)	Street Lighting	$0	$0	$0	$724,005
(20)	Customer Accounts-Related	$344,906	$146,943	$327,525	$93,322
(21)	DSM-Related	$10,231	$6,793	$0	$0
(22)	Non-FAC Fuel	$4,745,310	$3,524,675	$24,381	$44,712
(23)	WPM Fuel	$3,005,357	$1,995,365	$0	$0
(24)	Total Proforma B Operating Costs	$62,539,537	$44,329,965	$650,964	$1,202,144
(25)	Total Depreciation and Amortization Expens	$10,839,638	$6,713,753	$180,615	$328,495

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	(95,822)	(31,141)	(8,635)	(317)	(1,231)	(24,929)	(1,921)
(27)	Property Taxes	8,174,121	2,681,456	803,493	20,540	94,725	2,159,313	171,340
(28)	Utility Receipts Taxes	7,021,007	2,045,759	642,501	19,997	81,798	1,780,709	143,865
(29)	State Income Taxes	8,972,442	2,898,460	877,664	22,785	98,570	2,372,628	189,070
(30)	Federal Income Taxes	30,056,402	9,781,220	2,954,925	75,600	327,899	7,974,681	634,903
(31)	Total Operating Expenses	$420,834,611	$120,300,495	$38,077,567	$1,277,810	$5,038,181	$105,464,629	$8,548,393
(32)	Net Operating Income	$82,234,999	$26,773,204	$8,084,674	$206,833	$900,144	$21,813,778	$1,736,391
(33)	Total Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986
(34)	Rate of Return	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
(35)	Index	1.00	1.00	1.00	1.00	1.00	1.00	1.00

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	(16,183)	(10,688)	(194)	(583)
(27)	Property Taxes	1,344,799	819,391	24,001	55,063
(28)	Utility Receipts Taxes	1,348,151	910,907	14,639	32,682
(29)	State Income Taxes	1,513,017	927,420	19,512	53,316
(30)	Federal Income Taxes	5,015,827	3,045,753	64,733	180,861
(31)	Total Operating Expenses	$82,584,786	$56,736,502	$954,269	$1,851,979
(32)	Net Operating Income	$13,712,965	$8,328,416	$180,573	$498,022
(33)	Total Rate Base	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(34)	Rate of Return	8.08%	8.08%	8.08%	8.08%
(35)	Index	1.00	1.00	1.00	1.00

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

NORMALIZED COST OF SERVICE AT PROPOSED RATES

		TOTAL	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
	OPERATING REVENUES:							
(1)	Revenue from Gas Sales	$457,253,540	$135,498,169	$41,550,421	$1,363,406	$6,942,213	$112,552,893	$9,186,864
(2)	Revenues from Riders	$80,872	$31,702	$7,146	$318	$884	$18,181	$1,967
(3)	Miscellaneous Revenues	$45,735,200	$14,021,184	$3,885,965	$87,065	$474,897	$12,092,986	$934,669
(4)	Total Operating Revenues	$503,069,611	$149,551,055	$45,443,532	$1,450,789	$7,417,995	$124,664,059	$10,123,500
	OPERATING EXPENSES							
(5)	Production Demand	$93,435,650	$28,929,982	$6,908,778	$132,218	$730,674	$26,136,850	$1,922,981
(6)	Production Energy	$12,341	$2,587	$1,078	$34	$140	$2,847	$252
(7)	FAC Fuel	$127,995,233	$26,832,164	$11,177,641	$354,753	$1,450,330	$29,527,900	$2,608,472
(8)	Transmission Demand	$11,357,117	$2,808,416	$1,143,106	$27,960	$96,633	$3,001,374	$259,731
(9)	Sub-Transmission Demand	$12,598,502	$3,115,389	$1,268,052	$31,016	$107,196	$3,329,438	$288,121
(10)	Primary Distribution Demand	$1,766,712	$696,396	$314,190	$5,595	$10,546	$459,473	$44,470
(11)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$129,351	$61,378	$27,861	$384	$723	$34,953	$3,619
(13)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(14)	Line Transformers Demand	$1,837,175	$871,752	$395,712	$5,449	$10,269	$496,433	$51,402
(15)	Line Transformers Customer	$1,829,776	$1,105,946	$314,185	$65,675	$111,565	$98,760	$10,103
(16)	Services	$226,240	$128,437	$50,523	$0	$20,767	$24,052	$2,461
(17)	Meters	$2,271,265	$842,657	$313,834	$36,062	$225,565	$642,025	$65,681
(18)	Outdoor Lighting	$14,739	$0	$0	$0	$0	$0	$0
(19)	Street Lighting	$724,005	$0	$0	$0	$0	$0	$0
(20)	Customer Accounts-Related	$12,617,911	$7,477,573	$2,043,179	$263,260	$628,454	$1,206,703	$86,047
(21)	DSM-Related	$55,472	$17,175	$4,102	$78	$434	$15,517	$1,142
(22)	Non-FAC Fuel	$19,045,083	$3,992,499	$1,663,180	$52,786	$215,802	$4,393,611	$388,128
(23)	WPM Fuel	$16,295,008	$5,045,336	$1,204,878	$23,059	$127,428	$4,558,219	$335,364
(24)	Total Proforma B Operating Costs	$302,211,580	$81,927,687	$26,830,299	$998,328	$3,736,526	$73,928,156	$6,067,973
(25)	Total Depreciation and Amortization Expens	$64,494,881	$20,997,055	$5,977,321	$140,878	$699,894	$17,274,070	$1,343,162

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

NORMALIZED COST OF SERVICE AT PROPOSED RATES

		Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	OPERATING REVENUES:				
(1)	Revenue from Gas Sales	$88,132,951	$58,431,932	$1,080,086	$2,514,605
(2)	Revenues from Riders	$11,184	$9,489	$0	$0
(3)	Miscellaneous Revenues	$8,534,178	$5,598,649	$32,412	$73,194
(4)	Total Operating Revenues	$96,678,313	$64,040,070	$1,112,499	$2,587,798
	OPERATING EXPENSES				
(5)	Production Demand	$17,232,733	$11,441,433	$0	$0
(6)	Production Energy	$3,075	$2,284	$16	$29
(7)	FAC Fuel	$31,891,538	$23,688,085	$163,856	$300,494
(8)	Transmission Demand	$2,338,644	$1,669,482	$5,187	$6,584
(9)	Sub-Transmission Demand	$2,594,269	$1,851,964	$5,755	$7,303
(10)	Primary Distribution Demand	$229,718	$0	$2,640	$3,683
(11)	Primary Distribution Customer	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$0	$0	$181	$253
(13)	Secondary Distribution Customer	$0	$0	$0	$0
(14)	Line Transformers Demand	$0	$0	$2,571	$3,587
(15)	Line Transformers Customer	$1,232	$23	$104,114	$18,172
(16)	Services	$0	$0	$0	$0
(17)	Meters	$142,523	$2,917	$0	$0
(18)	Outdoor Lighting	$0	$0	$14,739	$0
(19)	Street Lighting	$0	$0	$0	$724,005
(20)	Customer Accounts-Related	$344,906	$146,943	$327,525	$93,322
(21)	DSM-Related	$10,231	$6,793	$0	$0
(22)	Non-FAC Fuel	$4,745,310	$3,524,675	$24,381	$44,712
(23)	WPM Fuel	$3,005,357	$1,995,365	$0	$0
(24)	Total Proforma B Operating Costs	$62,539,537	$44,329,965	$650,964	$1,202,144
(25)	Total Depreciation and Amortization Expens(	$10,839,638	$6,713,753	$180,615	$328,495

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	(95,822)	(31,141)	(8,635)	(317)	(1,231)	(24,929)	(1,921)
(27)	Property Taxes	8,174,121	2,681,456	803,493	20,540	94,725	2,159,313	171,340
(28)	Utility Receipts Taxes	7,021,007	2,080,442	632,439	19,523	102,513	1,744,108	141,607
(29)	State Income Taxes	8,972,442	3,109,035	816,574	19,907	224,342	2,150,409	175,361
(30)	Federal Income Taxes	30,056,402	10,562,454	2,728,280	64,925	794,513	7,150,246	584,042
(31)	Total Operating Expenses	$420,834,612	$121,326,988	$37,779,770	$1,263,783	$5,651,282	$104,381,374	$8,481,565
(32)	Net Operating Income	$82,235,000	$28,224,068	$7,663,762	$187,007	$1,766,712	$20,282,685	$1,641,935
(33)	Total Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986
(34)	Rate of Return	8.08%	8.52%	7.66%	7.31%	15.86%	7.51%	7.64%
(35)	Index	1.00	1.05	0.95	0.90	1.96	0.93	0.95

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
SUMMARY OF COST OF SERVICE RESULTS

DATA: 12 MOTNS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 10

(26)	Other Taxes	(16,183)	(10,688)	(194)	(583)
(27)	Property Taxes	1,344,799	819,391	24,001	55,063
(28)	Utility Receipts Taxes	1,353,479	896,559	14,326	36,011
(29)	State Income Taxes	1,545,365	840,308	17,613	73,529
(30)	Federal Income Taxes	5,135,837	2,722,568	57,687	255,851
(31)	Total Operating Expenses	$82,742,472	$56,311,856	$945,011	$1,950,510
(32)	Net Operating Income	$13,935,841	$7,728,214	$167,487	$637,288
(33)	Total Rate Base	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(34)	Rate of Return	8.21%	7.50%	7.49%	10.34%
(35)	Index	1.02	0.93	0.93	1.28

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF UNIT COSTS

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 11

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
BILLING DETERMINANTS							
(1) Annual Sales (kwh)	5,259,836,647	1,081,881,362	450,686,046	14,303,741	58,477,763	1,190,584,262	105,174,409
Annual Billing KW							
(2) Production/Transmission		N/A	N/A	N/A	N/A	360,432	26,938
(3) Primary Distribution		N/A	N/A	N/A	N/A	360,432	26,938
(4) Secondary Distribution		N/A	N/A	N/A	N/A	325,609	26,938
(5) Number of Customers	155,766	94,147	26,746	5,591	9,497	8,407	860
TOTAL COSTS - EQUAL RATE OF RETURN							
DEMAND ($)							
(6) Production Demand	$224,517,845	$69,516,263	$16,601,201	$317,708	$1,755,747	$62,804,607	$4,620,759
(7) Transmission Demand	$17,257,663	$4,267,517	$1,737,002	$42,486	$146,839	$4,560,726	$394,673
(8) Sub-Transmission Demand	$24,867,876	$6,149,389	$2,502,978	$61,221	$211,591	$6,571,897	$568,714
(9) Primary Distribution Demand	$23,361,453	$9,208,537	$4,154,567	$73,989	$139,448	$6,075,666	$588,034
(10) Secondary Distribution Demand	$2,812,850	$1,334,716	$605,865	$8,342	$15,723	$760,076	$78,700
(11) Line Transformers Demand	$4,552,115	$2,160,009	$980,488	$13,500	$25,444	$1,230,052	$127,363
(12) DSM-Related	$10,245,535	$3,172,270	$757,571	$14,498	$80,121	$2,865,994	$210,861
(13) WPM Fuel	$16,548,205	$5,123,732	$1,223,600	$23,417	$129,408	$4,629,046	$340,575
ENERGY ($)							
(12) Production Energy	$1,661,855	$348,382	$145,127	$4,606	$18,831	$383,382	$33,868
(13) FAC Fuel	$129,984,060	$27,249,090	$11,351,323	$360,265	$1,472,866	$29,986,713	$2,649,003
(22) Non-FAC Fuel	$19,341,011	$4,054,535	$1,689,023	$53,606	$219,155	$4,461,881	$394,159
CUSTOMER ($)							
(14) Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(15) Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0
(16) Line Transformers Customer	$4,533,781	$2,896,868	$822,963	$172,028	$292,229	$2,921	$26,464
(17) Services	$4,003,734	$2,272,930	$894,104	$0	$367,513	$425,641	$43,544
(18) Meters	$4,111,812	$1,525,514	$568,153	$65,286	$408,355	$1,162,298	$118,906
(19) Customer Accounts-Related	$13,241,164	$8,227,561	$2,267,884	$328,738	$741,434	$949,051	$71,652
DIRECT ($)							
(20) Outdoor Lighting	$264,694	$0	$0	$0	$0	$0	$0
(21) Street Lighting	$1,763,958	$0	$0	$0	$0	$0	$0
CORRECTION FACTOR							
(23) Total	$503,069,610	$147,507,315	$46,301,848	$1,539,689	$6,024,703	$126,869,953	$10,267,278
(24) Actual	503,069,610	147,073,700	46,162,241	1,484,643	5,938,324	127,278,407	10,284,784
(25) Difference	(0)	433,615	139,607	55,047	86,378	(408,454)	(17,506)
(26) Correction Factor		0.99706	0.99698	0.96425	0.98566	1.00322	1.00171

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF UNIT COSTS

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 11

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
BILLING DETERMINANTS				
(1) Annual Sales (kwh)	1,320,758,678	1,019,247,677	6,606,709	12,115,999
Annual Billing KW				
(2) Production/Transmission	230,299	130,709		
(3) Primary Distribution	188,027	0		
(4) Secondary Distribution	0	0		
(5) Number of Customers	105	2	8,863	1,547
TOTAL COSTS - EQUAL RATE OF RETURN				
DEMAND ($)				
(6) Production Demand	$41,408,778	$27,492,781	$0	$0
(7) Transmission Demand	$3,553,678	$2,536,855	$7,883	$10,004
(8) Sub-Transmission Demand	$5,120,764	$3,655,547	$11,359	$14,416
(9) Primary Distribution Demand	$3,037,593	$0	$34,913	$48,707
(10) Secondary Distribution Demand	$0	$0	$3,936	$5,492
(11) Line Transformers Demand	$0	$0	$6,370	$8,887
(12) DSM-Related	$1,889,628	$1,254,592	$0	$0
(13) WPM Fuel	$3,052,056	$2,026,370	$0	$0
ENERGY ($)				
(12) Production Energy	$414,071	$307,560	$2,127	$3,902
(13) FAC Fuel	$32,387,078	$24,056,158	$166,402	$305,163
(22) Non-FAC Fuel	$4,819,044	$3,579,442	$24,760	$45,407
CUSTOMER ($)				
(14) Primary Distribution Customer	$0	$0	$0	$0
(15) Secondary Distribution Customer	$0	$0	$0	$0
(16) Line Transformers Customer	$0	$0	$272,711	$47,598
(17) Services	$0	$0	$0	$0
(18) Meters	$258,018	$5,282	$0	$0
(19) Customer Accounts-Related	$118,155	$583	$431,014	$105,091
DIRECT ($)				
(20) Outdoor Lighting	$0	$0	$264,694	$0
(21) Street Lighting	$0	$0	$0	$1,763,958
CORRECTION FACTOR				
(23) Total	$96,058,862	$64,915,170	$1,226,169	$2,358,625
(24) Actual	96,297,751	65,064,918	1,134,842	2,350,001
(25) Difference	(238,889)	(149,748)	91,327	8,624
(26) Correction Factor	1.00249	1.00231	0.92552	0.99634

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF UNIT COSTS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 11

	Total	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)
UNIT COSTS - EQUAL RATE OF RETURN							
DEMAND ($)							
(1) Production Demand		N/A	N/A	N/A	N/A	$174.81	$171.83
(2) Transmission Demand		N/A	N/A	N/A	N/A	$12.69	$14.68
(3) Sub-Transmission Demand		N/A	N/A	N/A	N/A	$18.29	$21.15
(4) Primary Distribution Demand		N/A	N/A	N/A	N/A	$16.91	$21.87
(5) Secondary Distribution Demand		N/A	N/A	N/A	N/A	$2.34	$2.93
(6) Line Transformers Demand		N/A	N/A	N/A	N/A	$3.79	$4.74
(7) DSM-Related		N/A	N/A	N/A	N/A	$8.83	$7.84
(8) WPM Fuel		N/A	N/A	N/A	N/A	$14.26	$12.66
(9) Total Demand ($/kWh or kVa/Month)		N/A	N/A	N/A	N/A	$251.93	$257.68
ENERGY ($)							
(10) Total Energy ($/kWh)		$0.12219	$0.09235	$0.06564	$0.07105	$0.02935	$0.02931
		(Note: Non-demand metered rate schedules include demand costs)					
CUSTOMER ($)							
(11) Primary Distribution Customer		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(12) Secondary Distribution Customer		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(13) Line Transformers Customer		$2.56	$2.56	$2.47	$2.53	$0.03	$2.57
(14) Services		$2.01	$2.78	$0.00	$3.18	$4.23	$4.23
(15) Meters		$1.35	$1.76	$0.94	$3.53	$11.56	$11.54
(16) Customer Accounts-Relatec		$7.26	$7.04	$4.72	$6.41	$9.44	$6.95
(17) $/Customer/Month		$13.17	$14.14	$8.14	$15.65	$25.26	$25.29
DIRECT ($)							
(18) Outdoor Lighting							
(19) Street Lighting							

VECTREN ENERGY DELIVERY OF INDIANA-ELECTRIC
IURC CAUSE NO. 43111
CALCULATION OF UNIT COSTS

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 11

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

		Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	UNIT COSTS - EQUAL RATE OF RETURN				
	DEMAND ($)				
(1)	Production Demand	$180.25	$210.82		
(2)	Transmission Demand	$15.47	$19.45		
(3)	Sub-Transmission Demand	$22.29	$28.03		
(4)	Primary Distribution Demand	$16.20			
(5)	Secondary Distribution Demand				
(6)	Line Transformers Demand				
(7)	DSM-Related				
(8)	WPM Fuel				
(9)	Total Demand ($/kWh or kVa/Month)	$234.21	$258.31	$0.00	$0.00
	ENERGY ($)				
(10)	Total Energy ($/kWh)	$0.02855	$0.02748	$0.02708	$0.02915
	CUSTOMER ($)				
(11)	Primary Distribution Customer	$0.00	$0.00	$0.00	$0.00
(12)	Secondary Distribution Customer	$0.00	$0.00	$0.00	$0.00
(13)	Line Transformers Customer	$0.00	$0.00	$2.37	$2.55
(14)	Services	$0.00	$0.00	$0.00	$0.00
(15)	Meters	$205.45	$220.57	$0.00	$0.00
(16)	Customer Accounts-Relatec	$94.08	$24.37	$3.75	$5.64
(17)	$/Customer/Month	$299.53	$244.94	$6.12	$8.20
	DIRECT ($)				
(18)	Outdoor Lighting				
(19)	Street Lighting				

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA A REVENUES AT PRESENT RATES OF RETURN

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT KAH-3
SCHEDULE 1

Line	Description	(1) Total	(2) Residential (A)	(3) Electric Home Heating (EH)	(4) Water Heating (B)	(5) Small General Service (SGS)	(6) Demand General Service (DGS)	(7) Off-Season Service (OSS)	(8) Large Power Service (LP)	(9) Transmission Power (HLF)	(10) Outdoor Lighting (OL)	(11) Street Lighting (SL)
	Operating Revenues											
(1)	Revenues From Gas Sales	$324,589,615	$91,872,794	$29,154,071	$1,010,433	$5,982,248	$77,768,636	$6,164,062	$65,858,104	$43,803,418	$938,716	$2,037,132
(2)	Revenues from Riders	$42,334,996	$15,508,081	$3,376,955	$154,480	$477,634	$9,821,563	$1,064,940	$7,009,273	$4,922,070	$0	$0
(3)	Miscellaneous Revenues	$45,735,200	$13,826,505	$3,878,932	$90,198	$525,293	$11,980,615	$919,171	$8,680,791	$5,703,298	$41,721	$88,676
(4)	Total	$412,659,810	$121,207,380	$36,409,958	$1,255,111	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
	Operating Expenses											
(5)	Operation and Maintenance	$301,768,572	$82,044,609	$26,879,651	$1,039,556	$3,794,286	$73,574,749	$6,046,248	$62,287,574	$44,173,491	$722,769	$1,205,638
(6)	Depreciation and Amortization	64,494,881	20,997,055	5,977,321	140,878	699,894	17,274,070	1,343,162	10,839,638	6,713,753	180,615	328,495
(7)	Federal Income Taxes	1,687,545	1,586,807	(136,266)	(9,986)	639,526	(649,723)	(31,918)	445,247	(258,231)	(6,955)	109,043
(8)	State Income Taxes	1,325,265	689,878	44,524	(230)	182,643	47,525	9,305	280,722	36,652	284	33,963
(9)	Taxes Other Than Income	13,833,569	4,334,021	1,300,839	37,006	189,947	3,527,164	283,368	2,470,242	1,570,676	36,283	84,023
(10)	Total	$383,109,832	$109,652,371	$34,066,069	$1,207,224	$5,506,296	$93,773,785	$7,650,164	$76,323,422	$52,236,341	$932,998	$1,761,162
(11)	Net Operating Income	$29,549,979	$11,555,010	$2,343,889	$47,887	$1,478,879	$5,797,028	$498,008	$5,224,746	$2,192,445	$47,439	$364,646
(12)	Original Cost Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(13)	Rate Of Return On Original Cost Rate Base	2.90%	3.49%	2.34%	1.87%	13.28%	2.15%	2.32%	3.08%	2.13%	2.12%	5.92%
(14)	Earnings Index	100%	120%	81%	64%	457%	74%	80%	106%	73%	73%	204%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA A REVENUES AT EQUALIZED RATES OF RETURN

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT KAH-3
SCHEDULE 2

Line No.	Description	(1) Total	(2) Residential (A)	(3) Electric Home Heating (EH)	(4) Water Heating (B)	(5) Small General Service (SGS)	(6) Demand General Service	(7) Off-Season Service (OSS)	(8) Large Power Service (LP)	(9) Transmission Power (HLF)	(10) Outdoor Lighting (OL)	(11) Street Lighting (SL)
	Operating Revenues											
(1)	Revenues From Gas Sales	$324,589,614	$88,533,070	$30,102,278	$1,055,052	$4,095,299	$81,115,655	$6,361,652	$65,439,728	$45,166,344	$974,579	$1,745,958
(2)	Revenues from Riders	$42,334,996	$15,508,081	$3,376,955	$154,480	$477,634	$9,821,563	$1,064,940	$7,009,273	$4,922,070	$0	$0
(3)	Miscellaneous Revenues	$45,735,200	$13,863,089	$3,889,003	$90,717	$439,349	$12,119,392	$936,627	$8,591,751	$5,706,836	$35,649	$62,787
(4)	Total	$412,659,809	$117,904,239	$37,368,236	$1,300,249	$5,012,282	$103,056,609	$8,363,219	$81,040,752	$55,795,250	$1,010,228	$1,808,745
	Operating Expenses											
(5)	Operation and Maintenance	$301,768,572	$82,044,609	$26,879,651	$1,039,556	$3,794,286	$73,574,749	$6,046,248	$62,287,574	$44,173,491	$722,769	$1,205,638
(6)	Depreciation and Amortization	64,494,881	20,997,055	5,977,321	140,878	699,894	17,274,070	1,343,162	10,839,638	6,713,753	180,615	328,495
(7)	Federal Income Taxes	1,687,545	545,186	165,931	4,248	17,374	449,516	35,895	285,223	172,674	2,440	9,057
(8)	State Income Taxes	1,325,265	409,117	125,979	3,607	14,947	343,815	27,584	237,589	152,799	2,816	7,012
(9)	Taxes Other Than Income	13,833,569	4,287,702	1,314,242	37,638	162,327	3,575,988	286,383	2,463,169	1,589,834	36,701	79,585
(10)	Total	$383,109,831	$108,283,669	$34,463,123	$1,225,926	$4,688,828	$95,218,138	$7,739,271	$76,113,193	$52,802,552	$945,342	$1,629,788
(11)	Net Operating Income	$29,549,978	$9,620,570	$2,905,113	$74,322	$323,454	$7,838,471	$623,947	$4,927,559	$2,992,698	$64,886	$178,957
(12)	Original Cost Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(13)	Rate Of Return On Original Cost Rate Base	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
(14)	Earnings Index	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA B REVENUES AT EQUALIZED RATES OF RETURN

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT KAH-3
SCHEDULE 3

Line No.	Description	(1) Total	(2) Residential (A)	(3) Electric Home Heating (EH)	(4) Water Heating (B)	(5) Small General Service (SGS)	(6) Demand General Service	(7) Off-Season Service (OSS)	(8) Large Power Service (LP)	(9) Transmission Power (HLF)	(10) Outdoor Lighting (OL)	(11) Street Lighting (SL)
	Operating Revenues											
(1)	Revenues From Gas Sales	$457,253,539	$133,088,165	$42,249,590	$1,396,339	$5,502,771	$115,096,164	$9,343,763	$87,762,735	$59,428,917	$1,101,822	$2,283,272
(2)	Revenues from Riders	$80,872	$31,702	$7,146	$318	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(3)	Miscellaneous Revenues	$45,735,200	$13,953,833	$3,905,505	$87,985	$434,670	$12,164,062	$939,054	$8,523,832	$5,626,511	$33,020	$66,729
(4)	Total	$503,069,610	$147,073,700	$46,162,241	$1,484,643	$5,938,324	$127,278,407	$10,284,784	$96,297,751	$65,064,918	$1,134,842	$2,350,001
	Operating Expenses											
(5)	Operation and Maintenance	$302,211,580	$81,927,687	$26,830,299	$998,328	$3,736,526	$73,928,156	$6,067,973	$62,539,537	$44,329,965	$650,964	$1,202,144
(6)	Depreciation and Amortization	64,494,881	20,997,055	5,977,321	140,878	699,894	17,274,070	1,343,162	10,839,638	6,713,753	180,615	328,495
(7)	Federal Income Taxes	30,056,402	9,781,220	2,954,925	75,600	327,899	7,974,681	634,903	5,015,827	3,045,753	64,733	180,861
(8)	State Income Taxes	8,972,442	2,898,460	877,664	22,785	98,570	2,372,628	189,070	1,513,017	927,420	19,512	53,316
(9)	Taxes Other Than Income	15,099,306	4,696,074	1,437,358	40,220	175,292	3,915,093	313,285	2,676,767	1,719,610	38,446	87,163
(10)	Total	$420,834,611	$120,300,495	$38,077,567	$1,277,810	$5,038,181	$105,464,629	$8,548,393	$82,584,786	$56,736,502	$954,269	$1,851,979
(11)	Net Operating Income	$82,234,999	$26,773,204	$8,084,674	$206,833	$900,144	$21,813,778	$1,736,391	$13,712,965	$8,328,416	$180,573	$498,022
(12)	Original Cost Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(13)	Rate Of Return On *Original Cost Rate Base*	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%	8.08%
(14)	Earnings Index	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
STATEMENT OF OPERATING INCOME BASED UPON PROFORMA B REVENUES AT PROPOSED RATES OF RETURN

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT KAH-3
SCHEDULE 4

Line No.	Description	(1) Total	(2) Residential (A)	(3) Electric Home Heating (EH)	(4) Water Heating (B)	(5) Small General Service (SGS)	(6) Demand General Service	(7) Off-Season Service (OSS)	(8) Large Power Service (LP)	(9) Transmission Power (HLF)	(10) Outdoor Lighting (OL)	(11) Street Lighting (SL)
	Operating Revenues											
(1)	Revenues From Gas Sales	$457,253,540	$135,498,169	$41,550,421	$1,363,406	$6,942,213	$112,552,893	$9,186,864	$88,132,951	$58,431,932	$1,080,086	$2,514,605
(2)	Revenues from Riders	$80,872	$31,702	$7,146	$318	$884	$18,181	$1,967	$11,184	$9,489	$0	$0
(3)	Miscellaneous Revenues	$45,735,200	$14,021,184	$3,885,965	$87,065	$474,897	$12,092,986	$934,669	$8,534,178	$5,598,649	$32,412	$73,194
(4)	Total	$503,069,611	$149,551,055	$45,443,532	$1,450,789	$7,417,995	$124,664,059	$10,123,500	$96,678,313	$64,040,070	$1,112,499	$2,587,798
	Operating Expenses											
(5)	Operation and Maintenance	$302,211,580	$81,927,687	$26,830,299	$998,328	$3,736,526	$73,928,156	$6,067,973	$62,539,537	$44,329,965	$650,964	$1,202,144
(6)	Depreciation and Amortization	64,494,881	20,997,055	5,977,321	140,878	699,894	17,274,070	1,343,162	10,839,638	6,713,753	180,615	328,495
(7)	Federal Income Taxes	30,056,402	10,562,454	2,728,280	64,925	794,513	7,150,246	584,042	5,135,837	2,722,568	57,687	255,851
(8)	State Income Taxes	8,972,442	3,109,035	816,574	19,907	224,342	2,150,409	175,361	1,545,365	840,308	17,613	73,529
(9)	Taxes Other Than Income	15,099,306	4,730,757	1,427,296	39,746	196,007	3,878,492	311,027	2,682,095	1,705,262	38,133	90,492
(10)	Total	$420,834,612	$121,326,988	$37,779,770	$1,263,783	$5,651,282	$104,381,374	$8,481,565	$82,742,472	$56,311,856	$945,011	$1,950,510
(11)	Net Operating Income	$82,235,000	$28,224,068	$7,663,762	$187,007	$1,766,712	$20,282,685	$1,641,935	$13,935,841	$7,728,214	$167,487	$637,288
(12)	Original Cost Rate Base	$1,017,759,890	$331,351,537	$100,057,843	$2,559,813	$11,140,391	$269,972,497	$21,489,986	$169,714,918	$103,074,452	$2,234,810	$6,163,643
(13)	Rate Of Return On Original Cost Rate Base	8.08%	8.52%	7.66%	7.31%	15.86%	7.51%	7.64%	8.21%	7.50%	7.49%	10.34%
(14)	Earnings Index	100%	105%	95%	90%	196%	93%	95%	102%	93%	93%	128%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
COMPARISON OF PROFORMA OPERATING REVENUES AND DOLLAR SUBSIDY LEVELS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT KAH-4
SCHEDULE 1

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		PROFORMA REVENUES - PRESENT RATES			PROFORMA REVENUES - PROPOSED RATES				
Line	Rate Schedule	Revenues At Present Rates	Revenues Required For Equalized Returns	Present Subsidy	Revenues Required For Equalized Returns	Revenues At Proposed Rates	Proposed Subsidy	Subsidy Reduction Amount	Subsidy Reduction Percentage
(1)	Residential (A)	$121,207,380	$117,904,239	$3,303,141	$147,073,700	$149,551,055	$2,477,356	$825,785	25.00%
(2)	Electric Home Heating (EH)	$36,409,958	$37,368,236	($958,278)	$46,162,241	$45,443,532	($718,709)	($239,570)	25.00%
(3)	Water Heating (B)	$1,255,111	$1,300,249	($45,138)	$1,484,643	$1,450,789	($33,853)	($11,284)	25.00%
(4)	Small General Service (SGS)	$6,985,175	$5,012,282	$1,972,894	$5,938,324	$7,417,995	$1,479,670	$493,223	25.00%
(5)	Demand General Service (DGS)	$99,570,813	$103,056,609	($3,485,796)	$127,278,407	$124,664,059	($2,614,347)	($871,449)	25.00%
(6)	Off-Season Service (OSS)	$8,148,173	$8,363,219	($215,046)	$10,284,784	$10,123,500	($161,284)	($53,761)	25.00%
(7)	Large Power Service (LP)	$81,548,168	$81,040,752	$507,416	$96,297,751	$96,678,313	$380,562	$126,854	25.00%
(8)	Transmission Power (HLF)	$54,428,787	$55,795,250	($1,366,464)	$65,064,918	$64,040,070	($1,024,848)	($341,616)	25.00%
(9)	Outdoor Lighting (OL)	$980,437	$1,010,228	($29,791)	$1,134,842	$1,112,499	($22,343)	($7,448)	25.00%
(10)	Street Lighting (SL)	$2,125,808	$1,808,745	$317,063	$2,350,001	$2,587,798	$237,797	$79,266	25.00%
(11)	Total	$412,659,810	$412,659,809	$1	$503,069,610	$503,069,611	$1	$0	

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
COMPARISON OF EARNINGS INDICES AT PRESENT AND PROPOSED RATES

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT KAH-4
SCHEDULE 2
WITNESS: HEID

		PRESENT RATES		PROPOSED RATES	
Line	Rate Schedule (A)	Present Rates of Return (B)	Present Earnings Index (C)	Proposed Rates of Return (D)	Proposed Earnings Index (E)
(1)	Residential (A)	3.49%	120%	8.52%	105%
(2)	Electric Home Heating (EH)	2.34%	81%	7.66%	95%
(3)	Water Heating (B)	1.87%	0.64	7.31%	0.90
(4)	Small General Service (SGS)	13.27%	457%	15.86%	196%
(5)	Demand General Service (DGS)	2.15%	74%	7.51%	93%
(6)	Off-Season Service (OSS)	2.32%	80%	7.64%	95%
(7)	Large Power Service (LP)	3.08%	106%	8.21%	102%
(8)	Transmission Power (HLF)	2.13%	73%	7.50%	93%
(9)	Outdoor Lighting (OL)	2.12%	73%	7.49%	93%
(10)	Street Lighting (SL)	5.92%	204%	10.34%	128%
(11)	Total	2.90%	100%	8.08%	100%

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
COMPARISON OF REVENUES AT PRESENT AND PROPOSED RATES

DATA: 12 MONTHS ENDED MARCH 31, 2006 **PETITIONER'S EXHIBIT KAH-5**
TYPE OF FILING: CASE-IN-CHIEF

	(1)	(2)	(3)	(4)	(5)
		PROFORMA GAS SALES REVENUES			
Line No.	Rate Schedule No.	Revenues At Present Rates	Revenues At Proposed Rates	Increase or (Decrease) Amount	Increase or (Decrease) Percentage
(1)	Residential (A)	$107,380,875	$135,529,871	$28,148,996	26.21%
(2)	Electric Home Heating (EH)	$32,531,026	$41,557,567	$9,026,541	27.75%
(3)	Water Heating (B)	$1,164,913	$1,363,724	$198,811	17.07%
(4)	Small General Service (SGS)	$6,459,882	$6,943,097	$483,215	7.48%
(5)	Demand General Service (DGS)	$87,590,198	$112,571,073	$24,980,875	28.52%
(6)	Off-Season Service (OSS)	$7,229,002	$9,188,831	$1,959,829	27.11%
(7)	Large Power Service (LP)	$72,867,378	$88,144,135	$15,276,758	20.97%
(8)	Transmission Power (HLF)	$48,725,488	$58,441,421	$9,715,933	19.94%
(9)	Outdoor Lighting (OL)	$938,716	$1,080,086	$141,370	15.06%
(10)	Street Lighting (SL)	$2,037,132	$2,514,605	$477,473	23.44%
(11)	Total Revenues from Gas Sales	$366,924,610	$457,334,412	$90,409,801	24.64%
(12)	Miscellaneous Revenues	$45,735,200	$45,735,200	$0	
(13)	Total Operating Revenues	$412,659,810	$503,069,611	$90,409,801	21.91%

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – ELECTRIC)

IURC CAUSE NO. 43111

DIRECT TESTIMONY

OF

WILLIAM R. HOPKINS
EXECUTIVE ADVISOR, CONCENTRIC ENERGY ADVISORS

ON

RATE DESIGN

SPONSORING PETITIONER'S EXHIBITS WRH-1 THROUGH WRH-5

Direct Testimony of William R. Hopkins

Q. Please state your name and business address.

A. My name is William R. Hopkins. I am an Executive Advisor with Concentric Energy Advisors, 313 Boston Post Road, Marlborough, MA, a management consulting firm focusing upon the energy utility industry.

Q. What is the nature of your business practice and your qualifications?

A. I provide consulting services as an expert to utilities, regulatory bodies and large energy users on issues involving ratemaking and regulatory practices of the electric, gas, and water utility industries, both in North America and internationally. I have been professionally involved in such matters for over thirty five years. During this time I have provided utility rate and regulatory assistance to utilities throughout the U.S., Canada, and internationally for utilities, governmental and regulatory bodies in the Caribbean, Central America, South America, China and Africa.

Prior to joining the Concentric Energy Advisors as an Executive Advisor in 2003, I was employed in the utility industry as a consultant by several other firms; I have recently been a Director of Navigant Consulting, Inc., a Vice President of Reed Consulting, and employed for over thirty years by Stone Webster Management Consultants as a Vice President and the leader of the electric utility and rate and regulatory practices of that firm.

Q. Have you previously testified as an expert on utility ratemaking matters?

A. Yes. I have testified previously on numerous occasions before state and other jurisdictional bodies regarding utility rate design, costs of service studies and regulatory matters. I have presented testimony as an expert witness on utility ratemaking in the states of Arizona, Alabama, Connecticut, Delaware, Florida, Georgia, Indiana, Illinois, Maine, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Vermont. I have filed ratemaking testimony at the FERC/FPC and have testified in Canada before the provincial utility regulatory bodies in Quebec, Ontario, Manitoba and Nova Scotia.

I have previously testified before the Indiana Utility Regulatory Commission on a number of occasions regarding utility ratemaking on behalf of

Northern Indiana Public Service Company and Southern Indiana Electric and Gas Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or "Company"). I was the Company's rate design witness in Vectren South's last electric rate case (IURC Cause No. 39871).

Q. What is the purpose of your testimony in this proceeding?

A. My purpose is to describe and present the proposed changes to the Company's retail electric rates to implement the needed increase in the required revenues as defined in the Company's request in this Cause. My testimony will present the proposed changes to the terms of the existing rates, changes in rate structures, pricing, rate revenues, and the customer billing impacts of the proposals.

Q. Are you generally familiar with the Company's business?

A. Yes. For over twenty years I have worked with Vectren South on a variety of management and regulatory matters concerning its electric and gas utility business. This work has involved both its state and Federal jurisdictional utility businesses, and has concerned both rate case proceedings and other regulatory proceedings such as cogeneration, DSM programs, Least Cost Planning, and specific customer issues.

Q. Please outline the key elements of your testimony.

A. My testimony is organized according to the following topics:

- Overall Rate Design Objectives
- Rate Schedule Structural Changes
- Rate Rider and Appendices Changes
- Rate Revenue Targets
- Proposed Rate Pricing
- Rate Revenue Calculations
- Customer Billing Impacts
- Proposed Rate Tariff

Q. Are you sponsoring any Petitioner's Exhibits in this proceeding?

A. Yes, in addition to this direct testimony Petitioner's Exhibit No. WRH-1 I am sponsoring several additional Exhibits. Petitioner's Exhibit No. WRH-2 which summarizes the overall rate revenues at present and proposed rates for the test period, and details the amounts and percentages of rate revenue changes proposed. Petitioner's Exhibit No. WRH-3 which details how the proposed rate increases correspond to the proposed rate revenue targets adjusted to reflect the reduction of interclass subsidies as determined in the class cost of service study (COS) presented by Petitioner's Witness Kerry A. Heid. Petitioner's Exhibit No. WRH-4, with schedules for each of the proposed rates, that details the determination of the proposed base rate revenues by rate from the present rates and test period rate usages. Petitioner's Exhibit No. WRH-5 which presents comparisons of typical customer monthly bills at present and proposed rates.

Rate Design Objectives

Q. Please describe the overall rate design objectives you have followed in the development of the proposed rates.

A. The rate design objectives I have followed could be basically best be described as the "classic" objectives detailed by Professor J. C. Bonbright in his well recognized book "Principles of Public Utility Rates" (Columbia Univ. Press). The eight criteria of a sound rate structure he details are:

- Rates should have... *practical attributes of simplicity, understandability, public acceptance and feasibility of application.*

In designing the proposed rates in this filing I have continued with the present rate forms, adding simplicity and enhanced practicality as deemed helpful.

- The rates should provide...*freedom from controversies as to proper interpretation.*

I have designed the rate proposals to help eliminate details that may be confusing or misunderstood, such as in the changes proposed for the demand ratchets.

- The rates should provide...*effectiveness in yielding total revenue requirements under the fair-return standard.*

The proposed rates are designed to recover the rate revenue requirements filed by the Company, which is founded upon achievement of a fair return.

- Provide...*revenue stability from year to year.*

The proposed rates are based upon the existing which have demonstrated the capability of providing for reasonable revenue stability.

- Rates should have...*stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.*

I believe the continuation of the present rate classes and rate formats, as proposed, with minor simplifying changes, helps to meet this goal.

- The rates should represent... *fairness of the specific rates in the apportionment of total costs of service among the different consumers.*

As will be detailed, the proposed rate class revenues are based on the fully allocated class cost study results, with movement in the relationships of revenue to cost of service to improve the fairness.

- The rates should provide...*avoidance of undue discrimination in rate relationships.*

The proposed rates are based on the class cost results of the fully allocated cost of service study, and will apply uniformly to the customers within each class, with pricing based on the costs of service.

- The rates should provide...*efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:*
  - *(a) in the control of the total amounts of service supplied by the company,*
  - (b) *in the control of the relative uses of alternative types of service.*

The proposed rates are based on the costs of service by each rate class, and have the pricing established within the metering capabilities to fairly charge for the services rendered in relationship to the Company's cost of providing the service.

Rate Schedule Structural Changes

Q Please describe the structure of the proposed rate schedules and any changes from the present.

A. The Company's Tariff for Electric Service ("Tariff") contains a number of pricing schedules: its Rate Schedules, Rate Riders, Appendices (adjustment clauses), Purchase Rates (for cogeneration/small power production), as well as General Terms and Conditions and Affiliate and Cost Allocation Guidelines. Presently there are 17 Rate Schedules, 5 Riders and 6 Appendices (adjustment clauses) and a Purchase Rate.

Focusing on the Rate Schedules which contain the Company's basic pricing for its services, the following describes the rate structure change proposals by schedule:

All Rate Schedules

The changes to the terms and language of rate schedules and other tariff changes will be discussed in detail by Petitioner's Witness Jerrold L. Ulrey. I will comment on a few in the following as well.

On all of the proposed rate schedules there are sections added to describe the rate Appendices and Riders that are applicable to service under each Rate Schedule. This will help customers considering service to better identify the other provisions applicable to the service and pricing contained elsewhere in the Tariff.

Where applied the designation of "Service Charge" on all schedules is replaced with the title "Customer Facilities Charge" to help customers understand that it is a charge not related to usage. A "Customer Facilities Charge" is proposed for all rates except Rate HLF and the Lighting Rates (OL and SL).

Rate A — Residential Service

Only several minor format changes are proposed for this schedule. The proposed rate has the same 2 block–step kWh pricing structure as the present.

Rate EH— Home Heating Service

The proposed rate introduces an additional kWh block-step into the pricing of this schedule. The new step is for the first 250 kWh/mo. of usage. The second step is thereby changed to be the next 750kWh, and the present step for usage over 1000 kWh per month remains unchanged. This proposed new step will allow the Company to more closely align the charges for service in the customer's initial usage with that on Rate A, as such use does not realistically represent heating use. The proposed rate makes a minor change to the "Applicability" clause to clarify that electric equipment exclusively must be used for space heating under this rate.

Rate B---Water Heating Service

The proposed rate continues the present rate form. The Applicability clause is modified to help clarify that the rate is not available to any new customers.

Rate GS---General Service

The rate proposal will divide this rate class into two separate schedules; one for the smaller sized customer not presently required to be demand metered, and the other for customers presently demand metered (10kW or more). This separation will provide greater clarity and understandability to the present schedule, and allow for pricing to be more in line with costs of service. The class cost study prepared by Mr. Heid and the load data inherent in the study indicate that the small sized customers (non-demand metered) on the present schedule have a significantly different usage pattern than the larger. The separation of the present schedule into two will help to address this difference in costs with different pricing.

The proposed rate form for the smaller sized customers (under 10kW), Small General Service, Rate SGS, will be continued as a kWh usage block-step type, with the same size steps as applicable under the present rate (note: the present rate kWh step for use over 13,000 kWh/mo. is eliminated, as it was basically applicable to the larger customers under the GS Rate Schedule).

The proposed rate form for the larger, demand metered customers (10kW or more), Demand General Service, Rate DGS, will be a modification of the present rate form that applies. The proposed rate form will have a demand charge and three usage price steps similar to the present, with the exception that the hours-use-of-demand provisions in the present second and third usage steps (180 hrs and 120 hrs.) are proposed to be combined into one, such that 300 hours use of the demand is added to the proposed second use step. This change will help to both simplify the rate and provide for uniform pricing with the smaller size SGS rate.

The proposed Rate DGS has a change to the "Determination of Billing Demand" provision to help put this provision in line with the similar provisions in Rates LP and HLF for demand metered customers. The proposed provision will be basically similar to that presently in effect for Rate LP.

Rate OSS --- Off Season Service

The proposed rate basically continues the present rate form, but with the addition of a "Customer Facilities Charge" to make it more similar to the Company's other rates.

The proposed rate changes the present "Determination of Billing Demand" clause to specify that the billing demand will be equal to the highest monthly demand metered in the preceding months of June, July, August or September. This change better coordinates the determination of the "peak" season demand with the peak months used in the cost study, and eliminates the averaging of two months' demands (July and August) as in the present rate.

Rate LP --- Large Power

The proposed rate continues the present rate form. As in the other proposed rates, a "Customer Facilities Charge" is introduced.

Three changes to present Rate LP conditions are proposed. The first is to eliminate from the Determination of Billing Demand clause the special provision allowing prior Rate "PP-2" customer take service on Rate LP with billing demands of less than 300kVa. This was a transitional provision allowed for in a rate case several cases ago, to continue existing contracts when Rate PP-2 was being eliminated. The contracts with these customers have expired long ago, and most all of the original contract customers have now changed usages significantly, changed names and/or disappeared. The second change is to the Minimum Bill provision of the rate. The proposed Minimum Bill will include both the Customer Facilities Charge and a minimum Demand Charge based on 60% of the highest Billing Demand during the preceding 12 months. This revision to the Minimum Bill will help the Company avoid a large revenue loss where a Rate LP Contract customer may drop its demands to an extremely low level. The third change is to require customers on Rate LP to have a Contract with an initial term of 3 years, or a longer period if unusual expenditures by the Company are required to provide service, versus the present one year or longer term. This change will apply to new customers and will help the Company better protect its recovery of investments made to serve these larger accounts.

Rate HLF --- Transmission Power Service

The proposed rate continues the present rate form, which requires the customer to take power at transmission voltages and at a high load factor (>80%).

Rate BAMP --- Backup, Auxiliary and Maintenance Power Services

The proposed rate is similar to the existing with the exception that the provision for Maintenance Power is proposed to be simplified. As opposed to having a specially calculated price per kVa for such power, the proposed pricing provision for Maintenance Power Capacity Charge will state: "The Applicable Demand Charges per kVa currently in effect for Rate LP, exclusive of any minimums." Further, the Maintenance Energy Charge shall be the applicable Rate LP Energy charge plus all applicable Appendices.

The Customer Service Charge is proposed to continue at its present amount of $100.00/mo., as will the other stated pricing in the rate.

During the test year there was no service provided under this rate.

Street Lighting Rates (SL-1—SL8)

The present street lighting rates are proposed to be continued in the existing form, with the exception that we propose to eliminate any fixtures on "closed" rates that currently have no use. Further, Rates SL-4 and SL-6 are eliminated due to no remaining customers. It is proposed that service on these rates be subject to the same rate Appendices ("Adjustment clauses") as applicable to the other rate schedules. These adjustments would be applied based upon the estimated monthly kWh usages for each type of fixture in the schedules.

Rate OL --- Outdoor Lighting Service

The existing rate form is proposed to be continued. As mentioned for the Street Lighting it is proposed that service on this rate be subject to the same rate Appendices ("Adjustment clauses") as applicable to the other rate schedules. These adjustments would be applied based upon the estimated monthly kWh usages for each type of fixture in the schedules.

Rate CPS --- Cogeneration and Small Power Production

Under this rate the Company offers to purchase power from qualified (PURPA) power producers. The rate for purchases is updated annually, in filing to the IURC. There are no changes proposed to this schedule.

Rate Riders and Appendices

Q. Please discuss the changes proposed to the company's present Riders.

A. There are presently 5 Riders in the Tariff. These offer modifications to certain of the standard Rate Schedules (LP and HLF) to customers qualifying to take interruptible service (IP and IP-2) and those who qualify for energy efficiency incentives (LP-1 and HLF-1), as well as rider (NM) offering net metering service for customers (residential, schools and municipal corporations) with small (< 10kW) on-site photovoltaic, wind or hydro generators. Under the proposed Tariff the existing Interruptible Riders (IP and IP-2) would be continued for existing customers under contracts, but would be replaced for additional customers by two new riders, Interruptible Contract Rider ("Rider IC") and Interruptible Option Rider ("Rider IO"), offering an expanded level of possible service. The existing energy efficiency rider, Rider LP-1, would be closed to any new customers. The other energy efficiency rider, Rider HLF-1 is proposed to be eliminated as it has no remaining customers. The present Rider NM would be continued as is under the proposed Tariff.

Q. Are any new Riders being proposed?

A. Yes, an Economic Development Rider ("Rider ED") and an Area Development Rider ("Rider AD") are proposed and discussed in detail in the Company's testimony of Petitioner's Witness Ronald B. Keeping. In addition, Mr. Ulrey will describe Company's proposed Direct Load Control Rider ("Rider DLC").

Q. Please describe the proposed new interruptible service Riders in greater detail.

A. The two new proposed interruptible service riders are intended to offer customers with on-site generation and/or significant load control capability a wider choice of options to save money on their billings and the Company a greater capability to utilize the customer's resources to help meet costly peak load conditions on the system.

Proposed Rider IC, the Interruptible Contract Rider, will offer customers with 1000kVa or more of interruptible demand an opportunity to contract with the Company to have this capability made available to assist in meeting the system's peak loads. Subject to the terms specified in the Rider, the customer will receive fixed monthly payments for the ability of the Company to call upon the interruptible demand. The payments are linked to the Company's avoided costs specified in Rate CSP.

Proposed Rider IO, the Interruptible Option Rider, will offer an opportunity for large and smaller sized customers (with 250 kW or more of interruptible load capability) to also offer capacity to the Company on an optional basis. Under this Rider the Customer upon notice by the Company may, at its option, interrupt 250 kW or more of its demand. Subject to the terms of the Rider the Customer will be paid for any such interruption based upon a capacity payment linked to Rate CPS and a energy payment based upon its standard rate's energy charge.

Q. **Are any new Appendices being proposed?**

A. Yes. Mr. Ulrey describes the proposed Appendix J, Generation Cost and Revenue Adjustment. And Petitioner's Witness W. Steven Seelye describes the proposed Appendix I, MISO Cost and Revenue Adjustment.

Q. **Are any Appendices proposed to be eliminated?**

A. Yes. Mr. Ulrey describes the proposed elimination of Appendices E and F, the Qualified Pollution Control Property adjustments, and Appendices B and C – the DSM Lost Revenue Adjustment and the Clean Air Act Amendment Adjustment.

Rate Revenue Targets

Q. **Please describe the development of the proposed rate revenue levels used for design of the proposed rates.**

A. As was noted earlier, one of the key rate design objectives was to obtain a fair apportionment of the costs of service among the rates and customers within each rate. The results of the fully-allocated class cost of service study presented by Mr. Heid were therefore the principle basis for the development of the proposed class rate revenues. Within the class cost study the allocated test period costs are compared to the present rate revenue, the differences in these amounts reveals both the overall deficiencies in rate revenues and the cross-subsidies that exist in the rates.

Based on this Commission's previous rate design directives to the Company, setting a minimum objective of closing the differences in rate subsidies by 25% of the amount, the proposed rate revenues have been designed to reduce the existing "subsidies" by 25% as detailed by Mr. Heid in his testimony and exhibits. Petitioner's Exhibit No. WRH-3 details the "Rate Design Target" revenue needed to achieve this result and compares these to the results of the proposed rates, and demonstrates that the proposed pricing fully achieves the desired result.

Proposed Rate Pricing

Q. Please describe the overall goals of the proposed rate pricing.

A. There are essentially three goals sought in establishing the proposed rate pricing for each rate schedule; first, to obtain the objective rate revenue target, secondly, to improve on the reflection of the costs of service in the prices, and thirdly to moderate the impacts of new prices on customer bills.

As is detailed by rate in Petitioner's Exhibit No. WRH-3, the proposed rate "target" revenues are closely met by the rate pricing proposed in each schedule. To help better align the rate prices with costs of service all of the proposed rates, except HLF and Lighting, will now have a "Customer Facilities Charge" stated to help collect costs that do not vary with usage. Rates with Demand Charges have proportionately higher increases in these charges to better reflect the high level of ongoing fixed costs associated with the system's capabilities to meet customer demands. And energy (kWh) costs are modified accordingly for changes in the fixed cost recovery through the Customer Facilities and Demand charges. The proposed "Customer Facilities Charges" represent approximately 50% of each rate's customer related costs as determined in the class cost of service study. From the perspective of customer billing impacts, which will be detailed in Petitioner's Exhibit No. WRH-5, it was a goal of the pricing to attempt to limit the maximum bill impact to within twice the overall rate increase sought for each rate.

Q. Please describe the proposed pricing for Rate A-Residential Service.

A. As previously noted the proposed rate follows the form of the existing. The proposed "Customer Facilities Charge" ($7.50/mo.) raises the present rate "Service Charge" ($4.35/mo.) to equal approximately 56% of the customer-related costs for the rate class identified in the class cost of service study. Pricing in the two kWh use steps was increased disproportionately, with a higher amount to the first usage step, to reflect the fixed cost nature of the needed increase and the roll-in of riders.

Q. Please describe the proposed pricing for Rate EH-Home Heating Service.

A. The proposed format of Rate EH includes the addition of a new rate use step for the first 250 kWh/ mo. of use to help bring the initial billing under this rate into closer alignment with that under Rate A for small amounts of use, not related to the home heating.

As with Rate A the new Customer Facilities Charge, replacing the existing Service Charge increases the monthly amount to bring this charge into closer alignment with the costs of service. The proposed Customer Facilities Charge will collect approximately 55% of the customer costs determined in the class cost of service study prepared by Mr. Heid. The pricing changes to the three proposed usage steps are proposed with a proportionately greater increase to the new initial steps, to help draw the billings under this rate into closer alignment with Rate A billing for similar use below 1000kWh per month, to help focus this rate's pricing discount on use reflecting the home heating feature of its applicability.

Q. Please describe the proposed pricing for Rate B-Water Heating Service.

A. The pricing for this rate continues the present rate form, but increases the initial Customer Facilities Charge to better reflect the associated costs. The proposed Customer Facilities Charge increases the present rate's Service Charge from $2.00/mo. to $4.60/mo. The proposed charge equals approximately 56% of the monthly customer related costs for the class determined in the cost study. The kWh charge was adjusted upward to collect the balance of the overall required rate revenues.

Q. Please describe the proposed pricing for Rate SGS-Small General Service.

A. The proposed rate Customer Facilities Charge of $8.50/mo. will equal approximately 54% of the related customer costs. The proposed rate usage pricing steps are reduced to only three to simplify the rate in accord with its smaller sized customer applicability. The pricing of the usage steps was increased disproportionately, with the initial steps having larger per kWh increases, to reflect the fixed cost nature of the needed increase.

Q. Please describe the proposed pricing for Rate DGS-Demand General Service.

A. Similar to the other rates, the proposed Customer Facilities Charge represents an increase in the present rate Service Charge to better reflect the costs of service. The proposed Customer Facilities Charge of $12.70/mo. represents approximately 50% of the related customer costs from the cost study.

The proposed rate increases the present rate's Demand Charge from $1.30/kW to $4.90/kW to better reflect the underlying costs of service, and to help lead the rate's billing away from the present kWh block-extender kWh step form, towards a more straight forward demand-commodity format. The proposed combination of the present two block-extender use steps into one is also leading in that direction.

The kWh pricing in the proposed rate steps has been developed to both moderate the billing impact of the rate step combination and to reflect better recovery of fixed costs in the initial use steps.

The proposed rate pricing has been calculated based upon the proposed change in the rate's billing demand calculation. The proposed billing demand calculation will have as a minimum the highest demand occurring in the preceding 12 months, similar to that of present Rate LP, and common provisions in rates of other utilities for large customer general service rates. The change of this provision slightly increases the kW's billed and produces a small shift of energy billed from the last rate step to the next to last.

The kWh rate pricing was increased proportionately more for the initial rate steps, as in the other rates, to better reflect the fixed cost nature of the needed increase in the pricing.

Q. Please describe the proposed pricing for Rate OSS-Off-Season Service.

A. The proposed Rate OSS follows the same format as the existing with the exception that a "Customer Facilities Charge" of $12.00/mo. is added. This charge will collect approximately 47% of the customer related costs for this class identified in the cost of service study. Recognizing that the needed rate increase is to recover fixed costs, the rate's present Demand Charge is raised by approximately twice the increase applied to the Energy Charge.

The proposed Demand Charge is calculated taking into account the proposed change in the rate's "Determination of Billing Demand" provision to extend the determination period from July and August only to include June and September as well. Based upon analysis of the customer accounts for the test year, this proposal increases the billing demand amounts by 15.3%.

Q. Please describe the proposed pricing for Rate LP-Large Power Service

A. The proposed Rate LP continues the same form as the present rate, with the exception that a "Customer Facilities Charge" is added. As proposed the "Customer Facilities Charge" of $125.00/mo. will recover approximately 42% of the customer-related costs identified in the class cost study. Recognizing that the needed rate increase is to recover fixed costs, the rate's present Demand Charge is raised by approximately twice the increase applied to the Energy Charge. The proposed Demand Charge is $9.00/kVa a 23% increase over the present $7.30/kVa, and the proposed Energy Charge (including Riders/Adjustments) is approximately 14% higher than the present.

Based upon review of the costs of service in the cost study, the existing rate "Transmission Voltage Discount" of $1.75/kVa is not changed.

Q. Please describe the proposed pricing for Rate HLF- Transmission Power Service

A. The proposed Rate HLF follows the present rate form. The proposed pricing increases the rate's "Capacity Charge" which also includes 600 kWh per kVa of demand, to recover the majority of the needed revenue increase. The Energy Charge (including Riders/Adjustments), for use above 600 kWh/kVa (above 82% load factor) is increased only modestly, approximately 3%.

Q. Please describe the proposed pricing for Rates Street Lighting Services.

A. The proposed pricing for the Street Lighting rates is developed by applying at overall increase percentage needed to all existing prices in the schedules, with the exception that pricing for any fixtures on "closed" schedule that now have no use are eliminated.

Q. Please describe the proposed pricing for Rate OL-Outdoor Lighting Service (Dusk to Dawn).

A. The proposed pricing for the Outdoor Lighting Rate OL is developed by applying at overall increase percentage needed to all existing prices in the schedules.

Rate Revenue Calculations

Q. Please describe the calculations made to determine the revenues at proposed rates.

A. Petitioner's Exhibit No. WRH-4, details on schedules for each rate the calculation of present and proposed rate revenues by rate component. The proposed rate revenues have been calculated based upon the detail of consumption used in each rate pricing step of the proposed rates. This detail was derived by the Company from the customer billing data for the test period and adjusted for normalizing entries. The proof of the consumption details for each rate is made by the recalculation of present rate revenues as used in the test period.

As the proposed rates will reset the base amount of the fuel costs to be included in base rates and several other Rider costs to the cost level for the test year, the fuel revenues and Riders at present and proposed rates are shown, so as to clearly define the base rate increase amount exclusive of the change in the fuel clause base and Riders. Riders that will be rolled-in to base rates are shown, as is the revenue credits from the new GCRA Rider, described by Mr. Ulrey in his testimony.

Q. Have you prepared an Exhibit detailing the total proposed rate revenues?

A. Yes. Petitioner's Exhibit No. WRH-2 summarizes the total rate revenues at present and proposed rates for the test year, and shows the proposed revenue changes and percentage change for each rate. As shown on Petitioner's Exhibit No. WRH-2 the proposed rates with the new GCRA Rider produce an increase of

$76,727,656 over the present rates and Riders. Petitioner's Exhibit No. WRH-3 compares the proposed rate revenues with the rate increase and subsidy reduction "target" revenues from the class cost study results presented by Mr. Heid. Each of the proposed rates closely match these "target" amounts, and the overall increase is only $1,380, less that the overall "target" amount.

Customer Billing Impacts

Q. Have you prepared typical billing comparisons to detail the impacts on customer bills of the proposed rates?

A. Yes. The Schedules of Petitioner's Exhibit No. WRH-5 details for each rate schedule comparisons of typical customer bills at present and proposed rates. These comparisons include revenues billed under the present and proposed rate Appendices ("Adjustment clauses") and Riders. Comparisons for the Street Lighting ("SL") and Outdoor Lighting ("OL") rates are excluded as the increases to the base prices within these rates was made in a uniform, equal percentage, manner.

Q. Please discuss the impacts that fall outside of your general goal of keeping impacts within a 2x the rate's overall percentage of change.

A. Generally the bill impacts of the proposed rates will be within the objective range. Bill impacts exceeding the 2 times the overall goal occur in a number of instances for very small usage bills, due principally to the increases necessary to implement the Customer Facilities Charge and to have this rate feature more reflective of the costs of service. Such increases are not expected to be the overall billing impact to the vast majority of customers.

Proposed Rate Tariff

Q. Have you prepared a copy of the tariff with the proposed rate changes?

A. A copy of the Tariff with the proposed rate structure and pricing changes I have discussed is presented in the Exhibits of Mr. Ulrey, Petitioner's Exhibit No. JLU-2.

Q. Does this conclude you direct testimony?

A. Yes it does.

VECTREN SOUTH
Electric Division
Summary of Proposed Rates
(test year ended March, 2006)

RATE	Present Revenues	Proposed Revenues	Increase (Decrease)	Change %
A–Residential	$ 107,380,875	$ 131,292,288	$ 23,911,413	22.27%
EH–Home Heating	$ 32,531,026	$ 40,546,609	$ 8,015,583	24.64%
B– Water Heating	$ 1,164,913	$ 1,344,393	$ 179,480	15.41%
SGS--Small General	$ 6,459,882	$ 6,836,135	$ 376,253	5.82%
DGS--General Demand	$ 87,590,198	$ 108,744,941	$ 21,154,743	24.15%
OSS --Off-Season	$ 7,229,002	$ 8,906,462	$ 1,677,460	23.20%
LP -- Large Power	$ 72,867,378	$ 85,620,667	$ 12,753,289	17.50%
HLF -- High Load Factor	$ 48,725,488	$ 56,766,079	$ 8,040,591	16.50%
SL-- Street Lighting	$ 2,037,132	$ 2,514,605	$ 477,473	23.44%
OL--Outdoor Lighting	$ 938,716	$ 1,080,086	$ 141,370	15.06%
TOTALS	$ 366,924,610	$ 443,652,266	$ 76,727,656	20.91%

VECTREN SOUTH
Electric Division
Summary of Proposed Rate Increase Targets
(test year ended March, 2006)

RATE	COS based 25% Subsidy Reduction	New GCRA Rider	Net Increase Target	Proposed Rate Increases	Difference from Target
A--Residential	$ 28,148,996	$ (4,235,906)	$ 23,913,090	$ 23,911,413	$ (1,677)
EH--Home Heating	$ 9,026,541	$ (1,011,583)	$ 8,014,958	$ 8,015,583	$ 625
B-- Water Heating	$ 198,811	$ (19,345)	$ 179,466	$ 179,480	$ 14
SGS--Small General	$ 483,215	$ (106,984)	$ 376,231	$ 376,253	$ 22
DGS--General Demand	$ 24,980,875	$ (3,826,934)	$ 21,153,941	$ 21,154,743	$ 802
OSS --Off-Season	$ 1,959,829	$ (281,564)	$ 1,678,265	$ 1,677,460	$ (805)
LP -- Large Power	$ 15,276,758	$ (2,523,198)	$ 12,753,560	$ 12,753,289	$ (271)
HLF -- High Load Factor	$ 9,715,933	$ (1,675,251)	$ 8,040,682	$ 8,040,591	$ (91)
SL-- Street Lighting	$ 141,370	0	$ 141,370	$ 141,370	$ 0
OL--Outdoor Lighting	$ 477,473	0	$ 477,473	$ 477,473	$ -
TOTALS	$ 90,409,801	$ (13,680,765)	$ 76,729,036	$ 76,727,656	$ (1,380)

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "A" Residential Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
RATE A					
Number of Bills	1,129,766	$4.350	$4,914,482	$ 7.50	$ 8,473,245
Energy Charge					
First 250 kWh	265,672,210	$0.08235	$21,878,106	$ 0.14001	$ 37,196,766
Over 250 kWh	816,209,152	$0.06881	$56,163,352	$ 0.11001	$ 89,791,169
Total Calculated Base	1,081,881,362 kWh		$82,955,940		$ 135,461,180
Adjustment Factor			1.0002607		1.0002607
Adjusted Total Base			$82,977,565		$ 135,496,492
Riders:					
Fuel Adjustment		$0.008222	$8,895,229	$ -	$0
CAAA		$0.000029	$31,702	$ 0.000029	$31,702
DSM		$0.000177	$192,011	$ -	$0
QPCC-CC		$0.005186	$5,610,432	$ -	$0
-OE		$0.008942	$9,673,936	$ -	$0
GCRA		$0.000	$0	$ (0.003915)	($4,235,906)
MCRA		$0.000	$0	$ -	$0
TOTAL RATE(incl Riders)			$107,380,875		$ 131,292,288
PROPOSED INCREASE/(DECREASE)					$ 23,911,413
% INCREASE/(DECREASE)					22.27%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "EH" Electric Home Heating Service

Rate	Use in Block	Present Rate	Present Revenues		Proposed Rate	Proposed Revenues
RATE EH						
Number of Bills	320,952	$5.300	$1,701,046	$	7.750	2487378
Energy Charge						
First 250 kWh	78,202,880	$0.06328	$4,948,678	$	0.12730	$ 9,955,227
Next 750 kWh	184,207,100	$0.06328	$11,656,625	$	0.09697	$ 17,862,562
Over 1000 kWh	188,276,066	$0.03810	$7,173,318	$	0.06000	$ 11,296,564
Total Calculated Base	450,686,046 kWh		$25,479,667			$ 41,601,731
Adjustment Factor			0.9988			0.9988
Adjusted Total Base			$25,448,624			41,551,046
Riders						
Fuel Adjustment		$0.008222	$3,705,448	$	-	$ -
CAAA		$0.000016	$7,146	$	0.000016	$ 7,146
DSM		$0.000069	$30,965	$	-	$ -
QPCC-CC		$0.002951	$1,329,758	$	-	$ -
-OE		$0.004458	$2,009,085	$	-	$ -
						$ -
GCRA			$0	$	(0.002245)	$ (1,011,583)
MCRA			$0			$ -
TOTAL RATE			$32,531,026			$ 40,546,609
PROPOSED INCREASE/(DECREASE)						$ 8,015,583
% INCREASE/(DECREASE)						24.64%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "B" Water Heating Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
RATE B					
Number of Bills	67,090	$2.000	$134,180	$ 4.60	$ 308,614
Energy Charge					
All kWh	14,303,741	$0.05301	$758,241	0.07370	$ 1,054,186
Total Calculated Base	14,303,741 kWh		$892,421		$ 1,362,800
Adjustment Factor			1.00046		1.00046
Adjusted Total Base			$892,828		$ 1,363,420
Riders					
Fuel Adjustment		$0.008222	$117,605	$ -	$ -
CAAA		$0.000022	$318	$ 0.000022	$ 318
DSM		$0.000000	$0	$ -	$ -
QPCC-CC		$0.004075	$58,282	$ -	$ -
-OE		$0.006703	$95,880	$ -	$ -
					$ -
GCRA		$0.000000	$0	$ (0.001352)	$ (19,345)
MCRA		$0.000000	$0	$ -	$ -
TOTAL RATE			$1,164,913		$ 1,344,393
PROPOSED INCREASE/(DECREASE)					$179,480
% INCREASE/(DECREASE)					15.41%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate " SGS" Small General Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
RATE SGS					
Number of Bills	113,968	$7.000	$797,776	$ 8.500	$ 968,728
Energy Charge					
First 1000 kWh	40,345,866	$0.09438	$3,807,843	$ 0.11707	$ 4,723,291
Next 1000 kWh	9,992,895	$0.06426	$642,143	$ 0.08500	$ 849,396
Next 13,000	7,663,037	$0.03438	$263,455	$ 0.05300	$ 406,141
Over 15,000	475,965	$0.02892	$13,765	$ 0.05300	$ 25,226
Total Calculated Base	58,477,763 kWh		$5,524,982		$ 6,972,782
Adjustment Factor			0.99574		0.99574
Adjusted Total Base			$5,501,456		$ 6,943,091
Riders:					
Fuel Adjustment		$0.008222	$480,792		$ -
CAAA		$0.000015	$884	$0.000000	$ -
DSM		$0.000811	$47,407		$ -
QPCC-CC		$0.002717	$158,879		$ -
-OE		$0.004625	$270,464		$ -
					$ -
GCRA			$0	-0.001829	$ (106,956)
MCRA			$0		$ -
TOTAL RATE			$6,459,882		$ 6,836,135
PROPOSED INCREASE/(DECREASE)					$376,253
% INCREASE/(DECREASE)					5.82%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate " DGS" Demand General Service

Rate	Use in Block	Present Rate	Present Revenues	Use in Block with Proposed Demand Ratchet	Proposed Rate	Proposed Revenues
RATE DGS						
Number of Bills	100,887	$7.000	$706,209		$ 12.70	$ 1,281,265
Demand Charge						
Over 10 kW	3,316,313	$1.300	$4,311,207			$ -
Proposed(new demand ratchet)				3,431,721	$ 4.90	$ 16,815,431
Energy Charge						
First 1000 kWh	87,450,752	$0.094	$8,253,602	87,450,752	0.11557	$ 10,106,683
Next 1000 kWh*	595,176,541	$0.064	$38,246,045	595,176,541	0.08036	$ 47,828,387
Next 13000 kWh**	387,592,282	$0.034	$13,325,423	389,731,722	0.08036	$ 31,318,841
Over 15000 kWh	120,364,687	$0.029	$3,480,947	118,225,247	0.04905	$ 5,798,948
				1,190,584,262		
Transformer Ownership Discount	376,957	($0.100)	($37,696)		$ (0.190)	$ (71,622)
Total Calculated Base	1,190,584,262 kWh		$68,285,736			$ 113,077,934
Adjustment Factor			0.995521			0.995521
Adjusted Total Base			$67,979,897			$ 112,571,479
Riders:						
Fuel Adjustment		$0.008222	$9,788,738		$ -	$ -
IP-2 Credit			$0			$0
CAAA		$0.000015	$18,181		$ -	$0
DSM		$0.000819	$974,823		$ -	$ -
QPCC-CC		$0.002744	$3,267,011		$ -	$ -
-OE		$0.004671	$5,561,548		$ -	$ -
GCRA			$0		$ (0.003214)	$ (3,826,538)
MCRA			$0		$ -	$ -
TOTAL RATE			$87,590,198			$ 108,744,941

* plus, 180 kWh/kW(>10kW)
** plus, 120 kWh/kW(>10kW)

PROPOSED INCREASE/(DECREASE)	$21,154,743
% INCREASE/(DECREASE)	24.15%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "OSS" Off-Season Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
RATE OSS					
Number of Bills	10,321	$0.000	$0	$ 12.00	$ 123,852
Demand Charge					
All kW	323,257	$3.150	$1,018,260		
Proposed(new demand ratchet)	372,715			$ 4.30	$ 1,602,676
Energy Charge					
All kWh	105,174,409	$0.04076	$4,286,909	0.07104	$ 7,471,590
Total Calculated Base	105,174,409 kWh		$5,305,168		$ 9,198,118
Adjustment Factor			0.998902		0.998902
Adjusted Total Base			$5,299,341		$ 9,188,014
Riders:					
Fuel Adjustment		$0.008222	$864,722	$ -	$ -
CAAA		$0.000019	$1,967	$ -	$ -
DSM		$0.001123	$118,081	$ -	$ -
QPCC-CC		$0.003420	$359,703	$ -	$ -
-OE		$0.005564	$585,188	$ -	$ -
					$ -
GCRA			$0	$ (0.002677)	$ (281,552)
MCRA			$0	$ -	$ -
TOTAL RATE			$7,229,002		$ 8,906,462
PROPOSED INCREASE/(DECREASE)					$ 1,677,460
% INCREASE/(DECREASE)					23.20%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "LP" Large Power Service

Rate	Use in Block		Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
RATE LP						
Number of Bills	1,247		$0.000	$ -	$ 125.00	$ 155,875
Demand Charge						
All kVa	2,763,585		$7.300	$ 20,174,171	$ 9.00	$ 24,872,265
Energy Charge						
All kWh	1,320,758,678		$0.02704	$ 35,713,315	$ 0.04846	$ 64,003,966
Transmission Voltage Discount	507,265		($1.750)	$ (887,713)	$ (1.75)	$ (887,713)
Total Calculated Base	1,320,758,678	kWh		$ 54,999,772		$ 88,144,393
Adjustment Factor				0.99999		0.99999
Adjusted Total Base				$ 54,999,100		$ 88,143,316
Riders:						
Fuel Adjustment			$0.008222	$ 10,859,005	$ -	$ -
IP Credit						$ -
LP-1 Credit						$ -
CAAA			$0.000008	$ 11,184	$ -	$ -
DSM			$0.000414	$ 547,014	$ -	$ -
QPCC-CC			$0.001645	$ 2,172,536	$ -	$ -
-OE			$0.003239	$ 4,278,538	$ -	$ -
						$ -
GCRA				$ -	$ (0.001910)	$ (2,522,649)
MCRA				$ -	$ -	$ -
TOTAL RATE				$ 72,867,378		$ 85,620,667
PROPOSED INCREASE/(DECREASE)						$ 12,753,289
% INCREASE/(DECREASE)						17.50%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "HLF" Transmission Power Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
RATE HLF					
Number of Bills	24	$ 95,175	$ 2,284,200	$ 156,735	$ 3,761,640
Demand Charge					
All kVa>4,500/mo.	1,460,506	$ 21.15	$ 30,889,702	$ 34.83	$ 50,869,424
Energy Charge					
up to 600 kWh/kVa	918,914,323	$ -	$ -		$ -
>600kWh/kVa	100,333,355	$ 0.022420	$ 2,249,474	0.03798	$ 3,810,661
Total Calculated Base	1,019,247,677 kWh		$ 35,423,376		$ 58,441,725
Adjustment Factor			1.000000		1.000000
Adjusted Total Base			$ 35,423,374		$ 58,441,722
IP Credit (Includes Separate GE Credit)					$ -
Fuel Adjustment		$ 0.008222	$ 8,380,044	$ -	$ -
CAAA		$ 0.000009	$ 9,489	$ -	$ -
DSM		$ 0.000065	$ 65,920	$ -	$ -
QPCC-CC		$ 0.001785	$ 1,818,967	$ -	$ -
-OE		$ 0.002971	$ 3,027,694	$ -	$ -
					$ -
GCRA			$ -	$ (0.001644)	$ (1,675,643)
MCRA			$ -	$ -	$ -
TOTAL RATE			$ 48,725,488		$ 56,766,079
PROPOSED INCREASE/(DECREASE)					$ 8,040,591
% INCREASE/(DECREASE)					16.50%

VECTREN SOUTH
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "OL" Outdoor Lighting Dusk to Dawn Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
High Pressure Sodium					
100 watt	30,924	$ 5.79	$ 179,049.96	$ 6.66	$ 206,014.76
100 watt (directional)	9,180	$ 6.15	$ 56,457.00	$ 7.08	$ 64,959.39
200 watt	8,604	$ 8.40	$ 72,273.60	$ 9.67	$ 83,157.96
200 watt (directional)	14,736	$ 9.70	$ 142,939.20	$ 11.16	$ 164,465.75
400 watt (directional)	17,544	$ 16.76	$ 294,037.44	$ 19.28	$ 338,319.28
	80,988		$ 744,757.20		$ 856,917.13
Mercury Vapor					
175 watt	19,260	$ 5.79	$ 111,515.40	$ 6.66	$ 128,309.54
400 watt	2,100	$ 8.40	$ 17,640.00	$ 9.67	$ 20,296.57
400 watt (directional)	2,940	$ 9.70	$ 28,518.00	$ 11.16	$ 32,812.79
1000 watt (directional)	1,068	$ 16.76	$ 17,899.68	$ 19.28	$ 20,595.36
	25,368		$ 175,573.08		$ 202,014.27
Total Calculated			$ 920,330.28		$ 1,058,931.40
Adjustment Factor			1.0200		1.0200
Adjusted Total			$ 938,716.00		$ 1,080,086.00
PROPOSED INCREASE/(DECREASE)					$ 141,370.00
% INCREASE/(DECREASE)					15.06%

VECTREN ENERGY DELIVERY of INDIANA
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "SL" Street Lighting Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
SL-1 Street Lighting Service(A) --closed					
O.H.--Wood Poles (radial wave):					
2500 lumen(radial)	14	$32.00	$448.00	$ 39.50	$ 553.00
2500 lumen	7	$35.60	$249.20	$ 43.94	$ 307.61
6000 lumen	3	$55.99	$167.97	$ 69.11	$ 207.34
O.H.--Wood Poles):					
175 Watt	4416	$71.95	$317,731.20	$ 88.81	$ 392,202.60
250 Watt	27	$98.90	$2,670.30	$ 122.08	$ 3,296.18
400 Watt	915	$122.17	$111,785.55	$ 150.80	$ 137,986.40
1000 Watt	2	$183.23	$366.46	$ 226.18	$ 452.35
O.H.--Metal Poles):					
175 Watt	1219	$111.27	$135,638.13	$ 137.35	$ 167,429.66
175 Watt (twin arm)	15	$200.73	$3,010.95	$ 247.78	$ 3,716.67
250 Watt	40	$133.84	$5,353.60	$ 165.21	$ 6,608.40
400 Watt	830	$142.56	$118,324.80	$ 175.97	$ 146,058.35
400Watt (twin arm)	3	$252.37	$757.11	$ 311.52	$ 934.57
1000 Watt	6	$226.93	$1,361.58	$ 280.12	$ 1,680.71
U.G. --Metal Poles):					
175 Watt	36	$120.01	$4,320.36	$ 148.14	$ 5,332.99
175 Watt (twin arm)	7	$215.27	$1,506.89	$ 265.73	$ 1,860.08
SL-1 Street Lighting Service(B) --open					
O.H.--Wood Poles):					
175 Watt	3882	$71.95	$279,309.90	$ 88.81	$ 344,775.93
100 Watt (twin arm)	0	$0.00	$0.00	$ -	$ -
150 Watt	795	$75.95	$60,380.25	$ 93.75	$ 74,532.47
200 Watt	1465	$122.17	$178,979.05	$ 150.80	$ 220,929.04
400 Watt (twin arm; 40,00(	0	$0.00	$0.00	$ -	$ -
400 Watt	18	$183.23	$3,298.14	$ 226.18	$ 4,071.17
400 Watt (twin arm; 90,00(	0	$0.00	$0.00	$ -	$ -
O.H.--Metal Poles):					
175 Watt	729	$111.27	$81,115.83	$ 137.35	$ 100,128.16
100 Watt (twin arm)	43	$200.73	$8,631.39	$ 247.78	$ 10,654.46
150 Watt	10	$115.27	$1,152.70	$ 142.29	$ 1,422.88
200 Watt	2200	$142.56	$313,632.00	$ 175.97	$ 387,142.61
400 Watt (twin arm; 40,00(	20	$252.37	$5,047.40	$ 311.52	$ 6,230.43
400 Watt	445	$226.93	$100,983.85	$ 280.12	$ 124,652.94
400 Watt (twin arm; 90,00(	7	$392.72	$2,749.04	$ 484.77	$ 3,393.37
U.G. --Metal Poles):					
100 Watt	392	$120.01	$47,043.92	$ 148.14	$ 58,070.30
100 Watt (twin arm)	9	$215.27	$1,937.43	$ 265.73	$ 2,391.53
200 Watt (direct burial cab	63	$208.00	$13,104.00	$ 256.75	$ 16,175.38
200 Watt (twin arm)	5	$319.23	$1,596.15	$ 394.05	$ 1,970.26
200 Watt (conduit and anc	7	$251.61	$1,761.27	$ 310.58	$ 2,174.09
400 Watt	64	$314.17	$20,106.88	$ 387.81	$ 24,819.63
400 Watt (twin arm)	15	$453.83	$6,807.45	$ 560.20	$ 8,403.01

VECTREN ENERGY DELIVERY of INDIANA
Electric Division
Rate Revenue Calculations
(test year ended March, 2006)

Rate "SL" Street Lighting Service

Rate	Use in Block	Present Rate	Present Revenues	Proposed Rate	Proposed Revenues
SL-2 Ornamental Street Lighting Service Post Top Langern Type Luminaire					
U.G. --Wood Poles):					
175 Watt - Mercury vapor ı	138	$72.74	$10,038.12	$ 89.79	$ 12,390.90
100 Watt - High pressure ɛ	79	$72.74	$5,746.46	$ 89.79	$ 7,093.34
SL-3 Ornamental Street Lighting Service Contemporary Spherical Luminaire -- open					
U.G. --Metal Poles):					
200 Watt high pressure so	15	$189.12	$2,836.80	$ 233.45	$ 3,501.70
800 Watt high pressure so	0	$0.00	$0.00	$ -	$ -
SL-5 Expressway Lighting Service					
Mercury vapor street lighting (A) -- closed					
1000 Watt (code 5201)	73	$429.07	$31,322.11	$ 529.64	$ 38,663.54
1000 Watt (code 5203)	2	$411.61	$823.22	$ 508.09	$ 1,016.17
High pressure sodium street lighting (B) -- open					
400 Watt (code 5205)	182	$429.07	$78,090.74	$ 529.64	$ 96,394.03
Twin 400 Watt (code 5206	11	$603.62	$6,639.82	$ 745.10	$ 8,196.09
400 Watt (code 5207)	37	$411.61	$15,229.57	$ 508.09	$ 18,799.15
Twin 400 Watt (code 5208	0	$0.00	$0.00	$ -	$ -
SL-7 Ornamental street lighting service					
U.G. --Metal Poles):					
100 Watt high pressure so	227	$157.38	$35,725.26	$ 194.27	$ 44,098.72
SL-8 Ornamental street lighting service					
U.G. --Fiberglass Poles):					
100 Watt high pressure so	90	$85.65	$7,708.50	$ 105.73	$ 9,515.26
Total Calculated			$2,025,489.35		$2,500,233.49
Adjustment Factor			1.0057481		1.0057481
Adjusted Total			$2,037,132.00		2,514,605.00
PROPOSED INCREASE/ (DECREASE)					477,473.00
% INCREASE/(DECREASE)					23.44%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "A" Residential Service

Present Rate	Base	Fuel Adjustment	QPCP	DSM	CAAA	Total
Service Charge :	$ 4.35					$ 4.35
Energy Charge :						
First 250 kWh	$ 0.08235	$ 0.008222	$ 0.014128	$ 0.00018	$ 0.00003	$ 0.10491
Over 250	$ 0.06881	$ 0.008222	$ 0.014128	$ 0.00018	$ 0.00003	$ 0.09137

Present Rate Revenue = $ 107,380,875

Proposed Rate	Base	Fuel Adjustment	CAAA	GCRA	MCRA	Total
Customer Facilities Charge :	$ 7.50					$ 7.50
Energy Charge :						
First 250 kWh	$ 0.14001	$ -	$ 0.000029	$ (0.003915)	0	$ 0.13612
Over 250	$ 0.11001	$ -	$ 0.000029	$ (0.003915)	0	$ 0.10612

Proposed Rate Revenue = $ 131,292,288
Revenue change = $ 23,911,413
% Increase/(Decrease) = 22.27%

Monthly Use kWh	Demand	Present Bill	Proposed Bill	Increase (Decrease)	% Change
100		$ 14.84	$ 21.11	$ 6.27	42.3%
200		$ 25.33	$ 34.72	$ 9.39	37.1%
250		$ 30.58	$ 41.53	$ 10.95	35.8%
300		$ 35.14	$ 46.84	$ 11.69	33.3%
400		$ 44.28	$ 57.45	$ 13.17	29.7%
500		$ 53.42	$ 68.06	$ 14.64	27.4%
600		$ 62.55	$ 78.67	$ 16.12	25.8%
700		$ 71.69	$ 89.29	$ 17.60	24.5%
800		$ 80.83	$ 99.90	$ 19.07	23.6%
900		$ 89.96	$ 110.51	$ 20.55	22.8%
1000		$ 99.10	$ 121.12	$ 22.02	22.2%
1250		$ 121.94	$ 147.65	$ 25.71	21.1%
1500		$ 144.78	$ 174.19	$ 29.40	20.3%
2000		$ 190.47	$ 227.25	$ 36.78	19.3%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "EH" Electric Home Heating Service

Present Rate	Base	Fuel Adjustment	QPCP	DSM	CAAA	Total
Service Charge :	$ 5.30					$ 5.30
Energy Charge :						
First 250 kWh	$0.06328	$ 0.008222	$ 0.007408	$ 0.000069	$ 0.000016	$0.078995
Next 750 kWh	$0.06328	$ 0.008222	$ 0.007408	$ 0.000069	$ 0.000016	$0.078995
Over 1000 kWh	$0.03810	$ 0.008222	$ 0.007408	$ 0.000069	$ 0.000016	$0.053815

Present Rate Revenue = $ 32,531,026

Proposed Rate	Base	Fuel Adjustment	CAAA	GCRA	MCRA	Total
Customer Facilities Charge :	$ 7.75					$ 7.75
Energy Charge :						
First 250 kWh	$0.12730	$ -	$ 0.000016	$ (0.002245)	$ -	$0.125071
Next 750	$0.09697	$ -	$ 0.000016	$ (0.002245)	$ -	$0.094741
Over 1000	$0.06000	$ -	$ 0.000016	$ (0.002245)	$ -	$0.057771

Proposed Rate Revenue = $ 40,546,609
Revenue change = $ 8,015,583
% Increase/(Decrease) = 24.64%

Monthly Use kWh	Demand	Present Bill	Proposed Bill	Increase (Decrease)	% Change
250		$ 25.05	$ 39.02	$ 13.97	55.8%
300		$ 29.00	$ 43.75	$ 14.76	50.9%
400		$ 36.90	$ 53.23	$ 16.33	44.3%
500		$ 44.80	$ 62.70	$ 17.91	40.0%
600		$ 52.70	$ 72.18	$ 19.48	37.0%
700		$ 60.60	$ 81.65	$ 21.06	34.7%
800		$ 68.50	$ 91.13	$ 22.63	33.0%
900		$ 76.40	$ 100.60	$ 24.20	31.7%
1000		$ 84.29	$ 110.07	$ 25.78	30.6%
1250		$ 97.75	$ 124.52	$ 26.77	27.4%
1500		$ 111.20	$ 138.96	$ 27.76	25.0%
2000		$ 138.11	$ 167.85	$ 29.74	21.5%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "B" Water Heating Service

Present Rate		Base	Fuel Adjustment	QPCP	DSM	CAAA	Total
Service Charge :	$	2.00					$ 2.00
Energy Charge : All kWh	$	0.05301	$ 0.003831	$ 0.010090			$0.066931

Present Rate Revenue = $ 1,164,913

Proposed Rate		Base	Fuel Adjustment	CAAA	GCRA	MCRA	Total
Customer Facilities Charge :	$	4.60					$ 4.60
Energy Charge : All kWh	$	0.07370	$ -	$ 0.000022	$ (0.00135)	$ -	$ 0.07237

Proposed Rate Revenue = $ 1,344,393
Revenue change = $ 179,480
% Increase/(Decrease) = 15.41%

Monthly Use kWh	Demand	Present Bill	Proposed Bill	Increase (Decrease)	% Change
100		$ 8.69	$ 11.84	$ 3.14	36.17%
200		$ 15.39	$ 19.07	$ 3.69	23.97%
300		$ 22.08	$ 26.31	$ 4.23	19.17%
400		$ 28.77	$ 33.55	$ 4.78	16.60%
500		$ 35.47	$ 40.78	$ 5.32	15.00%
600		$ 42.16	$ 48.02	$ 5.86	13.91%
700		$ 48.85	$ 55.26	$ 6.41	13.12%
800		$ 55.54	$ 62.50	$ 6.95	12.51%
900		$ 62.24	$ 69.73	$ 7.49	12.04%
1000		$ 68.93	$ 76.97	$ 8.04	11.66%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "SGS" Small General Service

Present Rate		Base	Fuel Adjustment	QPCP	DSM	CAAA	Total
Service Charge :	$	7.00					$ 7.00
Demand Charge :	n/a <10kw						
Energy Charge :							
First 1000 kWh	$	0.09438	$0.008222	$ 0.007342	$ 0.000811	$ 0.000015	$ 0.110770
Next 1000	$	0.06426	$0.008222	$ 0.007342	$ 0.000811	$ 0.000015	$ 0.080650
Next 13000	$	0.03438	$0.008222	$ 0.007342	$ 0.000811	$ 0.000015	$ 0.050770
Over 15000	$	0.02892	$0.008222	$ 0.007342	$ 0.000811	$ 0.000015	$ 0.045310

Present Rate Revenue = $ 6,459,882

Proposed Rate		Base	Fuel Adjustment	CAAA	GCRA	MCRA	Total
Customer Facilities Charge :	$	8.50					$ 8.50
Demand Charge :	n/a <10kw						
Energy Charge :							
First 1000 kWh	$	0.11707	$ -	$ -	$ (0.001829)	0	$ 0.11524
Next 1000	$	0.08500	$ -	$ -	$ (0.001829)	0	$ 0.08317
Over 2000	$	0.05300	$ -	$ -	$ (0.001829)	0	$ 0.05117

Proposed Rate Revenue = $ 6,836,135
Revenue change = $ 376,253
% Increase/(Decrease) = 5.82%

Monthly Use kWh	Demand	Present Bill	Proposed Bill	Increase (Decrease)	% Change
250		$ 34.69	$ 37.31	$ 2.62	7.5%
500		$ 62.38	$ 66.12	$ 3.74	6.0%
750		$ 90.08	$ 94.93	$ 4.85	5.4%
1000		$ 117.77	$ 123.74	$ 5.97	5.1%
1500		$ 158.09	$ 165.33	$ 7.23	4.6%
2000		$ 198.42	$ 206.91	$ 8.49	4.3%
3000		$ 249.19	$ 258.08	$ 8.89	3.6%
4000		$ 299.96	$ 309.25	$ 9.30	3.1%
5000		$ 350.73	$ 360.43	$ 9.70	2.8%
6000		$ 401.50	$ 411.60	$ 10.10	2.5%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "DGS" Demand General Service

Present Rate			Base		Fuel Adjustment		QPCP		DSM	CAAA		Total
Service Charge		$	7.00								$	7.00
Demand Charge												
All billing demand in excess of												
10 kW		$	1.30								$	1.30
Energy Charge												
First	1,000	$	0.0944	$	0.008222	$	0.007415	$	0.000819	$ 0.000015	$	0.11085
Next *	1,000	$	0.0643	$	0.008222	$	0.007415	$	0.000819	$ 0.000015	$	0.08073
Next **	13,000	$	0.0344	$	0.008222	$	0.007415	$	0.000819	$ 0.000015	$	0.05085
Over	15,000	$	0.0289	$	0.008222	$	0.007415	$	0.000819	$ 0.000015	$	0.04539
For Billing Demand in excess of					*		180		kWh per kW to Block 2			
	10	KW add			**		120		kWh per kW to Block 3			

Present Rate Revenue = **$ 87,590,198**

Proposed Rate			Base	Fuel Adjustment		CAAA		GCRA		MCRA		Total
Customer Facilities Charge		$	12.70								$	12.70
Demand Charge												
All billing demand in excess of												
10 kW		$	4.90								$	4.90
Energy Charge												
First	1,000	$	0.116	0	$	-	$	(0.003214)	$	-	$	0.11236
Next*	1000)	$	0.080	0	$	-	$	(0.003214)	$	-	$	0.07715
Next*	13000)	$	0.080	0	$	-	$	(0.003214)	$	-	$	0.07715
Over	15,000	$	0.049	0	$	-	$	(0.003214)	$	-	$	0.04584
* For Billing Demand in excess of												
	10	KW add				300		kWh per kW to Block 2				

Proposed Rate Revenue = **$ 108,744,941**
Revenue Change = **$ 21,154,743**
% Increase/ (Decrease) **24.15%**

Monthly Use kWh	Demand	Present $ Bill	Proposed $ Bill	Increase (Decrease)	% Change
1,000	20	$ 130.85	$ 174.06	$ 43.20	33%
2,000	20	$ 211.58	$ 251.20	$ 39.62	19%
3,000	20	$ 292.31	$ 328.35	$ 36.03	12%
4,000	20	$ 367.07	$ 405.49	$ 38.43	10%
5,000	20	$ 417.92	$ 482.64	$ 64.72	15%
6,000	20	$ 468.77	$ 559.79	$ 91.02	19%
7,000	20	$ 519.62	$ 636.93	$ 117.31	23%
8,000	20	$ 570.47	$ 714.08	$ 143.60	25%
9,000	20	$ 621.32	$ 791.22	$ 169.90	27%
10,000	20	$ 672.18	$ 868.37	$ 196.19	29%
11,000	20	$ 723.03	$ 945.52	$ 222.49	31%
12,000	20	$ 773.88	$ 1,022.66	$ 248.78	32%
13,000	20	$ 824.73	$ 1,099.81	$ 275.08	33%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "DGS" Demand General Service

Monthly Use kWh	Monthly Use Demand	Present $ Bill	Proposed $ Bill	Increase (Decrease)	% Change
2,500	**50**	$ 290.95	$ 436.78	$ 145.83	50%
5,000	50	$ 492.78	$ 629.64	$ 136.86	28%
7,500	50	$ 694.60	$ 822.51	$ 127.90	18%
10,000	50	$ 872.53	$ 1,015.37	$ 142.84	16%
12,500	50	$ 999.66	$ 1,208.24	$ 208.58	21%
15,000	50	$ 1,126.78	$ 1,401.10	$ 274.32	24%
17,500	50	$ 1,253.91	$ 1,593.97	$ 340.05	27%
20,000	50	$ 1,381.04	$ 1,786.83	$ 405.79	29%
22,500	50	$ 1,508.17	$ 1,979.70	$ 471.53	31%
25,000	50	$ 1,635.29	$ 2,172.56	$ 537.27	33%
27,500	50	$ 1,759.69	$ 2,349.77	$ 590.08	34%
30,000	50	$ 1,873.17	$ 2,464.36	$ 591.19	32%
32,500	50	$ 1,986.65	$ 2,578.95	$ 592.30	30%
5,000	**100**	$ 557.78	$ 874.64	$ 316.86	57%
10,000	100	$ 961.43	$ 1,260.37	$ 298.94	31%
15,000	100	$ 1,365.09	$ 1,646.10	$ 281.01	21%
20,000	100	$ 1,714.96	$ 2,031.83	$ 316.87	18%
25,000	100	$ 1,969.21	$ 2,417.56	$ 448.35	23%
30,000	100	$ 2,223.47	$ 2,803.29	$ 579.82	26%
35,000	100	$ 2,477.73	$ 3,189.02	$ 711.29	29%
40,000	100	$ 2,731.98	$ 3,574.75	$ 842.77	31%
45,000	100	$ 2,969.86	$ 3,866.55	$ 896.69	30%
50,000	100	$ 3,196.81	$ 4,095.73	$ 898.92	28%
55,000	100	$ 3,423.77	$ 4,324.91	$ 901.14	26%
60,000	100	$ 3,650.73	$ 4,554.09	$ 903.36	25%
65,000	100	$ 3,877.68	$ 4,783.27	$ 905.59	23%
25,000	**500**	$ 2,692.40	$ 4,377.56	$ 1,685.16	63%
50,000	500	$ 4,710.68	$ 6,306.21	$ 1,595.53	34%
75,000	500	$ 6,728.96	$ 8,234.86	$ 1,505.90	22%
100,000	500	$ 8,454.41	$ 10,163.51	$ 1,709.10	20%
125,000	500	$ 9,725.69	$ 12,092.16	$ 2,366.47	24%
150,000	500	$ 10,996.97	$ 14,020.81	$ 3,023.84	27%
175,000	500	$ 12,197.27	$ 15,542.43	$ 3,345.16	27%
200,000	500	$ 13,332.05	$ 16,688.33	$ 3,356.28	25%
225,000	500	$ 14,466.83	$ 17,834.23	$ 3,367.40	23%
250,000	500	$ 15,601.61	$ 18,980.13	$ 3,378.52	22%
275,000	500	$ 16,736.38	$ 20,126.03	$ 3,389.65	20%
300,000	500	$ 17,871.16	$ 21,271.93	$ 3,400.77	19%
325,000	500	$ 19,005.94	$ 22,417.83	$ 3,411.89	18%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "OSS" Off-Season Service

Present Rate		Base	Fuel Adjustment	QPCP	DSM	CAAA	Total
Service Charge :	$	-					$ -
Demand Charge :	$	3.15000					$ 3.15000
Energy Charge :							
All kWh	$	0.04076	$ 0.008222	$ 0.008984	$ 0.001123	$0.000019	$ 0.059107

Present Rate Revenue = **$ 7,229,002**

Proposed Rate		Base	Fuel Adjustment	CAAA	GCRA	MCRA	Total
Customer Facilities Charge :	$	12.00					$ 12.00
Demand Charge :	$	4.30					$ 4.30
Energy Charge :							
All kWh	$	0.07104	$ -	$ -	$ (0.002677)	0	$ 0.06836

Proposed Rate Revenue = **$ 8,906,462**
Revenue change = **$ 1,677,460**
% Increase/(Decrease) = **23.20%**

Monthly Use kWh	Demand	Present Bill	Proposed Bill	Increase (Decrease)	% Change
0	30	$ 94.50	$ 141.00	$ 46.50	49.21%
1500		$ 183.16	$ 243.54	$ 60.38	32.97%
3000		$ 271.82	$ 346.09	$ 74.27	27.32%
4500		$ 360.48	$ 448.63	$ 88.15	24.45%
6000		$ 449.14	$ 551.18	$ 102.03	22.72%
7500		$ 537.80	$ 653.72	$ 115.92	21.55%
9000		$ 626.47	$ 756.27	$ 129.80	20.72%
10500		$ 715.13	$ 858.81	$ 143.69	20.09%
12000		$ 803.79	$ 961.36	$ 157.57	19.60%
13500		$ 892.45	$ 1,063.90	$ 171.45	19.21%
15000		$ 981.11	$ 1,166.45	$ 185.34	18.89%
16500		$ 1,069.77	$ 1,268.99	$ 199.22	18.62%
18000		$ 1,158.43	$ 1,371.53	$ 213.10	18.40%
19500		$ 1,247.09	$ 1,474.08	$ 226.99	18.20%

VECTREN SOUTH
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "LP" Large Power Service

Present Rate			Base		Fuel Adjustment		QPCP		DSM		CAAA		Total
Service Charge :		$	-									$	-
Demand Charge :	per kVa	$	7.30									$	7.30
Energy Charge :													
All kWh		$	0.02704	$	0.008222	$	0.004884	$	0.000414	$	0.000008	$	0.04057

Present Rate Revenue = **$ 72,867,378**

Proposed Rate	$	Base		Fuel Adjustment		CAAA		GCRA	MCRA		Total
Customer Facilities Charge :	$	125.00					$	125.00		$	125.00
Demand Charge :	$	9.00					$	9.00		$	9.00
Energy Charge :											
All kWh	$	0.04846	$	-	$	-	$	(0.001910)	0	$	0.04655

Proposed Rate Revenue = **$ 85,620,667**
Revenue change = **$ 12,753,289**
% Increase/(Decrease) = **17.50%**

Monthly Use kWh	Demand(kVa)	Present Bill	Proposed Bill	Increase (Decrease)	% Change
0	300	$ 2,190.00	$ 2,825.00	$ 635.00	29.00%
15000		$ 2,798.53	$ 3,523.25	$ 724.72	25.90%
30000		$ 3,407.06	$ 4,221.50	$ 814.44	23.90%
45000		$ 4,015.60	$ 4,919.75	$ 904.15	22.52%
60000		$ 4,624.13	$ 5,618.00	$ 993.87	21.49%
75000		$ 5,232.66	$ 6,316.25	$ 1,083.59	20.71%
90000		$ 5,841.19	$ 7,014.50	$ 1,173.31	20.09%
105000		$ 6,449.72	$ 7,712.75	$ 1,263.03	19.58%
120000		$ 7,058.26	$ 8,411.00	$ 1,352.74	19.17%
135000		$ 7,666.79	$ 9,109.25	$ 1,442.46	18.81%
150000		$ 8,275.32	$ 9,807.50	$ 1,532.18	18.52%
165000		$ 8,883.85	$ 10,505.75	$ 1,621.90	18.26%
180000		$ 9,492.38	$ 11,204.00	$ 1,711.62	18.03%
195000		$ 10,100.92	$ 11,902.25	$ 1,801.33	17.83%

VECTREN ENERGY DELIVERY of INDIANA
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "LP" Large Power Service

Monthly Use kWh	Demand(kVa)	Present Bill	Proposed Bill	Increase (Decrease)	% Change
0	1000	$ 7,300.00	$ 9,125.00	$ 1,825.00	25.00%
50000		$ 9,328.44	$ 11,452.50	$ 2,124.06	22.77%
100000		$ 11,356.88	$ 13,780.00	$ 2,423.12	21.34%
150000		$ 13,385.32	$ 16,107.50	$ 2,722.18	20.34%
200000		$ 15,413.76	$ 18,435.00	$ 3,021.24	19.60%
250000		$ 17,442.20	$ 20,762.50	$ 3,320.30	19.04%
300000		$ 19,470.64	$ 23,090.00	$ 3,619.36	18.59%
350000		$ 21,499.08	$ 25,417.50	$ 3,918.42	18.23%
400000		$ 23,527.52	$ 27,745.00	$ 4,217.48	17.93%
450000		$ 25,555.96	$ 30,072.50	$ 4,516.54	17.67%
500000		$ 27,584.40	$ 32,400.00	$ 4,815.60	17.46%
550000		$ 29,612.84	$ 34,727.50	$ 5,114.66	17.27%
600000		$ 31,641.28	$ 37,055.00	$ 5,413.72	17.11%
650000		$ 33,669.72	$ 39,382.50	$ 5,712.78	16.97%

VECTREN ENERGY DELIVERY of INDIANA
Electric Division
COMPARISON of TYPICAL MONTHLY BILLS

Rate "HLF" Transmission Power Service

Present Rate	Base	Fuel Adjustment	QPCP	DSM	CAAA	Total
Service Charge :	$ 95,175.00					$ 95,175.00
Demand Charge :	$ 21.15					$ 21.15
Energy Charge :						
up to 600 kWh/kVa	incl. above					incl. above
>600kWh/kVa	$ 0.02242	$ 0.008222	$ 0.004755	$ 0.000065	$ 0.000009	$ 0.03547

Present Rate Revenue = **$ 48,725,488**

Proposed Rate	Base	Fuel Adjustment	CAAA	GCRA	MCRA	Total
Customer Facilities Charge :	$ 156,735.00					$ 156,735.00
Demand Charge :	$ 34.83					$ 34.83
Energy Charge :						
up to 600 kWh/kVa	incl. above					
>600kWh/kVa	$ 0.03798	$ -	$ -	$(0.001644)	$ -	$ 0.03634

Proposed Rate Revenue = **$ 56,766,079**
Revenue change = **$ 8,040,591**
% Increase/(Decrease) = **16.50%**

Monthly Use kWh	Demand	Present Bill	Proposed Bill	Increase (Decrease)	% Change
0	5000	$ 105,750.00	$ 174,150.00	$ 68,400.00	64.68%
250000		$ 105,750.00	$ 174,150.00	$ 68,400.00	64.68%
500000		$ 105,750.00	$ 174,150.00	$ 68,400.00	64.68%
750000		$ 105,750.00	$ 174,150.00	$ 68,400.00	64.68%
1000000		$ 105,750.00	$ 174,150.00	$ 68,400.00	64.68%
1250000		$ 105,750.00	$ 174,150.00	$ 68,400.00	64.68%
1500000		$ 105,750.00	$ 174,150.00	$ 68,400.00	64.68%
1750000		$ 123,485.46	$ 192,318.00	$ 68,832.54	55.74%
2000000		$ 141,220.91	$ 210,486.00	$ 69,265.09	49.05%
2250000		$ 158,956.37	$ 228,654.00	$ 69,697.63	43.85%
2500000		$ 176,691.83	$ 246,822.00	$ 70,130.17	39.69%
2750000		$ 194,427.29	$ 264,990.00	$ 70,562.71	36.29%
3000000		$ 212,162.74	$ 283,158.00	$ 70,995.26	33.46%
3250000		$ 229,898.20	$ 301,326.00	$ 71,427.80	31.07%

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – ELECTRIC)

IURC CAUSE NO. 43111

DIRECT TESTIMONY
OF
JERROLD L. ULREY
VICE PRESIDENT REGULATORY AFFAIRS AND FUELS
ON THE PROPOSED
GENERATION COST AND REVENUE ADJUSTMENT (GCRA)
AND
TARIFF FOR ELECTRIC SERVICE

SPONSORING PETITIONER'S EXHIBITS JLU-1 THROUGH JLU-3

DIRECT TESTIMONY OF JERROLD L. ULREY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jerrold L. Ulrey and my business address is One Vectren Square, Evansville, Indiana 47708.

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

A. I am Vice President, Regulatory Affairs and Fuels for Vectren Utility Holdings, Inc., ("VUHI") the parent company of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or "Company"), and Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North").

Q. What are your present duties and responsibilities as Vice President, Regulatory Affairs and Fuels?

A. I am responsible for coordinating Vectren South's participation in rate and tariff related regulatory proceedings before the Indiana Utility Regulatory Commission. In addition, I am responsible for overseeing the gas supply function for VUHI's three gas utilities.

Q. Please describe your educational background.

A. In 1975, I obtained a Bachelor of Science degree in Industrial Management from Purdue University with a Computer Business Systems concentration. In 1985, I obtained a Master of Business Administration degree from Indiana University with a Finance concentration.

Q. Please describe your professional experience.

A. I have been employed by subsidiaries of Vectren Corporation (or its predecessor company, Indiana Energy, Inc.) since 1981. My primary focus has been in Regulatory Affairs and Gas Supply. I assumed my current position in 2001.

Q. Have you previously testified before this Commission?

A. Yes. I presented testimony on behalf of Vectren South in its last general rate proceeding, Cause No. 42596. I have presented testimony on behalf of Vectren North in its last four general rate proceedings, Cause Nos. 38080, 38918, 39353, and 42598. I have also presented testimony in numerous Gas Cost Adjustments ("GCA") and other regulatory proceedings for Vectren North and Vectren South.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony in this proceeding will:

1. Describe Vectren South's request for a Generation Cost and Revenue Adjustment ("GCRA").
2. Propose filing timing, implementation procedures and proforma filing schedules for processing the requested GCRA and MISO Cost and Revenue Adjustment ("MCRA") on a quarterly basis after the Commission's order in this proceeding.
3. Present Vectren South's proposed revisions to its Tariff for Electric Service ("Tariff") as shown in Petitioner's Exhibit No. JLU-2, reflecting a) the requested rate design and cost and revenue adjustment proposals advanced in this proceeding, b) certain changes to the General Terms and Conditions, and c) various other proposed Tariff changes.
4. Propose a method for reconciling, as of the effective date of rates in this proceeding, certain deferred balances being proposed for amortization in the revenue requirement supported by the direct testimony of Petitioner's Witness M. Susan Hardwick, and deferred amounts related to tracking Adjustments proposed to be eliminated.

II. GENERATION COST AND REVENUE ADJUSTMENT

Q. What is Vectren South's proposal regarding implementing a Generation Cost and Revenue Adjustment.

A. Vectren South is requesting the Commission approve its proposed GCRA, a comprehensive adjustment mechanism that would adjust Vectren South's Rates and Charges quarterly to reflect changes in certain material and variable costs and revenues related to Vectren South's generation facilities.

Q. What generation related costs and revenues does Vectren South propose to adjust through the GCRA?

A. The costs and revenues that are proposed to be adjusted by the GCRA are as follows:

1. Non-Firm Wholesale (NFW) margins
2. Municipal Wholesale (MW) margins
3. Purchased Power Non-Fuel costs
4. Environmental Chemical costs
5. Environmental Emission Allowance credits (net of costs)
6. Direct Load Control (DLC) billing credits
7. Interruptible Sales billing credits

Q. Please describe each of these costs and revenues and Vectren's proposal for tracking them through the GCRA.

A. <u>Non-Firm Wholesale (NFW) margins</u> are derived primarily by Vectren South's sales into the MISO Day Ahead and Real Time markets. As described by Petitioner's Witness Ronald G. Jochum in his direct testimony these margins are material and variable and their achievement is impacted by a number of factors largely outside the control of the Company. Vectren South has included a proforma amount of NFW margins in the revenue requirement in this proceeding and proposes to track through the GCRA any differences from that amount on a 50/50 sharing basis with customers.

<u>Municipal Wholesale (MW) margins</u> are derived by Vectren South's sales to Municipal customers. As described by Mr. Jochum in his direct testimony, contracts with these Municipal customers are short-term in nature, the margins received from these contracts are below fully allocated costs, and the Company does not expect to retain these contracts into the future. Vectren South proposes to credit to customers through the GCRA 100% of margins from existing MW agreements; margins from any future MW agreements would be tracked through the GCRA using the Non-Firm Wholesale NFW 50/50 sharing approach described above.

Purchased Power Non-Fuel costs are the charges Vectren South pays power suppliers to reserve purchased power capacity to help meet the peak and seasonal energy needs of its customers. These costs are typically not recovered through the Fuel Adjustment Clause ("FAC"), but are material and can change dramatically as the underlying purchased power agreements expire and are replaced. Mr. Jochum describes these costs in his direct testimony. Vectren South has included a proforma amount of Purchased Power Non-Fuel costs in its revenue requirement in this proceeding and proposes to track through the GCRA any differences from that amount.

Environmental Chemicals costs are the costs for the chemicals required as part of mandated environmental control equipment additions to Vectren South's coal fired generation facilities. As described by Mr. Jochum in his direct testimony, these costs are highly correlated with commodity fuel prices and therefore they vary dramatically with changes in the costs of the underlying fuel. Vectren South has included a proforma amount of Environmental Chemical costs in the revenue requirement in this proceeding and proposes to track through the GCRA any differences from that amount.

In addition, Vectren South proposes to reduce the Environmental Chemicals costs to be tracked through the GCRA by the net margins received from by-product sales arising from the operation of the environmental control equipment. These by-product sales opportunities are discussed in Mr. Jochum's testimony.

Environmental Emission Allowance Credits (Net of Costs) are the revenues resulting from the use or sale of emission allowances related to Vectren South's compliance with federally mandated coal-fired generation emission requirements, offset by the costs of the emission allowances used or sold. Vectren South proposes to track these net credits through the GCRA, utilizing the sharing provisions provided for in Vectren South's Multi-Pollutant Settlement in Cause No. 42861.

Direct Load Control (DLC) billing credits and Interruptible Sales billing credits are credits applied to the bills of customers who agree to a reduced level of electric usage during peak hours for peak load management purposes. The usage reductions help Vectren South reduce the amount of generation capacity or purchase power needed to meet peak needs. Vectren South has included a proforma amount of these billing credits in the revenue requirement in this proceeding and proposes to track through the GCRA any differences from those amounts.

Q. What are the proforma amounts included in base rates for these GCRA tracked costs and revenues?

A. The following table shows the proforma amounts included in base rates.

Item	GCRA Component	Base Rate Amount ($/year)
1	Non-Firm Wholesale Margins	$10,519,387
2	Municipal Wholesale Margins	$ 0 *
3	Purchase Power Non-Fuel Costs	$ 4,275,500
4	Environmental Chemical Costs	$16,357,958
5	Environmental Emission Allowance Credits (net of costs)	$ 0
6	Direct Load Control (DLC) Billing Credits	$ 915,081
7	Interruptible Sales Billing Credits	$ 1,126,676

* $13,680,764 of proforma Municipal Wholesale margins, although not a proforma credit in base rates, have been reflected as a credit in the proforma GCRA (Sheet No. 74) used by Petitioner's rate design Witness William R. Hopkins for calculation of customer bill impacts.

Q. Describe the proposed GCRA Tariff Sheet.

A. Sheet No. 74 of Vectren South's proposed Tariff contains the proposed Appendix J – Generation Cost and Revenue Adjustment. Quarterly the GCRA Rates applicable to each Rate Schedule would be updated using the calculation reflected in Appendix J. The updated GCRA Rates would then adjust the Energy Charge for each Rate Schedule.

The actual GCRA amounts passed back to or recovered from customers for each quarter would be reconciled with GCRA amounts calculated for passback to or recovery from customers for such quarter, with any variances being reflected in subsequent GCRA quarterly filings.

Q. Describe the GCRA calculation.

A. The equation for calculating the GCRA Rates is contained in Appendix J. It is as follows:

$$\frac{\text{(Generation Costs} - \text{Generation Revenues)} * \text{Rate Schedule Allocation Percentage}}{\text{Rate Schedule Quantities}}$$

Generation Costs include Purchased Power Non-Fuel costs, Environmental Chemicals costs, Direct Load Control billing credits, and Interruptible Sales billing credits, as described above, for the given quarter less the quarterly amounts for these costs and billing credits included in the base rates revenue requirement ("base rates").

Generation Revenues include the net margins from Non-Firm Wholesale sales, and Municipal Wholesale sales, and Emission Allowance Credits (net of costs) for the given quarter, less the base rate amount of these revenues for the quarter, if applicable, included in base rates, and as adjusted for any sharing between Company and Customer.

Rate Schedule Allocation Percentage is the proportion of the quarterly GCRA amounts applicable to each Rate Schedule. The percentages are the Production Demand Allocation percentages by Rate Schedule as determined in the cost of service study performed by Petitioner's Witness Kerry A. Heid and included in his direct testimony in this proceeding.

Rate Schedule Quantities are the quarterly Energy Charge quantities estimated for each Rate Schedule over which the allocated GCRA amounts would be passed back or recovered.

The GCRA Rates so calculated would be further adjusted to reflect the Indiana Utility Receipts Tax or other applicable revenue taxes.

Q. What are the benefits of tracking actual Non-Firm Wholesale and Municipal Wholesale sales margins in the GCRA?

A. As explained by Mr. Jochum, the NFW and MW margins are variable and not subject to being reasonably determined into the future on a fixed, known, and measurable basis. The margins are material and variable in amount and if included in base rates without tracking and then not realized would have a material adverse impact on Vectren South's earned return. On the other hand, if Vectren South realized NFW and MW margins in excess of any amount of such margin included in base rates, without tracking, the retail customers would not receive any of the benefit of the sales margins above the base rates amounts. Therefore, base rate treatment for these margins has risks for the Company and Customers that can be eliminated by using a tracking adjustment. Vectren South's proposed GCRA offers a balanced approach that tracks actual NFW and MW margins, benefiting both Vectren South and its customers.

Q. What are the benefits of tracking changes in base rate levels of Direct Load Control billing credits and Interruptible Sales billing credits?

A. These credits are provided to customers that agree to interruption or curtailment of service at the time of Vectren South's system peak or when otherwise required to maintain reliable service to customers. The GCRA treatment of these billing credits allows Vectren South to pursue demand reduction opportunities, reducing its peaking costs for the benefit of all its customers, without suffering financial harm through the loss of billing margins. If not able to track any increases in the billing credits provided, Vectren South would have a disincentive to pursue additional conversions to DLC and interruptible load. With the tracking, that disincentive is removed, and Vectren South can pursue peak load reductions that can reduce costs for all customers.

Q. Why have you proposed to allocate GCRA amounts to Rate Schedules based on Production Demand Allocation percentages?

A. The Production Demand Allocation percentages are used in the Cost of Service Study to allocate the costs of Vectren South's generation facilities and Purchased Power Non-Fuel costs to the various Rate Schedules. Because all of the cost and revenue components of the GCRA are directly related to generation facilities and/or Purchased Power, Vectren South has proposed to utilize the related Production Demand Allocation Percentages. For example, NFW and MW sales are made possible from Vectren South's otherwise unutilized generation and purchased power portfolio. Likewise, Emission Allowance credits are a function of generation operations, as is the level of Environmental Chemicals usage. And finally, the DLC and Interruptible Sales Billing Credits are provided to subscribing customers in order to minimize peak day generation costs.

Q. Do you believe that the approval of Vectren South's proposed GCRA is in the public interest?

A. Yes. In my opinion, Vectren South's proposed GCRA is an efficient and equitable means of adjusting Rates and Charges to reflect the variable costs and revenues arising from Vectren South's generation facilities and Purchased Power Non-Fuel costs. It provides the Company with an incentive to maximize NFW and MW sales margins to the benefit of the Company and its customers through the margin sharing aspect of the GCRA. It allows for the Company's recovery of Purchased Power Non-Fuel costs that are incurred to meet the peak and seasonal energy needs of its customers, while at the same time also removing a disincentive for the Company's offering of DLC and Interruptible Sales billing credits in an effort to reduce the peak energy needs of its electric system. The tracking of volatile Environmental Chemical costs will allow any reductions to such cost to flow to the benefit of customers with any increases being recoverable by the Company. The GCRA results in the alignment of Company and customer interests that helps ensure that adequate and reliable energy is available to retail customers at the lowest cost reasonably possible.

Q. Has the Commission previously approved regulatory mechanisms to track costs and revenues similar to these proposed for recovery in the GCRA?

A. Yes. Vectren South's proposed treatment for its Non-Firm Wholesale Sales margins of 50/50 sharing around a base rate amount is identical to the tracking approach approved for Duke Energy Indiana (PSI Energy), in its last rate case. In that proceeding, the Commission also approved tracking of certain Purchased Power Non-Fuel costs and the costs of interruptible sales programs similar to

Vectren South's proposal. The DLC Billing Credits proposed for tracking in the GCRA are similar in purpose to Interruptible Sales costs.

Regarding Environmental Chemicals, Vectren South is currently tracking the chemical costs related to operation of its NOx control equipment pursuant to Commission order approving Appendix F – QPCP-OE Adjustment, and would also track future costs related to the Warrick 4 scrubber pursuant to the Commission's Order in Cause No.42861.

And Vectren South currently tracks back to customers its Emission Allowance credits (net of costs) related to SO_2 through its CAAA, and related to the sales of NOx allowances through Appendix F – QPCP-OE Adjustment.

III. <u>PROPOSED REGULATORY PROCESS FOR GCRA AND MCRA</u>.

Q. What is Vectren South's proposal regarding a regulatory filing process for its proposed GCRA?

A. Vectren South proposes a similar quarterly process to that currently used for Vectren South's FAC. That is to say the Company would file its petition with the proposed GCRA Rates, 2) the Commission would schedule an evidentiary hearing in the proceeding, 3) the Company would file its pre-filed direct testimony supporting the proposed GCRA Rates, including the reconciliation from a prior quarter, 4) any interested parties would file pre-filed direct testimony, 5) the Commission would hold an evidentiary hearing limited to the generation costs and revenues reflected in the filing, and 6) the Commission would issue an order in the proceeding.

Q. What timing would you propose for the quarterly GCRA filings?

A. Vectren South proposes a quarterly filing schedule that would be offset one month from the current FAC filing schedule. Vectren South's FAC petitions, as well as its gas division's Gas Cost Adjustments ("GCA"), are filed in early December, March, June and September for implementation on the first days of February, May, August, and November. For the GCRA, the Company proposes petition filing dates of early January, April, July, and October with implementation dates of the first days of March, June, September, and December. The GCRA schedule's one-month offset to the FAC and GCA filing schedule helps spread the workload that would otherwise overlap under simultaneous filing schedules.

Q. What will Vectren South include in its quarterly filings?

A. The quarterly filings will consist of testimony and exhibits reflecting 1) the calculation of incremental Generation costs and revenues to be tracked in the upcoming quarter, 2) actual GCRA billing revenue from a prior quarter, 3) a reconciliation of the actual GCRA billing revenue with the incremental GCRA cost and revenues for such prior quarter, and 4) the derivation of the GCRA Rates by Rate Schedule to be applied for the upcoming quarter.

Q. Have you proposed proforma filing schedules to reflect the information that would be included in the quarterly GCRA filings?

A. Yes. Petitioners' Exhibit No. JLU-3 contains the proposed GCRA proforma filing schedules. All of the schedules are for illustrative purposes. Although the schedules contain numbers and derive GCRA rates, they are illustrative, intended only to demonstrate the calculations of the various schedules.

Q. Please describe the GCRA proforma filing schedules.

A. Schedule 1 is the Determination of GCRA Rates showing by each month of the quarter, and for each Rate Schedule, the estimated Energy Sales quantities, the Production Demand Allocation factor, and the incremental Generation Costs and Revenues to be tracked. A unit rate is then calculated, including any prior period variance, and IURT is applied, to derive the quarterly GCRA Rates.

Schedule 2 shows the GCRA Cost Allocation Factors used to allocate GCRA Costs by Rate Schedule, as derived from the Production Demand Allocation percentages in the Cost of Service Study.

Schedule 3 shows the calculation of the incremental Generation Costs and Revenues for the prior quarter including any sharing of NFW and MW margins. Schedule 3A separately calculates the sharing associated with the various Environmental Emission Allowance credits.

Schedule 4, pages 1 through 3, show the reconciliation of actual billed GCRA amounts from each month in the prior quarter and the GCRA amounts intended for recovery during each month. The resulting variance is carried forward for inclusion in the GCRA rate calculation for the upcoming quarter.

Q. What is Vectren South's proposal regarding a regulatory filing process and schedule for its proposed MISO Cost and Revenue Adjustment ("MCRA"), as described in Mr. Seelye's testimony?

A. Vectren South proposes the same filing process and the same quarterly schedule for its proposed MCRA as explained above for its GCRA. The MCRA petition would be filed separately from the GCRA petition, and would be on its own procedural schedule, but the quarterly timing would be simultaneous with the GCRA.

Q. Has Vectren South proposed proforma schedules to reflect the information that would be included in the quarterly MCRA filings?

A. Yes. Mr. Seelye describes those proforma filing schedules in <u>Petitioners' Exhibit Nos. WSS-1 and WSS-7.</u>

IV. <u>PROPOSED REVISIONS TO TARIFF FOR ELECTRIC SERVICE</u>

Q. What revisions have been proposed to Vectren South's Tariff for Electric Service contained in <u>Petitioner's Exhibit No. JLU-2</u>?

A. The Tariff reflects the following proposed revisions:

1. Rate and Charges revisions and Rate Schedule revisions and additions as detailed by Witness William Hopkins in his direct testimony including 1) splitting Rate GS - General Service into two Rate Schedules — Rate SGS - Small General Service and Rate DGS – Demand General Service, 2) elimination of certain Street Lighting Rate Schedules due to no remaining customers, and 3) the addition of two interruptible service Riders.
2. The addition of Rider ED – Economic Development Rider and Rider AD – Area Development Rider as described in the direct testimony of Petitioner's Witness Ronald B. Keeping.

3. The elimination of Rider HLF – 1 – Energy Incentive Rider, due to no remaining customers, and its replacement by the above mentioned economic development Riders.
4. The addition of Rider DLC – Direct Load Control Rider, which places in the Tariff the billing credits that are part of the Company's DSM program implementation.
5. The addition of Appendix I – MISO Cost and Revenue Adjustment as detailed in the testimony of Mr. Seelye.
6. The addition of Appendix J – Generation Cost and Revenue Adjustment as detailed in my testimony above.
7. The addition of a Definitions Section to contain definitions of words and terms that reoccur in the Tariff. The defined terms are shown with initial capital letters when they later appear in the Tariff.
8. The addition of Appendices and Riders sections to each Rate Schedule to more readily identify Adjustments and available Riders applicable to customers in each Rate Schedule.
9. The eliminations of Appendix B – Demand-Side Management Adjustment and Appendix C – Clean Air Act Amendment Adjustment, as described below.
10. The elimination of Appendix E – Qualified Pollution Control Property – Construction Cost Adjustment and the future elimination of Appendix F – Qualified Pollution Control Property – Operating Expense Adjustment, both as described below.
11. The addition of language providing more detailed descriptions for the recurring charges already reflected in Appendix D, Other Charges.
12. Revisions to the General Terms and Conditions, including 1) the proposed addition of a provision to Rule 1, Application of Rates, 2) the revision of language describing the Equal Payment Plan in Rule 10d., 3) the addition of details regarding Vectren South's Curtailment Procedures in Rule 19, and 4) the elimination of Rule 21 – Utility Residential Weatherization Program, all as described below.
13. And other minor changes in the nature of housekeeping throughout the Tariff.

Q. Why has Vectren South proposed to eliminate Rider HLF-1, Energy Efficiency Rider?

A. The Rider is proposed to be replaced by the economic development Riders being proposed by Mr. Keeping. The HLF-1 Rider had provided billing discounts on new load for Rate HLF customers that participated in an Energy Efficiency Audit. The proposed economic development Riders will provide similar opportunity for qualifying customers to obtain a discount on new load, subject to Applicability requirements.

Q. Please describe the proposed Rider DLC – Direct Load Control Rider.

A. Vectren South has provided billing discounts to DLC customers since the inception of the Direct Load Control program. These credits had not been reflected in Vectren South's Tariff. This Rider simply reflects the inclusion of those credits in the Tariff.

Q. Please explain the reason for the proposed elimination of Appendix B – Demand-Side Management Adjustment.

A. Pursuant to the Commission Order in Cause No. 40322 dated July 3, 1996, the Demand Side Management Adjustment, which recovers lost margin due to implemented DSM programs, was set to expire after Vectren South's next general rate case. Accordingly, the Adjustment tariff sheet will be eliminated on the effective date of new rates approved in this proceeding. Vectren South proposes that any balance remaining in the DSM Adjustment deferred account be reflected in the proposed GCRA until fully recovered from or passed back to customers, as descried in Section V below.

Q. Please explain the reason for the proposed elimination of Appendix C - Clean Air Act Amendment ("CAAA") Adjustment.

A. Vectren South is proposing that the CAAA, which flows back to customers the proceeds from Vectren South's use of SO_2 emission allowances for Non-Firm Wholesale Sales, be incorporated into Vectren South's proposed GCRA. As described above, upon approval of the proposed GCRA, all emission allowance credits, including SO_2 credits, would begin flowing through the GCRA upon its effectiveness.

Q. Please explain the reason for the proposed elimination of Appendix E – QPCP-CC and Appendix F – QPCP-OE.

A. Appendix E recovers the capital costs of Vectren South's investment in SCRs to control NOx emissions from its generation facilities, pursuant to the Commission's orders in Cause Nos. 41864, 42248, and 42340. Vectren South has rolled the investment associated with this NOx control equipment into its rate base in this proceeding. Prospectively, at the effective date of rates, Appendix E will no longer be required and it can be eliminated.

Appendix F recovers the operating costs of Vectren South's NOx control investments, including depreciation and chemical costs pursuant to the Commission orders in Cause Nos. 42248 and 42941.. Vectren South has rolled these costs into its revenue requirement in this proceeding. Just like the QPCP-CC Adjustment, the QPCP-OE Adjustment will be eliminated at the effective date of new rates. As described in Section II above, Vectren South proposes to continue to track Environmental chemical costs via its proposed GCRA. As described in Section V below, at the effective date of rates, Vectren South proposes to reconcile any remaining Appendix F deferred amounts, including reconciliation of prior periods OE expenses and recoveries, and track the differences through the GCRA.

Q. Please describe the proposed addition to Rule 1, Application of Rates.

A. Vectren South proposes to add paragraph 6. to Rule 1(a) containing the following statement:

"6. Company may refuse Electric Service or disconnect Electric Service on account of arrearages due for Electric Service furnished to persons formerly receiving Service at the Premises as Customer of Company, if the Customer continues to reside at such Premises."

The purpose of the added provision is to prevent the Customer's attempted reconnection or avoidance of disconnection for non-payment by virtue of transferring the service to the name of another person in the household. The change is intended to help manage bad debt expense.

Q. What changes are proposed to the Equal Payment Plan in Rule 10d.?

A. The current Tariff language reflects the mechanics of a prior version of Vectren South's equal payment plan. Because the mechanics may change from time to time, Vectren South has proposed to replace the outdated detailed mechanics language with generic language describing the Equal Payment Plan components.

Q. Have you eliminated Rule 17, Fuel Adjustment Clause (FAC)?

A. Yes. The language of Rule 17 referred to Appendix A, which now contains the description of the Company's FAC, Rule 17 was therefore eliminated and the subsequent rules were renumbered accordingly.

Q. Please describe the proposed revisions to Rule 19 – Mandatory Curtailment.

A. Rule 19 has been renumbered to Rule 18 and renamed to Curtailment Procedures and updated to include details regarding the procedures Vectren South would utilize in the event of a need to curtail electric service to its customers. The updates include a description of the reasons for the need to curtail, the Company's liability in the event of Curtailment of service, a definition of Human Needs customers, and information on Curtailment Initiation, Customer Notification, Curtailment Lifting, and Unauthorized Use of Energy during a Curtailment. The proposed Curtailment Procedure specifically references Vectren South's Capacity and Energy Emergency Plans, which Vectren South utilizes in the event of a Curtailment.

Q. Why have you proposed to eliminate Rule 21 – Utility Residential Weatherization Program ("URWP")?

A. Since the last update of the Tariff, the URWP has been discontinued. This update removes the program language from the Tariff.

Q. Is Vectren South proposing to revise the page numbering method for its Tariff?

A. Yes. Under the Company's current method of numbering tariff sheets, each sheet is first labeled "Original Sheet No. N, Page X of Y". Subsequent revisions are then labeled "First Revised Sheet No. N, Page X of Y", Second Revised Sheet No. N, Page X of Y", etc. Vectren South proposes a new method of tariff sheet numbering, wherein each tariff sheet would initially be labeled "Sheet No. N, Original Page X of Y". Subsequent revisions would then be labeled "Sheet No. N, First Revised Page X of Y", "Sheet No. N, Second Revised Page X of Y", etc. Under the proposed method, Vectren South would file with the Commission only the pages to which changes have been made, rather than filing each page of a tariff sheet to implement a change on only a single page. Vectren South believes this change will ease administrative burden on both the Commission and the Company.

V. DEFERRAL BALANCE RECONCILIATION

Q. Is Vectren South proposing to reconcile certain deferred balances as reflected in its revenue requirement with actual deferred balances as of the effective date of rates in this proceeding?

A. Yes. The deferred accounts that are being proposed for amortization in the revenue requirement in this proceeding will undoubtedly have different balances in those accounts as of the effective date of new rates. Vectren South is also proposing to eliminate or roll into a new tracker certain existing trackers, which will also have remaining balances as of the effective date of rates. Vectren South proposes to track the differences or remaining amounts in those deferred account balances, with such amounts being reflected in either the MCRA or the GCRA depending upon the nature of the deferred account being reconciled.

Q. Why is Vectren South proposing a reconciliation of deferred amounts?

A. A number of expenses have been deferred by the Company pursuant to orders of the Commission, with such deferred amounts to be considered in a subsequent general rate proceeding. Vectren South has proposed amortization of these deferred amounts in this proceeding, in some cases using estimates of the balances as of March 31, 2007, the end of the adjustment period. Pursuant to the deferral orders, Vectren will continue to defer applicable expenses to those deferred accounts until new rates are effective. The proposed reconciliation will allow the estimated deferred balances to be used for establishing the amortization, with the knowledge that any difference from the estimated deferred balances will be tracked dollar for dollar through the MCRA or GCRA, as applicable.

Q. What are the deferred accounts you are proposing to reconcile and through which proposed Adjustment—MCRA or GCRA—would the differences be tracked?

A. The following table shows the deferred amount to be reconciled and the Adjustment proposed to track the difference.

Item	Deferred Amount	Adjustment
1	DSM Lost Margin Deferral	GCRA
2	DSM – Other Deferrals (including DLC Billing Credits)	GCRA
3	QPCP-OE Deferrals	GCRA
4	CAAA Deferrals	GCRA
5	MISO Day 1 Deferrals	MCRA
6	MISO Day 2 Deferrals	MCRA

Q. Does this complete your Prepared Direct Testimony?

A. Yes, it does.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A
VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH)

TARIFF FOR ELECTRIC SERVICE

I.U.R.C. No. E-12

ISSUED PURSUANT TO ORDER OF THE
INDIANA UTILITY REGULATORY COMMISSION
IN CAUSE NO. 43111
EFFECTIVE ____________

Communications concerning this tariff may be addressed to:

Mail: Regulatory Affairs Department
Vectren Corporation
One Vectren Square
Evansville, IN 47708

Phone: 800-227-1376
E-mail: VectrenCustomerCare@Vectren.com

TARIFF SHEET INDEX

TARIFF SHEET INDEX
(Continued)

TARIFF SHEET INDEX
(Continued)

Effective:

TARIFF SHEET INDEX
(Continued)

DEFINITIONS

Except where the context requires otherwise, the following terms shall have the meanings defined below when used in this Tariff for Electric Service:

Abbreviations:

- **FAC** – Fuel Adjustment Clause
- **FERC** – Federal Energy Regulatory Commission
- **IURC** – Indiana Utility Regulatory Commission
- **kVa** – Kilovolt-Ampere
- **kW** – Kilowatt
- **kWh** – Kilowatt-hour
- **OUCC** – Indiana Office of Utility Consumer Counselor

Ampere – The unit used to measure an electric current or rate of flow of electricity in a circuit.

Bill – An itemized list or statement of fees and charges for Electric Service or other services provided by Company. A Bill may be rendered by mail or by electronic means.

Billing Demand – The Customer's measured, estimated, calculated or contracted usage in kW or kVa utilized for billing purposes, determined as specified in the applicable Rate Schedule.

Commission – The Indiana Utility Regulatory Commission.

Commission's Regulations – The Indiana Administrative Code, Article 4 for Electric Utilities, as promulgated from time to time by the Commission. (A copy of the Commission's Regulations is available upon request by contacting the Regulatory Affairs Department.)

Company – Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (Vectren South).

Company's General Terms and Conditions – General Terms and Conditions Applicable to Electric Service, as amended from time to time, and as approved by the Commission as part of this Tariff for Electric Service.

Curtailment – The interruption or limitation of the Electric Service available to Customer pursuant to Company's Curtailment Procedures.

Curtailment Period – The period of time, as specified by Company, during which Electric Service is subject to Curtailment.

Curtailment Procedures – Rule 19 of Company's General Terms and Conditions.

DEFINITIONS

Customer – Any individual, partnership, association, firm, public or private corporation or any other entity receiving Electric Service provided by Company with its consent. A Customer shall include any person receiving Electric Service from Company irrespective of whether that person is the individual in whose name the Electric Service is being received.

Fuel Adjustment Clause - Fuel cost recovery process approved for the Company through Commission orders, including the Commission's generic orders in Cause Nos. 33061, 35687 and 37712.

Industrial Customer – A Customer primarily engaged in a process that creates or changes raw or unfinished materials into another form or product.

K-12 School – An educational institution administering or providing educational programs from kindergarten through grade 12.

Month – the interval between successive regular meter reading dates.

Municipal Corporation – Corporation owned and operated by a city or town in Indiana.

Non-Residential Customer – Any Customer that is not a Residential Customer.

Premises – a distinct portion of real estate such as the living quarters for the use of a single family, or the main building of a Non-Residential Customer and may include the outlying or adjacent buildings used by the same, provided the use of service in the outlying buildings is supplemental to the service used in the main residence or building.

Rate Schedule – An Electric Service applicable to a particular classification of Customer with specific Availability, Applicability, Character of Service, Rates and Charges, and Terms and Conditions.

Residential Customer – Customer using Electric Service primarily for a single family dwelling unit, mobile home, apartment unit or condominium.

Service Area – Areas in which Company has Electric Service available or may offer Electric Service, as certified by the Commission.

Single Phase – A circuit energized by a single, alternating electromotive force.

Three Phase – A combination of three circuits energized by alternating electromotive forces that differ in phase by 120 degrees.

Watt – The unit of electric power represented by a current of one ampere under the pressure of one volt in a circuit of unity power factor.

RATE A
RESIDENTIAL SERVICE

AVAILABILITY
This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY
This Rate Schedule shall be applicable to any Residential Customer electing Service hereunder.

CHARACTER OF SERVICE
Service provided hereunder shall be alternating current, sixty hertz, Single Phase, three-wire 120/240 or 120/208 nominal volts, or any other mutually agreed upon voltages.

RATES AND CHARGES
The monthly Rates and Charges for service hereunder shall be:

Customer Facilities Charge:
$7.50 per month.

Energy Charge:
$0.14001 per kWh for the first 250 kWh used per month
$0.11001 per kWh for all over 250 kWh used per month

Minimum Monthly Charge:
The Minimum Monthly Charge shall be the Customer Facilities Charge.

Appendices:
The following Appendices shall be applied monthly:
- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

Riders:
The following Riders are available to qualified Customers:
- Rider NM – Net Metering Rider
- Rider DLC – Direct Load Control Rider

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE EH
HOME HEATING SERVICE

AVAILABILITY
This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY
This Rate Schedule shall be applicable to any Residential Customer who permanently and exclusively uses electric equipment for space heating, takes all service through one meter, and who elects service hereunder.

CHARACTER OF SERVICE
Service provided hereunder shall be alternating current, sixty hertz, Single Phase, three-wire 120/240 or 120/208 nominal volts, or any other mutually agreed upon voltages.

RATES AND CHARGES
The monthly Rates and Charges for service hereunder shall be:

Customer Facilities Charge:
$7.75 per month.

Energy Charge:
$0.12730per kWh for the first 250 kWh used per month
$0.09697 per kWh for the next 750 kWh used per month
$0.06000 per kWh for all over 1,000 kWh used per month

Minimum Monthly Charge:
The Minimum Monthly Charge shall be the Customer Facilities Charge.

Appendices:
The following Appendices shall be applied monthly:
- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

Riders:
The following Riders are available to qualified Customers:
- Rider NM – Net Metering Rider
- Rider DLC – Direct Load Control Rider

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE B
WATER HEATING SERVICE

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable to Customers electing service hereunder for separately metered service used for water heating, subject to the conditions set forth below. This Rate Schedule is closed to new Customers.

CHARACTER OF SERVICE

Service provided hereunder shall be alternating current, sixty hertz, Single Phase, three-wire 120/240 or 120/208 nominal volts, or any other mutually agreed upon voltages.

RATES AND CHARGES

The monthly Rate and Charges for service hereunder shall be:

Customer Facilities Charge:

$ 4.60 per month

Energy Charge:

$0.07370 per kWh for all kWh used per month.

Minimum Monthly Charge:

The Minimum Monthly Charge shall be the Customer Facilities Charge.

Appendices:

The following Appendices shall be applied monthly:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

Riders:

The following Rider is available to qualified Customers:

- Rider DLC – Direct Load Control Rider

Other Charges:

The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

TERMS AND CONDITIONS OF SERVICE

Service under this Rate Schedule shall be governed by Company's General Terms and Conditions, the Commission's Regulations and the following special provisions:

1. Any replacement heaters shall be thermostatically controlled and of a type approved by Company.
2. The water heaters shall be permanently installed and in regular use by Customer and shall not be less than 40 gallons capacity.
3. Company reserves the right to control the operation of water heaters where uncontrolled operation creates distribution system difficulties. In such event the controlled period will not exceed six hours per day, the hours of control to be determined by Company.
4. Electric Service will be furnished through a separate meter to which no other equipment may be connected.

RATE SGS
SMALL GENERAL SERVICE

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable to any Non-Residential Customer with 10kW or less of maximum demand electing service hereunder. The Company shall determine the Customer's estimated maximum demand by review of the connected load or other suitable means.

CHARACTER OF SERVICE

Service provided hereunder shall be alternating current, sixty hertz, Single Phase, three-wire 120/240 or 120/208 nominal volts, or any other mutually agreed upon voltages.

RATES AND CHARGES

The monthly Rates and Charges for service hereunder shall be:

Customer Facilities Charge:

$8.50 per month

Energy Charge:

$0.11707 per kWh for the first 1,000 kWh used per month
$0.08500 per kWh for the next 1,000 kWh used per month
$0.05300 per kWh for all over 2,000 kWh used per month

Minimum Monthly Charge:

The Minimum Monthly Charge shall be the Customer Facilities Charge.

Appendices:

The following Appendices shall be applied monthly:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

Riders:

The following Riders are available to qualified Customers:

- Rider NM – Net Metering Rider
- Rider DLC – Direct Load Control Rider

Other Charges:

The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

TERMS AND CONDITIONS OF SERVICE

Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE DGS
DEMAND GENERAL SERVICE

AVAILABILITY
This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY
This Rate Schedule shall be applicable to any Non-Residential Customer with a Maximum Demand of more than 10kW for light and/or power requirements supplied through one light meter and/or one power meter, or at the option of Company, through a single meter for lighting and power, who elects service hereunder.

CHARACTER OF SERVICE
Service provided hereunder shall be alternating current, sixty hertz, single or three phase, nominal voltages 120/240, 120/208, 240, 277/480, 480 volts, or any other mutually agreed upon voltages.

RATES AND CHARGES
The monthly Rates and Charges for service hereunder shall be:

Customer Facilities Charge:

$12.70 per month

Demand Charge:

The monthly charge for the first 10 kW of Billing Demand is included in the Energy Charge below:

All Billing Demand in excess of 10 kW $4.90 per kW.

Energy Charge:

$0.11557 per kWh for the first 1,000 kWh used per month
$0.08036 per kWh for the next 14,000 kWh used per month *
$0.04905 per kWh for all additional kWh used per month

*For Billing Demand in excess of 10 kW add 300 kWh per kW of such excess to this rate usage step.

Minimum Monthly Charge:

The Minimum Monthly Charge shall be the Customer Facilities Charge plus the Demand Charge.

TRANSFORMER OWNERSHIP DISCOUNT
This discount is available to Customers with Billing Demands exceeding 100 kW, when Customer owns, operates and maintains all transformer facilities and receives service at Company's available primary voltage. Customer's current monthly bill will be decreased nineteen cents ($0.19) per kW of Billing Demand.

RATE DGS
DEMAND GENERAL SERVICE
(Continued)

Appendices:
The following Appendices shall be applied monthly:
- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

Riders:
The following Riders are available to qualified Customers:
- Rider IP-2 – Interruptible Power Service
- Rider IO – Interruptible Option Rider
- Rider NM – Net Metering Rider
- Rider DLC – Direct Load Control Rider

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

DETERMINATION OF BILLING DEMAND
The Billing Demand for the current month shall be the average load in Kilowatts during the 15-minute period of maximum use in such month, as determined by suitable instruments installed by Company, but not less than 60% of the highest metered demand established during the 12 months preceding the billing date.

SEPARATE METERING
When the lighting and power demands are metered separately, the maximum demand of the Month shall be the arithmetical sum of the highest demands of each meter. The energy use of the lighting and power meters shall be added.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE OSS
OFF-SEASON SERVICE

AVAILABILITY
This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY
This Rate Schedule shall be applicable to any Non-Residential Customer with a Maximum Demand of more than 10kW for total electric service who permanently and exclusively uses electric equipment for space heating, taking all service through one meter, and who elects service hereunder.

CHARACTER OF SERVICE
Service provided hereunder shall be alternating current, sixty hertz, single or Three Phase, nominal voltages 120/240, 120/208, 240, 277/480, 480 volts, or any other mutually agreed upon voltages.

RATES AND CHARGES
The Monthly Rates and Charges for service hereunder shall be:

Customer Facilities Charge:
$12.00 per Month

Demand Charge:
$4.30 per kW per month for all kW of Billing Demand.

Energy Charge:
$0.07104 per kWh for all kWh used per month.

Minimum Monthly Charge:
The Minimum Monthly Charge shall be the Customer Facilities Charge plus the Demand Charge.

Appendices:
The following Appendices shall be applied monthly:
- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

Riders:
The following Riders are available to qualified Customers:
- Rider IP-2 – Interruptible Power Service
- Rider IC – Interruptible Option Rider
- Rider DLC – Direct Load Control Rider

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

RATE OSS
OFF-SEASON SERVICE
(Continued)

DETERMINATION OF BILLING DEMAND

The Billing Demand for the current month shall be the average load in Kilowatts during the 15-minute period of maximum use established during the previous months of June, July August or September, as determined by suitable instruments installed by Company, but not less than 10 kW.

TERMS AND CONDITIONS OF SERVICE

Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE LP
LARGE POWER SERVICE

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable to any Non-Residential Customer receiving service at primary or transmission voltage and having a Billing Demand of 300 kVa or greater.

CHARACTER OF SERVICE

Service provided hereunder shall be alternating current, sixty hertz, Three Phase, nominal voltages, 4160/2400, 12470/7200, 69000, 138000 volts or any other mutually agreed upon voltages. Customer shall furnish and maintain all necessary transforming, controlling and protective equipment. Service will be metered at the primary or transmission voltage supplied. Transmission voltage service, where available, shall be at 69kV or higher, at the option of Company.

RATES AND CHARGES

The monthly Rates and Charges for services hereunder shall be:

Customer Facilities Charge:
$125.00 per Month

Demand Charge:
$9.00 per kVa per month for all kVa of Billing Demand.

Transmission Voltage Discount (for delivery at 69 kV or higher):
$1.75 per kVa per month for all kVa of Billing Demand.

Energy Charge:
$0.04846 per kWh for all kWh used per month

Minimum Monthly Charge:
The Minimum Monthly Charge shall be the Customer Facilities Charge plus the minimum Demand Charge calculated as the Demand Charge per kVa multiplied by 60% of the highest Billing Demand over the preceding 12 months.

Appendices:
The following Appendices shall be applied monthly:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

RATE LP
LARGE POWER SERVICE
(Continued)

Riders:
The following Riders are available to qualified Customers:
- Rider IP – Interruptible Power Service
- Rider IP-2 – Interruptible Power Service
- Rider LP-1 – Energy Efficiency Rider
- Rider IC – Interruptible Contract Rider
- Rider IO – Interruptible Option Rider
- Rider ED – Economic Development Rider
- Rider AD – Area Development Rider

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

DETERMINATION OF BILLING DEMAND
Unless otherwise specified in the Contract, the Billing Demand for the current month shall be the average load in Kilovolt-Amperes during the 15-minutes period of maximum use in such month, as determined by suitable instruments installed by Company, but not less than 60% of the highest metered Demand during the 12 months preceding the billing date and in no event less than 300 kVa.

Off-peak demands which will be disregarded in determining the Billing Demand shall be those demands created: on Saturdays, Sundays, and holidays designated by Company or between 8:00 P.M. and 7:00 A.M. on any other day; provided that the Billing Demand for the month shall never be less than 50% of the maximum demand created during such month regardless of when such maximum demand occurred.

Company reserves the right, upon thirty days notice, to change the off-peak periods when peak load conditions on Company's system make such modification necessary. Company shall not be required to increase the capacity of any service facilities in order to furnish off-peak demands.

CONTRACT
For service hereunder, a written contract is required for an initial term of not less than three (3) years or for a longer period where unusual expenditures by Company may be necessary to provide service, and such contract shall continue for equal successive terms unless cancelled. The contract may be cancelled by either party by giving written notice to the other party not less than one (1) year prior to the date of termination.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE HLF
TRANSMISSION POWER SERVICE

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion. This service is available only from transmission facilities.

APPLICABILITY

This Rate Schedule shall be applicable to any Non-Residential Customer supplied at a single point of delivery who contracts for a capacity of not less than 4,500 kVa.

This Rate Schedule is not applicable to Customer where 1) an alternate source of power is used, 2) for resale to others, or 3) as a supplement to service furnished under any other Rate Schedule.

CHARACTER OF SERVICE

Service provided hereunder shall be alternating current, sixty hertz, Three Phase, nominal voltages 69,000, 138,000 volts or any other mutually agreed upon voltages. Customer shall furnish and maintain all necessary transforming, controlling and protective equipment.

RATES AND CHARGES

The monthly Rates and Charges for service hereunder shall be:

Demand Charge:

$156,735 per month for the first 4,500 kVa of Billing Demand
$34.83 per kVa per month for all over 4,500 of Billing Demand

Energy Charge:

The first 600 kWh per kVa of Billing Demand per month is included in the Capacity Charge.
$0.03798 per kWh for all additional kWh per month.

Minimum Monthly Charge:

The Minimum Monthly Charge shall be the Demand Charge, but not less than $156,735 per month.

Appendices:

The following Appendices shall be applied monthly:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation Cost and Revenue Adjustment

Riders:

The following Riders are available to qualified Customers:

- Rider IP – Interruptible Power Service
- Rider IC – Interruptible Contract Rider
- Rider IO – Interruptible Option Rider
- Rider ED – Economic Development Rider
- Rider AD – Area Development Rider

RATE HLF
TRANSMISSION POWER SERVICE
(Continued)

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

DETERMINATION OF BILLING DEMAND

The Billing Demand for the current month shall be the highest of the following:

(1) the average load in Kilovolt-Amperes during the 15-minute period of maximum use in such month, as determined by suitable instruments installed by Company;
(2) 90% of the highest Billing Demand occurring during the 12 months preceding the billing date;
(3) 75% of the contract demand;
(4) 75% of the highest Billing Demand occurring during the term of the contract.

Off-peak demands which will be disregarded in determining the Billing Demand shall be those demands created at night from 8 P.M. to 7 A.M., on Saturdays, Sundays, and holidays designated by Company; provided that the Billing Demand for the month shall never be less than 50% of the maximum demand created during such month regardless of when such maximum demand occurred.

Company reserves the right, upon thirty days' notice, to change the off-peak periods when peak load conditions on Company's system make such modification necessary. Company shall not be required to increase the capacity of any service facilities in order to furnish off-peak demands.

CONTRACT

For service hereunder, a written contract is required for an initial term of not less than five (5) years, or for a longer period where unusual expenditures by Company may be necessary to provide service, and such contract shall continue for equal successive terms unless cancelled. The contract may be cancelled by either party by giving written notice to the other party not less than three (3) years prior to the date of termination.

TERMS AND CONDITIONS OF SERVICE

Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE BAMP
BACKUP, AUXILIARY AND MAINTENANCE POWER SERVICES

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable to any Non-Residential Customer electing service hereunder whose electric capacity requirements are 1,000 kW or more and who own and operate 60 Hertz electric generating equipment, other than for emergency usage, to meet all or at least 1,000 kW of the Customer's electric loads. Both firm and non-firm services are available, however the firm capacity available under this Rate Schedule will be limited to 50 MW of contracted supply.

CHARACTER OF SERVICE

Backup Power Service is capacity and energy supplied by Company during forced outages of Customer's generation equipment in an amount not to exceed the lesser of (1) Customer's internal electric load, (2) the demonstrated capacity of its electric generating equipment, or (3) an otherwise mutually agreed amount. Backup Power is available as either firm or non-firm in its character. **Non-Firm Backup Power** is interruptible by Company and service may be interrupted for economic or system reliability reasons, Company will give Customer as much notice as possible of an economic interruption but will give Customer no less than ninety (90) minutes notice. When Company determines that load must be interrupted for system reliability reasons the Company will notify Customer as soon as possible of the interruption but will give Customer no less than ten (10) minutes notice. Company reserves the right to interrupt non-firm backup service whenever the incremental revenue to be received from Customer is less than the anticipated incremental expense to supply the energy during the interruption period. Customer may buy-through the economic interruption by notifying Company within thirty (30) minutes of the request for interruption whether it intends to interrupt load or wants Company to supply replacement energy for the interruptible load. The cost of the interruptible energy provided by Company will be the most expensive power used to provide for system load during the interruption period. Customer will be advised of the range of cost of the replacement energy. Customer cannot buy-through an interruption when the interruption is made for system reliability reasons. **Firm Backup Power** will only be available for a maximum period of 60 days in any contract year. Backup may be a combination of firm and non-firm capacity, the firm portion of which must be specified in the contract.

Auxiliary Power Service is capacity and energy supplied by Company to Customer to meet a portion of its native usage on an ongoing daily basis in parallel with Customer's use of its own electric generation equipment. The amount of Auxiliary Power Service made available from Company must be mutually agreed to by contract.

RATE BAMP
BACKUP, AUXILIARY AND MAINTENANCE POWER SERVICES
(Continued)

Maintenance Power Service is capacity and energy provided by Company to replace capacity and energy normally generated by Customer's generating equipment during a scheduled outage of such equipment. Maintenance Power will only be available by schedule as agreed to by Company a minimum of 14 days in advance.

All Power Services supplied hereunder shall be provided only to the extent of the available capacity of Company's electric facilities of its supply lines, at such frequency, phase, regulation and voltage as it has available at the location of service. Customer must provide protective and regulation equipment satisfactory to Company to interconnect and/or operate its electric generation facilities in parallel with Company's system.

RATES AND CHARGES

The monthly Rates and Charges for service hereunder shall be:

Customer Facilities Charge:	$100.00 per month
Capacity Charge:	
Backup Power	
-firm	$2.50 plus 120% of the capacity component in the current Rate CSP, per kVa of Rated Capacity.
-non-firm	$2.50 per kVa of Rated Capacity, plus $2.35 per kVa of Billing Demand.
Auxiliary Power	The Capacity Charge of the applicable retail Rate Schedule, per kVa of Billing Demand.
Maintenance Power	The applicable Demand Charge per kVa currently in effect for Rate LP, exclusive of any minimums.
Transmission voltage discount (for delivery at 69kv or higher)	$1.75 per kVa of Billing Demand or Rated Capacity.
Energy Charges:	
All energy used (Backup)	110% of the Company's hourly incremental energy costs for its peaking units, per kWh.
All energy used (Auxiliary and Maintenance)	The Energy Charge of the applicable retail Rate Schedule, per kWh of use, plus all applicable Appendices.

RATE BAMP
BACKUP, AUXILIARY AND MAINTENANCE POWER SERVICES

(Continued)

Appendices:
The following Appendices shall be applied monthly:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment
- Appendix J – Generation and Cost Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

DETERMINATION OF RATED CAPACITY, BILLING DEMAND AND ENERGY

Customer's Rated Capacity for Backup Power Service shall be equal to the nameplate rating of its owned and operated electric generating capacity at the service location, assuming a unity power factor, unless otherwise specified in the contract.

Customer's Billing Demand for Auxiliary Power Service shall be the average load in Kilovolt-Amperes during the 15 minute period of maximum usage in the month, but not less than the contract demand. If the contract demand is exceeded in any month, such higher amount shall be the new contract demand for balance of the agreement. The Billing Demand for Auxiliary Power Service shall not include any demand for capacity contracted as Firm Backup Power Service.

Customer's Billing Demand for Non-Firm Backup Power Service and Maintenance Power Service shall be the average load Kilovolt-Amperes during the 15-minute period of maximum usage in the month. The Billing Demand for Non-Firm Backup Power Service shall be the net resulting from the subtraction of any Auxiliary Power contracted for from the total metered demand. The usage billed for Auxiliary Power energy (kWh) shall be the metered supply by Company but not in excess of (a) 100% load factor for the contract demand and (b) the proportionate share of Customer's usage for its total electric load based on the ratio of the contracted Auxiliary Power capacity to Customer's total load. Any other energy (kWh) supplied shall be either Backup or Maintenance Service, as applicable.

RATE BAMP
BACKUP, AUXILLARY AND MAINTENANCE POWER SERVICES
(Continued)

CONTRACT

For Service hereunder, a written contract is required for an initial term of not less than three (3) years, or for a longer period where unusual expenditures by Company may be necessary to furnish service to Customer, and such contract shall continue for equal successive terms unless cancelled. The contract may be cancelled by giving written notice to the other party, not less than one (1) year prior to the date of termination. This contract shall specify the Rated Capacity of Customer's generating equipment and Auxiliary Contract Demand requested, as appropriate.

TERMS AND CONDITIONS OF SERVICE

Services under this Rate Schedule are governed by Company's General Terms and Conditions and the Commission's Regulations.

Auxiliary or standby services not available under this Rate Schedule shall be contracted in accordance with Company's General Terms and Conditions Applicable to Electric Service, Rule 15, Auxiliary or Standby Services.

RATE SL-1
STREET LIGHTING SERVICE

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable for standard street and highway lighting service to any Customer which is a Municipal Corporation.

CHARACTER OF SERVICE

Company will furnish, install, own and operate all equipment comprising the street lighting system, including poles, fixtures, street lighting circuits, transformers, luminaires and all appurtenances necessary to supply service hereunder. All equipment shall be of standard design and construction as approved by Company. Company will supply electric energy, replace lamps, repair and maintain all equipment. Company reserves the right to furnish such service from either series or multiple circuits, or both.

Service rendered hereunder is predicated upon the execution by Customer of a suitable agreement specifying the terms and conditions under which street lighting service will be provided by Company.

RATES AND CHARGES:

(Payable in equal monthly installments)

(A) Series and/or Multiple Incandescent Lamp Street Lighting Rates limited to Lamps in use and/or on Order as of August 1, 1968.

	Rate Per Lamp Per Year	
Overhead Construction – Wood Poles	Radial Wave Reflectors	Enclosing Globe
2500 Lumen	$ 39.50	$ 43.94
6000 Lumen		$ 69.11

RATE SL-1
STREET LIGHTING SERVICE
(Continued)

(B) Series and/or Multiple Mercury Vapor Lamp Street Lighting Rates Limited to Lamps in Use and/or on order as of December 31, 1980.

	Rate Per Unit Per Year	
Overhead Construction	Wood Poles	Metal Poles
175 Watt (Approximately 8,000 Lumens)	$ 88.81	$ 137.35
Twin arm 175 Watt (Approximately 16,000 Lumens), maximum arm length 15' ... 180° mounting	-	$ 247.78
250 Watt (Approximately 11,000 Lumens)	$ 122.08	$165.21
400 Watt (Approximately 20,000 Lumens)	$150.80	$ 175.97
Twin arm 400 Watt (Approximately 40,000 Lumens), maximum arm length 15' ... 180° mounting	-	$ 311.52
1000 Watt (Approximately 54,000 Lumens)	$226.18	$ 280.12

Underground Construction Where Breaking and Replacing Pavement and/or Sidewalk is Not Required	Rate Per Unit Per Year Metal Poles
175 Watt (Approximately 8,000 Lumens)	$ 148.14
Twin arm 175 Watt (Approximately 16,000 Lumens), maximum arm length 15' ... 180° mounting	$ 265.73

(C) Series and/or Multiple High Pressure Sodium Street Lighting Rates.

	Rate Per Unit Per Year	
Overhead Construction	Wood Poles	Metal Poles
175 Watt (Approximately 8,000 Lumens)	$88.81	$137.35
Twin arm 100 Watt (Approximately 16,000 Lumens) maximum arm length 15' ... 180° mounting	-	$247.78
150 Watt (Approximately 15,000 Lumens)	$93.75	$142.29
200 Watt (Approximately 20,000 Lumens)	$150.80	$175.97
Twin arm 200 Watt (Approximately 40,000 Lumens), maximum arm length 15' ... 180° mounting	-	$311.52
400 Watt (Approximately 45,000 Lumens)	$226.18	$280.12
Twin arm 400 Watt (Approximately 90,000 Lumens)	-	$484.77

RATE SL-1
STREET LIGHTING SERVICE
(Continued)

Underground Construction Where Breaking and Replacing Pavement and/or sidewalk is Not Required	Rate Per Unit Per Year Metal Poles
100 Watt (Approximately 8,000 Lumens)	$ 148.14
Twin arm 100 Watt (Approximately 16,000 Lumens), Maximum arm length 15' ... 180° mounting	$ 265.73
200 Watt (Approximately 20,000 Lumens) (where direct burial cable and imbedded type pole is used)	$ 256.75
Twin arm 200 Watt (Approximately 40,000 Lumens), Maximum arm length 15' ... 180° mounting (where direct burial cable and imbedded type poles is used)	$ 394.05
200 Watt (Approximately 20,000 Lumens), (where conduit and anchor base pole is used)	$ 310.58
400 Watt (Approximately 20,000 Lumens),	$ 387.81
Twin arm 400 Watt (Approximately 90,000 Lumens)	$ 560.20

In lieu of the annual rates herein set forth for underground service, Customer may elect to pay to Company prior to the installation of such underground service, the difference between the amount of investment required for the underground system and the amount required for a comparable overhead system. In the event Customer makes such election and payment, the rates herein provided for comparable overhead service shall apply.

Appendices:
The following Appendices shall be applied monthly to kWh determined based on Hours of Use:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

PAYMENT
Bills are payable monthly on or before the fifteenth day of the month following the calendar month during which service was supplied.

HOURS OF USE
Service shall extend from approximately one-half hour after sunset until one-half hour before sunrise, each and every night of the year, a total of approximately 4,000 hours each year.

CONTRACT
Service under this Rate Schedule requires a written contract for a term of not less than ten (10) years.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE SL-2
ORNAMENTAL STREET LIGHTING SERVICE
(Post Top Lantern Type Luminaire)

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable for ornamental street lighting service by Company to any Customer which is a Municipal Corporation, but restricted to use in groups for street lighting, in approved areas. This Rate Schedule is applicable only for post-top luminaires equipped with 175 Watt mercury vapor lamps, or 100 Watt high pressure sodium lamps mounted on wood posts suitable for a mounting height of approximately 15 feet and supplied from underground conductor.

CHARACTER OF SERVICE

Company will furnish, install, own and operate all equipment comprising the street lighting system, including posts, fixtures, street lighting circuits, transformers, luminaires and all appurtenances necessary to supply service hereunder. This service is limited to luminaire and post as approved by Company. Company will supply electric energy, replace lamps, repair and maintain all equipment.

Service rendered hereunder is predicated upon the execution by Customer of a suitable agreement specifying the terms and conditions under which street lighting service will be provided by Company.

RATES AND CHARGES

(Payable in equal monthly installments)

Underground Construction	Rate per Luminaire per year
175 Watt (Approximately 8,000 Lumens) Mercury Vapor Lamps – Wood Post (Restricted to Lamps in use as of October 6, 1983)	$89.79
100 Watt (Approximately 8,000 Lumens) High Pressure Sodium Lamp – Wood Post	$89.79

This Rate Schedule is restricted to the installation at Company expense of not more than an average of 50 feet of underground feeder per luminaire. Under this Rate Schedule, Company will not be required at its expense to break and replace or to bore under pavement and/or sidewalk. Customer will pay to Company in advance of installation the estimated installed cost of all underground feeder in excess of an average of 50 feet per luminaire and the estimated cost of breaking, replacing, and for boring under pavement and/or sidewalk. The average length of underground feeder per luminaire shall be determined by dividing the total length of underground feeder installed by the number of luminaires installed pursuant to any one order.

RATE SL-2
ORNAMENTAL STREET LIGHTING SERVICE
(Post Top Lantern Type Luminaire)
(Continued)

Appendices:
The following Appendices shall be applied monthly to kWh determined based on Hours of Use:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

PAYMENT
Bills are payable monthly on or before the fifteenth day of the month following the calendar month during which service was supplied.

HOURS OF USE
Service shall extend from approximately one-half hour after sunset until one-half hour before sunrise, each and every night of the year, a total of approximately 4,000 hours each year.

CONTRACT
Service under this Rate Schedule requires a written contract for a term of not less than ten (10) years.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE SL-3
ORNAMENTAL STREET LIGHTING SERVICE
(Contemporary Spherical)

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule is applicable for ornamental street lighting service by Company to any Customer which is a Municipal Corporation, but is restricted to use in groups for street lighting, in approved areas. This Rate Schedule is available only for post-top luminaires equipped with high pressure sodium lamps, on metal posts suitable for underground conductor.

CHARACTER OF SERVICE

Company will furnish, install, own and operate all equipment comprising the street lighting system, including posts, fixtures, street lighting circuits, transformers, luminaires and all appurtenances necessary to supply service hereunder. This service is limited to luminaire and post as approved by Company. Company will supply electric energy, replace lamps, repair and maintain all equipment.

Service rendered hereunder is predicated upon the execution by Customer of a suitable agreement specifying the terms and conditions under which street lighting service will be provided by Company.

RATES AND CHARGES

(Payable in equal monthly installments)

Underground Construction – Steel Post	Rate Per Fixture Per Year
200 Watt high pressure sodium lamp enclosed in approximately 28" diameter sphere mounted on 10' steel pole	$233.45

This Rate Schedule is restricted to installation at Company expense of not more than an average of 45' of underground feeder per unit. Under this Rate Schedule, Company will not be required at its expense to break and replace concrete or to bore under pavement and/or sidewalk. Customer will pay to Company in advance of installation the estimated cost of all underground feeder in excess of an average of 45' per unit and the estimated cost of breaking, replacing, and boring under pavement and/or sidewalk. The average length of the underground feeder per unit shall be determined by dividing the total length of underground feeder necessary for installation by the number of units installed pursuant to any one request order.

RATE SL-3
ORNAMENTAL STREET LIGHTING SERVICE
(Contemporary Spherical)
(Continued)

Appendices:
The following Appendices shall be applied monthly to kWh determined based on Hours of Use:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

PAYMENT
Bills are payable monthly on or before the fifteenth day of the month following the calendar month during which service was supplied.

HOURS OF USE
Service shall extend from approximately one-half hour after sunset until one-half hour before sunrise, each and every night of the year, a total of approximately 4,000 hours each year.

CONTRACT
Service under this Rate Schedule requires a written contract for a term of not less than ten (10) years.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RESERVED FOR FUTURE USE

RATE SL-5
EXPRESSWAY LIGHTING SERVICE

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable for expressway lighting service by Company to any Customer which is a Municipal Corporation.

This Rate Schedule is available only for luminaries equipped with mercury vapor and/or high pressure sodium lamps, on metal poles of extra height suitable for underground conductor.

CHARACTER OF SERVICE

Company will furnish, install, own and operate all equipment comprising the street lighting system including poles, fixtures, street lighting circuits, transformers, luminaires and all appurtenances necessary to supply service hereunder. This service limited to luminaire and poles as approved by Company. Company will supply electric energy, replace lamps, repair and maintain all equipment.

Service rendered hereunder is predicated upon the execution by Customer of a suitable agreement specifying the terms and conditions under which street lighting service will be provided by Company.

RATES AND CHARGES

(Payable in equal monthly installments)

(A) Mercury Vapor Street Lighting Rates Limited to Lamps In Use and/or On Order as of December 31, 1981.

Underground Construction – Metal Pole	Rate Per Fixture Per Year
1,000 Watt mercury vapor lamp and fixture with an approximate 40 foot mounting height (Frangible Construction)	$529.64
1,000 Watt mercury vapor lamp and fixture with an approximate 40 foot mounting height (Non-Frangible Construction)	$508.09

(B) High Pressure Sodium Street Lighting Rates

Underground Construction – Metal Poles	
400 Watt high pressure sodium lamp and fixture with an approximate 40 foot mounting height (Frangible Construction)	$529.64

RATE SL-5
EXPRESSWAY LIGHTING SERVICE
(Continued)

Twin 400 Watt high pressure sodium lamps and fixtures with an approximate 40 foot mounting height (Frangible Construction)	$745.10
400 Watt high pressure sodium lamp and fixture with an approximate 40 foot mounting height (Non-Frangible Construction)	$508.09

This Rate Schedule is restricted to installation at Company expense of not more than an average of 175 feet of underground feeder per unit. Under this Rate Schedule, Company will not be required at its expense to break and replace concrete or to bore under pavement and/or sidewalk. Customer will pay to Company in advance of installation the estimated cost of all underground feeder in excess of an average of 175 feet per unit and the estimated cost of breaking, replacing, and boring under pavement and/or sidewalk. The average length of the underground feeder per unit shall be determined by dividing the total length of underground feeder necessary for installation by the number of units installed pursuant to any one request order.

Appendices:
The following Appendices shall be applied monthly to kWh determined based on Hours of Use:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

PAYMENT
Bills are payable monthly on or before the fifteenth day of the month following the calendar month during which service was supplied.

HOURS OF USE
Service shall extend from approximately one-half hour after sunset until one-half hour before sunrise, each and every night of the year, the total of approximately 4,000 hours each year.

CONTRACT
Service under this Rate Schedule requires a written contract for a term of not less than ten (10) years.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RESERVED FOR FUTURE USE

RATE SL-7
ORNAMENTAL STREET LIGHTING SERVICE
(Turn of the Century)

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable for ornamental street lighting service by Company to any Customer which is a Municipal Corporation, but restricted to use in groups for street lighting, in specified areas that are approved by Company. This Rate Schedule is available only for post-top luminaires equipped with mercury vapor lamps, or high pressure sodium lamps, on metal posts suitable for underground conductor in which the Customer has made a contribution in aid of construction in the amount of the material cost of the posts and fixtures.

CHARACTER OF SERVICE

Company will furnish, install, own and operate all equipment comprising the street lighting system, including posts, luminaires, wiring, and all other appurtenances to supply service hereunder, except the Customer will furnish and install the anchor bases, grounding systems, conduits and handholds as specified by Company. This service is limited to luminaire and post as approved by Company. Company will supply electric energy, replace lamps, and repair and maintain all equipment unless otherwise agreed to by the parties.

Service rendered hereunder is predicated upon the execution by Customer of a suitable agreement specifying the terms and conditions under which street lighting service will be provided by Company.

RATES AND CHARGES

(Payable in equal monthly installments)

Underground Construction – Metal Post	Rate Per Fixture Per Year
100 Watt high pressure sodium lamp post top fixture on 12.5' steel post with cast iron ornamental top and base	$194.27

RATE SL-7
ORNAMENTAL STREET LIGHTING SERVICE
(Turn of the Century)
(Continued)

This Rate Schedule is restricted to installation at Company expense of not more than an average of 45' of underground feeder per unit. Under this Rate Schedule, Company will not be required at its expense to break and replace concrete or to bore under pavement and/or sidewalk. Customer will pay to Company in advance of installation the estimated cost of all underground feeder in excess of an average of 45' per unit and the estimated cost of breaking, replacing, and boring under pavement and/or sidewalk. The average length of the underground feeder per unit shall be determined by dividing the total length of underground feeder necessary for installation by the number of units installed pursuant to any one request order.

Appendices:
The following Appendices shall be applied monthly to kWh determined based on Hours of Use:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

PAYMENT
Bills are payable monthly on or before the fifteenth day of the month following the calendar month during which service was supplied.

HOURS OF USE
Service shall extend from approximately one-half hour after sunset until one-half hour before sunrise, each and every night of the year, a total of approximately 4,000 hours each year.

CONTRACT
Service under this Rate Schedule requires written contract for a term of not less than ten (10) years.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RATE SL-8
ORNAMENTAL STREET LIGHTING SERVICE
(Post Top Lighting Service)

AVAILABILITY

This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rate Schedule shall be applicable for ornamental street lighting service by Company to any Customer which is a Municipal Corporation, but restricted to use in groups for street lighting, in specified areas that are approved by Company. This Rate Schedule is available only for post-top luminaires equipped with high pressure sodium lamps, on fiberglass posts suitable for underground conductor in which Customer has made a contribution in aid of construction in an amount that will limit the installed cost to Company to the amount included in the rate ($400).

Customers other than a Municipal Corporation may be required to provide evidence of creditworthiness suitable to Company.

CHARACTER OF SERVICE

Company will furnish, install, own and operate all equipment comprising the street lighting system, including posts, luminaires, wiring, and all other appurtenances to supply service hereunder. This service is limited to luminaire and post as approved by Company. Company will supply electric energy, replace lamps, and repair and maintain all equipment unless otherwise agreed to by the parties.

Service rendered hereunder is predicated upon the execution by Customer of a suitable agreement specifying the terms and conditions under which street lighting service will be provided by Company.

RATES AND CHARGES:

(Payable in equal monthly installments) Underground Construction with Fiberglass Poles	Rate Per Unit Per Year
100 Watt high pressure sodium (8,000 lumen)	$105.73

Appendices:
The following Appendices shall be applied monthly to kWh determined based on Hours of Use:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

PAYMENT

Bills are payable monthly on or before the fifteenth day of the month following the calendar month during which service was supplied.

RATE SL-8
ORNAMENTAL STREET LIGHTING SERVICE
(Post Top Lighting Service)
(Continued)

HOURS OF USE
Service shall extend from approximately one-half hour after sunset until one-half hour before sunrise, each and every night of the year, a total of approximately 4,000 hours each year.

CONTRACT
Service under this Rate Schedule requires a written contract is required for a term of not less than ten (10) years.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by the Company's General Terms and Conditions and the Commission's Regulations.

RATE OL
OUTDOOR LIGHTING SERVICE (DUSK TO DAWN)

AVAILABILITY
This Rate Schedule shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY
This Rate Schedule shall be applicable for outdoor lighting to any Customer including Community Organizations or Real Estate Developers.

CHARACTER OF SERVICE
Service hereunder shall be dusk-to-dawn lighting service using a mercury lamp or a high pressure sodium lamp with photo-electric control. Lights installed in Municipal Corporations must be located on or extend over the property of Customer.

RATES AND CHARGES
The Rates and Charges for services hereunder shall be:

For each lamp with luminaire and bracket (not over four (4) feet in length) including one span of secondary conductors and/or service drop, mounted on a suitable existing pole, and served from Company's secondary distribution system.

MERCURY VAPOR

(Limited to lamps in use or on order as of December 31, 1981)

175 Watt (approximately 7,000 lumen) lamp	–	$6.66 per lamp per month
400 Watt (approximately 20,000 lumen) lamp	–	$9.67 per lamp per month
400 Watt (approximately 20,000 lumen) lamp	–	Directional Luminaire – $11.16 per lamp per month
1,000 Watt (approximately 50,000 lumen) lamp	–	Directional Luminaire – $19.28 per lamp per month

HIGH PRESSURE SODIUM

100 Watt (approximately 8,000 lumen) lamp	–	$6.66 per lamp per month
100 Watt (approximately 8,000 lumen) lamp	–	Directional Luminaire – $7.08 per lamp per month
200 Watt (approximately 20,000 lumen) lamp	–	$9.67 per lamp per month
200 Watt (approximately 20,000 lumen) lamp	–	Directional Luminaire – $11.16 per lamp per month
400 Watt (approximately 45,000 lumen) lamp	–	Directional Luminaire – $19.28 per lamp per month

When other new facilities are installed by Company, Customer will in addition to the above monthly charge, pay in advance of installation, the cost for the new overhead facilities extending from the nearest or most suitable pole of Company to the point designated by Customer for the installation of said lamp. Company, at its option may permit Customer to pay for such additional facilities in equal monthly installments extending over a period not to exceed twelve (12) months.

RATE OL
OUTDOOR LIGHTING SERVICE (DUSK TO DAWN)
(Continued)

Appendices:
The following Appendices shall be applied monthly to kWh determined based on Hours of Use:

- Appendix A – Fuel Adjustment Clause
- Appendix I – MISO Cost and Revenue Adjustment

Other Charges:
The Other Charges set forth in Appendix D shall be charged to Customer, if applicable.

CONTRACT
A Customer requesting service under this Rate Schedule, shall make and enter into a contract with Company in accordance with the following provisions:

1) The term of contract for Residential Customers will be for not less than one (1) year.
2) The term of contract for Non-Residential Customers will be for not less than three (3) years.
3) The term of contract for all Customers renting additional facilities on a monthly basis will be for not less than five (5) years.

Contracts for service hereunder may also contain other appropriate terms and conditions including annual payment in advance in cases where Company may deem it necessary to insure payment of Bills throughout the term of the contract.

HOURS OF USE
All lamps shall burn approximately one-half hour after sunset until approximately one-half hour before sunrise each day in the year, approximately 4,000 hours each year.

OWNERSHIP OF FACILITIES
All facilities installed by Company for service hereunder including fixtures, controls, poles, transformers, secondary line, lamps and other appurtenances shall be owned and maintained by Company. All service and necessary maintenance will be performed only during regular scheduled working hours of Company. Non-operative lamps will normally be restored to service within forty-eight (48) hours after notification by Customer.

When Customer requests that a lamp be mounted on Customer's pole or structure, Customer waives any claim for damages caused by the installation of secondary and lamp support attached to Customer's pole or structure.

TERMS AND CONDITIONS OF SERVICE
Service under this Rate Schedule shall be governed by Company's General Terms and Conditions and the Commission's Regulations.

RIDER IP
INTERRUPTIBLE POWER SERVICE

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rider shall be applicable to Rate LP and HLF Customers with an interruptible demand of at least 3,000 kW who were taking service under this Rider during September 1997.

CHARACTER OF SERVICE

(1) Company reserves the right to interrupt service to Customer at any time to maintain system integrity at the sole discretion of the Company.

(2) The number of interruptions shall not exceed one (1) per day and the hours of interruption shall not exceed eight (8) hours per day or two hundred fifty (250) hours per year. These limits shall not apply during any period of extended emergency experienced by Company.

(3) Company will endeavor to provide to Customer as much advance notice as possible of interruptions of service. However, Customer shall interrupt service within 10 minutes if so requested.

(4) Customer shall provide auxiliary switching in their plant for the purpose of separating the interruptible load from the firm power load specified in the contract.

(5) Customer shall specify in the initial contract a firm power level of demand, which Customer agrees not to exceed during each interruption period. The firm power level of demand may be changed at the end of a five year contract term by Customer giving Company at least three (3) years written notice of the proposed change, except (1) this restriction does not apply to increases in load resulting from application of Company's Efficiency Incentive Rider LP-1, and (2) this restriction may be waived at the sole discretion of Company after analysis of its capacity requirements.

Before accepting the specified firm power level, Company shall have the right to verify Customer's ability to operate at the level for up to eight (8) hours per day.

RIDER IP
INTERRUPTIBLE POWER SERVICE
(Continued)

(6) If Customer fails to interrupt load as requested by Company, Customer will not receive any credit for interruptible load for that month and will pay a penalty which is the greater of an amount equal to ten (10) times the capacity credit for each kW of demand above the firm power level or the cost incurred by Company due to Customer's failure to interrupt load as requested.

In addition, Company reserves the right to interrupt Customer's entire load including the specified firm power load, and to discontinue service under this tariff.

(7) No responsibility of any kind shall attach to Company, or on account of, any loss or damage caused by or resulting from any interruptions of service.

CREDIT FOR INTERRUPTIBLE LOAD

Customer will receive a credit to its monthly Bill equal to a capacity credit for each kW of monthly interruptible demand.

The capacity credit will be an amount equal to the avoided capacity cost of a combustion turbine as calculated using the method required by the Indiana Utility Regulatory Commission's "Rules and Regulations With Respect to Cogeneration and Alternate Energy Production Facilities."

The monthly interruptible demand will be the Billing Demand as determined by the applicable Rate Schedule less the specified firm power level of demand.

TERMS AND CONDITIONS OF SERVICE

Service under this Rider will be governed by the same terms and conditions as required under Customer's applicable Rate Schedule, Rate LP or Rate HLF.

CONTRACT

A written contract for an initial term of not less than five (5) years is required and such contract shall continue for equal successive terms unless canceled. Except as provided herein, this contract may be canceled by either party by giving written notice to the other party not less than three (3) years prior to the proposed date of termination.

RIDER IP – 2
INTERRUPTIBLE POWER SERVICE

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rider shall be applicable to Rate LP, HLF, DGS and OSS Customers with an interruptible demand of at least 200 kW who were taking service under this Rider during September 1997.

CHARACTER OF SERVICE

(1) Company reserves the right to interrupt service to Customer at any time to maintain system integrity at the sole discretion of Company.

(2) The number of interruptions shall not exceed one (1) per day and the hours of interruption shall not exceed eight (8) hours per day or one hundred twenty (120) hours per year. These limits shall not apply during any period of extended emergency experienced by Company.

(3) Company will endeavor to provide to Customer as much advance notice as possible of interruptions of service. However, Customer shall interrupt service within one hour if so requested.

(4) Customer shall provide auxiliary switching in their plant for the purpose of separating the interruptible load from the firm power load specified in the contract.

(5) Customer shall provide communication equipment as specified by Company.

(6) Customer shall specify in the initial contract a firm power level of demand which the Customer agrees not to exceed during each interruption period. The firm power level of demand may be changed at the end of a five year contract term by Customer giving Company at least three (3) years written notice of the proposed change, except (1) this restriction does not apply to increases in load resulting from application of Company's Efficiency Incentive Rider LP-1, and (2) this restriction may be waived at the sole discretion of Company after analysis of its capacity requirements.

If Customer provides interruptible load under both Riders IP and IP-2, the firm power level specified for Rider IP-2 will be the firm power level specified for Rider IP minus the additional interruptible load Customer will provide under Rider IP-2.

RIDER IP – 2
INTERRUPTIBLE POWER SERVICE
(Continued)

Before accepting the specified firm power level, Company shall have the right to verify Customer's ability to interrupt load within one hour and to operate at that level for up to eight (8) hours per day.

(7) If Customer fails to interrupt load as requested by Company, Customer will not receive any credit for interruptible load for that month and will pay a penalty which is the greater of an amount equal to ten (10) times the capacity credit for each kW of demand above the firm power level or the cost incurred by Company due to Customer's failure to interrupt load as requested.

In addition, Company reserves the right to interrupt Customer's entire load including the specified firm power load, and to discontinue service under this tariff.

(8) No responsibility of any kind shall attach to Company, or on account of, any loss or damage caused by or resulting from any interruptions of service.

CREDIT FOR INTERRUPTIBLE LOAD

Customer will receive a credit to their monthly Bill equal to a capacity credit for each kW of monthly interruptible demand.

The capacity credit will be an amount equal to 50% of the avoided capacity cost of a combustion turbine as calculated using the method required by the Indiana Utility Regulatory Commission's "Rules and Regulations With Respect to Cogeneration and Alternate Energy Production Facilities."

The monthly interruptible demand will be the Billing Demand as determined by the applicable rate less the specified firm power level of demand.

If Customer provides interruptible load under both Rider IP-2 and Rider IP, the monthly interruptible demand used to calculate the credit under Rider IP-2 will be the Billing Demand less the monthly interruptible demand used to calculate the credit under Rider IP less the firm power level specified for Rider IP-2.

TERMS AND CONDITIONS OF SERVICE

Service under this Rider will be governed by the same terms and conditions as required under Customer's applicable Rate Schedule, Rate LP, Rate HLF, Rate DGS or Rate OSS.

CONTRACT

A written contract for an initial term of not less than five (5) years is required and such contract shall continue for equal successive terms unless cancelled. Except as provided herein, this contract may be cancelled by either party by giving written notice to the other party not less than three (3) years prior to the date of termination.

RIDER NM
NET METERING RIDER

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rider is applicable to Residential Customers, K-12 Schools and Municipal Corporations electing service hereunder who have installed photovoltaic, wind, or hydroelectric generator systems on their Premises and who are provided single-phase service. Customers must meet the Generator System Requirements and Interconnection Requirements specified below. Total participation on this service will be limited to one-tenth of one percent of Company's most recent aggregate summer peak load. Service under this Rider shall be available on a first come, first served basis.

BILLING

The measurement of net electricity supplied by Company and delivered to Company shall be calculated in the following manner. Company shall measure the difference between the amount of electricity delivered by Company to Customer and the amount of electricity generated by Customer and delivered to Company during the billing period, in accordance with normal metering practices. If the kWh delivered by Company to Customer exceeds the kWh delivered by Customer to Company during the billing period, Customer shall be billed for the kWh difference. If the kWh generated by the Customer and delivered to Company exceeds the kWh supplied by Company to Customer during the billing period, Customer shall be billed for zero kWh in the current billing cycle and shall be credited in subsequent billing cycles for the kWh difference. Customer shall remain responsible for all applicable Bill charges, including Service Charges, Demand Charges and Capacity Charges. When Customer discontinues Net Metering Rider service, any unused credit will revert to Company.

Bill charges and credits will be in accordance with the standard Rate Schedule that would apply if Customer did not participate in this Rider.

METERING

If Customer's standard meter is capable of measuring electricity in both directions, it will be used for purposes of this Rider. If Customer's standard meter is not capable of measuring electricity in both directions, Company will at its expense install metering capable of net metering . For K-12 schools that are provided three-phase service pursuant to Rate SGS, Rate DGS or Rate OSS, Company will install, at Customer's expense, metering capable of net metering. Company's General Terms and Conditions Applicable to Electric Service will govern meter testing procedures.

In addition, Company reserves the right to install, at its own expense, a meter to measure the output of Customer's generator.

RIDER NM
NET METERING RIDER
(Continued)

GENERATOR SYSTEM REQUIREMENTS
Customer's generator system must meet the following requirements:

1. The nameplate rating of Customer's generator system must not exceed 10 kW;
2. The generator system must be owned and operated by Customer and must be located on Customer's Premises;
3. Customer's generator system must be intended primarily to offset part or all of Customer's requirements for electricity;
4. The generator system must operate in parallel with the Company's distribution facilities; and
5. The generator system must satisfy the Interconnection Requirements specified below.

INTERCONNECTION REQUIREMENTS
1. Customer shall comply with Company's interconnection requirements. A generator system shall be deemed in compliance with Company's interconnection requirements if such generator system conforms to the requirements of IEEE Standard 929-2000, has UL certification that it has satisfied the testing requirements of UL 1741 dated May 7, 1999, as revised January 17, 2001 or any IEEE or UL Standards that supersede these.

2. Customer shall provide proof of homeowners, commercial or other insurance providing coverage in the amount of at least one hundred thousand dollars ($100,000) for the liability of the insured against loss arising out of the use of a net metering facility. This coverage must be maintained as long as Customer is interconnected with Company's distribution system.

3. Conformance with these requirements does not convey any liability to Company for injuries or damages arising from the installation or operation of the generator system.

4. Customer shall execute Company's standard Net Metering Interconnection Application form and provide other information reasonably requested by Company for service under this Rider. Company shall require proof of qualified installation prior to acceptance and completion of the interconnection agreement. Certification by a licensed electrician shall constitute acceptable proof.

RIDER NM
NET METERING RIDER

TERMS AND CONDITIONS OF SERVICE

1. Any characteristic of Customer's generator that degrades or otherwise compromises the quality of service provided to other Company Customers will not be permitted.

2. Customer shall agree that Company shall at all times have immediate access to Customer's metering, control, and protective equipment.

3. Customer shall install, operate and maintain the net metering facility in accordance with the manufacturer's suggested practices for safe, efficient and reliable operation in parallel with the Company's system.

4. Company may, at its own discretion, isolate any net metering facility if Company has reason to believe that continued interconnection with the net metering facility creates or contributes to a system emergency. System emergencies causing discontinuance of interconnection shall be subject to verification at the Commission's discretion.

5. A disconnecting device must be located at the point of common coupling for all interconnections. For three-phase interconnections, the disconnecting device must be gang operated. The disconnecting device must be accessible to Company personnel at all times and be suitable for use by Company as a protective tagging location. The disconnecting device shall have a visible open gap when in the open position and be capable of being locked in the open position. The cost and ownership of the main disconnect switch shall reside with Customer.

6. Customer is responsible for operating the proposed net metering facility such that voltage unbalance attributable to the net metering facility shall not exceed 2.5% at the point of common coupling. Voltage unbalance is the maximum phase deviation from average as specified in ANSI C84.1.

7. Company reserves the right to witness compliance testing at the time of installation and maintenance testing of the interconnection system for compliance with these conditions of service.

8. Customer is responsible for establishing a program for and performing periodic scheduled maintenance on the net metering facility's interconnection system (relays, interrupting devices, control schemes and batteries that involve the protection of Company's distribution system). A periodic maintenance program is to be established in accordance with the requirements of IEEE 1547. Company may examine copies of the periodic test reports or inspection logs associated with the periodic maintenance program. Upon Company's request, Company shall be informed of the next scheduled maintenance and be able to witness the maintenance performed and any associated testing.

RIDER NM
NET METERING RIDER
(Continued)

9. The interconnection system hardware and software design requirements in the conditions of service are intended to assure protection of Company's distribution system. Any additional hardware and software necessary to protect equipment at the net metering facility is solely the responsibility of Customer to determine, design and apply.

10. Customer agrees that Company shall not be liable for any damage to or breakdown of Customer's equipment operated in parallel with Company's electric system.

11. Customer shall agree to release, indemnify, and hold harmless Company from any and all claims for injury to persons or damage to property due to or in any way connected with the operation of Customer-owned equipment and/or generators.

12. The supplying of, and billing for service under this Rider shall be governed by Company's General Terms and Conditions Applicable to Electric Service under the jurisdiction of the Indiana Utility Regulatory Commission.

RIDER LP-1
EFFICIENCY INCENTIVE RIDER

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rider is applicable to any Customer served on Rate LP electing service hereunder for new electrical loads that meet all of the following conditions:

(1) Customer agrees to permit Company to undertake an energy audit of its electrical load and cooperate in implementation of suggested improvements directed toward conservation and peak load reduction.

(2) Customer agrees to implement all operationally feasible energy saving improvements to its electrical load found in Company's audit to have a payback on the initial investment of three (3) years or less.

(3) New electrical load must be an expected minimum of three hundred (300) kW located at one existing point of service.

(4) The new electrical load will have an expected annual load factor in excess of 65%.

(5) A written contract for an initial term of not less than three (3) years is required and such contract shall continue for equal successive terms unless cancelled. The contract may be cancelled by either party only by giving written notice to the other party not less than three (3) years prior to the proposed date of termination.

(6) This Rider is closed to new Customers or loads effective on [the effective date of rates in this proceeding].

ADJUSTMENT

For the first thirty-six (36) months of the contract term, there shall be a credit to the Rate LP Billing Demand charge equal to $4.55 per kVa per month for the new electric load.

The monthly base period kVa load shall be specified in the contract and will be the average of that actually used during the twelve months preceding the new load addition or parts thereof. Any load served in addition to the monthly base period kVa will be considered new electric load and shall qualify for the adjustment.

DETERMINATION OF BILLING DEMAND

The Billing Demand for the current month shall be the highest of the following:

(1) The average load in Kilovolt-Amperes (kVa) during the 15-minute period of maximum use in such month, as determined by suitable instruments installed by Company.
(2) 60% of the highest demand occurring during the 12 months preceding the billing date;
(3) 60% of the contract demand
(4) 60% of the highest demand occurring during the term of the contract

RIDER DLC
DIRECT LOAD CONTROL RIDER

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rider shall be applicable to any Customer for whom Company has installed a Direct Load Control switch on its electric cooling unit(s), and electric water heater(s), as applicable. To enroll an electric water heater, an air conditioner or heat pump must be enrolled.

CHARACTER OF SERVICE

The Direct Load Control switch will be activated by a radio signal which will cycle off Customer's cooling units and electric water heaters for a few minutes each half hour, during periods of peak electricity demand, as determined by Company.

CREDITS

The DLC credits below shall be applied during the Months of June through September inclusive:

$5.00 per Month for each electric air conditioner or heat pump less than or equal to five (5) tons.

$4.00 per Month per kW for each electric air conditioner or heat pump greater that five (5) tons.

$2.00 per Month for each electric water heater.

TERMS AND CONDITIONS OF SERVICE

Service under this Rider will be governed by the same terms and conditions as required under Customer's applicable Rate Schedule.

RIDER IC
INTERRUPTIBLE CONTRACT RIDER

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and power supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

This Rider shall be applicable to any Rate Schedule LP or HLF Customer electing service hereunder who can provide for not less than 1000 kVa of interruptible demand during Peak Periods hereunder. Customers currently taking service under Company's previous Riders IP and IP-2, which are closed to new business, may apply for service hereunder, for the balance, or renewal of the existing contract. Contracts with existing customers not meeting the minimum interruptible load amount specified above for this Rider, will, however, not be extended in time.

CHARACTER OF SERVICE

Service under this Rider will require Customer to interrupt a portion of its normal utilization of power from Company ("Interruptible Demand"), limiting its demand to a predetermined Firm Power Level within 10 minutes notification by the Company for the period of Interruption. The Company reserves the right to call for Interruptions for any operating or economic purpose. This Rider shall not apply if a service interruption resulting from system emergency operating conditions should occur.

DEFINITIONS

Peak Periods: All hours between 8 a.m. and 10 p.m. for months of June though September, except Saturdays, Sundays and Holidays.

Interruptions: The number of interruptions called for by the Company shall not exceed one (1) per day, and the hours of interruption shall be specified by Company but not exceed eight (8) hours per day, or 250 hours per year in total. Interruptions may be called for by the Company by Notification, at any times though out the year. These limits shall not apply during any period of extended emergency conditions experienced by Company.

Notification: The Company shall endeavor to provide Customer with as much advanced notice of interruption as possible; however Customer must interrupt its use within ten (10) minutes if requested. Notification of an interruption will be provided by telephone to Customer, to a person and phone number specified by Customer; a message left for this person shall be deemed to be received when left.

Interruptible Demand (kVa): Customer's Actual Demand less the Firm Power Demand.

Firm Power Demand (kVa): The specified level of demand which Customer agrees not to exceed during an interruption, and which can reasonably be expected to result in 1000kVa or more of its normal usage demand being available for interruption.

RIDER IC
INTERRUPTIBLE CONTRACT RIDER
(Continued)

Billing Demand (kVa): Customer's Billing Demand as otherwise determined under the rate schedule covering its firm service.

Actual Demand (kVa): Customer's maximum actual demand recorded in the billing month.

Capacity Credit ($/kVa): The Capacity Credit is equal to 90% of the "Unadjusted Capacity Payment to a Qualifying Facility" in affect in the Company's Rate CSP. For purposes hereof the $ per kW per month determined from Rate CSP shall equal the amount of credit $ per kVa of this Rider.

DETERMINATION OF INTERRUPTIBLE CREDIT

Customer shall receive a credit to its monthly bill for service equal to the Capacity Credit for each kVa of Interruptible Demand.

PENALTY FOR FAILURE TO INTERRUPT

If Customer does not reduce its load to the Firm Power Demand within the time specified by Company's notification, or fails to maintain it at or below that level for the specified period of interruption no Interruptible Credit will be allowed for that month and the Customer will pay a penalty for each kVa of its demand above the Firm Power Demand equal to Ten (10) times the Capacity Credit per kVa. If Customer fails to interrupt on repeated occasions, Company may discontinue service hereunder upon notice.

CONTRACT

A written contract for an initial term of not less that five (5) years is required and such contract shall continue for equal successive terms unless canceled. Except as provided herein, this contract may be canceled by either party by giving written notice to the other party of not less that three (3) years prior to the contract expiration date.

TERMS AND CONDITIONS OF SERVICE

(1) Before accepting Customer's specified Firm Power Demand the Company shall have the right to verify Customer's ability to operate at that level for up to eight (8) hours per day, and that it will result in a reasonable expectation that 1000 kVa or more of normal usage demand will be available for interruption in Peak Periods.

(2) Customer shall provide at its own expense auxiliary switching in its facilities for the purpose of separating the interruptible load from the firm power load.

(3) No responsibility of any kind shall attach to Company, or on account of, any loss or damage caused by or resulting from any interruptions of service hereunder.

(4) Service under this Rider will also be governed by the same terms and conditions as required under Customer's applicable Rate Schedule, Rate LP or HLF.

RIDER IO
INTERRUPTIBLE OPTION RIDER

AVAILABILITY

This Rider shall be applicable to any Rate Schedule DGS, OSS, LP or HLF Customer electing service hereunder who will interrupt a portion of its normal electrical load during periods of request from Company. Customer's estimated load interruption capability must exceed 250kW to be eligible hereunder. This Rider is not applicable to service that is otherwise interruptible or subject to displacement under Rate Schedules or Riders of Company.

Customers currently taking service under Company's previous Riders IP and IP-2, which are closed to new business, may apply for service hereunder, if eligible, for the balance, or renewal of the existing contracts. Contracts with existing customers not meeting the minimum interruptible load amount specified above for this Rider, will, however, not be extended in time.

CHARACTER OF SERVICE

Service under this Rider will require Customer to operate to reduce its normal energy usage during requested energy interruption periods, by 250 kW or more. Notification of Interruption Periods will be made by Company with as much advanced notice as possible, but with a minimum of one (1) hour. Interruptions are expected to be requested during Peak Periods with high system demands and/or costs of power supply, but could be made at any time through out the year. The Company reserves the right to call for interruptions for any operating or economic purpose. This Rider shall not apply if a service interruption resulting from system emergency operating conditions should occur.

DEFINITIONS

Peak Periods: All hours between 8 a.m. and 10 p.m. for months of June though September, except Saturdays, Sundays and Holidays.

Curtailments: The number of interruptions called for by Company shall not exceed three (3) per day, and the hours of requested interruption shall be specified by Company from a minimum of one hour to a maximum of 8 hours, but shall not exceed eight (8) hours in total per day, or 300 hours per year in total. These limits shall not apply during any period of extended emergency conditions experienced by Company.

Notification: Company shall endeavor to provide Customer with as much advanced notice as possible, however Customer must respond within 60 minutes of the request with appropriate interruption to be eligible for credits.

Notification of an interruption will be provided by telephone to Customer, to a person and phone number specified by Customer; a message left for this person shall be deemed to be received when left.

RIDER IO
INTERRUPTIBLE OPTION RIDER
(Continued)

Interrupted Demand (kW):	The average hourly difference between Customer's actual demand during the Interruption period(s) in the month, and the average Actual Demand occurring in the two hours preceding Company's Notification.
Interrupted Energy (kWh):	The amount of energy calculated as interrupted by multiplying the Interrupted Demand by the hours of interruption during the month.
Billing Demand (kW/kVa):	Customer's Billing Demand as otherwise determined under its applicable Rate Schedule.
Actual Demand (kW/kVa)	Customer's actual use demand recorded on a 15 minute integrated period basis by Company metering in the two hours preceding any interruption notice in the month.
Interrupted Capacity Credit ($/Kw/kVa):	The Interrupted Capacity Credit is equal to 80% of the "Unadjusted Capacity Payment to a Qualifying Facility" in affect in the Company's Rate "CSP". For purposes hereof the $ per kW per month determined from Rate CSP shall equal the amount of credit $ per kVa of this Rider.
Interrupted Energy Credit ($/kWh):	The Interrupted Energy Credit is equal to the per kWh energy charge plus the applicable Fuel Cost Adjustment for Customer's applicable Rate Schedule.

DETERMINATION OF INTERRUPTION CREDIT

Customer shall receive a credit to its monthly bill for service equal to the Capacity Credit for each kW/kVa of Interrupted Demand determined for that month, from the following formula:

Capacity Credit = (Customer average Actual Demand(s) before Interruption period(s)-(kWh used during Interruption period(s)/hours duration of Interruption period(s)) X Interrupted Capacity Credit ($/kW)

Customer shall receive a credit to its monthly bill for service equal to the Energy Credit for each kWh of Interrupted Energy determined for that month, from the following formula:

Energy Credit = (Interrupted Energy) X Interrupted Energy Credit ($/kWh)

RIDER IO
INTERRUPTIBLE OPTION RIDER
(Continued)

ADJUSTMENTS TO MONTHLY BILLING ON RATE SCHEDULES

The Customer's monthly metered demand and energy under its applicable Rate Schedule shall be adjusted to include the calculated kW/kVa and kWh's of the Customer's interruptions occurring in the billing month as serviced load for computation of the Rate Schedule billing.

CONTRACT

A written contract for an initial term of not less that three (3) years is required and such contract shall continue for equal successive terms unless canceled. Except as provided herein, this contract may be canceled by either party by giving written notice to the other party of not less that one (1) year.

TERMS AND CONDITIONS OF SERVICE

Service under this Rider will be governed by the same terms and conditions as required under Customer's applicable Rate Schedule, Rate DGS, OSS, LP or HLF.

RIDER ED
ECONOMIC DEVELOPMENT RIDER

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

The Economic Development Rider shall be applicable to any new Non-Residential Customer who establishes initial permanent service in a new or existing establishment, and to any existing Non-Residential Customer who expands an existing establishment, who:

1. Receives service under Rate LP or HLF,
2. Makes application to Company for service under this Rider,
3. Has applied for and received economic development assistance from State or local government or other public agency,
4. Affirms that without this Rider, it would not be financially advantageous for the Customer to expand the existing or build the proposed new establishment.

Customers meeting all Applicability criteria above are eligible for incentives under the Rider at two levels:

Level 1 Incentives – Customer's new electric load addition must meet all of the following minimum criteria:

1. Expected monthly load factor of 50% or higher
2. Expected load addition of 500 kVa or more at one delivery point.
3. Result in the creation of 25 new full-time equivalent jobs at the same location.

Level 2 Incentives – Customer's new electric load must meet 2 out of 4 of the following minimum criteria:

1. Expected monthly load factor of 65%, or higher.
2. Expected load addition of 1500 kVa or more at one delivery point.
3. Result in the creation of 100 new full-time equivalent jobs at the same location.
4. Result in capital investment at the Customer's establishment of one million dollars ($1,000,000) or more for each 1000kVa of new load.

The Company may also apply this Rider to an existing customer who, but for economic incentives being provided from the State and/or local government or public agency, would leave or not expand facilities within the Company's service area. In this event, the Customer must agree, at a minimum, to retain the current number of full-time equivalent jobs at the existing location.

For new Customers, application for service hereunder must be made at the time of initial application for electric service.

RIDER ED
ECONOMIC DEVELOPMENT RIDER
(Continued)

This Rider is not available:

1. To a Customer who is a "new" Customer as a result of a change in ownership of an existing establishment, unless the prior owner was a customer hereunder or the ownership change is accompanied by State, local governmental or other public agency economic assistance.
2. To a new Customer who has relocated to Company's Service Area from another location within the State.
3. For renewal of service following service interruptions related to, but not limited to, equipment failure, temporary plant shutdown, work stoppage, or economic conditions.

EVIDENCE OF CONTINUING APPLICABILITY

Customer shall make available to Company, at its reasonable request, evidence of full-time employment levels and capital investments used as the basis for applicability for receiving service hereunder.

RATES AND CHARGES

Customer receiving service under this Rider:

1. Shall receive a credit to the Monthly Billing Demand Charge due per month under the applicable tariff rate schedule for a period of twenty-four (24) consecutive months, as follows:
    a. for all Level 1 demand additions, the credit is $2.25 per kVA
    b. for all Level 2 demand additions, the credit is $4.50 per kVA

    The monthly base period kVA demand shall be specified in the contract and will be the average of the demand actually used during the 12 months preceding the new demand addition or parts thereof. Any demand served greater than the monthly base period will be considered new electric demand additions and shall qualify for the credit.
2. Shall designate the date on which the Billing Demand credits shall commence, said date not to be later than twelve (12) months after Company's approval of Customer's application.
3. Shall continue to be billed the full amount all other Monthly Rates and Charges applicable to the Rate Schedule under which Customer is receiving service.
4. Shall resume being billed the full Monthly Rates and Charges under the applicable Rate Schedule after receiving service under this Rider for twenty-four (24) months.

RIDER ED
ECONOMIC DEVELOPMENT RIDER
(Continued)

CONTRACT

Upon approval of application by Company, Customer must enter into a Contract under this Rider for a contract period of six (6) years. Employment additions must occur no later than six months following Company's approval of the Contract and initiation of service hereunder. The Contract shall also include such other terms and conditions which Company determines in its reasonable discretion to be necessary or advisable in connection with offering service under this Rider, including, but not limited to, the requirement for Customer to pay to Company the difference between the total charges under this Rider and the otherwise applicable Rate Schedule charges if during the term of the Contract Customer fails to meet the employment additions / retentions specified at the beginning of the service relationship.

Establishments for which a change in ownership occurs after Customer enters into a Contract under this Rider shall continue to receive service hereunder for the balance of the term of the Contract, as long as all other conditions of the Contract and this Rider are upheld by Customer.

Company reserves the right to immediately terminate service under this Rider, if Company determines that Customer has failed to comply with the terms of Applicability at any time during the term of the Contract.

EXPIRATION

This Rider shall expire on December 31, 2012. Customers making application for service hereunder prior to this date shall be eligible for the full twenty-four (24) months of Billing Demand credit described herein.

RIDER AD
AREA DEVELOPMENT RIDER

AVAILABILITY

This Rider shall be available throughout Company's Service Area, subject to the availability of adequate facilities and supplies, which determinations shall be within Company's reasonable discretion.

APPLICABILITY

The Area Development Rider is applicable to any Non-Residential Customer who:

1. Receives service under Rate LP or HLF,
2. Makes application to Company for service under this Rider,
3. Uses at least 300 KVa per year at this single location, and
4. Qualifies for one of the following area development categories:

Urban Redevelopment: Any new Customer who locates in an existing building of 25,000 square feet or more, which has been unoccupied and/or remained dormant for a period of two (2) years or more, as determined by the Company, or

Brownfield Redevelopment: Any Customer who locates a new or existing establishment in a designated Brownfield Redevelopment Area (as defined by Indiana or Federal Law), or

Economic Development Zone: Any new Customer who locates in a new or existing establishment or any existing Customer who expands an existing establishment, in a designated Urban Enterprise Zone, Airport Development Zone, Certified Technology Park, or other similarly designated zone, and either (1) adds at least 15 incremental full-time employees to its workforce at the same location, or (2) makes an incremental capital investment of at least five hundred thousand dollars ($500,000) at the same location. Employment additions and capital investments must occur within a reasonable period following Company's approval of the Contract.

For new Customers, application for service under this Rider must be made at the time of initial application for Electric Service.

This Rider is not available:

1. To a Customer who is a "new" Customer as a result of a change in ownership of an existing establishment, or
2. For renewal of service following service interruptions related to, but not limited to, equipment failure, temporary plant shutdown, work stoppage, or economic conditions.

EVIDENCE OF CONTINUING APPLICABILITY

Customer shall make available to Company, at its reasonable request and as applicable, evidence of full-time employment levels and capital investments used as the basis for applicability for receiving service hereunder.

RIDER AD
AREA DEVELOPMENT RIDER
(Continued)

RATES AND CHARGES

Customer receiving service under this Rider:

1. Shall be billed the full Monthly Rates and Charges under the applicable Rate Schedule for all "incremental volumes" (defined below), for a period of sixty (60) consecutive months, except that the applicable Rate Schedule Demand Charge, exclusive of any included Energy Charges and any charges from applicable Appendices or Riders, shall be discounted as follows:
   a. For the first 12-month period, the Demand Charge will be discounted by 50% per month;
   b. For the second 12-month period, the Demand Charge will be discounted by 40% per month;
   c. For the third 12-month period, the Demand Charge will be discounted by 30% per month;
   d. For the fourth 12-month period, the Demand Charge will be discounted by 20% per month;
   e. For the fifth 12-month period, the Demand Charge will be discounted by 10% per month.
2. Shall resume being billed the full Monthly Rates and Charges under the applicable Rate Schedule after receiving service under this Rider for sixty (60) months.
3. Shall designate the date on which the discount applicable to Demand Charges on incremental volumes shall commence, said date not to be later than twelve (12) months after Company's approval of Customer's application.

INCREMENTAL VOLUMES

1. For new Customers, "incremental volumes" are defined as all volumes, subject to Customer having met the 300 kVa per year minimum threshold.
2. For existing Customers, "incremental volumes" must be at least 300 kVa per year, and will be determined by Company, giving consideration to Customer's historical usage.

CONTRACT

Upon approval of application by Company, Customer must enter into a Contract under this Rider. The Contract shall also include such other terms and conditions which Company determines in its reasonable discretion to be necessary or advisable in connection with offering service under this Rider, including, but not limited to, the requirement for Customer to pay to Company the difference between the total charges under this Rider and the otherwise applicable Rate Schedule charges if during the term of the Contract Customer fails to meet the employment additions / retentions specified at the beginning of the service relationship.

Establishments for which a change in ownership occurs after Customer enters into a Contract under this Rider shall continue to receive service hereunder for the balance of the term of the Contract, as long as all other conditions of the Contract and this Rider are upheld by Customer.

RIDER AD
AREA DEVELOPMENT RIDER
(Continued)

Company reserves the right to immediately terminate service under this Rider, if Company determines that Customer has failed to comply with the terms of Applicability at any time during the term of the Contract.

EXPIRATION

This Rider shall expire on December 31, 2012. Customers making application for service hereunder prior to this date shall be eligible for the full sixty (60) months of Demand Charge discount described herein.

APPENDIX A
FUEL ADJUSTMENT CLAUSE

APPLICABILITY

The Fuel Adjustment Clause (FAC), as updated from time to time, shall be applicable to fuel cost charges included in Rate Schedules as set forth below.

DESCRIPTION

The FAC shall recover the following costs, as reviewed and approved by the Commission:

1. The average cost of fossil and nuclear fuels consumed in jointly owned or leased plants.
2. The actual identifiable fossil and nuclear fuels costs associated with energy purchased.
3. The net energy costs, exclusive of capacity and/or demand charges for energy purchased on an economic dispatch basis.
4. The costs of fossil and nuclear fuels recovered through intersystem sales.
5. Applicable taxes, including Indiana Utility Receipts Tax.
6. All other costs approved for Fuel Adjustment Clause recovery by the Commission.

FUEL COST ADJUSTMENT

Pursuant to the Indiana Utility Regulatory Commission's Order in Cause No. 38708-FAC71, the Fuel Cost Adjustment for Rates A, EH, B, SGS, DGS, OSS, LP, HLF, SL and OL for August, September and October 2006 is $0.004168 per kWh.

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

APPENDIX D
OTHER CHARGES

Late Payment Charge:

If Customer does not pay a Bill for Electric Service on or before the gross payment due date, Customer shall be assessed a Late Payment Charge of three (3) percent of such Bill.

Reconnect Charge:

When Electric Service is discontinued (1) at the request of Customer, (2) for nonpayment of a Bill, (3) when authorized by Company's General Terms and Conditions or the Commission's Regulations, or (4) for any reason beyond the control of Company, and a reestablishment of Electric Service is required by Customer, Customer shall be charged a Reconnect Charge to cover a part of the cost of discontinuance and reestablishment of Electric Service. Such charge shall be thirty-five dollars ($35.00) at the meter. Also, an additional charge of one hundred seventy dollars ($170.00) shall be charged for reconnection of electric service at the pole or transformer, when the original disconnection at the pole or transformer was due to the Customer's denial of access to the meter. In addition, when Electric Service is reconnected or disconnected after normal working hours at Customer's request, Customer shall be charged an After Hours Charge.

A charge equal to the Customer Facilities Charge for each Month of discontinued Electric Service will also be made for re-establishing Electric Service for the same Customer at the same Premises where Electric Service has been discontinued at the Customer's request during the preceding nine Months. The minimum Customer Facilities Charge assessment under the provisions of this paragraph shall be one Month's Customer Facilities Charge.

After Hours Charge:

When Electric Service is connected, reconnected or disconnected after normal business hours at Customer's request, Customer shall be charged an After Hours Charge of forty-five dollars ($45.00) in addition to any other applicable charges for each connection, reconnection or disconnection.

Insufficient Funds Check Charge:

For each check of Customer returned by any bank due to insufficient funds, Customer shall be charged twenty-five dollars ($25.00) to cover a part of the cost of processing such check.

Fraudulent or Unauthorized Use or Tampering:

When the Company detects fraudulent or unauthorized use or tampering of the Company's regulation, measuring equipment or other service facilities, Company may assess a minimum charge of sixty-five dollars ($65.00) per occurrence for such field calls and repairs. Customer can also be responsible for payment of the reasonable cost of the service used during the period such fraudulent or unauthorized use or tampering occurred or is reasonably assumed to have occurred and for the cost of field calls, investigation and cost of effecting repairs necessitated by such use and/or tampering.

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT

APPLICABILITY

The MISO Cost and Revenue Adjustment (MCRA) shall be applicable to all Rate Schedules as reflected in the MCRA Rates section below.

DESCRIPTION

The MCRA shall be calculated quarterly for each Rate Schedule as follows:

$$MCRA = \frac{[(MCC + MTC)\ x\ Rate\ Schedule\ Allocation\ Percentages}{Rate\ Schedule\ Sales\ Quantities}$$

Where:

MCC is the MISO Charges Component described below.

MTC is the MISO Transmission Component described below.

Rate Schedule Allocation Percentage is the proportion of the annual MTC amount applicable to each Rate Schedule. The percentage for each Rate Schedule is shown in the MCRA Rate section below.

Rate Schedule Quantities are the quarterly estimated quantities of Energy Sales for each Rate Schedule.

The calculated MCRA shall be further modified to allow the recovery of the Indiana Utility Receipts Tax and other similar revenue-based tax charges.

The actual MCRA amounts passed back to or recovered from customers for each quarter shall be reconciled with MCRA amounts intended for pass back to or recovery from customers for such quarter, with any variance reflected in a subsequent MCRA quarterly filing.

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT
(Continued)

MISO CHARGES COMPONENT (MCC)

The MISO Charges Component shall be calculated quarterly for each Rate Schedule as follows:

$$MCC = MISO\ Charges - 25\%\ of\ Base\ Rate\ Amount$$

where:

MISO Charges is the estimated quarterly amount of the recoverable MISO costs, as billed to Company, calculated as follows:

(a) Schedule 10 – ISO Cost Recovery Adder and Schedule 10-FERC – FERC Annual Charges Recovery, or successor provisions, of the Midwest OATT, or successor tariff for the MISO; plus

(b) Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder, or a successor provision, of the MISO OATT, or any successor tariff for the MISO; plus

(c) Schedule 17 - Energy Market Support Cost Recovery Adder, or a successor provision of the MISO OATT, or any successor tariff for the MISO;

(d) Schedule 24 – Control Area Operator Cost Recovery, or a successor provision of the MISO OATT, or any successor tariff for the MISO;

(e) Schedule 26 – Network Upgrade Charge from Transmission Expansion Plan;

(f) Schedule 2 – Reactive Power costs charged by independent generators in Vectren's control area; plus

(g) Costs that are not otherwise recovered by MISO through other charges and are socialized for recovery from all market participants including Company ("uplift costs"), including the Real Time Revenue Neutrality Uplift Amount, Real Time Miscellaneous Amount, and Real Time Uninstructed Deviation Amount billed by MISO.

25% of Base Rate Amount is one-fourth of the base rate amount of $5,882,956 included in base rates for the MISO Charges.

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT
(Continued)

MISO TRANSMISSION COMPONENT (MTC)

The MISO Charges Component shall be calculated annually for each Rate Schedule as follows:

$$MTC = (MISOOE + MISORET - MISOREV)\ x\ 25\%$$

where:

MISOOE is the operating expenses from the most recent MISO Attachment O calculation for Company less the corresponding transmission operating expenses of $11,653,602 from Company's last rate case.

MISORET is the product of (a) the transmission net investment less transmission rate base adjustments from the most recent MISO Attachment O calculation for Company less the corresponding transmission net investment of $229,998,667 from Company's last rate case, and (b) the rate of return from the most recent MISO Attachment O calculation for Company grossed-up for income taxes.

MISOREV is the transmission revenue credits from the most recent MISO Attachment O calculation for Company less the corresponding transmission revenue credits of $3,193,974 from Company's last rate case, plus the transmission revenues received from the application of MISO's transmission rates to wholesale loads that sink within Company's control area less the corresponding transmission revenues of $1,167,271 from Company's last rate case.

APPENDIX I
MISO COST AND REVENUE ADJUSTMENT
(Continued)

MCRA RATES

Rate Schedule	Allocation Percentage	MCRA Rate ($ per KWh)
A	24.7261%	$0.0000
EH	10.0642%	$0.0000
B	0.2462%	$0.0000
SGS	0.8508%	$0.0000
DGS	26.4253%	$0.0000
OSS	2.2867%	$0.0000
LP	20.5950%	$0.0000
HLF	14.7020%	$0.0000
SL	0.0580%	$0.0000
OL	0.0457%	$0.0000
	100.0000%	

APPENDIX J
GENERATION COST AND REVENUE ADJUSTMENT

APPLICABILITY

The Generation Cost and Revenue Adjustment (GCRA) shall be applicable to all Rate Schedules as reflected in the GCRA Rates section below.

DESCRIPTION

The GCRA shall be calculated quarterly for each Rate Schedule as follows:

$$\frac{(\text{Generation Costs} - \text{Generation Revenues}) * \text{Rate Schedule Allocation Percentage}}{\text{Rate Schedule Quantities}}$$

Where:

Generation Costs is the sum of the following:

a. The non-fuel cost of Purchased Power during the prior quarter minus a portion of the test year level of Purchased Power non-fuel costs, plus
b. The cost of Environmental Chemicals for the prior quarter minus a portion of the test year level of Environmental Chemicals costs, plus
c. The cost of Direct Load Control credits pursuant to Rider DLC for the prior quarter minus a portion of the test year level of DLC billing credits, plus
d. The cost of Interruptible Sales billing credits for the prior quarter minus a portion of the test year level of Interruptible Sales billing credits.

Generation Revenue is the sum of the following:

a. The retail sharing portion of the margin from Wholesale Power Marketing sales for the prior quarter,, plus
b. The retail portion of the margin from Municipal Wholesale sales for the prior quarter, plus
c. The retail portion of the margin from Environmental Emission Allowance sales (net of costs) for the prior quarter.

Rate Schedule Allocation Percentage is the proportion of the quarterly GCRA amount applicable to each Rate Schedule. The percentage for each Rate Schedule is shown in the GCRA Rate section below.

Rate Schedule Quantities are the quarterly estimated quantities of Energy Sales for each Rate Schedule for the upcoming quarter.

The GCRA as calculated above shall be further modified to include the impact of Indiana Utility Receipts Tax and other applicable revenue taxes. The actual GCRA amounts passed back to or recovered from customers for each quarter shall be reconciled with GCRA amounts intended for pass back to or recovery from customers for such quarter, with any variance reflected in the subsequent GCRA quarterly filing

APPENDIX J
GENERATION COST AND REVENUE ADJUSTMENT
(Continued)

GCRA RATESs

Rate Schedule	Allocation Percentage	GCRA Rate ($ per KWh)
A	30.9625%	$0.003915
EH	7.3942%	$0.002245
B	0.1414%	$0.001352
SGS	0.7820%	$0.001829
DGS	27.9731%	$0.003214
OSS	2.0581%	$0.002677
LP	18.4434%	$0.001910
HLF	12.2453%	$0.001644
	100.0000 %	

RATE CSP
CONGENERATION AND SMALL POWER PRODUCTION

APPLICABILITY

The schedule of purchase prices set forth herein shall apply to owners of cogeneration or small power producing "qualifying facilities' as defined by the Commission, in Cause No. 37494, approved December 6, 1984. Prior to any purchase by Company, the qualifying facility must enter into a contractual agreement.

RATES FOR SALE OF ENERGY AND CAPACITY

If the qualifying facility desires to purchase electric service from Company, the electric requirements for the qualifying facility shall be separately metered and billed in accordance with the applicable Rate Schedule.

PURCHASE PRICES

Company will pay for energy and capacity received from the qualifying facility on a monthly basis as follows:

Energy Component:

Prices paid are based on Company's avoided cost of energy associated with a one (1) megawatt decrement of load. The energy payment is expressed on a cents-per-kWh basis in Table 1 of this schedule.

Payments for energy are adjusted to reflect line losses, expressed as a percentage for the previous year. It is expected that the projected energy payment will vary as Company's actual fuel costs change. Energy rates listed in Table 1 will be revised on or before February 28th in each subsequent year in accordance with the Commission Cause No. 37494.

In the case of contracts for purchases of 72,000 Kilowatt-hours or more per month from a qualifying facility, the following factors may be considered and an appropriate adjustment made to the agreed purchase price in each contract:

1. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of Company's generation facilities.

2. The relationship of the availability of energy from the qualifying facility to the ability of Company to avoid costs, particularly as is evidenced by Company's ability to dispatch the qualifying facility.

3. The availability of energy from a qualifying facility during Company's system daily or seasonal peak.

4. The usefulness of energy from a qualifying facility during Company system emergencies, including its ability to separate its load from its generation.

RATE CSP
COGENERATION AND SMALL POWER PRODUCTION

Capacity Component

There shall be demand credit paid to qualifying facilities who can enter into a contract with Company to provide firm capacity for specified term. Capacity payments are expressed on a dollars per Kilowatt per month basis in Table 1 of this schedule.

The monthly capacity payment shall be adjusted by the following factor:

$$F = \frac{Ep}{(K)\,(Tp)}$$

Where:

F = Capacity payment adjustment factor

Ep = Kilowatt-hours delivered to Company by the qualifying facility during the peak period defined as the hours of 7:00 a.m. to 10:00 p.m. during weekdays, excluding holidays.

K = Kilowatts of capacity the qualifying facility contracts to provide.

Tp = Number of hours in the peak period.

Company and a qualifying facility may negotiate a rate for energy or capacity which differs from the filed Rate CSP.

Table 1

ENERGY PAYMENT TO A QUALIFYING FACILITY [(1)]

Annual On-Peak	=	$0.04227/kWh
Annual Off-Peak	=	$0.02174/kWh

UNADJUSTED CAPACITY PAYMENT TO A QUALIFYING FACILITY

$3.44 per kW Per Month

(1) On-Peak hours = 6 am – 10 pm, weekdays
Off-Peak hours = All other hours, including weekends and designated holidays

RATE CSP
COGENERATION AND SMALL POWER PRODUCTION
(Continued)

CONDITIONS OF PURCHASE

1. A qualifying facility, operating electric generating equipment, may connect it in parallel with Company's system, providing the facility complies with applicable safety standards and provides, at its expense, all necessary protective and synchronizing equipment.

2. The qualifying facility shall pay in advance of construction all costs estimated by Company for metering or other facilities necessary to provide for the energy purchase. Upon completion of the construction, Company will reconcile the actual costs with the advance payment and bill or credit the facility accordingly.

3. The qualifying facility shall operate its electric generating equipment in such a manner so as not to adversely affect Company's voltage waveform.

4. The qualifying facility shall permit Company at any time as it deems necessary to install or modify any equipment to protect the safety of its employees or the accuracy of its metering equipment as a result of the operation of the facility's equipment. The facility shall reimburse Company for the cost of such installation or modification upon receipt of a statement from Company.

5. The qualifying facility shall permit Company's employees to enter upon its property at any reasonable time for the purpose of inspecting and/or testing its facilities to ensure their continued safe operation and the accuracy of Company's metering equipment, but such inspections shall not relieve the qualifying facility from its obligation to maintain the facilities in satisfactory operating condition.

6. The qualifying facility shall agree to indemnify Company and its employees against liability for any injuries or damages caused by the operation of the facility's equipment or by any failure of the facility to maintain its equipment in satisfactory and/or safe operating condition.

7. Company will require that a contract be executed which will detail meter reading and billing practices to be followed, as well as other technical and operating parameters for the qualifying facility's generation facilities.

RATE CSP
COGENERATION AND SMALL POWER PRODUCTION
(Continued)

8. Qualifying facilities wishing to operate electric generating equipment in parallel with Company system and not sell electricity to Company shall abide by these Conditions of Purchase, including allowing Company to prevent the existing Company metering facilities from recording any flow of energy from the facility's generation into Company's system.

9. Company need not purchase or sell at the time of a system emergency.

10. The determination of whether or not a facility qualifies, as well as other terms and conditions of purchase and sale, shall be subject to an in accordance with the Commission's order approved December 6, 1984, in Cause No. 37494.

11. Company's standard terms and conditions shall apply to the purchase and sale of surplus energy and capacity, unless specifically superseded by the terms and conditions presented herein.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE

1. APPLICATION OF RATES

(a) General.

1. A copy of all Rate Schedules, rules and regulations under which service will be supplied is posted or filed for the convenience of the public in the offices of Company and with the Commission.

2. A written application for electric service on forms provided for the purpose, or a properly executed contract, may be required from Customer before service will be supplied. Company shall have the right to reject, for any valid reason, any application for service.

3. No promise, agreement, or representation of any agent or employee of Company shall be binding upon Company unless the same shall be incorporated in the application or contract for service.

4. The Rate Schedules of Company are based on service being rendered separately for each Premises and for the ultimate use in or on such separate Premises. Electric service used by the same individual, firm, or corporation at different Premises will be delivered, measured, and billed separately as to each Premises.

5. If service is taken on more than one meter on the same Premise for the convenience of Customer each meter will be billed separately. Where service is taken on more than one meter on the same Premise for the convenience of Company or to meet legal requirements, the sum of the measurements of all such meters shall be used in calculating the Bill.

6. Company may refuse Electric Service or disconnect Electric Service on account of arrearages due for Energy Service furnished to persons formerly receiving service at the Premises as Customer of Company, if the Customer continues to reside at such Premises.

(b) Combined Residential and Non-Residential Service

When the principal use of service applied to a residential dwelling is for residential purposes, but a small amount of energy will be used for non-residential purposes, such non-residential use will be permitted only when the equipment for such use is within the capacity of the 120 volt, 30 Ampere branch circuit (or is less than 3,000 Watts capacity) and the non-residential consumption is less than the residential use on the Premises. When the non-residential equipment exceeds that above stated maximum limit, the entire non-residential wiring must be separated from the residential wiring, so that it may be metered separately, and the non-residential load will be billed under the appropriate non-residential rate, or the entire service will be billed under the appropriate non-residential rate.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE
(Continued)

(c) Choice of Rates

1. Company will assist Customer in determining the Rate Schedule which will give Customer the lowest annual cost for service. Where more than one Rate Schedule is available for the class of service requested, the choice of Rate Schedule lies with Customer. Company does not guarantee that Customer will be served under the most favorable Rate Schedule at all times, and no refund will be made representing the difference in charges between the Rate Schedule under which service has actually been rendered and another Rate Schedule applicable to the same class of service.

2. Not more than one change in Rate Schedules will be made in any twelve-month period for any Customer under the provisions of this rule.

(d) Resale of Electric Energy

No electric energy shall be resold except such as may be furnished to other public utilities. Electric energy supplied to Customer under any of Company's Rate Schedules shall be for the sole use of Customer.

(e) Apartment Buildings and Multiple Dwellings

Where residential service is supplied through one meter to a location containing two or more separate living quarters, the following will apply:

1. For Customers receiving service at the location on or prior to October 28, 1998 the service shall be classified as Residential, in which case, for billing purposes, the appropriate Residential Rate Schedule shall be applied on the basis of a single Customer.

2. For Customers who begin receiving service after October 28, 1998 the service shall be classified as Non-Residential, in which case, for billing purposes, the General Service Rate Schedule shall be applied on the basis of a single Customer.

3. Customer may change its wiring at Customer's expense and arrange with Company, subject to provision 1(f), to separate the combined service and permit Company to install a separate meter for each separate living quarters. In each such case the readings of each meter shall be billed separately on the appropriate Residential Rate Schedule.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE

(Continued)

(f) Unusual Facility Requirements

Company reserves the right, with respect to Customers whose establishments are remote from Company's existing suitable facilities, or whose load characteristics or load dispersal require unusual investments by Company in service facilities, to make special agreements as to duration of contract, reasonable guarantee of revenues, or other service conditions.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE

(Continued)

2. INTERRUPTIONS AND DAMAGES

Company will endeavor to furnish continuous service, but does not guarantee uninterrupted service, and shall not be liable for any damages which Customer may sustain by reason of the failure of the energy, or failure or reversal of phases, whether caused by accident, repairs or other uses; nor shall Company be liable for damages that may be incurred by the use of Customer's electrical appliances or equipment, or the presence of Company's property on Customer's Premises. Nor shall Company be liable for loss or damage occurring under or by virtue of the exercise of authority or regulation by governmental, military or lawfully established civilian agencies, or due to conditions or causes beyond Company's control.

3. DISCONNECTING SERVICE

Company may, at its option, discontinue service and remove any of its property on Customer's Premises without legal process:

(a) Notice will be given to Customers for (i) at the expiration of its agreement with the Customer; (ii) to facilitate repairs; (iii) for want of supply of electric energy, however, no notice will be required for (iv) where fraudulent use of electricity is detected; (v) where the Company's regulating or measuring equipment or other facilities have been tampered with; (vi) where a dangerous condition is found to exist on the Customer's Premises; or (vii) in compliance with the order of any court, Commission, or public authority having jurisdiction.

When Company detects fraudulent or unauthorized use of electricity, or Company's regulation, measuring equipment or other service facilities have been tampered with, Company may reasonably assume that Customer or other user has benefited by such fraudulent or unauthorized use or such tampering and, therefore, is responsible for payment of the reasonable cost of the service used during the period such fraudulent or unauthorized use or tampering occurred or is reasonably assumed to have occurred and for the cost of field calls, investigation and cost of effecting repairs necessitated by such use and/or tampering; provided, that Company may assess a minimum charge as set forth in Appendix D per occurrence for such field calls and repairs. Under such circumstances Company may, subject to any provision of Commission Rule 16 to the contrary, disconnect service without notice and Company is not required to reconnect the service until a deposit and all the above enumerated charges are paid in full. All statutory penalties shall be fixed by a court of competent jurisdiction or by agreement between Company and Customer.

(b) Upon fourteen (14) days' written notice mailed to Customer at such Customer's address as shown upon Company's records, (i) whenever any account contracted by Customer is in arrears; (ii) upon violation of these general terms and conditions and the general terms and conditions of any agreement between Company and Customer; or (iii) for misrepresentation of facts upon which Company was induced to render service.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE
(Continued)

4. COMPANY EQUIPMENT – LOCATION AND PROTECTION
   a. Customer shall provide, free of expense to Company and close to the point of service entrance, suitable space acceptable to Company for installation of the necessary metering equipment, said metering equipment to be owned and maintained by Company. Customer shall exercise due diligence to protect said metering equipment from damage or accident and shall permit no person other than an agent of Company or person otherwise lawfully authorized to do so, to inspect, test, remove or tamper with the same.

   b. If the Company's equipment is damaged or destroyed through the neglect of Customer, the cost of necessary repairs or replacements shall be paid by Customer.

5. SERVICE CONNECTIONS
   Company will install its service wires to a point designated by Company and Customer shall bring its wiring to that point.

6. CUSTOMER'S WIRING AND ELECTRICAL EQUIPMENT
   Customer shall maintain its wiring and equipment in the condition required by any authorized or appropriate regulatory authority and the properly constituted local authorities having jurisdiction. Company reserves the right to deny or terminate service to any Customer whose wiring or equipment fails to meet the above requirements and/or constitutes a hazard to Company's equipment or its service to other Customers. However, it disclaims any responsibility to inspect Customer's wiring or equipment, and shall not be held liable for any injury or damage resulting from the condition thereof.

7. ACCESS TO CUSTOMER'S PREMISES
   Company's authorized agents shall have access to Customer's Premises at all reasonable hours to install, inspect, read, repair, or remove its meters and other property, and to inspect and determine the connected load. If Company is denied access to Customer's Premises in order to disconnect service, and disconnection must be made at a pole or transformer due to the denial of access, Customer will be required to pay an Additional Charge for reconnection at the pole or transformer as set forth in Appendix D, Other Charges,

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE
(Continued)

8. DEPOSIT REQUIRED
   a. Residential Customer: Company will follow and apply the provisions of 170 IAC 4-1-15 in requiring deposits from Residential Customers, and Company hereby adopts said code provision and incorporates it by reference in its entirety in this Tariff.

   b. Non-Residential Customers: Company shall require all Non-Residential Customers to make a cash deposit in the amount of two Months' estimated revenue. Company may waive the deposit requirements if (1) Customer has previously established a good credit record with Company; (2) Company accepts Customer's financial statement in lieu of a deposit; or (3) a personal guaranty is accepted by Company in lieu of deposit.

   c. Deposits will be held for a minimum three-year period and will bear simple interest at a rate established by the provisions of 170 IAC 4-1-15 (D). Deposits, less any unpaid charges, may be refunded to Customer (1) upon establishment of a good credit record for at least three years, or (2) when service is disconnected.

   d. Interest will not be paid on deposits held by Company for less than one (1) year.

9. METER READING AND BILLING
   a. Bills will be rendered monthly based on metered or estimated usage. When Company is unable to read the meter, the usage for the month will be estimated on the basis of past service records or other available data. Bills rendered for electric service in months in which meters are not read shall have the same force and effect as those based on actual readings. Any Customer who desires not to receive a Bill for estimated usage may read its meter and send the readings to Company on appropriate forms which will be provided by Company upon request.

   b. Should a meter fail to register the amount of electricity supplied during any period, the usage will be estimated based upon the use during similar periods or on other available information and a Bill rendered accordingly.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE
(Continued)

10. PAYMENT OF BILLS – RECONNECTION CHARGE

a. Bills for service furnished to Customer by Company are due when rendered. Customers will be billed at gross and net amounts as provided for in the applicable Rate Schedule. If any Bill is paid on or before the final date shown on the, the net amount shall be payable; if not, the gross amount shall be payable. A Bill shall be considered delinquent if not paid within seventeen days of the date rendered.

b. A Deferred Due Date Plan is available to any Residential Customer who receives a social security or pension check.

c. A Customer who is on the Plan and receives two disconnect notices within a twelve (12) month period while on the Plan will be removed from the Plan at Company's discretion.

d. An Equal Payment Plan is available to any Residential Customer and small General Service Customers. The plan will allow for equal monthly payments and an annual true-up.

e. Customer shall notify Company when it desires electric service discontinued, and Customer shall pay for said service for a reasonable time after such notice is given, sufficient to enable Company to obtain a final meter reading. This rule shall not apply to any case where a Customer has entered into a contract with Company to take service from Company for a definite period of time specified or provided for in such contract.

f. When the service has been turned off by Company for nonpayment of Bills, or as otherwise provided in these General Terms and Conditions, a reconnection charge as set forth in Appendix D, Other Charges, must be paid by Customer before such service is reconnected. In addition, when Electric Service is reconnected or disconnected after normal working hours at Customer's request, Customer shall be charged an After Hours Charge as set forth in Appendix D, Other Charges.

g. When a reconnection of service is made for a Customer at the same location and service has been disconnected at Customer's request, a charge as set forth in Appendix D, Other Charges, will be made by Company for such reconnection of service. In addition, when Electric Service is reconnected or disconnected after normal working hours at Customer's request, Customer shall be charged an After Hours Charge as set forth in Appendix D, Other Charges.

11. PAYMENT OF BILLS – CHARGE FOR RETURNED CHECKS

A charge will be made to reimburse Company for the cost in handling a check returned by any bank, which charge shall be as set forth in Appendix D, Other Charges.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE

(Continued)

12. SECONDARY POWER – FACILITIES FURNISHED BY COMPANY – VOLTAGE

Company will furnish the necessary transforming equipment to service Customers billed on secondary voltage Rate Schedules and metered at primary voltage (2400 volts or higher) will be credited with three percent (3%) of the metered demand and Kilowatt hours. Company has the option of providing metering to compensate for the losses instead of crediting the metered demand and Kilowatt-hours with three percent.

13. PRIMARY POWER – FACILITIES FURNISHED BY COMPANY – VOLTAGE

Customers billed on primary voltage Rate Schedules shall own/lease, operate, and maintain all transforming, controlling and protective equipment. Service will be metered at the primary voltage supply of 2400 volts or higher. The supply voltage will be determined by Company. When Customer's requirements are metered on the load side of the meter, metered demand and Kilowatt-hours shall be increased by three percent (3%) to convert to the equivalent of service metered at the supply voltage. Company has the option of providing metering to compensate for the losses instead of increasing the metered demand and Kilowatt-hours by three percent. When compensation metering is provided and when Customer billing is based on kVa, the metering shall include compensation for VAR losses in addition to the kW and kWh losses.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE

(Continued)

14. TEMPORARY SERVICE

Customers desiring lighting and/or power service for a short time only, requiring the installation of facilities of a temporary nature shall pay to Company its cost of installing and removing such facilities.

In addition to the above, the Customer shall pay for the service supplied, which shall be metered, and computed under Small General Service, Rate SGS, or Demand General Service, Rate DGS, whichever applies.

Company may require an advance payment prior to the installation of service facilities by Company to cover the estimated cost of installing and removing the necessary facilities and to cover the estimated billing for service for the period involved.

15. AUXILIARY OR STANDBY SERVICE

Auxiliary service is that service which supplements another source of power where switching arrangements enable the use of either or both sources of power.

Standby service is that service which is capable of being used in place of another source of power where there is no actual use except during emergencies.

Customers utilizing auxiliary or standby service will be billed on the applicable Rate Schedule available for the size of load and class of service rendered, subject to the following special provisions:

(a) A 'contract' demand shall be initially established by mutual agreement, between Company and Customer and stated in the service contract. Whenever the contract demand, as initially established is exceeded by the creation of a greater demand, then such greater demand shall become the contract demand until again exceeded, and so on, for the duration of the contract.

(b) The off-peak provision in the applicable Rate Schedule shall not apply.

(c) The Billing Demand in the Rate Schedule shall be the highest demand created during the term of the contract, but in no case less than the contract demand.

(d) No Customer shall be permitted to effect a reduction in its contract demand by recontracting for the same service unless a bona fide reduction in load has occurred.

(e) Company reserves the right to require Customer to furnish, install and maintain a load limiting device, approved by and under the sole control of Company.

(f) The minimum monthly Bill for Auxiliary or Standby service shall be as specified on the applicable Rate Schedule.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE

(Continued)

16. METER TESTING

Company will test meters used for billing Customers in accordance with the rules as currently approved by the Commission. A copy of these Rules is on file at Company's office.

17. VOLTAGES

The standard nominal distribution service voltages within the Service Area of Company are:

Secondary		Primary
Single Phase	Three Phase	Three Phase
120/240 Volts	120/208 Volts	4160/2400 Volts
120/208	240	12470/7200
	277/480	
	480	

The availability and application of the voltages will be determined by the Company and applicable Rate Schedule. Other non-preferred voltages may be supplied to a Customer to meet specific requirements at the discretion of Company. These non-preferred voltages would be limited to localized areas and would be supplied at the discretion of Company.

18. CURTAILMENT PROCEDURES

In the event Company encounters or anticipates a power supply interruption, fuel shortage, or transmission/distribution emergency, or any other situation that would render Company unable to meet existing and reasonably anticipated demands for Electric Service, which determinations shall be within Company's reasonable discretion, Company shall have the right to implement this Curtailment Procedure to maintain and restore service to the extent possible under the circumstances.

(a) Definitions

Human Needs Customers - Human Needs Customers shall include hospitals, medical centers, nursing homes, and other Customers as determined by Company, whose Curtailment could adversely affect public health or safety.

(b) Curtailment Initiation

In the event a Curtailment is required in Company's sole judgment, Company shall have the right to curtail Electric Service to its Customers. Such Curtailment shall be effective as of the date and time specified in the notice to Customer. Company shall implement its Capacity and Energy Emergency Plans to maintain and restore service to the extent possible under the circumstances. When necessary in the sole opinion of Company, Electric Service shall be maintained to Human Needs Customers or other Customers who would otherwise be curtailed, to the extent necessary and practicable under the circumstances.

GENERAL TERMS AND CONDITIONS APPLICABLE TO ELECTRIC SERVICE
(Continued)

(c) Curtailment Notification
Company shall give notification of Curtailment in the most effective manner possible and with as much advance notice as reasonably possible, considering the circumstances and the number of Customers to be notified.

(d) Lifting of Curtailment
Service shall be restored to Customers pursuant to its Capacity and Energy Emergency Plans.

(e) A Customer who is mandated to curtail energy use, either by order of an appropriate governmental agency or under application of these rules and regulations, and who solely because of the mandate becomes subject to the ratchet provisions of an applicable Rate Schedule, will for the period during which the mandate is in effect be excluded from meeting the provisions of the ratchet requirements of the Rate Schedule.

19. GENERAL
All Company Rate Schedules and these General Terms and Conditions are subject to such changes and modifications as may be made from time to time and approved by the Commission, or otherwise imposed by lawful authority, and any requirements hereunder at any time shall not be more stringent from Customer's point of view than those in the Rules and Regulations of such Commission that are in effect at that time.

AFFILIATE AND COST ALLOCATION GUIDELINES

A.1 AFFILIATE GUIDELINES

The OUCC and Southern Indiana Gas and Electric Company ("Utility") (collectively "Parties") have negotiated in connection with Cause No. 41465 the following Affiliate Guidelines to govern the relationships between the Utility and its Affiliates. The Parties agree that these guidelines are intended to be enforced by the IURC, and they shall become effective upon their approval by the IURC. The OUCC and Utility may, through negotiation and agreement, jointly petition the IURC for modifications to these Affiliate Guidelines, in which case they would have the burden of proving any proposed change is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition. If either the OUCC or Utility desires changes to these Affiliate Guidelines and is unable to obtain agreement from the other party for such changes, then the party desiring changes may petition the IURC for the desired changes and bear the burden of proving that such changes are in the public interest. However, such petitions shall not be filed without first attempting to obtain the agreement of the other party. Subject to the following sentence, anyone else seeking a change to these Guidelines may also petition the IURC and would bear the burden of proving that the proposed changes are in the public interest. However, any such petition shall not be filed without the Utility and the OUCC first being notified and given a reasonable opportunity to consider the proposed change. The Commission may also make modifications to these Affiliate Guidelines on its own motion, after notice and hearing.

These Affiliate Guidelines should be read in conjunction with the "Cost Allocation Guidelines" developed by the OUCC and Utility and also approved by the Commission in Cause No. 41465. Subject to Section H of the Settlement Agreement in Cause No. 41465, the Affiliate Guidelines and the Cost Allocation Guidelines govern all current and future affiliate relationships between the Utility and its Affiliates, with the limited exception that the Commission may approve an Affiliate contract that differs from these Guidelines if the Utility files a petition requesting an exception from the Guidelines and satisfies its burden to demonstrate that such contract is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition.

One purpose of these Affiliate Guidelines is to establish standards for procurement on competitive terms to govern the Utility's procurement of goods, services, assets and other utility resources. Such procurement "on competitive terms" (as defined herein) shall be done with the objective of obtaining the best terms available for the Utility and its customers. The only exception to these procurement standards is the provision of "shared corporate support and administrative services" such as corporate treasury services and human resources. These services may be shared with other companies/affiliates within the Vectren organization. The pricing of those services to the Utility shall be based on cost and be in accordance with the Cost Allocation Guidelines. See the definitions section below for a complete definition of "shared corporate support and administrative services."

AFFILIATE AND COST ALLOCATION GUIDELINES

(Continued)

A.2. DEFINITIONS

The definitions below apply to terms used in the Affiliate Guidelines and the Cost Allocation Guidelines.

"Affiliate" "Affiliate" means a person that is an affiliated interest for purposes of I.C. 8-1-2-49 or that is otherwise found to be an "Affiliate" by the Commission or otherwise is an "Affiliate" under Indiana Law.

"Person" "Person" includes the following: (a) individual, (b) corporation, regardless of type or state or country of incorporation, (c) unincorporated association, (d) company, whether limited liability or otherwise, and (e) business trust, estate, partnership, trust, two (2) or more persons having a joint or common economic interest, and any other entity.

"Commission" "Commission" means the Indiana Utility Regulatory Commission.

"IURC" "IURC" means the Indiana Utility Regulatory Commission.

"OUCC" "OUCC" means the Indiana Office of Utility Consumer Counselor.

"Holding Company" "Holding Company" means the parent company, Vectren Corporation, or its successor in interest of Indiana Gas Company and/or Southern Indiana Gas and Electric Company.

"Competitive Terms" "Competitive Terms" means the best terms reasonably available in the competitive marketplace at that time (including the terms available from the Utility itself under efficient operation) giving due consideration to both price and non-price terms such as quality and reliability. If the Utility itself can provide the services at the lowest cost with comparable quality and reliability, then that cost shall be considered the "competitive terms."

"Shared Corporate Support and Administrative Services" "Shared Corporate Support and Administrative Services" means the following types of functions/services that the Utility may share with other companies/affiliates within the Vectren organization: (1) accounting and corporate treasury services; (2) human resources; (3) information technology and communications services; (4) corporate directors and officers services; (5) legal services; (6) insurance and claims; (7) billing; (8) customer call center services; (9) facility and fleet management; and (10) environmental services. (See Specific Affiliate Guidelines 10, 12, and 15 related to "Shared Corporate Support and Administrative Services.")

"Capital Costs" "Capital Costs" means the costs associated with obtaining the financial capital required to provide physical assets such as office buildings, computers or office equipment.

"Non-Regulated" "Non-Regulated" means not regulated by the Indiana Utility Regulatory Commission (IURC). "Non-Regulated" also applies to products or services over which the IURC has declined its jurisdiction.

"Similarly Situated" "Similarly Situated" means having general characteristics in common such as belonging to the same rate class or operating in the same or similar industries. A utility affiliated gas or power marketer would, for example, be considered similarly situated to other non-affiliated gas or power marketers.

AFFILIATE AND COST ALLOCATION GUIDELINES

(Continued)

A.3. GENERAL AFFILIATE GUIDELINES

A. **No Cross-Subsidies.** The Utility shall not subsidize Affiliates or non-regulated activities.

B. **Separation of Regulated and Non-Regulated Operations.** The separation of the Utility's regulated operations from the Holding Company's non-regulated business operations and Affiliates is necessary to prevent potential cross-subsidies. To the maximum extent practicable, the Utility shall separate its regulated operations from its own, its Affiliates and its Holding Company's non-regulated operations. Instances where such separation does not exist must otherwise be in compliance with the Affiliate Guidelines and the Cost Allocation Guidelines.

C. **No Discrimination.** The Utility shall not discriminate in favor of or otherwise give preferential treatment to its Affiliates, its Affiliates' customers or the Utility's own non-regulated activities

D. **Comparability of Service.** The Utility shall provide comparable service to all similarly situated marketers, customers or other entities, regardless of affiliation.

E. **Procurement on Competitive Terms.** With the exception of "shared corporate support and administrative services" (defined above) the procurement of goods, services, assets and other resources by the Utility shall be on competitive terms, consistent with the public interest and in compliance with these Affiliate Guidelines and the Cost Allocation Guidelines. The Utility may procure services from an Affiliate but such procurement must be done on competitive terms (defined above). The Utility's procurement process shall also comply with General Guideline C above (i.e., No Discrimination). The pricing of "shared corporate support and administrative services" to the Utility shall be based on cost and be in accordance with the Cost Allocation Guidelines.

AFFILIATE AND COST ALLOCATION GUIDELINES
(Continued)

A.4. SPECIFIC AFFILIATE GUIDELINES

1. Affiliates shall be charged for all costs incurred on their behalf. These costs shall be appropriately and reasonably allocated and shall include, but not be limited to, those associated with shared facilities, general and administrative support services and other corporate overheads.

2. The Utility shall process all similar requests for service in the same manner and within the same reasonable time period for all similarly situated customers, marketers and other entities, regardless of affiliation.

3. The Utility shall not give preference to or discriminate in favor of its Affiliates, its Affiliates' customers or its own non-regulated activities in matters including, but not limited to, the allocation, assignment, release, or transfer of rights to intrastate or interstate capacity, use of Utility distribution facilities, storage on system, rights to storage off system, or in the sale of gas.

4. The Utility shall not condition or tie any agreement to provide Utility service to any agreement relating to a service to be provided by an Affiliate.

5. To the maximum extent practicable, Utility employees shall function separately and independently from employees of Affiliates and those engaged in non-regulated activities including, but not limited to, gas marketers, power marketers and other service providers.

6. The Utility may not, through tariff or otherwise, give any Affiliate or an Affiliate's customer or any non-regulated activity a preference or an advantage with respect to the transportation of gas including, but not limited to, the movement or delivery of gas on its distribution system, the administration of customer contracts, scheduling, nomination, balancing, metering, storage, standby service, curtailment policy, or billing/invoice disputes.

7. The Utility shall apply tariffs and their provisions and all other aspects of Utility service on a consistent and non-discriminatory basis to all similarly situated marketers, customers, and other entities regardless of affiliation.

8. Any discount or rebate for utility service offered by the Utility to an Affiliate or an Affiliate's customer shall be offered on a non-discriminatory basis to all similarly situated marketers, customers or other entities, regardless of affiliations. If the Utility waives a penalty or fee related to Utility service for an Affiliate or an Affiliate's customer, it shall waive such penalty or fee for similarly situated others on a non-discriminatory basis.

9. The Utility shall not give preference to or discriminate in favor of its Affiliates or its Affiliate's customers in its provision of information. This includes, without limitation, information related to the sale or marketing of energy or energy services to existing or potential new customers and information related to the availability of transmission, distribution or storage capacity.

AFFILIATE AND COST ALLOCATION GUIDELINES
(Continued)

9. Specific customer information shall be made available to affiliated or unaffiliated entities only upon consent of the customer or as otherwise provided by law or commission rules or orders, except that customer name and address information may be provided to energy marketers or energy service providers.

10. The Utility may share information technology and communications services with other companies/affiliates within the Vectren organization. However, such sharing of information technology and communications services shall not be done in a manner that violates Specific Guideline 9 above regarding the non-discriminatory provision of information. The utility shall take whatever steps are necessary to fulfill this requirement such as, for example, the implementation of electronic "firewalls" or other measures to control access to Utility information.

11. The Utility shall not speak on behalf of its Affiliates or give the appearance that it speaks on behalf of its Affiliates. The Utility's Affiliates shall not speak on behalf of the Utility or give the appearance that they speak on behalf of the Utility.

12. Customer call handling shall be performed on a non-discriminatory basis without respect to affiliations of the customer or affiliations of the customer's marketer or energy service provider. If a customer requests information about alternative sources of supply, the customer service representatives shall offer to provide a list of all alternative suppliers known to be serving customers in the same rate class as the customer making the inquiry, except those suppliers excluded by mutual agreement of the Utility and the OUCC. Such a list may include utility affiliates, but the utility customer service representatives shall not promote or endorse services offered by an affiliate. To ensure compliance with Specific Guidelines 9, 10, 11 and 12, the guidelines for handling of customer calls and information have been set out in writing and attached as Customer Call Handling Process.

13. The Utility's Affiliates shall not trade upon, promote, or suggest that they receive preferential treatment as a result of affiliation with the Utility.

14. The Utility and its Affiliates shall not participate in joint advertising. An Affiliate may, however, reference the fact of its affiliation with the holding company. Such public references shall not: (a) make the Affiliate appear to be part of the Utility, or (b) suggest that the Affiliate or the Affiliate's customers will have any advantage as a result of the affiliation.

15. If the charges for Utility services are combined with charges for non-regulated energy services into a single bill, such a combined bill format will be made available on a non-discriminatory basis to non-affiliated entities that provide energy services in the Utility's service territory.

AFFILIATE AND COST ALLOCATION GUIDELINES
(Continued)

16. The Utility and its Affiliates shall maintain separate books and records, which shall be available for Commission inspection consistent with Indiana law.

17. The OUCC and its agents shall have access to officers and employees and access to the books and records of the Utility and its Affiliates as reasonably necessary to ensure compliance with these Affiliate Guidelines, the Cost Allocation Guidelines and Title 8 of the Indiana Code. If disputes arise between the OUCC and Utility regarding the reasonableness of the timing or scope of requested access to Affiliate and Utility books and records, if not resolved by the parties, then such disputes may be presented to the Commission through use of an alternative dispute resolution process as agreed upon by the OUCC and Utility. During this process, Utility shall bear the burden of demonstrating the unreasonableness of the OUCC's request. In seeking a resolution of access disputes, the parties agree that time is of the essence, and the intent of the parties is that the Commission's review of such disputes will be facilitated by the parties so that the review can be as expeditious as possible.

18. All complaints relating to these Affiliate Guidelines and the Cost Allocation Guidelines, whether written or verbal, shall be submitted to the general counsel of the Utility or the Utility's highest ranking legal employee ("general counsel"). The general counsel shall acknowledge to complainant such complaint within five (5) working days of receipt. The general counsel shall conduct a preliminary investigation and prepare a written statement of the complaint which shall contain the name of the complainant and a detailed factual report of the incident or incidents underlying the complaint, including all relevant dates, companies involved, employees involved, and the specific claim. The general counsel shall provide a copy of the written statement to the complainant. The general counsel shall communicate the results of the preliminary investigation to the complainant in writing within twenty (20) days after the complaint was received including a description of any course of action to be taken. In the event the Utility and the complainant are unable to resolve the complaint, the complainant may file a complaint with the Commission. Any complaint filed with the Commission before same was filed with the Utility under this section shall be held in abeyance while the procedures outlined here are followed. The general counsel shall keep a log of all complaints for a period of not less than three (3) years and shall keep such log available for inspection by the IURC, OUCC and complainant.

19. All transactions between the Utility and its Affiliates shall be in accordance with a written contract filed with the IURC pursuant to I.C. 8-1-2-49. The Utility shall maintain sufficient records of all such transactions for at least three (3) years so as to allow for a complete and thorough audit.

20. The Utility shall meet with the OUCC to review all proposed Affiliate contracts. Upon filing of Affiliate contracts with the IURC, copies of such contracts will be delivered to the OUCC. Affiliate contracts shall be governed by Indiana law and these Affiliate Guidelines and the Cost Allocation Guidelines. To the extent the Guidelines contain provisions or commitments that go beyond what would otherwise be required under Indiana law, the Guidelines shall control. The OUCC reserves its rights to challenge such contracts at any time.

AFFILIATE AND COST ALLOCATION GUIDELINES

(Continued)

A.5. PROCEDURES FOR FILING AFFILIATE CONTRACTS

All Affiliate contracts shall be filed with the IURC and be in conformance with these Guidelines, the Cost Allocation Guidelines and Indiana law. Such contracts shall be available for public inspection, except to the extent that information is protected from public disclosure under Indiana law. These Affiliate Guidelines in no way affect the IURC's duties and/or authority under Indiana law to *inter alia* investigate such contracts, hold public hearings related to such contracts and/or disapprove such contracts. These Affiliate Guidelines also in no way affect the OUCC's rights to *inter alia* initiate investigations of such contracts.

A.6. ANNUAL INFORMATIONAL FILING

The Utility shall file annually with the Commission and provide copies to the OUCC the following information concerning the Utility's Affiliates and its non-regulated activities.

1. The names and business addresses of the officers and directors of each Affiliate that has transacted any business with the Utility during the previous twelve (12) months. For each such Affiliate, the Utility shall also provide the following in its annual informational filing:
    a. The Affiliate's name and a description of the Affiliate's primary line(s) of business and a description of the nature of the Affiliate's business with other non-affiliated entities.
    b. A schedule detailing and summarizing the nature and dollar amounts of the transfers of assets, goods and services between the Utility and the Affiliate that took place during the applicable twelve-month period.
2. A listing of all contracts currently in effect between the Utility and Affiliate(s) indicating the nature of the transactions, the date the contract became effective and the contract's expiration date.
3. A corporate organization chart, which shows the parent holding company, the Utility, its Affiliates, and their relationships to one another.
4. A description of the method(s) used to identify, value, and record transfers of assets, goods and services between the Utility and its Affiliates.
5. A description of the method(s) used to allocate federal and state income tax expense, payments and refunds to the Utility and its Affiliates.
6. A description of sharing of personnel between the Utility and its Affiliates during the twelve-month period.
7. A log of complaints maintained by the Utility under section 18 of Specific Affiliate Guidelines.
8. A listing and description of all non-regulated activities engaged in by the Utility, including the amount of revenues and expenses generated by each such non-regulated activity.

These annual informational filings shall commence on the date thirty (30) days after the effective date of the Commission's approval of these Affiliate Guidelines, and shall repeat thereafter at the end of the Utility's fiscal year. These annual informational filings shall not serve or be interpreted as a pre-approval process.

AFFILIATE AND COST ALLOCATION GUIDELINES

(Continued)

B.1. COST ALLOCATION GUIDELINES

The OUCC and Southern Indiana Gas and Electric Company ("Utility") (collectively "Parties") have negotiated in connection with Cause No. 41465 the following Cost Allocation Guidelines to govern the allocation of costs between the Utility and its Affiliates. The OUCC retains all of its rights and authority to dispute the reasonableness of and/or recovery of all Utility costs, including those to which these Cost Allocation Guidelines may be applicable. Mere allocation of costs under these guidelines does not predetermine the reasonableness of rate recovery of such costs. The Parties agree that these guidelines are intended to be enforced by the IURC, and they shall become effective upon their approval by the IURC. The OUCC and Utility may, through negotiation and agreement, jointly petition the IURC for modifications to these Cost Allocation Guidelines, in which case they would have the burden of proving any proposed change is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition. If either the OUCC or Utility desires changes to these Cost Allocation Guidelines and is unable to obtain agreement from the other party for such changes, then the party desiring changes may petition the IURC for the desired changes and bear the burden of proving that such changes are in the public interest. However, such petitions shall not be filed without first attempting to obtain the agreement of the other party. Subject to the following sentence, anyone else seeking a change to these Cost Allocation Guidelines may also petition the IURC and would bear the burden of proving that the proposed changes are in the public interest. However, any such petition shall not be filed without the Utility and the OUCC first being notified and given a reasonable opportunity to consider the proposed change. The Commission may also make modifications to these Cost Allocation Guidelines on its own motion, after notice and hearing.

These Cost Allocation Guidelines should be read in conjunction with the "Affiliate Guidelines" developed by the OUCC and Utility and also approved by the Commission in Cause No. 41465. Subject to Section H of the Settlement Agreement in Cause No. 41465, the Affiliate Guidelines and the Cost Allocation Guidelines govern all current and future affiliate relationships between the Utility and its Affiliates, with the limited exception that the Commission may approve an Affiliate contract that differs from these Guidelines if the Utility files a petition requesting an exception from the Guidelines and satisfies its burden to demonstrate that such contract is in the public interest considering all relevant factors, including, but not limited to, price of service and the impact on competition.

The following Cost Allocation Guidelines govern the allocation of costs associated with "shared corporate support and administrative services" which have been defined in the definition section of the Affiliate Guidelines and which may be shared with other companies/affiliates within the Vectren organization. By their nature, these costs are associated with functions and operations that are shared and not separate. The allocation methods should apply to those Utility Affiliates who share corporate support and administrative functions in order to prevent subsidization from the regulated Utility and ensure equitable cost sharing among the regulated Utility and its Affiliates. The pricing of "shared corporate support and administrative services" to the Utility shall be based on cost and be in accordance with these Cost Allocation Guidelines.

AFFILIATE AND COST ALLOCATION GUIDELINES

(Continued)

B.2. DEFINITIONS

See the definitions section of the Affiliate Guidelines for the definitions of terms used in the Affiliate Guidelines and the Cost Allocation Guidelines.

B.3. GUIDELINES

1. No Cross-Subsidies. The Utility shall not subsidize Affiliates or non-regulated activities.
2. The Utility shall maintain and utilize an accounting system and records that identify and appropriately allocate costs between the Utility and its Affiliates.
3. The Utility's costs for jurisdictional rate purposes shall reflect only those costs attributable to its jurisdictional customers.
4. The Utility and all Affiliates that share corporate support and administrative services shall maintain documentation including organizational charts, accounting bulletins, procedure and work order manuals or other related documents, which describe how costs are allocated between regulated and non-regulated services or products.
5. Affiliates shall be charged an appropriate and reasonable allocation of all shared corporate support and administrative costs incurred on their behalf. These costs include, but are not limited to, those associated with shared facilities and other corporate overheads.
6. To the maximum extent practicable, shared corporate support and administrative costs should be accumulated and classified on a direct cost basis for each asset, service or product provided.
7. The shared corporate support and administrative costs that cannot be directly assigned per item (6) above, should to the maximum extent possible be allocated to the Utility and its Affiliates and to the services or products to which they relate using relevant allocators which best reflect or consider the cost causative characteristics of the product/service being provided.
8. Where allocation/assignment pursuant to (6) and (7) is not practical, general allocation factors shall be utilized to allocate all remaining costs between the Utility and its Affiliates and between service and product lines ultimately provided by the Utility and its Affiliates.
9. The allocation of capital costs between the Utility and its Affiliates (incurred in the provision of "shared corporate support and administrative" services) shall be based on the following:
    a. The cost of capital used for such allocations shall equal the Utility's weighted average cost of capital as last found by the Commission.

AFFILIATE AND COST ALLOCATION GUIDELINES
(Continued)

b. Depreciation shall be charged on a straight-line basis. Depreciation rates used for such allocations shall be consistent with the expected useful life of the asset(s) and in accordance with generally accepted accounting principles and regulatory accounting requirements, as applicable.

10. The Utility and its Affiliates shall maintain separate books and records, which shall be available for Commission inspection consistent with Indiana Law.

11. The OUCC and its agents shall have access to officers and employees and access to the books and records of the Utility and its Affiliates as reasonably necessary to ensure compliance with the Affiliate Guidelines, the Cost Allocation Guidelines and Title 8 of the Indiana Code. If disputes arise regarding the reasonableness of the timing or scope of requested access to Affiliate and Utility books and records, if not resolved by the parties, then such disputes may be presented to the Commission through use of an alternative dispute resolution process as agreed upon by the OUCC and Utility. During this process, Utility shall bear the burden of demonstrating the unreasonableness of the OUCC's request. In seeking a resolution of access disputes, the parties agree that time is of the essence, and the intent of the parties is that the Commission's review of such disputes will be facilitated by the parties so that the review can be as expeditious as possible.

12. The cost assignment/allocation methodologies discussed herein are applicable to shared corporate support and administrative services. The Utility's procurement of all other goods, services, assets or other resources shall be on competitive terms, consistent with the public interest and in compliance with the Affiliate Guidelines and the Cost Allocation Guidelines.

B.4. AUDIT REQUIREMENTS

Each year an independent auditor appointed by the OUCC shall do an audit. OUCC staff members may assist the auditor. The purpose of the audit shall be to ensure that the Utility complies with these Cost Allocation Guidelines. Any violations of the Cost Allocation Guidelines shall be noted and explained in the auditor's report, a copy of which shall be provided to the Utility, the Commission and the OUCC. Vectren shall annually contribute up to $50,000 toward the auditor's costs/fees.

AFFILIATE AND COST ALLOCATION GUIDELINES

(Continued)

B.5. CUSTOMER CALL HANDLING PROCESS

Outline of Customer Call Handling Guidelines and Infrastructure

In order to provide for the operation of an efficient, high quality call center operation that handles customer calls and information in a manner consistent with the terms of the Affiliate and Cost Allocation Guidelines, this outline has been developed. The intent is to describe the guidelines for customer call handling and the requirements for separation between staff handling calls about regulated services and staff handling calls about non-regulated services. The key components include:

- Staffing — A separate non-regulated service call handling staff including a separate exempt supervisory leader is required.
- Separation — Personnel devoted to handling calls related to regulated utility service will be physically separated from personnel handling non-regulated service calls through, at a minimum, the use of high height partitions and panels.
- Data — A data firewall will be created to require customer permission before non-utility related staff can access utility customer records. Acquisition of utility customer usage and billing history data will be with customer permission and consistent with Specific Affiliate Guidelines 9 and 10.
- Costs — Call center costs will be allocated per the Cost Allocation Guidelines. Any charges made to providers of non-regulated services will be reasonable and non-discriminatory.
- Process — Attached are summary call handling flowcharts and a script which have been developed to more specifically describe the process to be used in the event that the utility offers an energy choice program to its residential and small Non-Residential customers in the future.
- Monitoring — The IURC and OUCC will be able to monitor compliance with the Guidelines through the provision of access to customer calls. The IURC and OUCC (or their agents) will also be able to make on site visits and inspections of call center facilities.

AFFILIATE AND COST ALLOCATION GUIDELINES

(Continued)

B.6. CUSTOMER CALL HANDLING SCRIPT

For Inquiries Regarding Non-Regulated Energy Services

Mr./Ms. Customer,

I am very sorry but I can't directly handle this for you, but I can get you in touch with somebody who can.

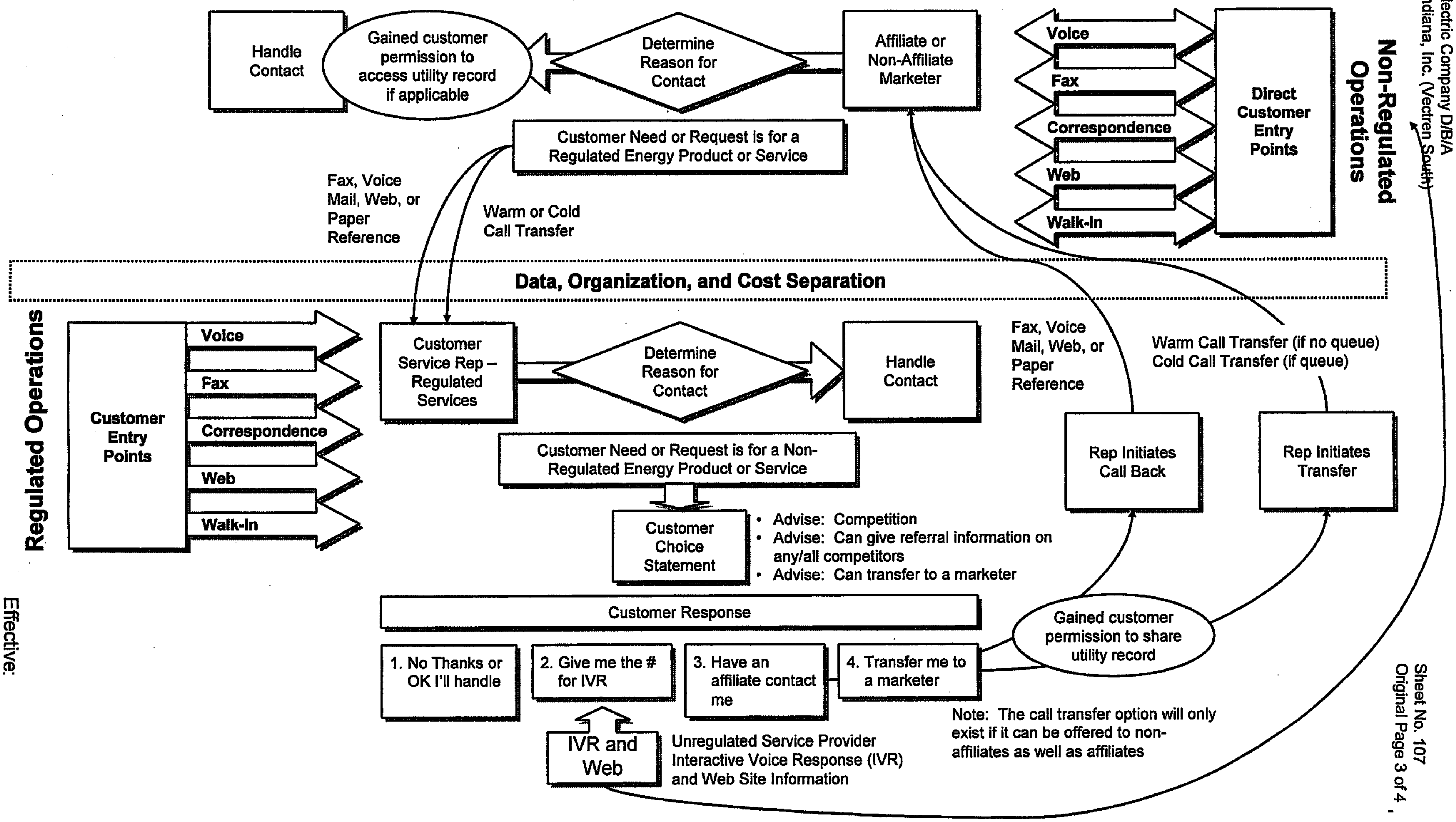
I can give you a telephone number from which you can get more information about the providers of these services, including our affiliate ________. This telephone number is: *(give telephone number).* If you have access to the web you can get this information on the web site. The web site address is: *(give web address).*

[If you prefer, I can transfer your call now to one of these service providers. *(see note)*

By the way, the providers may want to review your customer records. Do we have your consent to release this information at their request?

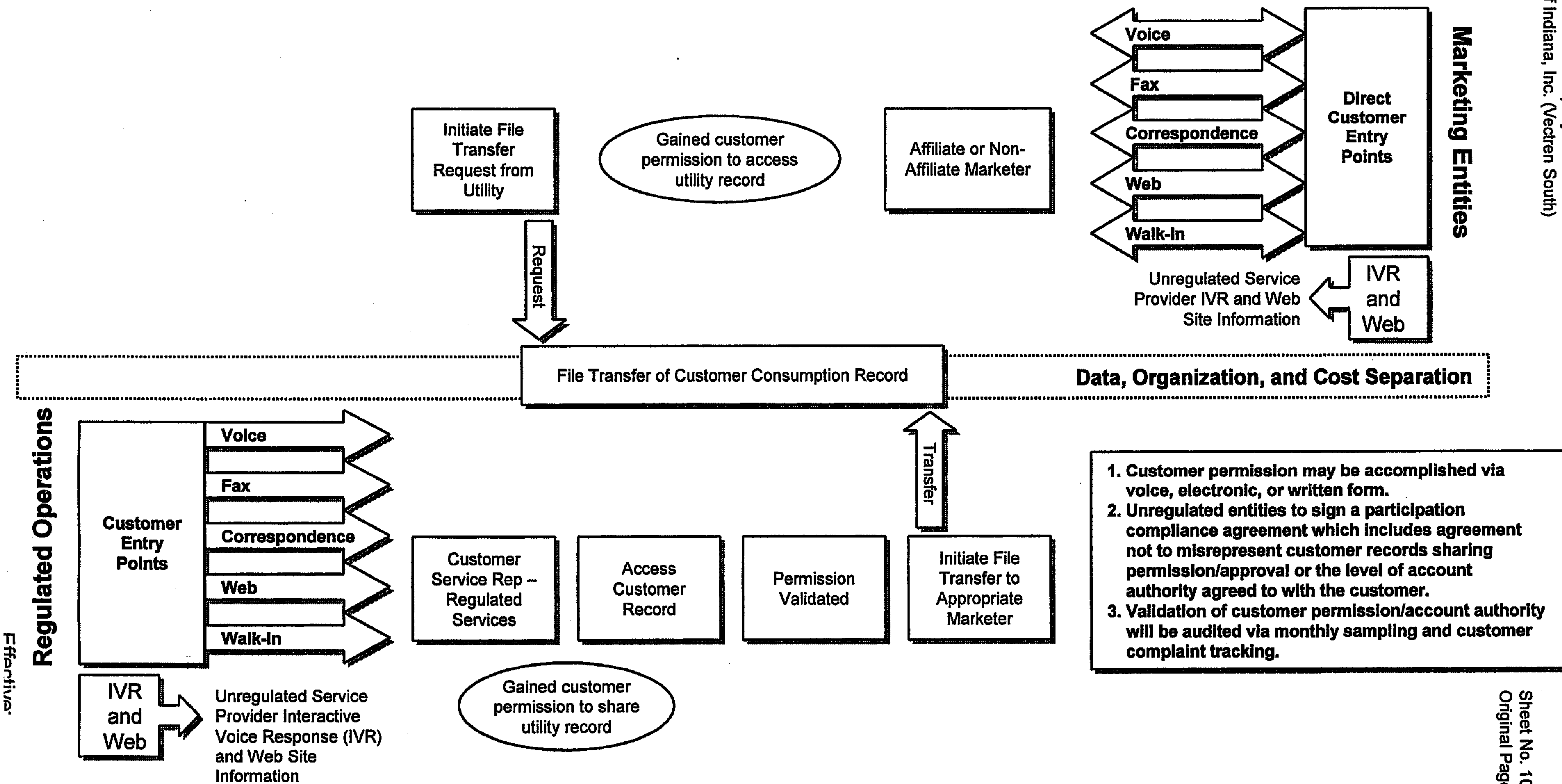
Note: The paragraph references call transfers and will only be part of the script if Vectren can offer the call transferring

Call Handling Process Summary



Effective:

Customer Permission and Information Transfer Summary



Effective:

Schedule 1
(Pro forma)

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
DETERMINATION OF GCRA
For the Months of Month A, Month B and Month C

	Estimated Sales (kWh)	Rate A	Rate EH	Rate B	Rate SGS	Rate DGS	Rate OSS	Rate LP	Rate HLF	Total
1	Month A	69,849,488	29,359,843	1,010,303	35,000,100	65,818,900	8,451,610	156,137,029	87,216,000	452,843,273
2	Month B	71,573,723	44,289,676	1,126,886	28,535,100	71,339,153	10,892,224	143,171,888	83,070,000	453,998,650
3	Month C	86,438,096	59,656,895	1,394,470	37,300,600	65,171,249	13,565,732	143,279,776	91,182,000	497,988,818
4	Total	227,861,307	133,306,414	3,531,659	100,835,800	202,329,302	32,909,566	442,588,693	261,468,000	1,404,830,741
5	GCRA Allocation Percentages (Sch 2)	30.9625%	7.3942%	0.1414%	0.7820%	27.9731%	2.0581%	18.4434%	12.2453%	100.0000%
6	Incremental GCRA Amounts (Sch 3 X Line 5)	$ (278,027)	$ (66,396)	$ (1,270)	$ (7,022)	$ (251,184)	$ (18,481)	$ (165,613)	$ (109,957)	$ (897,950)
7	Variance (Sum Sch 4, line 5 X line 5)	$ 33,396	$ 7,975	$ 153	$ 843	$ 30,172	$ 2,220	$ 19,893	$ 13,208	$ 107,860
8	GCRA Amounts plus Variance (line 6 + line 7)	$ (244,631)	$ (58,421)	$ (1,117)	$ (6,179)	$ (221,012)	$ (16,261)	$ (145,720)	$ (96,749)	$ (790,091)
9	GCRA per kWh Excl IURT	$ (0.001074)	$ (0.000438)	$ (0.000316)	$ (0.000061)	$ (0.001092)	$ (0.000494)	$ (0.000329)	$ (0.000370)	$ (0.000562)
10	GCRA per kWh Incl IURT	$ (0.001091)	$ (0.000445)	$ (0.000321)	$ (0.000062)	$ (0.001109)	$ (0.000502)	$ (0.000334)	$ (0.000376)	$ (0.000571)

Schedule 2
(Pro forma)

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
GCRA ALLOCATION PERCENTAGES

Rate Schedule	Description	Allocation Percentages Cause No. 43111 (%)
A	Residential	30.9625%
EH	Residential Electric Heating	7.3942%
B	Water Heating	0.1414%
SGS	Small General Service	0.7820%
DGS	Large General Service	27.9731%
OSS	Off-Season Service	2.0581%
LP	Large Power	18.4434%
HLF	Transmission Power	12.2453%
Total		100.000%

Schedule 3
(Pro forma)

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
CALCULATION OF INCREMENTAL GENERATION COSTS AND REVENUES
FOR THE THREE MONTHS ENDED MONTH ________, 2006

Line No.		Month 1	Month 2	Month 3	Total
	Generation Costs				
1.	Non-fuel component of Purchased Power Costs	$ 400,000	350,000	425,000	$ 1,175,000
2.	Environmental Chemicals Costs	1,450,000	1,300,000	1,500,000	4,250,000
3.	Direct Load Control (DLC) Billing Credits	950,000	450,000	100,000	1,500,000
4.	Interruptible Sales Billing Credits	190,000	195,000	95,000	480,000
5.	Subtotal (Sum of lines 1 through 4)	$ 2,990,000	2,295,000	2,120,000	$ 7,405,000
	Less portion of base rate amounts of:				
6.	Non-fuel component of Purchased Power Costs				150,000
7.	Environmental Chemicals Costs				2,500,000
8.	Direct Load Control (DLC) Billing Credits				700,000
9.	Interruptible Sales Billing Credits				3,000,000
10.	Subtotal (Sum of lines 6 through 9)				6,350,000
11.	Total Generation Costs (line 5 - line 10)				$ 1,055,000
	Generation Revenues				
12.	Net margin from WPM	$ 165,000	230,000	$ 700,000	$ 1,095,000
13.	Portion of WPM Margin Included in Base Rates	275,000	275,000	275,000	825,000
14.	Incremental WPM Margin Available	(110,000)	(45,000)	425,000	270,000
15.	Retail Percentage	50.00%	50.00%	50.00%	50.00%
16.	Incremental WPM Margin Available to Retail	(55,000)	(22,500)	212,500	$ 135,000
17.	Net Municipal Margin Available to Retail	$ 300,000	360,000	$ 280,000	$ 940,000
18.	Net Emission Allowance Margin Applicable to Retail (Schedule 3A)	$ 244,150	471,100	$ 162,700	$ 877,950
19.	Total Generation Revenues (line 16 + line 17 + line 18)	489,150	808,600	655,200	1,952,950
20.	Incremental GCRA Amounts to be tracked (To Schedule 1) (line 11 - line 19)				$ (897,950)

Schedule 3a
Page 1 of 1
(Pro forma)

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
CALCULATION OF EMISSION ALLOWANCE CREDITS
For the Months of Month 1, Month 2 and Month 3

Month 1

Line No.		Use				Sales				Total
1	Net Margin from SO2 Allowances	$	20,000			$	102,800			
2	Retail %		100%				90%			
3	SO2 Margin Available to Retail			$	20,000			$	92,520	$ 112,520
4	Net Margin from NOx Allowances	$	10,000			$	62,500			
5	Retail %		100%				80%			
6	NOx Margin Available to Retail			$	10,000			$	50,000	$ 60,000
7	Net Margin from Mercury Allowances	$	8,000			$	70,700			
8	Retail %		100%				90%			
9	Mercury Margin Available to Retail			$	8,000			$	63,630	$ 71,630
10	Total Retail Portion of Emission Allowance Margin			$	38,000			$	206,150	$ 244,150

Month 2

Line No.		Use				Sales				Total
11	Net Margin from SO2 Allowances	$	18,000			$	231,000			
12	Retail %		100%				90%			
13	SO2 Margin Available to Retail			$	18,000			$	207,900	$ 225,900
14	Net Margin from NOx Allowances	$	9,000			$	119,000			
15	Retail %		100%				80%			
16	NOx Margin Available to Retail			$	9,000			$	95,200	$ 104,200
17	Net Margin from Mercury Allowances	$	6,000			$	150,000			
18	Retail %		100%				90%			
19	Mercury Margin Available to Retail			$	6,000			$	135,000	$ 141,000
20	Total Retail Portion of Emission Allowance Margin			$	33,000			$	438,100	$ 471,100

Month 3

Line No.		Use				Sales				Total
21	Net Margin from SO2 Allowances	$	6,000			$	79,000			
22	Retail %		100%				90%			
23	SO2 Margin Available to Retail			$	6,000			$	71,100	$ 77,100
24	Net Margin from NOx Allowances	$	3,000			$	58,000			
25	Retail %		100%				80%			
26	NOx Margin Available to Retail			$	3,000			$	46,400	$ 49,400
27	Net Margin from Mercury Allowances	$	2,000			$	38,000			
28	Retail %		100%				90%			
29	Mercury Margin Available to Retail			$	2,000			$	34,200	$ 36,200
30	Total Retail Portion of Emission Allowance Margin			$	11,000			$	151,700	$ 162,700
31	Total for Three-month period			$	82,000			$	795,950	$ 877,950

Schedule 4
Page 1 of 3
(Pro forma)

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
Determination of GCRA Variance
Month 1

Line No.		Rate A	EH	B	SGS	DGS	OSS	LP	HLF	TOTAL
1	Total kWh Sales (Actual)	80,356,125	54,476,063	1,460,401	25,353,200	63,900,627	9,570,917	119,658,492	89,199,733	443,975,558
2	Applicable GCRA Rate ($/kWh)									
2a	Including Indiana Utility Receipts Tax	$ 0.000225	$ 0.000072	$ -	$ 0.001097	$ 0.001097	$ 0.001097	$ 0.000477	$ 0.000056	
2b	Excluding Indiana Utility Receipts Tax	$ 0.000222	$ 0.000071	$ -	$ 0.001080	$ 0.001080	$ 0.001080	$ 0.000470	$ 0.000055	
3	GCRA Billed									
3a	Including Indiana Utility Receipts Tax	$ 18,080	$ 3,922	$ -	$ 27,812	$ 70,099	$ 10,499	$ 57,077	$ 4,995	$ 192,484
3b	Excluding Indiana Utility Receipts Tax	$ 17,839	$ 3,868	$ -	$ 27,381	$ 69,013	$ 10,337	$ 56,239	$ 4,906	$ 189,583
4	GCRA Intended to be Billed (Excluding IURT)	$ 17,000	$ 2,900	$ 150	$ 25,000	$ 82,000	$ 9,000	$ 65,000	$ 6,200	$ 207,250
5	Under (Over) Recovery Variance (Line 4 - Line 3b)									$ 17,667

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
Determination of GCRA Variance
Month 2

Line No.		Rate A	EH	B	SGS	DGS	OSS	LP	HLF	TOTAL
1	Total kWh Sales (Actual)	84,373,800	57,199,810	1,533,400	26,620,650	6,709,988	10,048,510	125,640,926	93,660,136	405,787,220
2	Applicable GCRA Rate ($/kWh)									
2a	Including Indiana Utility Receipts Tax	$ 0.000225	$ 0.000072	$ -	$ 0.001097	$ 0.001097	$ 0.001097	$ 0.000477	$ 0.000056	
2b	Excluding Indiana Utility Receipts Tax	$ 0.000222	$ 0.000071	$ -	$ 0.001080	$ 0.001080	$ 0.001080	$ 0.000470	$ 0.000055	
3	GCRA Billed									
3a	Including Indiana Utility Receipts Tax	$ 18,984	$ 4,118	$ -	$ 29,203	$ 7,361	$ 11,023	$ 59,931	$ 5,245	$ 135,865
3b	Excluding Indiana Utility Receipts Tax	$ 18,731	$ 4,061	$ -	$ 28,750	$ 7,247	$ 10,852	$ 59,051	$ 5,151	$ 133,843
4	GCRA Intended to be Billed (Excluding IURT)	$ 17,000	$ 2,900	$ 150	$ 25,000	$ 82,000	$ 9,000	$ 65,000	$ 6,200	$ 207,250
5	Under (Over) Recovery Variance (Line 4 - Line 3b)									$ 73,407

VECTREN SOUTH
GENERATION COST AND REVENUE ADJUSTMENT
Determination of GCRA Variance
Month 3

Line No.		Rate A	EH	B	SGS	DGS	OSS	LP	HLF	TOTAL
1	Total kWh Sales (Actual)	76,338,239	51,752,201	1,387,813	24,085,351	60,705,497	9,091,553	113,675,198	84,739,832	421,775,684
2	Applicable GCRA Rate ($/kWh)									
2a	Including Indiana Utility Receipts Tax	$ 0.000225	$ 0.000072	$ -	$ 0.001097	$ 0.001097	$ 0.001097	$ 0.000477	$ 0.000056	
2b	Excluding Indiana Utility Receipts Tax	$ 0.000222	$ 0.000071	$ -	$ 0.001080	$ 0.001080	$ 0.001080	$ 0.000470	$ 0.000055	
3	GCRA Billed									
3a	Including Indiana Utility Receipts Tax	$ 17,176	$ 3,726	$ -	$ 26,422	$ 66,594	$ 9,973	$ 54,223	$ 4,745	$ 182,859
3b	Excluding Indiana Utility Receipts Tax	$ 16,947	$ 3,674	$ -	$ 26,012	$ 65,562	$ 9,819	$ 53,427	$ 4,661	$ 180,102
4	GCRA Intended to be Billed (Excluding IURT)	$ 16,150	$ 2,755	$ 143	$ 23,750	$ 77,900	$ 8,550	$ 61,750	$ 5,890	$ 196,888
5	Under (Over) Recovery Variance (Line 4 - Line 3b)									$ 16,786