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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND)
 ELECTRIC COMPANY d/b/a VECTREN ENERGY)
 DELIVERY OF INDIANA, INC. ("PETITIONER") FOR)
 APPROVAL OF AND AUTHORITY FOR (1) AN)
 INCREASE IN ITS RATES AND CHARGES FOR)
 ELECTRIC UTILITY SERVICE INCLUDING A SECOND)
 STEP THAT WILL INCLUDE THE REVENUE)
 REQUIREMENT FOR ITS DENSE PACK PROJECTS; (2))
 NEW SCHEDULES OF RATES AND CHARGES)
 APPLICABLE THERETO; (3) THE SHARING OF)
 WHOLESALE POWER MARGINS BETWEEN)
 PETITIONER AND ITS ELECTRIC CUSTOMERS; (4) A)
 SALES RECONCILIATION ADJUSTMENT TO)
 DECOUPLE FIXED COST RECOVERY FROM THE)
 AMOUNT OF CUSTOMER USAGE FOR CERTAIN)
 RATE CLASSES; (5) A DEMAND SIDE MANAGEMENT)
 PROGRAM WHICH WILL INCLUDE A MECHANISM)
 FOR THE TIMELY RECOVERY OF COSTS RELATING)
 THERETO AND PERFORMANCE INCENTIVES BASED)
 ON ACHIEVED SAVINGS; (6) AN ALTERNATIVE)
 REGULATORY PLAN ALLOWING PETITIONER TO)
 RETAIN ITS SHARE OF WHOLESALE POWER)
 MARGINS AND DEMAND SIDE MANAGEMENT)
 PERFORMANCE INCENTIVES; AND (7) APPROVAL OF)
 VARIOUS CHANGES TO ITS TARIFF FOR ELECTRIC)
 SERVICE INCLUDING NEW NET METERING,)
 ALTERNATE FEED SERVICE, TEMPORARY SERVICE,)
 AND STANDBY OR AUXILIARY SERVICE RIDERS,)
 REVISIONS TO ITS EXISTING ECONOMIC)
 DEVELOPMENT AND AREA DEVELOPMENT RIDERS,)
 REVISIONS TO ITS EXISTING MISO COST AND)
 REVENUE ADJUSTMENT AND RELIABILITY COST)
 AND REVENUE ADJUSTMENT (INCLUDING THE)
 ADDITION OF A COMPONENT TO TRACK VARIABLE)
 PRODUCTION COSTS) AND REVISIONS TO ITS)
 GENERAL TERMS AND CONDITIONS FOR SERVICE.)

CAUSE NO. 43839

APPROVED: APR 27 2011

BY THE COMMISSION:

James D. Atterholt, Chairman
Jeffery A. Earl, Administrative Law Judge

FINAL ORDER

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INTRODUCTION

On December 11, 2009, Southern Indiana Gas Company and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. (“Vectren South” or “Petitioner”) filed its Petition and Notice of Intent to File in Accordance with the Commission’s Rules on Minimum Standard Filing Requirements (“MSFRs”) with the Indiana Utility Regulatory Commission (“Commission”) seeking, among other things, authorizations and approvals for the following: (1) an increase in its rates and charges for electric utility service including a second step that will include the revenue requirement for its Dense Pack projects at Brown Unit 1 and Brown Unit 2 (“Dense Pack Projects”); (2) new schedules of rates and charges applicable thereto; (3) a rate design mechanism that decouples fixed cost recovery from customer usage; and (4) approval of various changes to its tariff for electric service and rate adjustment mechanisms as discussed hereinafter.

Vectren South filed its case-in-chief on December 11, 2009, supplemental direct testimony regarding legal and customer notices on January 8, 2010, and revisions and corrections to its direct testimony and exhibits on February 17 and 26, 2010.

Petitions to intervene were filed by Toyota Motor Manufacturing, Indiana, Inc. (“TMMI”), the City of Evansville (“Evansville”), SIGECO Industrial Group (“Industrial Group”) (whose members are Air Liquide Industrial U.S. LP, Countrymark Cooperative, Inc., and Mead Johnson & Company LLC), Citizens Action Coalition of Indiana, Inc. (“CAC”), and Natural Resources Defense Council (“NRDC”). The Presiding Officers granted the petitions, and the Intervenor parties were made parties to this Cause.

On December 31, 2009, the Indiana Office of Utility Consumer Counselor (“OUCC”) filed a Notice contending Vectren South’s filing did not comply with the Commission’s MSFR rule. Vectren South filed its Response in opposition to the OUCC’s Notice on January 11, 2010.

A Prehearing Conference and Preliminary Hearing (“Prehearing Conference”) was held in this Cause on January 26, 2010, at which time a procedural schedule and other procedural matters were agreed to as discussed in the Commission’s Prehearing Conference Order dated February 19, 2010. The Prehearing Conference Order also addressed the OUCC’s Notice challenging the applicability of the Commission’s MSFR rule to this proceeding. In its February 19, 2009 Prehearing Conference Order, the Commission determined Petitioner’s requests go beyond a request for a general rate change because of the request for decoupled fixed cost recovery, the ARP proposal, revisions to the RCRA tracker, and other issues. Therefore, the Commission found, “as this matter does not strictly comply with the MSFR rule, the Commission will not be bound by the time constraints contained in the rule.” Prehearing Conference Order at 3.

Pursuant to notice as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an Evidentiary Hearing was held in this Cause on March 8-11, 2010, at which time Vectren South presented its case-in-chief and its witnesses were cross-examined. Vectren South filed information responsive to questions from the Commission about Vectren South’s weather normalization adjustment and transmission tower painting costs on March 23, 2010.

Pursuant to Ind. Code § 8-1-2-61(b), two public field hearings were held at 2:00 p.m. and 6:00 p.m. on May 12, 2010, in the City of Evansville, the largest municipality in Vectren South's service area. At the field hearing, members of the public were afforded the opportunity to make statements to the Commission. The OUCC filed additional written comments of members of the public on June 25, and July 2, 2010.

Vectren South filed supplemental direct testimony and exhibits on May 17, 2010 and May 21, 2010, addressing the following: (1) the elimination of Vectren South's equity infusion proposal; (2) the elimination of the Medicare Part D subsidy tax benefit as part of the Federal health care legislation enacted in March, 2010; and (3) the effect of new special contracts with two large industrial customers. Vectren South also filed a motion for leave to submit the supplemental testimony and exhibits, indicating that the other parties had no objection to it. The motion was granted by the Commission's Docket Entry dated May 21, 2010.

On June 25, 2010, the OUCC, Evansville, Industrial Group, CAC, and NRDC filed the prepared testimony and exhibits constituting their respective cases-in-chief. CAC filed corrections to its prefiled testimony on July 9, 2010. The OUCC filed revisions and corrections to its case-in-chief evidence on August 20 and 23, 2010. On July 16, 2010, the OUCC, Industrial Group, CAC, and NRDC filed cross-answering testimony and exhibits. NRDC filed corrections to its cross-answering testimony on August 25, 2010.

On July 30, 2010, Vectren South filed its rebuttal testimony and exhibits. Vectren South filed revisions and corrections to its rebuttal testimony and exhibits on August 12, 17, 20, and 25, 2010. On August 12, 2010, Vectren South also filed a supplemental exhibit showing the in-service dates and actual costs of the post-test year major projects it proposed to include in its rate base.

The Evidentiary Hearing in this Cause resumed on August 23, 2010, and continued through August 31, 2010, during which Vectren South presented its supplemental direct testimony, the OUCC and Intervenors presented their respective cases-in-chief and cross-answering evidence, and Vectren South presented its rebuttal evidence.

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

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

2. Vectren South's Characteristics. Vectren South provides electric utility service to approximately 141,000 customers in six (6) counties in southwestern Indiana. Vectren South

renders such electric utility service by means of utility plant, property, equipment, and related facilities which are owned, leased, operated, managed and controlled by it, and which are used and useful for the convenience of the public in the production, transmission, distribution and sale of electricity.

3. Existing Rates. Vectren South's existing base rates for electric utility service were established pursuant to the Commission's Order in *S. Ind. Gas & Elect. Co.*, Cause No. 43111, 2007 Ind. PUC LEXIS 243 (IURC Aug. 15, 2007).

4. Relief Requested. In its original case-in-chief, Vectren South proposed a net increase in base rate revenues of \$54,155,363 per year, net of the inclusion, or roll in, of certain costs currently recovered in its Qualified Pollution Control Property ("QPCP") Construction Cost Adjustment ("QPCP-CC2"), QPCP Operating Expense Adjustment ("QPCP-OE2"), Blackfoot Landfill Gas Adjustment ("BLGA"), Reliability Cost and Revenue Adjustment ("RCRA"), Midwest Independent System Operator, Inc. ("MISO") Cost and Revenue Adjustment ("MCRA"), and Demand Side Management Adjustment ("DSMA"). Vectren South asserted its proposed base rates were intended to provide the opportunity to earn net operating income ("NOI") of \$98,623,521. Vectren South also sought approval of a Sales Reconciliation Adjustment ("SRA") to decouple fixed cost recovery from the amount of customer usage for certain rate classes. Vectren South proposed to continue the sharing of wholesale power margins above and below the level reflected in base rates. The Company also proposed revisions to its existing economic development rider ("Rider ED") and area development rider ("Rider AD"), MCRA, and RCRA (including the addition of a component to track variable production costs). Vectren South sought approval of other changes to its tariff for electric service including new net metering, alternate feed service, temporary service, and standby or auxiliary service riders and revisions to its general terms and conditions for service. Vectren South proposed a second step rate increase of \$4.6 million per year for the revenue requirement associated with its Dense Pack Projects when they are both completed in 2013.

In its supplemental testimony and exhibits filed on May 17 and 21, 2010, Vectren South reduced its proposed base rate increase net of tracker roll-ins to approximately \$41.9 million per year. In its rebuttal evidence filed on July 30, 2010, Vectren South accepted certain proposals of the OUC and Intervenors that reduced its proposed net revenue increase to approximately \$34 million per year.

5. Test Year and Rate Base Cutoff. As provided in the Prehearing Conference Order, the test year to be used for determining Vectren South's actual and pro forma operating revenues, expenses, and operating income under present and proposed rates is the twelve months ended June 30, 2009, adjusted for changes that are fixed, known, and measurable for ratemaking purposes and that will occur within twelve months following the end of the test year. The Prehearing Conference Order also provided the general rate base cutoff should reflect used and useful property at the end of the test year and allowed Vectren South to request to include in its rate base the following projects that were not in service at the end of the test year, provided Vectren South shows such projects have since been placed in service and the actual costs thereof: (1) a dry fly ash collection and disposal system at the A.B. Brown Generating Station ("Holcim Project"); (2) transmission lines from Culley Generating Station to Oak Grove Substation and substation modifications; and (3) transmission and substation facilities to serve Berry Plastics'

office and plant expansion in Evansville. In addition, the Prehearing Conference Order provided that Vectren South may propose a second step increase for the revenue requirement associated with the Dense Pack Projects and other parties may oppose the step rate proposal.

6. Overview. Carl L. Chapman, President and Chief Executive Officer of Vectren Corporation and Chief Executive Officer of Vectren South, provided an overview of Vectren South's request, industry and Company-specific challenges that have arisen since its 2006 base rate case, and its cost control and DSM initiatives. Mr. Chapman noted that since receiving its 2007 rate increase in Cause No. 43111, Vectren South has experienced a return on equity ("ROE") below its authorized level of 10.4%. He stated that despite cost increases in areas such as union wages and health care and pensions, overall operation and maintenance ("O&M") expenses have grown by only 2.7% annually since the current base rates became effective. He added that Vectren South has reduced its capital expenditures by reducing its capital budget over the next five years by \$80 million in an attempt to avoid capital costs to the extent possible.

Mr. Chapman described the direct and indirect steps taken by Vectren South to limit the magnitude of the requested rate relief. He stated that although Vectren South's proposed cost of equity expert recommends that Vectren South's ROE be established at 11.5%, Vectren South's cost of capital in this rate case reflects an ROE of 10.7%, which results in a reduction in Vectren South's revenue requirement of nearly \$9 million. Second, Vectren South is proposing to extend, without carrying costs, previously approved amortization periods for deferred expenses associated with its participation in MISO and Demand-Side Management ("DSM") programs, thereby further decreasing the requested revenue requirement by nearly \$8 million. Beyond these direct revenue requirement reductions, Mr. Chapman stated that Vectren South has made other efforts to hold the line on operating costs, such as freezing officer salaries in 2009 and being very deliberate in considering new investments such as smart grid technology. According to Mr. Chapman, by using every means possible to reduce electric use, costs will be controlled to the greatest extent possible.

Mr. Chapman stated that over the past two years, Vectren South has continued to invest in its system, established a renewable energy portfolio, and designed an aggressive DSM program. He provided a summary of the Company's most notable efforts, including the Warrick Unit 4 scrubber project, the Holcim Project, a Regional Expansion Criteria and Benefits ("RECB") transmission project, non-RECB transmission upgrade projects, generation turbine efficiency projects, renewable energy projects, reliability initiatives, and energy efficiency programs.

Mr. Chapman testified that only about 12% of the requested revenue increase consists of increases in operating costs. He explained that this case was filed to obtain a return on and of new net investments of over \$250 million (which represents just under 50% of the requested rate increase) and because of the loss of fixed cost recovery caused by the decline in retail and wholesale sales (which represents about 38% of the requested rate increase). He described events that have reduced current and projected earnings and created uncertainty regarding future capital attraction and financing costs, including environmental issues, economic issues, capital markets issues, and decreases in demand for electricity in all customer classes. He noted that traditional manufacturing customers have cut back production, thereby reducing retail revenues, and extremely low MISO energy prices have dramatically reduced the Company's wholesale

revenues.

Mr. Chapman explained some of the major issues currently facing the industry, including anticipated greenhouse gas (“GHG”) regulation, long-term changes in customer demand, volatile fuel costs, capital availability and cost, and rising customer costs. He testified these issues collectively create an environment of tremendous uncertainty in terms of the future cost to provide electric service. Mr. Chapman stressed the need for a balance between cost control and incurring costs necessary to provide reliable service to customers. He pointed out the Company will need to continue to invest in and maintain facilities during a period when large customer demand may continue to decline and the Company actively encourages reduced small customer demand. Mr. Chapman testified that the electric business has large fixed generation costs and Vectren South recovers about 28% of its fixed costs from a group of 101 large customers. He stated that declines in large customer sales have resulted in a margin loss of over \$15.6 million compared to the level assumed for base rates. Vectren South projects that margin recovery from 3 of its largest customers declined by over \$4.8 million in 2009. Similarly, Mr. Chapman explained that wholesale power marketing (“WPM”) revenues have plummeted. He noted that in 2009 wholesale results were below the \$10.5 million revenue credit used to reduce base rates in Cause No. 43111 and 2010 results are projected to be even lower.

Mr. Chapman stated that one of the main reasons that Vectren South’s rates have risen significantly over the last decade is a result of its investment in new facilities, especially pollution control technology and new transmission lines and substations. He attributed the rising cost of providing electric service to the ramp up of MISO operations, the maintenance of aging infrastructure, new North American Electric Reliability Corporation (“NERC”) operating requirements, and fuel cost volatility. Mr. Chapman asserted, however, that the Holcim Project and Dense Pack Projects represent strategies to reduce or avoid customer costs over time. He stated that the system reliability initiatives Vectren South continues to engage in should over time improve service quality, defer facility replacements and reduce repair expenses.

Mr. Chapman testified Vectren South has chosen energy efficiency as its preferred supply resource. He stated that Vectren South is changing its culture in an effort to partner with its customers to reduce energy use. He explained that after considering construction costs and GHG implications, Vectren South made the decision to not proceed with new generation and instead enter into a short-term capacity contract and pursue more aggressive DSM efforts. Mr. Chapman said part of Vectren South’s corporate mission is to “be the industry leader in helping our customers manage their energy costs.” Chapman Direct at 20. Mr. Chapman briefly described Vectren South’s DSM efforts. Mr. Chapman asserted that Vectren South proposes to bring similar cost saving opportunities to its electric customers as it has already brought to its gas customers, including information on efficiency measures, access to a web-based tool to perform self-audits, and rebates for new, more efficient appliances. According to Mr. Chapman, such efforts have multiple benefits – not only are fuel savings realized, but use reductions avoid emissions of nitrogen oxides (“NO_x”), sulfur dioxide (“SO₂”), and carbon dioxide (“CO₂”), and help the Company avoid or at least defer new generation. Mr. Chapman said that this efficiency partnership really involves the utility, customers, and regulators because the traditional method of fixed cost recovery via volumetric rates does not support the energy efficiency partnership that Vectren South is laying the groundwork to pursue.

Tyler E. Bolinger, Director of the OUCC's Electricity Division, provided an overview of the OUCC's case-in-chief. Mr. Bolinger pointed out that Vectren South chose a test year that occurred during one of the most recessionary periods since the 1930s. Mr. Bolinger opined that Vectren South is seeking general rate relief due in substantial measure to the recession and associated reductions in industrial sales.

Mr. Bolinger stated Vectren South currently has the highest residential electric rates in Indiana. Mr. Bolinger further stated that of twenty-four jurisdictional electric utilities, only three have average rates above 11 cents at 1,000 kWh. Mr. Bollinger discussed a bill survey, which revealed Vectren South's average charge was 12.89 cents per kWh (without taxes) at 1,000 kWh usage. Mr. Bolinger also noted Petitioner's Exhibit JLU-S7, which illustrates typical bill comparisons under the current and proposed rates, shows a current charge of 14.26 cents per kWh at current rates and projects a charge of nearly 15.91 cents per kWh under Vectren South's proposed rates.

Finally, Mr. Bolinger discussed inefficiencies in Vectren South's power production and expressed doubts about how competitive Vectren South is in the power production segment of its business. Mr. Bolinger expressed concern that under Vectren South's proposed rate structure, the costs of such inefficiency would be borne by Vectren South's captive retail customers. In addition, Mr. Bolinger noted Vectren South is proposing that all of its costs would be recovered either through a cost tracker, such as an Fuel Adjustment Clause ("FAC"), MCRA, RCRA, etc. or would be classified as a fixed cost and recovered through the SRA decoupling mechanism.

EVIDENCE AND COMMISSION FINDINGS

7. Vectren South's Rate Base.

A. Used and Useful Property. Vectren South's rate base as originally proposed in its case-in-chief reflected property recorded as electric utility plant in service as of June 30, 2009, the end of the test year, excluding non-jurisdictional Federal Energy Regulatory Commission ("FERC") approved RECB transmission projects, and certain major projects completed after the end of the test year. James M. Francis, Director of Engineering & Asset Management for Vectren Utility Holdings, Inc. ("VUHI"), testified Vectren South's property is well maintained, in good condition, and reasonably necessary for the provision of electric utility service. Mr. Francis also described the Company's work order procedure that ensures new construction costs are not transferred to utility plant in service until the property is in service and that retired property is removed from utility plant in service. The Commission finds that the utility plant in service as of June 30, 2009, is used and useful for the convenience of the public in Vectren South's provision of utility service. Therefore, such property is properly includible in Vectren South's rate base.

B. Original Cost Rate Base. In its case-in-chief, Vectren South quantified its original cost rate base to be \$1,294,217,920 including fuel stock, materials and supplies, and DSM and MISO regulatory assets. The OUCC proposed an original cost rate base of approximately \$1.289 billion. The Industrial Group proposed reductions in the Company's proposed original cost rate base of approximately \$53 million (\$47,862,635 adjustment to accumulated depreciation, *see* Ex. MPG-22, + \$5,174,929 reduction in coal inventory, *see* Ex.

MPG-21). In its rebuttal evidence, Vectren South adjusted its rate base proposal to \$1,300,416,852. The only disputed issues regarding Vectren South's original cost rate base concerned (1) infrastructure serving ethanol plants, (2) post-test year major projects, and (3) coal inventory levels.

(1) Ethanol Rate Base.

(a) Evidence. In its case-in-chief, Vectren South removed from its rate base infrastructure installed to serve two ethanol plants in Vectren South's service territory due to uncertainty surrounding the continued viability of the ethanol plants. This adjustment decreased utility plant by \$6,194,048 and accumulated depreciation by \$49,116. Petitioner also excluded ethanol customer sales revenue and depreciation expense on the ethanol plant.

OUCG Witness Thomas S. Catlin of Exeter Associates, Inc. noted that operations have ramped up at one of the ethanol facilities and that Vectren South has realized substantial non-fuel margins associated with that customer. He therefore proposed to include Vectren South's ethanol infrastructure in its rate base, to include margins on actual and projected ethanol customer sales in Vectren South's pro forma revenue, and to include depreciation expense on the ethanol rate base in its pro forma operating expenses.

In rebuttal, Vectren South Witness M. Susan Hardwick, Vectren South's Vice President, Controller, and Assistant Treasurer, agreed to the inclusion of the plant serving the ethanol customers in rate base and ethanol customer sales in pro forma revenue although she disagreed to a small extent with the amount of Mr. Catlin's revenue adjustment. Accordingly, Ms. Hardwick submitted a revised rate base calculation that restored the ethanol plant and accumulated depreciation.

(b) Commission Findings. Based upon the evidence, the Commission finds it is appropriate to include the plant serving the ethanol customers in Vectren South's rate base, the depreciation expense relating thereto in operating expenses, and the revenue from ethanol customer sales in pro forma revenues as proposed in Vectren South's rebuttal filing.

(2) Post-Test Year Plant Additions.

(a) Evidence. In its case-in-chief, Vectren South's rate base included the following three projects that were placed in service after the end of the test year: (1) the Holcim Project; (2) transmission lines from Culley Generating Station to Oak Grove Substation and modifications to substation; and (3) transmission and substation facilities to serve Berry Plastics office and plant expansion in Evansville. Vectren South identified these projects in its Petition, included cost estimates for the projects in its evidence, filed monthly investment updates describing the status of the projects and actual costs incurred at the end of each month, and submitted evidence at the final hearing regarding the in-service dates and final actual costs of the projects. This supplemental exhibit showed the last of the projects was in service on July 13, 2010, and the actual cost of the projects as of July 31, 2010, was \$43,601,919, which exceeded the amount Vectren South included in its rate base for the projects by about \$4.6 million.

The OUCG included these post-test year projects in its rate base determination. Industrial Group Witness Michael Gorman testified that either post-test year additions should be rejected

or, alternatively, an adjustment for accumulated depreciation during the same post-test year time period should be recognized. Otherwise, according to Mr. Gorman, the post-test year gross plant adjustment would overstate the net utility plant being used to provide service. Mr. Gorman asserted that the post-test year plant additions identified by Vectren South will be entirely offset by the buildup of accumulated depreciation reserve. He proposed adjustments for post-test year additions, which would lower rate base by \$5.2 million. Mr. Gorman also made a calculation reflecting eight months of additional depreciation of \$47,862,635, which would further decrease rate base.

In rebuttal, Ms. Hardwick testified that Mr. Gorman's recommendation ignores Commission precedent which has allowed for updates to rate base for known large projects that will become used and useful during the course of the case. She also cited the Commission's April 30, 2010 Order in Cause No. 43680 and its February 13, 2008 Order in Cause No. 43298 as recent instances in which the Commission authorized the inclusion of major projects completed post-test year, without a deduction for depreciation accrued after the general rate base valuation date. Ms. Hardwick also pointed out that the actual cost of the post-test year major projects was \$4.6 million more than the amount included by Vectren South in its rate base and Vectren South will not be able to earn a return on the excess until its next rate case. At the hearing Ms. Hardwick stated that Mr. Gorman's proposal was also erroneous because it ignored the significant increase in utility plant that occurred after the end of the test year. Mr. Gorman's approach of adjusting only for estimated depreciation post-test year would result in a net plant balance significantly below the actual net plant balance as of the end of the pro forma period.

(b) Commission Findings. The Commission has often allowed rate base adjustments for major projects that are placed in service after the general rate base valuation date but prior to the close of the record. See *Indiana-American Water Co.*, Cause No. 43680, 2010 Ind. PUC LEXIS 155 (IURC Apr. 30, 2010); *Indiana Gas Co.*, Cause No. 43298, 2008 Ind. PUC LEXIS 104 (IURC Feb. 13, 2008); *Southern Ind. Gas and Elec. Co.*, 2007 Ind. PUC LEXIS 243; *Indiana Gas Co.*, Cause No. 42598, 2004 Ind. PUC LEXIS 397 (IURC Nov. 30, 2004); *PSI Energy, Inc.*, Cause No. 42359, 2004 Ind. PUC LEXIS 150 (IURC May 18, 2004); *Indiana-American Water Co.*, Cause No. 41320, 1999 Ind. PUC LEXIS 125 (IURC July 1, 1999); and *PSI Energy, Inc.*, Cause No. 40003, 1996 Ind. PUC LEXIS 411 (IURC Sept. 27, 1996).

Vectren South identified the projects in its Petition and case-in-chief, the Prehearing Conference Order allows Vectren South to request the projects be included in its rate base and the need for the projects was demonstrated by Vectren South's evidence. The Holcim Project will reduce the need to store fly ash in on-site ash ponds and provide an alternative to building new landfills to replace filled up landfills and ponds and mine storage that will soon be no longer available. Dry fly ash can now be loaded onto barges at a collection point at the Brown Station for delivery to a cement manufacturer in Missouri. Mr. Jochum testified reuse of fly ash is not only environmentally friendly it is a less expensive alternative to periodic pond cleaning and new landfill development.

The Oak Grove project improves reliability, supports system growth, meets NERC performance requirements, and improves import capabilities to deliver reliable service to Vectren South's customer base. The Berry Plastics project accommodates the expansion of the Evansville facility of one of Vectren South's largest customers, a project that will create 300 new

jobs. The increased revenues associated with the Berry Plastics expansion were also included in the pro forma revenue adjustment to the test year. As shown by Petitioner's Exhibit MSH-S8, the amount included for the projects is conservative because the actual cost (\$43,601,919) exceeds by approximately \$4.6 million the estimate included in Vectren South's rate base (\$39,040,000).

We do not accept Mr. Gorman's proposal to reduce rate base for eight months of post-test year accumulated depreciation on all of Vectren South's utility plant. While the Commission sometimes uses a general rate base valuation date after the end of the test year, such general rate base updates reflect increases in utility plant as well as increases in accumulated depreciation. By updating only accumulated depreciation post-test year and ignoring utility plant additions that have actually occurred since the end of the test year, Mr. Gorman has significantly understated Vectren South's net plant in rate base. Accordingly, as proposed by Vectren South and the OUCC, we find use of an end of test year rate base valuation date adjusted to include the post-test year projects described above is reasonable.

(3) Coal Inventory Levels And Contract Renegotiation.

(a) Evidence. In its case-in-chief, Vectren South proposed to include in rate base its coal inventory amount as of the end of the test year, June 30, 2009, which was \$36,066,708. OUCC Witness Michael D. Eckert, Senior Utility Analyst in the OUCC's Electric Division, expressed concern about Vectren South's coal inventory level of 567,139 tons at the end of the test year, stating the level had risen during the test year. Mr. Eckert testified the level of coal inventory had continued to increase since the end of the test year reaching 1,119,111 tons by April 30, 2010. While Mr. Eckert agreed that a reasonable amount of coal supply inventory is properly included in rate base, he opined that Vectren South's inventory level exceeds what is necessary to provide reliable utility service to the public. Mr. Eckert attributed the inventory build up to MISO's dispatching of more competitive alternatives to Vectren South's generation and to Vectren South's coal contracts, including those with its affiliate Vectren Fuels. Mr. Eckert proposed including in rate base the 13-month average for the period of June, 2008, to June, 2009, which was 492,351.58 tons. Mr. Eckert asserted that Vectren South utilized a 13-month average inventory level in its last rate case in Cause No. 43111.

Mr. Eckert also expressed concern with the average price per ton of Vectren South's coal inventory at June 30, 2009, which was \$63.59 per ton. Mr. Eckert compared this price to the April 30, 2010 spot market price – as published by the Energy Information Administration – of \$41.40 per ton. Mr. Eckert proposed a price for Vectren South's coal inventory of \$50.55, which he calculated by dividing the 13-month average of Vectren South's coal inventory balance by the 13-month average coal inventory level. Based upon Mr. Eckert's calculation of the 13-month average inventory level and price, the OUCC proposed including in rate base a coal inventory amount of \$24,890,073, which was about \$11.2 million less than the end of test year amount proposed by Vectren South.

Finally, Mr. Eckert recommended the Commission require Vectren South to renegotiate its coal contracts with its affiliate, Vectren Fuels. He stated that Vectren South signed its current coal contract with Vectren Fuels, its major coal supplier, when spot market prices were at or near an all time high. He testified that Vectren South did not renegotiate its contract with Vectren

Fuels when spot market prices on coal dropped subsequently, although Vectren South did lower deliveries to the contract minimums. Mr. Eckert pointed out that in 2006 Vectren South agreed to renegotiate a contract with Vectren Fuels and pay a higher price to prevent or reduce future losses at Vectren Fuels. Mr. Eckert opined that these current contracts appear to be one-sided in favor of Vectren Fuels with the result that Vectren South's ratepayers are being asked to provide a return on excessive inventory buildup caused by non-competitive coal costs.

Industrial Group Witness Gorman also proposed an adjustment to Vectren South's coal inventory amount computed by multiplying the 13-month coal tonnage average by the June 30, 2009 average price. He stated that using a 13-month average coal inventory quantity is more consistent with the test year cost of service because it more accurately measures the variations in coal inventory throughout the test year. The effect of Mr. Gorman's adjustment was to reduce Vectren South's rate base by \$5.17 million.

In rebuttal, Ronald G. Jochum, Vectren South's Vice President, Power Supply, testified that Vectren South's coal inventory level is reasonable and not excessive when compared to historical levels. He stated that Vectren South's average inventory for the three year period of 2007-2009 was 558,000 tons, compared to 567,139 tons at the end of the test year. Mr. Jochum stated that the 567,000 tons of coal provides Vectren South with approximately fifty-six days of system burn capability. Mr. Jochum testified he calculated the fifty-six days of system burn capability by dividing the approximately 567,000 tons of coal inventory by a daily burn rate of 10,000 tons per day. Mr. Jochum explained 10,000 tons per day is a conservative estimate of Vectren South's maximum daily burn, but the absolute maximum daily burn is in excess of 12,000 tons. On cross-examination by the OUCC, Mr. Jochum agreed Vectren South's average daily burn during the test year was 7,775.93 tons per day. However, Mr. Jochum asserted that in 2009 Vectren South had the lowest daily burns it has had in the previous five years.

Mr. Jochum explained that coal inventory preserves reliable service in the event of a mine strike, railroad accident or mine operating or safety issue affecting production. He said that coal inventory also provides a supply cushion in the event the Company needs to find replacement supply. Mr. Jochum testified the 567,139 coal inventory amount, resulting in approximately fifty-six days of system burn capability is reasonable because the supply threats identified above could take up to two months to resolve. He disagreed with the OUCC's and Industrial Group's proposed removal of approximately 75,000 tons of inventory, leaving less than fifty days of system burn, noting the proposal was unsupported by any analysis of what constitutes a necessary operating reserve.

Mr. Jochum further testified that fifty-six days of inventory is consistent with levels of other Indiana utilities and is representative of Vectren South's future coal inventory requirements. For example, Mr. Jochum noted that Duke Energy Indiana in Cause No. 40003 targeted 70 days of burn as its inventory level, with the OUCC's support. He added that in Indiana Michigan Power Company's ("I&M") most recent rate case (Cause No. 43306), I&M used burn days, by unit, ranging from approximately forty-two to fifty-seven days. Mr. Jochum asserted Vectren South's current inventory level is much higher than the amount Vectren South proposes to include in rate base because, like most coal generators in the region, its inventory has grown in recent months due to market conditions. He stated that with increasing mine safety regulations that can impair production at coal mines, now is not the time to create an artificial

inventory ceiling by reducing inventory to less than 50 days of burn.

Mr. Jochum pointed out Mr. Eckert justified the OUCC's proposed price per ton for the coal inventory on the fact that the April 2010 spot market price was lower than Vectren South's actual June 30, 2009 price per ton. Mr. Jochum stated that spot prices are a point in time and are not useful to measure coal inventory purchased under long-term contracts. According to Mr. Jochum, the OUCC's calculation does not provide the best estimate of Vectren South's inventory cost while new rates will be in effect. Mr. Jochum explained that Mr. Eckert's calculation includes seven months of 2008 coal prices, which were based upon prices under expired contracts that were set in 2005 and 2006 and which are well below current and projected future coal prices. Mr. Jochum said that coal price forecasting provided by ICAP United, Inc. shows Vectren South's June 30, 2009 coal inventory cost will be representative of actual costs in the future. Mr. Jochum testified the demand for Illinois basin coal is increasing due to declining production and increased mining costs and scrubber installations. Mr. Jochum asserted ICAP price projections reflect delivered prices in the \$57-\$60 per ton range in 2012 with higher prices in 2013, which he claims shows that Vectren South's inventory cost of \$63.59 per ton is reasonably representative of future costs.

Mr. Jochum also responded to the OUCC's recommendation that Vectren South renegotiate its coal contracts with Vectren Fuels. He stated that the OUCC's reliance on a recent decline in spot market prices as a premise to mandate contract renegotiations ignores the facts that Vectren South is in the 19th month of its 2008 contracts and its purchases under the contracts have already been found to be reasonable in six prior FAC proceedings. Mr. Jochum stated that Vectren South has informed Vectren Fuels that it will not be repricing coal under a contract representing one-third of its annual supply, resulting in the suspension of deliveries of 1 million tons of contract coal which, in combination with Vectren South's exercise of its right to take only 85% of contract deliveries, resulted in a 2 million ton reduction in 2009-2011. He explained that within one year, a contract representing another one-third of Vectren South's supply will similarly be up for repricing. Thus, within the next twelve months, Vectren South will be assessing the need to purchase over two-thirds of its coal supply.

Mr. Jochum also reviewed the history of Vectren South's coal contracts and the decision made with the approval of the Commission and the agreement of the OUCC to purchase from an affiliated supplier in order to ensure the continued existence of local supply, minimize transportation costs, and respond to the increasing dominance of a single coal supplier in the local market. Mr. Jochum described the benefits achieved from this arrangement and sponsored a copy of an October, 2006 analysis performed by Navigant Consulting that confirmed Vectren South's coal supply was competitively priced. Chairman Atterholt questioned Mr. Jochum during rebuttal testimony, asking "[e]verything else being equal, does ... Vectren South ... make a conscientious effort to purchase Indiana coal?" Mr. Jochum responded Vectren South does as much as possible.

Mr. Jochum described in detail the 2008 request for proposals ("RFP") process undertaken because of the impending contract expirations. He said the timing was also affected by the Warrick Unit 4 scrubber project which became operational in January, 2009, and created the opportunity to reduce coal costs for that unit by using higher sulfur coal than was previously possible. Mr. Jochum testified issuing an RFP between 3-8 months prior to the requested

commencement of deliveries is common in the industry, citing multiple examples of other utilities doing so in 2008, 2009, and 2010. He explained that due to market conditions, Vectren South layered its potential contract termination dates and obtained a 15% volume reduction option. He emphasized delivery costs under its contracts are less than would otherwise be the case due to the proximity of the mines to Vectren South's generating stations. Mr. Jochum reviewed market information showing Vectren South's contract prices resulting from the 2008 RFP were very similar to those of the Indiana utilities entering into new contracts in the same time frame. For example, at the time a post-RFP contract with Vectren Fuels provided a delivered price of \$63 per ton, other Indiana utilities received coal under new contracts at a price of \$66 per ton.

Mr. Jochum also addressed the 2006 renegotiation of Vectren Fuel's Cypress Creek contract which occurred after the mine suffered \$12 million of losses in 2005 and 2006 putting the mine's financial viability at stake. At that time, the mine only had two years of remaining reserves. An agreement to a re-priced contract was reached to keep the mine open which avoided higher coal replacement costs and higher fly ash disposal costs. The contract was found reasonable and approved by the Commission with no opposition from the OUCC. Not only was the amended contract below market price, it sustained mine operations, which kept 70 miners employed.

Vectren South also provided testimony by Emily Medine, a principal with Energy Ventures Analysis, Inc. Ms. Medine presented an expert report detailing the coal market conditions confronting buyers in 2008 as well as an analysis of the prices paid by Vectren South. Ms. Medine's testimony focused on four issues raised by Mr. Eckert: (1) the increase in Vectren South's coal inventory; (2) the average cost of coal in Vectren South's coal inventory; (3) Vectren South's 2008 RFP; and (4) the proposal to require Vectren South to renegotiate its 2008 contracts with Vectren Fuels.

First, Ms. Medine testified that the increase in coal inventory levels experienced by Vectren South in 2008, 2009, and 2010 was typical of the industry at large. She disagreed with Mr. Eckert's assertion that the increase was due to Vectren South's mismanagement of its fuel procurement activities. From her review, Ms. Medine concluded Vectren South did an excellent job managing its inventory levels. She explained that the reduced generation experienced by Vectren South's coal units was a result of two changes in the power market: reduced electricity demand due to the economic recession and the decline in natural gas prices due to reduced industrial demand and increased supply, particularly from the increased availability of shale gas, resulting in gas-fired generators displacing coal generators. She stated that Vectren South is hardly alone in being affected by these changes in the power market. Ms. Medine recommended the Commission reject the OUCC's proposal because the increase in inventory levels was the consequence of events outside the control of Vectren South, which had been minimized by Vectren South's actions including exercising its contract rights to reduce deliveries by 15%, deferring deliveries to later periods, and waiving purchases. She also said that her recent audits make it clear that new procurement strategies to deal with volatility in coal burn levels should include maintaining higher inventory levels than in the past.

Second, Ms. Medine opposed Mr. Eckert's proposal to reduce the cost of coal in inventory from its actual cost of \$63.59 to \$50.55 per ton based on a 13-month average. She

characterized Mr. Eckert's proposal as an inappropriate hindsight review because at the time Vectren South entered into its supply agreements, the prices were at or below the prevailing market prices and contemporaneous reviews of the procurements found no problems with them. Ms. Medine also objected to Mr. Eckert's reliance on the April, 2010 spot price. She stated that Mr. Eckert provided insufficient information as to the quality of the coal represented by this price and whether this price is an FOB mine or barge price. She added that comparing spot prices to contract prices is an apples-to-oranges comparison because contract prices typically differ from spot prices, being below spot prices when markets are tight and above spot prices when markets are soft.

Third, Ms. Medine responded to Mr. Eckert's concerns regarding Vectren South's 2008 coal procurement practices. She noted that utilities cannot time purchases to market prices because of market volatility and price uncertainty, and it is only in hindsight that one can ultimately determine whether prices had been at the peak or on the way up. To support her opinion that Vectren South's coal purchases were reasonable, Ms. Medine compared the prices under Vectren South's contracts to three different measurements of the market price: (1) the forward price curve; (2) the prices paid by other utilities for similar coal in the same time period; and (3) other available sources of market information. Ms. Medine concluded all three of these comparisons confirmed Vectren South's efforts in 2008 were successful.

Finally, Ms. Medine disagreed with Mr. Eckert's proposal to require Vectren South to renegotiate its coal contracts. She stated that in terms of industry practice, coal supply agreements are often renegotiated, but such renegotiations are based on terms commercially acceptable to both parties, meaning prices are not reduced without equal value being provided through increased volume and/or extended term. With respect to the 2006 contract renegotiation involving Cypress Creek, Ms. Medine stated that in that instance, it was clear that the contract price was not only below market, but was below mine operating costs. She stated that it has become fairly standard in the industry to make these types of legitimate price adjustments if the alternative is the loss of the supplier. In these cases, Ms. Medine explained, the cost of an increase in the contract price is less than the cost of replacing the coal supplier at the market price, not to mention the cost associated with the disruption. She added that in developing its contract portfolio in 2008, Vectren South incorporated optionality into the Vectren Fuels contracts and staggered the pricing mechanisms such that Vectren South now has considerable flexibility with respect to both volume and pricing.

(b) Commission Findings on Coal Inventory. Vectren South's rate base includes 567,139 tons of coal, its coal inventory value as of June 30, 2009, the end of the test year. Since then, Vectren South's inventory has increased dramatically to a level in excess of 1 million tons. Low customer demand, due primarily to the economic downturn, and competitively priced generation in the MISO market, due primarily to a decline in gas prices in 2009, greatly reduced Vectren South's coal burn. This growth in inventory is not unique to Vectren South, although Vectren South has perhaps been disadvantaged to a larger degree than other similarly situated utilities due to the increased price it paid for coal compared to today's prevailing market coal and natural gas prices.

Vectren South's evidence indicates the inventory level of 567,139 tons represents approximately fifty-six days of reserve capability, using a system burn of 10,000 tons per day.

The OUCC and IG proposed an inventory level of 492,351.58 tons using a thirteen-month average, which corresponds to approximately forty-nine days of reserve capability at 10,000 tons per day. However, if we consider Vectren South's average daily burn rate during the test year of 7,773.93 tons per day, Vectren South's proposed inventory level of 567,139 tons corresponds to approximately seventy-three days of reserve capability, and the OUCC's and IG's proposed inventory level of 492,351.58 tons results in approximately sixty-three days of reserve capability. As Mr. Gorman noted, using a 13-month average coal inventory quantity is more consistent with the test year cost of service because it more accurately measures the variations in coal inventory throughout the test year. Even accepting Vectren South's assertion that the test year average daily burn is very low compared to previous years, the OUCC's proposed inventory level would provide Vectren South with approximately fifty-five days of reserve capability even with an average system burn of 9,000 tons per day. Therefore, the Commission finds a coal inventory level of 492,352 tons is reasonable.

Vectren South proposed to value its coal inventory at \$63.59 per ton based upon the average price per ton of its inventory as of June 30, 2009. The OUCC sought to reduce inventory costs on the basis that the April, 2010 spot market price of \$41.40 per ton was lower than the term contract prices paid by Vectren South. Initially, we note that spot market prices do not reflect delivered prices and are not good indicators of future term contract prices, and as such, they have limited usefulness in placing a value on coal supply. The OUCC proposed a value of \$50.55 per ton for Vectren South's coal inventory, calculated by dividing the 13-month average of Vectren South's coal inventory balance by the 13-month average coal inventory level.

Vectren South presented evidence that recent forward price curves show Illinois Basin prices for 2011 and 2012 above \$50/ton without including delivery costs. Thus, future prices for coal will likely be higher than the 2008 contract prices reflected in the 13-month average price proposed by the OUCC. In addition, Mr. Jochum accurately pointed out that half of the 13-month average coal price considered by the OUCC was based on pricing under contracts that have expired. Therefore, use of the 13-month average price, which includes significant weighting of non-representative inventory pricing, is not supported. Based on this evidence, as well as our findings in Vectren South's past FAC proceedings regarding the reasonableness of its coal prices, we will not make an adjustment to the actual average price per ton of Vectren South's inventory.

Utilizing an inventory level of 492,352 tons at a value of \$63.59 per ton, the Commission finds the value of Vectren South's coal inventory for rate-making purposes is \$31,310,694, and we will include this amount in our calculation of the rate base.

(c) Commission Findings on Coal Contract Renegotiation. With respect to Vectren South's existing coal contracts with Vectren Fuels, Mr. Jochum and Ms. Medine provided detailed testimony regarding the Company's 2008 competitive coal RFP process, the bids received, the subsequent review of the RFP and its results in multiple FAC proceedings, and the Commission's reasonableness findings in FAC orders related thereto. Mr. Jochum explained that the Vectren Fuels coal contracts were entered into because Vectren Fuels was the low bidder of the 5 bidders that responded to the RFP. Vectren South also contracted with the next low bidder, Alliance.

The OUCC argued the Commission should require Vectren South to renegotiate its coal contracts with its affiliate, Vectren Fuels, citing the 2006 contract renegotiation between the Company and Cypress Creek to support its recommendation. Mr. Jochum reviewed the facts of the 2006 contract renegotiation, which occurred because of Cypress Creek's inability to fund increased operating costs. Mr. Jochum also reviewed the benefits of that renegotiation in terms of continued receipt of low cost coal from the nearby Cypress Creek mine, ongoing low cost disposal of fly ash at the mine, and the continued employment of local coal miners. In addition, Ms. Medine testified that in the 2006 contract negotiation, Vectren South negotiated a contract price that was below market and below mine operating costs, but that allowed the mine to continue operation. Ms. Medine stated, these types of contract renegotiations are common if the cost of an increase in contract price is less than the cost of replacing the coal supplier at market price.

The situation in which Vectren South finds itself, namely that market prices for coal have dropped significantly below its contracted prices, is not analogous to the circumstances of the 2006 Cypress Creek contract renegotiation. As Ms. Medine testified, coal market volatility and price uncertainty prevent utilities from purchasing all of their coal at market prices. Utilities routinely enter into long-term contracts at a negotiated price that, over time, may be over or under the then-current market price. The reasonableness of a long-term contract cannot be determined by comparing it to the market price at a single point in time. Spot market prices do not include consideration of delivery costs and do not provide an accurate reflection of the price at which suppliers would sell coal over the term of a multi-year term contract. Mr. Jochum and Ms. Medine presented evidence comparing Vectren South's term coal contracts to the market price of 2008 term coal contracts entered into by other area utilities. Ms. Medine testified that the coal contracts contain prices that are either "equal to or below the prevailing market price" and that Vectren South's coal contracts are comparable to other utility coal contracts entered into in 2008. Her analysis revealed that Vectren South's 2008 contracts were priced very similarly to Duke Energy Indiana's 2008 contracts, as well as 2008 contracts of nearby Kentucky utilities. In addition, Ms. Medine's forward price curve analysis showed that the term contracts with Vectren Fuels compare very favorably to market prices.

We also note that since entry into the contracts, in response to the recession and low gas prices that reduced demand for electricity, the Company reduced contract deliveries throughout 2009-2011 by exercising its contract rights to take only 85% of the contract tonnage under its Vectren Fuels contracts, deferred other deliveries to future years, and suspended one million tons of coal in 2011 otherwise deliverable under its Vectren Fuels contracts. The OUCC's witness, Mr. Eckert, agreed this suspension of a contract for one-third of Vectren South's annual supply constituted a form of contract renegotiation.

Vectren South had two primary longer term contracts with Prosperity and Cypress Creek that had been in place for many years (Cypress Creek being modified in 2006) and both of these contracts expired at the end of 2008. Vectren South conducted a coal RFP for up to 480,000 tons to obtain competitive bids to price its new supply. Vectren South submitted the RFP, bids and new contracts for review in Cause Number 38708 FAC 81 in November, 2008. The OUCC reviewed the RFP and bids and raised no issues at that time. *See S. Ind. Gas and Elec. Co.*, Cause No. 38708 FAC 81, 2009 Ind. PUC LEXIS 35, at *7-8 (IURC Jan. 30, 2009).

In addition, we note that the two Vectren Fuels contracts, which make up two-thirds of the Company's annual coal supply, already have provisions that explicitly require the parties to renegotiate the prices for subsequent deliveries by June 2011. Thus, any renegotiation directive in this Order would be merely superfluous. We also recognize that the availability and use of Indiana coal, a local coal source, increases the reliability of the coal supply and enhances the local economy. Therefore, based upon the evidence provided in this case related to the RFP and resulting contracts and the proactive steps already taken by Vectren South to reduce or avoid contract deliveries, we find there is no basis to order Vectren South to renegotiate the existing contracts. However, the timing of the 2008 RFP and the fact that Vectren South placed itself in a position where all of its coal supply was exposed to market prices at effectively one point in time is concerning. While we recognize that Petitioner has taken steps to avoid a recurrence of this scenario, we are obligated to ensure such steps are more fully reviewed. Accordingly, we direct Vectren South to prepare for and request the creation of a sub-docket in its first FAC filing following the effective date of this Order for the purpose of reviewing its coal supply activities on a going forward basis.

(4) **Quantification of Original Cost Rate Base.** Based on the evidence and the findings made above, the Commission determines that the net original cost of Vectren South's property used and useful in the provision of electric utility service is:

<u>Description</u>	<u>Amount</u>
Utility Plant including CCNC ¹	\$2,077,676,005
Post-Test Year Projects	<u>39,040,000</u>
Total Utility Plant	2,116,716,005
Accumulated Dep. and Amort.	<u>(898,201,764)</u>
Net Utility Plant	1,218,514,241
Fuel Stock	31,903,265
Materials and Supplies	22,204,926
Allowance Inventory	294,447
Stores Expense	3,945,252
DSM Reg. Asset	18,400,327
MISO Reg. Asset	<u>352,038</u>
Total Original Cost Rate Base	<u>\$1,295,614,496</u>

C. Fair Value of Rate Base.

(1) **Legal Requirements.** Ind. Code § 8-1-2-6 states the Commission:

¹ Completed Construction Not Classified

shall value all property of every public utility actually used and useful for the convenience of the public at its fair value, giving such consideration as it deems appropriate in each case to all bases of valuation which may be presented or which the [C]ommission is authorized to consider by the following provisions of this section.

The Indiana Supreme Court held use of fair value reflects not only legislative policy, but also a requirement of the Indiana Constitution. *Public Serv. Comm'n of Ind. v. City of Indianapolis*, 131 N.E.2d 308, 317 (Ind. 1956). In determining fair value, the Commission cannot ignore the “commonly known and recognized fact of inflation.” *Indianapolis Water Co. v. Public Serv. Comm'n of Ind.*, 484 N.E.2d 635, 640 (Ind. Ct. App. 1985). For this reason, “reproduction cost new less depreciation cannot be disregarded in fixing a valuation for rate making purposes.” *Id.* (quoting *City of Indianapolis*, 131 N.E.2d at 325).

(2) **Evidence.** In addition to its evidence on the original cost of its rate base, Vectren South submitted evidence on the fair value of its property. Vectren South’s Witness John P. Kelly, an asset valuation specialist with Concentric Energy Advisors, Inc., determined the value of Vectren South’s electric properties including common plant allocated to the electric operation. In his valuation, Mr. Kelly used the reproduction cost new less depreciation (“RCNLD”) approach.

To determine the reproduction cost of Vectren South’s property, Mr. Kelly applied cost trend factors to the original costs by vintage for each plant account. The trend factors were developed from the Handy-Whitman Index of Public Utility Construction Costs and other indices. He then made a downward adjustment to reflect loss in service value due to age and condition of property. As part of this adjustment, Mr. Kelly also considered which assets would be replaced today with functionally-equivalent but different assets. For production plant, Mr. Kelly used the cost of a new scrubbed coal facility as the replacement of Vectren South’s existing base load and intermediate load units and a new combustion turbine as the replacement for Vectren South’s peaking units. The construction, operating, and maintenance costs of the alternative facilities were used to determine the physical and functional depreciation of the existing generating facilities. For transmission, distribution, and general plant, Mr. Kelly determined depreciation by reflecting the average service life, estimated remaining useful life, and condition percent for each account. The condition percent was derived from the well-accepted Robley Winfrey tables published by Iowa State University. To make sure the effect of technological change on the value of the assets was not understated, he made a further adjustment to reduce the RCNLD balances for property other than land and production plant by 2% per year from the date of installation. This adjustment was based on the change in productivity in the utility sector from 1987 through 2008 as reported by the Bureau of Labor Statistics. These steps resulted in RCNLD value of \$2,120,167,980 including RECB assets and \$2,079,535,940 excluding RECB assets.

(3) **Commission Findings.** Vectren South presented its RCNLD evidence to support the proposed fair value of its utility plant, and no evidence was submitted challenging Petitioner's RCNLD study or its fair valuation methodology. However, Vectren South is not seeking a revenue requirement based on fair value. Vectren South’s evidence and proposed order presented in this Cause contain its net operating income request based on the original cost

of its rate base. Further, Vectren South did not present evidence of an inflation-adjusted fair rate of return to apply to its proposed fair value, but rather, provided its cost of equity evidence in support of a return on its original cost rate base. Because Vectren South failed to provide any evidence concerning an inflation adjustment to its cost of equity evidence, we find this comparison inappropriate and unnecessary.

The Commission is cognizant of its obligation to make a fair value determination under Ind. Code § 8-1-2-6. However, it is unclear what purpose a fair value determination has in this Cause given Vectren South's use of original cost in proposing its NOI. The Commission does not engage in such decision-making for purely academic pursuits. A fair value determination is the first step to making the ultimate determination of a fair return using a fair rate of return. If the evidence is insufficient to support a subsequent step of the fair value calculation, the Commission need not proceed with any step of the calculation. *N. Ind. Pub. Serv. Co.*, Cause No. 43526, 2010 Ind. PUC LEXIS 294, at *40-41 (IURC Aug. 25, 2010). Rather, we must use the evidence available to determine an appropriate revenue requirement. *Id.*, at *41

Accordingly, although we find the evidence supports a finding that the fair value of Vectren South's utility property used and useful and in the provision of electric utility service is \$2,079,535,940, we give no weight to such valuation for purposes of calculating Vectren South's revenue requirement in this Cause. We must reach this conclusion given Vectren's failure to present evidence concerning the inflation-adjusted fair rate of return to apply to its fair value. Instead, as requested by Petitioner, we use Petitioner's original cost valuation for purposes of ratemaking in this proceeding.

8. Fair Rate of Return.

A. Capital Structure. Vectren South originally proposed to determine its cost of capital using its actual capital structure as of June 30, 2009, adjusted to reflect the potential infusion of \$80 million of additional common equity and the use of the invested proceeds to retire currently outstanding debt. Robert L. Goocher, Vectren South's Vice President and Treasurer, testified the additional equity funds were anticipated to come from Vectren Corporation's non-regulated businesses. Mr. Goocher stated if the equity infusion did not occur, the actual end of test year capital structure should be used. In supplemental direct testimony, Vectren South indicated the potential equity infusion was no longer expected to take place during the pendency of this proceeding. Therefore, Vectren South reverted to use of its actual capital structure as of June 30, 2009. Both the OUCC and Industrial Group agreed that Vectren South's actual capital structure as of June 30, 2009, was appropriate for purposes of this proceeding. The Commission agrees and finds Vectren South's actual capital structure as of June 30, 2009, should be used to determine Vectren South's cost of capital.

B. Cost of Capital.

(1) Introduction. Vectren South proposed that the Commission find its cost of capital to be 7.42%. The OUCC proposed a cost of capital of 6.79%. The Industrial Group proposed a cost of capital of 7.05%. Each of these parties computed the cost of capital using the June 30, 2009 capital structure, a 6.25% cost rate for long-term debt and a 3.43% cost rate for customer deposits. The only disagreement concerned the cost of common equity.

(2) **Vectren South's Direct Evidence.** Vectren South presented the testimony of William E. Avera, President of FINCAP, Inc., on its cost of equity. Dr. Avera concluded that Vectren South's cost of equity was 11.50%.

In his analysis, Dr. Avera considered both the specific risks faced by Vectren South as well as general conditions in the electric utility industry and the capital markets. Dr. Avera testified that since the 1930s, there has not been a time when the financial markets and economy have experienced such a degree of challenge and uncertainty for utilities. He stated that investors' risk perceptions of the utility industry have changed and the potential for energy market volatility remains an ongoing concern for investors. Dr. Avera explained that Vectren South's ongoing need to undertake significant electric utility capital expenditures creates additional financial pressure impacting its risk assessment. He contended support for the Company's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner. He noted investors recognize that electric utilities such as Vectren South are not immune to the effects of an economic downturn. Dr. Avera indicated this is particularly true for Vectren South's service territory as the Evansville economy is highly dependent on manufacturing, which has been hard-hit by the recession. In addition to these financial pressures, Dr. Avera testified Vectren South and other utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. Dr. Avera concluded that while conditions in the economy and capital markets appear to have stabilized, investors are apt to react swiftly and negatively to any future signs of trouble in the financial system or economy. Given the importance of reliable electric power for customers and the economy, Dr. Avera believed it would be unwise to ignore investors' increased sensitivity to risk in evaluating Vectren South's return on equity ("ROE").

Dr. Avera developed a proxy group of publicly traded utility companies ("Utility Proxy Group") for use in the models he applied to estimate Vectren South's cost of equity. These companies are all classified in the Value Line Investment Survey ("Value Line") as electric utilities with: (1) Standard & Poor's ("S&P") corporate credit ratings of BBB+ to A; (2) a Value Line Safety Rank of 1 or 2; (3) a Value Line Financial Strength Rating of B++ or higher; and (4) earnings per share ("EPS") growth projections from at least two of the following: Value Line; Thomson Reuters I/B/E/S; First Call Corporation; and Zacks Investment Research. In addition to his Utility Proxy Group, Dr. Avera also developed a reference group of comparable risk companies in the non-utility sectors of the economy ("Non-Utility Proxy Group"). This group is comprised of companies that pay common dividends, have a Safety Rank of 1, have investment grade credit ratings from S&P, and have a Value Line Financial Strength Rating of B++ or higher. Dr. Avera further limited the Non-Utility Proxy Group to companies with published EPS growth estimates from at least two of the sources identified above.

Dr. Avera first applied the discounted cash flow ("DCF") approach to his Utility Proxy Group. This model considers the cost of equity to be the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The discount rate or cost of common equity is determined by adding the forward-looking dividend yield on the market price of the stock to the growth rate investors expect from the stock. In applying the model, Dr. Avera used a dividend yield based on estimates of dividends to be paid by the Utility Proxy Group over the next twelve months divided by the recent stock price. Dr. Avera's growth rate was based on analyst EPS growth projections for each of the firms in the

Utility Proxy Group. He did not use historical growth rates in earnings, dividends, and book value to determine the projected growth rate because he believed they are not likely to provide a meaningful guide to investors' current long-term growth expectations. Dr. Avera asserted this was true because utilities have significantly altered their dividend policies in response to the more accentuated business risks in the industry with payout ratios falling from 80% to 60% and dividends being stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainty. Instead, Dr. Avera testified investors have shifted from dividends to future trends in earnings as a measure of long-term growth. He said earnings provide the source for future dividends, ultimately support share prices, and play a pivotal role in determining investors' expectations.

Dr. Avera testified historical growth rates were not likely to be representative of investors' expectations for utilities because the historical conditions giving rise to these growth rates are not expected to continue. He stated that this is clearly the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. He added that while these conditions continue to depress historical growth measures, they are not representative of long-term expectations for the utility industry. Dr. Avera cited publications showing financial professionals rely primarily on future earnings growth in evaluating stock prices. Because of the weight investors give to them, he believed analyst earnings growth forecasts are currently the best indicator of investors' growth expectations. These growth rates resulted in DCF cost of equity estimates for the Utility Proxy Group of 10.8% to 11.0%.

Dr. Avera stated that while he believes analysts' forecasts provide a superior and more direct guide to investors' growth expectations, he also included the "sustainable growth" approach for completeness. This method determines the growth rate in the DCF model as the sum of the expected earnings retention ratio times the expected ROE plus the percent of new common equity expected to be issued annually times the equity accretion rate. The result of Dr. Avera's DCF analysis for the Utility Proxy Group using sustainable growth was a cost of equity rate of 10.6%. Dr. Avera also applied his DCF analyses to the Non-Utility Proxy Group resulting in cost of equity estimates ranging from 11.4% to 13.0%. In each case, Dr. Avera excluded outliers at the high and low end of the range consistent with FERC procedures.

Dr. Avera also applied the Capital Asset Pricing Model ("CAPM") approach which measures the cost of equity as the sum of the risk free rate and the market equity risk premium adjusted by the beta coefficient. For the risk free rate, Dr. Avera used 4.3% based on the average yield on 20-year treasury bonds. Dr. Avera computed the market risk premium by conducting a DCF analysis on the 348 dividend paying firms in the S&P 500, resulting in an expected rate of return of 11.9%. From this rate he deducted the risk-free rate to determine a market equity risk premium of 7.6%. The beta reflects the stock's systemic risk or its volatility compared to the market as a whole. Dr. Avera used the beta values reported by Value Line, a widely referenced source. Dr. Avera's CAPM analysis of the Utility Proxy Group resulted in a cost of common equity estimate of 9.5%. Dr. Avera also applied his CAPM to the Non-Utility Proxy Group, which resulted in an average implied cost of common equity of 10.3%.

Dr. Avera testified that applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. He

discussed how the “flight to safety” to U.S. government bonds has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. Thus, according to Dr. Avera, recent capital market conditions may cause CAPM cost of common equity estimates to understate investors’ required returns for common stocks because the full effect of the “flight to safety” may not be captured in the market risk premium estimate. Dr. Avera also stated the validity of CAPM results has been affected by the precipitous drop and subsequent partial recovery in stock prices, which has caused many firms’ historical betas to become unstable. In addition, the market required rate of return may be distorted by the recent run-up in stock prices. As a result of these issues, Dr. Avera testified, there is every indication that CAPM approaches fail to fully reflect the risk perceptions of real-world investors in today’s capital markets.

Dr. Avera also applied the Expected Earnings Approach to estimate Vectren South’s cost of common equity. This approach considers ROEs forecasted by analysts on stocks comparable in risk to Vectren South. Dr. Avera explained that this approach is consistent with the economic underpinning for a fair rate of return established by the U.S. Supreme Court in *Bluefield Water Works & Improvement Co.*² and *Hope Natural Gas Co.*³ cases. Dr. Avera stated that reference to rates of returns available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. Moreover, according to Dr. Avera, this approach avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors. Using the Value Line projected returns on common equity for the Utility Proxy Group for 2009 through 2014, Dr. Avera concluded this approach suggested a required ROE for Vectren South of 11.5%.

Dr. Avera then considered the quantitative results of each of his approaches to analyzing Vectren South’s cost of equity as follows:

<u>DCF</u>	<u>Utility</u>	<u>Non-Utility</u>
Value Line	10.9%	11.4%
IBES	10.9%	12.3%
First Call	10.8%	12.7%
Zacks	11.0%	13.0%
br+sv	10.6%	12.3%
 <u>CAPM</u>	 9.5%	 10.3%
 <u>Expected Earnings</u>		
Electric Utilities - 2009	10.5%	
Electric Utilities – 2010	11.0%	

² *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm’n of WV*, 262 U.S. 679 (1923).

³ *Fed. Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Electric Utilities – 2012-14	11.5%
Utility Proxy Group	11.5%

Because the capital market crisis and ensuing recovery have created a number of problems in applying the CAPM, Dr. Avera stated he largely disregarded the resulting CAPM cost of equity estimates. Based on his assessment of the relative strengths and weaknesses inherent in each method, Dr. Avera stated the cost of common equity indicated by his analyses was in the 10.8% to 11.8% range. To this “bare bones” cost of common equity, Dr. Avera added a 20 basis point adjustment for flotation costs and concluded that a fair ROE for the proxy group of electric utilities is currently in the 11.0% to 12.0% range. Although Dr. Avera testified that Vectren South’s relatively small size could justify an increase of at least 100 basis points in excess of his cost of equity estimates, he did not make an explicit adjustment to the ROE range. Rather, Dr. Avera recommended that Vectren South’s smaller size be considered, along with other potential factors, in establishing a point estimate from within his recommended range. Dr. Avera concluded that the 11.5% midpoint of his recommended range represents a fair and reasonable ROE for Vectren South.

Dr. Avera testified his recommendation reflects the existence of Vectren South’s existing and proposed tracking mechanisms. Dr. Avera stated the Company’s proposed decoupling mechanism did not warrant any adjustments to his recommended ROE. He noted investors are aware decoupling only partially mitigates earnings attrition and does not prevent the disallowances that could result from the unique Indiana FAC earnings and expense tests. Moreover, Dr. Avera identified the many tracking mechanisms available to the companies in his Utility Proxy Group, including but not limited to decoupling and revenue stabilization mechanisms, to show decoupling would not make Vectren South less risky than the proxy group. While approval of a decoupling mechanism for Vectren South would be supportive of the Company’s financial integrity and credit ratings, Dr. Avera testified implementation of the proposed tracker alone would not alter Vectren South’s relative risk enough to warrant a change in its ROE. In addition, common equity investors do not view mechanisms that address revenue stabilization, such as rate design approaches that shift away from volumetric recovery of fixed costs, as entirely positive. This is because, while revenue decoupling dampens the volatility of a utility’s revenues, it also largely precludes the prospects of exceptional earnings due to growth in sales.

Vectren South Witness Chapman discussed Vectren South’s decision to propose rates that would produce an ROE of only 10.7%, which is below the ROE found reasonable by Dr. Avera. He stated this decision is one of several steps taken by Vectren South to limit the amount of the proposed rate increase in this case. Mr. Chapman indicated Vectren South has risks commensurate with its peers and continued regulatory support is highly important. He pointed out that of 65 electric rate cases pending as of November 2009, only five were filed with ROEs below 10.7% and the average request was 11.39%. Based on Dr. Avera’s analysis, Mr. Chapman stated Vectren South could not request an ROE lower than 10.7% without bringing into question the Company’s ability to compete for capital, since ROE represents the opportunity an investor perceives obtainable in exchange for risk. Mr. Chapman testified that 20 of 25 electric utility rate orders in 2009 set ROEs in the range of 10.5% to 11.5% with an average of 10.54%.

(3) OUCC's Evidence. Korlon L. Kilpatrick, a Utility Analyst in the OUCC's Resource Planning and Communications Division, testified in support of the OUCC's recommended cost of common equity of 9.25%. Mr. Kilpatrick used three approaches to estimate Vectren South's cost of common equity – a CAPM and two DCF approaches.

For his CAPM, Mr. Kilpatrick used a risk-free rate of 4.57%, which he described as the 5-month average yield (January – June 2010) on the 30-year U.S. Treasury bond. Mr. Kilpatrick used the beta values provided by Value Line for the same Utility Proxy Group utilized by Dr. Avera. For his market risk premium estimate, Mr. Kilpatrick used the difference in total returns between large stocks and long-term government bonds from the Morningstar Publication *2010 Ibbotson Stocks Bonds Bills and Inflation Yearbook Classic Edition* ("SBBI 2010 Yearbook"), which was 4.4% or 6%, based upon geometric or arithmetic means, respectively. Using these rates as endpoints, Mr. Kilpatrick adopted the midpoint measure of 5.2% as his risk premium estimate, which he said gives equal weight to the geometric and arithmetic mean approaches to measuring the historical market risk premium. Mr. Kilpatrick computed a CAPM result for the Utility Proxy Group of 7.43% to 8.99%, with a midpoint of 8.21% and an average of 8.10%.

Mr. Kilpatrick next discussed the results of his constant-growth DCF model. He assembled several estimates of dividend yields for the companies in the proxy group. For the growth rate of each company, Mr. Kilpatrick used a long-term growth estimate of the U.S. Gross Domestic Product ("GDP") of 4.45%, taken from the January 27-28 Minutes of the Federal Open Market Committee. He then adjusted his results by removing all results that were less than 6.25% or greater than 12.68%. He explained that the low-end value was set at Vectren South's cost of debt and that the high-end limit was derived using an average sector beta and Dr. Avera's risk-free rate and equity risk premium. Mr. Kilpatrick stated his constant-growth DCF model yielded a cost of equity range for the Utility Proxy Group of 6.75% to 11.05%.

Mr. Kilpatrick also used a two-stage DCF model, which he stated allows one to give weight to both the near-term growth rates provided by analysts and the long-term growth of the economy. He opined that this approach allows one to temper analysts' forecasts which may reflect "optimism" for economic recovery with a long-term growth perspective in the second stage. Mr. Kilpatrick developed the dividend yield using the closing price for the proxy group stocks as of January 4, 2010. For the first stage of growth representing five years, Mr. Kilpatrick used the Value Line forecasted growth rates from Dr. Avera's exhibits. For the second-stage growth rate (year 6 to perpetuity), Mr. Kilpatrick used the same 4.45% GDP forecast that he used in his constant growth DCF model. To derive the cost of equity values, Mr. Kilpatrick used a non-linear optimization in conjunction with the Goal Seek function in MS Excel to solve for the required rate of return. Mr. Kilpatrick testified that his application of the two-stage DCF model yielded cost of equity estimates in the range of 6.28%⁴ to 10.76%. He stated that the two-stage DCF approach reinforces the results obtained from the constant-growth approach and his overall recommended range.

Mr. Kilpatrick also provided a critique of Dr. Avera's testimony. With respect to Dr.

⁴ The 6.28% low end cited on page 11, line 7 is inconsistent with the low end of 7.25% cited on page 3, Table KKK-1. It appears Mr. Kilpatrick intended to use only his utility proxy group results. The correct low-end percentage for the utility proxy group would be 7.25%. See Ex. KKK-6.

Avera's CAPM analysis, Mr. Kilpatrick disagreed with Dr. Avera's determination of the market equity risk premium by applying the DCF model only to the dividend-paying firms in the S&P 500. Mr. Kilpatrick asserted this would lead to an imprecise conclusion because the market is comprised of both dividend-paying and non-dividend-paying stocks. Mr. Kilpatrick also objected to Dr. Avera's use of a five-year market growth rate of 9.2%, which he believed was too short a period to be considered either long-term or sustainable into perpetuity. He stated it is understandable that an investor might not look into the "distant horizon," but a prudent analyst must do so for the purpose of rate of return determination. Finally, Mr. Kilpatrick stated that Dr. Avera's use of the 20-year U.S. Treasury bond for his risk-free rate is incongruous with his use of a five-year rate for purposes of determining the market return.

With respect to Dr. Avera's DCF analysis, Mr. Kilpatrick expressed two principal disagreements. First, he questioned the reasonableness of Dr. Avera's use of three-to-five year growth rates as inputs to his constant-growth DCF model. He believed that the shorter term growth rate used by Dr. Avera reflected the optimism of the economic recovery and overstated the expected long-term growth rate, resulting in an upward bias on the resulting cost of equity. Mr. Kilpatrick contended a reasonable estimate of the long-term growth rate of a company is the estimated growth rate of the economy represented by GDP. Second, Mr. Kilpatrick disagreed with Dr. Avera's approach to eliminating outlier results in his analysis. In particular, he faulted Dr. Avera for eliminating several results that are in the range of 6.3 to 6.8 percent, which are greater than Vectren South's embedded cost of debt. He also opined that Dr. Avera's high-end threshold of 17.3% was excessively high and unsubstantiated.

Mr. Kilpatrick further disagreed with Dr. Avera's 20 basis point flotation adjustment and his position regarding risk and firm size. With respect to flotation costs, Mr. Kilpatrick believed that while Dr. Avera's adjustment is based on the actual expense incurred by Vectren South on stock issued in mid-2008, adding it to cost of equity allows it to be applied to a much larger base. He expressed concern that, in the absence of equity issues, this would provide a mechanism for unreasonable recovery. With respect to Dr. Avera's position regarding the need to consider Vectren South's relatively small size in determining Vectren South's cost of equity, Mr. Kilpatrick believed that the regulated nature of the electric industry mitigates any effects that firm size may have had. He also cited two 1993 articles that suggest there are no risk differences between small and large utilities. With respect to the relationship of trackers and risk, Mr. Kilpatrick also cited a Merrill Lynch report on Vectren Corporation stating regulatory initiatives foster a lower business risk utility earnings profile.

Finally, Mr. Kilpatrick did not agree with Dr. Avera's view that currently historical growth is not likely to be representative of investors' expectations. Mr. Kilpatrick believed that an investor would use historical rates as a part of any fundamental analysis that is performed to evaluate an investment decision. Mr. Kilpatrick relied on the 1994 edition of Roger Morin's book *Regulatory Finance: Utilities Cost of Capital* for giving equal weight to analyst forecasts and historical growth rates. Mr. Kilpatrick stated that relying solely on analysts' forecasts would not provide a growth rate estimate that represents long-term and sustainable growth.

Mr. Kilpatrick concluded, based upon the results of his models and giving more weight to the two-stage DCF results, that the appropriate cost of equity is 9.25%.

(4) Industrial Group's Evidence. Michael Gorman of Brubaker & Associates, Inc. provided the Industrial Group's ROE proposal. Mr. Gorman used multiple methods to estimate Vectren South's cost of common equity – three different versions of the DCF model, a Risk Premium model and the CAPM. In applying his models, he used the same proxy group as Dr. Avera. Mr. Gorman recommended a cost of common equity of 9.85%. Mr. Gorman considered the credit rating outlook for the electric utility industry to be strong and supportive of its financial integrity. He described the stock price performance of electric utilities as strong. He noted that credit analysts consider the regulatory treatment for Vectren South to be constructive and supportive of its excellent business risk profile and stable investment grade credit standing.

Mr. Gorman first applied a constant growth DCF model, using the most recent quarterly dividend and a 13-week average stock price to determine the dividend yield. He combined the proxy group dividend yield of 5.00% with a growth rate of 5.37%, the average analyst earnings growth forecast for the group, resulting in a cost of equity estimate of 10.37%. Mr. Gorman testified that analysts' growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data and influence observable stock prices more than historical data. However, Mr. Gorman believed that the proxy group's three-to-five-year growth rate exceeds a long-term sustainable growth rate because it is greater than the consensus GDP growth rate forecasts for the next five and ten years. He contended that the GDP growth projection should be considered a ceiling growth rate for utilities.

Mr. Gorman next described his sustainable growth DCF analysis. He said that a sustainable growth rate is based on the percentage of the utility's earnings that are retained and reinvested. To estimate this growth rate, Mr. Gorman relied upon Vectren South's current market-to-book ratio and Value Line's three-to-five year projections for earnings, dividends, return on book equity, and stock issuances. He indicated the average sustainable growth rate for the proxy group using this internal growth rate model is 4.99%. Using this growth rate and the dividend and price data used in his constant growth DCF study, Mr. Gorman's analysis produced a group average DCF result of 9.97%.

Mr. Gorman also performed a multi-stage DCF calculation that used decreasing growth rates for the first five years, years five through ten, and year eleven through perpetuity. The rates used in the first stage were the analysts' forecasts described above. The rates used in the second stage were adjusted by an equal factor reflecting the difference between the analysts' growth rates and the GDP. The rate used in the third stage was 4.8% which Mr. Gorman said was the 10-year GDP consensus growth rate as published by *Blue Chip Financial Forecasts* ("Blue Chip"). The result of the multi-stage DCF model was 9.92%. Mr. Gorman then averaged his three DCF results (10.37%, 9.97% and 9.92%) and rounded the average up to 10.09% as his ultimate DCF recommendation.

In his Risk Premium model, Mr. Gorman calculated the difference between regulatory commission-authorized returns for electric utilities in each year since 1986 and the yields on Treasury bonds and A-rated utility bonds in each of those same years. This method produced an average risk premium over U.S. Treasury bonds of 5.16% and over A-rated utility bonds of 3.71%. Mr. Gorman then selected ranges of 4.40% to 6.08% for the Treasury spread and 3.03% to 4.59% for the utility bond spread by focusing on where most of the annual results fell. Mr. Gorman next added the Treasury risk premium range to a projected Treasury bond yield of

4.55% and the utility bond risk premium range to a current 13-week average yield on A-rated utility bonds of 5.69%. From these results, Mr. Gorman recommended a 10.17% rate for the Treasury bonds analysis (the midpoint of his range) and a rate of 9.50% for the utility bond analysis (the midpoint of his range). Mr. Gorman indicated that the return estimate produced by his risk premium analyses ranges from 9.50% to 10.17%, with a midpoint estimate of 9.84%.

In his CAPM, Mr. Gorman used a 5.3% risk-free rate based upon a Blue Chip projected Treasury bond yield and a beta of 0.67, the average of the Value Line proxy group beta estimates. Mr. Gorman used risk premiums of 5.20% and 6.70%. The higher premium is the difference between the total return on the S&P 500 and the income return on long-term Treasury bonds over the period 1926 to 2009 as reported in the SBBI 2010 Yearbook. The lower premium is a “supply side” equity risk premium calculated in the SBBI 2010 Yearbook’s Valuation Edition after making a price/earnings ratio adjustment. Mr. Gorman’s CAPM results are 8.80% to 9.81% with a midpoint of 9.31%.

Based on the results of all of his analyses, Mr. Gorman recommended a ROE range of 9.6% to 10.10% with the low end being the average of his CAPM and risk premium results and the upper end being his DCF result. He recommended an ROE of 9.85%, the midpoint of his range. He contended his recommendation would support investment grade credit ratings under S&P’s credit metric benchmarks. However, he acknowledged S&P’s new credit metrics are not as transparent as its former metrics.

Mr. Gorman also commented on Dr. Avera’s testimony. He testified that Dr. Avera’s proposed flotation cost adjustment should be rejected because Dr. Avera did not show that his adjustment is based on Vectren South’s actual and verifiable flotation expenses. Mr. Gorman said that Dr. Avera’s use of a non-utility proxy group in his DCF analysis was flawed because those companies are subject to risks that are different from those affecting Vectren South’s utility operations and the regulatory process itself mitigates some market risks. Mr. Gorman stated that Dr. Avera’s DCF growth rate range of 5.4% to 6.2% was too high to be sustainable in the long run. He also stated that updating Dr. Avera’s traditional DCF model with the current stock price and growth rate estimates will produce a DCF return in the range of 9.7% to 10.5%, with an average of 10.1%. Mr. Gorman stated that applying a multi-stage DCF model to Dr. Avera’s utility group yields a DCF return of approximately 9.9%.

Mr. Gorman disputed the 7.6% market risk premium used by Dr. Avera in the CAPM analysis on the ground that it was premised upon an 11.9% projected market return which Mr. Gorman considered to be inflated and unreliable. Mr. Gorman asserted that long-term sustainable growth cannot exceed GDP growth over sustained periods of time. He stated that applying a market risk premium estimate in the range of 5.2% to 6.7%, using a 4.5% risk free rate (based on the 20-year treasury yield as of April, 2010) and an updated beta of 0.67 will produce a CAPM in the range of 8.0% to 9.0%, the high end of which would be a reasonable CAPM return estimate.

Mr. Gorman also disagreed with Dr. Avera’s Expected Earnings analysis. He stated that such an analysis does not measure the return an investor requires in order to make an investment. Rather, according to Mr. Gorman, it measures the earned return on book equity companies have experienced in the past or are projected to achieve in the future. He asserted that the return is not

developed from observable market data and does not measure the investor expected or required return.

Additionally, Mr. Gorman disputed Dr. Avera's testimony regarding the risks posed by Vectren South's size. Mr. Gorman contended selecting a proxy group that has a comparable total investment risk fully captures all the risks outlined by Dr. Avera.

Finally, Mr. Gorman expressed the opinion that Vectren South's proposed decoupling mechanism would mitigate operating risk. He cited S&P's view of "decoupling as a positive development from a credit perspective" although S&P "will only consider a decoupled mechanism good for credit quality if it minimizes the lag time before deferrals are included in rates, and does not subject the rate changes to a protracted prudence review." Mr. Gorman said the Oregon and Maryland commissions made downward ROE adjustments when approving decoupling. Mr. Gorman contended the 25 basis point difference between A-rated and Baa-rated utility bonds would be an appropriate ROE adjustment to account for regulatory mechanisms providing greater cost recovery assurance.

(5) Evidence of CAC and NRDC. Two other witnesses addressed the issue of whether decoupling should affect Vectren South's cost of capital. CAC Witness J. Richard Hornby, Senior Consultant at Synapse Energy Economics, Inc., stated that while he was not testifying as a witness regarding ROE, one proponent of decoupling, the Regulatory Assistance Project ("RAP"), indicated in a 2008 report to the Minnesota Commission that decoupling should result in a reduction in the utility's cost of capital, either through the equity capitalization ratio or through ROE.

NRDC presented the testimony of Pamela G. Morgan, President of Graceful Systems, LLC, a consultant to utilities, regulators and service and equipment providers for utilities on regulatory strategy, systems and problem solving. Ms. Morgan disagreed with the notion that decoupling shifts risk to the customers. She explained that decoupling is symmetrical. If the risk of revenues being too high or too low is evenly distributed, decoupling simply lessens the risk that both utility and customers bear. With respect to cost of capital, Ms. Morgan asserted that with more utilities operating under a regulatory and business model that includes decoupling, it is less clear that adopting such a mechanism will reduce the cost of capital. In any event, she stated, the models and procedures the Commission follows today to determine a reasonable rate of return will continue to apply under decoupling and presumably indicate the effect of the mechanism along with all of the other regulatory policies in place for a particular utility. Ms. Morgan quoted from the same 2008 RAP Report that was referred to by Mr. Hornby. The RAP Report pointed out that decoupling's favorable effect on bond ratings requires several years to play out but consumers can also benefit when a lower equity ratio is sufficient to maintain the same bond rating for the decoupled utility. RAP also warned that rating agencies will recognize risk mitigation sooner if they perceive it will be in effect for an extended period, rather than when it will be in effect only for a limited period or when the regulatory commission has a record of changing its regulatory principles frequently.

(6) Vectren South's Rebuttal Evidence. In rebuttal, Dr. Avera disagreed with the contentions of Mr. Kilpatrick and Mr. Gorman that GDP growth should be a ceiling on the growth in the DCF model. He stated it is entirely logical for investors to recognize the potential

for certain companies to grow faster than the overall economy. Dr. Avera rejected the notion that investors would base their growth expectations on an artificial GDP constraint and emphasized the purpose of the model is to determine investor expectations, not judge the reasonableness of their expectations. Dr. Avera testified investors do not look to a distant horizon where all companies grow at the same rate as the overall economy. He stated that other regulators, including FERC, have approved DCF estimates based on growth rates that exceed trends in GDP. He also said investors recognize that the electric utility industry has entered a long-term cycle of capital investment, which supports the reasonableness of the analysts' growth estimates he relied upon.

Dr. Avera contested Mr. Kilpatrick's assertion that analyst growth rate forecasts are optimistically biased, and cited peer-reviewed empirical studies to the contrary. While Mr. Kilpatrick relied on past Wall Street Journal articles on analyst optimism, Dr. Avera cited other recent articles saying analyst earnings forecasts have been too pessimistic. Dr. Avera also quoted from sources relied upon by Mr. Kilpatrick and Mr. Gorman, including Eugene Brigham and Roger Morin, confirming the reliance investors place on analyst forecasts and concluding they are the best estimate of growth for purposes of the DCF model. Dr. Avera pointed out Mr. Gorman's "sustainable" growth rate calculation for many of the proxy group companies as shown on his Exhibit MPG-9 exceeds his proposed GDP ceiling. Dr. Avera stated an alternative approach would be to use projected stock prices from investment advisory services such as Value Line to determine growth rates. He stated that Value Line's stock price projections for the proxy firms result in an average DCF cost of equity of 11.9%.

Dr. Avera testified that the multi-stage DCF models presented by Mr. Kilpatrick and Mr. Gorman are sensitive to changes in assumptions and thus are subject to greater controversy in a rate case setting. He stated these models do not reflect the expectations of real-world investors whose view of electric utilities does not anticipate their transition through a series of discrete, clearly defined stages. Dr. Avera also said that because the multi-stage DCF models rely on GDP growth, they are subject to the same criticisms as the single-stage DCF results presented by Mr. Kilpatrick and Mr. Gorman. Dr. Avera reapplied Mr. Kilpatrick's two-stage DCF model using cash flows from the dividend growth assumed by Mr. Kilpatrick and Value Line stock price projections to determine an average cost of equity estimate of 11.5%. Dr. Avera testified Mr. Gorman applied his multi-stage DCF model by using a program that assumed annual cash flows were received by investors at the end of each year. Dr. Avera said this is inconsistent with the periodic dividend payments that investors actually receive throughout the year. He asserted that correcting Mr. Gorman's multi-stage DCF model to reflect mid-year cash flows would increase Mr. Gorman's average cost of equity estimate to approximately 10.2%.

Dr. Avera criticized Mr. Kilpatrick's use of Vectren South's debt cost as the threshold for eliminating low-end DCF estimates. He stated the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. As a result, he opined Mr. Kilpatrick's making the low-end threshold equal to the cost of debt does not sufficiently screen for illogical cost of equity estimates. He said that other regulators have excluded low-end cost of equity estimates that exceed the yields available on utility bonds by 100 basis points or more and that a projected rise in long-term interest rates provides further confirmation that Mr. Kilpatrick's low-end threshold is insufficient. Dr. Avera similarly criticized Mr. Kilpatrick's high-end threshold as

being inconsistent with DCF estimates used by other regulators. FERC, for example, has used a range of reasonableness that extends far above the results Mr. Kilpatrick classified as outliers. Dr. Avera pointed out that Mr. Gorman did not exclude any illogical values in his DCF results. According to Dr. Avera, if the approach commonly employed by FERC to identify and exclude outliers were used, Mr. Gorman's DCF cost of equity range would have increased from 10.4% to 11.0%.

Dr. Avera disagreed with Mr. Kilpatrick's reliance on historical growth rates and noted that both he and Mr. Gorman recognized that analysts' estimates are superior to historical growth measures. Dr. Avera stated that the variability in historical growth rates renders them useless for calibrating future expectations.

Dr. Avera defended his use of a Non-Utility Proxy Group as consistent with investor behavior and the *Bluefield* and *Hope* decisions. He said that returns in the competitive sector of the economy form the underpinning for utility ROEs because regulation seeks to serve as a substitute for the actions of competitive markets. According to Dr. Avera, including a Non-Utility Proxy Group made his DCF estimate more reliable because it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

With respect to his Expected Earnings approach, Dr. Avera likewise defended his use of an ROE benchmark to measure returns expected from comparable risk stocks. He said that if a utility's allowed ROE is set below the returns available from other investments of similar risk, investors will be unwilling to supply capital on reasonable terms. Dr. Avera noted that the comparable-risk utilities in the proxy group are expected to earn on average an ROE that exceeds 11.0%. Accordingly, if the ROE recommendations of 9.25% and 9.85% made by Mr. Kilpatrick or Mr. Gorman are adopted, Vectren South's investors will be denied the ability to earn their opportunity cost. Dr. Avera pointed out that the average projected ROE for the Utility Proxy Group reflected in Mr. Gorman's sustainable growth rate DCF model was 11.1%.

Dr. Avera testified the use of historical rather than projected rates of return in the CAPM analyses performed by Mr. Kilpatrick and Mr. Gorman significantly understates the investors required rate of return because of distortions caused by the current market conditions and the "flight to safety" pushing down Treasury bond yields. He also criticized Mr. Kilpatrick's reliance on the geometric mean to determine the market equity risk premium in his CAPM as inconsistent with finance theory which requires use of the arithmetic mean to estimate returns in future periods. Dr. Avera also disagreed with Mr. Kilpatrick's use of the *total* return for long-term government bonds as the riskless return. Dr. Avera said that the *income* return should instead be used as confirmed by the SBBI 2010 Yearbook. Dr. Avera defended his use of only dividend-paying firms in applying the DCF model to the S&P 500 because the dividend yield is a key component of the DCF model.

Dr. Avera also rejected the position of Mr. Kilpatrick and Mr. Gorman that firm size is not a risk factor for investors in the utility industry. He said that in the case of a smaller utility, earnings are principally dependent on economic, social, regulatory and other factors affecting a more limited constituency and that can result in significant risk exposure. He cited a study showing a CAPM size adjustment is required for small utilities because betas do not fully account for their returns.

Dr. Avera contended Mr. Gorman's "forward-looking" CAPM was actually based almost entirely on historical data and thus is not consistent with the forward-looking expectations that are presumed in applying this approach. He said his own estimate of the market return, on the other hand, was truly forward-looking and therefore was consistent with the theory of the CAPM. Dr. Avera also took issue with Mr. Gorman's Risk Premium approach. He stated that Mr. Gorman's selective use of data since 1986 introduces an unnecessary subjective bias that artificially lowers the results. In addition, Dr. Avera highlighted Mr. Gorman's failure to incorporate the inverse relationship between interest rates and equity risk premiums in his analysis of historical authorized rates of return, which has been documented in several empirical studies.

Dr. Avera disagreed with Mr. Gorman's contention that an ROE adjustment should be made if decoupling is adopted. Dr. Avera noted utilities across the country are increasingly availing themselves of such mechanisms. He testified the companies in the Utility Proxy Group have similar mechanisms and therefore any effect on risk is already captured by the proxy group. He further stated that from the standpoint of the investment community these mechanisms are not viewed as entirely positive because they preclude the possibility of greater earnings due to higher consumption and introduce new risks associated with policies supporting aggressive energy efficiency programs. In light of the risk comparability of the proxy group and the loss of upside potential, Dr. Avera testified there is no reason to make a separate ROE adjustment.

Dr. Avera also defended the need for a flotation cost adjustment and provided a numerical example illustrating why such an adjustment is necessary to compensate investors for past flotation costs. Dr. Avera emphasized that the common equity provided by Vectren South's parent and invested in the infrastructure required to serve customers ultimately was raised through the sale of common stock and the associated costs are therefore a legitimate consideration in establishing a fair ROE.

In conclusion, Dr. Avera stated that a low authorized return, as proposed by Mr. Kilpatrick and Mr. Gorman, ultimately increases the cost to customers because it makes it more difficult and expensive for the utility to raise necessary capital. While Mr. Gorman quoted from the Edison Electric Institute ("EEI") *Q4 2009 Financial Update* to illustrate that in recent years commission-approved ROEs have been well received by the market, Dr. Avera cited the more recent EEI *Q1 2010 Financial Update*, which ranked utilities near the bottom of returns by sector. He also stated that between May 3, 2010 and June 1, 2010, the Dow Jones Utility Average dropped almost 10%. Dr. Avera concluded that the ongoing potential for such a dramatic drop in value highlights the exposure of utilities and their investors to market forces beyond the control of the Company and the Commission and underscores the need to allow a return that is sufficient to maintain access to capital on reasonable terms, even when capital market conditions are unfavorable.

In his rebuttal testimony, Mr. Chapman compared the ROE levels requested by and granted for other electric utilities. He stated that in 53 of the 57 electric rate cases decided in 2009, the utility proposed an ROE greater than the 10.7% that Vectren South requests in this case. The average awarded ROE in those cases was 10.52%. He said that in the 54 electric rate cases pending in July 2010, the average requested ROE is 11.24%.

(7) **Commission Findings.** The record contains a number of different methods of estimating Vectren South's cost of common equity. We recognize the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment. Due to this lack of precision, the use of multiple methods is desirable because no single method will produce the most reasonable result under all conditions and circumstances. Four models were used to determine a cost of equity: DCF; CAPM; Risk Premium; and Expected Earnings. Each was discussed in varying degrees by the Parties in this Cause. The expert witnesses of each Party used the same proxy group of seventeen electric utility companies to conduct their respective analyses. While Dr. Avera also submitted analyses using a proxy group of non-utility companies, we give little weight to those analyses due to the inherent differences between regulated utilities and non-utility companies operating in a free-market system.

In summary, the parties have presented evidence that the cost of equity could be as low as 6.75% and as high as 12.00%, and recommended a cost of common equity between 9.25% and 11.5%. Having considered the evidence of record and giving such weight to the evidence as we deem appropriate, we find that a cost of equity range of 9.90% to 10.50% is reasonable and appropriate for Vectren South in today's economic climate. This is comparable with our cost of equity findings in Vectren South's prior rate case, *Southern Ind. Gas and Elec. Co.*, 2007 Ind. PUC LEXIS 243, at *99 (approving Settlement Agreement, including 10.4% cost of equity) as well as our findings in *Ind. Mich. Power Co.*, Cause No. 43306, 2009 Ind. PUC LEXIS 107, at *155 (IURC Mar. 4, 2009) (approving Settlement Agreement, including 10.5% cost of equity), *PSI Energy, Inc.*, 2004 Ind. PUC LEXIS 150, at *146-47 (approving 10.5% cost of equity), and *N. Ind. Pub. Serv. Co.*, 2010 Ind. PUC LEXIS 294, at *99-100 (approving 9.9% cost of equity as a "clear and direct message ... concerning the need for improvement in the provision of ... utility service").

Vectren South submitted evidence supporting an 11.5% ROE but moderated its request to 10.7% to limit the amount of the proposed increase in this case. The OUCC proposes an ROE of 9.25% and the Industrial Group proposes an ROE of 9.85%. Vectren South must compete for capital attraction with other utilities. The expert witnesses of each party have used the same proxy group of 17 electric utility companies. Dr. Avera's exhibits show that these companies are projected by Value Line to have returns on average common equity of 11.5% over the next 3 to 5 years. In his Sustainable Growth Rate DCF calculation, Mr. Gorman has projected a return on year-end equity for these companies of 10.87%. Vectren South currently has an authorized ROE of 10.40%.

We do consider the effect tracking mechanisms have in reducing risk in order to ensure that these reduced risks are properly reflected in Vectren South's cost of equity. See *PSI Energy, Inc.*, 2004 Ind. PUC LEXIS 150, at *145. Vectren South has a number of trackers in place currently, and we have generally continued such trackers in this Cause. Therefore, the increased ROE proposed by Vectren South is not warranted. Similarly, because we are denying Vectren South's decoupling mechanism request, and its attendant reduction in risk to the Company, the reduction in ROE proposed by Mr. Gorman is also not warranted.

We find that continuing Vectren South's current ROE of 10.40% would be reasonable for purposes of determining Vectren South's cost of capital and rate of return. Our ROE finding is within the reasonable and appropriate range of 9.90% to 10.50%. Our ROE finding also gives

consideration to Vectren South’s company-specific risks including its small size, its manufacturing dependent service area, and its coal-based generation fleet. In addition, the Commission believes Vectren South’s strong credit rating is supported, at least in part, by its current authorized ROE.

Therefore, giving such weight to the evidence as we deem appropriate, we find that a 10.40% common equity cost rate should be used to determine Vectren South’s overall weighted cost of capital. Based on the foregoing findings, we find Vectren South’s overall weighted cost of capital to be 7.29% determined as follows:

<u>Description</u>	<u>Amount</u>	<u>Percent</u>	<u>Cost</u>	<u>Weighted Average Cost</u>
Common Equity	\$ 628,785,000	43.46%	10.40%	4.52%
Long-Term Debt	\$ 630,437,000	43.58%	6.25%	2.72%
Customer Deposits	\$ 7,072,000	0.49%	3.43%	0.02%
Cost Free Capital	\$ 174,603,000	12.07%	0.00%	0.00%
Post-1970 ITC	\$ 5,723,000	0.40%	8.32%	0.03%
Totals	<u>\$ 1,446,620,000</u>	<u>100.00%</u>		<u>7.29%</u>

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

<u>Description</u>	<u>Amount</u>	<u>Percent</u>	<u>Cost</u>	<u>Weighted Average Cost</u>
Common Equity	\$ 628,785,000	49.93%	10.40%	5.19%
Long-Term Debt	<u>\$ 630,437,000</u>	<u>50.07%</u>	6.25%	<u>3.13%</u>
Totals	<u>\$ 1,259,222,000</u>	<u>100.00%</u>		<u>8.32%</u>

C. Ultimate Findings on Fair Rate of Return. Having considered the evidence, we find a net operating income level for Vectren South of \$94,450,297 is just and reasonable. This return level represents a rate of return of about 4.54% on the fair value of Vectren South’s property which we have found to be \$2,079,535,940.

9. Operating Income at Present Rates.

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

B. Disputed Pro Forma Revenue Adjustments.

(1) Storm Related Sales Losses.

(a) **Evidence.** The OUCG proposed to increase test year revenue to eliminate the effect of two storms, Hurricane Ike in September, 2008, and an ice storm in January, 2009, on test year sales, which the OUCG considered extraordinary or non-recurring. OUCG Witness Anthony A. Alvarez, Utility Analyst II within the OUCG's Resource Planning and Communications Division, supported this adjustment with a total customer-hour loss analysis, using outage reports submitted by Vectren South to the Commission in an attempt to quantify the impact of these two storms on test year sales levels. According to Mr. Alvarez, the total customer-hour losses attributed to Hurricane Ike and the ice storm are approximately 1,710,465 and 5,758,547 respectively. Using the customer outage duration information provided by Mr. Alvarez, OUCG Witness Catlin proposed to increase test year revenue to account for the lost residential sales and revenue. Mr. Catlin estimated the revenue lost due to Hurricane Ike to be \$258,510, including \$200,886 of base revenues and \$57,624 of fuel revenue. For the ice storm, Mr. Catlin estimated the revenue loss to be \$852,996, comprised of \$643,433 of base revenues and \$209,563 of fuel revenue. Overall, Mr. Catlin's adjustment increased total revenues by \$1,111,507.

In rebuttal, Ms. Hardwick accepted Mr. Catlin's adjustment for the 2009 ice storm, but disagreed with the adjustment for Hurricane Ike. She stated that, as evidenced by Vectren South's periodic storm reports provided to the Commission, Hurricane Ike resulted in no more of an impact to Vectren South's sales than a normal, recurring summer storm. In fact, Ms. Hardwick testified that the average use per customer during September, 2008, compared to the same period in 2007 and 2009 shows no material variance. Ms. Hardwick's proposed adjustment increased total revenues by \$853,117. She stated that her calculation is consistent with that presented by OUCG Witnesses Alvarez and Catlin, modified slightly to correct the February residential customer figure used by Mr. Catlin and to include the impact of the weather normalization adjustment.

(b) **Commission Findings.** Vectren South and the OUCG agree with the abnormal impact that the 2009 ice storm had on Vectren South's test year revenue and margin, and that adjustments should be made accordingly. However, they disagree about the impact of Hurricane Ike. The OUCG reviewed the impact of the 2009 ice storm and Hurricane Ike on Vectren South's revenue and margin, but did not compare this impact to similar periods in prior years. There is no evidence in the record indicating that, once the 2009 ice storm is taken into account, the test year revenue and margin losses attributable to storms differed in any material way from prior years. As Ms. Hardwick testified, Hurricane Ike resulted in no more of an impact to Vectren South's sales than a normal, recurring summer storm. Based on the foregoing, we agree with Ms. Hardwick's proposal and find that Vectren South's revenues should be adjusted for the 2009 ice storm but not for the effect of Hurricane Ike. Therefore, we accept Ms. Hardwick's adjustment, which increases Vectren South's revenues by \$853,117 and fuel costs by \$206,459.

(2) RECB and Non-RECB Transmission Revenues.

(a) **Evidence.** Vectren South's Witness Michael W. Chambliss, Director of Network Operations and Dispatch, testified regarding MISO's control of Vectren South's electric transmission system. He explained that MISO is required to prepare an annual study known as the MISO Transmission Expansion Plan, which is intended to improve electric grid performance in the MISO footprint by ensuring continued compliance with national electric reliability standards, relieving congestion on the grid, and facilitating the development of new generation resources. Mr. Chambliss testified that RECB transmission projects are those MISO determines have a regional benefit. For RECB projects, MISO evaluates the projects, confirms the benefits support the cost, identifies the beneficiaries, and assigns costs accordingly. If the planned project is needed, but does not meet the criteria for RECB, then the costs are assigned to the local zone. Mr. Chambliss explained that Vectren South has four MISO-approved RECB projects, the costs of which are recovered under MISO Schedule 26. Pursuant to the Settlement Agreement approved in Cause No. 43111, RECB projects are treated as non-jurisdictional and Vectren South retains revenues recovered for them under Schedule 26. Accordingly, Vectren South has eliminated the RECB projects from its rate base and RECB revenues and expenses from its revenue requirement calculation. No party disagreed with this treatment.

Mr. Chambliss testified that Vectren South has also constructed or proposed projects that do not qualify for RECB treatment. He stated that these projects are needed for NERC compliance, service reliability, and/or customer load additions and include several 138/69 kV substations, 138 kV lines, and 69 kV lines. He further stated that Vectren South obtains non-RECB transmission revenues from MISO through MISO Attachment O, which is a formula rate approved by FERC. He testified that Vectren South updates Attachment O on an annual basis to update non-RECB transmission rate base as well as its other operating costs in order to establish just and reasonable wholesale rates.

Mr. Chambliss stated that non-RECB wholesale transmission revenues for the test year were \$4,635,770. He stated that these wholesale revenues are included as a credit to Vectren South's revenue requirement since the underlying in-service transmission assets are included in retail rate base in this case. Mr. Chambliss said going forward Vectren South will be exposed to variances in the annual amount of non-RECB revenue. He testified that because Vectren South will be investing in new non-RECB transmission facilities, it proposed to retain any increased revenues (rather than pass them back to retail customers in the MCRA) in order to provide some level of return on the new investment until the time of the next base rate case, consistent with the objectives of Attachment O.

Mr. Chambliss indicated that this approach, *i.e.* a revenue credit to base rates without any tracking of future results, is a change from the existing approach. He explained that in Vectren South's last rate case there was a mismatch between the retail rate base, which was valued as of October 31, 2006, and the plant used to determine Attachment O revenue, which was valued as of December 31, 2004. Therefore, Vectren South agreed to track actual revenue and pass any excess back to retail customers for the first year following the rate order in that Cause. Thereafter, a revised credit was provided to customers to better match the plant value included in retail rate base, with the Company retaining any revenue that exceeded the revised credit amount. According to Mr. Chambliss, even with growth in the level of investment used to calculate

Attachment O rates, reduced system usage can yield less revenue than previously received based on a smaller rate base. He therefore concluded that the revenue credit in this case appears representative of going forward revenues and a tracker is not appropriate.

OUCC Witness Catlin proposed a non-RECB transmission revenue credit of \$5,595,988, the amount of such revenues during the twelve months ended March 31, 2010. Mr. Catlin testified this more recent amount is a representative ongoing level. OUCC Witness Eckert disagreed with Vectren South's proposal to stop tracking non-RECB transmission revenues, while continuing to track MISO costs. First, he asserted that revenues and expenses would not be matched in the MCRA tracker. Second, he stated that Vectren South would be receiving the benefits of participation in MISO and part of its customers' benefits, which means that its customers will be receiving less than 100% of their benefits. Third, Vectren South's non-RECB investment is being included in its retail rate base. Mr. Eckert testified that if Vectren South wishes to maintain the MCRA tracker, it should be required to track both costs and revenues. Mr. Eckert therefore proposed that Vectren South track non-RECB transmission revenues as an offset to the MISO costs tracked through the MCRA. If the Commission chooses not to track non-RECB transmission revenues, Mr. Eckert recommended that it discontinue the MCRA tracker. Alternatively, if the Commission were to approve the continuation of the MCRA to track MISO costs, but not non-RECB transmission revenues, Mr. Eckert recommended that the Commission include \$5,595,988 of non-RECB transmission revenues as a base rate credit as recommended by Mr. Catlin. OUCC Witness David E. Dismukes contended failure to track non-RECB revenues would allow Vectren South to garner significant upside transmission revenues as power markets expand with little downside risk.

Industrial Group Witness Greg Meyer, a consultant with Brubaker & Associates, Inc., stated the test year level of non-RECB transmission revenues was abnormally low. Based upon his review of the historical trend, Mr. Meyer recommended that the test year level be increased by \$894,000 to \$ 5,529,770 which, according to Mr. Meyer's testimony, is the amount of non-RECB transmission revenues achieved in calendar year 2009.

In rebuttal, Vectren South agreed to increase the revenue credit to \$5,371,424, the actual adjusted level of revenues received for the twelve (12) months ended December 31, 2009, but opposed the OUCC's proposal to track non-RECB revenues. Mr. Chambliss stated that the 2009 amount supported by Mr. Meyer includes a MISO Attachment O "true up" that makes it an extremely accurate measure of the annual amount of non-RECB wholesale revenue based on transmission plant included in rate base. With respect to the need to retain non-RECB revenues above the base rate credit level, Mr. Chambliss testified that Vectren South's 2010 Attachment O filing reflects an increase of \$15,379,043 in non-RECB transmission plant that will not earn a return from retail customers until an order is approved in its next base rate case. Vectren South does earn through Attachment O a small wholesale return on its additional non-RECB investments of about 4.85%. But the revenue requirement related to plant increases allocated to retail load will not start to be recovered until Vectren South receives an order in its next base rate case. Mr. Chambliss asserted that if all non-RECB revenues in excess of the base rate credit are flowed back to customers as proposed by the OUCC, the MCRA would confiscate the return on new plant investment provided by Attachment O and credit retail customers with revenue attributable to plant that is not yet reflected in retail rates.

In response to Mr. Eckert's and Dr. Dismukes' concerns that Vectren South's retention of non-RECB revenues above the base level would unfairly deprive customers of increases due to greater use of transmission plant within the MISO footprint, Mr. Chambliss clarified that Vectren South would credit retail customers in the MCRA for revenue increases from MISO Schedules 1, 2, and 24 and from Alcoa, all of which are affected by volumetric changes. Mr. Chambliss said the Company's proposal is only to retain increases in non-RECB revenue from MISO Schedules 7, 8, and 9 above the proposed base rate level of \$3,333,682. He said these revenues link directly through Attachment O to Vectren South's required return on new plant not included in its retail rate base. Revenues from Schedules 1, 2, and 24 and Alcoa that exceed the base rate credit for such revenues of \$2,037,742 would be passed back in the MCRA. If these revenues fall short of the base rate credit, Vectren South will absorb the shortfall.

(b) Commission Findings. We find transmission revenues of \$5,371,424, the 2009 amount, should be included in Vectren South's pro forma revenues, thereby serving as a credit to the base rate revenue requirement. Vectren South and the Industrial Group both agree that this level is reasonable on a going forward basis. Mr. Chambliss' rebuttal testimony shows this level is closely related to the amount of transmission plant included in rate base. We find RECB investment revenues should continue to be treated as non-jurisdictional.

With respect to the distribution of MISO non-RECB revenues received by Vectren South, the Company South agreed to continue to pass through all transmission revenues from Schedules 1, 2, and 24, and from Alcoa, through the MCRA. Company Witness Chambliss proposed that any shortfall in these revenue amounts compared to base rate levels would be absorbed by Vectren South, so customers would receive the benefit of any increases without risk of reductions. With respect to MISO Attachment O revenues, also known as non-RECB transmission revenues (Schedules 7, 8, and 9), Vectren South proposed on rebuttal that the \$5,371,424 transmission revenue credit include \$3,333,683 of non-RECB transmission revenues. Currently, the Company flows through to its customers the actual amount of transmission revenue, inclusive of Schedules 1, 2, 7, 8, 9, 24, and Alcoa, up to \$6.1 million, and retains any additional amount. *Southern Ind. Gas and Elec. Co.*, Cause No. 43354 MCRA4, 2009 Ind. PUC LEXIS 186, at *12 (IURC May 27, 2009). The basis of this existing revenue treatment is that customers receive the benefit of revenues associated with the wholesale use of transmission plant investment included in retail rate base, as represented by the \$6.1 million revenue amount, while the Company retains any incremental wholesale transmission revenues it collects over \$6.1 million in order to earn some return on its incremental plant investment in excess of what was included in the retail rate base in its most recent rate case.

Vectren South Witness Chambliss provided an explanation of how Attachment O is designed to allow annual updates to transmission rate base and thereby reset wholesale transmission rates each year. Mr. Chambliss explained Vectren South's proposal in this case, as follows:

By isolating schedules 7, 8, and 9, which link directly to the amount of Vectren South-Electric's own revenue requirement as updated in Attachment O each year, Vectren South-Electric will obtain the wholesale return on its new plant that retail customers have not paid for because those transmission investments are not in retail rate base. All other non-RECB revenues will be tracked and "excess"

amounts above the amounts embedded in the base revenue credit will be passed through, dollar for dollar, to Vectren South-Electric's customers.

Chambliss Rebuttal at 6.

This Commission continues to directly participate in the development of the MISO markets, and reviews, and at times files formal comments on, all MISO tariff proposals and cost issues that impact Indiana's electric utilities. Retail customers pay costs and need to receive the corresponding benefits of MISO participation. Vectren South has proposed to provide customers with all transmission revenue it receives, with the limited exception of certain wholesale revenues that only exist due to post-rate case investment in new plant. Retail customers get the benefit of the new plant from a service perspective but will not pay for it until it is ultimately included in retail rate base in the next rate case. The Company's ability to retain incremental wholesale revenues in order to provide it with some level of return on the investment it has made since its last rate case is consistent with FERC policy to encourage improvement in transmission infrastructure. We find it is reasonable for Vectren South to retain wholesale revenues above the base level amount used to reduce retail rates that are shown to be received under Attachment O. All other MISO revenues will continue to be passed back to customers via the MCRA with the Company being at risk for shortfall.

(3) Wholesale Power Marketing Margins.

(a) **Evidence.** Vectren South excluded WPM revenues of \$23,479,396 and WPM fuel costs of \$13,511,239, which represented an estimate for the pro forma year ended June 30, 2010. Ms. Hardwick testified the decrease from the test year margin level of \$15,951,882 reflects the current state of the MISO energy market. She also testified that based on recent prices largely driven by a reduction in demand, she believes Vectren South has limited wholesale sales opportunity compared to prior periods. Ms. Hardwick explained that Vectren South proposes to continue the current approach of sharing 50/50 with retail customers all WPM margins above and below this adjusted base level of \$5,983,725 via the RCRA.

Mr. Jochum discussed the volatility of wholesale sales in recent years. He testified that the four primary factors driving volatility are: (1) outages affecting unit availability; (2) changes in retail and regional demand; (3) volatility in variable production costs; and (4) MISO's Locational Marginal Price ("LMP"), which dictates the ability to sell energy profitably into the market. Mr. Jochum testified that even small changes in LMP can greatly impact wholesale margin results.

Mr. Jochum testified the test year level for WPM margins of \$16 million reflects strong sales performance for six months that pre-dated the full effects of the economic recession. Moreover, in 2008, much like prior years, an average MISO day ahead LMP near \$50/MWh in most months allowed Vectren South's units to profitably sell energy into the market. However, in April to October of 2009, average day ahead prices barely exceeded \$25/MWh. As a result, for the latter part of the test year Vectren South had very limited sales. He stated that this trend of below normal LMPs has continued since the end of the test year and does not appear to be changing in the near term. He further stated that unless LMPs increase, MISO is unlikely to select Vectren South's units to run very frequently.

Mr. Jochum said for the twelve months ended June, 2010, Vectren South projected WPM margin results of \$5.98 million as reflected in Ms. Hardwick's exhibits. Given that volatility in the energy market has become even more dramatic, Mr. Jochum opined that there is an ongoing need to track actual WPM results as has been the case since the Order in Cause No. 43111. He noted that Vectren South's WPM results declined by over \$23 million in 2009 compared to 2008, and are projected to incrementally continue to decline by another \$3 million in 2010. He emphasized that Vectren South cannot exercise control over these sales since MISO controls unit dispatch decisions, which are largely a function of regional LMP. If LMP remains low, Mr. Jochum indicated that Vectren South will likely not increase its level of WPM sales but at the same time, customers will continue to benefit from that situation in the FAC from energy purchased at low LMP. If demand rises, LMP will likely rise, and the Company's WPM results should improve, providing both customers and Vectren South with upside opportunity.

OUCW Witness Wes R. Blakley, a Senior Utility Analyst for the OUCW, agreed there will always be some amount of volatility for wholesale sales and that current market price swings are further accentuated due to the economic downturn. However, he stated Vectren South's proposed base rate level of \$5.98 million for WPM margins is not an appropriate or accurate amount, as it was calculated utilizing an economically depressed projection. Mr. Blakley stated that recent poor economic conditions created the lower demand and lower LMP, which in turn resulted in lower WPM margins. Mr. Blakley expressed concern that should the economy improve, Vectren South's proposed base rate amount will not be representative. Mr. Blakley opined that \$10 million should be included in Vectren South's base rates for WPM margins. He stated that this level is comparable to Vectren South's current base rate amount and should be achievable in comparison to the test year amount and the five-year average. OUCW Witness Dismukes also expressed the opinion that wholesale prices could rebound and increase margins above the Company's forecast; although he said his analysis was not a specific forecast for power prices.

Regarding the sharing of WPM margins, Mr. Blakley agreed that Vectren South should continue to share 50/50 with customers WPM margins above the base rate amount. However, he argued that Vectren South should bear 100 percent of any shortfall below the base rate amount. Mr. Blakley asserted that this approach would continue to provide Vectren South with an incentive to operate its power plants efficiently and maximize investments, yet does not provide an unfair sharing arrangement for ratepayers.

Industrial Group Witness Meyer also agreed with Mr. Jochum that WPM margins have declined since 2008 and through the first quarter of 2010 and that the WPM sharing mechanism should be continued. However, Mr. Meyer recommended that Vectren South continue to use the WPM margin level of \$10.5 million that was established in Vectren South's last rate case. He opined that Vectren South's proposal to reduce these margins results in an abnormally low level of margins. He also recommended that the current form of the WPM tracker be modified to eliminate the sharing of WPM margin reductions below the base rate amount. Mr. Meyer stated that his proposal provides an incentive for Vectren South to make WPM sales to achieve the base rate level of margin revenues and is consistent with a tracker mechanism approved in a Stipulation and Settlement Agreement in I&M's most recent rate case.

In rebuttal, Ms. Hardwick, Mr. Jochum, and Mr. Chapman disagreed with the OUCW's

and Industrial Group's proposed adjustments to WPM margins. In his prefiled rebuttal testimony, Mr. Jochum testified actual results for the twelve months ended June, 2010, of \$6.8 million and the calendar year 2010 projected results of \$6.1 million (which include seven months of actual results) are consistent with the pro forma level proposed by Vectren South. Mr. Jochum said the OUCC and Industrial Group both ignore actual WPM results in 2009 and 2010 and assume factors contributing to the lower WPM margins will not continue in the future. He said Mr. Meyer provided no market analysis to support his proposed \$10.5 million amount and Mr. Blakley only refers generally to his belief that the economy will improve and to Dr. Dismukes' opinion. Dr. Dismukes contends increased demand for Vectren South's wholesale sales will increase when gas prices increase but provides no forecasts showing gas prices are rising.

Mr. Jochum testified that he examined current market conditions and reviewed current wholesale forecasts but none of these sources suggested 2009 and 2010 WPM results were unrepresentative of future expectations. He stated that there is no robust LMP increase and the Cinergy Hub forward price forecast through 2014 shows relatively flat LMP. Mr. Jochum also explained natural gas prices have declined because of the enormous rise in shale production, putting further downward prices on electricity. He also referenced a May, 2010 report from S&P predicting continued low natural gas prices and lower demand for energy which concluded that weak wholesale power prices were likely to endure. Fitch's Wholesale Power Market Update similarly forecasted weak wholesale power prices over the next few years and Energy Ventures Analysis projected prices will remain at current levels through 2011. Based on this data, Mr. Jochum concluded that LMP is unlikely to rise in the next couple of years. Moreover, Vectren South is also expecting to lose 270,000 MWhs of wholesale sales to municipal clients in the near future because the Indiana Municipal Power Agency ("IMPA") is bringing new generation on-line in 2011.

Mr. Jochum also opposed the OUCC's proposal to impose on Vectren South 100% of the downside risk of wholesale sales below the level set in base rates. He explained that sharing both WPM downside risk and upside opportunity is fair to customers and Vectren South. Mr. Jochum testified that the OUCC's proposal was not necessary to incent Vectren South to achieve WPM margins at the level established in base rates because Vectren South already incurs half of the loss associated with revenues below this level. He acknowledged that I&M had agreed to such an arrangement in a settlement, but noted that I&M presumably viewed the entire settlement as reasonable and gave-up some things to obtain the settlement. Mr. Jochum believed Duke Energy Indiana's litigated rate case was a more appropriate comparison. In that case, the Commission found that wholesale margins should be shared on a 50/50 basis, above and below the base rate level. *PSI Energy, Inc.*, 2004 Ind. PUC LEXIS 150, at *331-32.

Mr. Chapman disputed the position of the OUCC and Industrial Group that the economy will strongly rebound soon. He described the economy as highly uncertain with some economists predicting further deterioration and others predicting a mild and protracted recovery at best. Among sources cited by Mr. Chapman that predict a declining or tenuous economic climate were Federal Reserve Chairman Bernanke, the Commerce Department, the Indiana Auditor, and multiple articles from media sources. He also cited forecasts of a very long time for recovery by the Hamilton Project, the Federal Open Markets Committee, and Governor Daniels.

(b) Commission Findings. All parties agree that a mechanism to share WPM margins is appropriate for Vectren South. However, the parties disagree on two basic issues: 1) the appropriate level of WPM margins to include as a base rate credit; and 2) the sharing mechanism to account for actual wholesale power sales over or under the base amount included in rates.

Vectren South's generation fleet supports its service to retail customers and also, when available, can be dispatched by MISO to meet wholesale needs in the energy market. The ability to sell at wholesale is a function of a number of factors that include timing of unit outages, demand for electricity, competitiveness of gas generation, and LMP. Currently, Vectren South provides a wholesale margin credit to its base rates of \$10.5 million, and the Company and customers share in increases and decreases around that amount on a 50/50 basis.

All witnesses agreed that since 2008, LMP has declined significantly, a reflection of two key influences: the recession's impact on demand; and low natural gas prices that have allowed gas generation to become very competitive. From 2004 through 2008, Vectren South achieved WPM margins in excess of \$10 million per year, with a high of \$38 million in 2008. Vectren South's wholesale margin for the test year ended June 30, 2009 was \$16 million. However, during the pro forma period ending on June 30, 2010, results declined to \$6.8 million, and the Company projected annual results for 2010, inclusive of seven (7) months of known results, to be \$6.1 million. Ms. Hardwick indicated at the final hearing that the current expectation for calendar year 2010 was only \$5.4 million.

Although we rely upon an historic test year, in certain circumstances we can and do look at forward projections to determine a reasonable level of expense or revenue. All parties agree the nation is in the midst of an economic downturn, which has led to reduced demand for energy. However, most credible forecasts project at least moderately increased demand in the near future. Based upon the evidence, it is not prudent to set the WPM margin at the test year amount of \$16 million. Neither however, is it reasonable to set the WPM margin at its extreme low of \$6 million.

Like other revenues and expenses, the wholesale margin credit should be set at a level that reasonably represents likely results in the future. While the Company controls unit availability, it does not control LMP which all parties agreed would be the key driver of future results. OUCC Witness Dismukes and Vectren South Witness Medine both placed significant weight on the ongoing impact of low gas natural prices on LMP. Shale gas has substantially impacted gas prices such that LMP is likely to remain below historic levels in the near future. Vectren South's base rates currently include a WPM credit of \$10.5 million. In light of the evidence of the recent reduction in Vectren South's achieved wholesale power sales, we find a reduction in the WPM credit to \$7.5 million is reasonable.

In light of the uncertainty surrounding future wholesale performance, all parties supported continuation of sharing any increases in annual performance on a 50/50 basis between the Company and its customers. However, while recognizing this high level of market uncertainty, both the OUCC and the Industrial Group recommended that the Company bear all risks with respect to failure to achieve the base level amount. This would change the revenue tracking mechanism from a symmetrical sharing of performance risk and reward, to an

asymmetrical mechanism where customers have a guaranteed credit and benefit from increased wholesale revenues without any downside risk.

The existing mechanism benefits both customers and the Company and provides an incentive for the Company to sell into the market to at least meet, if not exceed, the base credit amount and thereby avoid a shortfall. The parties agree the reduction in LMP, and resulting decrease in Vectren South's revenues, is due primarily to the availability of low-cost natural gas and the reduced demand for energy. In light of this, and taking into account this period of market uncertainty, there is no basis to change the design of the sharing mechanism. Therefore, we find Vectren South shall continue to share shortfalls and excess revenues with customers on a 50/50 basis.

(4) Weather Normalization.

(a) Evidence. Vectren South's Witness Ms. Hardwick adjusted test year sales to reflect normal heating degree days and cooling degree days. She testified that normal weather was determined by reference to the 30 year normal degree days as published by the National Oceanic and Atmospheric Administration. Ms. Hardwick stated that this weather normalization adjustment is needed in order to remove the impact of abnormal test year weather on present and proposed rates. Her adjustment resulted in a decrease in test year margin of \$311,789.

OUCC Witness Catlin agreed that it is reasonable to adjust sales to reflect normal weather but proposed the use of an alternative methodology that Vectren South provided in discovery. This alternative approach calculated total base load by rate class as a whole rather than by rate step to eliminate anomalies between the calculated base load of electricity and monthly usage in a few of the rate steps. Mr. Catlin also eliminated \$46,915, the amount of sales that fell below the calculated base load for the Rate DGS class, from the weather normalization adjustment. The OUCC's adjustment results in a decrease in test year margin of \$264,874.

In rebuttal, Ms. Hardwick accepted Mr. Catlin's modifications to the weather normalization methodology. However, she explained that Mr. Catlin's exhibits did not capture the total impact because other revenue and fuel cost adjustments needed to be revised to incorporate the volume changes reflected in the weather normalization adjustment. Her rebuttal exhibits incorporated these additional changes.

(b) Commission Findings. We find it appropriate to normalize test year sales to eliminate the impact of abnormal weather that occurred during the test year. The OUCC proposed, and Vectren South accepted, modifications to Vectren South's initial normalization procedure to eliminate anomalies reflected in Vectren South's initial methodology. We accept the agreed upon methodology and find that Vectren South's test year revenues should be adjusted as proposed in Ms. Hardwick's rebuttal evidence. The result is a decrease in revenues of \$310,722 and a decrease in fuel costs of \$45,848 resulting in a change in margin of \$264,873. See Ex. MSH-R3, Adjustment A02R, p. 1, line 7.

(5) Large Customer Revenues.

(a) Evidence. Ms. Hardwick sponsored an adjustment to test year revenues

to reflect the impact of significant changes in its large customer operations. This adjustment reflected plant shutdowns, expansions and reductions. The aggregate impact of the adjustment was a decrease in the test year margin of \$8,377,477. This adjustment included eliminating revenue from ethanol plant customers (and related rate base) because of uncertainties about the ethanol business.

As previously discussed, OUCC Witness Catlin proposed to include ethanol infrastructure in rate base and ethanol margins in revenue because ethanol customer operations were ramping up. This adjustment resulted in an increase in revenues of \$3,075,097. Mr. Catlin also proposed to increase depreciation expense by \$155,754 to reflect depreciation expense associated with the infrastructure constructed by Vectren South to serve the ethanol plants.

In rebuttal, Ms. Hardwick generally agreed with the intent of the OUCC's adjustment, but disagreed with the amount used by Mr. Catlin. She stated that the amount proposed by the OUCC was provided by Vectren South in discovery and includes impacts of various rider mechanisms that are captured in other pro forma adjustments. She believed the more accurate approach is to multiply the kilowatt hour volumes by the tariff rates for Rate LP, thereby adjusting appropriately the rider mechanisms captured in other pro forma adjustments. Ms. Hardwick's modification increased revenue by \$1,239,449 and the cost of fuel by \$2,296,508.

(b) Commission Findings. We find that Mr. Catlin's proposed adjustment as modified in Ms. Hardwick's rebuttal testimony, is reasonable and should be accepted.

(6) Late Payment Fee Revenues.

(a) Evidence. OUCC Witness Catlin proposed an adjustment to test year revenue to reflect the relationship between late payment fee revenue and electric service revenue similar to Vectren South's uncollectibles expense adjustment. Mr. Catlin's adjustment was based on the three-year average ratio of late fees to electric revenue. The result was an increase in revenue of \$339,777. Mr. Catlin explained late payment fee revenue will increase as the result of any increase in retail rates that is allowed in this proceeding and this should be accounted for in determining the additional revenue to be derived from increases in the electric rates.

Ms. Hardwick accepted the intent behind Mr. Catlin's proposal to adjust late payment fees and the three-year ratio he used, but her adjustment was slightly different because it was based on Vectren South's proposed pro forma revenue. Ms. Hardwick's adjustment increased revenue by \$349,270.

(b) Commission Findings. We find that Mr. Catlin's proposed adjustment as modified in Ms. Hardwick's rebuttal testimony, is reasonable and should be accepted.

C. Fuel and Fuel Related Costs. Vectren South originally proposed to remove from base rates all fuel and fuel related costs trackable in the FAC and associated revenue taxes and to recover all such costs entirely through the FAC. The OUCC opposed that proposal and recommended that Vectren South continue to embed fuel costs in base rates and track changes from the base rate level in the FAC. In rebuttal, Vectren South withdrew its proposal but requested that base rate fuel costs be separately stated in each rate schedule for transparency purposes. We have included pro forma fuel costs in Vectren South's base rate revenue

requirement. As discussed below, we also approve identifying base rate fuel costs in the rate schedules.

D. Purchased Power Including MISO Day 1 and Day 2 Deferred Amortization.

(1) **Evidence.** In Cause No. 43111, the Commission approved the amortization of Vectren South's deferred MISO Day 1 and Day 2 costs over four years. The amortization period ends in August, 2011. To lessen the impact of the proposed rate increase in this case, Vectren South originally proposed to amortize the remaining balance of deferred MISO Day 1 and Day 2 over an additional five years. Vectren South's original calculation used the remaining balance as of June 30, 2010, the end of the pro forma period. This resulted in an increase of net margin of \$1,276,760 for Day 1 costs and \$3,072,998 for Day 2 costs.

OUCC Witness Catlin proposed that the revenue requirement reflect a five year amortization of the balance as of December 31, 2010. This calculation resulted in an increase of net margin of \$1,443,293 for Day 1 costs and \$3,473,824 for Day 2 costs. Mr. Catlin also said it would be appropriate to adjust the balance to reflect the actual effective date for the rates approved in this proceeding. Industrial Group Witness Meyer also supported calculating the amortization adjustment based on the balance on December 31, 2010, or, alternatively, the month preceding the issuance of the Commission's Order. In rebuttal, Ms. Hardwick indicated that she accepted Mr. Catlin's proposal.

(2) **Commission Findings.** In this Order, we set the cut-off for pro forma adjustments to the test year at June 30, 2010, with limited exceptions that were agreed to by the parties and approved by the Commission in its Prehearing Conference Order. Generally, we do not accept pro forma adjustments to the test year beyond the cut-off date. However, the Commission accepts the Parties' agreement regarding the amortization of the remaining balance of MISO Day 1 and Day 2 costs based upon the distinct character of the expense, namely that it is the re-amortization of a declining balance regulatory asset. In this unique circumstance, use of the most recently available balance is reasonable. Therefore, we accept Mr. Catlin's proposed adjustment based upon the balance on December 31, 2010, and we approve Vectren South's amortization of the remaining balance of MISO Day 1 and Day 2 costs. The result is an increase of the net margin of \$1,443,293 for Day 1 costs and \$3,473,824 for Day 2 costs. Upon completion of the amortization period, Vectren South shall notify the Commission and adjust its rates to eliminate the deferred cost amortization.

E. Operation and Maintenance Expense.

(1) **Labor Cost Adjustments.**

(a) **Evidence.** Ms. Hardwick calculated Vectren South's pro forma level of direct labor expense based on the actual number of employees (filled positions) as of June 30, 2009, and the level of wage increases, fringe benefits and payroll taxes expected to be in effect for the twelve months subsequent to the test year. Ms. Hardwick also sponsored an adjustment to reflect the expense of eleven incremental employees and contractor expenses primarily related to NERC compliance. She said that the positions are approved and most have been filled, or were expected to be filled, during the pro forma period. Ms. Hardwick's adjustments increased

labor expense for existing headcount by \$1,029,917 and for additional employees by \$1,203,989.

OUCW Witness Foster, limited Vectren South's pro forma labor calculation to actual employees as of March 31, 2010. To calculate the labor expense for each employee, Mr. Foster updated the annual salary, the amount allocated to O&M and the amount allocated to Vectren South as of March 31, 2010. Mr. Foster accepted Vectren South's pro forma amount for contractor expense associated with NERC compliance. Mr. Foster's resulting adjustment was \$1,373,426, a decrease of \$860,480 from the amount of Vectren South's combined adjustments.

Industrial Group Witness Meyer proposed that Vectren South's labor expense adjustment be reduced by the salary, fringe benefits and payroll taxes associated with four incremental employees who had not been hired as of February, 2010. His adjustment would reduce Vectren South's proposed adjustment by \$302,300.

In rebuttal, Ms. Hardwick accepted Mr. Foster's existing headcount adjustment except that the fringe benefit amount was understated because it did not include application of the non-productive loading rate to VUHI employees whose costs are allocated in part to Vectren South. She said this loading rate represented the cost of vacation, sick and holiday time. At the hearing, Mr. Foster agreed with Ms. Hardwick's modification to the fringe benefits amount. With respect to incremental positions, Ms. Hardwick testified that as of June 30, 2010, one additional position had been filled externally (CIP Security Manager) and one additional position was expected to be filled shortly (CIP Security IT). She revised Mr. Foster's adjustment to reflect these two incremental positions. The resulting change is a reduction to expense of \$1,266,116 from Vectren South's originally filed position and a reduction of \$62,127 for the test year amount.

Vectren South adopted Mr. Foster's position on the existing headcount adjustment, modified in a way that Mr. Foster accepted. Vectren South also largely accepted Mr. Foster's proposal on incremental positions modified only to include a position that had already been externally filled as of June 30, 2010, and another position expected to be filled shortly thereafter. Vectren South's proposal is an increase to test year labor expense of \$1,752,865 for existing headcount and a decrease to test year labor expense of \$62,127 for incremental positions.

(b) Commission Findings. The Commission finds the adjustments proposed by Vectren South on rebuttal to be reasonable with the exception of the CIP Security IT position, which Ms. Hardwick testified had not been filled as of the end of the pro forma period. Although Ms. Hardwick testified the position was expected to be filled shortly, no additional evidence confirmed this fact. The Commission finds it is not reasonable to include the incremental expense for a position that was not filled prior to the end of the pro forma period. The exclusion of this incremental expense results in a further decrease of \$22,240 from Vectren South's incremental positions adjustment. Therefore, we approve an increase to test year labor expense of \$1,752,865 for existing headcount and a decrease to test year labor expense of \$84,367 for incremental positions.

(2) Incentive Compensation.

(a) Vectren South's Evidence. Ms. Hardwick testified that Vectren South has designed a compensation structure to attract and retain employees. The key elements of

Vectren South's total compensation program include a combination of base salary, long-term performance-based compensation and annual (or short-term) performance-based compensation. Ms. Hardwick said that the combination of these elements is intended to provide market-based compensation at a target level of achievement. She indicated that having the utility's headquarters in Evansville, Indiana, makes it sometimes difficult to attract and retain the necessary talent to effectively run the organization since the utility must compete against larger cities. Moreover, given the aging workforce phenomenon and the need to attract experienced and skilled workers in all areas of the Company, Ms. Hardwick stated that it is important that Vectren South's compensation be part of a package that enables Vectren South to compete for employees. Even given that objective, Ms. Hardwick testified that Vectren South's current base salaries are generally below market based on a recent benchmarking analysis completed by Company consultants.

Ms. Hardwick discussed Vectren South's pro forma long-term and short-term performance-based compensation adjustment. She stated that the long-term compensation expense is based on the number of restricted stock units that are outstanding plus an estimated number of units expected to be granted effective January 1, 2010, and May 1, 2010. She said that the appropriate level of expense assumes a 5% return on Vectren South stock over an annual period, along with quarterly dividends. Ms. Hardwick noted that these assumptions are consistent with Vectren South's targeted shareholder return and generally consistent with historical share price performance. Her adjustment for long-term performance-based compensation is an increase to test year expenses of \$1,076,110.

With respect to Vectren South's annual compensation plan, Ms. Hardwick testified that the pro forma level reflects the performance targets for 2010 approved by Vectren Corporation's Board of Directors. The result is an increase of \$1,253,999 above the test year level which was below target due to lower financial performance. She stated that if the target is exceeded, the level of expense incurred over target will be borne by shareholders.

Ms. Hardwick then described the performance measures used to award annual performance-based compensation which include: (1) customer satisfaction, which is measured by equivalent availability of Vectren South's generation assets, surveys, and other tools; (2) safety measures; and (3) sound financial performance, which is necessary to attract capital to invest in Vectren South's business. Ms. Hardwick stated that based upon a 2009 benchmarking study performed by Vectren South's Human Resources organization and outside labor consultants, Vectren South's current base salaries were, on average, at 90% of market. For those same jobs, Ms. Hardwick stated that total cash compensation, which is the sum of base salary and target level incentive compensation, benchmarked at roughly the same 90% of market. She concluded that the level of overall compensation expense in the test year is below market, and that her proposed adjustments are necessary to simply move toward market.

Ms. Hardwick also sponsored an adjustment to test year deferred compensation expense. She stated that such deferrals are invested in various investment options, including phantom shares of Vectren South common stock. Ms. Hardwick's adjustment assumes a 5% return on investments over an annual period along with quarterly dividends on phantom Vectren South stock units. This adjustment results in an increase in test year operating expense of \$2,308,173, the size of which reflects the abnormal and significant negative investment returns experienced

during the test year.

(b) **OUCC's Evidence.** OUCC Witness Foster disagreed with Ms. Hardwick's proposed adjustments. He stated her use of an assumed 5.0% gain on a predicted stock price to quantify the cost of the long-term plan is not a suitable basis for a fixed, known, and measurable accounting adjustment as there has been extreme volatility in the stock market over the past 24 months. Mr. Foster testified Vectren stock closed at \$22.83 on June 2, 2010. Using the actual stock price with Petitioner's calculation results in a 4.9% loss rather than the 5% gain assumed by Petitioner.

Mr. Foster referred to Petitioner's workpapers, showing Vectren South's stock price as of June 30, 2008, was a near high and the Company experienced a 25% decline in stock price during the test year. Mr. Foster also opined the decline in Vectren's stock value may have been influenced by the collapse of the financial market and the recession. Mr. Foster therefore proposed to use a five-year average of actual long-term incentive compensation expense of \$0.9 million, which is \$880,660 less than Ms. Hardwick's proposed adjustment.

Mr. Foster also proposed to use a five-year average of actual short-term incentive compensation expense rather than Vectren South's target level. According to Mr. Foster, Vectren South has not consistently met its target level during the past five years and thus Vectren South's proposed level of expense would likely overstate revenue requirements. The result of Mr. Foster's approach was an increase of \$161,322 above the test year level, which is \$1,092,677 less than Ms. Harkwick's proposed adjustment.

(c) **Industrial Group's Evidence.** Industrial Group Witness Meyer recommended that the Commission disallow Vectren South's long-term incentive plan expense. He asserted that this expense is based solely on the achievement of financial goals that benefit Vectren South's shareholders, rather than its ratepayers. Therefore, according to Mr. Meyer, shareholders should bear the cost of this incentive plan.

With respect to Vectren South's annual or short-term plan, Mr. Meyer proposed to eliminate recovery of all of the incentive payments associated with the EPS financial measure. Mr. Meyer testified that he was opposed to the use of financial targets or EPS as a basis for the award of incentive payments because such targets may cause a reduction in the quality of service to customers and should not be a component of a properly constructed incentive plan for ratepayers to fund. Mr. Meyer expressed the opinion that criteria to be used for measurement of incentive plans could include safety, managing operations and maintenance ("O&M") expenses, transmission/distribution reliability, and customer service. Mr. Meyer cited three Missouri Public Service Commission ("Missouri PSC") orders in support of his position, and also discussed the Commission's 1996 Order in Cause No. 40003 and 2004 Order in Cause No. 42359. Mr. Meyer proposed the disallowance of \$2.2 million of incentive compensation relating to the EPS measure.

Mr. Meyer further proposed to limit the non-EPS based annual incentive compensation by the level of the average payout percentage for the past five years. He stated that in 2005 and 2007, Vectren South's annual incentive compensation payout exceeded the targeted level of expense, but in 2006, 2008, and 2009, Vectren South's annual incentive payments were below

the targeted level of expense. He believed that because Vectren South does not consistently incur incentive payments at the targeted level, it was appropriate to apply the percentage from the historical payments, 73.1%, to the test year incentive levels. This reduced annual incentive compensation expense by an additional \$256,000 resulting in a total reduction of \$2.5 million.

(d) Vectren South's Rebuttal Evidence. Mr. Benkert testified that Vectren South bases compensation levels and design, including base and incentive pay, on guidance from compensation experts. Vectren South's primary objective is to have compensation levels that are competitive with the marketplace. Mr. Benkert stated that Vectren South's annual compensation plans have been in existence since the formation of Vectren South. He explained that the compensation costs proposed to be included in rates were reasonable because the expenses were based on a base pay and target incentive payout level designed to be market competitive.

Mr. Benkert stated that Vectren South could not reduce its labor costs by eliminating or reducing incentive compensation because base pay would need to be increased to offset such elimination to ensure that Vectren South's total compensation package was competitive with market rates and sufficient to attract and retain qualified employees. Consequently, eliminating incentive pay would result in the same costs but loss of the incentive for employees to focus on reliability, safety, customer service, and O&M expenses.

Mr. Benkert stated that Vectren South uses both non-financial and financial factors in determining an employee's compensation under the annual incentive plan. Non-financial measures include: safety as measured by OSHA recordables; customer satisfaction, inclusive of call center service levels; and equivalent availability, which directly measures the availability for use of Vectren South's generating assets. The financial-based measure is EPS, which, Mr. Benkert explained, is impacted by cost control and efficiency of O&M spending for many departments. He rejected Mr. Meyer's assertion that EPS has no direct correlation to ratepayer benefit. Mr. Benkert described both direct and indirect benefits from an EPS goal. Solid EPS performance aids in capital attraction by making Vectren South an attractive issuer and lowering debt costs—savings ultimately inure to ratepayers. EPS targets also encourage lower and more efficient O&M costs and capital expenditures resulting in delayed requests for rate increases and lower revenue requirements for O&M expense, depreciation, and financing costs when rates are revised.

Mr. Benkert sponsored Petitioner's Exhibits JAB-R2 and JAB-R3 summarizing the history of annual incentive goal scoring during the Vectren Corporation years. The exhibits demonstrate that annual incentives have averaged near target since inception, although particular years have been above and below target. Mr. Benkert also explained that Petitioner's Exhibit JAB-R3 refuted Mr. Meyer's concern that EPS measures might actually cause a reduction in service quality because it demonstrates that over time, the operational measures have performed better than the financial measures.

Mr. Benkert also disagreed with Mr. Meyer's contention that the long-term incentive program is based solely on achievement of financial goals that benefit shareholders rather than ratepayers. He explained that the financial measures in the long-term incentive program (ROE and total shareholder return over a three-year period as compared to a group of industry peer group companies) bring the same direct benefits to ratepayers as the EPS measure in the annual

incentive plan. Mr. Benkert said ROE is an appropriate benchmark for a rate regulated company and Moody's uses it in its utility credit rating determinations. Meeting these measures can make Vectren South an attractive company to investors with increased access to and better rates in the capital markets. These benefits ultimately inure to ratepayers.

Mr. Benkert addressed OUCC Witness Foster's assertion that including incentive compensation cost in rates at target levels likely overstates expense based on Vectren South's 5-year actual historical payout. Mr. Benkert noted that the average since the creation of Vectren Corporation had been very close to target levels and there have been years of payments in excess of target that have been borne by shareholders. With respect to operating measures in particular, payouts have generally exceeded targets, again funded by shareholders, which demonstrates that behavior is balanced from a customer perspective. He emphasized that the below target achievement on the financial goals in the past 5 years has been due to financial underperformance. The rate case should address the financial underperformance, rendering this an inadequate projection of ongoing operations. Further, Mr. Benkert pointed out it is unreasonable to deliberately set rates to under recover labor costs merely because the Company has underperformed financially in the recent past.

Vectren South engaged Jonathan D. Weinstein, the Eastern Division Leader for Executive Compensation with Towers Watson, to assess the prevalence of annual incentive and long-term incentive compensation plans in the utility industry and to compare Vectren South's compensation levels and plan metrics to market practices. Towers Watson relied on proprietary databases on incentive compensation it has developed to conduct the review.

Mr. Weinstein explained that Towers Watson compared Vectren South's compensation to a national sample of all 59 investor-owned utilities in Towers Watson's databases ("National Sample") and a peer group of the 23 utilities that are both among the 29 peer utilities used by Vectren South for compensation benchmarking and participants in Towers Watson's 2009 compensation database ("Peer Group"). Towers Watson found that 100% of the companies in the Peer Group and the National Sample maintain a formal annual incentive plan for at least a portion of their employee population. While eligibility decreases somewhat at lower levels of an organization, Mr. Weinstein testified that all of the individual executive positions in the Peer Group and 99% of the individual executive positions in the National Sample were eligible for annual incentives. Ninety-three percent of the individuals in exempt level positions were eligible for annual incentives in both the Peer Group and the National Sample.

Mr. Weinstein compared Vectren South's 2009 base salary, target annual incentive compensation, and target total cash compensation (base salary plus target annual incentive compensation) to the market measures. He explained that pay levels for executive and exempt positions should be within 15% of market to be in competitive range. Based on this criteria, Mr. Weinstein concluded that Vectren South needs to offer annual incentive opportunities in order to provide a competitive compensation package. Absent incentive compensation, Vectren South's compensation for executives would be 38% to 39% below the Peer Group and 40% to 42% below the National Sample. For non-executive exempt positions, Vectren South would be 18% below the Peer Group and 21% below the National Sample. Mr. Weinstein acknowledged that Vectren South could stay competitive by raising its base pay levels to the market total cash compensation level instead of providing annual incentive opportunities to stay competitive. But

this would result in a higher level of fixed costs and eliminate the incentive for employees to continue performing. Towers Watson found that Vectren South's annual incentive opportunities for executives are lower than the market levels and for non-executive exempt positions are very close to the market levels. Vectren South's total cash compensation levels are within but toward the low-end of the competitive range.

Mr. Weinstein also reviewed Tower Watson's conclusions about the prevalence of long-term incentive mechanisms. Towers Watson found that all of the companies (100%) in both the Peer Group and National Sample maintain a formal long-term incentive plan for at least some portion of their executive population. On average, 96% of the individual executive positions in the Peer Group and 95% of the individual executive positions in the National Sample are eligible for long-term compensation. Vectren South's long-term incentive compensation level for executive positions was below the Peer Group median and National Sample average and median.

Mr. Weinstein concluded that Vectren South's total direct compensation levels (base salary, target annual incentive compensation and target long-term compensation) are toward the low-end or even below the competitive range as compared to the Peer Group and the National Sample. If Vectren South did not offer annual and long-term incentive compensation, Vectren South's compensation would be 58% to 63% below the Peer Group and National Sample. Mr. Weinstein concluded that Vectren South's base salaries, without incentives, are insufficient to be competitive.

Mr. Weinstein testified that incentive compensation is a standard component of the compensation package in the utility industry and plays a critical role in focusing employees on key organizational and business unit goals. Non-financial measures are designed to focus employees on achieving superior operational, safety and customer service results, while financial measures help focus employees on achieving those results in a cost effective manner. He stated that financially strong companies have greater access to credit markets and a lower cost of capital, which benefits ratepayers through a lower cost structure and ultimately lower rates. Mr. Weinstein noted that combining financial and non-financial incentives ensures that excellence in one area is not achieved at the expense of other areas.

Mr. Weinstein explained that Towers Watson's analysis revealed that it is very common for utilities to use financial goals in evaluating performance under annual incentive plans. Among the 25 largest utilities, all use financial performance measures in their incentive pay. Mr. Weinstein noted that 72% of these utilities use EPS as the financial metric for compensation.

In rebuttal, Ms. Hardwick reiterated that Vectren South based its incentive compensation adjustment on target levels. She said the OUCC's use of a five-year average is not based on any compensation theory and fails to recognize the long-standing compensation program design employed by Vectren South, a design that has been presented and accepted many times before this Commission.

Ms. Hardwick explained that the total compensation program is reviewed regularly by Vectren Corporation's Board of Directors in order to determine the appropriate combination and payout levels. These incentive mechanisms, combined, are designed to provide market-based compensation at a target level of achievement to attract and retain qualified employees.

Ms. Hardwick explained that the unadjusted test year reflects below target performance, primarily driven by lower financial performance. Setting the expense at the target level, Ms. Hardwick testified, ensures that rates are based on market compensation for employees—no more and no less. She acknowledged that there will be instances where target is not achieved but there will also be instances when the target is exceeded. She noted that when target is exceeded, shareholders bear the cost of incentives over target levels.

(e) **Commission Findings.** The Commission recognizes the value of incentive compensation plans as part of an overall compensation package to attract and retain qualified personnel. The criteria for the recovery of incentive compensation plan costs is well established. We will allow recovery in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. *N. Ind. Pub. Serv. Co.*, 2010 Ind. PUC LEXIS 294, at *195-96.

While Vectren South's annual incentive compensation plan incorporates financial performance measures (EPS), it also includes non-financial measures such as safety, customer satisfaction (inclusive of call center service levels), and generation unit availability. Industrial Group Witness Meyer expressed the opinion that incentive compensation plans should not include financial measures and proposed disallowance of incentive plan costs to the extent they relate to them on the ground that they only benefit shareholders. In Cause No. 43680, we approved cost recovery for an incentive compensation program that included significant components dependent upon Indiana-American reaching its financial goals as well as "operational and individual goals, which incent employees to aid Indiana American in improving its capabilities and service through increased efficiency and reliability." *Indiana-American Water Co.*, 2010 Ind. PUC LEXIS 155, at *219. Similarly here, we find Vectren South's incentive compensation plan sufficiently meets the requirements of the first criterion.

In addition, the evidence shows Vectren South's Human Resource Department evaluates the competitiveness of Vectren South's compensation package and a package is developed that is market competitive. This conclusion was confirmed by Towers Watson's analysis of the compensation package. The Towers Watson study showed Vectren South's incentive compensation (both annual and long-term) total cash compensation (base plus annual incentive) and total direct compensation (base plus annual incentive plus long-term incentive) are all at the low end of the market competitive range as established by peer companies and a broader national sample. Therefore, we find that Vectren South's incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce.

Finally, we note that Vectren South is seeking funding for its incentive compensation plan up to the board approved target level. The evidence shows that shareholders bear the expense of incentive compensation in excess of the target level. As shown by Petitioner's Exhibit JAB-R2, this is not an unusual occurrence. In the last ten years, payments have exceeded target in a number of years by as much as 190%. In those cases, the shareholders absorbed the excess. Thus, we find the shareholders are allocated part of the Company's incentive compensation costs.

For these reasons, we approve Vectren South's proposed incentive compensation adjustments.

(3) Pension and Postretirement Medical Expenses. In its Case-In-Chief, Vectren South proposed adjustments to increase pension expense and postretirement medical expense based on estimates provided by the Company's actuary. OUCC Witness Foster updated those adjustments to reflect more recent 2010 Plan Year actuarial valuations. In rebuttal, Ms. Hardwick agreed with Mr. Foster's adjustment, noting that it was based on information not available when the Company's Case-In-Chief was filed. We find Mr. Foster's proposed adjustment should be accepted which results in a decrease in pension expense of \$68,661 and an increase postretirement medical benefits expense of \$120,520 above test year levels.

(4) Ash Borer Expense.

(a) Vectren South's Evidence. Mr. Schach testified regarding Vectren South's ongoing reliability initiatives, including steps to properly deal with the Emerald Ash Borer's ("EAB") destruction of ash trees in Vectren South's service territory. Mr. Schach explained that the EAB is a non-native wood-boring pest that is fatal to 100% of all North American species of ash larger than two (2) inches in diameter. Mr. Schach explained EAB damage impacts reliability because dead ash trees create a significant risk of falling and damaging electric distribution and transmission lines. Ash trees may reach over sixty feet tall, so even dead trees seemingly a safe distance from the electric lines will pose a threat. He stated that EABs were first spotted in early 2002 in southeastern Michigan and since then over 50 million ash trees have been killed in that state alone. Mr. Schach indicated that more recently, EABs have spread to Dubois County, Indiana, which is part of Vectren South's service territory. He said that the Indiana Department of Natural Resources ("IDNR") estimates that approximately 6% of all the trees in Vectren South's service territory are ash trees.

Mr. Schach testified that the IDNR and the U.S. Department of Agriculture ("USDA") have adopted rules mandating containment and quarantine practices because efforts to eradicate EABs have proven to be unsuccessful. Compliance with new rules promulgated by IDNR will require all electric line clearance contractors to have their chippers certified by the IDNR and will require those contractors to remove EAB diseased trees and debris and chip up the brush and material into chips not larger than one inch in diameter. He said that Vectren South has worked with the IDNR to obtain compliance for 12 Certified Ash Reveal Sites to be used by Vectren South's contractors to quarantine ash debris that cannot be left on the premise or chipped to regulatory specifications. He stated that Vectren South anticipates that it will incur incremental expenses of \$3,337,950 over the next 5 years, or \$667,590 annually, to comply with new rules adopted to stem the spread of EAB in Indiana. Mr. Schach stated that these incremental expenses reflect the additional work required to trim or remove ash trees located near electric facilities and dispose of the infected vegetation in accordance with the handling and quarantine requirements. He further stated that Vectren South plans a proactive initiative of removal by cycling through its circuits over a period of five years during which it will clear ash trees in a manner that provides safe clearances from the electric lines.

(b) OUCC's Evidence. OUCC Witness Hand recommended the Commission deny the proposed \$3.3 million EAB adjustment because the adjustment is not

fixed, known, or measurable. He claimed that Mr. Schach admitted that Vectren South had not incurred actual additional costs due to EAB. He criticized both the estimated number of ash trees to be removed and the estimated removal cost per tree, claiming both were overstated. Mr. Hand did not believe that averaging the number of trees per mile for seventeen circuits produced results representative of the average number of trees per mile because the respective weight of each data element is not considered. He offered an alternative calculation by dividing the sum of the total trees by the sum of the total miles to arrive at an estimate of 53.14 trees per mile.

Mr. Hand also disagreed with Vectren South's estimated removal costs of \$280 per tree. Based on documents obtained from Vectren South and IDNR, Mr. Hand stated that although only about 1.3% of the ash trees in Vectren South's service territory are 21 inches or larger in diameter, this is the diameter Vectren South used to estimate its \$280 costs for each of the estimated 16,500 ash trees to be removed. In contrast, he said that 80.3% of the ash trees in the Vectren South service territory counties are less than 5 inches in diameter, which according to Vectren South's internal reports would cost about \$7 per tree to remove. Mr. Hand noted that once the trees are removed, they would not require future trimming, saving Vectren South an estimated \$219,000 per year.

Mr. Hand rejected Vectren South's assertions that EAB will increase risks to utility lines and potentially reduce reliability. Mr. Hand explained how EAB tunnels in the growth layer around the tree just under the bark. Mr. Hand further explained that unlike trees killed by diseases or insects that become hollowed out or rotted, an EAB-infested ash tree's roots continue to survive and the trunk remains structurally intact. However, because the EAB tunnels prevent water and nutrients from reaching the upper branches and treetop, growth is slowed. Trees can die after three to four years of heavy infestation. Mr. Hand testified that the resulting slower than normal growth of the tree and the loss of its leaves actually makes the tree less of a risk to negatively impact utility lines. He stated that Vectren South should be able to sufficiently address any infestation by following appropriate vegetation management practices.

(c) Vectren South's Rebuttal Evidence. Mr. Schach responded to Mr. Hand's criticisms of Vectren South's calculation of the adjustment for EAB related expenses. He noted that Vectren South is already addressing issues related to EAB infestation by adopting the USDA guidelines for handling EAB in an area that has been quarantined, obtained IDNR approval for storing ash tree chips in twelve sites throughout its service territory, engaged a line clearance contractor with IDNR certified chippers to assist in handling EAB infested ash trees and performed preliminary planning on twelve circuits to assess the number, type, and size of trees that will need to be addressed. Mr. Schach acknowledged that Vectren South is focusing its efforts on educating its customers about the EAB problem and assessing, planning, and preparing its response. He testified, however, that assuming the EAB's progression continues at its current pace, Vectren South will need to implement its removal and trimming process in the near future.

Mr. Schach clarified that additional expenses attributable to EAB infestation are an incremental cost of ongoing vegetation management and that test year vegetation management expense will not be sufficient to continue the planned trimming cycle and bear the expense of procedures necessary to address EAB. He committed to report expenditures on vegetation management and to demonstrate through those reports that Vectren South is using the full allotment of funds, inclusive of the EAB adjustment, for vegetation management. If the EAB

infestation is slower than projected, Mr. Schach committed Vectren South to spend the money to maintain or even exceed its trimming cycle. Absent the adjustment, Mr. Schach explained that the costs to deal with EAB will deplete Vectren South's overall vegetation management budget.

Vectren South accepted Mr. Hand's alternative method of determining the average trees per mile estimate. Mr. Schach did not accept the OUCC's analysis of the number of trees removed and the estimated removal cost. The IDNR Forest Inventory Analysis relied upon by OUCC Witness Hand summarized the stock of ash trees in forested areas, not the urban areas and roadsides where Vectren South's infrastructure is typically located. While Vectren South originally relied upon its 2009 tree count information to determine its adjustment, Mr. Schach presented a consultant's 2010 preliminary plan assessing the number, type, and size of trees implemented to obtain data on ash trees so that the cost to remove ash trees can be more accurately estimated. The consultant's report supports the total tree count resulting from Mr. Hand's methodology results in an estimate of 212,000 total trees. The report found that the actual tree population encountered as a percentage of total tree count is seven percent instead of the original estimate of six percent, resulting in an estimate of 14,840 ash trees. Mr. Schach explained that the report also allowed Vectren South to break down the total estimate of ash trees into two size ranges and reflect the cost differences in removing various sizes of trees. The detailed report caused Mr. Schach to reduce the requested adjustment associated EAB maintenance to \$2,025,800 over the five (5) year period, or \$405,160 per year.

Mr. Schach also rejected Mr. Hand's assertion that an EAB infestation would actually lower expenses. He explained that ash trees can grow as high as 60 feet tall and that falling limbs or treetops from the taller trees located outside the right-of-way jeopardize Vectren South's infrastructure and are likely to result in unscheduled maintenance work. Mr. Schach estimated the additional cost of unscheduled work attributable to EAB to represent about \$12,390 annually. Any potential future savings resulting from the EAB efforts will not occur during the period the proposed rates are projected to be in place, Mr. Schach explained. Moreover, other trees and vegetation will grow to replace the ash trees, minimizing any future savings Vectren South might recover.

After accepting Mr. Hand's methodology for estimating the average trees per circuit mile and incorporating the results of the consultant's 2010 analysis of ash trees within Vectren South's right-of-way, Mr. Schach revised the proposed EAB adjustment to \$417,550 annually.

(d) Commission Findings. All parties agree that Emerald Ash Borers have been found within Indiana, that they damage and eventually kill ash trees, and that one of the counties in Vectren South's service area has been identified as an EAB quarantined county. However, the parties disagree about both the derivation of the company's adjustment, and ultimately, the idea that EAB poses a significantly increased risk to Vectren South's system reliability.

EAB damages and kills ash trees. Dead trees close to electric distribution lines are more likely to fall on those lines, risking service interruptions. IDNR has adopted regulations regarding EAB ash tree disposal. Mr. Schach explained that Vectren South has already incurred costs to obtain approval of twelve sites throughout its service territory to dispose of debris, engaged a line clearance contractor with IDNR certified chippers and engaged a contractor to

conduct a preliminary plan for the response. While accepting Mr. Hand's weighted average method for estimating the number of trees to be removed and reducing its original annual revenue requirement request by more than one-third (from approximately \$668,000 to approximately \$418,000 annually, or approximately \$2.087M over five years), Mr. Schach cautioned that EAB expense was incremental and without it, Vectren South's existing Vegetation Management budget would not be sufficient.

While Vectren South presented some evidence in support of its request, there is significant evidence that the Company failed to put forth for our consideration. There is no evidence before us that there is any federal, state, or local requirement that mandates the removal of ash trees. There is no evidence demonstrating that ash trees affected by EAB have caused any actual increased system reliability risk for any electric utility, located in Indiana or elsewhere. There was no explanation as to why dead ash trees outside the right-of-way but within striking distance of utility lines pose any greater risk to Vectren South's system than similarly situated dead trees of another species.

In addition, we are not persuaded by the Company's claim that without these additional funds, its existing Vegetation Management budget would be insufficient. It is less expensive for Vectren South to remove a tree than to trim it, and once removed, the Company will not incur additional trimming costs. Regarding the trees themselves, Mr. Hand's testimony explains that since EAB does not affect the roots or trunk of the tree, affected ash are less susceptible to falling than other infected trees suffering from root deterioration or trunk hollowing/rot. Further, because the EAB ash trees suffer first from leaf loss, they are less susceptible to being blown over. Further, as water and nutrients are less able to reach the treetop and limbs, EAB affected ash will grow at a slower than normal rate, posing even less of a risk of horizontal encroachment from the side or vertical encroachment from below.

Having considered all of the evidence, we find that Vectren South has failed to demonstrate that it requires additional funds for an EAB infestation program beyond its regular appropriate vegetation management practices. We find further that there is insufficient evidence to support Vectren South's claim that EAB will pose a significant increased risk to system reliability. As such, Vectren South's proposed EAB adjustment is disallowed.

(5) Credit Facility Fees.

(a) **Evidence.** In its Case-In-Chief, Vectren South proposed an adjustment to increase its test year expenses by \$867,387 to reflect the estimated costs of a new short-term credit facility to replace the existing 5-year facility that was scheduled to expire in November, 2010. Vectren South Witness Goocher explained that the recent financial crisis has caused bank credit to be very constrained, which has adversely affected the availability, tenor, and cost of credit facilities. Mr. Goocher quoted from a number of rating agency reports issued in January, March, and July, 2009, which projected shorter tenors and significantly higher prices for credit facilities than in the past. Mr. Goocher said the amount of the Company's adjustment was based on discussions with its lead credit facility banks as to the expected pricing levels for the Company's new credit facility.

OUCC Witness Catlin proposed to remove this adjustment as he believed the expenses

are expected to be incurred outside of the pro forma period ending June 30, 2010, and the costs are not fixed, known, and measurable.

In rebuttal, Mr. Goocher stated that all of the major components of the increased credit facility costs have now been set for the next three years and thus should be considered as fixed, known and measurable in this case. He sponsored a revised adjustment to reflect the actual costs which reduced the adjustment from \$867,387 to \$447,105. The revised adjustment decreased the expected size of the credit facility obtained from \$400 million to \$350 million and used the actual costs of the credit facility, which decreased somewhat from the previous indicative pricing levels. Mr. Goocher said that these actual increased credit facility costs are now agreed to by all parties, firm commitments were signed on August 18, 2010, and the new credit agreement was filed with the Securities and Exchange Commission on August 19, 2010.

(b) Commission Findings. The evidence demonstrates that the pricing and terms of the new 3-year agreement have been agreed to and firm commitments have been executed by all parties to the credit agreement. While, it is true that the written commitments for the new agreement were not executed until after June 30, 2010, steps were being taken in anticipation of obtaining a new agreement several months earlier, as shown by Mr. Goocher's testimony. This combined with our preference to use a determinate amount as opposed to an estimated amount leads us to accept Vectren South's proposal. Accordingly, we find the Company's adjustment is sufficiently fixed, known, and measurable to be used for ratemaking purposes in this proceeding, and we approve Vectren South's \$447,105 rebuttal adjustment.

(6) Rate Case Expense. Vectren South proposed to amortize the estimated costs of the current rate case over a five year period. No parties opposed this amortization period. OUCC Witness Catlin revised the adjustment to reflect updated cost estimates provided in discovery. In rebuttal, Ms. Hardwick provided a further update to this adjustment. The Commission accepts the adjustment as presented in Vectren South's rebuttal filing as the most up to date. This results in a decrease in rate case amortization expense of \$135,751 below the test year level.

(7) Other Expense Adjustments. In rebuttal, Vectren South Witness Hardwick accepted the OUCC's proposal to eliminate the Company's deferred compensation adjustment. She also accepted the OUCC's proposed adjustments for gypsum disposal expense (to reflect a recently signed contract) and emission allowance expense (as recommended by OUCC Witness Armstrong). We accept the OUCC's position on these adjustments. Vectren South's and the OUCC's proposed adjustments for the Asset Charge differed only with respect to the applied rate of return. We have determined this adjustment based on the rate of return of 7.29% that we found reasonable above.

F. Depreciation and Amortization Expense.

(1) Blackfoot Landfill Gas Generating Station. Vectren South Witness Hardwick sponsored a pro forma level of depreciation expense based on utility plant balances included in rate base and the applicable depreciation rates approved in the last Vectren South electric base rate proceeding. She added there have been no significant changes in the operation of the assets, or the lives of assets in service, since the prior depreciation study, and the assets

added have been generally similar to assets currently in service. Ms. Hardwick said that the only exception to this is the addition of the Blackfoot Landfill Gas Generating Station Investment. She explained that the Commission's Order in Cause No. 43577 granted Vectren South a depreciable life on this asset of 20 years, or an annual rate of 5.0%, but indicated that this rate would be subject to review in Vectren South's next electric base rate case. Consistent with that Order, Ms. Hardwick proposed that the annual depreciation rate be lowered to 3.7% to capture an estimated useful life of 25 years, offset slightly by a net salvage amount to reflect the expected removal of these assets at the end of the useful life. No party disagreed with this proposal and we approve this change to the depreciation rate applicable to the Blackfoot Station.

(2) **Infrastructure Serving Ethanol Customers.** As discussed above, we have included in pro forma depreciation expense, depreciation on infrastructure serving ethanol customers consistent with our finding that it should be included in rate base.

(3) **Deferred DSM Costs.** Ms. Hardwick made an adjustment to amortization expense for deferred DSM costs. She explained that Vectren South is currently amortizing two deferred balances related to historical DSM costs – pre-1994 deferred expenses and post-1993 deferred expenses. She said that the pre-1994 balances will be completely amortized in June 2010, and her pro forma adjustment captures the expiration of the amortization. With respect to the post-1993 deferred DSM costs, Ms. Hardwick stated that pursuant to Vectren South's last electric rate case, those costs would be fully amortized in August 2012. However, to help lessen the impact of the base rate increase proposed in this case, Vectren South proposed to amortize the expected June 30, 2010 balance over five years, extending the amortization period by roughly three years. She stated that her pro forma adjustment, which reduced test year level of DSM Deferred Amortization by \$3,643,167, captures the impact of this change.

Industrial Group Witness Meyer agreed with Vectren South's proposal to extend the amortization period for the deferred DSM costs but proposed that the new amortization be calculated from the unamortized balance as of December 31, 2010, which he considered to be a reasonable estimate of the date when new rates from this case will be implemented. In rebuttal, Ms. Hardwick agreed to Mr. Meyer's adjustment, which results in a reduction to test year expenses of \$4,211,205.

We find that extending the amortization period of post-1993 deferred DSM costs by an additional three years is an acceptable way of minimizing the rate impact on customers. Similar to our treatment of the MISO Day 1 and Day 2 costs, the Commission finds the distinct character of the expense, namely that it is the re-amortization of a declining balance regulatory asset, merits use of the most recently available balance. Therefore, we accept Mr. Meyer's proposed adjustment based upon the balance on December 31, 2010, and we approve Vectren South's amortization of the remaining balance of deferred DSM costs. Upon completion of the amortization period, Vectren South shall notify the Commission and adjust its rates to eliminate the deferred cost amortization.

G. Tax Expense. In her supplemental direct testimony, Ms. Hardwick submitted a revised tax expense calculation reflecting the March, 2010 federal Health Care Bill. She explained that this legislation eliminated the exclusion from taxable income of the federal subsidy to employers providing retiree prescription drug coverage at least equivalent to Medicare

Part D coverage. Vectren South proposes to amortize the deferred tax liability of \$2,168,890 associated with this change over five years, with \$433,778 reflected in its revenue requirement in this proceeding. No party disagreed with the Company's amortization proposal and we find it should be approved.

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

<u>Description</u>	<u>Amount</u>
Operating Revenue	\$ 562,828,667
Fuel and Purchased Power	<u>226,197,159</u>
Gross Margin	\$ 336,631,508
Operation & Maintenance Expenses	\$ 131,552,292
Asset Charge	11,196,300
Depreciation and Amortization Expense	73,998,921
Income Taxes	26,664,461
Taxes Other Than Income	<u>15,456,353</u>
Total Operating Expenses	\$ <u>258,868,327</u>
Net Operating Income	<u>\$ 77,763,181</u>

In summary, we find that with appropriate adjustments for ratemaking purposes, Vectren South's annual net operating income under its present rates for electric utility service would be \$77,763,181, which represents a rate of return of 3.74% on its fair value rate base of \$2,079,535,940. We find that this opportunity is insufficient to represent a reasonable return.

10. Authorized Revenue Requirement. On the basis of the evidence presented in these proceedings, we find that Vectren South should be authorized to increase its rates and charges for electric utility service to produce net operating income of \$94,450,297 as follows:

<u>Description</u>	<u>Amount</u>
Operating Revenue	\$ 591,442,340
Fuel and Purchased Power	<u>226,197,159</u>

Gross Margin	\$ 365,245,181
Operation & Maintenance Expenses	\$ 142,867,766
Depreciation and Amortization Expense	73,998,921
Income Taxes	38,072,920
Taxes Other Than Income	<u>15,855,276</u>
Total Operating Expenses	\$ <u>270,794,883</u>
Net Operating Income	\$ <u>94,450,298</u>

11. Revenue Allocation.

A. Retail Cost of Service Study. Vectren South engaged Kerry A. Heid, an independent rate consultant, to prepare a retail cost of service study (“COSS”). Mr. Heid’s COSS was 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 June 30, 2009. Mr. Heid used the traditional cost of service approach of cost functionalization, classification, and allocation to customer classes.

The parties disagreed on the following aspects of the COSS:

(1) Allocation of Production and Transmission Costs.

(a) Vectren South’s Evidence. Mr. Heid classified all production and transmission plant costs as demand-related and allocated those costs to the rate schedules based on the four-month average of the coincident system peaks in June, July, August, and September (“4 CP method”). Mr. Heid testified that the Commission has approved the 4 CP method for allocating production plant for Vectren South since at least the 1970’s. Mr. Heid stated that the 4 CP method gives appropriate recognition to the system’s peak season because the four month period of June through September is consistently and significantly higher in load than the balance of the year. He noted the Commission in previous rate orders expressly approved the Company’s use of the 4 CP method for production plant, recognizing that it was well supported by experts in the field, consistent with the Company’s prior studies and supported by the Company’s summer peaking load pattern.

Mr. Heid also noted that FERC precedent supported use of a 4 CP methodology for assigning Vectren South’s production plant costs. FERC has held that the use of a 12 CP methodology (reflecting the coincident peaks for the twelve months of the year) should be used when a utility’s system demand curve is relatively flat. Mr. Heid also noted that an application of the FERC tests of the years 2000-2008 quantitatively demonstrates the appropriateness of the 4 CP demand allocation method for production plant. Petitioner’s Exhibit KAH-3 graphically demonstrates that Vectren South continues to experience its peak during the months of June through September and that its demand curve is not relatively flat. Mr. Heid concluded that use

of the 4 CP method was justified for Vectren South because it continues to be a summer peaking utility.

Mr. Heid did prepare an alternative COSS using the 12 CP method to allocate transmission costs as required by the Settlement Agreement and the Commission's Order in Vectren South's last rate case, Cause No. 43111. Mr. Heid stated Vectren South was not recommending approval of this analysis.

(b) OUCC's Evidence. OUCC Witness Dale E. Swan, senior economist and principal with Exeter Associates, Inc., testified that Vectren South's classification of production and transmission plant costs as 100% demand-related violates the principle of cost causality and produces incorrect indications of class rates of return and cross subsidization. Dr. Swan contended that Vectren's South's production and transmission plant investment costs have not been caused solely by the peak demands of its customers. He believed that a significant portion of those investment costs have been directly caused by the need to meet the energy requirements of Vectren South's customers and that a commensurate portion of the investment costs and the associated plant-related O&M costs should be allocated on the basis of class energy usage.

Dr. Swan contended that while system peak demands are responsible for the amount of generation capacity, the total cost of that capacity is not directly caused by the magnitude of the system peak demands. He stated that higher capital cost baseload generation capacity has been developed to meet sustained demands at lower operating costs than peaking plants. He noted that, as shown by its Integrated Resource Plans ("IRPs"), Vectren South has planned its generation mix to minimize revenue requirements based on the relative operating and capital costs of different generating technologies. Therefore, Dr. Swan believed a significant portion of generation plant costs should be classified as energy-related cost.

Dr. Swan contended Vectren South has a diverse mix of generating capacity, but the lion's share of that capacity (77%) is baseload generation that is connected to load for an average of over 85% of the hours during the year and provides 99.2% of total generation. Dr. Swan concluded that this baseload generation has been installed primarily to provide energy at lower costs and not to meet the four summer month hourly peak demands. On the other hand, Dr. Swan demonstrated that, while peaking units make up 22% of total generating capacity, they have been connected to load an average of only about 169 hours a year, or only two percent of total annual hours and have produced only 0.8% of the total energy output. Dr. Swan concluded that these peaking units, with significantly lower capital costs, were clearly installed to meet peak demands on the system, which occur for only a few hundred hours each year. Dr. Swan further concluded that, to properly reflect the actual planning causes that led to the existing mix of generation resources, a significant portion of these costs must be classified as energy related and allocated on energy usage.

Dr. Swan recommended allocating a portion of production plant to energy using a Peak and Average method. This method allocates a portion of the plant and related expenses on the basis of class contributions to the relevant measure of system coincident peak demand and the remainder on the basis of class energy use at source. Dr. Swan initially applied three variations of the Equivalent Peaker Method ("EPM"). Dr. Swan's first two EPM methods evaluated the baseload and peaking cost of generation by comparing both the installed original cost and a

restated cost reflecting inflation in the value of the dollar for each type of capacity. These methods resulted in an allocation of 31% to demand and 69% to energy for the original cost analysis and 21% to demand and 79% to energy, using constant 2009 dollars. Dr. Swan conducted a third EPM analysis using the replacement costs in Vectren South's 2009 IRP. Applying this method, Dr. Swan concluded that approximately 45% should be treated as demand-related and 55% should be treated as energy-related.

Dr. Swan also utilized a fourth method, a Peak and Average method, that treated as energy-related the percentage of production plant equal to the system load factor (the ratio of average demand to peak demand). Dr. Swan estimated that Vectren South's load factor ranged from 56% (using Vectren South's 2009 IRP) to 67% (using the 2009 FERC Form No. 1 which includes wholesale sales).

Based on the four methodologies identified by Dr. Swan, he recommended that 55% of production plant cost be allocated on class energy use and the remaining 45% be allocated on each class' contribution to the appropriate measure of peak demand. For purposes of allocating the demand portion of production plant, Dr. Swan agreed with Vectren South's use of the 4 CP method.

Turning to allocation of transmission system costs, Dr. Swan opined that Vectren South's transmission system is essential to the Company's reliance on large, fuel efficient, baseload generating plants that are sometimes located at some distance from load centers, rather than investment in several smaller peakers nearer to load that would require less transmission. Dr. Swan concluded that Vectren South's investment in its transmission system is largely related to energy use. He therefore recommended that transmission-related costs should be allocated in the same way as his recommendation for production-related costs, except for \$24 million of production expenses that the Company allocated on an energy basis pursuant to a special study which Dr. Swan accepted.

Dr. Swan acknowledged that the Commission has never accepted an electric COSS that classifies a portion of production and transmission costs as energy-related. However, he noted that the Commission had recently agreed to allocate gas distribution main costs on a combination of peak-day consumption and annual volumes for Citizens Gas & Coke Utility ("Citizens") in its October 16, 2006 Order in Cause No. 42767 (the "Citizens Order"). Dr. Swan contended that the method used by the OUCC in the Citizens case is comparable to allocating a significant portion of electric generation capital costs to annual energy use.

Dr. Swan recommended adoption of the alternative 12 CP allocation of production and transmission plant if his EPM and Peak and Average methods are not accepted. He testified that the broader 12 CP allocator recognizes year-round demands for which he contended baseload production and transmission plant costs were incurred.

(c) Industrial Group Evidence. Nicholas Phillips, Jr., a principal in the firm of Brubaker & Associates, Inc., agreed with Vectren South that production and transmission investment should be allocated by the 4 CP method because it: (1) is consistent with past practice having been utilized by the Company and approved by this Commission for past cases; (2) provides the most accurate evaluation of the cost to serve various customer classes; and (3) is

the most consistent with actual load analysis of the Vectren South electric system. He noted that Vectren South's electric system reflects a predominant summer peak on both a historic basis and a forecast basis and that this pattern is expected to continue over the next 20 years. Mr. Phillips stated that any energy-based method that does not adequately account for the dominant system peaks would fail to reflect the actual load characteristics of the Vectren South system. Mr. Phillips also explained that allocating costs on average demand is mathematically equivalent to a kWh allocation and ignores peak period usage as opposed to off-peak usage. Failing to utilize the 4 CP method, in Mr. Phillips's opinion, would lead to unjust and unreasonable rates that fail to reflect cost causation. He believed that any change in methodology should focus on using less than four summer peaks, not more.

(d) Cross-Answering Evidence Supporting EPM and Peak and Average Methods. In cross-answering testimony, OUCC Witness Dr. Swan reiterated his position that a significant share of production and transmission costs has actually been incurred in order to reduce energy costs and, therefore, some portion should be classified as energy-related. Dr. Swan asserted that the fact that Vectren South is a predominantly summer-peaking utility only relates to the proper way to allocate the portion of such costs that are classified as demand-related.

Dr. Swan believed that Mr. Phillips's conclusion that an energy-based allocation system would fail to reflect the actual load characteristics of the system is incorrect because it ignores the loads on the system during the non-peaking periods. He opined that the load duration curve shape has determined the composition of Vectren South's generation fleet. He testified that an allocation system that only recognizes the need to meet the four highest hourly peaks during the year fails to reflect the load characteristics of Vectren South's system.

Dr. Swan took issue with Mr. Phillips's suggestion that rates based upon a 4 CP allocation of generation and transmission costs would promote efficient use of the Company's resources and lead to appropriate resource conservation. Dr. Swan further disagreed with Mr. Phillips's suggestion that rates based on an energy-based allocation of production and transmission costs will lead to increased costs and discourage conservation. Dr. Swan said Mr. Phillips' proposal would not reflect the cost of meeting another kW of demand at the time of the system peak because the costs would be based on the average, embedded, accounting costs of the utility. Dr. Swan believed rates encouraging efficiency and conservation should be based on marginal cost and such rates could be designed based upon either a 4 CP or a P&A allocation of generation and transmission costs. Dr. Swan pointed out that the interruptibility credits in the Company's current Riders IC and IO are based on this very concept of avoided or marginal cost. Dr. Swan recommended that the Commission give no weight to Mr. Phillips's efficiency and conservation arguments in determining how generation and transmission costs should be classified and allocated among the customer classes.

(e) Cross-Answering Testimony Opposing EPM and Peak and Average Methods. Industrial Group Witness Mr. Phillips's cross-answering testimony disputed Dr. Swan's direct testimony. Mr. Phillips noted the industry has long recognized that customers use production and transmission on a year around basis but that the appropriate application of cost-causation principles leads to the conclusion that fixed costs should be allocated on a demand basis as opposed to an energy basis. He stated that the capacity rating of electric equipment must

be matched to peak load requirements of customers and is not related to annual kWh or average demand.

Mr. Phillips testified that Dr. Swan's approach resembled the EPM that was rejected by the Commission in Cause Nos. 39871 and 40078, both prior Vectren South rate cases. The Commission found the assumptions required for the EPM were not widely accepted and lacked evidentiary support. Mr. Phillips stated that nothing has changed with respect to the make-up of production plant to warrant departing from the Commission's prior findings. The Commission itself recognized in its May 18, 2004 Order in Cause No. 42359 that a change in cost allocation methods relative to the utility's last rate case should not be lightly undertaken and continued the same allocation methodology because so much of the plant was in service at the time of the last rate case.

Mr. Phillips pointed to Dr. Swan's own analysis as demonstrating that classes with higher than average load factors are dramatically and adversely impacted by the utilization of the EPM and Peak and Average methods. Significant costs are also shifted to non-industrial classes that do not consume significant amounts of power at the time of the system peaks.

Mr. Phillips contended the EPM and Peak and Average methods are not based on sound costing principles. He testified that adoption of these methods would discourage the efficient use of the system because high load factor customers allow for more efficient utilization of existing plant, benefitting all customers. He did not believe there is any rational link between the system load factor and the classification of plant investment on the basis of annual energy usage irrespective of the time of occurrence.

Mr. Phillips reiterated that it is appropriate to classify all production and transmission investment as demand-related and to allocate such costs on a coincident peak demand basis because utilities must provide adequate generating capacity to meet the demands of their customers when those customers decide to make those demands. Mr. Phillips testified that demand diversity is incorporated into the planning process by sizing such shared facilities to meet the maximum simultaneous system peak demand.

Mr. Phillips also addressed Dr. Swan's argument that some portion of the investment in baseload plant should be classified as energy-related because the additional cost reduces fuel costs. Mr. Phillips testified that the capital costs are not a function of the number of kWh generated but are fixed and therefore are properly related to system demands.

Mr. Phillips also contended that allocating production and transmission expense as a demand-related cost sends a strong, cost-based signal to discourage power use at the time of the system peak demand. All customers benefit from this price signal because it can reduce the need for construction of incremental generation plant. Mr. Phillips noted that use of the EPM and Peak and Average methods makes peak usage less expensive and could accelerate the need for additional generation investment and provides less incentive to shift loads away from peak hours.

Mr. Phillips also pointed out that the Commission rejected an energy-based allocation methodology proposed by the OUCC in I&M's rate case in Cause No. 39314. He was unaware of any Commission precedent that would support the classification and allocation of production

and transmission fixed costs on an energy basis. Mr. Phillips addressed the Citizens' Order by noting that it pertained to gas rather than electric costs and focused on the allocation of distribution rather than production or transmission costs.

Mr. Phillips noted that Dr. Swan would increase the allocation of baseload plant to one group of customers on the theory that they benefit more than others from lower energy costs but does not assign that group the lower cost energy that the baseload facilities produce. Mr. Phillips explained that ignoring fuel cost differentials between baseload and peaking units creates a fundamental mismatch between the theory underlying the Peak and Average method and its application.

Mr. Phillips indicated that another problem with the Peak and Average method is that it inappropriately counts energy consumption twice in the allocation of production and transmission fixed costs. This occurs because average demand is also a component of coincident peak demand. Allocating some capital costs relative to average demand (energy usage) and some relative to coincident peak demand counts the energy twice, Mr. Phillips explained. He said the Peak and Average method improperly allocates the cost of the capacity component of fixed production costs using total coincident peak demand, rather than just the portion of peak demand that is in excess of the average demand.

Mr. Phillips also disagreed with Dr. Swan's endorsement of a 12 CP methodology in the event the OUCC's Peak and Average method is rejected. He explained that a 12 CP allocator improperly incorporates year-round customer demands into the allocation of production fixed costs. Because Vectren South is a summer peaking utility, a 12 CP allocation approach would inappropriately give weight to non-summer demands that have no impact on the Company's need for incremental generation investment.

(f) Vectren South's Rebuttal. Mr. Heid described Dr. Swan's argument as a repackaging of the same argument presented by the OUCC and rejected by the Commission in Cause No. 39871. Mr. Heid also cited other orders in which the Commission has rejected energy-weighted demand cost allocation methodologies proposed by the OUCC, including Indiana Michigan Power's 1993 rate case (Cause No. 39314) and a previous PSI rate case (Cause No. 37414-S2). In those orders, the Commission noted that the Peak and Average methodology had not been widely accepted or routinely implemented in any other jurisdiction, encouraged low load factor use of a utility's system and focused only on the capital costs associated with the generating facilities and ignored the fuel cost trade-off that was the basis for the OUCC's arguments. Mr. Heid emphasized that no changes in Vectren South's system had occurred that would warrant a change in the Commission's historical treatment of production plant as demand-related and that all other major Indiana electric utilities assign 100 percent of production plant as demand-related and use a CP methodology for allocation of production costs.

Mr. Heid did not believe the Citizens Order supported Dr. Swan's proposal. Mr. Heid first noted the Citizens Order dealt with gas distribution and not electric production costs and that there is little similarity between the two. Mr. Heid also emphasized that the allocation in the Citizens Order was never implemented because of challenges to the Order resolved through a subsequent settlement.

Mr. Heid agreed with Mr. Phillips that Dr. Swan's EPM and Peak and Average methods result in inconsistent treatment of fuel costs. Mr. Heid noted that the Commission has previously found energy-weighted demand cost allocation methodologies like the Peak and Average method to be flawed because they ignore the fuel cost trade-off that is the basis for the argument.

Mr. Heid stated Dr. Swan's various approaches produce widely varying results which casts doubt on their reliability. Second, Dr. Swan never explains how he uses those results to arrive at his proposed energy-demand split recommendation. Mr. Heid also criticized Dr. Swan's specific methodologies, most of which failed to account for depreciation reserve or percent condition and were in conflict with the NARUC Electric Utility Cost Allocation Manual's ("NARUC Manual") preferred methodology. Some of the methodologies required numerous assumptions and did not rely on the widely accepted trending tools such as the Handy-Whitman Index of Public Utility Construction Costs and had no nexus with the Company's past, present or future generation planning.

Mr. Heid also disagreed with Dr. Swan's premise that baseload facilities are built solely because of the low fuel costs. Mr. Heid testified that total overall costs, regulatory restrictions on fuel sources, capital availability and regulatory approval also influence the type of generation constructed.

Mr. Heid testified that the same reasons he opposes using Dr. Swan's methodologies to allocate production plant as energy-related justify rejecting Dr. Swan's arguments for allocating a portion of transmission plant as energy-related.

(g) Commission Findings. Vectren South has used a 4 CP methodology since at least the 1970s to allocate production and transmission costs on a demand-basis. We have noted our preference to utilize previously approved allocation methodologies unless evidence demonstrates that system operating characteristics have changed since the last approved COSS allocation methodology. *Northern Indiana Public Serv. Co.*, 2010 Ind. PUC LEXIS 294, at *263. Dr. Swan provided no evidence that system operating characteristics have changed since the Company's last COSS and Mr. Phillips and Mr. Heid both affirmatively testified that no such changes had occurred. Further, endorsing Dr. Swan's method would dramatically change the allocation of costs to customers as noted by Mr. Phillips. Changes in allocation methodology that significantly alter cost assignment may unreasonably disadvantage customers who have made investments in response to previous cost assignments. Of specific concern to the Commission are those investments made to foster demand response or to remove load during the Company's historical peak periods.

Having concluded production and transmission costs should be allocated 100 percent on a demand-basis, we must now turn to the appropriate method for allocating those costs. All parties agree that the 4 CP method used by Vectren South since the 1970s is most consistent with the Company's load profile. Mr. Heid testified that FERC precedent supports use of a 4 CP methodology for assigning Vectren South's production plant costs. While we are not bound to directly apply the FERC Allocation Method Tests for retail ratemaking in Indiana, we find the guidelines useful information for determining the appropriate production cost allocation methodology. In *Golden Spread Elec. Coop. v. Sw. Pub. Serv. Co.*, FERC stated:

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

123 F.E.R.C. P61,047, 61,249 (2008) (citations omitted.) Application of these principles here supports use of the 4 CP method. The difference between the Company's average of system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak, is greater than 19% (20.3% in 2009). Similarly, Vectren South's 2009 lowest monthly peak as a percentage of the annual peak is below the 66% threshold (63%) FERC deems necessary to support a 12 CP method under the Low-to-Annual Peak test. Finally, the Company's 2009 Average to Annual Peak test of 78.3% is below the range for a utility to be considered 12 CP under the Average to Annual Peak test. For these reasons, as well as the desire for consistency in allocation methodology discussed above, we find Vectren South's use of a 4 CP method to allocate transmission and production costs is appropriate for use in this Cause.

(2) Allocation of Line Transformers.

(a) Vectren South's Evidence. Mr. Heid classified line transformer costs between the demand function and the customer function using a zero-intercept analysis. His rationale for functionalizing line transformers as both demand-related and customer-related is that transformer investments are a function of the number of transformers and the kVa capacity rating of the transformers. Mr. Heid noted that line transformers were similarly functionalized in Vectren South's previous rate case. He explained that the customer-related portion was determined by multiplying the average unit cost of a theoretical zero-sized line transformer times the total number of line transformers. The demand-related portion represents the balance of the remaining transformer costs. Mr. Heid stated that the number of transformers is a direct function of the number of customers.

(b) OUCC Evidence. Dr. Swan disagreed with the allocation of a significant portion of line transformers as customer-related because it has the effect of allocating 37% of upstream secondary distribution plant on the basis of number of customers. Dr. Swan believed this to be detrimental to the small customer classes.

Dr. Swan opined that line transformers should be classified as 100% demand-related. He did not believe a direct relationship between the number of line transformers and the number of customers existed. He stated that many transformers serve more than one customer and that

there is not even a unique requirement to install a transformer for a given number of customers on many systems. He testified that the peak demands on each transformer are caused by the coincidence of customer demands or the lack of diversity of demands, not by the number of customers. He concluded that there is no unique relationship between the number of customers and the number of line transformers and it is incorrect to classify any portion of this plant as customer-related.

OUCG Witness Emma L. Nicholson, also a senior economist with Exeter Associates, Inc., contended Mr. Heid's zero-intercept analysis should be rejected because it is unreliable. The primary basis for her challenge to the reliability of the zero-intercept analysis was her contention it relies on an insufficient sample size. While she acknowledged that the standard errors, t-tests for statistical significance and confidence bounds are statistically significant, Dr. Nicholson believed that the sample size was insufficient to generate credible results. She stated that at least 30 observations are generally required whereas Mr. Heid's model only had 5. She also believed Mr. Heid's zero-intercept model is not robust because the outputs change dramatically in response to small changes in the sample size. Dr. Nicholson further criticized Mr. Heid's methodology on the basis that the transformer size variable is crudely estimated and the presence of data peculiarities including a negative quantity for three-phase transformers and unknown transformer vintage. She noted that Mr. Heid assumed that all transformers in each size category had a kVa size equal to the mean of the boundaries of that category because he presumably did not have more detailed information.

Dr. Nicholson also believed that Mr. Heid misapplied the results of his zero-intercept study. She criticized his decision to estimate the zero-intercept model on a subset of transformers and apply the results to all transformers and capacitors. She also opined that the absence of transformer vintage information results in nominal dollars from different years.

(c) **Vectren South Rebuttal.** Mr. Heid explained that it is appropriate to allocate a portion of line transformer costs as customer-related. He noted that the NARUC Manual supports classifying these costs as customer-related. The Manual (on page 90) states that:

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, *transformers*, services, and meters *are directly related to the number of customers on the utility's system.* . . . [E]ach primary plant account can be separately classified into demand and customer components of distribution facilities. They are minimum-size-of-facilities method and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

Mr. Heid rejected Dr. Swan's argument that a portion of transformer costs are not customer-related because there is no unique one-to-one relationship between the number of customers and the number of line transformers. He stated there was a direct relationship between the two variables. Mr. Heid explained that as new customers are added, line transformers must be added as well. Mr. Heid demonstrated a direct relationship between the number of transformers and the number of customers by conducting a linear regression analysis resulting in

an R-Squared of 0.959. A perfect correlation would be 1.00. This analysis demonstrates a high correlation between the number of transformers and customer numbers. Mr. Heid demonstrated his regression analysis had a statistically significant correlation by applying the F-test and T-test.

In response to Dr. Nicholson's arguments that the sample size was insufficient, Mr. Heid noted that his analysis began with 47,032 line transformer observations by size resulting in a total of eight groups. The observation points were thus far higher than the eight Dr. Nicholson alleged. He explained that the largest three groups were excluded because they are not relevant to the determination of the cost of the zero kVa-sized line transformer that was the objective of the analysis due to their large size, these largest sizes account for only 12 of the 47,032 line transformers, and these line transformers have the broadest and thus least precise ranges. Mr. Heid further stated that a comparison of the zero-intercept value of \$400 to the actual minimum line transformer unit cost of \$492 gives a degree of comfort that the zero-intercept value is reasonable.

With respect to Dr. Nicholson's criticism that inclusion of outlier data dramatically impacted the projected results, Mr. Heid explained this outlier data had been excluded precisely because it adversely impacted the results and was not relevant to the determination of a zero-sized line transformer because it represented only the largest line transformers. Mr. Heid also explained that relying on grouping of line transformers within kVa ranges in the property records does not make the zero-intercept analysis unreliable. He noted that a common assumption in analyzing large quantities of data is that the data is normally distributed, which implies that it is a reasonable assumption to use the mean of the range. Use of the mean or average also is the most objective method, removing any application of judgment that could be subject to criticism.

Mr. Heid also dismissed Dr. Nicholson's criticisms on the use of nominal dollars being factored into the zero-intercept analysis, noting this is the common methodology for conducting such an analysis. He also clarified that the OUCC did have access to all of the line transformer vintages had they believed this would have impacted the zero-intercept methodology.

Next, Mr. Heid presented a minimum distribution system method as an alternative method for calculating the demand/customer splits of distribution plant in the event the Commission is reluctant to approve the use of his zero-intercept analysis because of the statistical issues discussed by Dr. Nicholson. He explained that the minimum distribution system method determines a minimum size line transformer and uses that as a proxy for the minimum cost of all line transformers simply to connect a customer. This methodology would slightly increase the allocation of customer-related line transformer expense to \$492.30. Mr. Heid noted that the minimum system distribution method is accepted by the NARUC Manual and by this Commission. However, Mr. Heid continued to recommended use of his zero-intercept methodology.

(d) Commission Findings. Vectren South's COSS appropriately allocates a portion of line transformer as customer-related. Mr. Heid has shown there is a direct relationship between the number of line transformers and the number of customers. Mr. Heid's linear regression analysis demonstrates a strong correlation in this relationship. Moreover, the NARUC Manual recommends allocating some portion of line transformers as customer-related, contrary to Dr. Swan's proposal. For these reasons, we reject Dr. Swan's proposal to allocate line

transformer costs as 100% demand-related.

Having concluded that some portion of transformer line costs should be allocated as customer-related, we must decide which methodology should be used to determine the allocated cost. Mr. Heid presented both a zero-intercept and a minimum distribution system alternative. The evidence before us from Mr. Heid and the NARUC Manual demonstrate that these are two commonly-used methodologies for determining the demand/customer splits of distribution plant. Dr. Nicholson pointed out several issues with Mr. Heid's statistical estimate of the zero-intercept value.

Mr. Heid indicated his alternative minimum distribution system calculation is accepted by the NARUC manual. During the Evidentiary Hearing, Mr. Heid indicated this calculation results in a fair result. In addition, we find the minimum distribution system calculation to be less subjective than Mr. Heid's zero-intercept method. As a result, we adopt Mr. Heid's alternative minimum distribution system study results as shown in Petitioner's Rebuttal Exhibit KAH-R2.

(3) Allocation of Uncollectible Accounts Expense.

(a) **Evidence.** Mr. Heid directly assigned uncollectible accounts expense to the rate classes from which the expenses originated. Dr. Swan recommended that this expense be allocated on the basis of class revenues. He asserted that bad debts are essentially a general cost of doing business like any other administrative cost. Because most bad debts arise from the residential class, Dr. Swan's method reduces the allocation to that class. He said that costs should be allocated in the way the costs have been caused and that residential customers who pay their bills do not cause the bad debts of residential customers who do not pay their bills. Dr. Swan said his proposal is an alternative recognized in the NARUC Manual.

Mr. Heid disagreed with Dr. Swan's position that uncollectible accounts expense is like general administrative costs. Mr. Heid opined that if large industrial customers generally pay their bills and create fewer uncollectibles, they should not be held responsible for uncollectibles of other customer classes. Conversely, if several large industrial customers went bankrupt during the test year, the residential customers should not be held responsible for their uncollectibles. Mr. Heid noted that while Dr. Swan is correct that the NARUC Manual recognizes uncollectible expense can be treated like a general business expense, the primary method recommended by the Manual is the direct assignment method used by Mr. Heid.

(b) **Commission Findings.** A COSS should directly assign costs where such costs can be directly assigned. Uncollectible accounts can be directly assigned to the classes of customers from which they originated. We find it is preferable to allocate costs on the basis of class causation in the most direct way practical and approve the Company's treatment of uncollectible accounts expense.

(4) Allocation of Customer Service and Information Expenses.

(a) **Evidence.** Mr. Heid allocated customer service and information expense to the rate classes based upon number of customers. Dr. Swan recommended that these expenses be allocated on the basis of energy use. He cited to the description of these accounts in the

Uniform Systems of Accounts (“USOA”) and contended the expenses booked in them are more directly related to class energy use and not the number of customers. He opined that activities like preparing materials for newspapers and periodicals bear no direct relationship to the number of customers. Dr. Swan acknowledged that the NARUC Manual treats these expenses as a customer-related cost but said the Manual is inconsistent because it recommends allocating accounts with similar functions, like sales expense, on a general allocation scheme. In rebuttal, Mr. Heid defended his allocation of customer service and information expense as customer-related and quoted the NARUC Manual as stating “these costs are classified as customer-related.”

(b) Commission Findings. Dr. Swan contends that customer service and information expense accounts should be allocated on the basis of energy usage. However, Dr. Swan presents no significant evidence that these types of expenses vary with the amount of energy used by customers. On the contrary the accounts in question include costs that vary with the number of customers such as postage, customer assistance, customer inquiries demonstrations, direct mailings and printing. In addition, Dr. Swan’s recommendation is contrary to the clear direction of the NARUC Manual. Therefore, we accept Mr. Heid’s method of allocating customer service and information expenses on the basis of the number of customers, as recommended by the NARUC Manual.

(5) Treatment of Special Contract Customers.

(a) Evidence. Dr. Swan also recommended the inclusion of special contract customers as a separate customer class in Vectren South’s COSS in its next rate case. Dr. Swan testified that Vectren South has allocated the total costs of service, including the costs incurred to serve the special contract customers, to all those classes of customers that are explicitly recognized in the COSS. The revenues received from sales to the special contract customers are then allocated as credits to all the specifically identified classes. Dr. Swan believed that this methodology prevents a determination of what costs are actually being incurred to serve special contract customers and the amount of any subsidy or discount they are receiving. Dr. Swan recommended that Vectren South establish a customer class made up only of special contract customers in its next COSS. Dr. Swan noted that this methodology would reveal the magnitude of the subsidy or discount that is being offered to these customers.

In rebuttal, Mr. Heid stated that Dr. Swan’s proposed treatment of special contract customers would constitute a radical change from the approach historically used by Vectren South and approved by the Commission in previous COSSs. Mr. Heid pointed out that each special contract, including its rates and other terms, has already been thoroughly reviewed and approved by the Commission in formal docketed proceedings. Mr. Heid noted that no explanation as to how such information would be relevant or used was provided by Dr. Swan. Mr. Heid did not believe special contract customers actually received any “subsidies or discounts” as mentioned by Dr. Swan because these rates are negotiated at arms length and the load would not exist absent the special rates. He also expressed concern with separately presenting special contract customer information (which is deemed highly proprietary by these customers) in a COSS.

(b) Commission Findings. With regard to the treatment of special contract

customers, we find that it would be unreasonable to require these customers to be considered a separate customer class in Vectren South's COSS. As noted by Mr. Heid, each special contract, including the proposed rates and charges, has been reviewed and approved by the Commission. This statutory requirement provides assurance that such arrangements are reasonable and just. Ind. Code § 8-1-2-24. The use of special contracts for distinct customers that are not readily served under standard tariff rates makes a subsidy or discount presentation difficult to present and compare in a standard COSS. The limited number of Vectren South special contract customers presents challenges to appropriately controlling proprietary information. Accordingly, we decline to require Vectren South to include such customers in a distinct customer class in future COSSs. The Commission finds that consideration of how to most reasonably address any discount or subsidy responsibility should occur in the specific special contract proceedings

(6) Reduction in Subsidy/Excess Revenues.

(a) Vectren South's Evidence. Mr. Ulrey described Vectren South's proposed distribution of revenues to rate schedules, explaining that Vectren South's rate design objective was to obtain a fair apportionment of the costs of service among rate schedules and, further, among customers within each rate schedule. He explained that in the Commission's rate order for Vectren South in Cause No. 37803, the Commission stated that in future rate cases 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 subsidy has been sufficiently reduced or eliminated. Although subsidy reductions proposed by Vectren South in this case are less than the 25% minimum expressed in the Commission's prior order, Mr. Ulrey testified that Vectren South believes the proposed subsidy reduction is consistent with the Commission's rationale expressed in the order that any subsidy reduction should be prudent, consistent and wherever possible should avoid rate shock to any particular customer class. He stated that because the indicated subsidies are much higher in this case than in Vectren South's previous rate case, exercising a full 25% minimum subsidy reduction would result in a larger shift in required revenue responsibility than seems prudent.

The Company proposed subsidy reductions of 12.5% to 14.36% for the various rate schedules except for municipal street lighting which was limited to one-half of the overall requested increase. Mr. Ulrey also explained that Vectren South's proposed Step 2 increase would further reduce the subsidies by distributing the Step 2 increase based on the same subsidy reducing percentages used to distribute the increase in Step 1. In the case of the Street Lighting Services, Mr. Ulrey described Vectren South's proposal to limit the percentage rate increase to one-half of the overall requested percentage increase in order to mitigate the bill impacts to the tax-funded municipalities that receive those services.

(b) OUCC's Evidence. Dr. Swan, on behalf of the OUCC, recommended that the spread of the allowed jurisdiction revenue increase among the classes be done on the basis of an equal percentage, across-the-board increase. Dr. Swan explained that the Company testified that the magnitude of the estimated subsidies is much greater in this case, primarily because, there has been a shift in the Production and Transmission Allocators from classes of larger customers to classes of smaller customers. This is the result of reductions in the loads of the Company's industrial customers due to the recession. Because of these reductions the residential class is now responsible for a much larger fraction of production and transmission

plant. Dr. Swan noted the Company indicated in response to OUCC Data Request 2-57 that it would have an estimated peak reserve of approximately 30%, when its planning reserve is only 15%. Because of the fall in industrial loads, the cost of carrying this excess generation is disproportionately imposed on the classes made up of smaller customers. As a result of this development, Dr. Swan concluded that it is not appropriate to base the revenue spread in this proceeding on the criterion of moving toward cost-based rates. Dr. Swan testified that he strongly recommended that the Commission order the allowed increase in this proceeding to be spread among the classes on the basis of an equal percentage across-the-board increase.

Dr. Swan further testified that the \$4.4 million that the Company proposed to recover in a Step 2 increase are associated with certain “dense pack” investments. He explained that the purpose of those dense pack investments are to reduce energy costs and to reduce the cost of emissions, both directly related to the production of energy. Consequently, Dr. Swan concluded that these costs, to the extent allowed, should be allocated among all the classes, including the lighting classes, on the basis of energy use at the generator.

(c) **Industrial Group’s Evidence.** Industrial Group Witness Phillips disagreed with Vectren South’s proposed distribution of the requested increase, stating that it will perpetuate the subsidization that has and continues to exist within Vectren South’s rate schedules. Instead, he recommended reducing all existing revenue subsidies by a percentage, such as 50%. He testified that this method would provide for a gradual, but meaningful, movement toward cost-based rates. Mr. Phillips also recommended that Vectren South make a compliance filing to remove subsidies in their entirety within a specified timeframe such as two years.

In cross-answering testimony, Mr. Phillips recommended the Commission reject Dr. Swan’s proposal to distribute the revenue increase among the customer classes on an equal percentage, across-the-board basis because it ignores cost-causation principles and does not support the movement of customer classes to cost-based rates.

(d) **Evansville’s Evidence.** Theodore J. Sommer, a partner with London Witte Group, LLC Certified Public Accountants, testified on behalf of the City of Evansville with respect to Vectren South’s proposed Step 2 increase. Mr. Sommer recommended that the Commission order Vectren South to file its rate design based upon the billing determinants that exist in 2013 as a condition precedent to putting in the Step 2 rates.

(e) **Vectren South’s Rebuttal Evidence.** Mr. Ulrey stated Dr. Swan’s proposed equal percentage increase approach does not reflect the results of Vectren South’s COSS and is therefore inappropriate. He also stated that the immediate 50% subsidy reduction proposed by Mr. Phillips is not appropriate because it does not support the important rate design principle of gradualism which would be achieved by moderation in reducing indicated subsidies. Mr. Ulrey reiterated Vectren South’s recommendation that the Commission approve a revenue increase distribution to rate schedules such that the interclass subsidies indicated by the 4 CP COSS be reduced by approximately 15%. Vectren South believes the 15% level is a suitable balance of movement toward cost based rates and gradualism. Mr. Ulrey went on to say that if the Commission were to require a larger subsidy reduction, Vectren South would recommend that it be accomplished in two parts, with an initial subsidy reduction reflected in the rates

implemented on the effective date of rates in this proceeding and a second set of rates that further reduce the indicated subsidies implemented at a later time.

With respect to the Step 2 increase, Mr. Ulrey expressed Vectren South's acceptance of the OUCS position that the Step 2 increase be allocated to the lighting rate schedules, but recommended that the Step 2 increase still be allocated to rate schedules on the basis of the Step 1 increase percentages as described in Mr. Ulrey's direct testimony. Mr. Ulrey disagreed with Mr. Sommer's proposal to use updated 2013 billing determinants in calculating the step 2 rates, stating such an approach was unnecessarily complicated for distributing a relatively small revenue increase.

(f) **Commission Findings.** Without diminishing the seriousness of our finding in Cause No. 37803 that Petitioner should be required to reduce any subsidy between classes to the extent of at least 25%, we recognize and agree with Petitioner's argument that reducing the subsidy to that extent under these circumstances would result in rate shock. We also recognize that reduced industrial demand during the test year has resulted in a shift in the COSS. Therefore, a moderate subsidy reduction is appropriate in partial recognition that the industrial demand is likely to rebound to some degree in the future.

Based upon the evidence presented, we find that Vectren South's proposed distribution of the approved revenue requirement is appropriate and find that interclass subsidy reductions of approximately 15% properly balances the need to reflect the results of the cost of service study while moderating effects that might otherwise produce rate shock. We find municipal street lighting shall not be treated differently than the other classes with respect to rate increase moderation. Based on our findings below disapproving the proposed step 2 increase, the issue of revenue allocation for that increase is moot.

12. **Rate Design.**

A. **Tariff Rate Schedule Proposals.**

(1) **Vectren South's Evidence.** Mr. Ulrey testified regarding Vectren South's proposed rate schedule structure changes. He explained that for all rate schedules, Vectren South is proposing to separate its variable costs from its fixed costs. He stated that these changes are intended, among other things, to provide more clarity and transparency in the rate schedules as to the variable costs that Vectren South can avoid as customers reduce usage. Accordingly, the proposed rate schedules contain a separately stated Variable Production Charge that includes the following: variable production costs such as costs relating to ammonia, catalyst, other chemicals, ash and gypsum disposal, and fuel handling; a separately stated Fuel Charge that includes fuel costs; and an Energy Charge that does not include such costs.

Mr. Ulrey originally testified that Vectren South proposes to remove from its Energy Charges trackable fuel costs (those fuel costs for which the Commission has authorized tracking via the FAC) and associated revenue taxes and recover such costs entirely in the FAC. However, as discussed below, this proposal was withdrawn in rebuttal.

Mr. Ulrey stated that Vectren South currently has two residential rate schedules. Rate EH consists of residential customers who exclusively use electric equipment for space heating. Rate

A consists of the large majority of Vectren South's residential customers who are non-electric space heating customers. Mr. Ulrey explained that Rate EH was established many years ago to promote electric space heating. Because of the Company's focus on energy efficiency and conservation, Mr. Ulrey opined that it is no longer appropriate to provide declining block rates that promote a particular electric use. He stated that Vectren South therefore proposes to close Rate EH to new customers as of the effective date of new rates in the proceeding. Furthermore, he stated that while existing EH customers will continue to be provided a declining block Energy Charge, Vectren South intends to reduce and then eliminate those declining block rates gradually over time, in this and subsequent rate cases.

Mr. Ulrey explained that Vectren South proposes to combine the customers under Rate A (the "Standard" customers) and Rate EH (the "Transitional" customers) into a single rate schedule, called Rate RS – Residential Service. He stated that Vectren South will have separate Energy Charges under Rate RS for these two residential customer groups to permit, for now, a continuation of a lower second block rate for Transitional customers. He stated that all other Rates and Charges for the two residential customer groups would be identical, including the Customer Facilities Charge, the proposed line-loss differentiated Variable Production Charge, and the FAC Charge.

With respect to the Energy Charge, Mr. Ulrey proposed that the first block (up to 250 kWh/month of usage) of both the Transitional and Standard customer be eliminated. This results in a single block rate for the Standard customer group and an initial block for the Transitional customer group for all usage up to 1000 kWh per month. He added that the existing over 1000 kWh block for Transitional customers would be split into Summer and Winter charges, so that the declining block rate for Summer usage can be eliminated on a quicker pace than the Winter declining block rate.

Mr. Ulrey testified that in its previous rate case, Vectren South separated the smaller General Service customers from the larger demand-metered General Service customers to create the Small General Service ("SGS") rate schedule. He stated that in this proceeding, Vectren South proposes to continue movement to recognize groups of different sized customers within the Demand General Service ("DGS") rate schedule. In particular, the Company proposes to recognize three groups of customers in the DGS rate schedule as follows: DGS-1 – Customers with Maximum Demands from 10 kW up to and including 70 kW; DGS-2 – Customers with Maximum Demands over 70 kW up to and including 300 kW; and DGS-3 – Customers with Maximum Demands over 300 kW. Mr. Ulrey stated that these three DGS groups would have different Customer Facilities Charges, but otherwise would have identical Rates and Charges.

Mr. Ulrey testified that the Transmission Power Service rate schedule has been renamed High Load Factor Service. He explained that the current two-step Demand Charge is changed to a one-step Demand Charge, and a Minimum Monthly Charge based on 4500 kVa replaces the first step. He said the single Demand Charge is also modified to exclude the recovery of the cost of 600 kWh per kVa of Billing Demand, which was originally designed to encourage at least an 82% load factor from HLF customers. Mr. Ulrey stated that the proposed Demand Charge will recover all of the rate schedule's fixed costs.

Mr. Ulrey stated that the Municipal Levee Authority ("MLA") rate schedule is proposed

to be modified similar to Rate DGS, with one exception. Because the minimum eligibility for Rate MLA based on Maximum Demand is 200 kW, he stated that only two customer groups will be identified as MLA-2 and MLA-3.

Vectren South also proposed two changes to the Street Lighting Service rate schedules. First, fuel costs, variable production costs and associated revenue taxes will be split out from the Annual Facilities Charges, based on approximately 4,000 Hours of Use for each lighting fixture. Mr. Ulrey stated that the Street Lighting rate schedule billing determinants reflect slightly revised fixture counts based on a recent comprehensive survey of such light fixtures in the Evansville area. The second change is the addition of a Minimum Monthly Charge to clarify the required minimum payment of fixed costs in the event that street lighting fixtures are voluntarily shut off by the customer to reduce energy consumption and thereby avoid variable costs.

(2) OUCC's Evidence. OUCC Witness Swan testified that Vectren South's proposed Customer Facilities Charges for residential customers (\$11.00 per month from \$5.50) unreasonably skews the breakdown of revenue recovery toward fixed charges and violates the rate design criterion of gradualism. He said the proposed charge was high compared to the corresponding charges of other Indiana investor-owned and municipal utilities which range from \$5.95 to \$11.00 with an average of \$7.97. Dr. Swan recommended that the existing residential Customer Facilities Charge be retained or, at the most, the increase should be limited to the allowed overall percentage rate increase authorized by the Commission.

OUCC Witness Swan testified that although he believed the flattening of Rate EH proposed by Vectren South was a reasonable first step toward moving the rate serving electric space heating customers to the standard residential rate, he had concerns regarding the equity of closing the rate to all new customers. He recommended that instead of grandfathering the right to remain on Rate RS – Transitional by customer, Vectren South should tie the grandfathering provision to the premises. Dr. Swan opined that this would avoid requiring a new owner of a house with an electric heating system to pay for space heating at the standard rates. As to the gradual elimination of the lower tail block rates, Dr. Swan recommended that such elimination take place over a 10-year period.

Dr. Swan further proposed that the Customer Facilities Charge for the Small General Service Rate be retained or limited to the overall increase and that the last block increase be moderated. He also thought the Commission may wish to require the Company to moderate the shift of revenue recovery from the Rate DGS Energy Charge to the Demand Charge and the Customer Facilities Charge. Dr. Swan testified that the Company should close the Off Season Service ("OSS") rate schedule to new customers because it provides a reduced rate for space heating and begin to move those customers to comparable DGS rates with an eye toward eliminating this rate within the next couple of rate cases. He also testified the Commission may want to temper somewhat the shifting of revenue recovery under the Large Power Service ("LP") rate schedule from the Energy Charge to the Demand Charge and Monthly Facilities Charge.

(3) Industrial Group's Evidence. Industrial Group Witness Phillips testified that any reduction to Vectren South's requested increase should lower Energy Charges to reflect only energy-related costs.

(4) **Evansville's Evidence.** Evansville Witness Sommer explained that the City is in the process of evaluating energy savings contracts and may find it least expensive to work with Vectren South to decrease its energy costs through DSM programs. He recommended that Vectren South should appoint an energy conservation specialist as a liaison to the City to assist with these issues. He also testified that the City wants assurance that if the City takes action to increase the efficiency of its MLA pumps, the Company will not change the methodology it uses to apportion its proposed Sales Reconciliation Adjustment that would put the MLA rate class on its own footing for purposes of that Adjustment.

(5) **Vectren South's Rebuttal Evidence.** In rebuttal, Mr. Ulrey agreed with Dr. Swan's position that the grandfathering of the discounted residential electric space heating customers should be linked to the premises, that Transition rate eligibility shall not be closed until one year after the effective date of new rates to provide for projects planned or under construction, and that the discounts should be phased out over a period of time. Mr. Ulrey proposed annual rate adjustments for these customers over a ten year period to bring them up to standard rates.

Mr. Ulrey agreed that Rate OSS can be closed to new premises and the discounts phased out over time to transition these customers to Rate DGS. However, he did not agree the phase-out could occur over two rate cases because of the complexity of the transition and the larger more complicated and longer-lived equipment owned by Rate OSS customers. Mr. Ulrey proposed closing Rate OSS on the first anniversary of new base rates. He said the Company will propose a transition plan for these customers in its next rate case.

Mr. Ulrey disputed Dr. Swan's position that the proposed Customer Facilities Charges are too high. He stated the proposed residential charge of \$11.00 per month would recover only 83% of the customer-related costs determined in Mr. Heid's COSS. With respect to gradualism, he said the Company's proposed elimination of the higher cost first rate block significantly moderates the increase in the Customer Facilities Charge on small use customers. As a result, a customer using 250 kWh per month would see a percentage increase little different from the class overall increase. Mr. Ulrey disputed Dr. Swan's contention that Vectren South's proposal is out of line with monthly fixed charges of other Indiana utilities. He provided a list of the customer charges for 13 different Indiana REMCs, which showed an average of \$27.43 per month. Mr. Ulrey made similar points about the Rate SGS Customer Facilities Charge, showing it would recover substantially less than the customer-related costs for this class as determined in the COSS and that even low usage customers would receive increases only slightly different than the overall class increase. Mr. Ulrey further testified the proposed fixed charges for Rate DGS and Rate LP were reasonable and total bills for these customers were not in need of further moderation.

Mr. Ulrey agreed with Mr. Phillips that if the Commission approves a reduction to the requested increase for Rate LP, the reduction should lower the Rate LP Energy Charges. Mr. Ulrey pointed out a large percentage of fixed costs are still being recovered in the Energy Charges for that rate schedule.

Mr. Ulrey acknowledged the last block of Rate SGS was disproportionately increased but explained this was an intentional step to begin flattening the block rates with the intention of

moving from three blocks to two blocks or one block in future rate cases. The resulting rate increases for customers purchasing in the last block are still reasonable compared to the class increase.

Mr. Ulrey also elaborated on the reason for separating Rate DGS into three separate size categories based on Maximum Demands. He said this change continued changes begun in the Company's last rate case and sets the stage for continuing differentiation for Rate DGS customers in the future. To simplify rate design and be better able to respond to the needs of individual classes, the Company intends to move Rate DGS toward a more straightforward Demand/Energy rate design. Creating separate DGS size categories will make this change easier to accomplish.

In response to Mr. Sommer, Mr. Ulrey stated that the Company is not at this time proposing nor intending to propose in the future that Rate MLA-2 accounts be placed in a rate class of their own for purposes of the Sales Reconciliation Adjustment calculations. Mr. Ulrey also identified a correction the Company was making to its proposed MLA rate schedule to prevent inadvertent migration among MLA rate group or perhaps out of Rate MLA altogether.

(6) Commission Findings. We find Vectren South's rate design proposals are reasonable and should be approved. Including a separate Variable Production Charge and a separate Fuel Charge on the rate schedules will increase transparency of charges representing variable costs that are affected by usage and charges representing fixed costs which are not affected by usage. Terminating the availability of Rate RS-Transition (now Rate EH) and Rate OSS beginning one year from the effective date of new rates is reasonable to allow current installation plans to proceed while eliminating discounts from standard rates for space heating customers who have not yet made such installation plans. Rather than establish at this time a fixed transition plan to gradually move these customers to RS-Standard or Rate DGS rates, we find the Company should file for the Commission's consideration within two years of the date of this order rate design analyses for both Rate RS and Rate OSS that provide revenue neutral transition plans and any required alterations to the rates of the standard customers on these rate schedules.

B. Decoupling. Vectren South proposes to implement revenue decoupling through a Sales Reconciliation Adjustment ("SRA") rate design mechanism that will adjust the rates of certain rate classes (Rates RS, B, SGS, DGS-1 DGS-2, MLA-2 and OSS) for differences between fixed costs approved for recovery in this proceeding, adjusted for changes in the number of customers, and fixed costs actually recovered by the Company. These differences would be deferred on a monthly basis for subsequent inclusion in an annual SRA filing which would recover from or pass back to customers the accumulated deferred decoupling amounts. Vectren South sought a decoupling mechanism in Cause No. 43427, and we rejected the request, finding that any decoupling mechanism should be pursued in the context of a base rate case. *S. Ind. Gas & Elec. Co.*, Cause No. 43427, 2009 Ind. PUC LEXIS 495, at *90-93 (IURC Dec. 16, 2009).

(1) Vectren South's Evidence. Vectren South Witness Ulrey described the Company's proposal to implement the SRA. Mr. Ulrey stated Vectren South is proposing a decoupling mechanism to recover the difference between actual fixed cost recovery for certain rate classes and the fixed costs approved by the Commission for recovery from those rate classes

in the Company's most recent general rate proceeding. Fixed costs are those costs included in Vectren South's approved revenue requirement that do not vary based on units produced or sold to customers. Therefore, fixed costs that would be decoupled under the Company's proposal include costs such as return, depreciation, labor costs, other O&M expenses, property taxes, and revenue taxes that are incurred irrespective of actual production or sales units. Variable costs - those costs the Company incurs that do vary with actual sales units or units of production - are excluded from the revenues to be considered in the decoupling amount calculations as described below.

Mr. Ulrey explained that decoupling eliminates the Company's disincentive to help its customers reduce their electric usage. In order to aggressively pursue programs that help customers reduce usage or take advantage of the most efficient use of energy, the Company must not suffer the adverse financial impacts of lower use. Based on its current largely volumetric rate design, the Company would forfeit fixed cost recovery as it helped its customers reduce their actual usages. This misalignment of Company and customer interests can be mitigated with a decoupling mechanism which assures that the Company will recover the amount of fixed costs per customer approved by the Commission in the most recent rate proceeding for the applicable rate classes.

Mr. Ulrey stated that each month, for each of the applicable rate classes, the Company would first calculate the actual fixed costs recovered that month. Then, the fixed costs recovered would be compared to the monthly portion of fixed costs approved for recovery in the most recent rate case, as adjusted for the actual number of customers. The differences between these calculated amounts would be the decoupling amounts for the rate classes for such month. The monthly decoupling amounts for all rate classes would be summed and deferred for subsequent inclusion in an annual SRA filing, which would recover from or pass back to customer classes the accumulated deferred decoupling amounts.

To determine actual fixed costs recovered each month, the Company would deduct from total costs recovered for each rate class the non-SRA Adjustment revenues and variable cost revenues recovered. The Company will allocate annual fixed costs for each rate class to each of the months based on test year and proforma adjustment data as approved by the Commission to determine monthly fixed costs per customer. The monthly per customer amount will be multiplied by the number of actual customers in each rate class for each month to obtain the "order-granted" fixed costs. Finally, to the order-granted fixed costs will be added a prorated portion of the annual return amount reflected in Qualified Pollution Control Property - Construction Cost Adjustment ("QPCP-CC"), if then in effect, which is fixed cost recovery approved by the Commission between rate cases, to achieve the monthly fixed costs approved for recovery. The net result of the SRA is that over a year's time the Company would realize the fixed costs approved for recovery by the Commission - both in the most recent rate case and in subsequent QPCP-CC filings, if any - as adjusted for actual number of customers.

Mr. Ulrey testified Vectren South previously implemented a decoupling mechanism for its gas utility. The Sales Reconciliation Component of the Vectren South-Gas Energy Efficiency Rider is essentially identical to that proposed herein for the electric utility. The major difference between the gas and electric mechanisms is the existence of significant variable costs in the revenue requirement for the electric utility, while the gas utility has virtually no non-fuel variable

costs in its revenue requirement. According to Mr. Ulrey, that difference requires the treatment of variable costs as described above for the electric decoupling mechanism.

Vectren South Witness Chapman testified working with customers to reduce energy consumption is the right response to both volatile fuel costs and to the rising costs associated with controlling emissions created by production of electricity to meet demand. He stated Vectren made the decision to wholeheartedly sponsor energy efficiency a few years ago when its gas utilities implemented DSM programs and began educating customers regarding conservation. He testified Vectren has been a consistent and vocal advocate of energy efficiency efforts, noting that employees have been challenged to hand out energy conservation materials to customers, neighbors, and family members. He stated Vectren's gas DSM programs have exceeded targeted savings. According to Mr. Chapman, the cultural change from the traditional utility role of encouraging energy sales to becoming a conservation advocate has largely occurred.

Mr. Chapman testified that in approving decoupling for Vectren North and Vectren South-Gas, the Commission found that it is now widely recognized that decoupling margin recovery from sales volume is necessary to enable a partnership to reduce usage through energy efficiency. Mr. Chapman indicated this same need of electric utilities to recover fixed costs while encouraging energy efficiency has been expressly supported in the Energy Independence and Security Act of 2007 (the "EISA").

Mr. Chapman described the multiple financial challenges facing the Company regarding customer count, wholesale sales, large customer use and potential GHG legislation. Mr. Chapman emphasized that to the extent a utility in these circumstances would attempt to further reduce its sales to small customers through DSM programs and other efficiency efforts in the absence of a rate design that provides protection of fixed cost recovery, it would further undermine ongoing financial stability that is already under extreme pressure, and would add yet another negative issue to the Company's financial profile. It is important that the Company have an opportunity to collect previously approved revenues to support its operations. Decoupling, for at least half of retail sales, provides this necessary support. He also described the importance rating agencies and investors place on the perceived quality of regulation and constructive regulation that supports reasonable cost recovery and mechanisms that provide cash flow to support investment. He said having a rate design consistent with efficiency efforts will be a big part of the Company's message to that community.

Vectren South Witness L. Douglas Petitt, Vice President of Marketing and Conservation, explained the need for a rate design in the form of "decoupling" that supports the Company's efforts and makes sponsorship of energy efficiency a sustainable long-term objective of Vectren South. Mr. Petitt stated that public policy recognizes the importance of implementation of rate design mechanisms that align the increased use of energy efficiency as a resource alternative, citing the Indiana Strategic Energy Plan, the Commission's Phase II Order in Cause No. 42693 and federal legislation. He described Vectren South's efficiency efforts in the past several years and proposed for the future. He also described Vectren South's efforts to encourage the direct use of natural gas as a more efficient and environmentally friendly alternative to electricity.

(2) OUCC's Evidence. OUCC Witness Dr. Dismukes recommended the Commission reject Petitioner's revenue decoupling proposal because it is based upon faulty

premises that are unsupported by any credible evidence, inconsistent with sound regulatory principles, and contrary to the public interest. These premises, as discussed in detail in his testimony, include the faulty argument that traditional utility regulation is deficient and in need of a complete overhaul, especially regarding the traditional risk/reward relationship between a utility and its ratepayers. Another faulty premise identified by Dr. Dismukes is the premise that revenue trackers, like revenue decoupling, will somehow better align the interests of electric utilities and their customers.

Dr. Dismukes testified that Petitioner's revenue decoupling proposal would shift revenue recovery risk associated with changes in the weather, economy, and other factors away from the Company and its shareholders and onto ratepayers. The mechanism would provide guaranteed revenues to the Company whether or not it meets any verifiable performance-based energy efficiency goals or standards. The mechanism, as proposed, will make Petitioner whole for changes in sales that have absolutely nothing to do with its energy efficiency efforts and more to do with the recent economic recession. Additionally Dr. Dismukes explained why revenue decoupling is especially inappropriate for a vertically-integrated electric utility.

Dr. Dismukes opined that revenue trackers like Petitioner's proposed decoupling mechanism ultimately lead to higher utility costs compared to traditional regulation because they eliminate the positive incentives attendant to the regulatory process. He testified that it is a basic economic fact that rational utility management has little incentive to control costs if it has no effect on the utility's profits. Another disincentive that arises with revenue trackers like decoupling is that utilities are less likely to take steps that reduce price volatility for their customers through reasonable risk management practices in fuel supply procurement. Dr. Dismukes observed that Vectren South, like many utilities, has faced investment and operational challenges over the past few years. Some utilities have done a better job at reacting to these challenges. The optimal regulatory solution to Vectren's problems, however, is not to provide a series of revenue and cost trackers, but to promote a ratemaking framework that is based upon performances and accountability, not guarantees.

Another criticism Dismukes posits regarding revenue decoupling is that reduced revenues associated with energy efficiency programs are quite small. Other factors such as weather or the economy result in greater changes in energy usage. Vectren's decoupling mechanism would allow it to recover lost margins associated with energy reductions not associated with its energy efficiency efforts. Dr. Dismukes states that a regulatory framework, like Indiana's, that allows lost revenue recovery with an opportunity to earn shareholder savings is sufficient to incent a utility to pursue energy efficiency opportunities. He stated that, according to his analysis, in 60% of the cases he studied decoupling cost ratepayers more money than they would have paid under a standard lost margin mechanism. In fact, Dr. Dismukes demonstrated that had Vectren South's decoupling mechanism been in place during the test year utilized in this Cause, ratepayers would have seen additional rate increases of some \$4.1 million without any hearing or investigation regarding whether Vectren South's costs had changed during the same time period.

Dr. Dismukes also testified that Vectren, as a regulated public utility, operates in the public interest. It extracts and utilizes valuable natural resources. Regardless of what type of incentive the Company would like to be awarded for its conservation efforts, it already has an obligation to use natural resources efficiently.

Dr. Dismukes concluded that the SRA should not be approved for the following reasons: (1) it would shift risk from the Company to ratepayers; (2) no review or analysis prior to permanent implementation has been performed; (3) it is not tied to verifiable efficiency goals; and (4) it is likely to make the Company whole for changes in sales having nothing to do with efficiency efforts.

As an alternative to the Company's decoupling proposal, Dr. Dismukes proposed an Efficiency Incentive Mechanism ("EIM") to promote effective provision of DSM programs and improved efficiency and competitiveness in power production. His proposed EIM would use gains from off-system sales made possible by "freed-up" generation to offset stranded costs created by energy efficiency.

(3) Industrial Group's Evidence. Industrial Group Witness Mr. Phillips examined the policy implications of adding electric decoupling and recommended the proposed decoupling mechanism not be approved. Mr. Phillips asserted decoupling departs from traditional ratemaking principles and is not needed to correct alleged deficiencies in the incentives created by the base ratemaking process. He testified the SRA should be rejected because it would frustrate the voluntary efforts of customers to reduce energy consumption, transfer traditional utility business risks to customers, reduce the Company's motivation to be responsive to the needs of its customers, and create unnecessary rate volatility and uncertainty.

Industrial Group Witness Mr. Gorman testified that the decoupling mechanism lowers Vectren South's operating risk for providing service to its customers because it provides a mechanical means to ensure that the Company will more likely earn its authorized return on equity. As such, he said this decoupling mechanism mitigates Vectren South's operating risk, and will strengthen its earnings and cash flow in support of its utility operations. He explained that credit agencies view decoupling mechanisms credit supportively, because they shift the risk from the utility to the ratepayers and gave several examples. He also explained that several other jurisdictions have recognized that decoupling mechanisms do reduce risk to investors by shifting risk from investors to customers. He noted that some commissions have made return on equity adjustments to reflect reduced operating risk by the implementation of decoupling programs. Based on an analysis of the market-required return available for an investment that produces a higher probability of cost recovery, the normal bond yield spread between an "A" rated utility bond and a "Baa" rated utility bond, Mr. Gorman recommended a 25 basis point reduction to Vectren South's ROE if decoupling were approved.

(4) CAC's Evidence. CAC Witness Mr. Hornby stated it is appropriate to allow the Company to make a limited change in rate design to collect the revenues it would otherwise lose due to those new, future reductions in sales. He opined that the Company's proposed SRA would do much more than simply collect the lost revenues resulting from reductions in future sales due to new DSM programs. He testified that the SRA would eliminate the Company's existing revenue risk from all factors that affect its sales as well as eliminate its financial disincentive to promote sales of electricity to customers in those rate classes.

Mr. Hornby testified a Lost Revenue Adjustment Mechanism ("LRAM") would achieve those energy policy and ratemaking objectives in a balanced manner. He said an LRAM would only adjust the Company's rates for the reduction in sales from the new DSM programs under

the Phase II Order and would benefit the Company by preventing an increase in revenue risk from the new DSM programs and would benefit ratepayers by limiting the amount of revenue risk shifted to them. Mr. Hornby recommended the Commission deny the Company's decoupling proposal but allow the Company to implement an LRAM on a three-year trial basis.

(5) NRDC's Evidence. NRDC Witness Ms. Morgan testified NRDC supports the Company's decoupling request. She stated decoupling is the only regulatory policy that eliminates a utility's incentive to increase sales of electricity, as well as ensures that the savings it helps its customers achieve do not come at the cost of its bottom line. She asserted decoupling is best for utility customers because it does not compensate the utility for revenue "lost" through the operation of energy efficiency programs that was actually not lost because of increases in usage elsewhere in the system and does not deprive customers of the highest possible short-term economic benefits of energy efficiency. She stated decoupling permits utilities to stop focusing on selling more and more electricity and permits them to begin orienting their business to helping customers use energy wisely instead. She described the deficiencies of the LRAM approach and provided information on the number of states using gas and electric decoupling.

NRDC Witness Mr. Dylan E. Sullivan testified as an advocate for revenue decoupling. He provided testimony about the OUCC's EIM proposal and CAC's LRAM proposal. Mr. Sullivan explained that CAC's proposed LRAM is a poor alternative to the SRA because it does not remove a utility's disincentive to help its customers become more efficient in every possible way, does not remove a utility's incentive to increase sales between rate cases, is costly, restores revenue to the utility that might never have been lost, creates new perverse incentives, and adds needless contention to the process of evaluating and measuring the impacts of energy efficiency programs. He argued that the OUCC's proposed EIM is also a poor alternative to the SRA because it is based on a misunderstanding of decoupling, would not remove the disincentive of the Company to help its customers become more efficient, includes an LRAM that is subject to the same problems noted concerning the CAC's proposed LRAM, would worsen the Company's incentives to engage in energy efficiency compared to current practice under some scenarios, and would make an unsupported connection between off-system sales and energy efficiency performance.

On cross-examination, Mr. Sullivan acknowledged that he is not an expert in regulatory accounting or finance and that he has never performed a load forecast or electric utility benchmarking analysis. He also acknowledged that he did not review Dr. Dismukes' workpapers. Mr. Sullivan also explained during cross-examination that he does not want to limit Vectren South's ability to recover lost margins to those actually caused by its efforts. He believes this would discourage the Company from implementing "high value but difficult to evaluate activities." One of the limitations he sees with a standard lost margin recovery program is the difficult task of verifying and measuring savings.

(6) Vectren South's Rebuttal Evidence. In rebuttal, Mr. Pettit stated that under a traditional volumetric rate design, if a utility sells its customers the exact amount of adjusted test year kWh, it will receive the amount of revenue needed to recoup its approved costs. The concept of decoupling, which each year retrospectively trues-up actual sales revenue to the rate case level of sales revenue, is that rather than having a rate design that creates a "throughput incentive," the utility is freed of a sales mindset and can partner with customers to reduce energy

use without being concerned that it will lose revenue necessary to cover its costs. Often, the result is referred to as an alignment of interests of the customer and the utility in efficiency. Mr. Petitt argued that the OUCC's position on this issue flies in the face of the agency's own support of gas decoupling to create alignment of interests. Mr. Petitt testified if the throughput incentive is a recognized obstacle to efficiency, then a known means of eliminating that incentive should be favorably received. If the throughput incentive remains, then every action the Company takes will have to be assessed in terms of how harmful it will be to the Company's financial performance.

Dr. McDermott responded to criticisms of the proposed SRA. He said decoupling rectifies a rate design issue that has traditionally required utilities to attempt to recover a large portion of fixed costs in volumetric charges. While this problem has existed for years it has become more problematic as the system has expanded, costs have increased, and energy efficiency has taken a more important role in providing reliable and reasonably priced service to customers. If parties want utilities to continue to move toward a conservation ethic, decoupling is a tool that can be used to induce utilities to undertake expenditures and actions that serve broader public interests.

Dr. McDermott also contended decoupling's effect on the traditional regulatory lag incentive is overstated. This is because the utility will continue to have the incentive to undertake cost saving actions, as those actions will increase utility profits in the same manner as under traditional regulation, and the success or failure to control costs goes directly to the utility's bottom line. He further asserted decoupling does not remove Commission oversight, ex post prudence reviews, or other methods regulators use to ensure that only approved, prudently incurred costs are paid by customers. Moreover, Indiana is unique in that it includes a statutory earnings test that protects against over-earnings.

Dr. McDermott testified rate cases will continue to provide the main focus of regulatory review; decoupling only serves as a stop gap to provide utilities with a reasonable opportunity to recover the level of fixed costs that have already been approved by the Commission. He expressed the opinion that the OUCC's proposed EIM alternative and the lost revenues approach are both unworkable and do not address the fundamental issue related to decoupling - changing the utility's sales ethic to a conservation ethic.

The Commission questioned Mr. Chapman during his rebuttal testimony, asking whether Vectren South looked to a particular state or other electric utility company as a model for its decoupling proposal. Mr. Chapman responded, "I don't think there was a particular company. I think we've more general in looking at what's been going on. There's no doubt that the gas drove it more than looking at other electrics." Tr. at R-101. Similarly, the Commission questioned Mr. McDermott, asking: "Which state or particular utility's decoupling model has been deemed most successful." *Id.* at U-36. Mr. McDermott answered: "Well, I mean, California has done wonderful stuff, and if you look at the level of consumption per household in a place like California, it has come down dramatically over the last 20 years." *Id.*

(7) Commission Discussion and Findings. Throughout its testimony, Petitioner contends that its proposed decoupling mechanism is reasonable and necessary because it: (1) removes the Company's disincentive to pursue energy efficiency initiatives by removing the

relationship between collecting revenues and making sales; and (2) aligns the interest of the Company with its ratepayers in attempting to promote conservation of natural resources. After careful review of the evidence outlined herein, we reject Vectren South's decoupling proposal for the reasons discussed below.

Initially, it is prudent to start with a discussion of what is called the regulatory "bargain" or regulatory "compact" that exists in this state. Vectren South is provided a monopoly service area in which retail consumers cannot choose to obtain their electric service from another provider. In turn, Vectren South must plan for and serve all of those consumers. Thus, the public is provided reasonable and adequate utility service at reasonable rates and, in exchange, utilities are ensured cost recovery and an opportunity to earn a reasonable return on its investment. We discussed the regulatory compact in some detail in our recent Order in Cause No. 43566:

Indiana law declares this traditional monopoly structure to be "in the public interest" and unalterable by the authority granted to the Commission in Ind. Code § 8-1-2.5 *et seq.* Ind. Code §§ 8-1-2.3-1; 8-1-2.5-11. The Service Area Act is a cornerstone of Indiana's retail electric utility service framework. Assigned service areas were created to provide for the "orderly development of coordinated statewide electric service at retail, to eliminate or avoid unnecessary duplication of electric utility facilities, to prevent the waste of material and resources, and to promote economical, efficient, and adequate electric service to the public." Ind. Code § 8-1-2.3-1.

Commission's Investigation into Any and All Matters Related to Commission Approval of Participation by Indiana End-Use Customers in Demand Response Programs Offered by the Midwest ISO and PJM Interconnection, Cause No. 43566, 2010 Ind. PUC LEXIS 255, at *123-24 (IURC July 28, 2010).

As Dr. Dismukes testified, Vectren South operates "in the public interest" not only because it provides basic and necessary customer service, but also because it extracts and utilizes valuable natural resources in providing that service. He stated further that intentionally wasting those natural resources is inconsistent with this public interest standard and the promotion of inefficient sales for profit is simply inconsistent with an underlying public interest principle of close to 100 years of utility regulation. We agree, whether Vectren South receives a particular cost recovery mechanism or not, it remains obligated to conserve resources as part of its regulatory bargain. *See* Ind. Code § 8-1-2.3-1.

One of the ways that the Commission can ensure that utilities are complying with the mandate to prevent the waste of material and resources is through the Integrated Resource Plan ("IRP") that each utility is obligated to provide. The biennial IRP filing is intended to provide the Commission with the utilities' long-term resource planning. As we stated in our Order in Cause No. 43566:

An integral component of the IRP in Indiana is that the evaluation of supply and demand resources is to be undertaken with cost effectiveness in mind. Specifically, 170 IAC [] 4-7-1(s) defines "integrated resource planning" to be "a utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs."

2010 Ind. PUC LEXIS 255, at *128. Therefore, Vectren South, like all other electric utilities in the State, is legally obligated to consider demand side options on a level playing field with supply side options.

Not satisfied with the efforts of many Indiana utilities' conservation efforts, in 2004 the Commission initiated an investigation to examine the overall effectiveness of DSM programs in the state (Cause No. 42693). The Commission designated Testimonial Staff which included Ms. Susan Stratton, Executive Director of the Energy Center of Wisconsin. Ms. Stratton's report stated that Indiana ranked below average for spending for energy efficiency and in savings attained by its energy utilities. *Commission's Investigation, Pursuant to IC § 8-1-2-58, into the Effectiveness of Demand Side Management ("DSM") Programs*, Cause No. 42693, Phase I Order, 2008 Ind. PUC LEXIS 190, at *15 (IURC April 23, 2008). Ms. Stratton also found that Indiana's per-capita energy consumption in 2003 was the highest in the Midwest and well above the national average. *Id.*, at *10-11. Ms. Stratton concluded that increased DSM programs can result in overall cost savings to energy consumers in the state. *Id.*, at *11.

In 2006, Governor Daniels's administration published Hoosier Homegrown Energy: Indiana's Strategic Energy Plan ("Indiana Plan").⁵ The Indiana Plan set improvement in energy efficiency as one of three overall State goals. In terms of achieving that goal, the Indiana Plan expressed support for the National Action Plan for Energy Efficiency ("National Action Plan")⁶ through gas and electric utilities, regulators, and industry partners to create a sustainable and aggressive commitment to energy efficiency.

Our Phase II Order in Cause No. 42693, advanced the Governor's Plan. *Commission's Investigation, Pursuant to IC § 8-1-2-58, into the Effectiveness of Demand Side Management ("DSM") Programs*, Cause No. 42693, Phase II Order, 2009 Ind. PUC LEXIS 482 (IURC December 9, 2009). We ordered all Indiana jurisdiction electric utilities to create core DSM programs and set an annual energy savings goal of two percent within ten years with interim savings goals for years one through nine. Therefore, Vectren South has been ordered to increase its conservation efforts and the evidence in this Cause demonstrates it appears that it is attempting to comply.

The Indiana Plan also included a directive to "support alternative pricing regulatory mechanisms that encourage utilities to promote efficiency and conservation by their customers without incurring negative financial results." Indiana Plan at 14. This directive ties closely to one of the recommendations of the National Action Plan which also identified the modification of policies "to align utility incentives with the delivery of cost effective energy efficiency and modify ratemaking practices to promote energy efficiency investments" as a key objective. Pet. Ex. CX-5 at ES-1.

The Commission has considered "alternative pricing regulatory mechanisms" when they have been brought before us. Notably, Petitioner's gas affiliates Vectren North and Vectren

⁵ A copy of the Indiana Plan is available at <http://www.in.gov/oed/2384.htm>.

⁶ Information about the National Action Plan is available at <http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html>.

South entered into settlement agreements with the OUCC and other intervenors that included a rate decoupling mechanism, and the Commission approved those settlements. *See Ind. Gas Co.*, Cause Nos. 43046 and 43298, 2006 Ind. PUC LEXIS 376 (IURC Dec. 1, 2006). As we evaluate the need for alternative pricing regulatory mechanisms in this case, it is prudent to look at what cost recovery mechanisms are currently available to Vectren South and whether those mechanisms encourage utilities to promote efficiency and conservation by their customers without incurring negative financial results.

Indiana electric utilities, unlike their natural gas counterparts, have specific cost recovery mechanisms in place that provide them the opportunity to not only avoid negative financial results, but to earn incentives on prudently implemented energy efficiency measures. Under the Federal Energy Independence and Security Act of 2007 (“EISA”), States were required to consider modification of rate designs to align utility incentives with the promotion and delivery of energy efficiency resources. *See* 16 U.S.C. § 2621. As we have recently found in addressing this EISA directive, our review of Indiana law and regulations demonstrate that the Commission presently possesses sufficient authority under existing statutes and regulations to ensure that energy efficiency resources are considered by utilities and timely cost recovery provided through rates. *Investigation of the Indiana Utility Regulatory Commission*, Cause No. 43580, 2009 Ind. PUC LEXIS 496, at *82 (IURC December 16, 2009).

170 IAC 4-8 provides Indiana utilities the opportunity to: (1) recover program costs; (2) recover lost revenue caused by the implementation of those programs; and (3) receive shareholder incentives. One of the stated purposes for the development of this regulatory framework is to allow:

a utility an incentive to meet long term resource needs with both supply-side and demand-side resource options in a least cost manner and ensures that the financial incentive offered to a DSM program participant is fair and economically justified. The regulatory framework attempts to eliminate or offset regulatory or financial bias against DSM or in favor of a supply-side resource, a utility might encounter in procuring least-cost resources.

170 IAC 4-8-3(a).

To balance the interests of both the utilities and their ratepayers, this rule limits a utility’s right to seek recovery of lost margins specifically caused by that utility’s energy efficiency efforts. In other words, the utility’s ratepayers will not be forced to reimburse the utility for revenues lost due to free riders or to reductions in demand caused by other factors not associated with the utility’s programs. This is particularly relevant at this time due to the local, national, and global emphasis placed on conservation of natural resources. For example, some of Vectren South’s customers are likely taking steps, independent of Vectren South, to reduce their energy consumption. Another factor that contributes to the reduction in demand is the current economic downturn and the necessity of ratepayers to conserve as much money as possible. It would not be equitable to allow Petitioner to recover from its ratepayers for energy savings caused by ratepayers’ own responsible efforts to conserve. In addition, Vectren South has already sought and gained approval of its energy efficiency programs and it is entitled to pursue program cost recovery and shareholder incentives. *See S. Ind. Gas & Elec. Co.*, 2009 Ind. PUC LEXIS 495.

Vectren South indicates its desire to pursue energy efficiency efforts in addition to those than have been approved by the Commission to date. We encourage Vectren South to do so, but we do not feel such efforts justify a cost recovery tracking mechanism such as decoupling that differs from the existing mechanisms under Indiana law, which provide a better, more equitable way to reward conservation efforts.

Second, a decoupling mechanism is not well suited for use by a vertically integrated fully regulated electric utility. As we have previously discussed, Vectren's natural gas utilities have pilot decoupling programs in place. The vast majority of decoupling mechanisms that have been approved in this and other jurisdictions were approved on a pilot basis for distribution-only utilities. The differences between decoupling for a gas distribution company, as opposed to a vertically integrated electric utility with generation, transmission, and distribution assets and functions, are considerable. Decoupling became viable when gas prices began rising earlier this decade. This, coupled with increased state-driven energy efficiency requirements, resulted in a consistently decreasing average use per customer. This has generally not been the case for vertically integrated electric companies. In fact, under questioning by the Commission to identify other successful decoupling programs with vertically integrated electric utilities, Mr. Chapman did not identify any other companies or states except for Vectren's gas utility and Mr. McDermott only referred in very general terms to the State of California.

Further, distribution-only utilities' fixed costs are considerably less than electric utilities. Since there is no generation function for a distribution-only utility, it simply procures and transports the commodity, natural gas for example, to its end users. The fixed cost component of a typical distribution-only utility's bill is generally around 25% of the total amount. Decoupling the distribution revenues of a distribution-only company from its sales has minimal impact on its customers. A customer, through its distribution-only company or otherwise, who implements efficiency measures can realize significant savings since seventy-five percent of the bill is the commodity that the customer is now using more efficiently. In contrast, the fixed cost component of a typical fully integrated electric utility, such as Vectren South, is approximately 75% of the bill. Since the commodity costs are such a relatively small portion of the bill (25%), a reduction of usage by Vectren South customers will not result in as high a proportional reduction in their bills.

Finally, Vectren South's decoupling proposal would allow the Company to recover revenues for reductions in energy consumption that were not caused by its conservation efforts. Vectren South's proposal is for a "full" decoupling, which means that it will recover its lost margin regardless of causation. Dr. Dismukes testified that a reduction in revenue associated with energy efficiency programs is quite small. Other factors, namely changes in weather, income, commodity prices, or economic conditions, often result in greater reductions in sales. Vectren South has no control over these factors; certainly it cannot control the weather or the economy. The Commission is convinced that its present DSM rules allow for a more reasonable and targeted approach to decoupling a utilities conservation efforts from any related financial harm.

Based upon the discussion above, we find that the proposed decoupling mechanism is not in the public interest. Therefore, we reject Vectren South's proposed SRA. The Commission acknowledges that creative rate designs, which enhance the efficient use of energy such as time-

differentiated rates, may influence the attractiveness of a decoupled rate design. We note, however, that Vectren South's tariff proposals contained no such creativity.

C. Cost and Revenue Tracking Mechanisms.

(1) **Use of Cost Tracking Mechanisms.** In this proceeding, Vectren South proposed to continue use of several cost tracking mechanisms, including its MCRA, RCRA and DSMA. Both Vectren South and the other parties proposed certain modifications to the trackers as discussed below. In addition, there was debate among the parties as to the magnitude of these non-fuel cost trackers. Currently, the Company's approved tracking mechanisms primarily cover non-fuel MISO costs, purchased power demand costs and DSM costs. Many other utilities also track these types of costs.

(2) **FAC.**

(a) **Base Rate Fuel Level.** Vectren South originally proposed to remove all trackable fuel costs from base rates and recover them in the FAC. After the OUCC opposed this proposal, the Company withdrew the proposal in its rebuttal evidence. Consequently, we find Vectren South's base rates shall include a level of fuel costs of \$195,533,802 with associated revenue based taxes.

(b) **Voltage-Differentiation Line Loss Adjustments.** The Company proposed that its FAC be changed to reflect the line loss differentiation by rate schedule to remedy a cost allocation deficiency. The Company's current FAC calculation does not adjust the FAC for individual rate schedules to reflect their different voltage service levels. Mr. Ulrey testified that different voltage service levels result in different line losses being experienced by each rate schedule. Consequently, the amount of generation or purchases, and therefore fuel, necessary to provide kWh of sales varies by rate schedule. Mr. Ulrey stated that revising the FAC to reflect these line losses ensures a more correct allocation of fuel costs and that each rate schedule pays the appropriate per unit fuel cost without subsidizing or being subsidized by other rate schedules. No party disagreed with Vectren South's proposal on line losses and we find this proposal provides a more correct allocation of fuel costs between rate classes and should be approved pending resolution of the issue discussed below in the Company's first FAC filing after this Order goes into effect.

OUCC Witness Eckert did express concern about how the FAC Application schedules and workpapers would reflect the line-loss allocation. Mr. Eckert sought confirmation that this change would not impede the ability of the OUCC to timely perform its fuel cost analysis as required by law. The OUCC raised this concern because the Company did not provide sample FAC Application schedules and workpapers demonstrating how the line-loss percentages would be utilized. On rebuttal, Vectren South Witness Albertson explained that Petitioner's Exhibit JLU-S8 demonstrated how the line-loss adjustment would be projected by rate schedule in the FAC. Mr. Albertson also provided schedules and workpapers illustrating how actual FAC variances will be allocated to the rate schedules.

The Bench questioned Mr. Ulrey and Mr. Albertson about whether Vectren South's rate schedule based adjustment uses actual line losses. Mr. Ulrey responded the adjustment uses the

actual system energy loss and allocates it appropriately to each rate schedule. Mr. Albertson responded that the adjustment “is not a function of actual losses,” tr. at X-93, but rather “is a function of the losses attributable to each rate schedule based on the study that was performed about three years ago,” tr. at X-93 to 94. Although we find Vectren South’s adjustment proposal is not unreasonable, Mr. Albertson’s testimony causes us concern about whether the line loss calculation will be based upon the Company’s actual total company losses.

Vectren South’s proposal to allocate the total line loss to the various rate schedules on a pro rata basis is acceptable provided the Company begins its computation with the actual total company losses. Therefore, we conditionally approve the Company’s line-loss proposal subject to the provision of evidence that the allocation methodology is based upon the Company’s actual total company losses. Vectren South shall provide such evidence in its first FAC filing after this Order goes into effect.

(c) **Weather Normalization For Earnings Test.** Vectren South Witness Hardwick testified that the Company is proposing to weather normalize NOI in each future quarterly FAC for purposes of the earnings test so that its authorized return is compared against its actual return on a weather normalized basis. The Company intends to use the same weather normalization procedure used in this proceeding. Ms. Hardwick believed weather normalizing both actual results and the authorized NOI ensures that the results of the earnings test truly reflect the operating results of the business. Weather is an uncontrollable factor that Ms. Hardwick stated can materially impact financial results.

OUCG Witness Bolinger opposed weather normalizing Vectren South’s NOI for purposes of the FAC. Mr. Bolinger noted that he was unaware of any electric utility weather normalizing earnings in the FAC earnings test since the earnings test was introduced in the 1980s. He stated that the Commission rejected the same proposal that Vectren South is now making in its November 20, 2008 Order in Cause No. 38708 FAC78 S1. Mr. Bolinger emphasized that the Company did not identify any ratepayer benefits from weather normalizing earnings in the FAC. Mr. Bolinger did not believe that making a normalization adjustment in a rate case necessitated similar normalization adjustments for the FAC earnings test and emphasized that the expedited nature of the FAC proceedings do not lend themselves to the types of normalization adjustments made in rate cases.

Ms. Hardwick’s rebuttal testimony contended that the Commission’s Order in Cause No. 38708 FAC78 S1 did not foreclose a future proposal to weather normalizing the NOI for FAC purposes but only indicated such a discussion should occur in the base rate case. The Company is now raising this issue in its base rate case. She testified that a weather normalization adjustment has long been conducted in Gas Cost Adjustment (“GCA”) proceedings and that while the electric and gas industries are affected differently by weather, both face changes in sales volumes and revenues driven by weather variations that are beyond management’s control. She stated that the desire to obtain the most accurate and reasonable comparison of authorized earnings to actual earnings should be no different in the FAC earnings test than in the GCA earnings test. Ms. Hardwick pointed-out that the Commission had previously found that, for GCA proceedings, if the last rate case used weather normalized operating results, the use of consistent weather normalizing procedures should result in a more relevant calculation of the rate of return currently being earned by the utility in a more reasonable comparison with the return

authorized in the utility's last rate case. She believed this same principle applied to electric utilities.

The Commission finds the introduction of weather normalization into Vectren South's FAC proceedings creates an unnecessary complication to the summary proceeding. Allowing this adjustment in the context of an electric utility introduces too much uncertainty about what other adjustments should be made. The potential for such protracted litigation in what should be an expedited FAC proceeding outweighs any gain from the weather normalization "accuracy" and presents no benefit to ratepayers. Therefore, we reject Vectren South's proposal to weather normalize its NOI in FAC proceedings.

(3) **RCRA.** Mr. Albertson proposed several modifications and enhancements to Vectren South's existing Reliability Cost and Revenue Adjustment ("RCRA") mechanism. First, he stated that Vectren South proposes to rename "Generation" Costs and Revenues as "Reliability" Costs and Revenues in the DESCRIPTION section on Sheet No. 74, to coincide with the name of this adjustment. Second, he stated that Vectren South is proposing to track both Environmental Emission Allowance ("EEA") costs and Variable Production Costs ("VPC") through the RCRA. Mr. Albertson testified that, with respect to other costs recovered in the RCRA, Vectren South proposes to continue, in Cause No. 43406, the current RCRA methodology for the remaining components of the RCRA while updating the base rate amounts around which such components are tracked. Other than as discussed below, we agree with Mr. Albertson that Vectren South should continue its current RCRA methodology.

(a) **Environmental Emission Allowance Costs.** Mr. Albertson testified that Vectren South proposes to add to the RCRA a component to track the difference from the base level of EEA expense because such EEAs are used on behalf of retail customers. He explained that currently, Vectren South recovers in base rates a fixed level of expense associated with the cost of EEAs as those allowances are used. In this proceeding, the test year level is \$515,108. While Vectren South does not currently track around this base level of expense, Mr. Albertson opined that because these costs are unpredictable and volatile, it was appropriate to track these expenses. He indicated that all other EEA-related components of the RCRA would remain unchanged.

OUCW Witness Armstrong testified that the OUCW is not opposed to tracking emission allowance expenses attributed to retail electricity sales above the base rate amount. However, she believed that the test-year level of retail EEA expenses of \$515,108 was unreasonably high for several reasons. First, she stated that the test year level of expense is five to ten times higher than the previous four years, mainly due to Vectren South's purchase of 2,000 allowances in July 2008, which increased the weighted average inventory cost of the EEAs to \$32.38 per EEA. Second, Ms. Armstrong noted that Vectren South made a lump-sum adjustment outside of the test year to correct past mistakes with the accounting for retail EEA consumption expense. She said that although the problem occurred during the test year, the correction was not made until after the test year, thereby resulting in inaccurate test year retail EEA expense. Finally, Ms. Armstrong argued that the test year amount of retail EEA expense will not accurately reflect Vectren South's true need for emission allowances in future years. Ms. Armstrong therefore recommended that the Commission use the five-year historical average of \$135,627 to calculate the test year retail EEA expense.

With respect to the tracking of EEA expense, Ms. Armstrong agreed that EEA costs could be volatile on a year-to-year basis. She also found that Vectren South has prudently managed its emission allowance portfolio and has taken steps to minimize its reliance on the EEA markets. Ms. Armstrong recommended that if Vectren South is permitted to track EEA costs above the test year level, then it should credit ratepayers with 100% of the revenues from the sale of retail emission allowances. She stated that the OUCC agreed to an EEA revenue sharing mechanism with Vectren South in the past in order to pass back benefits associated with the installation of pollution control projects to consumers. She noted that requiring Vectren South to pass back 100% of EEA revenues would remove any incentive for Vectren South to acquire emission allowances with the hopes of selling them for a profit later. In addition, she stated that the EEA trackers approved for Duke and I&M currently credit ratepayers with 100% of the proceeds from the sale of allowances.

Finally, Ms. Armstrong testified that the Commission should only allow Vectren South to track SO₂, NO_x Seasonal and NO_x Annual allowances at this time. While she indicated that the OUCC is not opposed to the tracking of CO₂ allowances in the future, she believed that Vectren South (and other utilities) should be required to present an environmental compliance plan for managing CO₂ emissions before the utility is approved to track CO₂ EEA costs.

In rebuttal, Vectren South agreed with the OUCC's proposal to use a five-year historical average of retail EEA expense as the base level. However, Mr. Jochum testified that the previously approved allowance proceeds sharing mechanism should continue. He stated that under Senate Bill 29, when Vectren South built its selective catalytic reduction units ("SCRs") and the Warrick 4 scrubber, there were a number of incentives available including a premium return on the investment. He explained that while Vectren South did not seek such incentives, it did reach agreement with the OUCC on sharing of proceedings from allowance sales with the vast majority of proceeds going to customers. He pointed out that Ms. Armstrong agrees that Vectren South has done a good job managing its allowance portfolio. Furthermore, he stated that with regulation changes Vectren South currently faces risk related to devalued allowances. He added that Vectren South has not, and will not, engage in speculative allowance trading. Therefore, Mr. Jochum recommended that the sharing mechanism previously approved should be continued.

We agree with the OUCC's proposal, which Vectren South agreed to in its rebuttal testimony, to allow Vectren South to track its EEA expenses, using the five-year average expense as the base level. However, we find Vectren South's arguments regarding the continuation of the current sharing mechanism persuasive, and we see no reason why the current incentive sharing arrangement for allowance sales proceeds should be discontinued. That said, the Commission agrees with the OUCC that Vectren South should not be allowed to track the EEA expense for EEAs it acquires solely for the purpose of reselling at a profit or for any other reason not related to environmental compliance. Rather, the tracker is meant to recover only EEA expense incurred to comply with environmental emission regulations. Therefore, Vectren South may continue to share the proceeds of EEA sales using its current sharing mechanism.

(b) Variable Production Costs.

(i) Vectren South's Evidence. Mr. Albertson testified that Vectren

South also proposes to track differences between the actual level of VPC expenses incurred and the actual level of VPC recoveries. He stated that the VPCs would be allocated to customers based on energy (kWh) sales, adjusted for line losses, rather than on 4 CP as are all other RCRA components. Mr. Albertson explained that Vectren South will add the VPC Component of the RCRA to the Reliability Component (which is allocated on 4 CP) by Rate Schedule in each RCRA filing, based on this allocation distinction. Mr. Albertson provided an illustrative example of how the VPC Component will be determined in Petitioner's Exhibit SEA-8 (Revised).

Mr. Jochum provided further support for Vectren South's proposed VPC tracking mechanism. He testified that Vectren South incurs significant variable costs associated with the operation of its generating units. More specifically, he explained that there are four main categories of VPC that are incurred to produce energy (outside of fuel): (1) chemicals associated with the operation of SCRs and scrubbers, which include lime, soda ash, limestone, ammonia and catalyst; (2) coal combustion byproduct disposal, which includes fly ash, bottom ash, and scrubber byproduct including gypsum; (3) fuel handling; and (4) boiler water chemicals.

Mr. Jochum testified that VPC is both significant and volatile. He stated that the total test year cost of VPC was \$22.9 million, which represented one-third of total generation operating expenses incurred during the test year. Moreover, he said that for the period of 2006-2008, VPC ranged from \$18.23 - \$25.28 million annually. Mr. Jochum stated that these expenses have become so volatile because of two primary factors—unit run levels and natural gas and fuel oil prices. He explained that going forward, increased volatility is possible given the many uncertainties driving unit run times, including customer demand, LMP and changes to environmental regulations. He added that, as always, natural gas and fuel oil prices will also be volatile.

Mr. Jochum explained that unit run levels are largely outside of Vectren South's control as MISO, not Vectren South, controls unit dispatch. He stated that until 2009, this had not been an issue because Vectren South's units were selected to run most of the time. However, because of the unprecedented low LMP in 2009, Mr. Jochum stated that Vectren South's units have been idled far more frequently than normal, resulting in reduced VPC. He explained that to the extent volatile market conditions cause changes to LMP, unit run levels, and thus VPC, will remain unpredictable from year to year and will not be within Vectren South's control.

Mr. Jochum further explained that VPC were volatile even before changes in unit run levels due to the volatile nature of chemical expenses. He said that in order to operate Vectren South's pollution control equipment, Vectren South uses limestone, lime, soda ash and other chemicals. He stated that oil and natural gas prices are key inputs either in the production and/or transport of these chemicals, and so the prices for these materials have tracked volatility in oil and gas prices. Mr. Jochum added that because oil and gas prices are a function of global markets, the changes in prices of these chemicals have been passed on to Vectren South, and because chemical suppliers are aware of this volatility, they typically will not enter into long-term fixed price contracts. Mr. Jochum stated that, as a result, chemical costs have also been largely beyond Vectren South's ability to control.

Mr. Jochum identified other factors that influence the level of VPC, including coal

combustion byproduct disposal costs, the loss of gypsum sales revenue together with new delivery costs, fuel handling expense and boiler water chemical expense. He described in detail the volatility associated with these expenses and the factors contributing to their variability.

Mr. Jochum argued that a VPC tracking mechanism is necessary to address the great deal of future uncertainty in these expenses. He stated that each of the four types of costs will continue to vary, based upon MISO's dispatching, and that changes in natural gas and oil prices will continue to drive pricing of chemicals and the cost to transport chemicals and coal combustion byproduct. In addition, Mr. Jochum said that potential changes in environmental requirements can also impact the level of usage of the various chemicals, and that there is great uncertainty in this area as the United States Environmental Protection Agency ("USEPA") considers changes to multiple regulations.

Mr. Jochum testified that the hours of run time of Vectren South's baseload units will always be a key driver of non-fuel variable costs, and that history has shown WPM performance and non-variable fuel costs are linked. Thus, according to Mr. Jochum, fluctuations in wholesale activity impact the level of these costs. He opined that, just as Vectren South's customers share in the ups and downs of WPM performance, changes in VPC tied to energy production, which exhibit similar volatility to WPM, and are largely subject to the same types of demand, fuel price and market price influences that are outside of Vectren South's control, supports implementation of a tracking mechanism. He concluded that implementation of a VPC tracking mechanism is fair to both Vectren South and its customers as it allows Vectren South to smooth these costs year over year, and because it is consistent with the sharing of increases and decreases in WPM results.

(ii) **OUCC's Evidence.** OUCC Witness Blakley testified regarding Vectren South's proposed VPC tracking mechanism. He opposed inclusion of VPC in the RCRA because of concern that such tracking may disproportionately address costs which trend upward without tracking other costs which trend downward or revenues that increase. He opined that Vectren South's request could be considered "piecemeal" ratemaking. He also opined that unit run levels are a result of market conditions which affect other electric utilities as well. He stated that the market constantly changes and companies manage within these market changes. He disagreed with Mr. Jochum's assessment of VPC expenses as being volatile, and recommended that the chemical and other operating costs continue to be recovered through base rates and not through the RCRA tracking mechanism.

OUCC Witness Dismukes also provided testimony regarding the VPC tracking mechanism. He asserted that Vectren South's proposal runs counter to sound regulatory principles and, if adopted, would create a host of disincentives that are contrary to regulatory efficiency and the public interest. More specifically, Dr. Dismukes believed that the VPC tracking mechanism would create disincentives for cost efficiency and would lead to an expedited regulatory oversight process that would challenge most regulatory stakeholders. According to Dr. Dismukes, the regulatory process has long recognized the importance of retrospective reviews in motivating a utility to be efficient. He worried that the VPC tracking mechanism would insulate Vectren South from the risks associated with its actions. He cited academic literature suggesting that tracking mechanisms have many deficiencies and can result in higher utility costs.

Dr. Dismukes presented an analysis of Vectren South's production costs, which showed that Vectren South's non-fuel O&M expenditures per MWh have been relatively high in comparison to Vectren South's peers, while its transmission O&M costs per MWh remain much lower than its peers. Based on this analysis, Dr. Dismukes concluded that Vectren South's cost performance record is somewhat mixed, and does not reflect sufficient volatility to warrant a tracking mechanism. Dr. Dismukes also discussed the results of a 2008 benchmarking study conducted by Vectren South, and opined that a performance-based approach to regulation would be more suitable than an expansion of revenue and cost trackers. Dr. Dismukes concluded that the Commission should not approve the VPC tracking mechanism.

(iii) Industrial Group's Evidence. Industrial Group Witness Phillips also opposed the tracking of VPC through the RCRA. According to Mr. Phillips, the recovery of various cost components through separate trackers would circumvent the base ratemaking process by allowing Vectren South to recover increases in these base rate cost items without taking into account the possibility that reductions in other costs or increases could offset the requested cost recovery. He opined that the VPC tracker amounted to "single issue" ratemaking and should be rejected as a matter of policy. Mr. Phillips also asserted that the proposed mechanism would shift regulatory risk from utility investors to customers by allowing for full cost recovery for these items.

(iv) Vectren South's Rebuttal. In rebuttal, Mr. Jochum testified that the OUCC's own testimony supports Vectren South's position that the costs it seeks to track are significant, volatile, and outside the control of the utility. He stated that Mr. Blakley acknowledges that VPC has annually changed in amount by over \$7 million, which would correspond to a 10% decrease in net operating income in 2009. He stated that if the proposed base level of VPC of approximately \$24 million increases or decreases by \$7 million in a twelve month period that would represent a 30% change in these costs. Furthermore, Mr. Jochum testified that even greater volatility is highly likely due to anticipated USEPA regulations. As to Vectren South's ability to control the costs, Mr. Jochum noted that even Mr. Blakley conceded that the electric market "constantly changes" and there are "no guarantees that Locational Marginal Prices ("LMP") will remain low or high." With respect to the price of natural gas and fuel oil, Mr. Jochum reiterated that chemical producers are unwilling to enter into multi-year fixed price contracts because of the volatility in their production costs, and thus Vectren South cannot "manage" this volatility as Mr. Blakley suggested.

Mr. Jochum next refuted the "piecemeal ratemaking" argument against tracking these costs. He testified that the case relied upon by the OUCC, Cause No. 40402, represented an example where the Commission found that the utility's requested accounting treatment did not constitute piecemeal ratemaking, but rather was necessary to "mitigate the negative effects of regulatory lag" by preventing earnings erosion caused by certain capital projects going into service between rate cases. He explained that the piecemeal ratemaking argument is the reason for the application of the established three-part test (material, volatile and outside the control of the utility) which is used to determine whether a cost should be tracked. He stated that tracking of material, volatile, and difficult to control expenses is contemplated because when these criteria are demonstrated to exist, absent cost tracking, the reasonable opportunity to achieve the approved return can be compromised. He said that the piecemeal ratemaking concept simply requires the criteria for a tracker to be met, which is the case with respect to VPC.

Mr. Jochum also disputed the claim that the VPC tracker would be a significant shift of risk. He said that Vectren South's trackers, including VPC, will only cover less than 10% of its non-fuel costs. Furthermore, while \$24 million of VPC would become the subject of a tracker, only decreases and increases in costs would be reflected in the mechanism. He stated that while a \$7 million change in VPC would be very material to Vectren South, such an allocated annual cost change is less of an issue for individual customers. Moreover, Mr. Jochum explained that changes in VPC will likely reflect changes in wholesale revenue that could be used to offset an increase in this expense.

While Mr. Jochum continued to support the proposed VPC tracker, he testified that in order to be responsive to the other parties' expressed concerns, Vectren South is willing to modify the proposed VPC tracker to only cover changes to the costs of chemicals (including ammonia) and catalyst. He explained that these costs tie directly to compliance with changing federal regulations and LMP influenced demand, and thus are likely to be the most volatile of the VPC costs and the least within Vectren South's ability to control. Moreover, Mr. Jochum stated that Vectren South must incur these costs to comply with federal law—such compliance with USEPA regulation of air emissions is not optional. He stated that this modified tracker proposal resembles the cost tracking Vectren South has been authorized to do under Senate Bill 29 in the past related to the operating costs for the SCRs, and more recently the Warrick 4 scrubber.

(v) **Commission Findings.** Vectren South originally requested the VPC tracker to track the difference between the actual level of VPC expenses incurred and the amount contained in base rates. The original proposal included four categories of costs in the VPC tracker, namely: (1) chemicals and catalyst; (2) coal combustion byproduct disposal; (3) boiler water treatment; and (4) fuel handling. In rebuttal, Vectren South modified its proposal to include only chemical and catalyst expenses. Vectren South's proposed base rates in this Cause include \$15.4 million for chemical and catalyst costs. The VPC tracker would track the difference between the actual expense incurred by the Company and the \$15.4 million included in base rates.

In considering whether to approve a new cost tracking mechanism, we not only review whether a specific type of cost qualifies as material, volatile and difficult to control, but also, from a broader perspective, we review the utility's risks related to its operating costs and the other tracking mechanisms it has in place. In general, tracking of costs should remain limited in nature so the Company is responsible for managing its overall operating costs. Typically, utilities track operation & maintenance expenses, such as those proposed to be included in the VPC tracker, only while a QPCP construction project is in progress. Once a QPCP project is complete and a rate case is filed, the maintenance and operation expenses are included in base rates along with the capital value of the project. All of the company's pollution control property is operating and in service at this time, and the property and its associated operating expenses have been rolled into Vectren South's rate base in this Cause.

This Commission has previously allowed trackers for several types of expenses. These include the previously mentioned FAC process, environmental cost recovery trackers, demand side management ("DSM") trackers, and MISO cost trackers. Vectren South believes that the chemical and catalyst costs that it has incurred are volatile, substantial, and largely outside of the control of the utility. These three qualities for an expense to be tracked, are basic guidelines to

follow, they are not rigid principles requiring the creation of a tracker. We believe the causes for determining if an expense or revenue is appropriate for tracking are often times situational. While we have approved a number of trackers in the past, we acknowledge Dr. Dismukes's warnings. Revenue or cost trackers tend to make utilities less accountable for their actions because they are less incented to streamline costs or operations. We are also concerned that the proliferation of trackers in the electric industry may result in utilities unreasonably extending the time between rate cases. If they can recover the majority of their variable costs through trackers, they have no incentive to come before the Commission and account for other, non-tracked, decreasing costs or increasing revenues.

Based upon the discussion above, we do not find Vectren South's VPC tracker proposal to be reasonable. While we acknowledge the possibility that chemical and catalyst costs may be volatile in the future, we find it is reasonable to confirm that possibility before moving toward tracking such costs. As Vectren South has embedded an amount for this expense into its base rates it will receive timely recovery of a representative level of costs. We do not foreclose the future consideration of such a tracker should the potential volatility be realized and established with evidence.

(4) MCRA.

(a) Vectren South's Evidence. Mr. Jochum testified regarding Vectren South's MISO Cost and Revenue Adjustment ("MCRA") mechanism. He explained that the MCRA was approved in Cause No. 43111 to allow for recovery of MISO charges not recovered in quarterly FAC filings. He stated that the MCRA is calculated on a semi-annual basis for each of Vectren South's rate schedules based on the calculation of non-fuel cost components, such as MISO Schedule 10, Schedule 16, Schedule 17, Schedule 24, Schedule 26, and Schedule 2 charges, as well as costs not otherwise recovered by MISO that are socialized for recovery from all market participants. Mr. Jochum described the major developments in MISO since Vectren South's last rate case, including the advent of the Ancillary Services Market ("ASM") and the Commission's Orders in Cause No. 43426, wherein the Commission approved the tracking of various MISO charges and credits through either the MCRA or the FAC.

Mr. Jochum recommended that the Commission approve Vectren South's continued use of the MCRA. He stated that the MCRA provides an accurate and manageable regulatory recovery mechanism for critical MISO non-fuel related costs to allow participation in MISO and its ASM and energy markets on an ongoing basis. He noted that the charges and credits to be recovered under the MCRA have been federally mandated by FERC and are a necessary cost in the provision of safe, adequate and reliable service. Second, Mr. Jochum explained that these costs are variable both in amount and in timing. Third, he stated that these charges and credits are outside the control of Vectren South, as FERC rulemakings, litigated proceedings, refunds, additional charges, actions of the MISO, new generation, loss of generation, variation in loads and customer levels within MISO's footprint, and the normal vagaries of weather and economic and business cycles all impact their level. Finally, Mr. Jochum testified that the ability to timely recover these credits and charges on an ongoing basis is important to Vectren South's financial well being and important to the accuracy of price signals sent to Vectren South's customers.

Mr. Albertson explained that the primary change Vectren South proposes to make with

respect to the MCRA concerned transmission revenues discussed by Mr. Chambliss. With respect to the other costs currently tracked through the MCRA, Mr. Albertson proposed to continue, in Cause No. 43354, the current MCRA methodology which tracks differences from the level of MISO costs included in base rates, while updating the base rate amount around which such costs are tracked.

(b) OUCC's and Industrial Group's Evidence. OUCC Witness Eckert provided background on the MCRA and testified that the OUCC supports Vectren South's participation in MISO. Mr. Eckert testified if the Commission chooses not to track non-RECB transmission revenues, then Mr. Eckert recommended the discontinuance of the MCRA mechanism.

Industrial Group Witness Meyer recommended that the Commission discontinue the MCRA, as, in his opinion, the level of expense proposed to be tracked is not sufficiently material to warrant a tracker. He asserted that because the base rate amount of \$3.2 million in MCRA-related costs is less than 1% of Vectren South's total expenses, Vectren South should simply include that amount in base rates and not track changes above and below the base amount.

(c) Vectren South's Rebuttal. In rebuttal, Mr. Jochum responded to Mr. Meyer's assertion that the costs to be tracked in the MCRA were not material enough to justify a tracker mechanism. He testified that the base level of \$3.2 million does not tell the story in terms of the potential magnitude of these costs. He explained that the MCRA currently covers 19 MISO charges, and the annual amount over the last 2 years has varied from negative \$1.8 million to positive \$13.9 million. He thus concluded that the costs were in fact material, especially when the potential for new or modified charges is considered.

Mr. Jochum testified that the costs assessed by MISO are, and continue to be, volatile and beyond Vectren South's control. He provided examples of MISO charges that have varied on a monthly basis by as much as 4500%. He also provided specific examples of the changing nature of the MISO footprint, which impacts socialized and volumetric charges that Vectren South must pay on behalf of its retail customers. Mr. Jochum testified that although Vectren South provides input on tariff and policy issues, it does not result in control over MISO's decision making, FERC's resolution of issues, or the decision of other utilities on what RTO to join. Thus, according to Mr. Jochum, Vectren South's exposure to MISO cost volatility will remain a reality for the foreseeable future.

Mr. Albertson also testified in support of the continuation of the MCRA. He provided an exhibit documenting the actual level of MISO non-fuel costs approved for recovery in 2008 and 2009. He explained that absent MISO non-fuel cost tracking, given the current base rate amount of approximately \$3.9 million, in 2008 customers would have overpaid these non-fuel costs by over \$5.8 million; given the \$3.2 million MISO non-fuel costs base rate amount proposed in this proceeding, the foregone credit for customers would have been more than \$5.1 million. Mr. Albertson stated that the opposite occurred in 2009; Vectren South would have had to absorb nearly \$3.2 million in additional costs beyond its control had the cost tracker not been in place.

Mr. Albertson testified that a significant component of MISO cost volatility in 2008 and 2009 has been the MISO resettlements process as required by directives from the FERC. He

stated that Vectren South has no control over these processes which impact actual costs. He further stated that the net change in costs in two recent successive years of nearly \$9 million demonstrates that MISO cost tracking is absolutely critical to ensure that neither customers nor shareholders are at risk for this level of volatility.

(d) Commission Findings. The existing MCRA mechanism recovers the difference between base rates and actual non-fuel MISO costs, net of certain MISO revenues collected by Vectren South. As set forth in Petitioner's Exhibit SEA-R6, the proposed base level of these costs is \$3,231,252. Vectren South's rebuttal evidence provided a multi-year historical analysis of these costs that showed that the MCRA had varied dramatically over time, from a customer credit of (\$5,130,872) in a 2008 MCRA filing to a customer charge of \$4,974,127 in the very next MCRA in 2009. On a prospective basis, Vectren South submitted Mr. Jochum's testimony regarding factors that continued to create uncertainty and potential volatility in the amount of non-fuel MISO costs, including (1) MISO membership changes such as the departures of Duke Energy-Ohio and First Energy, which, if allowed, would alter existing allocations of MISO revenue and costs, (2) MISO tariff changes that could create new costs or significantly change existing costs, and (3) reconciliations of MISO settlements that could shift large costs or credits into future periods.

Over the last two years, on a net basis Vectren South's MISO costs have not been large, but they are material and have exhibited volatility. At this time, changes continue to occur in terms of PJM/MISO membership switches and new and modified services to be provided by MISO. These various changes, which can impact costs significantly in the future, are not within Vectren South's control. Based on this evidence, uncertainty and volatility in MISO non-fuel costs continue to exist, and thus, the MCRA should remain in place. We will continue to monitor MISO changes, and the resulting costs and revenues. At some point, tracking these costs may not be necessary; however, the ongoing evolution of MISO and PJM indicate that this is not the time to eliminate this tracker.

(5) DSMA. The Company proposed that the costs of two additional programs be recovered in its DSMA: a Direct Use pilot program targeting electric water heating customers and a Direct Load Control ("DLC") inspection and maintenance program. Mr. Albertson explained the Direct Use program costs would be limited to \$100,000 in the first year and would be allocated to rate classes on the basis of the 4 CP allocation percentages approved in this proceeding. The DLC costs would also be allocated on a 4 CP basis. Vectren South Witnesses Petitt and Sears discussed the benefits of these programs. Mr. Albertson also proposed that energy-apportioned DSMA costs approved in Cause No. 43427 be allocated on projected energy sales adjusted for line losses. No party objected to these proposals and we find they should be approved.

(6) Tracker Roll-Ins and Terminations. With respect to Petitioner's MCRA, RCRA, and DSMA (collectively, "Adjustments"), the same projected costs and revenues from the most recently approved Adjustment filings will be used to determine Adjustments to be implemented concurrent with new base rates in this proceeding. Those projected costs and revenues will be compared to new base rate levels of costs and revenues approved herein, with differences included in the new Adjustments. Reconciliation amounts included in the most recently approved Adjustments will remain unchanged. Finally, rate schedule allocation

percentages applicable to each of the Adjustments shall be updated as approved in this Cause.

Petitioner's investment in the Warrick 4 FGD approved in Cause No. 42861 has been included in base rates. Therefore, Appendix G of Petitioner's Tariff (QPCP-CC2) is eliminated.

Similarly, operating expenses related to the Warrick 4 FGD have been included in the revenue requirement in this proceeding. Therefore, Appendix H of Petitioner's Tariff (QPCP-OE2) is eliminated. Petitioner will reconcile QPCP-OE2 expenses and recoveries as of the date of rates in this proceeding, and will include any remaining difference in its next RCRA filing.

Petitioner may in the future propose similar construction cost and operating expense recovery mechanisms to the extent it makes investments in pollution control equipment which qualifies for such treatment.

Petitioner has included its investment in Blackfoot Landfill Gas Generating equipment in base rates in this proceeding. Therefore, Appendix K of Petitioner's Tariff (BLGA) is eliminated.

D. Riders.

(1) **Rider NM.** Vectren South Witnesses Sears and Albertson described proposed changes to the Company's Rider NM. Rider NM allows certain customers to install renewable generation facilities and return any energy not used by the customer from such facilities to the grid. Mr. Sears described Vectren South's experience with net metering under Rider NM. He indicated that five active customers currently participate and that the Company works with customers and their contractors who are interested in establishing a net metering service. Due to customer feedback indicating interest in net metering projects which exceed the current tariff's limit, the Company is proposing to expand Rider NM to allow commercial customers to participate and for facilities as large as 100 kW to connect. The Company also proposed to increase the total participation on Rider NM from one-tenth of one percent to one percent of the most recent aggregate summer peak load. Mr. Sears testified that net metering applications allow customers to self-generate electricity and thereby reduce the use of electricity supplied by the Company and use any amount in excess of the customer's need to serve other customers. He noted that absent decoupling, Vectren South's cost recovery is impeded by net metering.

Mr. Albertson explained that Vectren South requested a variance from 170 IAC 4-4.2-1 in order to make Rider NM available to customer generators with a nameplate rating in excess of 10 kW. He explained that the Company will also comply with the level of interconnection review requirements consistent with the nameplate rating of the generator. Mr. Albertson stated that Vectren South also sought a variance from the limitations on the insurance limitations imposed by 170 IAC 4-4.2-8(a) due to the increase in the size of customer generators also proposed under the rules. The Company proposed instead to apply the provisions of 170 IAC 4-4.3-10(b)(1) such that it may require additional insurance commensurate with the specific risks of a particular net metering application.

The Commission is currently in the process of revisiting its net metering rules codified at 170 IAC 4-4.2. Vectren South has sought several variances from our current rules that are

consistent with the proposed modifications to those rules. Consequently, we find Vectren South's requested variances as to the size of net metering facilities, the amount of net metering the Company will allow, participation by commercial customers and increased insurance requirements for larger facilities should be approved consistent with the proposed tariffs submitted by the Company. We anticipate adopting new net metering rules in the near future. To the extent Vectren South's revised Rider NM is inconsistent with those rules, the Company should file a revised Rider NM that complies with such rules under the Commission's thirty-day filing procedure within 60 days of the date any new net metering rules become effective.

(2) **Other Riders.** The Company has proposed a new Alternate Feed Service Rider, Temporary Service Rider, and Standby or Auxiliary Service Rider. The Company has proposed changes to its Economic Development Rider and Area Development Rider. The Company proposes to eliminate its Interruptible Power Service Rider and Efficiency Incentive Rider in which no customers currently participate. Mr. Albertson discussed these Riders in his direct testimony. No party objected to these proposals and we find they should be approved.

13. **Rules.** Vectren South Witness Albertson described a number of revisions to the Company's General Terms and Conditions (the "Rules"). Mr. Albertson described the revisions to the Rules in his testimony which included modernization of the rules, minor changes to improve clarity, revisions to ensure safe, reliable and cost effective service and revised facility extension rules. Vectren South provided copies of the revised Rules and a redline identifying all changes from the existing Rules.

OUCG Witness Hand advocated wholesale rejection of Vectren South's proposed Rules and retention of the current Rules claiming the Company offered little justification or rationale, and inadequate empirical evidence to support the Revisions. He claimed most of the Rules are designed exclusively to benefit Vectren South at the expense of customers. Mr. Hand identified specific concerns including access to Company tariffs only through the Internet and other issues we address specifically below.

On rebuttal, Mr. Albertson opposed outright rejection of the proposed Rules, explaining that the Company has proposed a number of changes to improve clarity and consistency with the Tariff and to update the Rules to reflect current procedures. We agree with Mr. Albertson that outright rejection of Vectren South's Rules is not warranted. The OUCG raised specific concerns with certain of the Rules, which the Company has either addressed or responded to and we will evaluate those specific concerns below. However, these enumerated concerns do not warrant rejection of the entirety of the Rules proposed by Vectren South. Vectren South has proposed a number of revisions to modernize its Rules and bring consistency between the Rules and its existing Tariff and practices. Except as noted below, we find Vectren South's proposed Rules as reflected in Petitioner's Exhibit SEA-R2 should be approved.

A. **Rule 1(a)(7).** Rule 1(a)(7), as initially proposed, would have allowed Vectren South to deny service at a Premises if a customer residing at the Premises has accrued unpaid arrearages. Mr. Hand raised concerns that proposed Rule 1(a)(7) would give the Company the authority to terminate electric service to customers who are current on their payments and have no history of non-payment based on a co-tenant's outstanding debt. Mr. Albertson explained the Company had proposed this rule to keep bad debt as low as possible for all customers and stated

that it was consistent with 170 IAC 4-1-16(c)(2). The Company did propose revisions to address the OUCG concerns. Petitioner's Exhibits SEA-R2 and SEA-R3 set forth revised language which specified that either the Applicant or Co-Applicant must have an unpaid debt at another Premise. We find these revisions sufficiently alleviate the concern raised by the OUCG that service would not be available to a person merely because another co-tenant who is no longer a Vectren South customer resides at the Premises and approve Rule 1(a)(7) as set forth in Petitioner's Exhibit SEA-R2.

B. Rule 3(a). On cross-examination, Mr. Albertson was asked about the meaning of the term "deceptive" in Rule 3(a). He explained in rebuttal that the term was added to address circumstances wherein customers falsely claim that a bill they have received for electric service is not for service provided to them but that they have been the victim of identity theft and the falsehood is established by a subsequent investigation. We agree that customers who falsely assert they are identity theft victims to avoid paying bills should pay the cost of investigating their assertions. We find this concept appropriate, but instruct Vectren South to incorporate the following definition of deception in its Rules to avoid dispute about the meaning of the word deceptive:

As used in Company's General Terms and Conditions, Rule 3(a), receipt of Electric Service by Customer at Customer's premises the term "deceptive" refers to a situation wherein a Customer has made a claim of identity theft that is, upon investigation, determined to be not legitimate.

C. Rule 6(b). Rule 6(b) was proposed by Vectren South to ensure that no alternative source of electric light or power is used at a Premise without appropriate equipment necessary to isolate the Company's system. Mr. Hand expressed concern that language in the proposed Rule could be read as discouraging or preventing alternative source generation (solar, wind, electric vehicle, etc) or net metering. He acknowledged the Company had stated this was not the intent of this Rule. The Company proposed modified language reflected in Petitioner's Exhibit SEA-R2 that we find sufficiently alleviates the concern and should be utilized by the Company.

D. Rule 7. Currently Rule 7 permits fees to be assessed by the Company if a Customer denies a Company representative access to disconnect service. Vectren South proposed to replace the word "denies" with "fails to provide access." Mr. Hand opposed this change because it allows more frequent punitive customer penalties/fees based on potentially non-deliberate acts. Vectren South did not propose to amend this revision, maintaining that customers receive multiple notices of an impending disconnection. Mr. Albertson also explained that Vectren South would incur additional costs if it could not access a customer's meter which cost should be borne by that customer and not others whether intentionally incurred or not.

We find that Vectren South has failed to provide sufficient evidence of the need for a change to the language of Rule 7. We agree with the OUCG that allowing Vectren South to expand the charge to customers who fail to provide access runs the risk of imposing punitive penalties/fees for non-deliberative acts. Therefore, we find the language of Rule 7 should remain unchanged.

E. Rule 8. The Company has proposed revisions to its non-residential customer

deposit rules in Rule 8. Mr. Hand opposed these revisions on the grounds that Vectren South offered no evidence that these charges are necessary to recover additional costs of serving these customers nor that the utility is suffering any negative consequences by the absence of these changes. Mr. Phillips opposed these revisions for similar reasons and further noted that the potential for significant deposits was not reflected in the Company's capital structure and that there was no provision for interest on the deposits.

Vectren South Witness Goocher testified in rebuttal that the changes were made because the Company's current rules governing deposits for non-residential customers are very general in nature and subject to differing interpretations. He testified that more detailed provisions will be more informative to customers and will more clearly provide the flexibility needed to more efficiently and consistently manage deposits in the best interests of both customers and the Company. Mr. Goocher explained that the new rules would make it easier for Vectren South to return deposits to customers whose creditworthiness satisfies its standardized approach with the knowledge that future deposits can be required if the customer's creditworthiness deteriorates. Mr. Goocher described the factors reviewed by the Company in determining creditworthiness and noted the analysis was consistent with the approach used by MISO and other utilities. Mr. Goocher stated that the proposed rules would not require all non-residential customers to post or increase deposits but only existing or new non-residential customers whose creditworthiness is inadequate. Mr. Goocher also clarified that the Company was proposing to pay interest on deposits at the Federal Funds Effective Rate.

We find it is appropriate for Vectren South to add clarity regarding its rules for deposits from non-residential customers. A number of questions came up at the hearing about the proposed rules. To address those issues, we find Subsection 8(c)(1) of the Company's proposed rules shall be revised to read as follows:

(1) Unless otherwise stated in Customer's contract with Company, Company will require new Non-Residential Customers to provide a deposit, and may require the same of existing Non-Residential Customers, if Company reasonably determines that Customer's creditworthiness is inadequate or if a history of late or non-payment exists. The amount of the deposit will be based on the amount of the two (2) highest months' usage based upon the most recent twelve (12) months' historical usage or projected annual usage. In determining creditworthiness of Non-Residential customers, Company shall consider the size of the credit exposure and the availability of information about Customer, and shall review information such as, but not limited to: Customer's independently audited annual and quarterly financial statements, including an analysis of its leverage, liquidity, profitability and cash flows; credit rating agency information; publicly available news and information about Customer's business or industry; Customer's payment history.

Subpart 8(c)(2) shall also be modified to add the term "existing Non-Residential" before the word Customer in the first line to ensure the increased deposit requirement is applied only to existing Non-Residential Customers. Subpart 8(c)(4) should be modified to add the following language to ensure that deposits are not unfairly retained by the Company:

The deposit will be refunded to Customer if Company later determines that Customer's creditworthiness has become adequate based on the evaluation of creditworthiness described in (c)(1) above. In lieu of a cash deposit, Customer may provide an irrevocable standby letter of credit in a form, and from a financial institution, satisfactory to Company.

Our revision to subpart 8(c)(4) renders the last sentence of subpart 8(c)(5) duplicative so it shall be stricken. These changes will ensure that Vectren South fairly applies deposit requirements to Non-Residential Customers.

F. Rule 19. The Company also proposed to revise Rule 19 concerning Extension of Company Facilities to change the test to determine whether a facilities extension or modification deposit is required from 2½ years of total revenue to 3 years of fixed cost revenue, defined as revenue from Customer Facilities Charge, Energy Charge, and Demand Charge, less any Transformer Ownership or Transmission Voltage discounts. The proposal is made pursuant to 170 IAC 4-1-27(D)(3) which provides for variances from the 2½ years of revenue test in the Commission's Rule. No party opposed the Company's proposal. We find it should be approved and we grant the Company a variance from the 2½ years of revenue test as necessary to implement the Company's proposed rule.

G. Summary. We find Vectren South's proposed General Terms and Conditions are reasonable and should be approved except as otherwise provided above. Further, we find Vectren South's proposed Tariff For Electric Service, including the General Terms and Conditions, as admitted with Petitioner's rebuttal evidence (Pet. Ex. SEA-R2) in all other respect is reasonable and should be approved except as otherwise provided above.

14. Dense Pack Projects.

A. Evidence. In its petition and case-in-chief, Vectren South stated it has turbine overhauls scheduled for Unit 1 of its Brown Station in 2012 and Unit 2 of the Brown Station in 2013. Vectren South asserts that due to recent proposed rules of the USEPA that will regulate CO₂ emissions, Vectren South could be required to install Best Available Control Technology ("BACT") on the turbines at the time of these overhauls. The Company believes the BACT for turbine overhauls is the Dense Pack technology. To install this technology during the 2012 and 2013 overhauls, Vectren South needs to proceed in making contractual commitments beginning this year that will include substantial payments. Regardless of the potential USEPA rules, the fuel cost and emission reductions resulting from the improved steam path efficiency made possible by the Dense Pack technology support the decision to proceed with these projects. The capital costs for these projects are estimated to be \$35 million.

In its Order in Cause No. 43568 dated June 17, 2009, the Commission found a Dense Pack project should not be included in Vectren South's tracking mechanism for Clean Coal and Energy Projects ("CCEP") adopted pursuant to Ind. Code Ch. 8-1-8.8 but instead should be "included in the normal course of ratemaking," *i.e.*, a base rate case. Order at 9. Based on the benefits provided by this technology and the Commission's finding that Dense Pack Projects cannot be included in Vectren South's CCEP tracking mechanism, Vectren South proposed that the Commission authorize a second step to the base rate increase sought herein to be effective

when both the Brown Unit 1 and Unit 2 Dense Pack Projects have been completed and placed in service that would provide a return on the Company's capital investment in the projects and recovery of related depreciation expense. Vectren South also requested authority to continue to accrue allowance for funds used during construction ("AFUDC") and to defer depreciation on the Dense Pack projects from their respective in-service dates until they are reflected in the second step rate increase, as well as to include a return on such AFUDC and an amortization of such deferred depreciation in the step two revenue requirement. Vectren South asserted the proposal is reasonable because of the importance and size of the projects and the environmental benefits and fuel cost savings that will be passed on to customers.

OUCG Witness Bolinger opposed the second step proposal and contended rate recognition for the Dense Pack Projects should be considered in a future base rate case because of other changes that may occur between now and 2013. However, Mr. Bolinger stated Vectren South could seek post-in-service AFUDC and deferred depreciation treatment for the projects at a time closer to their completion. Industrial Group Witness Gorman also opposed the step 2 rate increase. Evansville Witness Sommer recommended any step 2 increase be based on updated billing determinants.

In rebuttal, Mr. Jochum estimated the fuel cost savings from the Dense Pack Projects to be \$4.4 million per year and annual CO₂ allowance savings under pending federal carbon reduction legislation to be as much as \$1.9 million. He said the Company has already spent over \$8 million on the projects and the first Dense Pack will be in service about one year after new rates are expected to be approved in this case and both Dense Packs will be in service within 18 months of the new rates. Mr. Jochum testified that if the step 2 proposal is not accepted, the Commission should authorize post-in-service AFUDC and deferred depreciation at this time. He said the Company would commit to reporting on the actual improvements achieved and demonstrate heat rate improvement at each unit of at least 5%. Jochum Rebuttal at 17-20. Ms. Hardwick also testified this accounting treatment should be granted to avoid earnings erosion in the event the step 2 proposal is not accepted.

B. Commission Findings. We accept the position of the OUCG and Industrial Group not to authorize a second step rate increase for the Dense Pack Projects and instead authorize post-in-service AFUDC and deferred depreciation as described by Vectren South in its alternative rebuttal position. Given the fact that contracts have already been executed, over \$8 million in capital expenditures have already been made and the units are expected to be in service within twelve months and 18 months of our Order in this Cause, we do not believe it is necessary or appropriate to require the Company to make a separate accounting request at a later time. We grant this request because of the earnings erosion which would otherwise occur but also because of the significant environmental and cost savings benefits that will immediately accrue to the customers from these projects. Further, we note the approved accounting treatment proposed by the company is contingent upon a demonstration of at least 5% heat rate improvement from each project. *See* Pet Ex. RGJ-R1, p. 20. We find that the Company shall file a verified certification when each project is completed and placed in service and report on the actual improvements achieved by the projects.

15. Reliability Metrics and Reporting.

A. OUCC's Evidence. OUCC Witness Alvarez recommended that Vectren South adopt a standard reliability index and definition of Major Event Day ("MED"). He further recommended that Vectren South continue its Enhanced Service Reliability Reporting to the Commission and the OUCC using the standard reliability index and MED calculations as the framework for the report.

More specifically, Mr. Alvarez stated that Vectren South should use the IEEE Standard 1366-2003 Major Event Days ("IEEE 1366") as its standard method of calculating major events and reliability indices, rather than its internal definition of a major event. He opined that Vectren South's use of its own definition has made it difficult to directly compare its system performance with other utilities that do use the industry standard.

Mr. Alvarez next discussed the reliability indices used by other Indiana investor-owned utilities, which include: (1) System Average Interruption Frequency Index ("SAIFI"); (2) System Average Interruption Duration Index ("SAIDI"); and (3) Customer Average Interruption Duration Index ("CAIDI"). He stated that these are also the most commonly reported indices by utilities to state public utility commissions across the United States. Mr. Alvarez reviewed Vectren South's historic reliability indices and explained the relationship between CAIDI and the other two indices, suggesting that improved CAIDI results may merely reflect more short duration outages.

Mr. Alvarez recommended that Vectren South include the adoption of the IEEE 1366 standard to calculate major events in its Enhanced Service Reliability Report. He opined that Vectren South's internal definition overstates the number of major events and makes it difficult to compare Vectren South's reliability with the three largest Indiana IOUs that have adopted IEEE 1366.

Mr. Alvarez also explained that as part of the Settlement Agreement approved in Cause No. 43111, Vectren South agreed to provide written reports to the OUCC twice a year, for a period of three years, regarding certain system metrics and progress on maintenance programs. Alvarez Direct at 16-17. He stated that Vectren South has met this obligation by compiling and submitting an "Enhanced Service Reliability Report" to the OUCC twice a year. He opined that this report is valuable to the OUCC because it represents an initial step towards performance-based efficient operations and maintenance and therefore should be continued.

B. Vectren South's Evidence. In rebuttal, Mr. Chambliss testified that Mr. Alvarez confuses the concepts of "major event" and MEDs. He testified that Vectren South uses its definition of "major event" in its annual report to the Commission, not the definition of an MED. He explained that if a major event spans more than one day, the subsequent days are MEDs. Mr. Chambliss stated that this distinction is important because confusing the two terms can easily lead to errors when evaluating system performance.

Mr. Chambliss testified that Vectren South does not use the IEEE 1366 standard because Vectren South has found this definition inadequate. He stated that the IEEE 1366 definition of MED does not provide a method to identify days following a major event when a utility is

involved in significant restoration efforts. Mr. Chambliss indicated that identifying these days is important because random outages that follow a major event generally take longer to restore than they would ordinarily, due to their having occurred during a major event where Vectren South is already engaged in significant restoration and repair activities. Consequently, he believed that application of IEEE 1366 can underestimate the number of MEDs. He also stated that IEEE 1366 requires utilities to discard days with a SAIDI of zero; that is, days with no interruptions. He noted that in 2009, Vectren South had six days with a SAIDI of zero.

Mr. Chambliss disagreed with Mr. Alvarez's assertion that Vectren South's definition of major event overstates the number of major events. On the contrary, he stated that Vectren South's definition identified two fewer major events for 2008 and 2009 when compared to the number of major events identified when using the IEEE 1366 definition. He also disagreed with Mr. Alvarez's claim that improved CAIDI results could simply reflect that the utility was experiencing more short duration outages. He stated that determining the drivers behind these metrics requires a much more thorough examination and understanding of the underlying data, as Mr. Alvarez's own sources attest.

Mr. Schach responded to Mr. Alvarez' request that Vectren South provide an enhanced level of service reliability reporting. He testified that currently Vectren South reports SAIFI, SAIDI and CAIDI to the Commission, which are the most common indicators used to measure electric system reliability. While Mr. Schach did not oppose providing the OUCC with the same information already reported to the Commission, he believed that the enhanced reporting, which would require significant effort in tracking, compiling and reporting additional detail to the OUCC, is unjustified. He stated that the indices already reported to the Commission reflect the overall reliability performance of Vectren South and effectively summarize decisions made related to planning and prioritizing reliability-based spending. He added that it was unclear as to whether the OUCC simply wants to gain a better understanding of utility maintenance and engineering practices, or instead wants to provide recommendations on operational issues. Mr. Schach stated that the former can be accommodated informally through review of the information provided to the Commission and without increased reporting obligations.

Mr. Schach then described the complexities associated with planning and prioritizing reliability-based spending. He explained that such spending requires a review of electric system performance from a variety of perspectives, including evaluations of the worst performing circuits, small area reviews and cause-based analyses. In addition, Mr. Schach stated that a variety of other factors influence decisions concerning electric system reliability, including the availability of circuit contingency support, physical condition of the assets and their exposure to environmental risks, customer considerations and system protection design considerations. He explained that numerous other factors must be considered as well, further demonstrating that the planning and prioritizing of reliability-based spending is a complex topic that includes the review of many factors.

Mr. Schach concluded that the indices already reported to the Commission (SAIDI, SAIFI and CAIDI), along with the notification of major storms, provides an effective mechanism for evaluating reliability performance over time. He stated that when Vectren South originally agreed to supply the Enhanced Service Reliability Reporting to the OUCC it was for a fixed period of time, knowing that the evaluation of reliability planning requires constant changes in

reliability program design to effectively improve reliability performance. He therefore stated that Vectren South proposes to provide the OUCC with the same information currently provided to the Commission, but does not believe that continued “enhanced reporting” to the OUCC would be useful. He added that Vectren South is always willing to meet with OUCC representatives to respond to questions and explain approaches to reliability.

C. Commission Findings on Reliability Metrics. State regulation requires that investor-owned utilities report major events as part of their Reliability Indices Report. *See* 170 IAC 4-1-23(e)(2). However, these regulations bestow each utility with the power of defining major events for itself, and this Commission has never required a uniform definition of “major event” by utilities in contradiction of such regulations. Likewise, no law, regulation or Commission order has ever required a uniform definition of MED. The OUCC desires more conformity with the definitions in order to compare utility performance. However, regardless of the definitions used, service territory geography, size, and customer mix will make such comparisons difficult. Moreover, Vectren South has provided reasonable and substantial concerns with the IEEE 1366 standard definition of major event and MED, including concerns voiced by the IEEE 1366 standards committee itself. We find that the utility has provided reasonable justification for its chosen definition. Further, the record does not provide a basis to ignore our existing rule which expressly allows each utility to define such terms itself. Based on the foregoing, we conclude that Vectren South may continue to use its current definitions for major event and MED.

D. Commission Findings on Reliability Reporting. As outlined and approved in the Settlement Agreement in Cause No. 43111, as part of its receipt of funding for new or expanded reliability related initiatives, Vectren South agreed to provide certain system metrics and maintenance program progress reports during the “interim period” between approval of the Settlement Agreement and Vectren South’s next base rate case. Upon a final order in this proceeding the interim period will end. Vectren South proposes to discontinue the “enhanced” maintenance program reports to the OUCC, and instead continue providing reports to the OUCC of the system metrics and indices (SAIDI, SAIFI and CAIDI), which it also reports to the Commission. Although Mr. Alvarez testified that the enhanced reports provide value to the OUCC, there is no evidence that such value warrants extending them beyond the interim period agreed to in the Settlement Agreement. Mr. Schach testified that the standard reliability reports provided to both the Commission and the OUCC sufficiently reflect the overall reliability performance of Vectren South, and that “enhanced” reporting requirements create unnecessary burdens to Vectren South with minimal value to the OUCC. We find no reasonable justification for extending the interim period beyond that which was agreed to by the parties in the Settlement Agreement. Based on the foregoing, we find that Vectren South should continue reporting its system metrics currently provided to both the OUCC and the Commission, and that no further “enhanced” reporting requirements are necessary.

16. Confidential Information. Vectren South filed three motions for protective orders and Vectren South and the OUCC filed one joint motion for a protective order, all of which were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code § 5-14-3-4(a)(4) and (19) and Ind. Code § 24-2-3-2. The presiding officers issued docket entries and made rulings from the bench finding such information to be preliminarily confidential, after which such information was submitted under

seal. We find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner") shall be and hereby is authorized to increase its basic rates and charges for electric utility service in accordance with the findings herein. Such rates shall be designed to produce additional annual revenue of \$28,613,673 in order to produce total annual revenue of \$591,442,340, gross margin of \$365,245,181 and net operating income of \$94,450,297. For purposes of computing the authorized net operating income for Ind. Code § 8-1-2-42(d)(3), the increase in Petitioner's return shall be phased-in over the appropriate period of time that the Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order.

2. Petitioner shall file with the Commission's Electricity Division new schedules of rates and charges which properly reflect the revenue, revenue allocation and rate design authorized herein. Petitioner shall submit with its new rate schedules a revised cost of service study reflecting the findings herein along with a revenue proof demonstrating the new rates produce the revenue authorized herein. The new rates and rate schedules shall be effective upon filing with and approval by the Electricity Division.

3. Simultaneously with the filing of the new rate schedules, Petitioner shall file with the Electricity Division revisions to its Fuel Adjustment Clause, MISO Cost and Revenue Adjustment and Reliability Cost and Revenue Adjustment and eliminate its Qualified Pollution Control Property Multi-Pollutant Construction Cost Adjustment, Qualified Pollution Control Property Multi-Pollutant Operating Expense Adjustment and Blackfoot Landfill Generation Adjustment to reflect the rolling into base rates of costs currently reflected in these adjustments. Petitioner is authorized to implement line loss adjusted FAC factors in its FAC filings as described herein.

4. Subject to the modifications required herein, Petitioner's proposed Tariff For Electric Service, including the General Terms and Conditions, as admitted with Petitioner's rebuttal evidence in Ex. SEA-R2 is approved to be effective upon its filing with and approval by the Commission's Electricity Division.

5. Petitioner is hereby authorized to revise its Reliability Cost and Revenue Adjustment, MISO Cost and Revenue Adjustment, and Demand Side Management Adjustment as approved herein.

6. Petitioner's request for a second step rate increase for the Dense Pack Projects is denied. Petitioner is authorized to continue to accrue allowance for funds used during construction and to defer depreciation expense on its Dense Pack projects from their in-service dates until they are included in Petitioner's rate base for purposes of setting base rates as discussed herein. Petitioner shall file a verified certification when each project is completed and

placed in service and report on the improvements actually achieved by the projects.

7. Petitioner's request for a variance from the Commission's rules on net metering and facilities extensions for purposes of implementing Rider NM and Company Rule 19 is approved as described herein.

8. Petitioner shall adjust its rates to eliminate the amortizations of rate case expense, MISO Day 1 costs, MISO Day 2 costs, DSM costs and the deferred tax liability relating to the Medicare Part D subsidy receivable at the end of their respective amortization periods by filing revised rate schedules with the Commission's Electricity Division.

9. Sharing of wholesale power marketing margins above and below the base rate level on a 50/50 basis between the Company and the ratepayers is approved.

10. Petitioner's proposal to revise the depreciation rate applicable to the Blackfoot Landfill Gas Generating Station to 3.7% is approved as discussed herein.

11. The Confidential Information submitted under seal in this Cause pursuant to motions for protective orders are determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and therefore exempt from public access and disclosure pursuant to Ind. Code § 5-14-3-4 and § 8-1-2-29.

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

ATTERHOLT, LANDIS AND ZIEGNER CONCUR; BENNETT AND MAYS NOT PARTICIPATING:

APPROVED: **APR 27 2011**

I hereby certify that the above is a true and correct copy of the Order as approved.



Shala M. Coe
Acting Secretary to the Commission