STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, INC. SEEKING AUTHORITY TO REFLECT ADDITIONAL VALUES OF QUALIFIED POLLUTION CONTROL PROPERTY UNDER CONSTRUCTION IN ITS RATES THROUGH ITS STANDARD CONTRACT RIDER NO. 62, PURSUANT TO IND. CODE SECTIONS 8-1-2-6.6, 8-1-2-6.8 AND 170 I.A.C. 4-6-18; SEEKING APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT CONCERNING CERTAIN CLEAN COAL TECHNOLOGY PROJECTS PURSUANT TO IND. CODE SECTION 8-1-8.7-7; SEEKING APPROVAL OF AN UPDATED COMPLIANCE PLAN, UPDATED COST ESTIMATES AND ESTIMATED IN-SERVICE DATES FOR ENVIRONMENTAL PROJECTS; SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS CLEAN COAL OPERATING COST REVENUE ADJUSTMENT STANDARD CONTRACT RIDER NO. 71, IN ACCORDANCE WITH IND. CODE SECTION 8-1-8.8-11; AND SEEKING APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS SO_2, NO_X AND Hg EMISSION ALLOWANCE ADJUSTMENT, STANDARD CONTRACT RIDER NO. 63	)	CAUSE NO. 42061 ECR 18 APPROVED: JAN 25 2012

ORDER OF THE COMMISSION

Presiding Officers:
Kari A.E. Bennett, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On October 26, 2011, Duke Energy Indiana, Inc. ("Petitioner", "Company" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking: (1) to reflect additional values of qualified pollution control property ("QPCP") in its rates and charges for electric service, through Standard Contract Rider No. 62 "Rider 62"); (2) approval of an ongoing review progress report concerning certain clean coal technology projects; (3) approval of updated environmental projects, cost estimates and in-service dates for environmental projects; (4) approval of an adjustment to its rates through its Clean Coal Operating Cost Revenue Adjustment mechanism, Standard Contract Rider No. 71 ("Rider 71"); and (5) approval of an adjustment to its rates through its sulfur dioxide ("SO_2"), nitrogen oxide ("NO_x") and mercury ("Hg") Emission Allowance Adjustment, Standard Contract Rider No. 63 ("Rider 63").

Pursuant to notice published as required by law, proof of which was incorporated into the record, an Evidentiary Hearing was held in this case on January 11, 2012 at 10:00 a.m. in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the Indiana Office of Utility Consumer Counselor ("OUCC") appeared at the hearing. Petitioner offered into evidence the testimony and exhibits of Mr. John J. Roebel, Ms. Diana L. Douglas, Mr. John P. Griffith, and Mr. Edward O. Abbott, as well as Petitioner's responses to Docket Entries issued on January 5 and 6, 2012. The OUCC offered the testimony of Mr. Wes R. Blakley and Ms. Cynthia Armstrong. The evidence of both parties was admitted without objection. No members of the public appeared or sought to testify at the hearing.

Based upon the applicable law and the evidence presented herein, and being duly advised, the Commission now finds as follows:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the Evidentiary Hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility within the meaning of the Public Service Commission Act, as amended, Ind. Code § 8-1-2-1, 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. Petitioner requests relief pursuant to Ind. Code §§ 8-1-2-6.6, 8-1-2-6.8, 8-1-2-42(a), Ind. Code chs. 8-1-8.7 and -8.8, and 170 IAC 4-6. The Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under the laws of the State of Indiana, and has its principal office at 1000 East Main Street, Plainfield, Indiana 46168. It is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such electric service to the public.

3. **Petitioner's Electric Generating Properties.** As of the date Petitioner filed testimony in this Cause, Petitioner's electric generating properties consisted of: (1) steam capacity located at four stations comprised of sixteen coal-fired generating units supplied by sixteen coal-fired boilers;[1] (2) combined cycle capacity comprised of three natural gas-fired Combustion Turbines ("CT") and two steam turbine-generators; (3) a run-of-river hydroelectric generation facility comprised of three units; (4) peaking capacity consisting of seven oil-fired diesels located at two stations, seven oil-fired CT units located at two stations, and sixteen natural gas-fired CTs, one of which has oil back-up.

[1] As noted in prior orders, pursuant to the New Source Review ("NSR") remedy order ("remedy order"), issued on May 29, 2009, Wabash River Units 2, 3, and 5 were shut down, effective September 30, 2009, pending a decision on appeal of the remedy order. On October 12, 2010, the United States Court of Appeals for the Seventh Circuit reversed the District Court. On April 15, 2011, the District Court vacated the remedy order and entered an Amended Judgment in favor of the Company. As a result, Wabash River Units 2, 3, and 5 were brought back on-line on May 31, May 5, and July 5, 2011, respectively. In addition, on March 1, 2011, Edwardsport Units 6-8 were shut down and retired in anticipation of the first firing of the auxiliary boiler of the new Edwardsport Integrated Gasification Combined Cycle ("IGCC") unit, and on June 1, 2011, Miami Wabash Unit 4 Combustion Turbine was retired.

4. **Background to this Proceeding.**

a. **NO_x SIP Call.** The federal NO_x State Implementation Plan ("SIP") Call and related Indiana NO_x SIP Call required that Indiana reduce its NO_x emissions during the ozone season of May 1 through September 30 to a level of 0.15 lb/mmBtu by May 31, 2004. The reductions in NO_x emissions in Indiana came primarily from industrial and utility sources.

On July 3, 2002, this Commission issued an order in consolidated Cause Nos. 41744 S1 and 42061, wherein, among other things, we: (1) found that Petitioner's NO_x Compliance Plan was reasonable; (2) issued a Certificate of Public Convenience and Necessity ("CPCN") for the use of clean coal technology; (3) approved the use of Petitioner's proposed QPCP; (4) approved Petitioner's updated cost estimates related to its NO_x Compliance Plan equipment; and (5) approved Rider 62 that allows for construction work in progress ("CWIP") ratemaking treatment for Petitioner's QPCP. We found that Petitioner may update the value of its QPCP for CWIP ratemaking purposes no more often than every six months. Additionally, we found that, under our ongoing review rules, Petitioner should submit, at least annually, a progress report detailing any revisions in its cost estimates or in the planned construction of its clean coal technology projects.

b. **CAIR and CAMR Compliance Requirements.** In January 2004, the U.S. Environmental Protection Agency ("EPA") published two new significant proposed emission reduction requirements: (1) the Clean Air Interstate Rule ("CAIR"); and (2) the Clean Air Mercury Rule ("CAMR"). EPA finalized CAIR on May 12, 2005 (70 Fed. Reg. 25162) and CAMR on March 29, and May 18, 2005 (70 Fed. Reg. 15994 and 70 Fed. Reg. 28606).

The final CAIR requires major SO_2 and NO_x emission reductions, established annual and seasonal NO_x trading programs, and set limitations on use of SO_2 emission allowances. The Indiana Air Pollution Control Board adopted the final CAIR on November 1, 2006.[2] The final CAMR provides regulatory authority for a mercury cap and trade program, with a mercury cap for 2010 set at 38 tons, and 15 tons in 2018. The Indiana Air Pollution Control Board adopted the CAMR on October 3, 2007.[3]

On May 24, 2006, the Commission issued an order in consolidated Cause Nos. 42622 and 42718 approving a Settlement Agreement among Petitioner, the OUCC, and the PSI Industrial Group wherein, among other things, we: (1) found that the Settlement Agreement was in the public interest; (2) approved Petitioner's Phase 1 CAIR/CAMR Compliance Plan; (3) found that the proposed scrubber, scrubber upgrade and baghouse projects constitute clean coal technology,

---

[2] On July 11, 2008, the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit") in *State of North Carolina v. Environmental Protection Agency* issued an opinion vacating and remanding CAIR; however, parties to the litigation requested rehearing of aspects of the Court's decision, including the vacatur of the rules. On December 23, 2008, the D.C. Circuit granted rehearing only to the extent that it remanded the rules to EPA without vacating them. The practical effect of this ruling is that CAIR remains in place until EPA issues a new rule in accordance with the July 11, 2008 decision ("CAIR Decision").

[3] On February 8, 2008, the U.S. Court of Appeals for the District of Columbia, in *State of New Jersey, et al., Petitioners v. Environmental Protection Agency, Respondent*, vacated the Federal CAMR.

clean coal and energy projects and QPCP; (4) issued a CPCN for the Phase 1 CAIR/CAMR Compliance Plan projects; (5) approved Petitioner's request for ongoing review of the Phase 1 CAIR/CAMR Compliance Plan projects; (6) approved Petitioner's cost estimates for the Phase 1 CAIR/CAMR Compliance Plan projects; (7) approved the use of accelerated (20-year) depreciation for the Phase 1 CAIR/CAMR Compliance Plan projects as provided in the Settlement Agreement; and (8) approved the timely recovery of costs associated with Petitioner's CAIR/CAMR Compliance Plan.

c. **Emission Allowance ("EA") Adjustment.** In Cause Nos. 42411 and 42359 the Commission approved the recovery of NO_x EA costs in Petitioner's then-existing SO_2 Emission Allowance Adjustment mechanism. In Consolidated Cause Nos. 42622 and 42718, the Commission approved the inclusion of Mercury EA costs in this same mechanism. Petitioner has used the Commission's 30-day filing process to implement these adjustments quarterly in accordance with the Settlement Agreement and Order in Cause No. 42411, but beginning with Cause No. 42061 ECR 10 elected to include future updates in these Proceedings.

5. **Relief Sought in this Proceeding.** In this six-month update proceeding, Petitioner requests the authority to reflect additional values of QPCP, as of June 30, 2011, in its rates and charges for electric service. Petitioner further requests approval of: (1) an ongoing review progress report concerning certain clean coal technology projects; (2) updated environmental projects, cost estimates and in-service dates for environmental projects; (3) an update and adjustment to Petitioner's Clean Coal Operating Cost Revenue Adjustment Rider (including approval of a credit to customers of the amount of incremental demand revenues, under a contract with Nucor, which has been apportioned to Riders 61, 62, and 71); and (4) an update and adjustment to Petitioner's SO_2, NO_x and Hg Emission Allowance Adjustment Rider.

6. **Statutory and Regulatory Framework.**

a. **Clean Coal Technology Statute.** Ind. Code § 8-1-8.7-7 provides that an applicant for a certificate of clean coal technology may elect ongoing review of its construction activities and construction costs, in which case the utility must periodically submit progress reports and cost estimate revisions to the Commission.

b. **CWIP Statute and Administrative Rules.** 170 IAC 4-6-4 provides that the Commission shall approve the use of QPCP if it consists of one or more air pollution control devices, the devices meet applicable state or federal requirements, the devices are designed to accommodate the burning of coal from the geological formation known as the Illinois basin, and the estimated costs of construction and installation are reasonable. Once pollution control equipment is found to be QPCP, then the utility is allowed to add the value of the QPCP to the value of the utility's property for ratemaking purposes. *See* 170 IAC 4-6-5; Ind. Code §§ 8-1-2-6.6 and -6.8. Per the Commission's CWIP rules, CWIP ratemaking treatment is available for QPCP that has been under construction for six months or longer, and a utility can update the amounts of its CWIP balances no more often than every six months. *See* 170 IAC 4-6-9 and -18.

c. **Utility Generation and Clean Coal Technology Statute, Ind. Code ch. 8-1-8.8 (also referred to as "Senate Bill 29").** Ind. Code § 8-1-8.8-11(a)(1) and (5) provide that "the commission shall encourage clean coal and energy projects by creating the following

financial incentives for clean coal and energy projects, if the projects are found to be reasonable and necessary: (1) the timely recovery of costs incurred during construction and operation of projects described in section 2(1) or 2(2) of this chapter; . . . (5) other financial incentives the commission considers appropriate." Ind. Code § 8-1-8.8-2(1)(B) defines "clean coal and energy projects" as "projects to provide advanced technologies that reduce regulated air emissions from existing energy generating plants that are fueled primarily by coal or gases from coal from the geologic formation known as the Illinois Basin, such as flue gas desulfurization and selective catalytic reduction equipment."

d. Emission Allowance Adjustment Authority. Ind. Code § 8-1-2-42(a) contemplates and recognizes rate adjustments in accordance with tracking provisions approved by the Commission, specifically exempting such rate adjustments from Indiana's "fifteen month rule."

7. Summary of Evidence. Petitioner presented case-in-chief testimony and exhibits of Mr. John J. Roebel, Senior Vice President of Generation Support, Ms. Diana L. Douglas, Director, Rates, Mr. John P. Griffith, Director, Portfolio Optimization, Fuel and Emissions, and Mr. Edward O. Abbott, Consulting Engineer, Performance & Measures.

Mr. Roebel stated that Petitioner is constructing its NO_x Compliance Plan projects to meet federal and state NO_x SIP Call requirements effective in May 2004 and is constructing its CAIR/CAMR Projects in order to comply with those federal requirements. Mr. Roebel explained that Petitioner's NO_x Compliance Plan is continuously changing and indicated that the current NO_x Compliance Plan is not significantly different from the plan presented in Cause No. 42061 ECR17, the most recent six-month update case. Thus, the following projects are currently included in Petitioner's current active NO_x Compliance Plan for which Petitioner is seeking CWIP and Senate Bill 29 recovery:

Gallagher Station Boiler Optimization Units 1- 4 Low NO_x Burners & Fuel Flow Monitoring Unit 4 Gibson Station Selective Catalytic Reduction ("SCRs") Units 1-5, including Injection System Boiler Optimization Units 1-5 SCR Catalyst Beds Units 1-5	Cayuga Station Boiler Optimization Units 1-2 Electrostatic Precipitator Units 1-2 Wabash River Station Boiler Optimization Units 2-6 Low NO_x Burners Units 2, 3, 4, 5, and 6 (Units 4 and 6 Low NO_x Burner recovery sought and approved for Senate Bill 29 only).

Additionally, Mr. Roebel reiterated that the estimated costs of the NO_x Compliance Plan have remained reasonably accurate, although as with any multi-year plan there are ongoing impacts and refinements that could potentially affect costs. He further added that with the Commission's approval, for CWIP ratemaking purposes, the Petitioner proposes to include the actual costs of the projects once they are known, whether higher or lower than the original estimates.

Mr. Roebel testified that the NO_x SIP Call Compliance Plan cost estimates that were previously approved remain valid, taking into account the adjustments as previously recorded. Overall, Petitioner's estimated costs for its NO_x Compliance Plan have increased slightly, reflecting certain cost increases on the replacement catalyst beds planned through 2019.[4]

Mr. Roebel testified the only projects added to the Company's CAIR/CAMR Compliance Plan since the Settlement Agreement in Cause Nos. 42622/42718 have been the addition of mercury emission monitors that were under construction or purchased by the time CAMR was vacated. Mr. Roebel testified that the mercury monitors at Gibson Station were either installed or almost completely installed at that time. The Company completed the installation of the Gibson Station monitors and one monitor at Gallagher Station, and placed the remainder of the purchased monitors in storage. Mr. Roebel testified that in anticipation of pending mercury rules, the Company removed the Cayuga Station monitors from storage and installed those monitors earlier this year. The Company is currently operating some of the already installed monitors at Gibson Station and the monitors at Cayuga Station to learn more about how this equipment operates and to collect more data about what the Company's actual mercury emissions from these units are in order to help with compliance planning. The following projects are currently included in Petitioner's current Phase 1 CAIR/CAMR Compliance Plan for which Petitioner is seeking CWIP and Senate Bill 29 recovery:

Gallagher Station Units 1 & 2—Common Baghouse Units 3 & 4—Common Baghouse Landfill Mercury Monitors Gibson Station Unit 1—Wet Scrubber Unit 2—Wet Scrubber Unit 3—Wet Scrubber Unit 4—Scrubber Upgrade Unit 5—Scrubber Upgrade Mercury Monitors	Cayuga Station Unit 1—Wet Scrubber Unit 2—Wet Scrubber Switchyard Addition Landfill Mercury Monitors Edwardsport Mercury Monitors Wabash River Station Mercury Monitors
Compliance Engineering Mercury Removal Study	

Mr. Roebel discussed Petitioner's updated cost estimates for the CAIR/CAMR Compliance Plan projects. He explained that as with any multi-year plan, there are incremental changes from ongoing impact and refinements as a normal part of an ongoing construction program. He added that Petitioner expects these costs to continue to be refined to a small degree.

[4] In response to a Commission Docket Entry, Petitioner explained it has historically used regenerated catalyst beds as replacements beds. The mechanical integrity of the catalyst bed structures, however, deteriorates after multiple regenerations. Therefore, Petitioner expects to use some new, rather than regenerated, catalyst beds in the future.

Overall, Petitioner's estimated costs for its CAIR/CAMR Compliance Plan have increased slightly.

Mr. Roebel indicated that Petitioner proposed, for CWIP ratemaking purposes, to include only the actual costs of the projects once they become known, whether those costs are higher or lower than the original estimate on any specific project. He stated he believes the current cost estimates of Petitioner's CAIR/CAMR Compliance Plan continue to be reasonable.

Ms. Douglas described the proposed implementation of CWIP ratemaking treatment via Rider 62, and provided the schedules and information required by 170 IAC 4-6-12 (calculated consistent with the Commission's CWIP rules). Specifically, Ms. Douglas provided information establishing the incremental value of QPCP investment through June 30, 2011, for which Petitioner is seeking recovery; showed the computation of the jurisdictional revenue requirement associated with that investment; and determined the allocation of the jurisdictional revenue requirement to various retail customer groups (including the calculation of a voluntary credit included in the rates for the HLF rate class due to the correction of a clerical error in the development of the billing determinants used to develop the factors for this class of customers in Cause Nos. 42061 ECR 15 and 16). Ms. Douglas explained that consistent with the Commission's Order in consolidated Cause Nos. 41744 S1 and 42061 and subsequent related Orders, the QPCP projects will be deemed to be under construction, and Petitioner will continue to receive revenues through Rider 62, until the Commission determines that these projects are used and useful in a proceeding that involves the establishment or investigation of Petitioner's base rates and charges, or until these projects no longer satisfy the other requirements of the Commission's CWIP ratemaking rules.

Ms. Douglas testified that the Company included in Rider 62 only the costs for the purchase of the mercury monitors (and the previous costs to install monitors at Gibson and Gallagher stations). She stated that the Company has not included any additional capital costs or operating and maintenance expenses associated with the installation, operation or testing of any of the mercury monitors, as discussed by Mr. Roebel, in Rider 62 or 71.

Ms. Douglas testified regarding the retirement of certain layers of SCR catalyst beds and explained how the Company reflected these retirements in Rider 62. She explained the retirements have been accounted for on the Company's accounting books and records pursuant to U.S. Generally Accepted Accounting Principles. In addition, she explained that depreciation of an asset on the accounting books stops upon retirement, and the Company has appropriately reflected this in the actual and estimated depreciation amounts included in this filing, as appropriate based on the dates the equipment was retired. In addition, she testified that because depreciation was inappropriately reflected in previous filings for catalyst beds which have been retired, the Company adjusted the beginning balance of accumulated depreciation to what it would have been if its previous filings had reflected the retirement of the catalyst beds. Ms. Douglas stated the Company included an adjustment to the Rider 71 revenue requirement as a voluntary credit to refund customers for the difference in revenue requirement that would have occurred if the depreciation expense had been appropriately adjusted in previous filings.

Ms. Douglas testified the federal income tax rate used in the calculation of the jurisdictional revenue requirement was not adjusted to reflect a tax deduction under the Internal Revenue Code Section 199 provided for in the American Jobs Creation Act of 2004 because the Company will not be allowed to take the deduction in 2012 (when the factors developed in this filing will be billed to customers) due to its expected tax position after reflecting bonus depreciation for the Edwardsport IGCC plant. In response to the Commission's January 5, 2012, Docket Entry, Petitioner explained that customers will benefit from rate reductions in the amount of return calculated for ratemaking in ECR or IGCC rider filings as appropriate as the deferred tax impacts of the bonus depreciation are reflected on the accounting books and records during 2012 (and in future years). At the hearing, Ms. Douglas explained the Company will be able to take advantage of bonus depreciation in 2012 for tax purposes because the IGCC plant will be operational this fall. She explained the loss of the Section 199 deduction will be a temporary loss, affecting rates for about two years, but that the benefits from the bonus depreciation will affect rates for a longer period of years and in a greater amount than the impact of the loss of the Section 199 deduction. Petitioner filed Late Filed Exhibit 1 on January 12, 2012, quantifying the estimated impact of the bonus depreciation for the IGCC plant on deferred income tax balances through 2015 and on estimated revenue conversion factors. Petitioner also explained in its response to the January 5, 2012, Docket Entry how the approved Edwardsport IGCC project specific ratemaking for deferred income tax treatment interrelates to the ratemaking treatment proposed in this proceeding.

Ms. Douglas also explained that Petitioner pledged to return the difference between the property tax expense approved in Cause No. 42359 and actual jurisdictional property tax expense, if lower. Ms. Douglas testified that based on this commitment, there is a net jurisdictional amount to be refunded to retail customers of $1,289,000.

Ms. Douglas testified regarding the residential customer impact of the proposed CWIP ratemaking treatment. Ms. Douglas stated that the monthly bill of a typical residential customer using 1,000 kilowatt-hours would increase by approximately ten cents, or 0.1%, when compared to the last approved factor (excluding other various tracking mechanisms).[5]

Ms. Douglas explained that the Company requests the Commission's authority to begin including costs for capital maintenance associated with the environmental projects that have been approved for recovery in Rider 62 and 71 as QPCP beginning with its next ECR filing. Ms. Douglas explained that much of the environmental QPCP is now out of warranty, and the Company is beginning to incur incremental costs for capital maintenance. She stated that these incremental costs, like the incremental operation and maintenance expense recovered under Rider 71, are a direct result of the installation of the QPCP, are required to be capitalized (thus not recoverable under Rider 71) under the Uniform System of Accounts, and the Company believes are appropriate to be recovered as QPCP. Ms. Douglas explained that maintenance capital is related to replacing equipment during maintenance when that equipment is a property unit. The original cost of the equipment that is replaced would be removed from both the plant balance and accumulated depreciation when the equipment is removed, and depreciation on the equipment that is replaced would cease. Depreciation on the maintenance capital would begin when it is installed and in-service. In addition, Ms. Douglas explained that because June 30,

[5] This also excludes sales tax.

2011 was the cutoff date for QPCP investment in this proceeding, the Company is requesting the Commission authorize it to begin including costs for capital maintenance associated with the environmental projects which have been approved for recovery in Riders 62 and 71 that are incurred after June 30, 2011, beginning it its next ECR filing. Petitioner requests approval to include the cost of the capital maintenance projects and reflect the retirements associated with the equipment replacement in determining the QPCP on which a return is earned under Rider 62 and in recovering the cost of the capital maintenance projects once they are in service via depreciation under Rider 71.

Ms. Douglas also explained and supported Petitioner's proposed adjustments to Rider 71 covering the reconciliation of depreciation and operation and maintenance ("O&M") expenses billed versus depreciation and O&M expenses actually incurred for the six months ended June 30, 2011, and the estimated costs for the period July through December, 2011. Ms. Douglas explained that in accordance with the Commission's Order approving the Settlement Agreement in consolidated Cause Nos. 42622 and 42718, the Company has credited customers with a reduction in O&M expense related to removal of the electrostatic precipitators at Gallagher Station. In addition, Ms. Douglas explained that a credit for the amount of Nucor demand revenues apportioned to Riders 61, 62, and 71 in the amount of $1,132,153, representing the apportioned amount of 2012 demand revenues applicable to Nucor's interruptible load ("the Nucor Credit"), and a reconciliation of the credit applicable to January through June 2011, was included in the development of the revenue requirement used in developing the Clean Coal Operating Cost Revenue Adjustment Factors. The Nucor Credit was calculated in accordance with the Commission's Order in Cause No. 43754 and its Order in Cause No. 42061 ECR 15 using the revenue requirements proposed in this proceeding for both Rider 62 and Rider 71 (excluding the Nucor Credit) and the revenue requirements from the most recently approved Rider 61 (Cause No. 43114 IGCC4, which was approved by the Commission on July 28, 2010). She further explained that Petitioner planned to include credits representing six months' worth of apportioned Nucor demand revenues in each Rider 71 rate adjustment in future ECR proceedings until such time as Nucor demand revenues have been included in new base rates approved by the Commission. Ms. Douglas indicated the monthly bill of a typical residential customer using 1000 kilowatt-hours would increase by approximately fifty-two cents, or approximately 0.7% when compared to the last approved factor (excluding other various tracking mechanisms).[6]

Finally, Ms. Douglas explained and supported Petitioner's proposed adjustments to Rider 63, Petitioner's SO_2, NO_x and Hg Emission Allowance Adjustment Rider covering the reconciliation of SO_2 and NO_x EA expenses, net of the impact of sales of native load emission allowances, billed to retail jurisdictional customers versus the expenses net of sales actually incurred for the six months ended August 31, 2011, and the estimated NO_x and SO_2 EA costs for the period March through August 2012. Ms. Douglas explained that in this filing the Company has changed the forecast period used to develop the proposed new factor to March through August 2012, rather than using a January through June 2012 forecast period. The Company is proposing that the new factor be approved for implementation beginning with the first billing cycle of March 2012 (or upon Commission approval, if later). She explained that this change synchronizes the months in the forecast period with the months the Company expects to bill customers. The Company is proposing this change so that its forecast period better coincides

[6] This also excludes sales tax.

with actual billing implementation to help prevent what has been a driver of reconciliation variances in prior filings, as noted in the Company's response to the Commission's June 30, 2011, Docket Entry questions in Cause No. 42061 ECR 17. Ms. Douglas testified that realized gains from the sale of SO_2 and NO_x EAs of approximately $301,000 were booked in March 2011 through August 2011, and included in the development of the factor.[7] She explained that approximately $6,000 of the gains was from the EPA's annual SO_2 auction and $295,000 was from active management of the native load EA portfolio. Ms. Douglas stated that no estimates were included of EA sales during the projected period. Ms. Douglas indicated the residential rates under Rider 63 would decrease by approximately $0.17 or 0.2% when compared to the last approved factor (excluding other various tracking mechanisms).[8]

Mrs. Douglas concluded that the combined impact of the proposed factors for Riders 62, 63 and 71 for a typical residential customer using 1,000 kilowatt-hours would be an increase of $0.45 or 0.5% when compared to the last approved factors.

Mr. Griffith explained that on July 7, 2011, the EPA finalized the Cross State Air Pollution Rule ("CSAPR" or "Cross State Rule"), with subsequent revisions issued on October 6, 2011. The Cross State Rule creates new SO_2, Seasonal NO_x and Annual NO_x emission programs starting January 1, 2012. If CSAPR takes effect, the CAIR Annual NO_x and CAIR Seasonal NO_x programs will terminate when 2011 compliance is completed for each program. After compliance, it is expected that the unused 2011 Annual NO_x and Seasonal NO_x allowances will be removed from Duke's inventories by EPA. EPA has already removed the CAIR Annual NO_x and CAIR Seasonal NO_x allowances for vintages 2012 and beyond from Duke's inventories. While 2011 SO_2 compliance will take place under the CAIR rules and using the compliance ratio mandated by CAIR, if CSAPR takes effect the current SO_2 program will not terminate. Instead, the program will continue, but the compliance ratio will revert to one-to-one as set forth in the original Title IV/Acid Rain Program before CAIR became effective. He explained that if CSAPR takes effect on January 1, 2012, the Company will have to comply with four emission programs: CSAPR Annual NO_x, CSAPR Seasonal NO_x, CSAPR SO_2, and Title IV/Acid Rain SO_2.[9]

Mr. Griffith discussed the CAIR Decision and stated that immediately after the Court vacated and remanded CAIR, the SO_2 and NO_x EA markets became much less liquid, while the seasonal NO_x market was not as affected because a number of market participants still needed to use the market to prepare for 2008 compliance. He noted that since the Court's remand of CAIR, after a brief initial price increase, EA prices have decreased steadily into 2011. Mr. Griffith stated that after the EPA issued the Cross State Rule and transactions for CSAPR EAs had taken place, the markets for CAIR allowances saw liquidity deteriorate further and prices continued to decrease.

---

[7] In response to the Commission's June 30, 2011 Docket Entry in Cause No. 42061 ECR 17, Petitioner explained that gains from the sales of emission allowances included as an offset to actual emission allowance expense were the primary reason for the apparent trend of over-collection, and that without these sales Petitioner would have under-collected in all but the two most recent filings.

[8] This also excludes sales tax.

[9] We note that on December 30, 2011, the U.S. Court of Appeals for the District of Columbia granted requests to stay the CSAPR rule pending court review of challenges to the rule. Until the CSAPR rule is litigated, the CAIR rules remain in effect for 2012.

Mr. Griffith discussed that under CAIR there were some SO_2 compliance issues on the horizon, namely with vintage 2010 SO_2 EAs. Two EAs of vintage 2010 must be surrendered for each ton of SO_2 emitted in 2010 and this ratio is in effect for SO_2 EAs for vintages 2010 through 2014, but the compliance ratio for SO_2 EAs of vintage 2009 or earlier does not change. He stated this may contribute to increasing compliance costs as long as CAIR remains in effect. Mr. Griffith testified that Duke Energy Indiana was naturally short of SO_2 EAs in 2007, 2008 and 2010, and required purchased allowances to meet compliance needs. He stated the purchase of EAs has been the Company's primary form of compliance with Phase II of the Clean Air Act Amendments of 1990. With the construction of the additional scrubbers at Gibson and Cayuga as described above, the Company was naturally long only in 2009. Mr. Griffith explained there is considerable uncertainty about the Company's EA positions given the effects of future power, coal and gas pricing on the Company's generation fleet, along with the legal uncertainty surrounding CAIR and CSAPR. He testified that notwithstanding the uncertainty, the Company expects to be able to purchase SO_2 and both types of NO_x EAs to meet compliance needs using the EA markets if the EA positions become short.

Mr. Griffith described the sophisticated production costing model Petitioner uses to determine whether the Company needs to purchase EAs or if the Company has a surplus and can sell some of its EA inventory. According to Mr. Griffith, the model recognizes and reflects the interrelationship and interaction of the various inputs, such as fuel costs, purchased power prices and EA prices, on the operation of Petitioner's system. Mr. Griffith explained Petitioner's goal is to approach a balanced position for EAs plus a reserve for contingencies, and that all transactions, either purchases or sales of EAs, are conducted at the then-current market price and are based on the results of the model's forecasts. Mr. Griffith also explained that there were a few sales of NO_x EAs in order to balance the Company's position and that the Company identified $295,000 in realized gains from the sale of NO_x EAs. Mr. Griffith stated that the purchases and sales of native load EAs have been conducted in a reasonable manner and in an effort to provide energy to native load customers as economically as possible.

Mr. Griffith testified that he provided information with respect to the Company's estimated EA consumption for Ms. Douglas to use for updating estimated EA costs for the months of March 2012 through August 212. He stated these forecasts are based on the same modeling the Company has used for a number of years. However, the forecasted EA consumption used in this proceeding assumes that CSAPR will take effect January 1, 2012. Mr. Griffith testified that if, for some reason, these rules do not take effect on that date, the Company's EA consumption could be different, and the Company's actual EA costs for the forecasted period could be greater than the estimated costs used by Ms. Douglas to develop the rates in this proceeding.

Mr. Edward O. Abbott, Consulting Engineer, Performance & Measures, testified the Company's recent replacement of fabric filter bags for the Gallagher Unit 2 baghouse was an example of a maintenance project that would be classified as a capital project and, as proposed by Ms. Douglas, included for future ECR tracker recovery. He explained that because this maintenance involved the replacement of property which the Company's accounting guidelines classify as a property unit, the costs of the maintenance are capitalized rather than expensed. He

also provided examples of capital maintenance projects expected in the near future, such as replacement of absorber recycle pump impellors and gearboxes on flue gas desulfurization ("FGD") equipment at Gibson Station.

Mr. Abbott testified that the projects having incremental O&M expenses associated with the Company's NO_x SIP Call Compliance Plan are the Gibson Station Units 1-5 SCRs and arsenic mitigation system and the SO_3 mitigation systems. He stated these incremental costs will fluctuate based on demand and the generation level of the units.

Mr. Abbott also testified regarding the incremental O&M expenses associated with the Company's CAIR/CAMR Compliance Plan. He explained that the projects associated with these expenses are the Cayuga Units 1 and 2 FGDs, Gibson Units 1-3 FGDs, Gibson Units 4 and 5 FGD upgrades, and Gallagher Units 1-4 baghouses. He concluded the incremental costs associated with these projects will also vary based on demand and the generation level of the units.

Mr. Wes R. Blakley, Senior Utility Analyst for the OUCC, testified he reviewed Petitioner's filings in this Cause, as well as its previous filings, and nothing came to his attention that would indicate Petitioner's calculation of estimated ECR adjustment factors for the relevant period is unreasonable. Mr. Blakely described Petitioner's proposed apportionment of the revenue from the Nucor demand charge to the impacted riders and noted that the total amount is reflected in Rider 71 to avoid a separate adjustment for all three impacted riders. He further noted Petitioner's voluntary revenue requirement adjustment reduces the rate for HLF customers to correct for a tracker administration clerical error. Mr. Blakley also noted the testimony of Ms. Douglas and Mr. Abbott regarding capital maintenance projects.

Ms. Cynthia M. Armstrong, Utility Analyst in the Electric Division for the OUCC, testified she reviewed Petitioner's filings in this Cause, as well as filings from prior ECR proceedings. She also conducted a field audit to review detailed accounting material for randomly selected dates of EA transactions and spoke to Duke Energy Indiana staff. Ms. Armstrong testified Petitioner's calculation of EA adjustments was accurately applied and Petitioner's EA trades were reasonable.

8. Commission Discussion and Findings. Based upon the evidence presented, the Commission finds that Petitioner's requests in this Cause should be approved. Specifically, the Commission finds that Petitioner should be authorized to reflect the additional values of QPCP in its rates and charges for electric service in accordance with Rider 62, as indicated in the direct testimony and exhibits of Ms. Douglas.

Petitioner should be authorized to recover its O&M and depreciation expenses in accordance with Rider 71, as described in the testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period January through June 2011 and the estimated amounts for the period July through December 2011.

As to the inclusion of additional capital maintenance projects associated with the environmental projects that have been approved for recovery as QPCP, we find reasonable and

appropriate Petitioner's proposal to begin, with its next ECR filing, including the costs for such projects which have been incurred after June 30, 2011, as QPCP investment subject to CWIP ratemaking treatment in Rider 62 and to recover the costs of such projects through depreciation via Rider 71, as described in the direct testimony and exhibits of Ms. Douglas. In doing so, we note this treatment is consistent with our prior Orders for Indianapolis Power & Light Company in Cause Nos. 42170 ECR 14 through ECR 17, and direct Petitioner to include in its prefiled testimony in future filings discussion of any additional capital maintenance projects added.

Petitioner should also be authorized to recover its SO_2 and NO_x emission allowance expenses in accordance with Rider 63, as described in the direct testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period March through August 2011 and the estimated amounts for the period March through August 2012. Petitioner should be authorized to use a March through August 2012 forecast period to develop the proposed new factor beginning with the first billing cycle of March 2012, and a similar change to forecast and implementation periods in the future. This change in the forecast period results in the forecast period matching the period customers are actually billed based on those forecasts, which should reduce future reconciliation amounts.

In addition, Petitioner's ongoing review progress report regarding its clean coal technology projects is hereby approved. We find that the updated construction cost estimates and updated in-service dates provided by Petitioner in this Cause are reasonable and are hereby approved as such.

9. Confidential Information. Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") with the Affidavits of Mr. Roebel and Mr. Griffith on November 17, 2011. In this Motion, Petitioner demonstrated a need for confidential treatment for the detailed cost estimates associated with its NO_x SIP Call Compliance Plan and its CAIR/CAMR Compliance Plan and specific EA transaction prices. In its January 5, 2012 Docket Entry, the Commission preliminarily found that such information should be subject to confidential procedures. The Affidavits of Mr. Roebel and Mr. Griffith indicate that such confidential information has actual or potential independent economic value for Petitioner and its ratepayers, the disclosure of the confidential information could provide Petitioner's competitors and suppliers an unfair advantage, and Petitioner and its affiliates have taken all reasonable steps to protect the confidential information from disclosure. Accordingly, pursuant to Ind. Code §§ 5-14-3-4(a)(4) and 8-1-2-29, we find the detailed cost estimates are "trade secrets" and should be afforded confidential treatment.

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

1. Petitioner's proposed updated Rider 62, as reflected in the direct exhibits and testimony of Duke Energy Indiana, including QPCP values as of June 30, 2011, is hereby approved. Rider 62 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of this Order.

2. Petitioner's proposed updated Rider 71, as reflected in the exhibits and testimony of Duke Energy Indiana, is hereby approved. Rider 71 shall go into effect upon the filing of the final Rider with the Commission's Electricity Division for all bills rendered after the effective date of the Commission's Order in this proceeding.

3. Petitioner's proposed updated Rider 63, as reflected in the direct exhibits and testimony of Duke Energy Indiana, is hereby approved. Rider 63 shall go into effect the first billing cycle of March 2012, or for all bills rendered after the effective date of the Commission's Order in this proceeding, if later, upon the filing of the final Rider with the Commission's Electricity Division.

4. Petitioner's ongoing review progress report on its clean coal technology projects is hereby approved.

5. Petitioner's updated cost estimates, in-service dates and updated environmental projects for its NO_x Compliance Plan equipment are hereby approved as reasonable.

6. Petitioner's updated cost estimates and in-service dates for its Phase 1 CAIR/CAMR Compliance Plan equipment are hereby approved as reasonable.

7. Petitioner is authorized beginning with its next ECR filing to include the cost of additional capital maintenance projects and reflect the retirements associated with the equipment replacement in determining the QPCP on which a return is earned under Rider 62 and to recover the cost of the capital maintenance projects once they are in service via depreciation under Rider 71.

8. Petitioner's proposed apportionment of Nucor demand charge reserves applicable to interruptible load as described in the testimony of Ms. Douglas is approved.

9. The detailed cost estimate information contained in the testimony and exhibits of this case are found to be confidential and trade secrets and therefore excepted from public access.

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

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

JAN 25 2012

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission