ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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| 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 16<br><br>APPROVED: FEB 09 2011 |

**BY THE COMMISSION:**
**Carolene Mays, Commissioner**
**Loraine L. Seyfried, Administrative Law Judge**

On October 26, 2010, Duke Energy Indiana, Inc. ("Petitioner", "Company" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking to reflect additional values of qualified pollution control property ("QPCP") in its rates and charges for electric service, through Standard Contract Rider No. 62; seeking approval of an ongoing review progress report concerning certain clean coal technology projects; seeking approval of updated environmental projects, cost estimates and in-service dates for environmental projects; seeking approval of an adjustment to its rates through its Clean Coal Operating Cost Revenue Adjustment mechanism, Standard Contract Rider No. 71; and seeking 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.

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 18, 2011 at 9:30 a.m. in Room 224, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the Indiana Office of

Utility Consumer Counselor ("OUCC") appeared at the hearing. During the hearing, Petitioner presented its case-in-chief, consisting of the testimony and exhibits of Mr. John J. Roebel, Ms. Diana L. Douglas, Mr. John P. Griffith, and Mr. Edward O. Abbott. The OUCC presented the testimony of Mr. Wes R. Blakley and Ms. Cynthia Armstrong.

The Commission has considered the evidence presented in this Cause in arriving at the findings and conclusions set forth in this Order. Accordingly, based upon the applicable law and the evidence 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, Ind. Code § 8-1-2-6.8, Ind. Code § 8-1-2-42(a), Ind. Code § 8-1-8.7-1 *et seq.*, Ind. Code § 8-1-8.8-1 *et seq.*, and 170 IAC 4-6-1 *et seq.* 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 of the Petition in this Cause, Petitioner's electric generating properties consisted of: (1) steam capacity located at five stations comprised of nineteen coal-fired generating units supplied by nineteen coal-fired boilers[1] and one oil-fired boiler; (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, eight oil-fired CT units located at two stations, and sixteen natural gas-fired CTs, one of which has oil back-up.

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.

[1] 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. Because the time for the EPA to appeal that ruling has not expired, Wabash River Units 2, 3, and 5 remained shut down at the time of the pre-filed testimony. Therefore, although Petitioner's generating properties consist of nineteen coal-fired boilers, only sixteen of those coal-fired boilers are in service at this time.

On July 3, 2002, this Commission issued an order in consolidated Cause Nos. 41744 S1 and 42061, wherein, among other things, we: found that Petitioner's $NO_x$ Compliance Plan was reasonable; issued a certificate of public convenience and necessity for the use of clean coal technology; approved the use of Petitioner's proposed QPCP; approved Petitioner's updated cost estimates related to its $NO_x$ Compliance Plan equipment; and approved a Standard Contract Rider No. 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. <u>CAIR and CAMR Compliance Requirements</u>.** In January 2004, the EPA published two new significant proposed emission reduction requirements: (1) the interstate air quality rule (later renamed the Clean Air Interstate Rule or "CAIR"); and (2) the utility mercury reductions rule (later renamed the Clean Air Mercury Rule or "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).

CAIR requires 29 states (plus the District of Columbia, and including Indiana) to adopt plans to dramatically reduce $SO_2$ and $NO_x$ emissions from power plants and other sources, to facilitate compliance with the 8-hour ozone and fine particulate matter ("PM 2.5") national ambient air quality standards ("NAAQS"). CAMR regulates mercury emissions from power plants for all states. The final CAIR requires major $SO_2$ and $NO_x$ reductions in two stages: (1) a cap of 3.6 million $SO_2$ tons by 2010, and a cap of 2.5 million $SO_2$ tons by 2015 (for a total $SO_2$ decrease of approximately 65%); and (2) a cap of 1.5 million $NO_x$ tons by 2009, and a cap of 1.3 million tons of $NO_x$ by 2015 (for a total $NO_x$ reduction of approximately 70%). CAIR also establishes both an annual $NO_x$ trading program and a seasonal $NO_x$ trading program (similar to and replacing the $NO_x$ SIP Call requirements), effective in 2009. CAIR also prescribes that, instead of $SO_2$ emission allowances continuing to allow the holder to emit one ton of $SO_2$, post-2010 vintage $SO_2$ emission allowances will only allow the holders to emit one-half to one-third as much per emission allowance. 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]

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[2] On July 11, 2008, the U.S. Court of Appeals for the District of Columbia 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 Court 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.

On May 24, 2006, this 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: found that the Settlement Agreement was in the public interest; approved Petitioner's Phase 1 CAIR/CAMR Compliance Plan; found that the proposed scrubber, scrubber upgrade and baghouse projects constitute clean coal technology, clean coal and energy projects and qualified pollution control property; issued a Certificate of Public Convenience and Necessity for the Phase 1 CAIR/CAMR Compliance Plan projects; approved Petitioner's request for ongoing review of the Phase 1 CAIR/CAMR Compliance Plan projects; approved Petitioner's cost estimates for the Phase 1 CAIR/CAMR Compliance Plan projects; approved the use of accelerated (20-year) depreciation for the Phase 1 CAIR/CAMR Compliance Plan projects as provided in the Settlement Agreement; and 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 the date ending June 30, 2010, in its rates and charges for electric service. Petitioner further requests approval of an ongoing review progress report concerning certain clean coal technology projects, approval of updated environmental projects, cost estimates and in-service dates for environmental projects, approval of 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 approval of 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 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, 4-6-18.

**c. Utility Generation and Clean Coal Technology Statute, Ind. Code § 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, 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 in order to meet federal and state $NO_x$ SIP Call regulations that took effect 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 42061 ECR15, 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:

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| Gallagher Station<br>Boiler Optimization Units 1- 4<br>Low $NO_x$ Burners & Fuel Flow Monitoring Unit 4<br><br>Gibson Station<br>Selective Catalytic Reduction ("SCRs") Units 1-5, including Injection System<br>Boiler Optimization Units 1-5<br>SCR catalyst beds Units 1-5 | Cayuga Station<br>Boiler Optimization Units 1-2<br>Electrostatic Precipitator Units 1-2<br><br>Wabash River Station<br>Boiler Optimization Units 2-6<br>Low $NO_x$ Burners Units 2, 3, 4, 5, and 6 (Unit 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, Petitioner proposes to include the actual costs of the projects once they are known, whether higher or lower than the original estimates.

Mr. Roebel then testified that the $NO_x$ SIP Call Compliance Plan cost estimates that were approved in the previous ECR Cause Nos. 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 the additional replacement catalyst beds planned through 2020.

Mr. Roebel testified that 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. The Company's remaining mercury monitors in Indiana are being stored pending further actions by the State of Indiana and/or the EPA related to mercury regulations. Thus, 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:

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| Gallagher Station<br>Units 1 & 2—Common Baghouse<br>Units 3 & 4—Common Baghouse<br>Landfill<br>Mercury Monitors<br><br>Gibson Station<br>Unit 1—Wet Scrubber<br>Unit 2—Wet Scrubber<br>Unit 3—Wet Scrubber<br>Unit 4—Scrubber Upgrade<br>Unit 5—Scrubber Upgrade<br>Mercury Monitors | Cayuga Station<br>Unit 1—Wet Scrubber<br>Unit 2—Wet Scrubber<br>Switchyard Addition<br>Landfill<br>Mercury Monitors<br><br>Edwardsport<br>Mercury Monitors<br><br>Wabash River Station<br>Mercury Monitors |
| Compliance Engineering<br>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. 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 Duke Energy Indiana Standard Contract Rider No. 62 ("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, 2010, 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. 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 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 $4,259,000.

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 decrease by approximately four cents, or 0.1%, when compared to the last approved factor (excluding other various tracking mechanisms).[4]

Ms. Douglas also explained and supported Petitioner's proposed adjustments to Standard Contract Rider No. 71 - Clean Coal Operating Cost Revenue Adjustment ("Rider 71") covering the reconciliation of depreciation and operation and maintenance expenses billed versus depreciation and operation and maintenance expenses actually incurred for the six months ended June 30, 2010, and the estimated costs for the period July through December, 2010.[5] 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 operation and maintenance expense related to removal of the electrostatic precipitators at Gallagher Station once in service. 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 $671,734, representing the apportioned amount of 2011 demand revenues applicable to Nucor's interruptible load ("the Nucor Credit"), 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 ("ECR 15") using the revenue requirements proposed in this ECR 16 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

[4] We note this also excludes sales tax.

[5] Due to the EPA's appeal period from the Seventh Circuit's reversal of liability in the NSR litigation, Wabash River Units 2, 3, and 5 remained shut down at the time of the pre-filed testimony. Because of the uncertainty regarding the timing of their future use, no estimated depreciation cost was included in this filing for the projects for these units.

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 in Petitioner's next retail base rate case. Ms. Douglas indicated that the monthly bill of a typical residential customer using 1,000 kilowatt-hours would decrease by approximately eighty cents, or 1.0% when compared to the last approved factor (excluding other various tracking mechanisms).[6]

Finally, Ms. Douglas explained and supported Petitioner's proposed adjustments to Standard Contract Rider No. 63, Petitioner's $SO_2$, $NO_x$ and Hg Emission Allowance Adjustment Rider covering the reconciliation of $SO_2$ and $NO_x$ emission allowance 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, 2010, and the estimated $NO_x$ and $SO_2$ EA costs for the period January through June 2011. Ms. Douglas testified that realized gains from the sale of $SO_2$ and $NO_x$ emission allowances of approximately $1.4 million were booked in March through August 2010, and included in the development of the factor ($0.1 million of the gains were from the EPA's annual $SO_2$ auction and $1.3 million in gains were 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 that the monthly bill of a typical residential customer using 1,000 kilowatt-hours would decrease by approximately $0.55 or 0.7% when compared to the last approved factor (excluding other various tracking mechanisms).[7]

Ms. Douglas concluded that the combined impact of the proposed factors for Standard Contract Riders 62, 63 and 71 for a typical residential customer using 1,000 kWh would be a decrease of $1.39 or 1.6% when compared to the last approved factors (excluding other various tracking mechanisms).[8]

Mr. Griffith discussed the CAIR Decision and stated that immediately after the Court vacated and remanded CAIR, the $SO_2$ and $NO_x$ emission allowance 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 during 2010.

Mr. Griffith discussed that under CAIR there were some $SO_2$ compliance issues on the horizon, namely effective with vintage 2010 $SO_2$ EAs. Two EAs of vintage 2010 must be surrendered for each ton of $SO_2$ emitted in 2010 and 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 that this may contribute to increasing compliance costs.

Mr. Griffith testified that Duke Energy Indiana has been naturally short of $SO_2$ EAs and that the purchase of EAs has been the Company's primary form of compliance with Phase II of the Clean Air Act Amendments of 1990. However, with the construction of the additional

[6] We note this also excludes sales tax.

[7] We note this also excludes sales tax.

[8] We note this also excludes sales tax.

scrubbers at Gibson and Cayuga as described above, the Company does not expect to be as short in the future.

Mr. Griffith described the sophisticated production costing model that 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 that 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 $1.3 million 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. Edward O. Abbott, Consulting Engineer, Performance & Measures testified that the projects having incremental operation and maintenance ("O&M") expenses associated with the Company's $NO_x$ SIP Call Compliance Plan are the Gibson Station Units 1-5 SCRs, arsenic mitigation system, and the $SO_3$ mitigation systems. He stated that 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. Mr. Abbott stated that the Gallagher Units 1-4 baghouses have not had any incremental costs, but will need to have the bags replaced periodically along with repairs to the baghouse structures and ash handling system as the units operate longer. He concluded that 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 that he had reviewed Petitioner's filings in this Cause, as well as from 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.

Ms. Cynthia M. Armstrong, Utility Analyst in the Electric Division for the OUCC, testified that she had reviewed Petitioner's filings in this Cause, as well as from its previous filings. She also conducted a field audit to review detailed accounting material for randomly selected dates of emission allowance transactions and spoke to Duke Energy Indiana staff. Ms. Armstrong also testified that Duke informed the OUCC that an error was made in the Petitioner's recording of one of the EA transactions that would result in increased allowance consumption costs of $73,000, which would be corrected in November's business. Ms. Armstrong noted that the monthly review process for data gathered in the semi-annual EA filings changed in December 2010. This change should permit an opportunity to adjust entries in the event of errors to avoid similar problems in the future. Because the reconciliation period for this

proceeding ended in August 2010, the OUCC and Petitioner agreed that the adjustment to correct the error would be included in Petitioner's next ECR filing and explained in testimony in that proceeding. Ms. Armstrong testified that Petitioner's calculation of emission allowance adjustments was accurately applied and Petitioner's emission allowance trades were reasonable.

**8. Commission Discussion and Findings.** In accordance with the clean coal technology certificate statute, if the Commission approves the construction and the costs of such equipment, that approval forecloses subsequent challenges to the inclusion of those costs in the utility's rate base on the basis of excessive cost, inadequate quality control, or inability to employ the technology. *See* Ind. Code § 8-1-8.7-7(c). Based upon the evidence presented, the Commission finds that Petitioner's request 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 Duke Energy Indiana's Rider 62, as indicated in the direct testimony and exhibits of Ms. Diana L. Douglas. Petitioner should be authorized to recover its operation and maintenance and depreciation expenses in accordance with Duke Energy Indiana's Rider 71, as described in the testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period January 2010 through June 2010 and the estimated amounts for the period July 2010 through December 2010. Petitioner should also be authorized to recover its $SO_2$ and $NO_x$ emission allowance expenses in accordance with Duke Energy Indiana's Rider 63, as described in the direct testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period March 2010 through August 2010 and the estimated amounts for the period January 2011 through June 2011.

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. John J. Roebel and Mr. John P. Griffith on November 19, 2010. 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 emission allowance transaction prices. In a November 29, 2010, 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 that the detailed cost estimates are "trade secrets" and should be afforded confidential treatment. The Commission hereby orders that procedures should be taken so that such information is appropriately secured and made available only to selected members of the Commission staff who are under an obligation not to publicly disclose such information.

**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, 2010, is hereby approved. The 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. The 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. The Rider 63 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.

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's proposed apportionment of Nucor demand charge revenues applicable to interruptible load as described in testimony of Ms. Diana Douglas is approved.

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

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

**ATTERHOLT, BENNETT, MAYS, and ZIEGNER CONCUR; LANDIS ABSENT:**

**APPROVED:** FEB 09 2011

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

Brenda A. Howe

**Brenda A. Howe**
**Secretary to the Commission**