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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 13 APPROVED: AUG 1 9 2009

BY THE COMMISSION:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On April 24, 2009, 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 on June 19, 2009, at 9:30 a.m. in Room 224, National City Center, 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 and Mr. John P. Griffith. The OUCC presented the testimony of Mr. Wes R. Blakley. Petitioner then presented the rebuttal testimony and exhibits of Ms. Diana L. Douglas.

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, the 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 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.

On July 3, 2002, the 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.[1]

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.[2]

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[11] 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").

[2] 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. ("CAMR Decision").

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 the use of the proposed clean coal technology as qualified pollution control property; 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 Emission Allowance 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 December 31, 2008, in its rates and charges for electric service. Petitioner also 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, 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, Engineering and Technical Services, Ms. Diana L. Douglas, Director, Rates and Mr. John P. Griffith, Director, Portfolio Optimization, Fuel and Emissions. 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 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, but indicated that the current NO_x Compliance Plan is not significantly different from the plan presented in 42061 ECR12, 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 (Unit 4 Low NO_x Burners 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, reminding us to take into account the adjustments as previously recorded. Overall, Petitioner's estimated costs for its NO_x Compliance Plan have decreased slightly.

Mr. Roebel testified that the only projects included in the Company's CAMR compliance plan related solely to mercury emissions are the mercury emission monitors. Petitioner has eliminated the mercury monitor associated with the Wabash River Repowering project, because Wabash Valley Power Association now owns that unit, and the mercury monitor at Edwardsport, because that station is not expected to operate at a high enough capacity factor to require monitoring. Mr. Roebel stated that the Company had purchased the mercury monitors well before the CAMR Decision and the mercury monitors at Gibson were either installed or almost completely installed by February of 2008. A mercury monitor was also installed at Gallagher in the stack for Units 1 and 2, because the project was already in progress at the time of the court opinion. The remainder of the Company's mercury monitors in Indiana is 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:

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 Wabash River Station Mercury Monitors
Compliance Engineering Mercury Removal Study	

Mr. Roebel testified that all of the Company's Phase I CAIR compliance projects, except for the Cayuga Unit 1 FGD (and the associated landfills at Cayuga and Gallagher), were in service by the date of the CAIR Decision. The Cayuga Unit 1 FGD, which was approximately 90% complete, is now in service. He stated that because the Company is still subject to SO_2 emission limits, and because the future of CAIR is uncertain, it made no sense to stop construction on the project that was nearly completed. On December 23, 2008, the Court granted rehearing to the extent that it remanded the rules to the Environmental Protection Agency ("EPA") without vacating them, which means that CAIR remains in place until EPA issues a new rule in accordance with the July 11, 2008 decision.

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 change, except for the Gallagher Baghouse projects where Petitioner has reflected the "capped" costs from the Settlement Agreement in Consolidated Cause Nos. 42622 and 42718. Overall, Petitioner's estimated costs for its CAIR/CAMR Compliance Plan have decreased slightly.

Mr. Roebel indicated that Petitioner proposes, 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. Finally, Mr. Roebel stated that current cost estimates of Petitioner's CAIR/CAMR Compliance Plan continue to be reasonable.

Mr. Roebel also discussed Duke Energy Indiana's operation of the SCRs at the Gibson Station for between 15 and 19 days during the months of January and April 2008 and for a few days in December of 2008 to acquire Early Reduction Credits ("ERC"). Mr. Roebel explained that the cost to operate these SCRs for January to April and December of 2008 was approximately $420,000. He stated that Petitioner spent about $1.1 million during 2007 and 2008 to operate the SCRs out of ozone seasons and earned approximately 3700 CAIR ERCs, at a cost of about $300 per ERC, which compares to market prices of approximately $1,000 per ERC at the beginning of May 2009.

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 December 31, 2008, 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. Based on this commitment, Petitioner determined that rather than a refund to customers, there is a net jurisdictional amount to be recovered from retail customers of $4,665,000 because too much was refunded to customers through December 31, 2008, due primarily to the use of estimates in developing the refund amounts in previous ECR filings.

Ms. Douglas also discussed a proposed adjustment to reduce revenue requirements by crediting customers $127,000, an adjustment that the Company first proposed in Cause No. 42061 ECR 11 ("ECR 11"). However, the Commission did not approve the adjustment at that time due to the pending appeal of the Cause No. 42061 ECR 10 Order ("ECR 10"). This proceeding is the first of Petitioner's ECR proceedings since the appeal of ECR 10 became final. At the evidentiary hearing, Ms. Douglas testified that Petitioner proposes to refund $127,000 to customers because the Company believed it to be the right thing to do.

Ms. Douglas addressed the residential customer impact of the proposed CWIP ratemaking treatment. She indicated that the monthly bill of a typical residential customer using 1,000 kilowatt-hours would increase by approximately nineteen cents, or 0.2%, when compared to the last approved factor.

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 December 31, 2008, and the estimated costs for the period January through June, 2009. 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. Ms. Douglas indicated that residential rates under Rider 71 would increase by approximately one dollar and eight cents, or 1.4% when compared to the last approved factor.

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 EA expenses, net of the impact of sales of native load EAs, billed to retail jurisdictional customers versus the expenses net of sales actually incurred for the six months ended February 28, 2009, and the estimated NO_x and SO_2 EA costs for the period July through December 2009. Although there were no sales of EAs that were booked during the reconciliation months, a credit of $382,000 was included to reverse part of the offset to gains that was made in the calculation of the emission allowance cost adjustment factor in Cause No. 42061 ECR 12. Ms. Douglas indicated that the monthly bill of a typical residential customer using 1,000 kilowatt-hours would increase by approximately one dollar and fourteen cents, or 1.5% when compared to the last approved factor.

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 explained that Duke Energy Indiana is 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 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. For example, when the price of purchased power is lower, all else equal, the Company will use less EAs. 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 although there were a few purchases of SO_2 EAs in order to balance the Company's position, there were no realized gains or losses because all sales transactions were closed after February 28, 2009. Therefore, any gains related to those sales will be credited to customers in the next ECR proceeding.

Mr. Wes R. Blakley, Principal Utility Analyst for the OUCC testified that he had reviewed Petitioner's filings in this Cause, as well as its previous filings in ECR 12. Except for an issue relating to a retroactive revenue requirement adjustment relating to an allowance for funds used during construction ("AFUDC") rate change as discussed below, he stated nothing came to his attention that would indicate Petitioner's calculation of estimated ECR adjustment factors for the relevant period are unreasonable.

Mr. Blakley testified that he believed Petitioner's retroactive adjustment of $127,000 related to its AFUDC calculations in ECR 10, which adjusted its AFUDC rates retroactively back to 2004, constituted retroactive ratemaking. Mr. Blakley testified that basic ratemaking principles should apply when considering cutoff dates for the CWIP tracker. He believes that it is inappropriate to accept Petitioner's adjustment unless it is shown to be an appropriate remedy under Ind. Code § 8-1-2-69 of an act or practice, such as a failure to comply with a prior Commission order. Mr. Blakley discussed three past Commission cases where retroactive revenue adjustments were approved, but noted that they all were corrections of errors made concerning legal requirements. He stated that although the proposed adjustment favors ratepayers, it may still be inappropriate under the statutes and general ratemaking principles. He stated, given that neither the Commission nor the Court of Appeals has ruled on the permissibility of a retroactive revenue requirement adjustment related to the AFUDC plant balance correction, a determination must still be made on its appropriateness.

In rebuttal testimony, Ms. Douglas explained that as first discussed in her direct testimony in ECR 10 and in her direct testimony in ECR 11, as well as in the direct testimony of

Ms. Lisa Carver in ECR 11, the Company included in the value of the QPCP as of June 30, 2007 an accounting correction related to past calculations of AFUDC, which was subsequently approved by the Commission in its Order in ECR 10. The AFUDC calculation error, which involved three components, affected both projects that are included as QPCP for purposes of the CWIP Tracker and projects that are not QPCP. Ms. Douglas testified that before the proposed correction was recorded, it was determined by the Company's accounting department as well as the Company's external auditors, that corrections for two of the components basically offset one another, resulting in a net change to the projects that was deemed immaterial. Therefore, these two components of the correction were not booked in June 2007; just the equity AFUDC component was booked. After that time, it became apparent to Petitioner that although the net change from those two components was immaterial on a total Company basis, when the CWIP Tracker projects were viewed as a separate group, Indiana customers would have benefitted had the debt AFUDC and trust fund interest components of the correction been recorded. If the adjustment had been recorded in June 2007, the value of the CWIP Tracker projects as of June 30, 2007, which would have been included in ECR 10, would have been $1,337,320 less, as Ms. Douglas agreed on cross examination.

Ms. Douglas continued her explanation by stating that to ensure the Company's customers received the full benefit of the needed correction through the CWIP Tracker rates, the Company's accounting group subsequently recorded to the value of QPCP projects, the debt AFUDC, and trust fund interest components of the AFUDC correction, including the additional AFUDC that would have been accrued prior to inclusion of the adjustment in CWIP Tracker rates. The Company voluntarily included an additional reduction in revenue requirements to account for the difference in revenue requirements that would have resulted in ECR 10, if this correction had been recorded in June 2007 when the equity AFUDC correction was recorded, instead of when it was actually recorded.

Ms. Douglas concluded her rebuttal testimony by explaining that the Company is willing to voluntarily credit customers to ensure they were not harmed by the accounting delay as it originally proposed, or the Company is also willing to remove the credit from its revenue requirement and factor calculations, should the Commission agree with Mr. Blakley that the adjustment is inappropriate. The removal of the $127,000 revenue requirement credit would not change the typical residential customer's monthly bill, although rate factors for each individual rate group would increase. As Ms. Douglas stated in her direct testimony, the monthly bill of a residential customer using 1,000 kilowatt-hours would increase by nineteen cents or approximately 0.2%, when compared to the last approved factor.

8. <u>Commission Discussion and Findings</u>. The Commission has, and continues to, encourage all utilities to periodically review their accounting practices for accuracy. *See In re IPL,* Cause No 42170 ECR 9 (September 13, 2007) ("the Commission would encourage IPL and all utilities to conduct periodic audits of its accounting methodologies to ensure that the results match the original intent."). The evidence demonstrates that this is what Petitioner has done in this case.

Ms. Douglas testified that after the Commission's Order in ECR 10 was issued, Duke Energy Indiana discovered that Indiana jurisdictional customers would have benefitted in the

amount of $127,000 had it booked the debt AFUDC and trust fund interest components, rather than just the equity AFUDC, in the accounting correction. Consequently, Petitioner requested approval to include an additional reduction in revenue requirements for the difference in revenue requirements that would have resulted if the correction had been made in ECR 10. The OUCC believes that such an adjustment would constitute retroactive ratemaking and should not be approved. In response to the OUCC's position, Duke Energy indicated that it would like to provide a voluntary credit to customers. Therefore, because Duke Energy Indiana has proposed to voluntarily provide the $127,000 in question as a credit to its customers, we need not decide whether the adjustment proposed by Petitioner constitutes retroactive ratemaking as asserted by the OUCC.

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 July 2008 through December 2008 and the estimated amounts for the period January 2009 through June 2009.

Petitioner should also be authorized to recover its SO_2 and NOx emission allowance expenses in accordance with Duke Energy Indiana's Rider 63, as described in the testimony and exhibits of Ms. Douglas, including the reconciliation of such expenses for the period September 2008 through February 2009 and the estimated amounts for the period July 2009 through December 2009.

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. We note that 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).

Finally, the Commission finds that its July 30, 2008 Interim Order in ECR 11 should be made final. The Commission's Interim Order provided that its decision should be an interim order pending appellate review and a final non-appealable decision in ECR 10. On November 14, 2008, the Indiana Court of Appeals issued its decision affirming the Commission's January 30, 2008 Order in ECR 10. No further appeals have been taken. Therefore, the Commission finds that the July 30, 2008 Interim Order in ECR 11 should be made a final order.

9. <u>Confidential Information.</u> Petitioner filed a *Motion for Protection of Confidential and Proprietary Information* ("Motion") with the Affidavit of Mr. John J. Roebel

on May 4, 2009. 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. In a May 8, 2009, Docket Entry, the Commission preliminarily found that such information should be subject to confidential procedures. The Affidavit of Mr. Roebel indicates 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), 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 December 31, 2008 and the $127,000 credit, 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 the Commission's Order in this proceeding.

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 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. 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.

8. The Interim Order issued on July 30, 2008 in Cause No. 42061 ECR 11 shall be made final and Cause No. 42061 ECR 11 should be closed.

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

HARDY, ATTERHOLT, GOLC, LANDIS, and ZIEGNER CONCUR:

APPROVED: AUG 1 9 2009

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