ORIGINAL

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; APPROVAL OF AN ADJUSTMENT TO ITS RATES THROUGH ITS SO2, NOX, AND HG EMISSION ALLOWANCE ADJUSTMENT, STANDARD CONTRACT RIDER NO. 63	**CAUSE NO. 42061 ECR 25** **APPROVED:** JUL 29 2015

ORDER OF THE COMMISSION

Presiding Officers:
Angela Rapp Weber, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On April 28, 2015, Duke Energy Indiana, Inc. ("Petitioner" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to reflect additional values of qualified pollution control property ("QPCP") and of other clean coal and energy projects, as of December 31, 2014, in its rates and charges for electric service through Petitioner's Qualified Pollution Control Property Revenue Adjustment, Standard Contract Rider No. 62 ("Rider 62"). Petitioner further requests approval of: (1) an ongoing review progress report concerning certain clean coal technology projects; (2) updated environmental projects, cost estimates and estimated in-service dates for environmental projects; (3) an update and adjustment to Petitioner's Clean Coal Operating Cost Revenue Adjustment, Standard Contract Rider No. 71 ("Rider 71"); and (4) an update and adjustment to Petitioner's Emission Allowance Adjustment, Standard Contract Rider No. 63 ("Rider 63").

An evidentiary hearing was held on July 7, 2015, at 9:30 a.m. in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the Indiana Office of Utility Consumer Counselor ("OUCC") appeared and participated at the hearing. 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, the Commission finds:

1. **Notice and Jurisdiction.** Due, legal, and timely notice of the evidentiary hearing was given and published by the Commission. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1 and requests relief pursuant to Ind. Code §§ 8-1-2-6.6, -6.8, and -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 of the Petition in this proceeding, Petitioner's electric generating properties consist of: (1) two syngas/natural gas-fired combustion turbines ("CT") and one steam turbine located at Edwardsport; (2) steam capacity located at four stations comprised of 14 coal-fired generating units; (3) combined cycle capacity located at one station comprised of three natural gas-fired CTs and two steam turbine-generators; (4) a run-of-river hydroelectric generation facility comprised of three units; and (5) peaking capacity consisting of seven oil-fired diesels located at two stations, seven oil-fired CT units located at two stations, and 24 natural gas-fired CTs, one of which has oil back-up.

4. **Background to this Proceeding.**

a. **NOx SIP Call.** The federal NOx State Implementation Plan ("SIP") Call and related Indiana NOx SIP Call required that Indiana reduce its nitrogen oxide ("NOx") 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 NOx 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: (1) found that Petitioner's NOx 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 NOx Compliance Plan equipment; and (5) approved 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. 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 sulfur dioxide ("SO_2") and NOx emission reductions, established annual and seasonal NOx trading programs, and set limitations on the use of SO_2 emission allowances. 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. The Indiana Air Pollution Control Board adopted CAMR on October 3, 2007.[2]

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, it: (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, 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 Phase 1 CAIR/CAMR Compliance Plan.

c. Mercury and Air Toxic Compliance Requirements. The EPA first proposed Maximum Achievable Control Technology standards for coal- and oil-fired utility steam generating units, known then as the Utility MACT rule, on May 3, 2011. In December 2011, the EPA signed the final rule, which was renamed the Mercury and Air Toxic Standards ("MATS"). The MATS rule became effective April 16, 2012.

The MATS rule regulates hazardous air pollutant emissions from new and existing coal- and oil-fired steam electric generating units that are greater than 25 MWs in capacity. On April 9, 2014, the Indiana Environmental Rules Board adopted the MATS provisions and repealed the CAMR at 326 IAC 24-4 that was vacated by the D.C. Circuit Court on February 8, 2008.[3]

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[1] CAIR has since been replaced by the Cross State Air Pollution Rule, which was upheld by the U.S. Supreme Court on April 29, 2014, in *EPA v. EME Homer City Generation, L.P.,* 134 S.Ct. 1584 (2014).

[2] On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit in *State of New Jersey v. EPA,* 517 F.3d 574 (D.C. Cir. 2008) vacated the federal CAMR.

[3] On June 29, 2015, the U.S. Supreme Court in *Michigan v. EPA*, 2015 WL 2473453 (2015) reversed and remanded the D.C. Circuit Court's decision upholding the MATS rule.

On April 3, 2013, in Cause No. 44217, the Commission approved the Phase 2 MATS Compliance Plan projects as QPCP eligible for CWIP ratemaking treatment in accordance with Ind. Code §§ 8-1-2-6.6 and -6.8, and as clean coal and energy projects qualifying for incentives in accordance with Ind. Code § 8-1-8.8-11.

On August 27, 2014, in Cause No. 44418, the Commission approved the Phase 3 MATS Compliance Plan projects as QPCP eligible for CWIP ratemaking treatment in accordance with Ind. Code §§ 8-1-2-6.6 and -6.8, and as clean coal and energy projects qualifying for incentives in accordance with Ind. Code § 8-1-8.8-11.

d. Dry Sorbent Injection Projects at Gallagher Units 2 and 4. As part of the terms of a Consent Decree with the U.S. Department of Justice, Petitioner agreed to install and operate dry sorbent injection ("DSI") systems on Gallagher Units 2 and 4 ("Gallagher DSI Projects"). On September 8, 2010, in Cause No. 43873, the Commission granted a CPCN to Petitioner for the use of the Gallagher DSI Projects, approved the estimated costs for the projects, and found that the Gallagher DSI Projects constituted "clean coal technology" as that term is defined in Ind. Code ch. 8-1-8.7. On December 28, 2011, in Cause No. 43956, the Commission granted Petitioner authority to include the Gallagher DSI Projects in its QPCP, to recover a return on the capital expenditures for the Gallagher DSI Projects through Rider 62, and to recover the incremental operation and maintenance ("O&M") (including the cost of reagents) and depreciation expenses of the Gallagher DSI Projects through Rider 71.

e. Emission Allowance Adjustment. In Cause Nos. 42411 and 42359, the Commission approved the recovery of emission allowance ("EA") costs for NOx emissions in Petitioner's then-existing SO_2 EA 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 specifically seeks: (1) authority to reflect additional values through December 31, 2014, of QPCP in its rates and charges for electric service, through Rider 62; (2) approval of an ongoing review progress report related to Petitioner's NOx and Phase 1 CAIR/CAMR Compliance Plans, Gallagher DSI Projects, and Phase 2 and Phase 3 MATS Compliance Plans; (3) approval for recovery of Petitioner's O&M and depreciation expenses related to its NOx and Phase 1 CAIR/CAMR Compliance Plans, Gallagher DSI Projects, Phase 2 and 3 MATS Compliance Plans and associated capital maintenance, including the reconciliation through December 31, 2014, and the estimated amounts for the period January 1, 2015, through June 30, 2015, through Rider 71 (including approval of a credit to customers of the amount of incremental demand revenues under contracts with Nucor Corporation and International Paper[4]); (4) approval of the amounts included for recovery in Rider 71 for the amortization of the Phase 2 and Phase 3 MATS Compliance Plans development costs and post-in-service carrying costs accrued at Petitioner's allowance for funds used during construction ("AFUDC") rate for the Gallagher DSI

[4] Formerly known as Temple-Inland.

Projects; (5) approval of Petitioner's updated environmental plan, cost estimates, and estimated in-service dates for the NOx and Phase 1 CAIR/CAMR Compliance Plans and the Phase 2 and Phase 3 MATS Compliance Plans; (6) approval of an adjustment to its rates for the reconciliation of actual SO_2 and NOx EA costs incurred September 2014 through February 2015 and recovery of estimated SO_2 and NOx EA costs for September 2015 through February 2016 through Rider 63.

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. 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. 170 IAC 4-6-9 and -18.

c. Clean Energy Project Statute. Ind. Code § 8-1-8.8-11(a)(1) and (5) provide that the commission shall encourage clean coal and energy projects by creating certain financial incentives for projects found to be reasonable and necessary, including the timely recovery of costs incurred during construction and operation and any 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 Petitioner's Evidence. Petitioner presented case-in-chief testimony and exhibits of Mr. Joseph A. Miller, Jr., Vice President of Central Engineering and Services for Duke Energy Business Services LLC, Ms. Diana L. Douglas, Director, Rates & Regulatory Planning for Duke Energy Business Services LLC, Mr. Joseph F. McCallister, Director, Gas Oil and Emissions for Duke Energy Progress, and Ms. Jennifer M. Pope, Midwest Director Fossil-Hydro Finance for Duke Energy Business Services LLC.

a. Compliance Plan Project Reports. Mr. Miller stated Petitioner is constructing its NOx Compliance Plan projects in order to comply with federal and state NOx SIP Call regulations that took effect in May 2004. Mr. Miller explained that Petitioner's NOx Compliance Plan is continuously changing, but indicated that the current NOx Compliance Plan is not significantly different from the plan presented in Cause No. 42061 ECR 24 ("ECR 24").

Mr. Miller stated that although the estimated costs of the NOx Compliance Plan have changed, Petitioner's cost estimates have been reasonably accurate. He explained that as with any multi-year plan there are ongoing impacts and refinements that could potentially affect costs. He indicated that changes in cost estimates generally reflect adjustments on the catalyst bed replacements planned for future years. He 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. Miller testified that the NOx Compliance Plan cost estimates that were previously approved reflect adjustments due to future Gibson catalyst bed replacement projects resulting in a slight overall increase in the total plan cost. Mr. Miller also mentioned the fact that although the NOx projects are in-service,[5] additional construction dollars may be spent or recorded on the project.

Mr. Miller testified that the only projects added to the current Phase 1 CAIR/CAMR Compliance Plan since the Settlement Agreement in Cause Nos. 42622 and 42718 have been mercury emission monitors that are now being used for MATS compliance.

Mr. Miller described the emission benefits associated with the Gallagher baghouses. He explained that the baghouses resulted in significant decreases in emission rates of filterable particulate matter ("PM"), mercury, and SO_2. The baghouses and DSI systems also enable Gallagher Station to comply with the MATS filterable PM and acid gas emission limits.

Mr. Miller discussed the cost estimates for the Phase 1 CAIR/CAMR Compliance Plan projects. He explained that the estimated costs have not changed, but there are incremental changes from ongoing impacts and refinements to the projects 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, the Phase 1 CAIR/CAMR Compliance Plan estimated costs are the same as the estimated costs approved in ECR 24. However, 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. Mr. Miller stated he believes the current cost estimates continue to be reasonable.

Mr. Miller provided Petitioner's progress report on the Gallagher DSI Projects stating that construction and testing of the DSI systems on Units 2 and 4 were substantially complete in 2010 and that Duke Energy Indiana has been able to maintain the required sulfur limits. He further stated that the cost estimates of the Gallagher DSI Projects remain the same as in Petitioner's last progress report.

Next, Mr. Miller discussed the reasons Petitioner is constructing Phase 2 MATS Compliance Plan projects, which were approved in Cause No. 44217. He explained that Duke

[5] "In-service" means the equipment has been installed and is in operation.

Energy Indiana must further reduce the mercury emissions from its generating facilities in order to comply with the MATS rule and its anticipated compliance date of April 16, 2015. He indicated that the primary focus of the plan is reducing the mercury emissions at Cayuga and Gibson Stations.

Mr. Miller stated that Petitioner received approval in Cause No. 44418 of its Phase 3 MATS Compliance Plan needed to ensure and demonstrate compliance with MATS limits, mainly at Gibson Station. He explained that in Cause No. 44418, Petitioner proposed to withdraw its previous request to install an activated carbon injection ("ACI") system at Gibson Unit 5 and to replace the ACI with a calcium bromide injection system in order to save both capital and O&M costs. In addition, Mr. Miller testified that Petitioner intends to defer installation of the ACI projects previously approved for Cayuga pending additional mercury emission testing after the selective catalytic reduction systems ("SCRs") are operational and will provide an update in future ECR proceedings.

Mr. Miller testified that the estimated costs of the Phase 2 MATS Compliance Plan have changed due to the approval of the Phase 3 MATS Compliance Plan, which changes the Gibson Unit 5 ACI to calcium bromide. The cost estimate also reflects the deferral of the Cayuga ACI systems. Mr. Miller again explained that he expects to see minor changes from ongoing impacts and refinements to the projects as a normal part of an ongoing construction program. He further explained that Petitioner is currently working on the future Cayuga SCR catalyst replacement program forecast, which will be similar to what has been presented in these proceedings for Gibson.

Mr. Miller explained the status of construction at Cayuga as of the end of December 31, 2014, noting: the general works contractor had completed installation of the Unit 1 SCR; work has continued on the piping and electrical installation for the Unit 2 SCR; ductwork and structural steel were complete for the Unit 2 SCR; and installation of the Unit 2 SCR is expected to be completed in the Spring of 2015. In addition, installation of Unit 1 sorbent projects was completed and the piping and electrical installation for the Unit 2 sorbents scope continued with installation to be completed in the Spring of 2015.

Mr. Miller testified that there are not any changes to the Phase 3 MATS Compliance Plan and there are no changes to the estimate at this time. However, Mr. Miller stated he would expect to see minor changes from ongoing impacts and refinements to the projects as a normal part of an ongoing construction program.

Mr. Miller described the status of the Phase 3 MATS Compliance Plan construction as of April 30, 2015, noting: the PM continuous emission monitors ("CEMS") at Gibson and Cayuga are installed and operating; the Gibson Unit 4 precipitator refurbishment project is in-service; the Gibson Unit 3 precipitator refurbishment outage is under way; and the Gibson calcium bromide system construction is nearly complete.

b. **<u>Rider 62</u>.** 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. Specifically, Ms. Douglas provided information establishing the incremental value of investment through December 31, 2014, for approved NOx and Phase 1 CAIR/CAMR

Compliance Plan projects (and of related capital maintenance projects), the Gallagher DSI Projects, and the Phase 2 and Phase 3 MATS Compliance Plan projects 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 projects will be deemed to be under construction until the Commission determines that these projects are used and useful in a base rate proceeding or until these projects no longer satisfy the other requirements of the Commission's CWIP ratemaking rules. Until such time, Petitioner will continue to receive revenues through Rider 62.

Ms. Douglas testified regarding how retirements have been accounted for on Petitioner's accounting books and records pursuant to U.S. Generally Accepted Accounting Principles. The retirements reflected in this filing are all considered normal retirements. In addition, she explained that depreciation of an asset on the accounting books stops upon retirement. Petitioner has reflected this in the actual and estimated depreciation amounts included in this filing, as appropriate based on the dates the equipment was retired.

Ms. Douglas explained the inclusion of the costs of capital maintenance projects associated with the approved NOx and Phase 1 CAIR/CAMR Compliance Plan projects, which were approved by the Commission in Cause No. 42061 ECR 18 for recovery in Riders 62 and 71. Ms. Douglas also described the term capital maintenance, how Petitioner classifies its property pursuant to the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts, and how Petitioner determines whether something is a property unit that must be capitalized.

Ms. Pope discussed the 45 capital maintenance projects for which costs, incurred after June 30, 2011, have been included. Ms. Pope explained that 42 of the projects have been approved for recovery in prior ECR proceedings and 35 of the projects are in service as of December 31, 2014, the cutoff for this filing. The three new capital maintenance projects included for Commission approval in this proceeding are:

Project	**Equipment Type**	**Completion Status**
Cayuga U2 FGD 6.9 KV Aux Transformer	FGD[6]	In Progress
Gibson FGD 1-3 GH2A Conveyor Belt	FGD	In Service
Gallagher Mercury Sorbent Trap	CEMS	In Progress

Additionally, Ms. Pope testified about other future maintenance projects, such as replacing the soda ash mitigation control system at Gibson Station. In addition, with the installation of SCRs at Cayuga, there will also be periodic replacement of catalyst layers just as at Gibson.

[6] Flue Gas Desulfurization

Ms. Douglas explained the amount of accumulated depreciation as of December 31, 2014, that is applicable to the investment for projects under the NOx and Phase 1 CAIR/CAMR Compliance Plans and their related capital maintenance projects, for the Gallagher DSI Projects, and the Phase 2 and Phase 3 MATS Compliance Plan projects. She also explained how the cost of the Gallagher baghouse projects and the retirement of Gallagher Units 1 and 3 in January 2012 was reflected.

Ms. Douglas testified regarding the calculation and allocation of the jurisdictional revenue requirement for CWIP, net of a $7,572,000 annual credit (which continues until new base rates become effective) for the jurisdictional net savings associated with the differential between the costs included in rates for Wabash River Unit 1 and the Wheatland Plant. In accordance with the Commission's Order in consolidated Cause Nos. 42908 and 43211 approving the sale of Wabash River Unit 1 to Wabash Valley Power Association, the credit is included in the Rider 62 revenue requirement calculation.

c. Rider 71. Ms. Douglas also explained and supported Petitioner's proposed adjustments to Rider 71 covering the reconciliation of depreciation and O&M expenses billed versus depreciation and O&M expenses actually incurred for the six months ended December 31, 2014, and the estimated costs for the period January through June 2015. Ms. Douglas also explained that for the first time, depreciation and incremental O&M expenses applicable to the approved Phase 2 and 3 MATS Compliance Plan projects were included in this proceeding. Ms. Douglas testified that Petitioner requests the continued recovery of amortization of the Phase 2 MATS Compliance Plan development costs over a three-year period, as presented and approved in Cause No. 42061 ECR 21, and post-in-service carrying costs accrued on the Gallagher DSI Projects, as approved for recovery in Rider 71 in Cause No. 42061 ECR 23. Petitioner also requests approval of the amortization of Phase 3 MATS Compliance Plan development costs over a three-year period, as approved for recovery in Cause No. 42061 ECR 24. In addition, Ms. Douglas testified that Petitioner requests approval of the inclusion of a credit to customers under a contract with Nucor and International Paper, which has been apportioned to Riders 62 and 71, as well as to Rider 61 for the Nucor credit only.

Ms. Pope testified that the projects having incremental O&M expenses associated with Petitioner's NOx Compliance Plan are the Gibson Units 1-5 SCRs, Gibson Units 1-5 arsenic mitigation systems, and the Gibson Units 1-5 sulfur trioxide mitigation systems. She stated that these incremental costs will fluctuate based on demand and the generation level of the units. Ms. Pope also testified regarding the incremental O&M expenses associated with Petitioner's Phase 1 CAIR/CAMR Compliance Plan. She 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 Station baghouses and that O&M expenses associated with mercury monitoring at all stations are starting to be incurred. She concluded that the incremental costs associated with these projects will also vary based on demand and the generation level of the units. With regard to the Gallagher DSI Projects, Ms. Pope explained the incremental O&M expenses associated with these projects and that the incremental costs associated with these projects are not fixed, but will vary based on demand and the generation level of the units. Finally, Ms. Pope discussed the O&M expenses that will be expected with the Phase 2 and Phase 3 MATS Compliance Plan projects, which include various chemicals and reagents as well as increased labor, contract labor, and materials and supplies.

Ms. Douglas explained that pursuant to the Consent Decree entered into with the Department of Justice resolving New Source Review litigation, Petitioner retired Gallagher Units 1 and 3 at the end of January 2012. She explained that the Commission's December 28, 2011 Order in Cause No. 43956 approves the amortization and recovery of the net book value of these units over 14 years. As such, the estimated depreciation expense for the Gallagher Units 1 and 3 projects, which are included in Riders 62 and 71, has been reflected using a 14-year amortization rather than using the approved accelerated depreciation rates, which had been previously used for the NOx and Phase 1 CAIR/CAMR Compliance Plan projects.

Ms. Douglas further explained that both Petitioner's capital maintenance projects and Gallagher DSI Projects are being depreciated using the depreciation rates approved in Cause No. 43114 IGCC 4S1 based on the FERC accounts associated with the property. She stated that the Order in that Cause also approved a provision of a 2012 Settlement Agreement that allowed Petitioner to continue to use the accelerated rates previously approved by the Commission for depreciation of the NOx and Phase 1 CAIR/CAMR Compliance Plan projects for purposes of Riders 62 and 71 recovery, while also approving the use of non-accelerated depreciation rates for book accounting purposes until the next base rate case. Ms. Douglas explained that the Phase 2 and Phase 3 MATS Compliance Plan projects are being depreciated using a depreciation rate that reflects a 20-year recovery period and a negative net salvage factor of 10%, in accordance with the Commission's Orders in Cause Nos. 44217 and 44418. Ms. Douglas testified that depreciation has been adjusted, as appropriate, for retirements.

Next, Ms. Douglas described the conversion of O&M, depreciation, and the amortization of the Phase 2 and Phase 3 MATS Compliance Plan development costs and post-in-service carrying costs to revenue requirements. She testified that depreciation expense and the amortization of post-in-service carrying costs were separated into two components before converting to revenue requirements: (1) the portion related to equity AFUDC, and (2) the portion related to all other costs comprising the investment being depreciated or amortized. The portion of depreciation and post-in-service carrying cost amortization expense applicable to equity AFUDC costs was converted to revenue requirements using a calculation that includes a provision for both state and federal income taxes, and the remainder of the depreciation and post-in-service amortization expense was converted to revenue requirements using the same revenue conversion factor as for O&M and the amortization of the Phase 2 and Phase 3 MATS Compliance Plan development costs.

Ms. Douglas also stated that Petitioner included credits to customers in the amount of incremental demand revenues under contracts with Nucor Corporation ("Nucor Credit") and International Paper ("International Paper Credit"). Ms. Douglas explained that a credit for the amount of Nucor demand revenues apportioned to Riders 61, 62, and 71 representing the apportioned amount of 2015 demand revenues applicable to Nucor's interruptible load and a reconciliation of the credit applicable to July through December 2014 was included in the revenue requirement used in developing the Rider 71 factors. The Nucor Credit was calculated in accordance with the Commission's Orders in Cause No. 43754 and 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 International Paper Credit) and the revenue requirements from the most recently approved Rider 61 in Cause No. 43114 IGCC 10. Ms. Douglas testified that the International Paper Credit was calculated in accordance with the Commission's Orders in Cause No. 44087 and Cause No. 42061 ECR 15 (related to the Nucor Credit) using actual steam demand for the period July through December 2014 and the revenue requirements proposed in this proceeding for Riders 62 and 71 (excluding the Nucor Credit and International Paper Credit).[7] She further explained that Petitioner planned to include credits representing six-months' worth of apportioned Nucor and International Paper demand revenues in future ECR proceedings until such time as Nucor and International Paper demand revenues have been included in new base rates or the Commission approves revised contracts.

Ms. Douglas explained that there have been no further adjustments to the allocation factors used in Riders 62 and 71 for customer migrations from those approved by the Commission in Cause No. 42061 ECR 24. She further explained that Petitioner committed to continue to monitor the rate migrations between the LLF and HLF rate classes each year and propose an update to the allocation factors if there were a net change of greater than 10 MW from the prior level. Ms. Douglas explained that the 2014 study will be completed prior to the next ECR filing, and any adjustments to the allocation factors will be proposed at that time.

d. Rider 63. Ms. Douglas explained and supported Petitioner's proposed adjustments to Rider 63, covering the reconciliation of SO_2 and NOx net EA expenses versus the net expenses incurred for the six months ended February 2015, and the estimated mercury, NOx and SO_2 EA costs for the period September 2015 through February 2016.

Ms. Douglas testified that a realized gain from the sale of annual NOx EAs was included in the development of the factor and that no estimates of EA sales were included during the projected period. She also testified that Petitioner included costs associated with the write-off of the remaining inventory value of CAIR seasonal NOx EAs, which were on Petitioner's books in December 2014 due to the termination of the CAIR program. She stated there would be a similar write-off of the value remaining in the CAIR annual NOx inventory after the 2014 compliance.

Ms. Douglas explained the impact of implementation of the Cross State Air Pollution Rule ("CSAPR") on January 1, 2015. She stated Petitioner reflected the reversion back to SO_2 compliance, which requires a ratio of one-for-one (one SO_2 allowance per every ton of SO_2 emissions) rather than the higher ratio required under CAIR, and the termination of the CAIR annual and seasonal NOx programs in the January and February 2015 actual expense and the September 2015 through February 2016 forecasted expense. She noted that because Petitioner is projecting to have sufficient CSAPR EA inventories to cover 2015 and 2016 CSAPR compliance without requiring purchases, no additional costs for CSAPR EAs were included in January or February 2015 actuals or the forecast.

Mr. McCallister provided an update on CSAPR, noting that it became effective on January 1, 2015. He testified that based on its recent forecast, Petitioner currently projects having sufficient SO_2 and NOx CSAPR EAs in its inventory to cover 2015 and 2016 CSAPR compliance. But, Petitioner will continue to monitor the EA forecasts to determine if any purchases will be needed.

[7] Rider 61 is not applicable to the International Paper steam contract.

Mr. McCallister explained how the reinstatement of CSAPR affects the CAIR programs, CAIR allowances in inventory, and compliance. He testified that for 2014, the last year of CAIR compliance programs, Petitioner had to comply with the requirements of CAIR Annual NOx, CAIR Seasonal NOx, and Title IV/Acid Rain SO_2 using the CAIR SO_2 ratio requirements.[8] For 2015, Petitioner will have to comply with the requirements of CSAPR Annual NOx, CSAPR Seasonal NOx, CSAPR Group 1 SO_2 and Title IV/Acid Rain SO_2 using the pre-CAIR allowance ratio requirement of one allowance to one ton of emissions.

Mr. McCallister described the trading market for CSAPR EAs. He stated that since the lifting of the stay on CSAPR in October 2014, there has been very limited observed activity for CSAPR EAs. Market activity for Title IV Acid Rain SO_2 allowances has been similarly limited. As of mid-April 2015, market prices for 2015 CSAPR SO_2 Group 1 allowances are approximately \$57.50/ton, CSAPR Annual NOx allowances are approximately \$122.50/ton, and Seasonal NOx allowances are approximately \$112.50/ton. Petitioner will continue to monitor CSAPR emission markets and currently expects to have sufficient allocations of CSAPR allowances to meet 2015 compliance requirements.

Mr. McCallister described the types of transactions that occur in the EA market and why it is necessary for Duke Energy Indiana to participate. He described the production costing model that Petitioner uses to determine whether it needs to purchase EAs or if it has a surplus and can sell some of its EA inventory. He said the model recognizes and reflects the interrelationship and interaction of the various inputs, such as capacity, fuel type, heat rate, forced outage rates, and emission rates. Mr. McCallister explained that Petitioner strives to meet its native load customers' energy requirements by purchasing energy from the wholesale power market when such purchases are more economic than running its own generating units. Mr. McCallister stated that the model is just a tool, and that judgment must be applied to the output. He explained that the model distinguishes between native load EA requirements and EAs to support non-native sales, and those inventories are managed separately. He stated that once a purchase is made for native load, those EAs remain with native load, and similarly for purchases made for non-native load. All zero cost allowances Petitioner receives are maintained for the benefit of native load customers.

Mr. McCallister explained that Petitioner's goal is to approach a balanced position after considering allocations provided by EPA, existing inventory, and emission usage based on forecasting and actual usage. In addition, because EAs that do not have to be surrendered to EPA are valid in later years, Petitioner must also consider its position in later years.

Next, Mr. McCallister described how the implementation of CSAPR would affect the management of the CSAPR EA positions for 2015. He explained that Petitioner will have to comply with the requirements of CSAPR Annual NOx, CSAPR Seasonal NOx, CSAPR SO_2 Group 1 and Title IV/Acid Rain SO_2 Group 1 and Title IV/Acid Rain SO_2, using the pre-CAIR allowance ratio requirement of one allowance to one ton of emissions. Based on 2015 actual emissions through February and estimates for the remainder of 2015, Petitioner projects it will have adequate EAs in inventory to comply with 2015 and 2016 CSAPR SO_2 and NOx requirements. He explained that Petitioner continues to monitor its EA positions under CSAPR

[8] Two allowances for one ton of SO_2 emissions.

and Title IV/Acid Rain and continuously looks for ways to optimize the EA positions by using the EA market to buy and sell EAs, as needed, passing through to customers the costs of purchases and the gains or losses on sales in the normal course of business.

Mr. McCallister testified that there was one sale of CAIR Annual NOx EA transactions during the reconciliation months for this proceeding. Since the CAIR compliance program ended after 2014, this transaction is likely the last one relating to the CAIR compliance program.

Finally, Mr. McCallister stated that Petitioner's purchases and sales of native load EAs for the period were conducted in a reasonable manner. He further stated that he provided information with respect to Petitioner's estimated EA consumption to Ms. Douglas for use in updating estimated EA costs for the forecast months. He stated these forecasts are reasonable and based on the same modeling that has been used for a number of years.

8. Summary of the OUCC's Evidence. The OUCC presented the testimony and exhibits of its Senior Utility Analysts, Mr. Wes R. Blakley and Ms. Cynthia M. Armstrong.

Mr. Blakley testified he reviewed Petitioner's filings and the Commission's Order in ECR 24 and nothing came to his attention that would indicate Petitioner's calculation of estimated ECR adjustment factors for the relevant period is inaccurate. Mr. Blakley noted that Petitioner has fully amortized the Wheatland plant's deferred asset balance and that the revenues from the Wabash River Unit 1 can be refunded to customers. He also noted that Petitioner has requested recovery of costs associated with the Gallagher DSI Projects, approved in Cause No. 43956 on December 28, 2011, and a recalculation of depreciation expense related to the pollution control assets at retired Gallagher Units 1 and 3. Mr. Blakley 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. Mr. Blakley also referenced that the testimony of Ms. Douglas and Ms. Pope discussed capital maintenance projects.

Ms. Armstrong testified that she reviewed Petitioner's filings. She testified that Petitioner had one sale of EAs during this period and that she found this sale to be reasonable. Ms. Armstrong further testified that based on her analysis, Duke Energy Indiana's calculations of the EA adjustment factor were accurately applied.

9. Commission Discussion and Findings. Based upon the evidence presented, we find that Petitioner's requested relief in this proceeding is reasonable, consistent with regulatory requirements and prior Commission Orders, and should be approved. Specifically, costs and expenses through December 31, 2014, for the NOx and Phase 1 CAIR/CAMR Compliance Plans, Gallagher DSI Projects, capital maintenance, and the Phase 2 and Phase 3 MATS Compliance Plan projects shall be included in Petitioner's 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. Douglas.

Petitioner is authorized to recover its O&M and depreciation expenses related to the NOx and Phase 1 CAIR/CAMR Compliance Plans, Gallagher DSI Projects, Phase 2 and Phase 3 MATS Compliance Plan projects, and capital maintenance, 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 2014 through December 2014 and the estimated amounts for the period January 2015 through June 2015.

Petitioner is authorized to recover its SO_2 and NOx EA costs 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 September 2014 through February 2015 and the estimated amounts for the period September 2015 through February 2016.

The combined impact of the proposed factors for Riders 62, 63, and 71 for a typical residential customer using 1,000 kilowatt-hours will increase by $1.08 or 1.3% when compared to the last approved factors.

In addition, Petitioner's ongoing review progress reports related to its NOx and Phase 1 CAIR/CAMR Compliance Plans, Gallagher DSI Projects, and Phase 2 and Phase 3 MATS Compliance Plans are hereby approved. We find that the updated environmental plans, construction cost estimates, and updated in-service dates for the various projects, including changes described in the testimony of Mr. Joseph A. Miller, are reasonable and approved.

10. Confidential Information. Petitioner filed a Motion for Protection of Confidential and Proprietary Information with the Affidavits of Mr. Miller, Mr. McCallister, and Ms. Douglas on April 30, 2015. The Presiding Officers granted the Motion in a May 11, 2015 Docket Entry, finding the information should be held confidential on a preliminary basis.

The Affidavits of Mr. Miller, Ms. Douglas, and Mr. McCallister indicate that the 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 confidential information is trade secret and exempt from public access and disclosure by the Commission.

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 investment values as of December 31, 2014, is approved. The Rider 62 rates 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, including reconciliation through December 31, 2014 and estimated amounts for January 1, 2015 through June 30, 2015, for recovery of O&M and depreciation expenses related to its NOx and Phase 1 CAIR/CAMR Compliance Plans, Gallagher DSI Projects, Phase 2 and 3 MATS Compliance Plans and capital maintenance, as reflected in the exhibits and testimony of Duke Energy Indiana, is approved, including the amortizations of the Phase 2 and Phase 3 MATS Compliance Plan development costs and post-in-service carrying costs accrued on the Gallagher DSI Projects. The Rider 71

rates 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.

3. Petitioner's proposed updated Rider 63, including reconciliation through February 2015 and estimated EA costs for September 2015 through February 2016, as reflected in the direct exhibits and testimony of Duke Energy Indiana, is approved. The Rider 63 rates 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.

4. Petitioner's ongoing review progress reports related to its NOx and Phase 1 CAIR/CAMR Compliance Plans, Gallagher DSI Projects, and Phase 2 and Phase 3 MATS Compliance Plans are approved.

5. Petitioner's updated environmental plans, cost estimates, and estimated in-service dates for its NOx, Phase 1 CAIR/CAMR, and Phase 2 and Phase 3 MATS Compliance Plan projects are approved.

6. The detailed cost estimate and actual expenditure information, unit-specific O&M costs, specific EA transaction prices, International Paper price information, Nucor load and price information, and retirement detail contained in the testimony and exhibits are confidential trade secret information and therefore excepted from public access.

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

STEPHAN, MAYS-MEDLEY AND ZIEGNER CONCUR; HUSTON AND WEBER ABSENT:

APPROVED: JUL 29 2015

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

Brenda A. Howe

Brenda A. Howe
Executive Secretary to the Commission