On April 22, 2019, Duke Energy Indiana, LLC ("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"), federally mandated coal combustion residuals projects, and other clean coal and energy projects through December 31, 2018 in its rates and charges for electric service, through Petitioner’s Environmental Compliance Investment 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 and federally mandated coal combustion residuals projects; (2) updated environmental projects, cost estimates, and estimated in-service dates for environmental projects; (3) an update and adjustment to

An evidentiary hearing was held in this case on June 27, 2019 at 9:30 a.m. in Room 222, 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.

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, -62(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) one solar-powered facility located at NSA Crane; (3) steam capacity located at three stations comprised of nine coal-fired generating units; (4) combined cycle capacity located at one station comprised of three natural gas-fired CTs and two steam turbine-generators; (5) a run-of-river hydroelectric generation facility comprised of three units; and (6) peaking capacity consisting of four oil-fired diesels 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 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, CAMR, and CSAPR 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 Indiana Air Pollution Control Board adopted the final CAIR on November 1, 2006.

The final CAIR requires major sulfur dioxide (“SO₂”) and NOx emission reductions, established annual and seasonal NOx trading programs, and set limitations on the use of SO₂ emission allowances. The final CAMR provided for a mercury cap and trade program. The Indiana Air Pollution Control Board adopted CAMR on October 3, 2007. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the federal CAMR.

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

On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit issued an order vacating and remanding CAIR. On December 23, 2008, the D.C. Circuit granted rehearing only to the extent that it remanded the rules to EPA without vacating them. The ruling held that CAIR would remain in place until EPA issued a new rule in accordance with the July 11, 2008 decision.

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (“CSAPR”), with subsequent proposed revisions issued on October 6, 2011. CSAPR placed statewide caps on overall SO₂ and NOx power plant emissions in 2012 and 2014, and was due to replace CAIR starting January 1, 2012. On August 21, 2012, the D.C. Circuit Court vacated CSAPR in its entirety and directed EPA to continue administering CAIR pending completion of a valid replacement rule. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit Court opinion vacating CSAPR and remanded the case to the D.C. Circuit for further proceedings. On October 23, 2014, the D.C. Circuit lifted the stay on CSAPR. CSAPR’s Phase 1 emission budgets took effect on January 1, 2015 for the annual programs and May 1, 2015 for the ozone-season NOx program. The CSAPR Phase 2 annual budgets took effect on January 1, 2017. On November 16, 2015, the EPA proposed an update (“CSAPR Update Rule”) to the CSAPR ozone season program to reflect the 2008 ozone National Ambient Air Quality Standards (“NAAQS”). The final CSAPR Update Rule, signed on September 7, 2016, required NOx emissions reductions from power plants in 22 states in the eastern U.S., including Indiana, beginning with the 2017 ozone season. The final rule set a 2017 CSAPR Update NOx budget
of 23,303 tons for Indiana.\(^1\) Final briefs for Judicial Review of Final Agency Action of the U.S. EPA CSAPR Update Rule were submitted on March 17, 2018 and oral argument was held on October 3, 2018 in the U.S. Court of Appeals for the D.C. Circuit.

c. **Utility MATS Compliance Requirements.** EPA first proposed Maximum Achievable Control Technology standards for coal- and oil-fired utility steam electric generating units 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 megawatts in capacity. The deadline for compliance was April 16, 2015. Certain of Petitioner’s units had received one-year MATS compliance extensions. 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.

On April 3, 2013, in Cause No. 44217, the Commission approved 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 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. **Federally Mandated Compliance Requirements.** On May 24, 2017, the Commission in Cause No. 44765 approved a settlement agreement and issued a CPCN for certain projects (“CCR Compliance Plan projects”) necessary for compliance with the following federal mandates: (1) EPA’s Coal Combustion Residuals (“CCR”) rule, which regulates the disposal of CCR under Subtitle D of the Resource Conservation and Recovery Act as a non-hazardous waste; (2) EPA’s Steam Electric Effluent Limitations Guidelines (“ELG”) rule, which governs the quality of water discharged from generating facilities; and (3) EPA’s National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (“RICE NESHAP”), which establishes certain air emission and operating limits. The Commission also approved the recovery of certain capital expenditures and operation and maintenance (“O&M”) costs associated with the CCR Compliance Plan projects through Riders 62 and 71.

e. **Dry Sorbent Injection Projects at Gallagher Units 2 and 4.** As part of the terms of a Consent Decree agreed to by Petitioner and 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 and to recover a return

\(^1\) In comparison to the 2015 emissions of 36,353 tons.
on the capital expenditures for the Gallagher DSI projects through Rider 62 and to recover the incremental O&M (including the cost of reagents) and depreciation expenses of the Gallagher DSI projects through Rider 71.

f. **Emission Allowance Adjustment.** In Cause Nos. 42411 and 42359, the Commission approved the recovery of NOx emission allowance ("EA") costs in Petitioner’s then-existing SO2 EA adjustment mechanism. In consolidated Cause Nos. 42622 and 42718, the Commission approved the inclusion of mercury EA costs in this same mechanism. Petitioner 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) to reflect additional values through December 31, 2018 of the NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Gallagher DSI projects, capital maintenance, Phase 2 and Phase 3 MATS Compliance Plan projects, and CCR Compliance Plan projects in its rates and charges for electric service, through Rider 62; (2) approval of an ongoing review progress report related to its NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Gallagher DSI projects, Phase 2 and Phase 3 MATS Compliance Plan projects, and CCR Compliance Plan projects; (3) approval of the estimated depreciation and expenditures related to its NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Gallagher DSI projects, Phase 2 and Phase 3 MATS Compliance Plan projects, CCR Compliance Plan projects, capital maintenance projects, along with amortization of post-in-service allowance for funds used during construction ("AFUDC") on the Phase 1 CAIR/CAMR Compliance Plan projects, CCR Compliance Plan development, and post-in-service carrying costs incurred through June 30, 2019, and the reconciliation of actual expenses through December 31, 2018 via 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) approval of Petitioner’s updated environmental plan, cost estimates, and estimated in-service dates for the NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Gallagher DSI projects, Phase 2 and Phase 3 MATS Compliance Plan projects, and CCR Compliance Plan projects; and (5) approval of an adjustment to its rates for the reconciliation of actual SO2 and NOx EA costs incurred through February 2019 and recovery of estimated EA costs for September 2019 through February 2020 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) provides that the Commission shall encourage clean 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 energy projects” in part, 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. **Federally Mandated Requirements Statute.** Under Ind. Code ch. 8-1-8.4, an energy utility may petition the Commission for the recovery of “federally mandated costs” associated with projects necessary to comply with “federally mandated requirements,” as those terms are defined in Ind. Code §§ 8-1-8.4-4 and -5, respectively. If the Commission finds that the public convenience and necessity is served by issuing a CPCN after consideration of the factors set forth in Ind. Code § 8-1-8.4-6(b) and approves the projected federally mandated costs, a petitioning utility shall recover 80% of those costs through a periodic rate adjustment mechanism; the remaining 20% shall be deferred with post-in-service carrying costs and recovered by the utility as part of the utility’s next general rate case. Ind. Code § 8-1-8.4-7(c). In addition, Ind. Code § 8-1-8.4-7(c)(1) requires the Commission to adjust an electric energy utility’s authorized net operating income to reflect any approved earnings associated with the compliance projects for purposes of Indiana Code § 8-1-2-42(d)(3).

e. **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.”


a. **Compliance Plan Project Reports.** Mr. Miller stated that 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 and indicated that the current NOx Compliance Plan is not significantly different from the plan presented in Cause No. 42061 ECR 32 (“ECR 32”).

Mr. Miller stated that although the estimated costs of the NOx Compliance Plan equipment 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 reflect adjustments on the recently completed and future Gibson catalyst bed replacement projects. 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. Miller also noted that although the NOx projects are "in-service," additional construction dollars may be spent or recorded on the project.

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

Mr. Miller described the emissions 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 SO2, and have accommodated utilization of dry sorbent injection. 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 that he would expect to see 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 projects estimated costs are the same as the estimated costs approved in ECR 32. Mr. Miller stated he believes the current cost estimates of Petitioner’s Phase 1 CAIR/CAMR Compliance Plan projects 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 was substantially complete in 2010 and the systems were placed in service in December 2010. Since then, Duke Energy Indiana has been able to maintain the required sulfur limits. Mr. Miller 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 constructed Phase 2 MATS Compliance Plan projects, which were approved in Cause No. 44217. He explained that the Petitioner had to further reduce the mercury emissions from its generating facilities in order to comply with the MATS rule and its compliance date of April 16, 2015. He indicated the primary focus of the Phase 2 MATS Compliance Plan is reducing the mercury emissions at Cayuga and Gibson Stations.

Mr. Miller testified that while there haven’t been any changes to Petitioner’s Phase 2 MATS Compliance Plan at this time, the estimated costs have increased from the estimate provided in ECR 32, primarily due to the difference between the estimated and direct cost of a Cayuga Unit 1 catalyst layer. 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. As of the end of December 31, 2015, all of the Phase 2 MATS Compliance Plan projects have been completed and placed in-service, with the exception of the ongoing costs associated with the replacement of Cayuga’s selective catalytic reduction ("SCR") catalyst beds.

Mr. Miller stated that Petitioner received approval in Cause No. 44418 of its Phase 3 MATS Compliance Plan for investments needed to ensure and demonstrate compliance with MATS limits at

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2 "In-service" means the equipment has been installed and is in operation.
Cayuga and Gibson Stations. He explained that in Cause No. 44418, the Phase 3 development costs were approved, which included additional mercury and hydrogen chloride emission testing.

Mr. Miller explained that there are not any changes to the Phase 3 MATS Compliance Plan and that the estimated costs have remained the same as those filed in ECR 32. As with any multi-year plan, Mr. Miller testified that he expects to see minor changes from ongoing impacts and refinements to the projects.

Mr. Miller explained that Petitioner was required to make additional investments at Gibson and Cayuga to comply with the EPA’s CCR rule. He described Petitioner’s CCR Compliance Plan projects and stated that recovery was approved in Cause No. 44765. He explained that the approved recovery included Petitioner’s CCR Compliance Plan developments costs, which include the assessment of its surface impoundments leading to the determination of the approved CCR Compliance Plan projects.

Mr. Miller explained that there are not any changes to the CCR Compliance Plan and that the estimate has not changed from that approved in Cause No. 44765. He again testified that with any multi-year plan, he expects to see minor changes from ongoing impacts and refinements to the projects as a normal part of an ongoing construction program. Mr. Miller provided a status on construction, testifying that the gypsum storage pads at both Cayuga and Gibson were placed in-service in October 2015; the Gibson dry bottom ash handling systems were placed in-service in December 2017; the Cayuga dry bottom ash handling systems were placed in-service in February 2018; the lined retention ponds at Gibson and Cayuga were placed in-service in December 2017; the Cayuga and Gibson water reroute projects were placed in-service in March 2018; the RICE NESHAP projects for the Cayuga diesel generators were placed in-service in March 2017; and that all CCR Compliance Plan projects have now been placed in service. Concluding, Mr. Miller testified that although the CCR Compliance Plan and RICE NESHAP projects are in service, additional construction dollars may still be recorded on the projects.

b. Rider 62. Ms. Diaz 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. Diaz provided information establishing the incremental value of investment through December 31, 2018 for approved NOx and Phase 1 CAIR/CAMR Compliance Plan projects, the Phase 2 and Phase 3 MATS Compliance Plan projects, Phase 1 CAIR/CAMR Compliance Plan post-in-service AFUDC, the Gallagher DSI projects, the CCR Compliance Plan projects and related plan development costs, capital maintenance projects, and CCR post-in-service carrying costs, for which Petitioner is seeking recovery; showed the computation of the jurisdictional revenue requirement associated with Petitioner’s investment; and determined the allocation of the jurisdictional revenue requirement to various retail customer groups. Ms. Diaz 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 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. Until such time, Petitioner will continue to receive revenues through Rider 62.

Ms. Diaz testified regarding how retirements have been accounted for on the 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. She explained that the value of both the investment and its depreciation are reduced by the original cost of the equipment that has been retired. 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. Diaz explained the inclusion of the costs of capital maintenance projects associated with the approved NOx, Phase 1 and Phase 2 CAIR/CAMR, and CCR Compliance Plan projects, which were approved by the Commission in Cause No. 42061 ECR 18 for recovery in Riders 62 and 71. Ms. Diaz 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 96 capital maintenance projects for which costs, incurred after June 30, 2011, have been included. Ms. Pope explained that 89 of the projects have been approved for recovery in prior ECR proceedings and 84 of the projects are in service as of the December 31, 2018 cut-off for this filing. The seven new capital maintenance projects included for Commission approval in this rider proceeding are as follows:

<table>
<thead>
<tr>
<th>Project</th>
<th>Equipment Type</th>
<th>Completion Status</th>
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<tbody>
<tr>
<td>Cayuga LH-1 Belt Replacement</td>
<td>FGD</td>
<td>In Service</td>
</tr>
<tr>
<td>Cayuga GH-2-B Belt Replacement</td>
<td>FGD</td>
<td>In Service</td>
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<tr>
<td>Cayuga FGD Dribble Screw</td>
<td>FGD</td>
<td>In Service</td>
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<tr>
<td>Gibson Soda Ash Mitigation Control System</td>
<td>SCR</td>
<td>In Progress</td>
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<tr>
<td>Gibson FGD Unit 3 Vacuum Filter Belt</td>
<td>FGD</td>
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<tr>
<td>Gibson FGD Unit 3-2 Vacuum Filter Belt</td>
<td>FGD</td>
<td>In Progress</td>
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<tr>
<td>Gibson FGD Unit 5-A Booster Fan Coupling Assembly</td>
<td>FGD</td>
<td>In Progress</td>
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Additionally, Ms. Pope testified that other future capital maintenance projects include belt replacement on Gibson Unit 1 FGD Vacuum Filter, and power cell replacements on the Gibson Unit 1-C ID Fan variable frequency drives.

Ms. Diaz explained the amount of accumulated depreciation as of December 31, 2018 that is applicable to the investment for projects under the NOx and Phase 1 CAIR/CAMR Compliance Plan projects, the Gallagher DSI projects, the Phase 2 and Phase 3 MATS Compliance Plan projects, the related capital maintenance projects, and the CCR Compliance Plan projects. She also explained how the cost of Gallagher DSI projects and the retirement of Gallagher Units 1 and 3 in January 2012 was reflected.

Ms. Diaz testified to the Phase 1 CAIR/CAMR Compliance Plan post-in-service AFUDC and related amortization over a 20-year period that was approved in Cause No. 42061 ECR 30 and the Commission’s ordered reduction in Cause No. 42061 ECR 31 of the post-in-service AFUDC balance in this proceeding for the period of July 2018 through December 2018. She provided the unamortized post-in-service balance as of December 31, 2018 and the 20-year amortization balance.

3 Flue Gas Desulfurization.
Ms. Diaz also discussed the inclusion of the CCR Compliance Plan development costs and its impact. She explained that these costs, approved in Cause No. 44765, are federally mandated costs subject to timely rider recovery at the 80% level, with 20% deferred until the next rate case.

Ms. Diaz testified regarding the CCR Compliance Plan post-in-service carrying costs and its impact. She explained that included with the 60% cost of the CCR plant is also post-in-service AFUDC and the related amortization over three years, which recovery was also approved in Cause No. 44765.

Ms. Diaz testified regarding the calculation and allocation of the jurisdictional revenue requirement for CWIP, net of an annual credit (which continues until new base rates become effective) for the retail 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.

Ms. Diaz explained that as a result of the Tax Act, the amounts collected from customers when the federal income tax rate was at 35% were included in the deferred income tax account. These amounts were recalculated using the 21% federal rate, with the difference reclassified in a separate regulatory liability account. Customers will continue to get the benefits for return calculation purposes in this rider of this excess deferred income tax regulatory liability until the excess deferred income taxes are returned to customers per the Commission’s Order in Cause No. 45032 S2.

c. **Rider 71.** Ms. Diaz 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, 2018, and the estimated costs for the period January through June 2019. She testified that Petitioner is requesting the recovery of amortization of 80% of CCR Plan development costs over a three-year period; amortization of post-in-service carrying costs for the Phase 1 CAIR/CAMR Compliance Plan projects over a 20-year period; amortization of 60% of post-in-service carrying costs for the CCR Compliance Plan projects over a three-year period; and the depreciation credit for the Gibson precipitator refurbishments. In addition, Ms. Diaz testified that Petitioner is requesting 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 the NOx Compliance Plan equipment are the Gibson Units 1-5 SCRs, Cayuga Units 1 and 2 arsenic mitigation systems, and the Gibson Units 1-5 sulfur trioxide mitigation systems. Most of the expense is for various reagents, with some additional O&M expenses for operating and maintaining the Gibson SCRs associated with the Process Safety Management (“PSM”) compliance projects. 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 projects. 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, Gallagher baghouses, and that O&M expenses associated with mercury monitoring at these
stations are also being incurred. She explained 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 are not fixed and will vary based on demand and the generation level of the units.

Ms. Pope also discussed the O&M expenses associated with the Phase 2 and Phase 3 MATS Compliance Plan projects, which include various chemicals and reagents as well as additional O&M expenses for operating and maintaining the Cayuga SCRs (including those associated with the PSM compliance programs) and sorbent injection systems, mercury re-emission chemical systems for Cayuga and Gibson Stations, the calcium bromide injection systems and PM continuous emission monitors on all five Gibson units and Cayuga Units 1 and 2. She stated that incremental O&M work scope is also needed to support other MATS compliance equipment and processes, such as the PM continuous emission monitors, mercury sorbent traps, and work practice standards testing requirements.

Regarding the costs associated with Petitioner’s CCR Compliance Plan projects, Ms. Pope explained that most of these projects remain under construction, but will have future O&M costs. However, Petitioner has incurred federally mandated O&M costs, not associated with the construction projects but approved for recovery in Cause No. 44765, which are included with this filing. Ms. Pope described the various costs associated with Petitioner’s compliance with the CCR rule. She explained the majority of these costs are not fixed and will vary due to maintenance cycles, emergent maintenance projects required to be completed under the CCR rule, and station operations.

Ms. Pope concluded that the capital maintenance costs included in this proceeding, which Ms. Diaz used in her testimony, are reasonable and necessary incremental expenditures associated with environmental compliance projects.

Ms. Diaz testified that Petitioner’s NOx Compliance Plan projects are being depreciated on an 18-year recovery, including a 20% negative net salvage factor, pursuant to Commission Orders in Cause Nos. 42359 and 42061 and that the depreciation rate for the Phase 1 CAIR/CAMR Compliance Plan projects reflects a 20-year recovery period with a 10% negative net salvage factor based on provisions of the 2006 Settlement Agreement. She testified that Petitioner also limited the amount included for estimated and actual depreciation of the Gallagher DSI projects in accordance with the 2006 Settlement Agreement.

Ms. Diaz explained that pursuant to the Consent Decree entered into by Petitioner and the U.S. Department of Justice resolving New Source Review litigation, Gallagher Units 1 and 3 were retired 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. Diaz further explained that Petitioner’s capital maintenance projects, Gallagher DSI projects, and CCR Compliance Plan 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 the 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. Diaz explained that 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. Diaz also explained that the settlement agreement in Cause No. 44418 required Petitioner to reduce the amount of depreciation to be included for recovery in Rider 71 for the Gibson Units 3, 4, and 5 precipitator refurbishment projects that are part of Phase 3, to reflect the effect of the retired investment in the original Gibson electrostatic precipitators and that depreciation has been included. Ms. Diaz testified that depreciation has been adjusted, as appropriate, for retirements.

Ms. Diaz described the conversion of O&M expense and CCR Compliance Plan development 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 expense and post-in-service carrying cost amortization 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 CCR Compliance Plan development costs.

Ms. Diaz also said that, as shown on her Exhibit 2-E, Petitioner was including credits to customers in the amount of incremental demand revenues under contracts with Nucor Corporation (“Nucor Credit”) and International Paper (“International Paper Credit”). Ms. Diaz explained that the credit for the amount of Nucor demand revenues was apportioned to Riders 61, 62, 71, and Standard Contract Rider No. 73 – Renewable Energy Project Revenue Adjustment (“Rider 73”) was calculated for the July through December 2019 period, and a reconciliation of the credit applicable to July through December 2018 was included in the development of the revenue requirement for Rider 71 factors. The Nucor Credit was calculated in accordance with the Commission’s Orders in Cause Nos. 44932 (relating to renewable projects) and 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 and 73. Ms. Diaz 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 2018 and the revenue requirements proposed in this proceeding for Riders 62 and 71 (excluding the Nucor Credit and International Paper Credit).

She further explained that Petitioner plans 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.

4 Riders 61 and 73 are not applicable to the International Paper steam contract.
d. **Rider 63.** Ms. Diaz explained and supported Petitioner’s proposed adjustments to Rider 63, covering the reconciliation of SO\(_2\) and NO\(_x\) net EA expenses versus the net expenses incurred for the six months ended February 2019, and the estimated mercury, NO\(_x\) and SO\(_2\) EA costs for the period September 2019 through February 2020.

Ms. Diaz testified that there were EA gains of $271,868 recorded in the reconciliation period covered in this proceeding included in the development of the factor, and that no estimates of EA sales were included during the projected period. She explained that Petitioner is not requesting recovery of any costs due to the surrender of additional SO\(_2\) EAs related to its New Source Review litigation.

Ms. Diaz further explained that Petitioner had reflected the impact of the January 1, 2015 implementation of CSAPR in this proceeding. Petitioner reflected the reversion back to SO\(_2\) compliance which requires a ratio of one-for-one\(^5\) along with the termination of the CAIR annual and seasonal NO\(_x\) programs, in the actual and forecasted expense included in this filing. She said Petitioner is projecting to have sufficient CSAPR EA inventories to cover the remainder of 2019 CSAPR compliance and will be purchasing or selling allowances in the normal course of business.

Mr. McCallister explained that CSAPR became effective January 1, 2015. On September 9, 2016, the EPA published the CSAPR Seasonal NO\(_x\) update rule, which reduced the CSAPR Seasonal NO\(_x\) allowance allocations for all states remaining in the program. Duke Energy Indiana has completed its 2018 compliance requirements for CSAPR SO\(_2\) Group 1, CSAPR seasonal and annual NO\(_x\) and Title IV/Acid Rain SO\(_2\) requirements and expects to be in compliance for its 2019 requirements.

Mr. McCallister described the trading market for CSAPR EAs stating there has been limited observed activity for CSAPR SO\(_2\) Group 1, seasonal and annual NO\(_x\) emission allowances, and Title IV Acid Rain SO\(_2\) allowances. Based on early April 2019 indications, market prices for 2019 or earlier CSAPR SO\(_2\) Group 1 allowances are approximately $1.50/ton, 2019 or earlier CSAPR Annual NO\(_x\) allowances are approximately $2.50/ton, 2019 or earlier CSAPR Seasonal NO\(_x\) allowances are approximately $150.00/ton, and Title IV Acid Rain SO\(_2\) allowances are approximately $0.50/ton. Petitioner successfully completed its 2018 compliance filings and expects to have sufficient EAs for its 2019 compliance requirements, but will continue to monitor the EA forecasts inventories and position through the planning horizon and make adjustments as needed.

Mr. McCallister described the types of transactions that occur in the EA market and those commonly used by Petitioner, and why it is necessary for Duke Energy Indiana to participate. He described the sophisticated 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 Duke Energy Indiana’s own generating units. He stated that the model is just a tool, and that judgment must be applied to the output. Mr. McCallister explained that the model distinguishes between native load EA requirements and EAs to support non-native sales, and those inventories are managed separately. He

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\(^5\) One SO\(_2\) allowance per every ton of SO\(_2\) emissions.
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 the EPA, existing inventory, and emission usage based on forecasting and actual usage. In addition, because EAs that do not have to be surrendered to the EPA are valid in later years, Petitioner must also consider its position in later years.

Next, Mr. McCallister described how the implementation of CSAPR affected the management of the CSAPR EA positions for 2019. He explained that Petitioner expects to be in compliance for all native load emission obligations, 2019 CSAPR Annual NOx, CSAPR Seasonal NOx, CSAPR SO2 Group 1 and Title IV/Acid Rain SO2, for 2019. He explained that Petitioner continues to monitor its EA positions under CSAPR 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 Duke Energy Indiana booked seven EA transactions for this reconciliation period, four for the sale of 1,412 CSAPR Ozone Season NOx allowances and three for the sale of 1,100 Annual NOx allowances, resulting in gross proceeds of $271,868.

He further stated that Petitioner continues to monitor the CSAPR emissions markets and looks for ways to optimize the EA positions, which could include the sale of additional CSAPR Group 1 SO2 allowances, and CSAPR Seasonal NOx and Annual NOx allowances.

Mr. McCallister concluded by stating that Petitioner’s estimated EA consumption and costs for the forecasted months, September 2019 through February 2020, were developed using the same modeling previously used and that in his opinion these forecasts are reasonable.

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 that he had reviewed Petitioner’s filings and the Commission’s Order in ECR 32 and nothing came to his attention that would indicate Duke Energy Indiana’s calculation of estimated ECR adjustment factors were unreasonable. He summarized Petitioner’s requests for recovery and identified the QPCP costs to be tracked in this proceeding. He also noted that a credit appears as a result of the difference between Wabash River Unit 1, sold in 2007, and the deferred costs of the Wheatland plant, purchased in 2005 with costs not included in rates. Because Petitioner has fully amortized the Wheatland plant’s deferred asset balance, the revenues from the Wabash River Unit 1 can be refunded to customers.

Mr. Blakley described Petitioner’s proposed apportionment of the revenue from the Nucor and International Paper demand charges to the impacted riders. He noted the Nucor demand charge was being apportioned to Rider 73 and that the total amount is reflected in Rider 71. He also noted that Petitioner included capital maintenance projects as discussed by Ms. Pope.

Ms. Armstrong testified that she had reviewed Petitioner’s filings in this Cause. She said that Petitioner made seven EA sales during this period, resulting in gross proceeds of $271,868, and that
based on her review of the EA markets, Petitioner sold the allowances at a reasonable price consistent with the market. Ms. Armstrong further testified that based on her analysis, Duke Energy Indiana’s calculations of the EA adjustment factor were accurately applied, and she recommended that the proposed EA adjustment for Rider 63 be approved.

9. Commission Discussion and Findings. Based on the evidence presented, the Commission finds that Petitioner’s requested relief in this proceeding is reasonable, consistent with regulatory requirements and prior Commission Orders, and should be approved as set forth below. Specifically, costs and expenses through December 31, 2018, for the NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Phase 1 CAIR/CAMR post-in-service AFUDC, Gallagher DSI projects, Phase 2 and Phase 3 MATS Compliance Plan projects, capital maintenance, CCR Compliance Plan projects and related plan development costs, and CCR Compliance Plan post-in-service carrying costs 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. Diaz.

Petitioner is authorized to recover in Rider 71 its reconciliation of O&M expenditures and depreciation expenses related to its NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Gallagher DSI projects, Phase 2 and Phase 3 MATS Compliance Plan projects, CCR Compliance Plan projects, CCR Compliance Plan development costs, and post-in-service AFUDC for the Phase 1 CAIR/CAMR Compliance Plan projects for the period July 2018 through December 2018, as described in the testimony and exhibits of Ms. Diaz.

Petitioner is authorized to recover in Rider 71 its reconciliation of capital maintenance expenses related to the NOx and Phase 1 CAIR/CAMR Compliance Plan projects, the Phase 2 MATS Compliance Plan projects, and the CCR Compliance Plan projects for the period July 2018 through December 2018, as described in the testimony and exhibits of Ms. Diaz.

Petitioner is authorized to recover in Rider 71 the estimated depreciation and expenses related to its NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Gallagher DSI projects, Phase 2 and Phase 3 MATS Compliance Plan projects, and the CCR Compliance Plan projects for the period January 2019 through June 2019, as described in the testimony and exhibits of Ms. Diaz.

Petitioner is authorized to recover in Rider 71 the estimated capital maintenance project expenses related to the NOx and Phase 1 CAIR/CAMR Compliance Plan projects, the Phase 2 MATS Compliance Plan projects, and the CCR Compliance Plan projects for the period January 2019 through June 2019, as described in the testimony and exhibits of Ms. Diaz.

Petitioner is authorized to recover its SO2 and NOx EA costs in accordance with Rider 63, as described in the direct testimony and exhibits of Ms. Diaz, including the reconciliation of such expenses for the period September 2018 through February 2019 and the estimated amounts for the period September 2019 through February 2020.

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 $0.07 or 0.1% when compared to the last approved factors, as established in Duke Energy Indiana’s updated schedules.

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

10. **Confidential Information.** Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") with the Affidavits of Mr. Joseph A. Miller, Jr. and Ms. Maria T. Diaz on April 24, 2019. In this Motion, Petitioner demonstrated a need for confidential treatment for the detailed cost estimates and actual expenditures associated with Petitioner’s environmental compliance plan, unit-specific O&M costs, certain load and price information concerning a confidential Commission-approved special contract with Nucor Steel-Indiana, certain price information for a confidential Commission-approved special contract with International Paper, and certain retirement detail that contains actual costs. In a May 8, 2019 Docket Entry, the Presiding Officers preliminarily found that such information should be subject to confidential procedures.  

The Affidavits of Mr. Miller and Ms. Diaz 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 information contains trade secrets and is excepted from public access and disclosure by the Commission. 

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

1. Petitioner’s proposed updated Riders 62 and 71, as reflected in the direct exhibits and testimony of Duke Energy Indiana, including investment values as of December 31, 2018 are approved as set forth in this Order.  

2. Petitioner’s proposed updated Rider 63, including the reconciliation for six months ended February 2019 and estimated emission allowance costs for September 2019 through February 2020 as reflected in the direct exhibits and testimony of Duke Energy Indiana, is approved as set forth in this Order.  

3. Petitioner’s ongoing review progress reports related to its NOx and Phase 1 CAIR/CAMR Compliance Plan projects, Gallagher DSI projects, Phase 2 and Phase 3 MATS Compliance Plan projects, and CCR Compliance Plan projects are approved.  

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

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6 We note that the various projects included in this ECR proceeding were approved under different statutes that contain different requirements relating to their ongoing review and approval (compare Ind. Code § 8-1-8.7-7 with Ind. Code § 8-1-8.4-7) and therefore, may require different requests for relief (such as a request to modify a certificate) when changes to the projects and/or its estimates occur.
5. Prior to implementing the rates authorized herein, Petitioner shall file the tariff and applicable rate schedules under this Cause for approval by the Commission’s Energy Division. Such rates shall be effective on or after the Order date subject to Division review and agreement with the amounts reflected.

6. The information submitted by Petitioner pursuant to a preliminary finding of confidentiality is determined to be confidential trade secret information and therefore excepted from public access.

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

HUSTON, FREEMAN, OBER, AND ZIEGNER CONCUR; KREVDA ABSENT:

APPROVED: AUG 21 2019

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

Mary M. Becerra
Secretary of the Commission