STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY PROPERTY UNDER CONSTRUCTION, INCLUDING THE COST OF POST-IN-SERVICE NORMAL CAPITALIZED REPAIRS AND MAINTENANCE EXPENDITURES, IN ITS RATES AND TO REFLECT APPLICABLE RELATED COSTS AND CREDITS, INCLUDING OPERATING EXPENSES, DEPRECIATION, AND TAX CREDITS, THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO INDIANA §§CODE 8-1-8.8-11 AND -12; (2) APPROVAL OF AMORTIZATION AMOUNTS INCLUDED FOR RECOVERY IN RIDER NO. 61 FOR POST-IN-SERVICE AFUDC, THE 2012 SETTLEMENT AGREEMENT REGULATORY ASSET, AND COMMISSION-ORDERED REGULATORY LIABILITY; (3) APPROVAL OF ONGOING REVIEW PROGRESS REPORTS PURSUANT TO IND. CODE §8-1-8.5 AND §8-1-8.7; (4) APPROVAL TO REFLECT A CHANGE DUE TO MIGRATION BETWEEN TWO RATE CLASSES AND BETWEEN CERTAIN LIGHTING RATE CLASSES; (5) APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, (6) FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND (7) TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	**) CAUSE NO. 43114 IGCC-15**

<u>SUBMISSION OF SETTLING PARTIES' PROPOSED FORM OF ORDER</u>

Duke Energy Indiana, LLC, by counsel and on behalf of the Office of Utility Consumer Counselor, the Duke Energy Indiana Industrial Group, Nucor Steel-Indiana, and the Citizens Action Coalition of Indiana, Inc., Save the Valley, Inc., Valley Watch, Inc., and the Sierra Club (collectively "Settling Parties"), respectfully submit the Proposed Form of Order in the above-captioned matter to the Indiana Utility Regulatory Commission.

DUKE ENERGY INDIANA, LLC

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that copies of the foregoing submission was electronically delivered this 11th day of May, 2016 to the following:

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY PROPERTY UNDER CONSTRUCTION, INCLUDING THE COST OF POST-IN-SERVICE NORMAL CAPITALIZED REPAIRS AND MAINTENANCE EXPENDITURES, IN ITS RATES AND TO REFLECT APPLICABLE RELATED COSTS AND CREDITS, INCLUDING OPERATING EXPENSES, DEPRECIATION, AND TAX CREDITS, THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO INDIANA §§CODE 8-1-8.8-11 AND -12; (2) APPROVAL OF AMORTIZATION AMOUNTS INCLUDED FOR RECOVERY IN RIDER NO. 61 FOR POST-IN-SERVICE AFUDC, THE 2012 SETTLEMENT AGREEMENT REGULATORY ASSET, AND COMMISSION-ORDERED REGULATORY LIABILITY; (3) APPROVAL OF ONGOING REVIEW PROGRESS REPORTS PURSUANT TO IND. CODE §8-1-8.5 AND §8-1-8.7; (4) APPROVAL TO REFLECT A CHANGE DUE TO MIGRATION BETWEEN TWO RATE CLASSES AND BETWEEN CERTAIN LIGHTING RATE CLASSES; (5) APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, (6) FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND (7) TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	**) CAUSE NO. 43114 IGCC-15**

SETTLING PARTIES' PROPOSED FORM OF ORDER

BY THE COMMISSION:
David E. Ziegner, Commissioner
David E. Veleta, Administrative Law Judge

On May 29, 2013, Duke Energy Indiana, LLC ("Duke Energy Indiana," "Petitioner" or "Company") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") in Cause No. 43114 IGCC-11. In its Petition, Duke Energy Indiana requested:

(1) approval of the Company's updated ongoing progress report associated with its Edwardsport Generating Facility ("Plant" or "Station"); and (2) authority to reflect costs incurred with respect to the construction of the IGCC Project through March 31, 2013, and other related costs and credits and applicable reconciliation amounts and credits, in its retail electric rates through Petitioner's Integrated Coal Gasification Combined Cycle Generating Facility Cost Recovery Adjustment, Standard Contract Rider No. 61 ("Rider 61" or "IGCC Rider"). Pursuant to notice as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an Evidentiary Hearing was held in: IGCC-11 on December 17, 2013. At the evidentiary hearing for IGCC-11, Petitioner presented the testimony and exhibits of Jack L. Stultz, General Manager II, Regulated Fossil Stations (Petitioner's Exhibits A, A-1, Confidential A-1, A-2); Gary S. Thompson, Senior Project Manager, Edwardsport IGCC (Petitioner's Exhibits B, B-1, Confidential B-1, B-2, Confidential B-2); and Diana L. Douglas, Director of Rates for Duke Energy Indiana (Petitioner's Exhibits C, Revised C-1, Revised C-2, Revised Confidential C-2, Revised C-3, C-4, C-5, Confidential C-5, C-6; D, D-1, D-2, Confidential D-2, D-3, D-4, D-5, Confidential D-5, D-6; and Petitioner's Exhibit E). Petitioner also submitted its response to the Commission's 12-10-13 Docket Entry as Petitioner's Exhibit 1. The testimony and exhibits offered by the Petitioner were admitted into evidence without objection. At the request of the Commission, Petitioner also presented its late-filed Exhibit 1, which was admitted into evidence without objection. The OUCC presented the testimony of Mr. Wes R. Blakley, Senior Utility Analyst (Public Exhibit 1), which was admitted into evidence without objection. Joint Intervenors presented the testimony of Mr. Ralph Smith, Senior Regulatory Consultant at Larkin & Associates, PLLC (Joint Intervenors' Exhibit A, LA-1 through LA-7, and Confidential LA-8) which was admitted into evidence without objection.

On December 20, 2013, Duke Energy Indiana, Inc. filed its Verified Petition with the Commission in IGCC-12 relating to approvals sought associated with its Plant. Following an attorneys' conference, on May 8, 2014, the Commission consolidated proceedings in IGCC-12 with proceedings in IGCC-13. On June 11, 2014, Duke Energy Indiana filed its Verified Petition with the Commission in IGCC-13. Pursuant to notice as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an Evidentiary Hearing was held in Consolidated Cause Nos. IGCC-12 and -13 on February 4-5, 2015. At the evidentiary hearing for consolidated cause nos. IGCC-12 and -13, Petitioner presented the testimony and exhibits of Mr. Jack L. Stultz, General Manager III, Regulated Fossil Stations (Petitioner's Exhibits 1 and 1-C (pre-filed in IGCC-12 as Exhibits A, A-1, Confidential A-1, and A-2)); Mr. Gary S. Thompson, Senior Project Manager, Edwardsport IGCC (Petitioner's Exhibits 3 and 3-C (pre-filed as Exhibits B, B-1, Confidential B-1, B-2, Confidential B-2)); and Ms. Diana L. Douglas, Director of Rates for Duke Energy Indiana (Petitioner's Exhibits 8 and 8-C (pre-filed as Exhibits C, C-1, C-2, Confidential C-2, C-3, and C-4)) for IGCC-12. With respect to IGCC-13, Petitioner also presented the testimony and exhibits of Mr. Stultz (Petitioner's Exhibits 2 and 2-C (pre-filed as Exhibits A, A-1, Confidential A-1, A-2); and Ms. Douglas (Petitioner's Exhibits 9 and 9-C (pre-filed as Exhibits B, B-1, B-2, Confidential B-2, B-3, B-4)). The testimony and exhibits offered by the Petitioner were admitted into evidence without objection. Intervenors also introduced cross-examination exhibits during the evidentiary hearing in this Cause. Joint Intervenors presented the testimony of Mr. Ralph Smith, Senior Regulatory Consultant at Larkin & Associates, PLLC (Joint Intervenors' Exhibit A, A-Confidential, and LA-1 through LA-33 Confidential), the testimony and confidential testimony of Mr. David A. Schlissel, President of

Schlissel Technical Consulting, Inc. (Joint Intervenors' Exhibit B, B-Confidential, and DAS-1 through DAS-19), and the testimony of Mr. Nachy Kanfer, Deputy Director for the Central Region of the Beyond Coal Campaign (Joint Intervenors' Exhibit C). The Duke Energy Indiana Industrial Group ("IG" or "Industrial Group") presented the testimony and exhibits of Mr. Michael P. Gorman, Managing Principal of Brubaker & Associates, Inc. (IG Exhibit 1 and Sub-Exhibits 1 through 26). The OUCC presented the testimony of Mr. Wes R. Blakley, Senior Utility Analyst (Public Exhibit 1), the testimony and confidential testimony of Mr. Anthony A. Alvarez, Utility Analyst (Public Exhibits 2, 2-C, 3, and 3-C), and consumer comments received by the agency (Public Exhibit 4).[1] Duke Energy Indiana objected to portions of Public's Exhibit 2 to the extent they were General Electric ("GE") letters as inadmissible hearsay, which was overruled. The other testimony and exhibits sponsored by the OUCC, Industrial Group, and Joint Intervenors were admitted into evidence without objection. On rebuttal, Petitioner presented the testimony and exhibits of Mr. Douglas F Esamann, President of Duke Energy Indiana (Petitioner's Exhibit 4); Mr. Danny Wiles, Director of Regulated Accounting for Duke Energy (Petitioner's Exhibit 5); Mr. John D. Swez, Director, Generation Dispatch and Operations (Petitioner's Exhibits 6 and 6-C); Mr. Stultz (Petitioner's Exhibit 7 and 7-C); and Ms. Douglas (Petitioner's Exhibits 10 and 10-C). Petitioner also submitted into evidence its response to the Commission's 1-16-15 Docket Entry as Petitioner's Exhibit 11 and 11-C. Intervenors introduced cross-examination exhibits relating to the Company's rebuttal testimony during the evidentiary hearing in this Cause.

On December 23, 2014, the Company filed its Verified Petition in IGCC-14 requesting (1) authority to reflect costs incurred through September 30, 2014, including post-in-service capitalized repairs and maintenance expenditures, and other costs and credits and applicable reconciliation amounts and credits; and (2) approval of the amortization amounts for post-in-service AFUDC, the 2012 Settlement Agreement Regulatory Asset, and Commission-ordered Regulatory Liability. On June 4, 2015, Duke Energy Indiana filed its Verified Petition in IGCC-15 with the Commission requesting (1) authority to reflect costs incurred through March 31, 2015, including post-in-service normal capitalized repairs and maintenance expenditures; (2) approval of recovery of certain other Plant-related costs and credits, forecasted and actual depreciation and incremental operating expenses; and (3) approval of the amortization amounts for post-in-service AFUDC, the 2012 Settlement Agreement Regulatory Asset, and Commission-ordered Regulatory Liability included for recovery via the IGCC Rider. On September 18, 2015, Duke Energy Indiana, Nucor Steel-Indiana ("Nucor"), the Industrial Group, and the OUCC filed a joint motion to consolidate the IGCC-11 through IGCC-15 proceedings, and Cause No. 38707 FAC 99-S1 proceeding for purposes of establishing a new procedural schedule for taking additional evidence related to a settlement agreement reached in the Consolidated Cause among the Settling Parties. On October 14, 2015, the Commission consolidated Cause Nos. 43114 IGCC-11, IGCC-12, IGCC-13, Cause No. 38707 FAC 99S1 along with IGCC-14 and IGCC-15 in order to provide for administrative efficiency. On January 18, 2016, Duke Energy Indiana, IG, the OUCC, Nucor, and Joint Intervenors (collectively referred to herein as "Settling Parties") submitted to the Commission a January 14, 2016 a 2016 Settlement Agreement ("2016 Settlement Agreement"). Michael Mullett and Patricia Marsh[2]

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[1] Before the hearing, Duke Energy Indiana moved to strike portions of the testimony of Messrs. Schlissel and Gorman and certain exhibits and related testimony of Mr. Alvarez, which the Commission denied.

[2] Individual Intervenors were only a party to the Consolidated IGCC-15 proceeding.

(collectively "Individual Intervenors" or "II") petitioned to intervene in opposition to the 2016 Settlement Agreement.

Pursuant to notice as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an Evidentiary Hearing was held in: Consolidated Cause No. IGCC-15 on April 18, 2016 in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the Commission addressed an outstanding Motion for Administrative Notice, Motion for Leave to File Additional Testimony, and an Objection to Testimony and Exhibits. The Commission denied IIs request to file additional testimony, denied Duke Energy Indiana's request to strike a portion of IIs testimony, denied Duke Energy Indiana's request for the admittance of certain duplicate II exhibits, granted Duke Energy Indiana's motion to strike IIs exhibits that reference Black & Veatch, and granted IIs Motion for Administrative Notice.

The parties to the consolidated proceedings, other than Duke Energy Indiana, included the OUCC, IG, Nucor, Steel Dynamics, Inc.[3], the Citizens Action Coalition of Indiana, Inc. ("CAC"), Save the Valley, Inc. ("STV"), Valley Watch, Inc., and the Sierra Club (collectively "Joint Intervenors" or "JI"), and Individual Intervenors.

Based upon applicable law and the evidence presented herein, the Commission finds as follows:

1. <u>Notice and Jurisdiction</u>. Due, legal, and timely notice of the hearing in this Cause was given and published by the Commission as required by law. Duke Energy Indiana is a public utility as defined by Indiana Code § 8-1-2-1, and is subject to regulation by the Commission to the extent provided in the Public Service Commission Act, as amended. Accordingly, the Commission has jurisdiction over Duke Energy Indiana and the subject matter of this proceeding.

2. <u>Petitioner's Characteristics</u>. Duke Energy Indiana is an Indiana corporation with its principal office located at 1000 East Main Street, Plainfield, Indiana. Duke Energy Indiana is engaged in the business of supplying electric utility service to the public in the State of Indiana. The Company owns, operates, manages and controls plant property and equipment used and useful for the production, transmission, distribution and furnishing of electric utility service to the public in the State of Indiana. Duke Energy Indiana directly supplies electric energy to approximately 810,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. The Company also sells electric energy for resale to municipal utilities, Wabash Valley Power Association, Inc. and Indiana Municipal Power Agency, and to other public utilities that in turn supply electric utility service to numerous customers in areas not served directly by Duke Energy Indiana.

3. <u>Relief Requested</u>. In its Verified Petition in IGCC-11, Duke Energy Indiana requested: (1) approval of an ongoing review progress report pursuant to Ind. Code §§ 8-1-8.5-6 and 8-1-8.7-7; and (2) authority to add to the valuation of its utility property for ratemaking purposes the actual Project costs incurred through March 31, 2013, and authority to recover certain

[3] Nucor Steel-Indiana, a division of Nucor Corporation was not a party to IGCC-11. Steel Dynamics, Inc. was only a party to the Consolidated IGCC-12/13 and FAC 99S1 proceedings.

other applicable costs and credits via Petitioner's IGCC Rider and such reconciliation of charges or credits to actual amounts as are applicable.

In its Verified Petition in IGCC-12, Duke Energy Indiana requested: (1) approval of the Company's final updated ongoing review progress report pursuant to Ind. Code §§ 8-1-8.5-6 and 8-1-8.7-7; (2) authority to add to the valuation of its utility property for ratemaking purposes the actual Project costs, including post-in-service normal capitalized repairs and maintenance expenditures, incurred through September 30, 2013, (3) authority to recover certain other Project-related costs and credits, including Black & Veatch expenses, operating expenses, depreciation, tax credits, and applicable reconciliation amounts; (4) approval to recover certain forecasted and actual depreciation and incremental operating expenses, including O&M, fringe benefits, payroll taxes, property insurance and property taxes, tax credits, and including applicable reconciliation amounts, related to Edwardsport Station via the IGCC Rider consistent with the Commission's prior decisions in the CPCN Order and subsequent update cases; (5) approval to reflect a change due to rate migration between Duke Energy Indiana's High Load Factor and Low Load Factor customers; and (6) authority to amortize post-in-service allowance for funds used during construction ("AFUDC") and to amortize the Settlement Agreement Regulatory Asset and Commission-ordered Regulatory Liability.

In its Verified Petition in IGCC-13, Duke Energy Indiana requested similar relief for the next six-month period: (1) authority to reflect costs incurred through March 31, 2014 for Edwardsport, including the cost of post-in-service normal capitalized repairs and maintenance expenditures, in its retail electric rates; (2) approval to recover certain other Plant-related costs and credits, including Black & Veatch expenses, forecasted and actual depreciation and incremental operating expenses, including O&M, fringe benefits, payroll taxes, property insurance and property taxes, tax credits, and including applicable reconciliation amounts, related to Edwardsport Station via the IGCC Rider consistent with the Commission's prior decisions in the CPCN Order and subsequent update cases; (3) approval to reflect a change due to rate migration between Duke Energy Indiana's High Load Factor and Low Load Factor customers and between certain lighting rate classes; and (4) approval of the amortization amounts for post-in-service AFUDC, the 2012 Settlement Agreement Regulatory Asset, and Commission-ordered Regulatory Liability included for recovery via the IGCC Rider.

On December 23, 2014, the Company filed its Verified Petition in IGCC-14 requesting (1) authority to reflect costs incurred through September 30, 2014, including post-in-service capitalized repairs and maintenance expenditures, and other costs and credits and applicable reconciliation amounts and credits; and (2) approval of the amortization amounts for post-in-service AFUDC, the 2012 Settlement Agreement Regulatory Asset, and Commission-ordered Regulatory Liability.

On June 4, 2015, Duke Energy Indiana filed its Verified Petition in IGCC-15 with the Commission requesting (1) authority to reflect costs incurred through March 31, 2015, including post-in-service normal capitalized repairs and maintenance expenditures; (2) approval of recovery of certain other Plant-related costs and credits, forecasted and actual depreciation and incremental operating expenses; and (3) approval of the amortization amounts for post-in-service AFUDC, the 2012 Settlement Agreement Regulatory Asset, and Commission-ordered Regulatory Liability included for recovery via the IGCC Rider.

4. Duke Energy Indiana's Case-in-Chief Evidence.

a. IURC Cause No. 43114 IGCC-11: Duke Energy Indiana witnesses Mr. Stultz and Mr. Thompson provided the Commission with an ongoing review progress report concerning the IGCC Project. Mr. Stultz testified that, as of the end of March 2013, the primary progress in the power block involved the installation for testing purposes and later removal of the instrumented rotor on one of the combustion turbine/generators ("CTG"), which was used to collect data during Phase 5 of GE's New Product Introduction ("NPI") Testing. Both gasifiers were successfully commissioned with the train 1 gasifier lit off and operating for approximately 3 hours on October 25, 2012. Train 2 gasifier was lit off and operated for the first time on December 8, 2012. During this reporting period, Mr. Stultz testified that there were 16 total successful gasifier starts and the longest run time, 13.5 days, was achieved on train 2 gasifier. A considerable amount of time was also spent completing NPI testing, including the "fouling" of both Radiant Syngas Coolers ("RSC"), a critical stage of NPI Phase 3 testing, and running the power block on natural gas, syngas and mixtures of each at different loads as part of NPI Phase 5.

Mr. Stultz explained that the NPI Phase 5 testing of the power block has been completed, which allowed GE to provide a technical release of the power block to Duke Energy Indiana operations. Remaining are NPI Phases 6-8, which will be completed during the coming months and involve the tuning and optimizing of performance of the IGCC Plant.

Mr. Stultz testified that significant progress was made in May 2013 by completing the rotor outage. He explained that although the plant intended to be commercially available upon completion of the outage, there were several issues that required resolution before the plant was fully back online and could be considered in-service, such as repair and replacement of the liquid nitrogen pumps. Mr. Stultz stated that the train 2 gasifier was lit off on May 31, 2013. Once the slag crusher packing was repaired and stack testing performed, the train 1 gasifier was lit off and both gasifiers ran for a period of time to check for issues and to allow the plant to thermally stabilize before declaring it in-service and commercially in-service for customers on June 7, 2013. Mr. Stultz explained that the Plant has been offline since June 13, 2013 due to damage to the grey water system vapor concentrator fans and that the Plant is expected to return to service in early July.

Mr. Stultz continued his testimony describing the plant's most notable recent successes: there were no recordable injuries during the current reporting period and March 2013 marked the 12th consecutive month in which the Project did not have a recordable incident; the entire power block has operated for months with few issues; the gasification island was successfully commissioned over several gasifier runs in which all equipment operated within design expectations; GE completed installation of the replacement 3rd stage buckets of the combustion turbines, resolving a vibration issue and ensuring reliable operation of the CTGs going forward; Distributed Control System software was upgraded for enhanced performance; gas clean-up equipment has run extensively and performed exceptionally well, which is critical to the Plant's environmental compliance; RSC fouling was completed in 6 days per unit instead of the scheduled two weeks per unit; and the operations, engineering and maintenance teams have performed well without a safety incident or environmental exceedance and gained experience with equipment and systems.

Mr. Stultz provided an update on how the power block and gasification island have been running. He explained that since receiving the technical release from GE to operate the combustion turbines on natural gas on May 14, 2012, the combustion turbines have been running on natural gas for commissioning purposes, while also putting energy on the grid. The steam turbine was synchronized for the first time on August 8, 2012, and operated, as testing would allow, reliably since that time. Once syngas was produced from the gasifiers, the combustion turbines were operated on natural gas, syngas and various combinations as part of the NPI testing. Mr. Stultz continued explaining that syngas has been switched successfully between the CTGs or sent to flare as necessary. During the period January through May 2013, the gasifiers ran over 550 hours and the power block produced 336,308 MWhs of energy. Even with portions of the plant down for commissioning purposes or repairs during this time, Mr. Stultz emphasized that this is a significant accomplishment. He explained that because the Plant had not yet been placed in-service for accounting purposes during the time period of this proceeding, costs associated with the operations (and associated revenues from selling energy into MISO) were charged/credited to the capital budget of the Project.

Next, Mr. Stultz testified that his operations, engineering and maintenance teams have proven to be well-equipped to handle the challenges posed and now that later phases of NPI testing are taking place, he believes that they have largely uncovered the "first run" types of issues and are correcting them.

Mr. Stultz stated that the vibration of the 3rd stage buckets of the combustion turbines and the broken pinion shaft on coal mill #1 discussed by Mr. Womack in his IGCC-10 testimony have been resolved. The issue of amp fluctuation in the coal grinding mill drive motors continues to be discussed with the vendor.

Continuing his testimony, Mr. Stultz described the slag handling, air separation unit, feed injector, and freeze protection issues that occurred during commissioning of the gasification island. He explained that these issues have been corrected or are expected to be corrected so there should be no effect on future plant performance and reliability. The Project team continues to make use of the commissioning process to identify and resolve issues. He testified that he expects there will be issues for a period of time after the Plant is in-service, but that through the start-up, validation and commissioning activities, all reasonable steps have been taken to best position the Plant for reliable performance.

Mr. Stultz testified that the start-up of any large complex construction project will have some issues and problems. He expects the majority of these first run engineering, design and construction issues to have been resolved by the time the Plant is in-service, but there will likely be some technical issues after the Plant begins commercial operations, which are expected to be wear-and-tear based or run-hour influenced and are not significant in terms of corrections required.

With regard to environmental permitting, in his prefiled testimony Mr. Stultz explained that the appeal of the air permit remains pending before the Indiana Office of Environmental Adjudication and that the parties are pursuing mediation. The final Title V renewal permit, issued by Indiana Department of Environmental Management ("IDEM") on April 3, 2013, was appealed by Joint Intervenors on April 17, 2013. Authorization received under previous permits remain effective for Duke Energy Indiana to complete start-up activities and commence commercial operation of the IGCC Plant.

Mr. Stultz explained that since the IGCC Project began commercial operation, the Company has been incurring normal operating and maintenance expenses, just as other generating plants do. He explained that these costs include a combination of fixed and variable costs. Fixed costs include full time Duke Energy employee labor costs and costs associated with air permit testing, NPDES sampling and reporting, and variable costs such as operation costs for the plant. He explained that the chemicals that are consumed during operation of the IGCC Project are considered variable, as well as equipment maintenance and contractor costs. Overhead and allocations are also O&M budget expense items. These O&M expenses will vary depending on the timing of maintenance cycles, unexpected costs, operating characteristics and operating time of the Project. Forecasted O&M expenses will be trued-up once actual costs are known, and customers will pay only the actual O&M incurred for the Project. He stated that the current budget includes labor for 140 Duke Energy employees on site and approximately 40 contract personnel. Continuing, Mr. Stultz explained that the O&M expenses will vary depending on the timing of maintenance cycles, unexpected costs, operating characteristics and operating time of the Project. Mr. Stultz updated the O&M forecast and provided it to Ms. Douglas for her use in estimating the IGCC Rider impacts.

Mr. Stultz reported that the coal handling system has been receiving truck and train deliveries and has performed as expected.

Mr. Stultz and Mr. Thompson presented the Commission with additional Project information, as requested by the Commission in its IGCC-1 and IGCC-2 Orders. This information requested by the Commission was outlined by Messrs. Stultz and Thompson and contained in Petitioner's Exhibit A-1, Petitioner's Confidential Exhibit A-1, Petitioner's Exhibit B-1, Petitioner's Confidential Exhibit B-1, Petitioner's Exhibit B-2, and Petitioner's Confidential Exhibit B-2. As noted in Mr. Womack's IGCC-8 testimony, much of this information pertained to the design and construction phases of the Project, which are now essentially complete, and accordingly, Mr. Stultz and Mr. Thompson provided only information that focused on pre-commissioning, commissioning, and operations issues and status. Mr. Stultz explained that, in the future, information previously requested by the Commission in its IGCC-1 and IGCC-2 Orders will also be stale due to the progress of the Plant. He provided a proposal to submit documentation in future filings.

Mr. Thompson provided a high level update on the construction status of the Project. He testified that as of the end of March 2013, the engineering, procurement, and construction work was complete with the exception of certain punch list items and some scope modifications. The pre-commissioning start-up is also complete. He explained that during this reporting period, the primary progress on the Project involved testing of various components, commissioning of the plant, and significant portions of GE's New Product Introduction ("NPI") testing. As of the filing of Mr. Thompson's direct testimony, the remaining construction activities were Phases 6-8 of GE's NPI testing.

Mr. Thompson provided an update on the status of the Project's schedule and cost. He stated that the Project reached the in-service milestone on June 7, 2013. He continued stating that the Project cost forecast has not changed from that communicated in IGCC-10 and is still expected to fall within the $3.153 billion (without AFUDC) budget approved by the Duke Energy Board of Directors in October 2012. The actual project cost (without AFUDC) as of March 31, 2013 was $3,065,784,275, which is shown in Petitioner's Confidential Exhibit B-1.

In IGCC-11, Ms. Douglas explained that the purpose of her testimony was to explain the Company's request for timely recovery of costs in connection with the Company's IGCC Project, including CWIP ratemaking treatment for retail jurisdictional IGCC Project expenditures. Ms. Douglas explained that she developed rates and presented exhibits reflecting the terms of the approved 2012 Settlement Agreement issued in the IGCC 4S1 Subdocket ("Subdocket Order").

On behalf of Duke Energy Indiana, Ms. Douglas requested that the Commission approve the following: (1) the value of the IGCC Project upon which the Company is requesting authorization to earn a return; (2) the amount of Duke Energy Indiana's expenditures for the IGCC facility incurred through March 31, 2013; (3) recovery of incremental fees and expenses of Black & Veatch incurred by the Company from October 2012 through March 2013; (4) recovery of the estimated operating expenses net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expense that are expected to be incurred from October 2013 through March 2014; (5) recovery of estimated depreciation that will be incurred from October 2013 through March 2014; (6) inclusion of a credit to retail customers in Rider 61 to reflect the jurisdictional impact of a change in depreciation rates for in-service plant, which took place effective January 1, 2013, and which was approved in the IGCC 4S1 order; (7) inclusion of a credit for the retail portion of one-half of the Indiana Coal Gasification Technology Investment Tax Credit, $15 million on an annual basis ("State Tax Credit"); (8) the cumulative reconciliation of revenue requirements for the actual cost of items other than return on investment which have been included for recovery in IGCC Tracker filings to actual amounts billed for these items through March 2013; (9) a voluntary credit to HLF customers to correct for a clerical error in the development of rates approved in IGCC-4, which were billed to customers during October through December 2012; and (10) adjustment of Petitioner's retail electric rates, via Rider 61 to reflect the revenue effect of such investment and cost recovery.

Ms. Douglas described Petitioner's Exhibit C-1, Duke Energy Indiana's Rider 61, of which the Company is requesting approval. Petitioner's Rider 61 includes definitions of the components of the formula used to develop the IGCC Revenue Adjustment Factors, a formulaic representation of the calculations used in developing the factors, revenue adjustment factors by retail rate group, a listing of retail allocation factors (based on the allocation factors approved in the Company's last general retail electric base rate case), and the billing cycle kWh and/or non-coincident peak demands used to develop the proposed IGCC Cost Recovery Adjustment. Petitioner's Exhibit C-1 also reflects the proposed change in the Rider 61 language to reflect the use of Commission-approved depreciation rates for the IGCC plant rather than tying depreciation rates to the original estimated 30-year life of the plant.

Her testimony also explained Petitioner's Exhibit C-2, which includes the schedules that develop and support the IGCC-11 revenue adjustment factors. She explained that this exhibit sets forth schedules for the IGCC Project and includes data consistent with the requirements of 170 IAC 4-6-12 and the Commission's Orders in Cause Nos. 43114, 43114-S1, 43114 IGCC-1, and subsequent orders, and with the terms of the 2012 Settlement and Subdocket Order; actual in-service dates for the transmission system and production projects; Project expenditures as of March 31, 2013, subject to CWIP ratemaking treatment; Project expenditures applicable to wholesale jurisdictional customers; retail IGCC facility investment as of March 31, 2013; the amount of retail AFUDC included in the cost of the Project as of March 31, 2013; and the total amount of AFUDC included in the Project.

Ms. Douglas also explained the ratemaking treatment for the costs of four Project-related transmission projects, which are in-service and were included in the $2.35 billion approved Project estimate. Ms. Douglas explained that for the two transmission projects that qualify as part of MISO's transmission expansion plan and are recognized by the MISO as Regional Expansion and Criteria Benefit ("RECB") projects, the Company first sought cost recovery for such projects pursuant to its Rider No. 68 and the MISO's Schedule 26, consistent with the Commission's June 25, 2008 Order in Cause No. 42736-RTO-14. If and to the extent that costs for an IGCC-related transmission project are not eligible for recovery through Rider No. 68 and Schedule 26, then the Company would seek cost recovery for such project (or portion of a project) through the IGCC Rider. The projects are in-service, and the Company expects a 50% reimbursement for such RECB projects; therefore, the Company has included 50% of the value of the projects in its IGCC Project valuation for CWIP ratemaking purposes (representing the 50% of the projects that are not expected to receive MISO RECB reimbursement). Accordingly, Page 1 of Petitioner's Exhibit C-2 shows the expenditures for the two RECB projects, including the reduction in IGCC Project expenses by the 50% amount for which the Company expects to be reimbursed by MISO through the RECB process.

Ms. Douglas continued her testimony stating that Page 2 of Petitioner's Ex. C-2 shows the amount of accumulated depreciation as of March 31, 2013, applicable to the IGCC Project investment. As of March 31, 2013, the only portions of the Project that have been placed in-service and are being depreciated are the four transmission projects. The jurisdictional accumulated depreciation applicable to the jurisdictional Project investment as of March 31, 2013, was $762,796, which reflects the reduction due to the anticipated 50% MISO RECB reimbursement amount.

Ms. Douglas' Exhibit C-2, page 3 developed the jurisdictional revenue requirement. The retail jurisdictional portion of the total construction costs exceeded the retail jurisdictional portion of the $2.595 billion June 30, 2012 Hard Cost Cap amount; therefore, the Company limited the amount of Project investment on which a return will be earned in its calculations. Ms. Douglas explained that the retail jurisdictional portion of the $2.595 billion June 30, 2012 Hard Cost cap amount was $2,431,816,000. She stated that the Additional AFUDC (as per the terms of the 2012 Settlement) related to the Hard Cost Cap amount accrued from October 2012 through March 2013 was $28,673,000. The total of the retail jurisdictional Hard Cost Cap plus Additional AFUDC as of March 31, 2013 was $2,459,404,000, which is a reduction of $749,011,000 from the total retail jurisdictional CWIP investment as of March 31, 2013. The six-month jurisdictional revenue requirement for return on investment as of March 31, 2013 was $122,350,000. This is a $59,000 increase from the amount proposed in IGCC-10.

Ms. Douglas next discussed how the revenue conversion factors are determined.

Continuing her testimony, Ms. Douglas explained the calculation of the jurisdictional revenue requirement applicable to Project-related operating expenses, including depreciation expense, and tax credits. These operating expenses included: expenses incurred by the Company from October 2012 through March 2013 for services from Black & Veatch; estimated retail portion of operating expenses and property tax expenses from October 2013 through March 2014; estimated retail jurisdictional depreciation expense from October 2013 through March 2014; a credit to retail customers of $17,587,500 ($35,175,000 on an annual basis), approved by the Commission in the Subdocket Order, to reflect the jurisdictional impact of a change in depreciation rates for in-service plant, which took place effective January 1, 2013 ("Credit for Effect of New Depreciation Rates"); and a credit for the retail portion of one-half of the estimated State Tax Credit. *See* Pet. Ex. C-2, p.4.

Ms. Douglas' testimony also demonstrated that the fees and expenses incurred by the Company from October 2012 through March 2013, for services by Black & Veatch for Project oversight totaled $53,540.

Ms. Douglas stated that the Company forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Edwardsport steam generating facility which were included in base rates, and the retail jurisdictional property taxes in the amount of $31,816,734 for the period October 2013 through March 2014. She testified the Company forecasts retail jurisdictional depreciation expense of $51,572,002 for the October 2013 through March 2014 period. *See* Pet. Conf. Ex. C-2, p. 2. Credits of $17,587,500 reflecting the Credit for Effect of New Depreciation Rates and a credit of $6,884,250 reflecting the retail jurisdictional portion of one half of the annual estimated $15 million State Tax Credit have also been included.

Ms. Douglas then explained how these Project-related operating expenses, depreciation expense, and the Credit for Effect of New Depreciation Rates, and the State Tax Credit were converted to revenue requirements and that the result was the inclusion of $63,187,853 in the calculation of the billing factors for this rider. *See* Pet. Ex. C-2, p. 7.

Confidential Exhibit C-2, p. 5 detailed the support for the retail jurisdictional amount of forecasted depreciation expense and other expenses included in the revenue requirements calculation on page 4 of exhibit C-2. She again noted that the depreciation amount was reduced by 50% of the depreciation associated with the two RECB transmission projects for which reimbursement will be received from MISO's RECB process. She continued explaining that the depreciation expense for the remainder of the plant investment included for ratemaking was calculated using the weighted average depreciation rate of 4.20% in the IGCC depreciation study approved by the Commission in its IGCC-8 order. The property tax estimate reflects 100% of the

October 2013 through March 2014 benefit forecasted to be received for the ten-year property tax abatement from Knox County and the thirty-year reimbursement due to designation of the IGCC Project as a Tax Increment Financing District. In addition, as approved by the Commission in the CPCN Order, a monthly credit of $1/12^{th}$ of an annual amount of $5,756,000 has been included to reduce the forecasted operating expenses.

Ms. Douglas explained that she had reconciled the retail jurisdictional revenue requirements included in prior tracker proceedings, which were applicable to operating expenses to the portion of all IGCC tracker revenues billed through March 2013. This cumulative reconciliation resulted in an over collection of $1,736,628, which was included in the calculation of the billing factors for this rider. *See* Pet. Ex. C-2, p. 7.

Page 7 of Petitioner's Exhibit C-2 shows the calculation of the IGCC Revenue Adjustment Factors, by jurisdictional rate group. Also included is a voluntary credit adjustment by the Company to revenue requirements in the amount of $305,219, which reduces the proposed rate for HLF customers to correct for a tracker administration clerical error. This error affected the rates that were proposed, approved and billed to HLF customers under IGCC-4 rates beginning in July 2010. The error stemmed from the use of an incorrect value for the kW billing determinants used to establish the rates approved in IGCC-4. The billing determinant used was understated, which caused the IGCC-4 factor to be overstated. Accordingly, the Company is providing the HLF customer class with a voluntary credit for the amount of the difference between what they were billed under IGCC-4 rates from October through December 2012[4] and what they would have been billed had the error not occurred. Ms. Douglas stated that the kW billing determinants for HLF have been computed correcting for this error in this proceeding.

Ms. Douglas discussed the derivation of the Company's weighted average cost of capital as of March 31, 2013, as shown on Petitioner's Exhibit C-2, p. 8. Ms. Douglas stated that the weighted average cost of capital has been calculated consistent with the Commission's administrative rules, the Commission's CPCN Order, the IGCC-1 Order, and the 2012 Settlement Agreement to prospectively discontinue the deferred income tax incentive for the Project and include deferred income taxes in the capital structure.

Ms. Douglas also summarized AFUDC rates for the period October 2012 through March 2013 which were used in determining the amounts of AFUDC included in the value of the Company's IGCC facility through March 31, 2013. She also explained that amounts of Additional AFUDC applicable to December 2012 through March 2013 have been included in the retail investment on which a return will be earned, and these amounts reflect 85% rather than 100% of the AFUDC amount calculated using these rates.

Ms. Douglas next explained when CWIP ratemaking treatment for the IGCC Project will cease. She stated that consistent with 170 IAC 4-6-22 and in accordance with the Commission's CPCN Order, the IGCC Project will be deemed to be under construction, and Duke Energy Indiana will continue to receive revenues through Rider 61, until the Commission determines that

[4] December 2012 is the last month IGCC-4 rates were in effect and as such, this will be the final credit included in IGCC proceedings for this issue.

this Project is used and useful in a proceeding that involves the establishment or investigation of Duke Energy Indiana's retail electric base rates and charges**.**

According to Ms. Douglas, the total adjusted revenue requirement for this filing, consistent with the 2012 Settlement Agreement provisions and reflecting inclusion of the State Tax Credit, is $183,496,006. *See* Pet. Ex. C-2, p. 7.

Ms. Douglas also stated that the impact of the proposed IGCC Project ratemaking treatment, under the terms of the 2012 Settlement Agreement and assuming approval of the IGCC-10 proposed factor,[5] on the monthly bill of a typical residential customer using 1,000 kilowatt-hours would be an increase of $1.55, or approximately 1.8%, from the base bill plus the IGCC-10 factor then being billed to customers.

Ms. Douglas concluded her testimony by discussing the accounting treatment for costs incurred and revenues generated during testing before the plant will be declared in-service as discussed by Mr. Stultz. She explained that the FERC Uniform System of Accounts provides for the inclusion in the cost of constructed plant the necessary costs of testing or running a plant or parts thereof during a test period prior to such plant becoming ready for or placed in-service. She explained that these costs and revenues will be charged to the IGCC capital Project until the plant is declared in-service for accounting purposes, after which time they will be accounted for as O&M expenses or revenues as appropriate.

Ms. Douglas also provided supplemental testimony to address the Commission's September 11, 2013 IGCC-10 Order ("IGCC-10 Order") regarding the appropriate timing for including the regulatory liability created by the Subdocket order related to the previously approved deferred income tax incentive ("Regulatory Liability") and the offsetting rate mitigation asset created as a result of Term 3 ("Regulatory Asset") in the 2012 Settlement Agreement approved in the Subdocket Order. Her testimony specifically addressed corrections to rates to ensure proper reconciliation of the portion related to voluntary credits intended to be provided to HLF customers to the HLF rate class instead of to all rate classes.

Ms. Douglas explained that the revised rates correct for the voluntary HLF credit reconciliation error. She explained that the revenue requirements under the new revised Petitioner's Exhibit C did not change in total, however the revenue requirements allocated to each customer class did change. The rates of all customer classes except HLF increased, while the rate for the HLF rate class decreased. Ms. Douglas clarified that Petitioner's Exhibits C-1 through C-3 do not reflect any amortization for the net amount of the Regulatory Liability and Regulatory Asset because the Company had planned to begin including the amortization of the net amount in IGCC-12 and is providing revisions to show only the impact of the HLF credit reconciliation change.

Continuing, Ms. Douglas presented a new set of exhibits, Petitioner's Exhibit D-1 through D-3, to reflect the Company's interpretation of the Commission's language in the recent IGCC-10 Order, read in conjunction with the Subdocket Order and 2012 Settlement Agreement. She explained that these exhibits include the same HLF credit reconciliation correction, but also

[5] On September 11, 2013, the Commission approved the rate factor in the IGCC-10 proceeding.

include amortization of the Regulatory Liability.[6] As a result, revenue requirements were reduced by the $5,121,965 amount of Regulatory Liability amortization and the overall effect was a decrease in rates for all customer classes.

Ms. Douglas testified regarding the HLF credit reconciliation correction by explaining that the method used in the development of the cumulative reconciliation failed to separately reconcile the voluntary credits previously included in the rates approved in IGCC-7 through IGCC-9, which were intended to be provided to HLF customers. As a result, all customers would have received a portion of the credits intended for only HLF customers. She further explained that this methodology has been corrected so that the HLF credit will be directly assigned to HLF customers. She confirmed that this credit was properly applied only to the HLF class in IGCC-7 through IGCC-10, and that only with this IGCC-11 proceeding, did this error occur. Ms. Douglas reviewed her exhibits explaining the adjustments made to account for the correction.

Ms. Douglas next explained that with the issuance of the Commission's IGCC-10 Order and its language regarding IGCC-11 being the appropriate time to include for ratemaking the Regulatory Liability, and offsetting Regulatory Asset, to the extent there is one, the Company is presenting revised rates to begin amortizing the Regulatory Liability and crediting customers even if no Regulatory Asset amount existed as of March 31, 2013. Under this approach, the Regulatory Liability amortization will begin in advance of the amortization of the Regulatory Asset, which will begin in IGCC-12 and be based on the amount of operating expenses incurred and deferred from the June 7, 2013 in-service date through September 11, 2013, the last date before IGCC-10 rates began to be billed. She described her Exhibit D-2 and the update that shows the development of the revenue requirements for total operating expenses, including the credit of $5,121,965, which is one-sixth of the total Regulatory Liability amount.

Ms. Douglas testified that the $28 million Regulatory Liability referenced in the Subdocket Order was just an estimate and further explained how the $30,731,789 Regulatory Liability was developed.

Petitioner's Exhibit D-2 shows that the monthly bill of a typical residential customer, under the terms of the IGCC order and including the corrected HLF reconciliation, using 1,000 kilowatt-hours would see an increase of $1.30, or approximately 1.5%, from the base bill plus the IGCC-10 factor then being billed to customers. This is a decrease of $0.25 per month, as compared to the rates Ms. Douglas filed in her Direct Testimony.

Ms. Douglas explained that if the Commission approves the rates presented in Petitioner's Exhibits D-1 through D-3, which include amortization of the Regulatory Liability, but not yet offsetting of a Regulatory Asset, in future IGCC Rider filings the amortization for the Regulatory Liability would continue for the remainder of the three year amortization period.[7] The amortization of the Regulatory Asset would begin in IGCC-12 and be amortized over three years in accordance with the terms of the 2012 Settlement Agreement, ending in IGCC-17.

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[6] The Company used a three-year amortization period for the Regulatory Liability based on the provision in the Subdocket Order requiring the Regulatory Liability to be netted against the Regulatory Asset.
[7] The three-year amortization period extends through IGCC-16.

b. IURC Cause No. 43114 IGCC-12: In direct testimony in IGCC-12, Duke Energy Indiana witnesses Mr. Stultz and Mr. Thompson provided the Commission with the final ongoing review progress report under Indiana Code 8-1-8.5 concerning the Edwardsport IGCC construction project ("IGCC Project" or "Project") covering the period of April 1, 2013 through the June 7, 2013 in-service date. Mr. Stultz also provided additional information and background regarding the station's operations post-in-service.

Mr. Stultz testified that in April 2013, the Plant was largely engaged in completing the outage in which GE's instrumented rotor was replaced with the permanent rotor and repairing the slag drag conveyors. Although Petitioner originally intended to be commercially available after completing that outage, other matters required resolution before the Plant could be declared in-service. In late May, liquid nitrogen process pumps in the air separation units ("ASU") were repaired. The Company then lit off the train 2 and train 1 gasifiers on May 31, 2013, and June 5, 2013, respectively, and declared the Plant in-service and commercially available on June 7, 2013. The Company made this determination pursuant to Federal Energy Regulatory Commission ("FERC") accounting guidance and subject to consultation with the Project team and others. Due to damage in the grey water system vapor concentrator fans, the Plant went offline on June 13, 2013. In early July 2013, the fans were repaired and the Plant returned to service on coal. Mr. Stultz reported that after these initial issues, the Company has been gaining experience with longer term operations of the Plant's systems and maintenance needs. During the reporting period (April 1, 2013 through September 30, 2013), there were 34 successful combustion turbine starts and 20 successful gasifier starts. During the reporting period, gasifier 1 operated a consecutive 585 hours or 24.4 days and gasifiers 1 and 2 operated at the same time for 394 hours or 16.4 days.

Mr. Stultz testified that the Plant completed GE's New Product Introduction ("NPI") testing program in September 2013. Duke Energy Indiana and GE have been working on the conditions necessary to complete the performance testing so that the Project can be considered "substantially complete" under the Duke Energy/GE Contract. The parties have been working toward a preliminary test prescribed by the standards of ASME PTC 47, the industry standard for testing IGCC plants. GE will have an opportunity to correct any deficiencies noted in the preliminary test. The standard requires temperatures above 30 degrees Fahrenheit, and so scheduling such testing is weather-dependent.

Mr. Stultz described other significant progress between the reporting period and the filing of his testimony. The Station experienced one of its longest dual train runs until tripping in late October 2013. The Company used the opportunity to move up its fall outage to perform routine maintenance. After coming out of that outage, the Plant had performed well through the filing date of this testimony as a direct result of the optimization and tuning work.

Mr. Stultz further testified as to other Plant successes. During the reporting period, the Plant experienced one OSHA recordable injury, a smashed finger due to improper use of a tool. This incident occurred after many months without any recordable injuries; the overall Plant safety record is excellent by Duke Energy Indiana and industry standards. The entire power block has operated for months with few issues, logging hundreds of hours of run time on natural gas, syngas, and combinations of each. The gasification island was successfully commissioned. The gas clean up equipment has run and performed exceptionally well. The Plant is operating at full environmental compliance during all gasifier runs to date; it has not had a single air emission exceedance. The Plant changed operations of various systems to enhance performance. The final revision to simulator software was completed and operating training on the simulator will become a vital part of new hire training. In general, Mr. Stultz reported that the operations, engineering, and maintenance teams were operating at a strong and safe level of performance and start-ups of the gasification island had become routine.

Mr. Stultz testified regarding the performance of the power block and gasification island. During the reporting period, the gasifiers ran over 2,600 hours, producing more than 4,218,000 Dktms of syngas, and the power block produced 933,000 MWhs of energy. Even when the gasification island was offline, the power block has consistently been available to be dispatched on natural gas. Mr. Stultz described this phase as having largely uncovered "first run" type issues and explained that his team would now focus on improving performance.

Mr. Stultz also provided an update of issues that were not resolved by the time of his IGCC-11 testimony: (1) slag handling issues; (2) ASU issues; and (3) freeze protection deficiencies. The Plant has made improvements to resolve slag handling issues through procedure changes, design changes, training, and other methods. Mr. Stultz testified to various issues with the liquid nitrogen pumps in the ASU, including certain issues resolved under warranty. Mr. Stultz explained that an investigation revealed that there is a deficiency in the ASU capacity such that it does not produce sufficient nitrogen to consistently meet the Plant's needs when operating both gasifiers simultaneously or during transient conditions. The Company is clarifying the report and determining next steps. The Plant has obtained sufficient nitrogen such that this deficiency has not impacted commissioning activities or operations. The Plant has engaged a vendor to address malfunctioning and inadequately designed heat tracing; future cold weather may expose additional areas needing attention. The costs and expenses of these issues are being borne by shareholders under the terms of the 2012 Settlement Agreement as repairs and modifications to the original design or construction. Mr. Stultz further testified that the Company has performed extensive testing and is working with the vendor to determine the cause of the current fluctuation in the coal grinding mill drive motor. The drive motors are performing the required work, but the Company is concerned that the fluctuation may have longer-term life expectancy implications.

Mr. Stultz then testified that the main issues the Plant experienced between April and September 2013 were with the (1) grey water concentrator fans; (2) radiant syngas cooler ("RSC") sump levels; (3) diluent gaseous nitrogen ("DGAN") system; and (4) quench ring pluggage and consequent flow reductions. The grey water fans failed due to high cycle fatigue caused by insufficient filter material in the fans; after repairs, the fans have experienced no additional problems. The RSC sump issues were resolved by adding a defoaming agent to the water stream prior to startup, and there have been no related issues. The DGAN system strainers, which prevent particles from entering the combustion zone, experienced differential pressure and reached the maximum allowable pressure drop across the strainer; the team resolved the issue by performing additional pipe cleaning and adjusting the particle size allowed to pass the strainer. The Plant was experiencing foreign material buildup and high differential pressure in the RSC quench water supply and strainer system, which resulted in low quench water flows and reduced plant output. During an outage, the quench ring design was modified to present the differential pressure, and no further issues have occurred.

Mr. Stultz testified that the issues discovered should not present continuing issues for the performance and reliability of the Plant. However, he also explained that due to the size and complexity of the Plant, he expects issues to arise for some time after the Plant is in-service. Mr. Stultz further testified that in his experience every major project will have numerous engineering, design and construction issues; because of the extensive start-up and commissioning process for the Plant, he expects that the majority of "first run" engineering, design, and construction issues were resolved by the time the Plant was in-service. Technical issues typical of generating facilities may still arise during initial and ongoing commercial operations.

Mr. Stultz reported that administrative appeals related to the air permits for Edwardsport were resolved by a settlement between Duke Energy Indiana and the Joint Intervenors; the Settlement did not require changes to the previously approved air permits for the Plant.

Mr. Stultz testified regarding the expenses incurred while operating the Plant post-in-service. He explained that the expenses were the same as operating expenses incurred at other power plants during operations and maintenance activities, such as labor, chemicals, and parts for maintenance work. During the period at issue, routine maintenance capital included several valve replacements, an LOX process pump, and replacing the catalyst in the mercury guard drum. The Company expects to repair and replace valves and pumps as part of its regular, routine maintenance. Mr. Stultz testified that expenditures for the period have been predictable and in line with the forecast presented in the IGCC-10 proceeding.

Mr. Stultz further testified in support of the Plant's operation and maintenance ("O&M") forecast. He explained that the Plant will incur fixed costs, such as labor costs, and variable costs, such as chemical costs. The Company has forecasted O&M expenses in 2014 and provided forecast information to Ms. Douglas for use in estimating IGCC Rider impacts. Forecasted O&M expenses will be trued-up to actual expenses, and customers pay only actual O&M. The current budget includes labor for 158 Duke Energy employees on site, as well as necessary Company-allocated labor (such as environmental, safety and business support), and an expectation of approximately 40 contract personnel for insulation work, scaffolding, general housekeeping and general support labor. It also includes labor for identified and planned outage work and plans for chemical consumption based on the projected 75% availability in the first 15 months of commercial operations and for 85% availability in the following months.

Mr. Stultz also testified to a parts agreement with GE. Mr. Stultz noted that the Company has reached an agreement with GE for GE to provide required parts for the combustion turbines for eight years at a base discounted price. Duke Energy Indiana will pay $77 million for the initial parts order; these are parts the Plant would normally keep in stock to complete scheduled inspections and part replacements. The majority of expenses associated with this agreement are not included in the O&M forecast in this proceeding because most of the costs will be spent on parts used in normal capitalized maintenance and repairs.

Mr. Stultz and Mr. Thompson presented the Commission with additional construction Project information, as requested by the Commission in its IGCC-1 and IGCC-2 Orders, to the extent it continued to be relevant. This information requested by the Commission was outlined by

Messrs. Stultz and Thompson and contained in Petitioner's Exhibits A-1, Confidential A-1, B-1, Confidential Exhibit B-1, B-2, and Confidential B-2. Mr. Stultz further explained that the Company proposes to provide an operational update rather than construction progress review information in future tracker proceedings.

Mr. Thompson provided a final high-level update on the construction status of the Project. He testified that the period of April 2013 through June 7, 2013, involved testing of various components, commissioning of the Plant, and significant portions of GE's NPI testing program. The Plant has been turned over to the operations group managed by Mr. Stultz. As of the end of September 2013, the engineering, procurement and construction work of the Project is complete with the exception of certain punch list items and specific scope modifications and additions listed in Exhibit B-2, Section 4.b. As such, this is the Company's final ongoing review report of station construction.

Mr. Thompson testified that the Project's cost forecast has not changed from the forecast communicated in IGCC-10 and is still expected to fall within the $3.153 billion (without AFUDC) budget approved by the Duke Energy Board of Directors in October 2012. The actual project cost (without AFUDC) as of September 30, 2013, was $3,096,139,847, which is shown in Petitioner's Confidential Exhibit B-1.

In IGCC-12, Ms. Douglas testified on behalf of the Company with respect to ratemaking issues. She explained that the purpose of her testimony was to explain the Company's request for timely recovery of costs in connection with the Company's IGCC Project, including construction work in progress ("CWIP") ratemaking treatment for retail jurisdictional IGCC Project expenditures.

In particular, she provided (1) certain information which establishes the value of the IGCC investments applicable to IGCC facilities; (2) information that shows the computation of the jurisdictional revenue requirement associated with the expenses, including forecasted operating expenses and reconciliation of prior forecasted amounts to actual expenses and amounts collected from customers; and (3) information that determines the allocation of the resulting jurisdictional revenue requirement to various retail customer groups. She also testified to inclusion in the development of the proposed rates of new items stemming from the commercial operation of the Plant: (1) the cost of related post-in-service ongoing capital projects necessary as of September 30, 2013; (2) a net amortization of operating costs deferred through September 30, 2013 and of the deferred income tax incentive regulatory liability ("Commission-Ordered Regulatory Liability") which was included in the proposed rates presented for Commission approval in Petitioner's Exhibits D-1 through D-6 in IGCC-11 in response to the Commission's Order in IGCC-10; (3) the amortization of post-in-service AFUDC; and (4) the reconciliation of actual costs associated with the operation and maintenance of the production portion of the Plant to amounts collected for such costs through rates. Ms. Douglas also addressed some proposed changes to Rider 61 to clarify language regarding miscellaneous costs and to reflect the migration of customers between two rate classes.

On behalf of Duke Energy Indiana, Ms. Douglas requested that the Commission approve the following: (1) the value of the IGCC Project upon which the Company is requesting authorization to earn a return; (2) the amount of Duke Energy Indiana's expenditures for the IGCC facility incurred through September 30, 2013; (3) recovery of incremental fees and expenses of Black & Veatch incurred by the Company from April through September 2013; (4) recovery of the estimated operating expenses net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expenses that are expected to be incurred from April through September 2014; (5) recovery of estimated depreciation that will be incurred from April through September 2014; (6) inclusion of a credit to retail customers in Rider 61 to reflect the jurisdictional impact of a change in depreciation rates for in-service plant, which took place effective January 1, 2013, and which was approved in the IGCC-4S1 order; (7) inclusion of a credit for the retail portion of one-half of the Indiana Coal Gasification Technology Investment Tax Credit, estimated to be $15 million on an annual basis ("State Tax Credit"); (8) the inclusion of a net amortization of deferred operating expenses, including depreciation, associated with the production portion of the Plant from June 7, 2013, through September 30, 2013, which have been deferred in the 2012 Settlement Agreement Regulatory Asset, and of the Commission-Ordered Regulatory Liability established pursuant to the Cause No. 43114 IGCC 4S1 or "Subdocket" Order; (9) the inclusion of the amortization of post-in-service AFUDC over the same three-year period being used to amortize the deferred operating expenses; (10) the reconciliation of revenue requirements for the actual cost of items other than return on investment which have been included for recovery in IGCC Tracker filings to actual amounts billed for these items from April through September 2013; and (11) adjustment of Petitioner's retail electric rates, via Rider 61 to reflect the revenue effect of such investment, cost recovery, credits, amortizations, and reconciliation.

Her testimony also explained Petitioner's Exhibit C-2, which includes the schedules that develop and support the IGCC-12 revenue adjustment factors. She explained that this exhibit sets forth schedules for the IGCC Project and includes data consistent with the requirements of 170 IAC 4-6-12 and the Commission's Orders in Cause Nos. 43114, 43114-S1, 43114 IGCC-1, and subsequent orders, and with the terms of the 2012 Settlement Agreement and Subdocket Order; actual in-service dates for the transmission system and production projects; Project expenditures as of September 30, 2013, subject to CWIP ratemaking treatment; Project expenditures applicable to wholesale jurisdictional customers; retail IGCC facility investment as of September 30, 2013; the amount of retail AFUDC included in the cost of the Project; and the total amount of AFUDC included in the Project.

Ms. Douglas continued her testimony stating that Page 2 of Petitioner's Ex. C-2 shows the amount of accumulated depreciation as of September 30, 2013, applicable to the recoverable in-service IGCC Project investment. The jurisdictional accumulated depreciation applicable to the jurisdictional Project investment as of September 30, 2013, was $33,013,613, which reflects the reduction due to the anticipated 50% MISO Regional Expansion and Criteria Benefit or "RECB" project reimbursement amount.

Ms. Douglas' Exhibit C-2, page 3 includes the total expenditures as of September 30, 2013, for certain post-in-service ongoing capital projects related to the IGCC facility. The Company is requesting approval for CWIP ratemaking treatment and cost recovery of the retail jurisdictional portion of the ongoing capital projects' costs, as discussed in Mr. Stultz's testimony. The cost of these projects was not included in the approved estimate for the Project, and they have arisen as part of the normal operation of the Plant since its June 7, 2013 in-service date. The projects were not identified during start-up, testing, validation, and commissioning as necessary for "final completion" as defined in the 2012 Settlement Agreement, and the 2012 Settlement Agreement contemplated that such post-in-service ongoing capital projects would not be subject to the Hard Cost Cap but rather retail rate recovery:

> "Construction Costs" of the Project and the Hard Cost Cap shall not include normal operating and maintenance (O&M) expenditures on the Project, which, according to FERC guidelines, begin after the "In-Service Operational Date" and shall not include subsequent ongoing capital spent on the Project for normal capitalized repairs or maintenance expenditures or additional plant and equipment necessary for the continued operation of the Project after the "in-Service Operational Date", unless identified during start-up, testing, validation and commissioning as being necessary to reach "final completion", nor does the cap apply to orders of the Commission approving cost recovery related to carbon capture and storage (including study costs) involving the Project." (2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.E., p. 3)

The jurisdictional balance of the Company's investment in these post-in-service ongoing capital projects is $239,000 as of September 30, 2013.

None of these post-in-service ongoing capital projects were in-service for accounting purposes as of September 30, 2013; therefore no depreciation or accumulated depreciation is reflected in this filing for these projects. However, depreciation expense and accumulated depreciation will be reflected in future filings once the projects are in-service on the accounting books and records.

Ms. Douglas testified that the Commission has previously approved this treatment of capitalized maintenance projects and retirements of plant in its order in Cause No. 42061-ECR 18 for costs included in Standard Contract Rider No. 62—Qualified Pollution Control Property Revenue Adjustment and Standard Contract Rider No. 71—Clean Coal Operating Cost Revenue Adjustment. The Company intends to treat normal capitalized repairs and maintenance and any additional plant and equipment necessary for the operation of the Station in the same manner as it does for tracked equipment in the ECR proceedings.

Ms. Douglas' Exhibit C-2, page 4 developed the jurisdictional revenue requirement. The retail jurisdictional portion of the total construction costs exceeded the retail jurisdictional portion of the $2.595 billion June 30, 2012 Hard Cost Cap amount; therefore, the Company limited the amount of Project investment on which a return will be earned in its calculations. Ms. Douglas explained that the retail jurisdictional portion of the $2.595 billion June 30, 2012 Hard Cost cap amount as filed in IGCC-10 was $2,404,075,000. She stated that the Additional AFUDC (as per the terms of the 2012 Settlement Agreement) related to the Hard Cost Cap amount accrued from July 1, 2012, through the June 7, 2013 in-service date was $55,952,000 ($623,000 of this was accrued during the IGCC-12 period; the remainder was reflected in IGCC-10 and IGCC-11). In accordance with the 2012 Settlement Agreement, the Additional AFUDC amounts included for December 2012 through June 7, 2013 reflect a 15% reduction. The adjusted total of the retail jurisdictional Hard Cost Cap plus Additional AFUDC as of September 30, 2013, was $2,460,027,000, which is a reduction of $788,849,000 from the total retail jurisdictional CWIP investment as of September 30, 2013. Ms. Douglas explained the Project investment was reduced by $33,014,000 of retail accumulated depreciation, resulting in a net plant amount of $2,427,013,000 on which a retail return was calculated. The six-month jurisdictional revenue requirement for return on investment as of September 30, 2013 was $117,715,000. This is a $4,635,000 decrease from the amount proposed in IGCC-11.

Ms. Douglas explained the calculation of the jurisdictional revenue requirement applicable to Project-related operating expenses, including depreciation expense, and tax credits. These operating expenses included: expenses incurred by the Company from April through September 2013 for services from Black & Veatch; estimated retail portion of operating expenses and property tax expenses from April through September 2014; estimated retail jurisdictional depreciation expense from April through September 2014; a credit to retail customers of $17,587,500 ($35,175,000 on an annual basis), approved by the Commission in the Subdocket Order, to reflect the jurisdictional impact of a change in depreciation rates for in-service plant, which took place effective January 1, 2013 ("Credit for Effect of New Depreciation Rates"); a credit for the retail portion of one-half of the estimated State Tax Credit; a net amortization over three years of the 2012 Settlement Agreement Regulatory Asset and Commission-Ordered Regulatory Liability stemming from the IGCC-4S1 Order; and an amortization of the post-in-service AFUDC accrued through September 30, 2013, also over a three-year period. *See* Pet. Ex. C-2, p. 5.

Ms. Douglas stated that the Company incurred $55,222 between April through September 2013 for Black & Veatch Project-related oversight services. She also testified the Company forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Edwardsport steam generating facility which were included in base rates, and the retail jurisdictional property taxes in the amount of $31,655,773 for the period April through September 2014 period. *See* Pet. Conf. Ex. C-2, p. 6. The Company forecasts retail jurisdictional depreciation expense of $50,862,346 for the April through September 2014 period. A credit of $17,587,500 reflecting the Credit for Effect of New Depreciation Rates and a credit of $6,884,250 reflecting the retail jurisdictional portion of one half of the annual estimated $15 million State Tax Credit have also been included. A net revenue requirement amount of $2,849,345 was included for the $5,121,965 (credit) amortization of the $30,731,789 Commission-Ordered Regulatory Liability established pursuant to the Commission's IGCC-4S1 order over three years, net of the $7,971,310 revenue requirement for the amortization over three years of the $45,143,216 September 30, 2013 balance of the operating expenses, including depreciation, deferred from June 7, 2013, through September 30, 2013, in the 2012 Settlement Agreement Regulatory Asset.

Finally, Ms. Douglas explained that a revenue requirement of $429,493 has been included for the amortization of the $1,754,084 balance of post-in-service AFUDC through September 30, 2013, over a three-year period, consistent with the three-year period over which the 2012 Settlement Agreement Regulatory Asset and Commission-Ordered Regulatory Liability will be amortized. Post-in-service AFUDC has been computed using the 15% reduction in the AFUDC rate, which was agreed to in term 2.B of the 2012 Settlement Agreement. *See* the 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.B., p. 2. Additional post-in-service AFUDC will accrue until all the Hard Cost Cap plus Additional AFUDC amounts and post-in-service AFUDC costs have been included in the IGCC Rider or retail base rates.

Ms. Douglas further explained why the regulatory asset included in the calculation of revenue requirements included deferred expenses past the September 12, 2013 implementation of IGCC-10 rates. The 2012 Settlement Agreement provided for a three year amortization period for the deferred operating expenses, including depreciation from the In-Service Operational Date of the IGCC facility until the IGCC-10 rates were in effect. *See* the 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 3, p. 4. The IGCC plant was declared in-service on June 7, 2013. IGCC-10 rates went into effect on September 12, 2013. The terms of the 2012 Settlement Agreement provided for the deferral of costs during this period with recovery over three years, but the 2012 Settlement Agreement also contemplated that IGCC-10 would include six months of operating expenses, rather than four. 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 3, p. 4. Therefore, even after IGCC-10 rates were in effect, the rates customers are paying do not fully cover the level of operating expenses. Normally those differences would be part of the six-month reconciliation for the tracker. However, as a rate mitigation provision, the 2012 Settlement Agreement provided that no estimated operating expenses should be included in IGCC-9 rates and that any amounts incurred after the Plant was in-service while IGCC-9 rates were being billed should be deferred in the Regulatory Asset and recovered over a three-year period rather than the standard six-month reconciliation period. 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 3, p. 4.

Ms. Douglas testified that in the spirit of the 2012 Settlement Agreement, the Company desires to voluntarily continue to defer the operating expenses not recovered via IGCC-10 rates as a Regulatory Asset in order to avoid a large reconciliation variance that would need to be collected over a six-month tracker period. By including these costs in the Regulatory Asset and amortizing them with the remainder of the costs deferred from June 7 through September 11, 2013, it will smooth out the impact of the under-collection in IGCC-10 rates and serve to mitigate rate volatility. The September 30, 2013 Regulatory Asset balance the Company has amortized over three years therefore includes expenses deferred pursuant to the terms of the 2012 Settlement Agreement that were incurred from June 7 through September 11, 2013, and incremental expenses incurred over the amount included in IGCC-10 rates from September 12-30, 2013. Additional incremental expenses will be deferred for each month IGCC-10 rates remain in effect and factored into the amortization amounts in the next (or subsequent) IGCC Tracker filing. Ms. Douglas asked the Commission to approve this treatment.

Confidential Exhibit C-2, p. 6 detailed the support for the retail jurisdictional amount of forecasted depreciation expense and other expenses included in the revenue requirements calculation on page 5 of Exhibit C-2. She again noted that the depreciation amount was reduced by 50% of the depreciation associated with the two RECB transmission projects for which reimbursement will be received from MISO's RECB process. She continued explaining that the depreciation expense for the plant investment included for ratemaking was calculated using the current Commission-approved depreciation rates for the FERC plant accounts to which the projects were assigned. The property tax estimate reflects 100% of the April through September 2014 benefit forecasted to be received for the ten-year property tax abatement from Knox County and the thirty-year reimbursement due to designation of the IGCC Project as a Tax Increment Financing District. In addition, as approved by the Commission in the CPCN Order, a monthly credit of 1/12th of an annual amount of $5,756,000 has been included to reduce the forecasted operating expenses.

Ms. Douglas explained the reconciliation amounts included in revenue requirements for the April through September 2013 period which were supported on Petitioner's Exhibit C-2, Page 8, including a reconciliation of the voluntary credit adjustment provided in IGCC-10 to HLF customers to correct for an IGCC Rider administration clerical error.

Page 9 of Petitioner's Exhibit C-2 shows the calculation of the IGCC Revenue Adjustment Factors, by jurisdictional rate group, developed to recover the total revenue requirements for this filing of $184,099,276.

Ms. Douglas also explained the derivation of the cost of capital used in developing revenue requirements and the AFUDC rates used in determining the amounts of Additional AFUDC included in the IGCC Project investment amount through June 6, 2013, for the Ongoing Capital Projects, and the amount of post-in-service AFUDC from June 7 through September 30, 2013.

Ms. Douglas next explained when CWIP ratemaking treatment for the IGCC Project will cease. She stated that consistent with 170 IAC 4-6-22 and in accordance with the Commission's CPCN Order, the IGCC Project will be deemed to be under construction, and Duke Energy Indiana will continue to receive revenues through Rider 61, until the Commission determines that this Project is used and useful in a proceeding that involves the establishment or investigation of Duke Energy Indiana's retail electric base rates and charges.

Ms. Douglas also stated that the impact of the proposed IGCC Project ratemaking treatment, under the terms of the 2012 Settlement Agreement and assuming approval of the proposed factor, on the monthly bill of a typical residential customer using 1,000 kilowatt-hours would be an increase of $2.13, or approximately 2.4%, from the base bill plus the IGCC-11 factor then being billed to customers.

Ms. Douglas concluded her testimony by discussing rate migrations. She explained that after a review of changes in the number of customers and sales to Rate HLF and LLF customers since the last rate case, the Company is proposing a rate migration adjustment. The Company has seen a net migration of customers and load from Rate HFL to Rate LLF. To account for this change and better align the Rider with costs and customer loads, the Company proposes to adjust the allocation for the net migration between the two rate classes by approximately 1%. The Company makes this proposal after tracking customers migrating between Rate HLF and LLF from 2008 through December 31, 2012. Approximately 50 MWs moved from Rate HLF to Rate LLF. The Company proposes to use this adjustment on a going-forward basis and will continue to monitor rate migrations each year.

c. IURC Cause No. 43114 IGCC-13. Mr. Stultz provided the Commission with information about the operations of the Plant from October 1, 2013, through March 31, 2014 in his prefiled June 12, 2014 testimony. He also provided information on the Station's O&M costs, the forecasted O&M budget for the Plant, and normal capitalized repair and maintenance expenditures.

Mr. Stultz stated that between October 1, 2013, and March 31, 2014, Edwardsport had both a fall and a spring outage. The fall outage began in October 2013 and extended into November 2013. The spring outage began in February 2014 and ended in early March 2014. The Plant also experienced relatively minor, yet plant-wide equipment and system issues during December 2013 and January 2014 that were exacerbated by the extreme winter temperatures in Indiana. Mr. Stultz stated that following the spring outage, Edwardsport saw significant improvements in gasifier operations with some of its best runtimes to date.

Mr. Stultz explained that the fall outage was originally planned for early November, but when the plant tripped on October 23, 2013, due to low instrument air pressure, the Company decided to move up the fall outage. During the outage, the Company performed a routine borescope of the combustion turbines to examine their condition and general wear and tear. Following completion of the borescopic examination and review of the operational data, GE extended the inspection/maintenance intervals on the turbines from every 8,000 operational hours to every 11,500 operational hours. According to Mr. Stultz, the inspection/maintenance interval on a typical GE 7F turbine is every 12,000 hours, but Edwardsport's syngas-operated turbines were originally set conservatively at 8,000-hour maintenance intervals. Mr. Stultz stated that the Company hopes that after another inspection, GE will further extend the maintenance interval to every 12,000 hours. Mr. Stultz stated that during the fall outage, the Company also inspected and cleaned the gasifiers. According to Mr. Stultz, the refractory brick inside the gasifiers is performing well. Repair and replacement of the refractory brick will be part of the Station's ongoing routine maintenance over the life of the Plant.

Mr. Stultz explained that although the fall outage workscope was completed as planned, when the Station attempted to light off, the thermal oxidizer would not light. An inspection revealed corrosion of the burner, which prevented light off. The Company ordered and subsequently installed a new burner. Gasifier 1 was lit off on November 20, 2013, and Gasifier 2 was lit off on November 21, 2013.

After returning from the fall outage, Mr. Stultz reported that the Plant faced multiple events with the thermal swing adsorption ("TSA") valves experiencing sticking during operation. Air Products, the manufacturer of the valves, came onsite to assist with the issue. Together, Air Products and Duke Energy Indiana resolved the matter by replacing the bearings and rotating the valves 90 degrees. This rotation prevents collection of foreign material in the bearing. Once the TSA valves were repaired, the Company lit off the gasifiers six times in December, and experienced five trips. Three of the trips were related to the freezing of various equipment. According to Mr. Stultz, the equipment freezes when it is insufficiently protected from the elements or when temperatures are abnormally cold for long periods of time. Mr. Stultz noted that the Company has previously found inadequately designed and installed heat tracing at the Edwardsport facility. Although the Company made a concerted effort to protect all equipment known to be prone to freezing before the start of the winter, additional equipment ended up needing protection due to the much colder winter temperatures.

Mr. Stultz stated that based on the last two winters, the Company has identified approximately 3,400 issues, including the need for additional or replacement insulation, tracing, or heated boxes, that the station has been fixing. Many issues were resolved before the 2013-2014 winter, but additional heat tracing and insulation issues were identified during this winter due to colder temperatures than experienced the year prior. Because some level of heat tracing was part of the original design for the project, and because it is difficult to parse out which of these costs could be considered ongoing capital repairs, the Company decided to charge back the cost of this work to the capital construction budget, which means that Duke Energy shareholders are covering these expenses.

Mr. Stultz noted that many of the temporary heated and unheated structures that the Company designed and constructed can be stored and reused in future winters as part of the Station's winterization plan. Mr. Stultz stated that because preparedness plans are part of normal ongoing Plant operations, the annual cost of implementing these plans will be charged as ongoing O&M or normal capital repairs in the future. The Company expects that execution of its winterization plan and improvements made to the heat trace and insulation of the equipment will render the Plant better protected in future winters. Although extreme temperatures could reoccur, Mr. Stultz noted that his team has the experience and knowledge to know which systems are most vulnerable so that they can stay in front of any extreme cold.

Mr. Stultz explained that winter weather continued to affect the Plant in January and February 2014. Gasifier 2 tripped on January 3, 2014, due to a lockhopper flush valve leaking, which meant that the Plant could not keep pressure in the slag system. The Company pulled that valve and sent it to Houston to be rebuilt. After the valve was repaired, gasifier 2 was lit off three times and tripped three times. One of the trips was due to a frozen transmitter. The other two trips were due to loss of quench flow. The loss of quench flow issue was resolved through a control change and adjustment of the radiant syngas cooler level and, according to Mr. Stultz, the Company has not seen a reoccurrence of this issue. Gasifier 1 was lit off twice and tripped twice. Both trips were due to freezing equipment, making a total of three trips in January 2014 due to freezing.

January 2014 operations were also challenging because the Plant experienced a variety of leaks in various systems. The extremely cold temperatures exacerbated operational challenges in that the Plant would trip due to a frozen transmitter or other piece of equipment, but then inspection would uncover an additional issue that would need to be resolved before light off could again be attempted. Gasifier 2 tripped on January 23, 2014 due to a loss in feedwater. The Company lit off Gasifier 2 again on February 5, 2014. After running for approximately 8 hours, Mr. Stultz's team discovered a more major issue in both trains of the sulfur recovery unit, which is part of the Station's syngas clean up system and separates elemental sulfur out of the acid gas and ultimately results in the sale of elemental sulfur. On February 5, 2014, the Company discovered that the entire sulfur recovery unit was blocked by ammonia salts. Duke Energy Indiana took the Plant offline and had a subject matter expert come to the Plant to assist with the removal of the existing salts and to help prevent this from reoccurring. The Company learned that the ammonia salts were caused by a combination of the loss of feedwater on January 23, 2014 and reaction furnace temperatures. Those two factors allowed the gases to cool enough so that the ammonia changed from gaseous form and precipitated out into the salt that blocked the sulfur recovery unit. The expert assisted the Company with removing the salts by opening up the system and using high pressure water to remove it.

Because the system was down for a significant period of time related to the cleanup of the sulfur recovery unit, the Company moved its previously scheduled spring outage forward to take advantage of the station downtime. This worked well because while a portion of Duke Energy Indiana's staff was working to remove the sulfur and ammonia from the acid gas systems, another portion of the staff was simultaneously able to complete the spring outage work on the gasifiers and the combustion and steam turbines. Mr. Stultz stated that whenever possible, the Company takes advantage of unexpected downtime to perform necessary outage and maintenance work. Because Duke Energy Indiana performed the spring outage work in February, there was only one period of downtime and the Plant was able to run much of April when it was scheduled for a maintenance outage.

Mr. Stultz testified that during the spring outage, the Company inspected both the gasifiers and the combustion turbines and replaced nine rows of refractory brick in the throat of gasifier 1. The Company had anticipated having to replace refractory brick earlier and Mr. Stultz noted they were pleased that the brick lasted beyond the testing and pre-optimization operations.

Following the spring outage, Mr. Stultz has seen improved gasifier hours of operation and MWhs. Gasifier 1 ran from its light off after the spring outage on March 13, through March and into April. Also following the spring outage, Gasifier 2 ran from March 7 through March 19, was relit after an issue with the feed injector valves was resolved on March 29 and then also ran into April 2014.

Mr. Stultz then provided some background explanation regarding power plant performance metrics. He explained that capacity factor is the measure of the percentage power output of a generating unit and is calculated by dividing the actual generation in MWhrs by the maximum capacity of the unit in MWhrs for a certain period times 100%. Capacity factor of a generating facility varies dramatically for shorter periods due to planned and unplanned periods when the station is not in service. As a result, he stated that one year is typically the minimum period one would look at capacity factor for a particular generating facility. Assuming the facility is being properly maintained, the greater the capacity factor of a station, the better from the standpoint of a power plant operator.

Mr. Stultz then explained that, from his perspective as an operator, availability, not capacity factor, is the best measure of a generating facility's performance. Availability is a percentage measure of the hours that a unit is available to produce power divided by the number of hours in a given period times 100%. As with capacity factor, the availability of a unit will vary dramatically when measured over short periods of time because during a given week or month if the unit is unavailable due to a major planned outage, the availability factor would be zero, but when the planned outage is over, the availability factor could be well above 80% for a given period. According to Mr. Stultz, availability is also a better measure of a unit's performance because there are causes beyond an operator's control that affect the capacity factor of a unit. For example, MISO generally determines what units will run at what energy output levels to meet load. If a unit is available but not dispatched by MISO for economic or reliability reasons, these are factors over which the power plant operator generally has little control. Mr. Stultz stated that the most important determinants of these factors for a baseload unit such as Edwardsport, are planned maintenance outages and unplanned forced outages. Planned maintenance outages are a prerequisite for every power plant. A key goal is to maintain expensive equipment and the overall plant in good condition so the productive life of the equipment will continue as long as possible. Planned outages also avoid unplanned outages resulting from equipment failures. Unplanned forced outages are generally undesirable, though the risk of an unplanned outage cannot be avoided. Cost, reliability, and safety must be taken into account in determining the appropriate amount of planned maintenance outages.

Mr. Stultz stated that the Company has focused on operating the Plant as reliably and consistently as possible. Mr. Stultz stated that he believed the Plant had operated about where the Company expected it to in the early months of operation because the Company has not identified any major issues with the Plant systems or components or the integrated operations of the Plant. When it did experience technical problems or issues, the Company learned from them, corrected them, and moved on. Overall, Mr. Stultz stated that he was pleased with the Plant's performance demonstrating increased availability and gasification operating hours following the spring 2014 outage.

According to Mr. Stultz, it is reasonable to expect the Plant to operate at 85% availability over the long-term life of the station. He stated that Edwardsport's availability had not yet reached 85%, nor had it reached the 75% the Company expected it would for the first 15 months of commercial operation. Mr. Stultz emphasized that the first 15 months of commercial operation had not yet even concluded, and the Company still had more than 30 years of Edwardsport operations ahead of it. He also noted that following the spring outage, the Company saw steadily improving reliability from the gasifiers—May 2014 represented the Company's best month yet for MWhrs on gasified coal. Mr. Stultz emphasized that he and his team would continue to do all they could to achieve the expected availability, consistent with high safety standards, appropriate maintenance, and reasonable costs.

With respect to progress towards substantial completion, Mr. Stultz stated that GE completed the preliminary performance testing on April 2, 2014. The test proceeded smoothly. After GE spent time analyzing and reviewing the data gathered during the preliminary test and Duke Energy Indiana and GE worked together on the conditions for the equipment, GE performed the final performance test on May 15 and 16, 2014. The collected data and samples have been sent to a lab to process and review and Duke Energy Indiana hopes to receive the final results from GE shortly.

Mr. Stultz explained that in order for Edwardsport to be considered "substantially complete" under the GE Contract, the following conditions must be met: (1) delivery of all GEP Equipment shall have occurred; (2) the performance of the Work shall be complete (other than Work that by its nature cannot be completed until after Substantial Completion (*e.g.*, warranty Work)), with the exception of the Punch List; (3) the Facility shall have satisfied the Minimum

Performance Guarantees and the Make-Right Performance Guarantees; (4) the Seller shall have delivered to the Buyer all Documentation that the Seller is required to deliver to the Buyer pursuant to this Contract, with the exception of the Punch List; (5) the Seller shall have provided all training required by Exhibit S, with the exception of the Punch List; and (6) the Seller shall have delivered to the Buyer a certificate signed by the Seller certifying that all of the preceding conditions have been satisfied.

Mr. Stultz stated that delivery of the GEP equipment and the contractually required training is complete. The performance testing is considered part of the "Work" and reporting of those results is considered part of the "Documentation," so neither of those two conditions can be complete until the performance test data is provided to Duke Energy Indiana. When the performance test data is fully analyzed and reported to Duke Energy Indiana, it will also presumably be determined whether the "Minimum Performance Guarantees" and the "Make-Right Performance Guarantees" under the contract have been met. The "Make-Right Performance Guarantees" are generally related to Plant emissions, while the "Minimum Performance Guarantees" are related to the guaranteed net facility electrical output and the net facility heat rate. Mr. Stultz stated that Duke Energy Indiana hopes to soon learn that the Make-Right and Minimum Performance Guarantees under the contract have been met and receive its remaining Documentation and the "certificate" of completion from GE so that Edwardsport will be substantially complete under the Duke/GE Contract. Once the plant is substantially complete, the main item remaining is completion of the GE contractual "Punch List Work" before "final completion" under the contract will be achieved.

Mr. Stultz provided an update to his IGCC-12 testimony and noted several issues that require longer-term fixes to resolve. Those include the liquid nitrogen pumps ("LIN pumps") in the ASU, the nitrogen capacity of the ASU, and the heat tracing/freeze protection for the Plant. Mr. Stultz noted that Edwardsport experienced premature failure of the Plant's process LIN pumps in the spring of 2013. Although the LIN pumps have been repaired and replaced, several additional failures have occurred. In addition, a temporary maintenance and operating strategy has been adopted to ensure Plant reliability while the original equipment manufacturer reviews and makes final recommendations, under warranty, to permanently resolve design-related issues. While the Company has continued to follow the temporary maintenance and operating strategy necessary to maintain the process LIN pumps, it has determined the best long-term solution is to replace the existing process LIN pumps with a newer design. There is an extensive lead time on these pumps so although they have already been ordered, the Company does not anticipate receiving and installing them until 2015. Until these new pumps are installed, Edwardsport will continue to have to purchase additional liquid nitrogen and perform the required maintenance on the existing pumps to meet the plant's operation demands. Edwardsport has also increased the capacity of the pumps and believes that these will resolve the concern the Company has had that the nitrogen capacity of the ASU is insufficient to meet the plant's demands. Through work with Burns and McDonnell, the Company has found that the ASU generates sufficient liquid nitrogen for the Plant's needs but the LIN pumps cannot pump it in the necessary quantities. The new pumps should be able to handle the liquid nitrogen demands of the Plant such that purchases of liquid nitrogen to supplement the ASU production will be greatly diminished.

Mr. Stultz stated that the costs to resolve the supplemental liquid nitrogen, the costs to rebuild the existing pumps as needed during this interim period, and the new pumps have been, and will continue to be, charged to the original capital project. Accordingly, they are being covered by Duke Energy shareholders under the terms of the 2012 Settlement Agreement. Duke believes the liquid nitrogen pumps and the heat tracing should be considered repairs and modification needed to the original design or construction that were identified during start-up, testing, validation, and commissioning, not normal operating and maintenance expenditures or recoverable capitalized repairs and maintenance expenditures.

Mr. Stultz testified that the Company pays close attention to the cause of any necessary repairs or maintenance at the plant. Mr. Stultz and members of his team meet on a regular basis to review the Plant's maintenance needs to ensure that no expenses are presented for recovery that would contravene the Commission's Order in Cause No. 43114 IGCC-4S1.

Mr. Stultz stated that the types of expenses that Duke Energy Indiana incurred to operate Edwardsport from September 2013 through March 2014 are the types of expenses that all Duke Energy Indiana power plants incur during operation and maintenance activities, such as labor, chemical, maintenance, and outage costs. Parts for maintenance work, such as worn bearings, seals, packing, valve maintenance, and computer hardware that allows communication within the group and with specialized equipment, are also included in the Station's O&M. During this reconciliation period, the Plant's actual expenses have been close to the forecasted budget.

Mr. Stultz testified that the Plant's operating and maintenance expenses are reasonably and prudently incurred. He noted that the Company understands the obligations imposed by the 2012 Settlement Agreement and has no intention of seeking to recover expenses in this, or any other, proceeding that should be borne by the original construction budget, and ultimately by Duke Energy shareholders. In light of the 2012 Settlement Agreement, Duke Energy Indiana has not sought to recover costs associated with GE's NPI testing or the recently conducted performance testing because "all start-up and testing, validation and commissioning costs" are to be subject to the Hard Cost Cap. Similarly, when Duke Energy Indiana has identified necessary repairs or modifications to the Plant during the early periods of operation that it reasonably believes arose during design or construction, it has not sought to recover those expenses from customers because the 2012 Settlement Agreement provides costs of repairs and modifications identified during start-up, testing, validation and commissioning as necessary to reach final completion under the Duke/GE Contract should be subject to the Hard Cost Cap. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.E., p. 3. Examples of such repairs include, but are not limited to: repairs to the grey water concentrator fans, the DGAN system, array ball valve coating repairs, grey water acid gas line replacement, liquid nitrogen pumps and related purchases of liquid nitrogen, quench ring pluggage, slag handling, and heat trace/freeze protection.

Mr. Stultz testified that the ongoing capitalized repair and maintenance expenditures during this period included replacements of the coal handling sump pumps and replacement of a water treatment transformer. The Company also installed a heavy duty inventory rack at the Plant for the purpose of storing parts purchased under the GE parts agreement. Another replacement was changing the original stainless steel grey water barometric condenser pipe to a Teflon-lined pipe that can better handle the hot, acidic water. There were also general equipment purchases, fan motor replacements, and rod mill lube oil replacements, among other relatively minor projects considered units of property under the applicable accounting guidance.

Mr. Stultz explained that these projects are part of the normal maintenance that will be repaired and replaced on a regular, routine basis. This equipment has, and will, experience significant run times and must be replaced or repaired from time to time. It is not unusual for a new plant to require repairs and replacements during the early months of operations, as well as over its useful life. Whenever Duke Energy Indiana identifies a part that needs replacing, it looks to the market to determine whether to replace in-kind or to try out a newly designed part in order to save on ongoing maintenance. Mr. Stultz stated that there is a balancing that takes place at any power plant between ongoing O&M expenses and ongoing maintenance capital expenses and Duke Energy Indiana seeks to strike the right balance for the continued efficient and reliable operation of the Plant.

According to Mr. Stultz, actual O&M expenses for the period have been predictable and in line with the forecast presented in the IGCC-11 proceeding.

Mr. Stultz testified that in 2014 and 2015, the Plant will incur normal O&M expenses, just as Duke Energy Indiana's other generating plants do. These costs include a combination of fixed and variable costs. Fixed costs include full time Duke Energy employee labor costs and costs associated with air permit testing, NPDES sampling, and reporting. Variable costs are costs that are associated with operation costs for the Plant. Chemicals that are consumed during operation of the Plant are considered variable, maintenance of equipment is variable, and contractor costs are variable. Overheads and allocations are also O&M budget expense items. The Project's budget is determined following an operating strategy for the coming years, reviewed by the financial groups and ultimately adjusted and/or approved by Duke Energy executives. Regular periodic reporting of budget compliance, including any changes, is done by local management to Duke Energy financial and department executives to ensure compliance with expectations.

According to Mr. Stultz, the Company updated its forecast of the expected O&M expenses involved in operating the IGCC Plant in 2014 and 2015, and provided this information to Ms. Douglas for her use in estimating the IGCC Rider impacts. O&M expenses will vary depending on the timing of maintenance cycles, unexpected costs, operating characteristics, and operating time of the Plant. The Company's maintenance strategy will influence a variety of costs, such as the use of contractors or use of Company employee labor, the purchase of OEM parts or after-market parts suppliers, and the rent, lease, or purchase of certain equipment. Mr. Stultz stated that it is important to note that the Company's forecasted O&M expenses will be trued-up once actual costs become known, and customers will pay only the actual O&M incurred for the Plant. The current budget includes labor for 158 Duke Energy employees on the site, as well as necessary Company-allocated labor, such as environmental, safety, and business support. It also includes an expectation of approximately 40 contract personnel for insulation work, scaffolding, general housekeeping, and general support labor. The Company's current budget includes labor for identified and planned outage work.

Ms. Douglas testified on behalf of the Company with respect to ratemaking issues relevant to the IGCC-13 time period. She explained that the purpose of her testimony was to explain the

Company's request for timely recovery of costs in connection with the Company's IGCC Project, including CWIP ratemaking treatment for jurisdictional IGCC Project expenditures. Her testimony also shows the calculations used to develop the Company's proposed IGCC Revenue Adjustment Factor and includes an updated set of retail electric tariff pages applicable to the IGCC Tracker.

Ms. Douglas noted that her calculations were based on data recorded on the Company's books and in the Company's records as of March 31, 2014. Her testimony requested that the Commission approve: (1) the value of the IGCC facility, including the value of related post-in-service ongoing capital project expenditures, upon which the Company is requesting authorization to earn a return; (2) the amount of Duke Energy Indiana's expenditures for the IGCC facility and related ongoing capital project expenditures incurred through March 31, 2014, for which cost recovery is requested; (3) recovery of incremental Black & Veatch Corporation fees and expenses incurred by the Company from October 2013 through March 2014; (4) recovery of the estimated operating expenses net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expense that are expected to be incurred from October 2014 through March 2015; (5) recovery of the estimated depreciation that will be incurred from October 2014 through March 2015, including depreciation of in-service ongoing capital projects; (6) the inclusion of a credit to retail customers in Rider 61 to reflect the jurisdictional impact of a change in depreciation rates for non-IGCC in-service plant, which took place effective January 1, 2013, and was approved in the IGCC 4S1 Order; (7) the inclusion of a credit for the retail portion of one-half of the Indiana Coal Gasification Technology Investment Tax Credit, estimated to be $15 million on an annual basis (the "State Tax Credit"); (8) the inclusion of a net amortization of deferred operating expenses, including depreciation, associated with the production portion of the plant from June 7, 2013, through March 31, 2014, which have been deferred in the 2012 Settlement Agreement Regulatory Asset, and of the Commission-Ordered Regulatory Liability established pursuant to the IGCC 4S1 Order; (9) the inclusion of the amortization of post-in-service AFUDC accrued through March 31, 2014, over the same three-year period being used to amortize the deferred operating expenses; and (10) that Petitioner's retail electric rates be adjusted, via Rider 61, to include the revenue effect of such investment, cost recovery, credits, and amortizations.

Ms. Douglas described Petitioner's Exhibit B-1, Duke Energy Indiana's Rider 61, of which the Company is requesting approval. Rider 61 was last updated and approved by the Commission on September 11, 2013, in IGCC-10. Rider 61 includes definitions of the various components of the formula that was used to develop the IGCC Revenue Adjustment Factors, a formulaic representation of the calculations used to develop the proposed factors, revenue adjustment factors by retail rate group based on data as of March 31, 2014, a listing of retail allocation factors used to allocate the jurisdictional revenue requirement to various rate groups (based on data from the Company's cost of service study approved in Cause No. 42349, as adjusted to reflect the impact of customer migrations between the HLF and LLF industrial rate classes and also between the AL, OL, and UOLS lighting rate classes), and the billing cycle kWh and/or non-coincident peak demands used to develop the proposed IGCC Revenue Adjustment Factors. Petitioner's Exhibit B-1 also contains the tariff revisions that were proposed in IGCC-12 and an additional modification to the language regarding rate migrations to include the additional rate migration for certain lighting rate classes and to the amount of the HLF/LLF rate migration.

Ms. Douglas also explained Petitioner's Exhibit B-2, which sets forth schedules for the IGCC Project and includes data consistent with the requirements of 170 IAC 4-6-12 and the Commission's Orders in Cause Nos. 43114, 43114 S1, 43114 IGCC-1, and subsequent orders, and with the terms of the 2012 Settlement Agreement and Subdocket Order. Exhibit B-2 includes actual in-service dates for the transmission system and production plant projects; total expenditures for the Project as of March 31, 2014, subject to CWIP ratemaking treatment; Project expenditures applicable to the wholesale jurisdiction; retail IGCC facility investment as of March 31, 2014; the amount of retail AFUDC included in the cost of the Project; and, the total amount of AFUDC included in the cost of the Project.

Ms. Douglas explained the ratemaking treatment for the costs of four Project-related transmission projects that were included in the approved cost estimate for the Project in Petitioner's Exhibit B-2. Ms. Douglas stated that for the IGCC-related transmission projects that qualify as part of MISO's transmission expansion plan and are recognized by MISO as RECB projects, the Company will first seek cost recovery pursuant to its Rider No. 68 and MISO's Schedule 26, consistent with the Commission's June 25, 2008 Order in Cause No. 42736 RTO-14. If, and to the extent that, costs for an IGCC-related transmission project are not eligible for, and cannot be recovered through, Rider No. 68 and Schedule 26, then the Company will seek cost recovery for such project (or portion of a project) through the IGCC Tracker. MISO will provide a 50% reimbursement for the two IGCC-related RECB projects, therefore, the Company has included as part of the value of the IGCC plant for CWIP ratemaking treatment the remaining 50% of the value of these projects that will not be reimbursed by MISO. Accordingly, Page 1 of Petitioner's Exhibit B-2 shows the expenditures for the two RECB projects, including the reduction in IGCC Plant costs by the 50% amount for which the Company will be reimbursed by MISO through the RECB process. The IGCC-related transmission projects that are not RECB projects are also shown on page 1 of Petitioner's Exhibit B-2, and the full costs for these projects have been considered in IGCC Tracker ratemaking.

Ms. Douglas stated that Page 2 of Petitioner's Exhibit B-2 shows the amount of accumulated depreciation as of March 31, 2014, applicable to the recoverable in-service IGCC Project investment. The accumulated depreciation for the two RECB transmission projects has been reduced by the 50% MISO RECB reimbursement amount. The jurisdictional accumulated depreciation applicable to the jurisdictional Project investment as of March 31, 2014, after reductions to reflect retired plant associated with the in-service Ongoing Capital Projects, is $83,591,622.

Page 3 of Petitioner's Exhibit B-2 includes the total expenditures as of March 31, 2014, for certain ongoing capital projects related to the IGCC facility. The Company is requesting approval for CWIP ratemaking treatment and cost recovery of the retail jurisdictional portion of the ongoing capital projects' costs. Ms. Douglas explained that the costs of these projects were not included in the approved estimate for the Project and the costs have arisen as part of the normal operation of the plant since its June 7, 2013 in-service date. These projects were not identified during start-up, testing, validation, and commissioning as being necessary to reach "final completion" as defined in the 2012 Settlement Agreement. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.E., p. 3. The 2012 Settlement Agreement contemplated such post-in-service ongoing capital projects that would not be subject to Hard Cost Cap and that would be subject to retail rate recovery. The jurisdictional balance of the Company's investment in these post-in-service ongoing capital projects at the IGCC facility subject to CWIP ratemaking treatment is $1,441,000, as of March 31, 2014.

Just as she explained in her IGCC-12 testimony, Ms. Douglas again testified that it was appropriate to include these ongoing capital project costs in the IGCC Tracker because the costs are incremental costs incurred post-in-service to enable to reliable operation of the Plant, the same as the O&M costs included in the tracker. Because the work completed for these projects includes the installation or replacement of a unit of property, the FERC's Uniform System of Accounts requires electric utilities to account for the cost in the appropriate electric plant account and recover the cost over the life of the equipment via depreciation, rather than expensing the cost in an O&M account. If the costs were not a unit of property, they would be recovered as incremental O&M costs in the tracker as the expenses are incurred. Therefore, it is appropriate that such post-in-service capital projects receive timely recovery via the tracker. Timely recovery includes a return on the retail jurisdictional portion of the investment to cover financing costs, as well as recovery on the investment over its life via depreciation expense in the tracker, once the capital project is in-service.

To determine whether something is a retirement unit that must be capitalized, Ms. Douglas stated that the Company maintains a written property units listing for use in accounting for additions and retirements of electric plant, as required by FERC. This listing is applied consistently in determining whether additions or replacements of equipment during maintenance should be capitalized or expensed. Because everything the Company owns is either a retirement unit or a minor item of property, if the item is not specifically identified as a retirement unit on the property listing, then it is, by default, a minor item.

Ms. Douglas explained that the cost of ongoing capital projects was not included in the Hard Cost Cap because the 2012 Settlement Agreement specifically excluded these costs. The 2012 Settlement Agreement established that such "ongoing additions, replacements, and maintenance capital expenditures made separate and apart from and not including the Construction Costs" could be included in "future retail electric base rate cases and riders." 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.C., p.3. Because the first costs were incurred during the period covered by IGCC-12, the Company requested approval to begin including the costs in Rider 61 in IGCC-12.

Because some of these ongoing capital projects were in-service for accounting purposes as of March 31, 2014, Ms. Douglas explained that accumulated depreciation and depreciation expenses have been included in the development of revenue requirements for this filing for such in-service projects on Pages 4 and 9 of Petitioner's Exhibit B-2.

Ms. Douglas explained that as a result of these ongoing capital projects, there were retirements of other plant that is already included in the IGCC tracker. Ms. Douglas stated that the retirements were reflected in the tracker as they are handled on the accounting books and records.

Ms. Douglas then stated that the Company has approval to include similar capital projects and retirements in other rate riders because the Commission first approved inclusion of capital maintenance projects and reflection of retirements of plant in its order in Cause No. 42601-ECR 18 for costs included in Standard Contract Rider No. 62 – Qualified Pollution Control Property Revenue Adjustment and Standard Contract Rider No. 71 – Clean Coal Operating Cost Revenue Adjustment. The Company intends to treat the normal capitalized repairs and maintenance, and any additional plant and equipment necessary for the continued operation of the Station, in the same manner as it does for tracked equipment in its ECR proceedings.

Ms. Douglas explained that Page 4 of Petitioner's Exhibit B-2 shows the amount of accumulated depreciation as of March 31, 2014, applicable to the jurisdictional portion of the ongoing capital projects that are in-service. The jurisdictional portion of the ongoing capital projects investment as of March 31, 2014 is $9,000.

Page 5 of Petitioner's Exhibit B-2 develops the jurisdictional revenue requirements for the return on the net jurisdictional investment in the IGCC Plant and Ongoing Capital Projects. Because the retail jurisdictional portion of the total construction costs exceeded the $2.595 billion June 30, 2012 Hard Cost Cap amount plus applicable Additional AFUDC accrued from July 2012 through the June 7, 2013 in-service date, the Company has limited the amount of Project investment on which a return will be earned in its calculations. Ms. Douglas explained that the retail jurisdictional portion of the $2.595 billion June 30, 2012 Hard Cost Cap amount was $2,404,075. She stated that the Additional AFUDC related to the Hard Cost Cap amount accrued on the accounting books from July 1, 2012, through the June 7, 2013 in-service date was $55,952,000. These amounts have not changed from what was filed in IGCC-12. In accordance with the terms of the 2012 Settlement Agreement, the Additional AFUDC amounts included for December 2012 through June 7, 2013, reflected a 15% reduction. In other words, only 85% of the Additional AFUDC applicable to the Hard Cost Cap amount plus Additional AFUDC has been included for accounting periods after November 30, 2012. The adjusted total of the retail jurisdictional Hard Cost Cap plus Additional AFUDC as of March 31, 2014, is $2,460,027,000. This amount was reduced by the retail jurisdictional retirements as of March 31, 2014 ($279,000) and by $83,592,000 of retail accumulated depreciation. The resulting net plant amount was $2,376,156,000.

The $1,441,000 retail jurisdictional portion of the post-in-service Ongoing Capital Projects was reduced by $9,000 of retail accumulated depreciation. The resulting net plant amount for Ongoing Capital Projects was $1,432,000.

The $2,377,588,000 total of the net Edwardsport investment and the Ongoing Capital Projects was multiplied by the Company's overall weighted average cost of capital of 6.52% as of March 31, 2014, which was computed consistent with traditional Indiana ratemaking. This includes deferred income taxes as a zero cost source of capital in the cost of capital construction. The deferred income tax amount includes the net impact of any income tax benefits or liabilities associated with the portion of the plant that customers will pay for under the terms of the 2012 Settlement Agreement, but excludes the net impact of any tax benefits or liabilities associated with the portion of the plant that shareholders will pay for under the terms of the 2012 Settlement

Agreement. The development of the cost of capital used in this calculation is shown on Page 11 of Petitioner's Exhibit B-2.

Ms. Douglas testified that the six-month jurisdictional revenue requirement for return on the qualified investment as of March 31, 2014, after revenue conversion, was $115,610,000. This is a $2,105,000 decrease from the amount proposed in IGCC-12.

Continuing her testimony, Ms. Douglas explained the calculation of the jurisdictional revenue requirement applicable to operating expenses including depreciation expense, tax credits, and amortizations. These operating expenses included: expenses incurred by the Company from October 2013 through March 2014 for services from Black & Veatch; the estimated retail jurisdictional portion of operating expenses (including O&M, fringe benefits, payroll taxes, and property insurance), net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expense that are forecasted to be incurred from October 2014 through March 2015; the estimated retail jurisdictional depreciation expense for the October 2014 through March 2015 six-month forecast period, including depreciation of in-service ongoing capital projects; a credit to retail customers of $17,587,500 ($35,175,000 on an annual basis), approved by the Commission in its Subdocket Order to reflect the jurisdictional impact of a change in depreciation rates for in-service plant, which took place effective January 1, 2013; a credit for the retail portion of one-half of the estimated State Tax Credit; a net amortization over three years of March 31, 2014, balances of the 2012 Settlement Agreement Regulatory Asset Commission-Ordered Regulatory Liability stemming from the IGCC 4S1 Order; and amortization of the post-in-service AFUDC accrued through March 31, 2014, also over a three-year period.

Ms. Douglas explained that the cost the Company incurred between October 2013 and March 2014 for services from Black & Veatch was $49,644. She stated that the Company forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Edwardsport steam generating facility, which were included in base rates, and of the retail jurisdictional property taxes in the amount of $32,238,872 for the period October 2014 through March 2015. She testified the Company forecasts retail jurisdictional depreciation expense of $50,857,000 for the October 2014 through March 2015 period. *See* Pet. Ex. B-2, p. 7. A credit of $17,587,500 reflecting the Credit for Effect of New Depreciation Rates and a credit of $6,884,250 reflecting the retail jurisdictional portion of one half of the annual estimated $15 million State Tax Credit have also been included.

Ms. Douglas also noted that the Company forecasts retail jurisdictional depreciation expense of in-service ongoing capital projects of $14,344 for the October 2014 through March 2015 period.

A net revenue requirement amount of $8,245,395 was included for the $13,367,360 revenue requirement for the amortization over three years of the $75,871,863 March 31, 2014 balance of operating expenses, including depreciation, deferred in the 2012 Settlement Agreement Regulatory Asset, net of the $5,121,965 amortization of the $30,731,789 Commission-Ordered Regulatory Liability established pursuant to the Commission's IGCC 4S1 order over three years.

Finally, Ms. Douglas stated that a revenue requirement of $669,901 has been included for the amortization of the $2,728,992 balance of post-in-service AFUDC as of March 31, 2014, over a three-year period consistent with the three-year period over which the 2012 Settlement Agreement Regulatory Asset and Commission-Ordered Regulatory Liability will be amortized. The accrual and recovery of post-in-service AFUDC was approved in Cause No. 43114. The post-in-service AFUDC has been computed using the 15% reduction in the AFUDC rate that was agreed to in term 2.B. of the 2012 Settlement Agreement. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.B., p. 2. Additional post-in-service AFUDC will accrue until all the Hard Cost Cap plus Additional AFUDC amounts and post-in-service AFUDC costs have been included in the IGCC Tracker or retail base rates.

Just as she did in her IGCC-12 testimony discussed above, Ms. Douglas again explained that the regulatory asset that was included in the calculation of revenue requirements included deferred expenses past the September 12, 2013 implementation of IGCC-10 rates because term 3 of the 2012 Settlement Agreement provided for the deferral (and recovery in the IGCC Tracker via amortization over a three-year period) of operating expenses, including depreciation, from the In-Service Operational Date of the IGCC facility until IGCC-10 rates were in effect. As a rate impact mitigation measure, Ms. Douglas stated that the 2012 Settlement Agreement provided that no estimated operating expenses should be included in Cause No. 43114 IGCC-9 rates and that any amounts incurred after the plant was in-service while IGCC-9 rates were being billed should be deferred in the Regulatory Asset and recovered over a three-year period rather than the standard six-month reconciliation period. Ms. Douglas testified that in the spirit of that rate mitigation measure, the Company desires to voluntarily continue to defer the operating expenses not recovered via IGCC-10 rates as a Regulatory Asset in order to avoid a large reconciliation variance amount which would need to be collected over a six-month tracker period in this or future IGCC Tracker filings covering reconciliation periods in which IGCC-10 rates are billed. By including these costs in the Regulatory Asset and amortizing them with the remainder of the costs deferred from June 7 through September 11, 2013, it will smooth out the impact of the under-collection that will occur due to the continued billing of IGCC-10 rates and serve to mitigate rate volatility. The March 31, 2014 Regulatory Asset balance the Company has amortized over three years therefore includes expenses deferred pursuant to the terms of the 2012 Settlement Agreement that were incurred from June 7 through September 11, 2013, and also incremental expenses incurred over the amount included in the IGCC-10 rates from September 12, 2013, through March 31, 2014. Additional incremental expenses will be deferred for each month IGCC-10 rates remain in effect and factored into the amortization amounts in the next IGCC Tracker filing (and the subsequent one, if needed). On behalf of the Company, Ms. Douglas requested that the Commission approve this treatment. She noted that the additional deferrals will cease if the Commission approves the Company's requested relief in the pending IGCC-11, IGCC-12, or in this case because the revenue requirements in these three proceedings included a full six months of operating expenses.

Ms. Douglas next explained how the operating expenses, depreciation expense (including the Credit for Effect of New Depreciation Rates), and the State Tax Credit were converted to revenue requirements and stated that the result was the inclusion of $71,761,993 in the calculation of the billing factors for this rider. *See* Pet. Ex. B-2, p. 6.

According to Ms. Douglas, Petitioner's Exhibit B-2, Page 7 details the support for the retail jurisdictional amount of forecasted depreciation expense and other operating expenses included in the revenue requirements calculation on Page 6 of Petitioner's Exhibit B-2. Ms. Douglas noted that the depreciation amount was reduced by 50% of the depreciation associated with the two RECB transmission projects for which reimbursement will be received from MISO's RECB process. Depreciation expense was calculated using the current Commission-approved depreciation rates for the FERC plant accounts to which the projects were assigned. She noted that as approved by the Commission in the CPCN Order, a monthly credit of $1/12^{th}$ of an annual amount of $5,756,000 was included to reduce the forecasted operating expenses. In accordance with the terms of the 2012 Settlement Agreement, the property tax estimate reflects 100% of the October 2014 through March 2015 benefit forecasted to be received for the ten-year property tax abatement from Knox County and the thirty-year reimbursement due to the designation of Edwardsport as a Tax Increment Financing District.

Ms. Douglas stated that Page 10 of Petitioner's Exhibit B-2 shows the calculation of the IGCC Revenue Adjustment Factors, by jurisdictional rate group, developed to recover the total revenue requirements for this filing of $187,371,993. This is an increase of approximately $3.3 million over the revenue requirements included in IGCC-12. The increase is driven by an increase in the amortization amount for additional operating expenses being deferred in the regulatory asset account due to the IGCC-10 rates currently being billed not covering the full level of operating expenses. Ms. Douglas explained that this increase is partially offset by the benefits of additional accumulated depreciation on the return component of the rider. Based on the Commission's CPCN Order, the Rate HLF adjustment factor has been developed on a non-coincident peak demand basis for the applicable period. The total jurisdictional revenue requirement for all other rate groups was divided by actual kilowatt-hour sales for the six-month period ending March 31, 2014, to arrive at the revenue adjustment factors per kilowatt-hour.

Similarly to her IGCC-12 testimony discussed above, Ms. Douglas explained the transitioning of certain lighting customers, stating that it does not affect the total retail peak demand or allocation to other customer classes.

Ms. Douglas testified that the rate migration adjustment included in her IGCC-12 testimony was based on the migration of customers and sales from the HLF rate schedule to the LLF rate schedule using data from 2008 through 2012. This adjustment resulted in approximately 50 MW moving from Rate HLF to Rate LLF. As she noted in her IGCC-12 testimony, the Company committed to continue to monitor the rate migrations between these two classes each year and to propose an update to the allocation factors if there was a net change of greater than 10 MW from the 2012 level. The Company has completed the 2013 monitoring and it resulted in an additional migration of approximately 26 MW, therefore, the Company has included this change to the HLF/LLF rate migration adjustment in the development of the rates in this proceeding.

Ms. Douglas noted that both of these adjustments will impact the "KW Share of System Peak (12CP)" amounts shown in Petitioner's Exhibits B-1, B-2, and B-4. *See* Pet. Ex. B-1, p. 4; Pet. Ex. B-2, p. 10; Pet. Ex. B-4, p. 3.

According to Ms. Douglas, these rate migrations are not one-time adjustments and the Company proposes to use both of these adjustments on a going-forward basis in this, and other riders, using historical demand allocations. In addition, the Company will continue to monitor the rate migrations between HLF and LLF each year and if there is a net change of greater than 10 MW from the current level, the Company would propose an update to the factors at that time.

Ms. Douglas noted that the reconciliation amounts in Columns F and H on Page 10 of Petitioner's Exhibit B-2 would normally contain an amount representing the reconciliation of amounts collected from customers from October 2013 through March 2014 to actual expenses and an additional amount representing the reconciliation of the voluntary credit adjustment provided to HLF customers in IGCC-11 to correct for an IGCC Tracker administration clerical error, which affected the rates that were proposed, approved, and billed to HLF customers under Cause No. 43114 IGCC-4 rates. However, the IGCC-11 rates have not yet been approved, so the credits included in the IGCC-11 rates have not yet been billed. Including a reconciliation in IGCC-13 would result in the building in of additional credits, which, if the Commission approved IGCC-11 rates for billing prior to the proposed IGCC-13 rates, would be refunded to customers in advance of the IGCC-13 rates. To avoid double refunds and future refund volatility, Ms. Douglas, on behalf of the Company, proposed to hold all additional reconciliations until the proposed IGCC-13 rates are in effect, after which a cumulative reconciliation will be completed in the next subsequent filing to ensure all costs and credits subject to reconciliation have been fully collected or refunded. As a result, no reconciliation amounts have been included in this filing, and Ms. Douglas, on behalf of the Company, requested that the Commission approve this proposed treatment.

Ms. Douglas next explained when CWIP ratemaking treatment for the IGCC Project will cease. She stated that consistent with 170 IAC 4-6-22 and in accordance with the CPCN Order, the IGCC Project will be deemed to be under construction, and Duke Energy Indiana will continue to receive revenues through Rider 61, until the Commission determines that this Project is used and useful in a proceeding that involves the establishment or investigation of Duke Energy Indiana's retail electric base rates and charges.

Ms. Douglas then stated that Petitioner's Exhibit B-3 shows the impact of the proposed IGCC ratemaking, should the Commission approve it, on the monthly bill of a typical residential customer using 1,000 kilowatt-hours. Upon approval of the proposed factors, the monthly bill of a residential customer using 1,000 kilowatt-hours will increase by $0.27, or approximately 0.3%, from the base bill plus the IGCC factor currently being billed to customers. This would be a decrease of $1.03, or approximately 1.2%, from the factors pending in IGCC-11. These changes for residential customers over current IGCC-10 rates and pending IGCC-11 rates are due primarily to much larger than normal residential sales during the period used to develop the IGCC-13 rates. They are not representative of other customer classes, which generally will see larger increases over both IGCC-10 and IGCC-11 rates due to the inclusion of the full six months of operating expenses and the amortization of the deferred operating expense.

Ms. Douglas concluded by noting that Duke Energy Indiana is proposing to update its Rider 61 Ninth Revised Sheet No. 61, Pages 1 through 5, should the Commission approve the Company's proposed rates. Upon approval, and upon Duke Energy Indiana's filing of the updated

Rider 61 with the Commission's Electricity Division, the proposed factor will be billed to customers for all bills rendered beginning on the effective date of the Commission's Order in this proceeding.

d. IURC Cause No. 43114 IGCC-14. Mr. Stultz provided the Commission with information about the operations of the Plant from April 1, 2014 through September 30, 2014 in his prefiled December 23, 2014 testimony. He also provided information that the Station performed consistently through the summer, with May, July and August 2014 being its highest months of generation since in-service until the station's fall maintenance outage, which began on September 6, 2014. During this reporting period, GE performed the contractually-required preliminary and final thermal performance tests in April and May 2014, respectively.

Edwardsport remained on its fall outage through September and the power block remained unavailable until October 1, with the gasifiers remaining unavailable until October 18, 2014, Upon returning to service, the Station operated reliably and consistently in November, performing the contractually-required ramping demonstration on November 2014. GE provided Duke Energy with a certificate of substantial completion in December 2014, indicating that GE considers Edwardsport to be substantially complete[8], and which Duke Energy accepted on December 17, 2014.

Next, Mr. Stultz explained the plant's operations from April until the fall maintenance outage. He discussed the Plant's availability, gasification availability and the focus on improving the consistency of Plant operations. He explained that the operational and equipment challenges have limited the Plant's generation during the first year of operations and that his team is learning to address the challenges, making improvements to prevent them in the future, and getting faster at restarting operations after the gasifiers trip or require shutting down. Mr. Stultz discussed the experience that his team is gaining with the particular challenges of the first integrated gasification combined cycle facility of its size and that he has the confidence that his team is up to the challenge and proud of the process made to date.

During this period, Mr. Stultz emphasized the strong Plant performance and explained the minor equipment issues leading up to the fall outage. He discussed the high pressure condenser vacuum pump "C" trip in April 2014 and the addition of an alarm in the control room to help prevent this type of cascading trip from occurring again; the gasifier trips in May and June due to boiler feedwater issues and how they were resolved by programming changes; and refrigeration compressor trips in the acid gas removal system in July causing both gasifiers to shut down.

Mr. Stultz described the work performed during the fall maintenance outage in detail. The fall maintenance outage was scheduled to begin on September 6, 2014 and end on September 21, 2014 for combustion turbine ("CT") 2 and on September 27, 2014 for gasifier 1. Gasifier 2 also came down on September 12, 2014 due to a radiant syngas cooler ("RSC") blow down leak, and ultimately the station decided to make CT 1 unavailable for a borescope inspection. During this time, two of the four pilots on the flare were repaired. He also explained that due to incorrect grease being applied to the liquid oxygen pump motors, the gasifiers were kept out-of-service after

[8] As defined by the Duke Energy/GE contract.

the scheduled maintenance and repair work was completed in order to mitigate the issue. Gasifier 2 was re-lit on October 18, with gasifier 1 on October 20.

Since the fall outage, Mr. Stultz described operations and that the Plant has operated consistently and reliably through November and that November was the highest month of generation since in-service.

Mr. Stultz described the operational statistics attached to his testimony as Petitioner's Exhibit A-1 and their meaning. He also provided his opinion on the trajectory of the Plant's performance as positive.

Continuing his testimony, Mr. Stultz provided an update on the status of GE's performance test stating that the preliminary performance test was completed on April 2, 2014 with the final performance test on May 15 and 16. GE also completed the final ramping demonstration on November 12, 2014. In December 2014, the Company received the final certificate of substantial completion from GE which indicates that Edwardsport has reached Substantial Completion,[9] which Duke Energy accepted on December 17, 2014. Mr. Stultz stated that it is anticipated reaching Final Completion in Spring 2015.

Mr. Stultz provided an update on issues he discussed in his IGCC-12 and IGCC-13 testimony, particularly the liquid nitrogen pumps and the remedial heat trace and insulation work.

Next, Mr. Stultz discussed the actual operating and maintenance expenses for this period included labor, chemicals, maintenance and outage costs and that these expenses were reasonable and prudently incurred. He emphasized that in conjunction with the 2012 Settlement Agreement, the Company has not sought to recover costs associated with NPI testing or performance testing because all these costs are subject to the Hard Cost Cap. He also described the forecasted operating and maintenance expenses the Company will be incurring.

Mr. Stultz walked through the ongoing capitalized repairs and maintenance expenditures that were completed during this period and that these projects were considered to be part of routine maintenance that is and will be performed at the plant on an on-going basis. He explained that the actual operating and maintenance expenses were in-line with his forecast provided in his IGCC-12 testimony. In general, the Company labor costs are predictable, however contract labor and expenses, material and supplies, and outage expenses will tend to be more variable depending on the timing and duration of outages and the nature of maintenance and repairs required, and that the emergent work is more difficult to provide budget projections for.

Ms. Douglas testified on behalf of the Company with respect to ratemaking issues relevant to the IGCC-14 time period. She explained that the purpose of her testimony was to explain the Company's request for timely recovery of costs in connection with the Company's IGCC Project, including CWIP ratemaking treatment for jurisdictional IGCC Project expenditures. Her testimony also shows the calculations used to develop the Company's proposed IGCC Revenue Adjustment Factor and includes an updated set of retail electric tariff pages applicable to the IGCC Tracker.

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[9] As defined by the Duke Energy/GE contract.

Ms. Douglas noted that her calculations were based on data recorded on the Company's books and in the Company's records as of September 30, 2014. Her testimony requested that the Commission approve: (1) the value of the IGCC facility, including the value of related post-in-service ongoing capital project expenditures, upon which the Company is requesting authorization to earn a return; (2) the amount of Duke Energy Indiana's expenditures for the IGCC facility and related ongoing capital project expenditures incurred through September 30, 2014, for which cost recovery is requested; (3) recovery of estimated operating expenses, net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expenses that are expected to be incurred from April through September 2015; (4) recovery of the estimated depreciation that will be incurred from April through September 2015, including depreciation of in-service ongoing capital projects; (5) the inclusion of a credit to retail customers in Rider 61 to reflect the jurisdictional impact of a change in depreciation rates for non-IGCC in-service plant, which took place effective January 1, 2013, and was approved in the IGCC 4S1 Order; (6) the inclusion of a credit for the retail portion of one-half of the Indiana Coal Gasification Technology Investment Tax Credit, estimated to be $15 million on an annual basis (the "State Tax Credit"); (7) the inclusion of a net amortization of deferred operating expenses, including depreciation, associated with the production portion of the plant from June 7, 2013, through September 30, 2014, which have been deferred in the 2012 Settlement Agreement Regulatory Asset, and of the Commission-Ordered Regulatory Liability established pursuant to the IGCC 4S1 Order; (8) the inclusion of the amortization of post-in-service AFUDC accrued through September 30, 2014, over the same three-year period being used to amortize the deferred operating expenses; and (9) that Petitioner's retail electric rates be adjusted, via Rider 61, to include the revenue effect of such investment, cost recovery, credits, and amortizations.

Ms. Douglas described Petitioner's Exhibit B-1, Duke Energy Indiana's Rider 61, of which the Company is requesting approval. Rider 61 was last updated and approved by the Commission on September 11, 2013, in IGCC-10. Rider 61 includes definitions of the various components of the formula that was used to develop the IGCC Revenue Adjustment Factors, a formulaic representation of the calculations used to develop the proposed factors, revenue adjustment factors by retail rate group based on data as of September 30, 2014, a listing of retail allocation factors used to allocate the jurisdictional revenue requirement to various rate groups (based on data from the Company's cost of service study approved in Cause No. 42349, as adjusted to reflect the impact of customer migrations between the HLF and LLF industrial rate classes and also between the AL, OL, and UOLS lighting rate classes), and the billing cycle kWh and/or non-coincident peak demands used to develop the proposed IGCC Revenue Adjustment Factors. Petitioner's Exhibit B-1 also contains the tariff revisions that were proposed in IGCC-13 and an additional modification to the language regarding rate migrations to include the additional rate migration for certain lighting rate classes and to the amount of the HLF/LLF rate migration.

Ms. Douglas also explained Petitioner's Exhibit B-2, which sets forth schedules for the IGCC Project and includes data consistent with the requirements of 170 IAC 4-6-12 and the Commission's Orders in Cause Nos. 43114, 43114 S1, 43114 IGCC-1, and subsequent orders, and with the terms of the 2012 Settlement Agreement and Subdocket Order. Exhibit B-2 includes actual in-service dates for the transmission system and production plant projects; total expenditures for the Project as of September 30, 2014, subject to CWIP ratemaking treatment;

Project expenditures applicable to the wholesale jurisdiction; retail IGCC facility investment as of September 30, 2014; the amount of retail AFUDC included in the cost of the Project; and, the total amount of AFUDC included in the cost of the Project.

Ms. Douglas explained the ratemaking treatment for the costs of four Project-related transmission projects that were included in the approved cost estimate for the Project in Petitioner's Exhibit B-2. Ms. Douglas stated that for the IGCC-related transmission projects that qualify as part of MISO's transmission expansion plan and are recognized by MISO as RECB projects, the Company will first seek cost recovery pursuant to its Rider No. 68 and MISO's Schedule 26, consistent with the Commission's June 25, 2008 Order in Cause No. 42736 RTO-14. If, and to the extent that, costs for an IGCC-related transmission project are not eligible for, and cannot be recovered through, Rider No. 68 and Schedule 26, then the Company will seek cost recovery for such project (or portion of a project) through the IGCC Tracker. MISO will provide a 50% reimbursement for the two IGCC-related RECB projects, therefore, the Company has included as part of the value of the IGCC plant for CWIP ratemaking treatment the remaining 50% of the value of these projects that will not be reimbursed by MISO. Accordingly, Page 1 of Petitioner's Exhibit B-2 shows the expenditures for the two RECB projects, including the reduction in IGCC Plant costs by the 50% amount for which the Company will be reimbursed by MISO through the RECB process. The IGCC-related transmission projects that are not RECB projects are also shown on page 1 of Petitioner's Exhibit B-2, and the full costs for these projects have been considered in IGCC Tracker ratemaking.

Ms. Douglas stated that Page 2 of Petitioner's Exhibit B-2 shows the amount of accumulated depreciation as of September 30, 2014, applicable to the recoverable in-service IGCC Project investment. The accumulated depreciation for the two RECB transmission projects has been reduced by the 50% MISO RECB reimbursement amount. The jurisdictional accumulated depreciation applicable to the jurisdictional Project investment as of September 30, 2014, after reductions to reflect retired plant associated with the in-service Ongoing Capital Projects, is $131,010,158.

Page 3 of Petitioner's Exhibit B-2 includes the total expenditures as of September 30, 2014, for certain ongoing capital projects related to the IGCC facility. The Company is requesting approval for CWIP ratemaking treatment and cost recovery of the retail jurisdictional portion of the ongoing capital projects' costs. Ms. Douglas explained that the costs of these projects were not included in the approved estimate for the Project and the costs have arisen as part of the normal operation of the plant since its June 7, 2013 in-service date. These projects were not identified during start-up, testing, validation, and commissioning as being necessary to reach "final completion" as defined in the 2012 Settlement Agreement. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.E., p. 3. The 2012 Settlement Agreement contemplated such post-in-service ongoing capital projects that would not be subject to Hard Cost Cap and that would be subject to retail rate recovery. The jurisdictional balance of the Company's investment in these post-in-service ongoing capital projects at the IGCC facility subject to CWIP ratemaking treatment is $5,046,000, as of September 30, 2014.

Just as she explained in her IGCC-13 testimony, Ms. Douglas again testified that it was appropriate to include these ongoing capital project costs in the IGCC Tracker because the costs are incremental costs incurred post-in-service to enable to reliable operation of the Plant, the same as the O&M costs included in the tracker. Because the work completed for these projects includes the installation or replacement of a unit of property, the FERC's Uniform System of Accounts requires electric utilities to account for the cost in the appropriate electric plant account and recover the cost over the life of the equipment via depreciation, rather than expensing the cost in an O&M account. If the costs were not a unit of property, they would be recovered as incremental O&M costs in the tracker as the expenses are incurred. Therefore, it is appropriate that such post-in-service capital projects receive timely recovery via the tracker. Timely recovery includes a return on the retail jurisdictional portion of the investment to cover financing costs, as well as recovery on the investment over its life via depreciation expense in the tracker, once the capital project is in-service.

To determine whether something is a retirement unit that must be capitalized, Ms. Douglas stated that the Company maintains a written property units listing for use in accounting for additions and retirements of electric plant, as required by FERC. This listing is applied consistently in determining whether additions or replacements of equipment during maintenance should be capitalized or expensed. Because everything the Company owns is either a retirement unit or a minor item of property, if the item is not specifically identified as a retirement unit on the property listing, then it is, by default, a minor item.

Ms. Douglas explained that the cost of ongoing capital projects was not included in the Hard Cost Cap because the 2012 Settlement Agreement specifically excluded these costs. The 2012 Settlement Agreement established that such "ongoing additions, replacements, and maintenance capital expenditures made separate and apart from and not including the Construction Costs" could be included in "future retail electric base rate cases and riders." 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.C., p.3. Because the first costs were incurred during the period covered by IGCC-12, the Company requested approval to begin including the costs in Rider 61 in IGCC-12.

Because some of these ongoing capital projects were in-service for accounting purposes as of September 30, 2014, Ms. Douglas explained that accumulated depreciation and depreciation expenses have been included in the development of revenue requirements for this filing for such in-service projects on Pages 4 and 9 of Petitioner's Exhibit B-2.

Ms. Douglas explained that as a result of these ongoing capital projects, there were retirements of other plant that is already included in the IGCC tracker. Ms. Douglas stated that the retirements were reflected in the tracker as they are handled on the accounting books and records.

Ms. Douglas then stated that the Company has approval to include similar capital projects and retirements in other rate riders because the Commission first approved inclusion of capital maintenance projects and reflection of retirements of plant in its order in Cause No. 42601-ECR 18 for costs included in Standard Contract Rider No. 62 – Qualified Pollution Control Property Revenue Adjustment and Standard Contract Rider No. 71 – Clean Coal Operating Cost Revenue Adjustment. The Company intends to treat the normal capitalized repairs and maintenance, and any additional plant and equipment necessary for the continued operation of the Station, in the same manner as it does for tracked equipment in its ECR proceedings.

Ms. Douglas explained that Page 4 of Petitioner's Exhibit B-2 shows the amount of accumulated depreciation as of September 30, 2014, applicable to the jurisdictional portion of the ongoing capital projects that are in-service. The jurisdictional portion of the ongoing capital projects investment as of September 30, 2014 is $31,000.

Page 5 of Petitioner's Exhibit B-2 develops the jurisdictional revenue requirements for the return on the net jurisdictional investment in the IGCC Plant and Ongoing Capital Projects. Because the retail jurisdictional portion of the total construction costs exceeded the $2.595 billion June 30, 2012 Hard Cost Cap amount plus applicable Additional AFUDC accrued from July 2012 through the June 7, 2013 in-service date, the Company has limited the amount of Project investment on which a return will be earned in its calculations. Ms. Douglas explained that the retail jurisdictional portion of the $2.595 billion June 30, 2012 Hard Cost Cap amount was $2,404,075. She stated that the Additional AFUDC related to the Hard Cost Cap amount accrued on the accounting books from July 1, 2012, through the June 7, 2013 in-service date was $55,952,000. These amounts have not changed from what was filed in IGCC-12 and IGCC-13. In accordance with the terms of the 2012 Settlement Agreement, the Additional AFUDC amounts included for December 2012 through June 7, 2013, reflected a 15% reduction. In other words, only 85% of the Additional AFUDC applicable to the Hard Cost Cap amount plus Additional AFUDC has been included for accounting periods after November 30, 2012. The adjusted total of the retail jurisdictional Hard Cost Cap plus Additional AFUDC as of September 30, 2014, is $2,460,027,000. This amount was reduced by the retail jurisdictional retirements as of September 30, 2014 ($3,702,000) and by $131,010,000 of retail accumulated depreciation. The resulting net plant amount was $2,325,315,000.

The $5,046,000 retail jurisdictional portion of the post-in-service Ongoing Capital Projects was reduced by $31,000 of retail accumulated depreciation. The resulting net plant amount for Ongoing Capital Projects was $5,015,000.

The $2,330,330,000 total of the net Edwardsport investment and the Ongoing Capital Projects was multiplied by the Company's overall weighted average cost of capital of 6.31% as of September 30, 2014, which was computed consistent with traditional Indiana ratemaking. This includes deferred income taxes as a zero cost source of capital in the cost of capital construction. The deferred income tax amount includes the net impact of any income tax benefits or liabilities associated with the portion of the plant that customers will pay for under the terms of the 2012 Settlement Agreement, but excludes the net impact of any tax benefits or liabilities associated with the portion of the plant that shareholders will pay for under the terms of the 2012 Settlement Agreement. The development of the cost of capital used in this calculation is shown on Page 11 of Petitioner's Exhibit B-2.

Ms. Douglas testified that the six-month jurisdictional revenue requirement for return on the qualified investment as of September 30, 2014, after revenue conversion, was $108,710,000. This is a $6,900,000 decrease from the amount proposed in IGCC-13.

Continuing her testimony, Ms. Douglas explained the calculation of the jurisdictional revenue requirement applicable to operating expenses including depreciation expense, tax credits, and amortizations. These operating expenses included: expenses incurred by the Company from April through September 2014; the estimated retail jurisdictional portion of operating expenses (including O&M, fringe benefits, payroll taxes, and property insurance), net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expense that are forecasted to be incurred from April through September 2015; the estimated retail jurisdictional depreciation expense for the April through September 2015 six-month forecast period, including depreciation of in-service ongoing capital projects; a credit to retail customers of $17,587,500 ($35,175,000 on an annual basis), approved by the Commission in its Subdocket Order to reflect the jurisdictional impact of a change in depreciation rates for in-service plant, which took place effective January 1, 2013; a credit for the retail portion of one-half of the estimated State Tax Credit; a net amortization over three years of September 30, 2014, balances of the 2012 Settlement Agreement Regulatory Asset Commission-Ordered Regulatory Liability stemming from the IGCC 4S1 Order; and amortization of the post-in-service AFUDC accrued through September 30, 2014, also over a three-year period.

Ms. Douglas stated that the Company forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Edwardsport steam generating facility, which were included in base rates, and of the retail jurisdictional property taxes in the amount of $33,384,296 for the period April through September 2015. She testified the Company forecasts retail jurisdictional depreciation expense of $50,770,240 for the April through September 2015 period. *See* Pet. Ex. B-2, p. 7. A credit of $17,587,500 reflecting the Credit for Effect of New Depreciation Rates and a credit of $7,518,427 reflecting the retail jurisdictional portion of one half of the annual estimated $15 million State Tax Credit have also been included.

Ms. Douglas also noted that the Company forecasts retail jurisdictional depreciation of in-service Ongoing Capital Projects of $77,877 for the April through September 2015 period.

A net revenue requirement amount of $14,817,482 was included for the $19,939,447 revenue requirement for the amortization over three years of the $79,705,434 September 30, 2014 balance of operating expenses, including depreciation, deferred in the 2012 Settlement Agreement Regulatory Asset, net of the $14,617,482 amortization of the Commission-Ordered Regulatory Liability established pursuant to the Commission's IGCC 4S1 order over three years.

Finally, Ms. Douglas stated that a revenue requirement of $965,131 has been included for the amortization of the $2,728,992 balance of post-in-service AFUDC as of September 30, 2014, over a three-year period consistent with the three-year period over which the 2012 Settlement Agreement Regulatory Asset and Commission-Ordered Regulatory Liability will be amortized. The accrual and recovery of post-in-service AFUDC was approved in Cause No. 43114. The post-in-service AFUDC has been computed using the 15% reduction in the AFUDC rate that was agreed to in term 2.B. of the 2012 Settlement Agreement. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.B., p. 2. Additional post-in-service AFUDC will accrue until all the Hard Cost Cap plus Additional AFUDC amounts and post-in-service AFUDC costs have been included in the IGCC Tracker or retail base rates.

Just as she did in her IGCC-13 testimony discussed above, Ms. Douglas again explained that the regulatory asset that was included in the calculation of revenue requirements included deferred expenses past the September 12, 2013 implementation of IGCC-10 rates because term 3 of the 2012 Settlement Agreement provided for the deferral (and recovery in the IGCC Tracker via amortization over a three-year period) of operating expenses, including depreciation, from the In-Service Operational Date of the IGCC facility until IGCC-10 rates were in effect. As a rate impact mitigation measure, Ms. Douglas stated that the 2012 Settlement Agreement provided that no estimated operating expenses should be included in Cause No. 43114 IGCC-9 rates and that any amounts incurred after the plant was in-service while IGCC-9 rates were being billed should be deferred in the Regulatory Asset and recovered over a three-year period rather than the standard six-month reconciliation period. Ms. Douglas testified that in the spirit of that rate mitigation measure, the Company desires to voluntarily continue to defer the operating expenses not recovered via IGCC-10 rates as a Regulatory Asset in order to avoid a large reconciliation variance amount which would need to be collected over a six-month tracker period in this or future IGCC Tracker filings covering reconciliation periods in which IGCC-10 rates are billed. By including these costs in the Regulatory Asset and amortizing them with the remainder of the costs deferred from June 7 through September 11, 2013, it will smooth out the impact of the under-collection that will occur due to the continued billing of IGCC-10 rates and serve to mitigate rate volatility. The September 30, 2014 Regulatory Asset balance the Company has amortized over three years therefore includes expenses deferred pursuant to the terms of the 2012 Settlement Agreement that were incurred from June 7 through September 11, 2013, and also incremental expenses incurred over the amount included in the IGCC-10 rates from September 12, 2013, through March 31, 2014. Additional incremental expenses will be deferred for each month IGCC-10 rates remain in effect and factored into the amortization amounts in the next IGCC Tracker filing (and the subsequent one, if needed). On behalf of the Company, Ms. Douglas requested that the Commission approve this treatment. She noted that the additional deferrals will cease if the Commission approves the Company's requested relief in the pending IGCC-11, IGCC-12, IGCC-13, or in this case because the revenue requirements in these three proceedings included a full six months of operating expenses.

Ms. Douglas next explained how the operating expenses, depreciation expense (including the Credit for Effect of New Depreciation Rates), and the State Tax Credit were converted to revenue requirements and stated that the result was the inclusion of $79,705,434 in the calculation of the billing factors for this rider. *See* Pet. Ex. B-2, p. 6.

According to Ms. Douglas, Petitioner's Exhibit B-2, Page 7 details the support for the retail jurisdictional amount of forecasted depreciation expense and other operating expenses included in the revenue requirements calculation on Page 6 of Petitioner's Exhibit B-2. Ms. Douglas noted that the depreciation amount was reduced by 50% of the depreciation associated with the two RECB transmission projects for which reimbursement will be received from MISO's RECB process. Depreciation expense was calculated using the current Commission-approved depreciation rates for the FERC plant accounts to which the projects were assigned. She noted that as approved by the Commission in the CPCN Order, a monthly credit of 1/12th of an annual amount of $5,756,000 was included to reduce the forecasted operating expenses. In accordance with the terms of the 2012 Settlement Agreement, the property tax estimate reflects 100% of the April through September 2015 benefit forecasted to be received for the ten-year property tax abatement from Knox County and the thirty-year reimbursement due to the designation of Edwardsport as a Tax Increment Financing District.

Ms. Douglas stated that Page 10 of Petitioner's Exhibit B-2 shows the calculation of the IGCC Revenue Adjustment Factors, by jurisdictional rate group, developed to recover the total revenue requirements for this filing of $188,415,434. This is an increase of approximately $1.0 million over the revenue requirements included in IGCC-13. The increase is driven by an increase in the amortization amount for additional operating expenses being deferred in the regulatory asset account due to the IGCC-10 rates currently being billed not covering the full level of operating expenses. Ms. Douglas explained that this increase is partially offset by the benefits of additional accumulated depreciation on the return component of the rider. Based on the Commission's CPCN Order, the Rate HLF adjustment factor has been developed on a non-coincident peak demand basis for the applicable period. The total jurisdictional revenue requirement for all other rate groups was divided by actual kilowatt-hour sales for the six-month period ending September 30, 2014, to arrive at the revenue adjustment factors per kilowatt-hour.

Similarly to her IGCC-13 testimony discussed above, Ms. Douglas explained the transitioning of certain lighting customers, stating that it does not affect the total retail peak demand or allocation to other customer classes.

Ms. Douglas testified that the rate migration adjustment included in her IGCC-12 testimony was based on the migration of customers and sales from the HLF rate schedule to the LLF rate schedule using data from 2008 through 2012.

Ms. Douglas noted that the reconciliation amounts in Columns F and H on Page 10 of Petitioner's Exhibit B-2 would normally contain an amount representing the reconciliation of amounts collected from customers from April through September 2014 to actual expenses (or credits) and an additional amount representing the reconciliation of the voluntary credit adjustment provided to HLF customers in IGCC-12 to correct for an IGCC Tracker administration clerical error, which affected the rates that were proposed, approved, and billed to HLF customers under Cause No. 43114 IGCC-4 rates. However, the IGCC-12 rates have not yet been approved, so the expenses and credits included in the IGCC-12 rates have not yet been billed. To avoid double refunds and future refund volatility, Ms. Douglas, on behalf of the Company, proposed to hold all additional reconciliations until the proposed IGCC-13 rates are in effect, after which a cumulative reconciliation will be completed in the next subsequent filing to ensure all costs and credits subject to reconciliation have been fully collected or refunded. As a result, no reconciliation amounts have been included in this filing, and Ms. Douglas, on behalf of the Company, requested that the Commission approve this proposed treatment.

Ms. Douglas next explained when CWIP ratemaking treatment for the IGCC Project will cease. She stated that consistent with 170 IAC 4-6-22 and in accordance with the CPCN Order, the IGCC Project will be deemed to be under construction, and Duke Energy Indiana will continue to receive revenues through Rider 61, until the Commission determines that this Project is used and useful in a proceeding that involves the establishment or investigation of Duke Energy Indiana's retail electric base rates and charges.

Ms. Douglas then stated that Petitioner's Exhibit B-3 shows the impact of the proposed IGCC ratemaking, should the Commission approve it, on the monthly bill of a typical residential customer using 1,000 kilowatt-hours. Upon approval of the proposed factors, the monthly bill of a residential customer using 1,000 kilowatt-hours will increase by $4.44, or approximately 5.1%, from the base bill plus the IGCC factor currently being billed to customers. This would be an increase of $4.17, or approximately 4.7% from the factors pending in IGCC-13. This increase is driven by the much larger than normal residential sales during the IGCC-13 period as compared to residential sales during the IGCC-14 period. Revenue requirements allocated to residential customers are roughly the same between IGCC-13 and IGCC-14, however, the lower billing determinant in IGCC-14 has resulted in a higher calculated IGCC factor. This increase is not representative of other customer classes. Most industrial customers will see lower rates for IGCC-14 than IGCC-13. The revenue requirements for IGCC-11 through IGCC-14 all included the full level of operating expenses for Edwardsport, but the IGCC-10 rates currently being billed only included 4/6^{ths} of the operating expenses, so all customers can expect an increase from the IGCC-10 rates currently being paid.

Ms. Douglas concluded by noting that Duke Energy Indiana is proposing to update its Rider 61 Tenth Revised Sheet No. 61, Pages 1 through 5, should the Commission approve the Company's proposed rates. Upon approval, and upon Duke Energy Indiana's filing of the updated Rider 61 with the Commission's Electricity Division, the proposed factor will be billed to customers for all bills rendered beginning on the effective date of the Commission's Order in this proceeding.

e. IURC Cause No. 43114 IGCC-15. Mr. Stultz provided testimony on the operations of the Plant from October 2014 through March 2015 as well as on the operating and maintenance costs, the forecasted operating and maintenance budget and the ongoing capitalized repairs and maintenance expenditures.

Mr. Stultz testified that at the beginning of this reporting period, the Plant was still on its fall 2014 maintenance outage that began on September 6, 2014 and continued into October with the power block being available on October 1, and the gasifiers on October 18, 2014. He explained that the majority of the heat trace and insulation deficiencies have been mostly resolved. The spring 2015 outage on the unit 1 gasifier began on April 4 and on gasifier unit 2 on April 7 with the full power block available and on-line starting May 15, 2015, and cleared at MISO while being offered with a commit status of Economic on natural gas when the gasifiers were still unavailable.

During this reporting period, Mr. Stultz testified that there were two issues that impacted gasifier availability involving the ASU and the slurry charge pumps. There was an incident of slag build up and pluggage on train 1 related to a failed valve in the lockhopper. Mr. Stultz detailed the issues experienced with the slurry charge pumps and that he considers both managing erosion and corrosion to be long-term maintenance challenges for the Plant. He explained that the more experience with operations and data from the mechanical integrity program, the better they will be at determining the useful lives of the piping and valves in these systems and allowing the performance of predictive maintenance rather than forced or unplanned maintenance.

Next, Mr. Stultz explained the issues experienced with the ASU during this period. He testified that the ASU is one of the main impactors of gasification availability and requires a diligent effort by station personnel and the manufacturer to find and resolve issues that will result in high performance of the ASU. Mr. Stultz also provided on update on the issues with the liquid nitrogen pumps.

Mr. Stultz also discussed the 71 day run on gasifier 2 and that the station does not expect a run much longer than this. He explained that the station's feed injectors are only designed for 100 days of run time at a time.

Mr. Stultz described the operational statistics attached to his testimony as Petitioner's Exhibit C-1 and their meaning. He also states that has been pleased with the Plant's operations and that his team is now focused on the reliability of the station.

Next, Mr. Stultz discussed the actual operating and maintenance expenses for this period included labor, chemicals, maintenance and outage costs and that these expenses were reasonable and prudently incurred. He explained that the Plant's actual expenses have increased recently when compared to his forecasted budget[10], due to an increase in contract labor and expenses with the intent of reducing operational risks, but that he intends to address that increase through the hiring of additional employees, which will be more cost effective.

Mr. Stultz walked through the ongoing capitalized repairs and maintenance expenditures that were completed during this period and that these projects were considered to be part of routine maintenance that is and will be performed at the plant on an on-going basis. He explained that the forecast in this proceeding is similar to the actual expenditures, but for employee labor and expenses, which is expected to increase. Mr. Stultz also explained that sometimes there will be differences between the timing of forecasted and actual outage expenses.

Ms. Douglas testified on behalf of the Company with respect to ratemaking issues relevant to the IGCC-15 time period. She explained that the purpose of her testimony was to explain the Company's request for timely recovery of costs in connection with the Company's IGCC Project, including CWIP ratemaking treatment for jurisdictional IGCC Project expenditures. Her testimony also shows the calculations used to develop the Company's proposed IGCC Revenue Adjustment Factor and includes an updated set of retail electric tariff pages applicable to the IGCC Tracker.

Ms. Douglas noted that her calculations were based on data recorded on the Company's books and in the Company's records as of March 31, 2015. Her testimony requested that the Commission approve: (1) the value of the IGCC facility, including the value of related post-in-service ongoing capital project expenditures, upon which the Company is requesting authorization to earn a return; (2) the amount of Duke Energy Indiana's expenditures for the IGCC facility and related ongoing capital project expenditures incurred through March 31, 2015, for which cost recovery is requested; (3) recovery of estimated operating expenses, net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expenses that are expected to be incurred from October 2015 through March 2016; (4) recovery of the estimated depreciation that will be incurred from October 2015 through March 2016, including depreciation of in-service ongoing capital projects; (5) the inclusion of a credit to retail customers

[10] *See*, Petitioner's Exhibit C-1, Section 3.

in Rider 61 to reflect the jurisdictional impact of a change in depreciation rates for non-IGCC in-service plant, which took place effective January 1, 2013, and was approved in the IGCC 4S1 Order; (6) the inclusion of a credit for the retail portion of one-half of the Indiana Coal Gasification Technology Investment Tax Credit, estimated to be $15 million on an annual basis (the "State Tax Credit"); (7) the inclusion of a net amortization of deferred operating expenses, including depreciation, associated with the production portion of the plant from June 7, 2013, through March 31, 2015, which have been deferred in the 2012 Settlement Agreement Regulatory Asset, and of the Commission-Ordered Regulatory Liability established pursuant to the IGCC 4S1 Order; (8) the inclusion of the amortization of post-in-service AFUDC accrued through March 31, 2015, over the same three-year period being used to amortize the deferred operating expenses; and (9) that Petitioner's retail electric rates be adjusted, via Rider 61, to include the revenue effect of such investment, cost recovery, credits, and amortizations.

Ms. Douglas described Petitioner's Exhibit B-1, Duke Energy Indiana's Rider 61, of which the Company is requesting approval. Rider 61 was last updated and approved by the Commission on September 11, 2013, in IGCC-10. Rider 61 includes definitions of the various components of the formula that was used to develop the IGCC Revenue Adjustment Factors, a formulaic representation of the calculations used to develop the proposed factors, revenue adjustment factors by retail rate group based on data as of March 31, 2015, a listing of retail allocation factors used to allocate the jurisdictional revenue requirement to various rate groups (based on data from the Company's cost of service study approved in Cause No. 42349, as adjusted to reflect the impact of customer migrations between the HLF and LLF industrial rate classes and also between the AL, OL, and UOLS lighting rate classes), and the billing cycle kWh and/or non-coincident peak demands used to develop the proposed IGCC Revenue Adjustment Factors. Petitioner's Exhibit B-1 also contains the tariff revisions that were proposed in IGCC-13 and an additional modification to the language regarding rate migrations to include the additional rate migration for certain lighting rate classes and to the amount of the HLF/LLF rate migration.

Ms. Douglas also explained Petitioner's Exhibit D-2, which sets forth schedules for the IGCC Project and includes data consistent with the requirements of 170 IAC 4-6-12 and the Commission's Orders in Cause Nos. 43114, 43114 S1, 43114 IGCC-1, and subsequent orders, and with the terms of the 2012 Settlement Agreement and Subdocket Order. Exhibit D-2 includes actual in-service dates for the transmission system and production plant projects; total expenditures for the Project as of March 31, 2015, subject to CWIP ratemaking treatment; Project expenditures applicable to the wholesale jurisdiction; retail IGCC facility investment as of March 31, 2015; the amount of retail AFUDC included in the cost of the Project; and, the total amount of AFUDC included in the cost of the Project.

Ms. Douglas explained the ratemaking treatment for the costs of four Project-related transmission projects that were included in the approved cost estimate for the Project in Petitioner's Exhibit D-2. Ms. Douglas stated that for the IGCC-related transmission projects that qualify as part of MISO's transmission expansion plan and are recognized by MISO as RECB projects, the Company will first seek cost recovery pursuant to its Rider No. 68 and MISO's Schedule 26, consistent with the Commission's June 25, 2008 Order in Cause No. 42736 RTO-14. If, and to the extent that, costs for an IGCC-related transmission project are not eligible for, and cannot be recovered through, Rider No. 68 and Schedule 26, then the Company will seek cost recovery for such project (or portion of a project) through the IGCC Tracker. MISO will provide a 50% reimbursement for the two IGCC-related RECB projects, therefore, the Company has included as part of the value of the IGCC plant for CWIP ratemaking treatment the remaining 50% of the value of these projects that will not be reimbursed by MISO. Accordingly, Page 1 of Petitioner's Exhibit D-2 shows the expenditures for the two RECB projects, including the reduction in IGCC Plant costs by the 50% amount for which the Company will be reimbursed by MISO through the RECB process. The IGCC-related transmission projects that are not RECB projects are also shown on page 1 of Petitioner's Exhibit D-2, and the full costs for these projects have been considered in IGCC Tracker ratemaking.

Ms. Douglas stated that Page 2 of Petitioner's Exhibit D-2 shows the amount of accumulated depreciation as of March 31, 2015, applicable to the recoverable in-service IGCC Project investment. The accumulated depreciation for the two RECB transmission projects has been reduced by the 50% MISO RECB reimbursement amount. The jurisdictional accumulated depreciation applicable to the jurisdictional Project investment as of March 31, 2015, after reductions to reflect retired plant associated with the in-service Ongoing Capital Projects, is $165,677,972.

Page 3 of Petitioner's Exhibit D-2 includes the total expenditures as of March 31, 2015, for certain ongoing capital projects related to the IGCC facility. The Company is requesting approval for CWIP ratemaking treatment and cost recovery of the retail jurisdictional portion of the ongoing capital projects' costs. Ms. Douglas explained that the costs of these projects were not included in the approved estimate for the Project and the costs have arisen as part of the normal operation of the plant since its June 7, 2013 in-service date. These projects were not identified during start-up, testing, validation, and commissioning as being necessary to reach "final completion" as defined in the 2012 Settlement Agreement. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.E., p. 3. The 2012 Settlement Agreement contemplated such post-in-service ongoing capital projects that would not be subject to Hard Cost Cap and that would be subject to retail rate recovery. The jurisdictional balance of the Company's investment in these post-in-service ongoing capital projects at the IGCC facility subject to CWIP ratemaking treatment is $37,137,000, as of March 31, 2015.

Just as she explained in her IGCC-14 testimony, Ms. Douglas again testified that it was appropriate to include these ongoing capital project costs in the IGCC Tracker because the costs are incremental costs incurred post-in-service to enable to reliable operation of the Plant, the same as the O&M costs included in the tracker. Because the work completed for these projects includes the installation or replacement of a unit of property, the FERC's Uniform System of Accounts requires electric utilities to account for the cost in the appropriate electric plant account and recover the cost over the life of the equipment via depreciation, rather than expensing the cost in an O&M account. If the costs were not a unit of property, they would be recovered as incremental O&M costs in the tracker as the expenses are incurred. Therefore, it is appropriate that such post-in-service capital projects receive timely recovery via the tracker. Timely recovery includes a return on the retail jurisdictional portion of the investment to cover financing costs, as well as recovery on the investment over its life via depreciation expense in the tracker, once the capital project is in-service.

To determine whether something is a retirement unit that must be capitalized, Ms. Douglas stated that the Company maintains a written property units listing for use in accounting for additions and retirements of electric plant, as required by FERC. This listing is applied consistently in determining whether additions or replacements of equipment during maintenance should be capitalized or expensed. Because everything the Company owns is either a retirement unit or a minor item of property, if the item is not specifically identified as a retirement unit on the property listing, then it is, by default, a minor item.

Ms. Douglas explained that the cost of ongoing capital projects was not included in the Hard Cost Cap because the 2012 Settlement Agreement specifically excluded these costs. The 2012 Settlement Agreement established that such "ongoing additions, replacements, and maintenance capital expenditures made separate and apart from and not including the Construction Costs" could be included in "future retail electric base rate cases and riders." 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.C., p.3. Because the first costs were incurred during the period covered by IGCC-12, the Company requested approval to begin including the costs in Rider 61 in IGCC-12.

Because some of these ongoing capital projects were in-service for accounting purposes as of March 31, 2015, Ms. Douglas explained that accumulated depreciation and depreciation expenses have been included in the development of revenue requirements for this filing for such in-service projects on Pages 4 and 9 of Petitioner's Exhibit D-2.

Ms. Douglas explained that as a result of these ongoing capital projects, there were retirements of other plant that is already included in the IGCC tracker. Ms. Douglas stated that the retirements were reflected in the tracker as they are handled on the accounting books and records.

Ms. Douglas then stated that the Company has approval to include similar capital projects and retirements in other rate riders because the Commission first approved inclusion of capital maintenance projects and reflection of retirements of plant in its order in Cause No. 42601-ECR 18 for costs included in Standard Contract Rider No. 62 – Qualified Pollution Control Property Revenue Adjustment and Standard Contract Rider No. 71 – Clean Coal Operating Cost Revenue Adjustment. The Company intends to treat the normal capitalized repairs and maintenance, and any additional plant and equipment necessary for the continued operation of the Station, in the same manner as it does for tracked equipment in its ECR proceedings.

Ms. Douglas explained that Page 4 of Petitioner's Exhibit D-2 shows the amount of accumulated depreciation as of March 31, 2015, applicable to the jurisdictional portion of the ongoing capital projects that are in-service. The jurisdictional portion of the ongoing capital projects investment as of March 31, 2015 is $448,000.

Page 5 of Petitioner's Exhibit D-2 develops the jurisdictional revenue requirements for the return on the net jurisdictional investment in the IGCC Plant and Ongoing Capital Projects. Because the retail jurisdictional portion of the total construction costs exceeded the $2.595 billion June 30, 2012 Hard Cost Cap amount plus applicable Additional AFUDC accrued from July 2012 through the June 7, 2013 in-service date, the Company has limited the amount of Project investment on which a return will be earned in its calculations. Ms. Douglas explained that the retail jurisdictional portion of the $2.595 billion June 30, 2012 Hard Cost Cap amount was $2,404,075,000. She stated that the Additional AFUDC related to the Hard Cost Cap amount accrued on the accounting books from July 1, 2012, through the June 7, 2013 in-service date was $55,952,000. These amounts have not changed from what was filed in IGCC-12, IGCC-13, and IGCC-14. In accordance with the terms of the 2012 Settlement Agreement, the Additional AFUDC amounts included for December 2012 through June 7, 2013, reflected a 15% reduction. In other words, only 85% of the Additional AFUDC applicable to the Hard Cost Cap amount plus Additional AFUDC has been included for accounting periods after November 30, 2012. The adjusted total of the retail jurisdictional Hard Cost Cap plus Additional AFUDC as of September 30, 2014, is $2,460,027,000. This amount was reduced by the retail jurisdictional retirements as of March 31, 2015 ($19,564,000) and by $165,678,000 of retail accumulated depreciation. The resulting net plant amount was $2,274,785,000.

The $37,137,000 retail jurisdictional portion of the post-in-service Ongoing Capital Projects was reduced by $448,000 of retail accumulated depreciation. The resulting net plant amount for Ongoing Capital Projects was $24,620,000.

The $2,299,405,000 total of the net Edwardsport investment and the Ongoing Capital Projects was multiplied by the Company's overall weighted average cost of capital of 6.30% as of March 31, 2015, which was computed consistent with traditional Indiana ratemaking. This includes deferred income taxes as a zero cost source of capital in the cost of capital construction. The deferred income tax amount includes the net impact of any income tax benefits or liabilities associated with the portion of the plant that customers will pay for under the terms of the 2012 Settlement Agreement, but excludes the net impact of any tax benefits or liabilities associated with the portion of the plant that shareholders will pay for under the terms of the 2012 Settlement Agreement. The development of the cost of capital used in this calculation is shown on Page 11 of Petitioner's Exhibit D-2.

Ms. Douglas testified that the six-month jurisdictional revenue requirement for return on the qualified investment as of March 31, 2015, after revenue conversion, was $107,530,000. This is a $1,180,000 decrease from the amount proposed in IGCC-14.

Continuing her testimony, Ms. Douglas explained the calculation of the jurisdictional revenue requirement applicable to operating expenses including depreciation expense, tax credits, and amortizations. These operating expenses included: $38,153,274 for the estimated retail jurisdictional portion of operating expenses (including O&M, fringe benefits, payroll taxes, and property insurance), net of the applicable prorated amount of an annual credit of $5,756,000 approved in the CPCN Order, and property tax expense that are forecasted to be incurred from October 2015 through March 2016; $54,545,595 for the estimated retail jurisdictional depreciation expense for the October 2015 through March 2016 six-month forecast period, including $636,049 for the estimated retail jurisdictional depreciation of in-service ongoing capital projects; a credit to retail customers of $17,587,500 ($35,175,000 on an annual basis), approved by the Commission in its Subdocket Order to reflect the jurisdictional impact of a change in depreciation rates for in-service plant, which took place effective January 1, 2013; a credit of $7,518,427 for the retail portion of one-half of the estimated State Tax Credit; a net amortization of $21,754,620 over three years of March 31, 2015, balances of the 2012 Settlement Agreement Regulatory Asset

Commission-Ordered Regulatory Liability stemming from the IGCC 4S1 Order; and amortization of the post-in-service AFUDC of $1,224,404 accrued through March 31, 2015, also over a three-year period.

Ms. Douglas stated that the Company forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Edwardsport steam generating facility, which were included in base rates, and of the retail jurisdictional portion of 100% of the October 2015 through March 2016 benefit forecasted to be received for the ten-year property tax abatement from Knox County and the thirty-year reimbursement due to designation of Edwardsport as a Tax Increment Financing District. She testified the Company forecasts retail jurisdictional depreciation expense of $54,545,595 for the October 2015 through March 2016 period. *See* Pet. Ex. D-2, p. 7. A credit of $17,587,500 reflecting the Credit for Effect of New Depreciation Rates and a credit of $7,518,427 reflecting the retail jurisdictional portion of one half of the annual estimated $15 million State Tax Credit have also been included.

Ms. Douglas also noted that the Company forecasts retail jurisdictional depreciation expense on the Project of $621,964 for the October 2015 through March 2016 period.

A net revenue requirement amount of $21,754,620 was included for the $26,876,585 revenue requirement for the amortization over three years of the $91,208,015 March 31, 2015 balance of operating expenses, including depreciation, deferred in the 2012 Settlement Agreement Regulatory Asset, net of the $14,817,482 amortization of the Commission-Ordered Regulatory Liability established pursuant to the Commission's IGCC 4S1 order over three years.

Finally, Ms. Douglas stated that a revenue requirement of $1,224,404 has been included for the amortization of the $2,728,992 balance of post-in-service AFUDC as of March 31, 2015, over a three-year period consistent with the three-year period over which the 2012 Settlement Agreement Regulatory Asset and Commission-Ordered Regulatory Liability will be amortized. The accrual and recovery of post-in-service AFUDC was approved in Cause No. 43114. The post-in-service AFUDC has been computed using the 15% reduction in the AFUDC rate that was agreed to in term 2.B. of the 2012 Settlement Agreement. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.B., p. 2. Additional post-in-service AFUDC will accrue until all the Hard Cost Cap plus Additional AFUDC amounts and post-in-service AFUDC costs have been included in the IGCC Tracker or retail base rates.

Just as she did in her IGCC-13 testimony discussed above, Ms. Douglas again explained that the regulatory asset that was included in the calculation of revenue requirements included deferred expenses past the September 12, 2013 implementation of IGCC-10 rates because term 3 of the 2012 Settlement Agreement provided for the deferral (and recovery in the IGCC Tracker via amortization over a three-year period) of operating expenses, including depreciation, from the In-Service Operational Date of the IGCC facility until IGCC-10 rates were in effect. As a rate impact mitigation measure, Ms. Douglas stated that the 2012 Settlement Agreement provided that no estimated operating expenses should be included in Cause No. 43114 IGCC-9 rates and that any amounts incurred after the plant was in-service while IGCC-9 rates were being billed should be deferred in the Regulatory Asset and recovered over a three-year period rather than the standard six-month reconciliation period. Ms. Douglas testified that in the spirit of that rate mitigation measure, the Company desires to voluntarily continue to defer the operating expenses not recovered via IGCC-10 rates as a Regulatory Asset in order to avoid a large reconciliation variance amount which would need to be collected over a six-month tracker period in this or future IGCC Tracker filings covering reconciliation periods in which IGCC-10 rates are billed. By including these costs in the Regulatory Asset and amortizing them with the remainder of the costs deferred from June 7 through September 11, 2013, it will smooth out the impact of the under-collection that will occur due to the continued billing of IGCC-10 rates and serve to mitigate rate volatility. The September 30, 2014 Regulatory Asset balance the Company has amortized over three years therefore includes expenses deferred pursuant to the terms of the 2012 Settlement Agreement that were incurred from June 7 through September 11, 2013, and also incremental expenses incurred over the amount included in the IGCC-10 rates from September 12, 2013, through March 31, 2015. Additional incremental expenses will be deferred for each month IGCC-10 rates remain in effect and factored into the amortization amounts in the next IGCC Tracker filing (and the subsequent one, if needed). On behalf of the Company, Ms. Douglas requested that the Commission approve this treatment. She noted that the additional deferrals will cease if the Commission approves the Company's requested relief in the pending IGCC-11, IGCC-12, IGCC-13, IGCC-14, or in this case because the revenue requirements in these five proceedings included a full six months of operating expenses.

Ms. Douglas next explained how the operating expenses, depreciation expense (including the Credit for Effect of New Depreciation Rates), and the State Tax Credit were converted to revenue requirements and stated that the result was the inclusion of $91,208,715 in the calculation of the billing factors for this rider. *See* Pet. Ex. D-2, p. 6.

According to Ms. Douglas, Petitioner's Exhibit B-2, Page 7 details the support for the retail jurisdictional amount of forecasted depreciation expense and other operating expenses included in the revenue requirements calculation on Page 6 of Petitioner's Exhibit D-2. Ms. Douglas noted that the depreciation amount was reduced by 50% of the depreciation associated with the two RECB transmission projects for which reimbursement will be received from MISO's RECB process. Depreciation expense was calculated using the current Commission-approved depreciation rates for the FERC plant accounts to which the projects were assigned. She noted that as approved by the Commission in the CPCN Order, a monthly credit of $1/12^{th}$ of an annual amount of $5,756,000 was included to reduce the forecasted operating expenses. In accordance with the terms of the 2012 Settlement Agreement, the property tax estimate reflects 100% of the April through September 2015 benefit forecasted to be received for the ten-year property tax abatement from Knox County and the thirty-year reimbursement due to the designation of Edwardsport as a Tax Increment Financing District.

Ms. Douglas stated that Page 10 of Petitioner's Exhibit D-2 shows the calculation of the IGCC Revenue Adjustment Factors, by jurisdictional rate group, developed to recover the total revenue requirements for this filing of $198,738,015. This is an increase of approximately $10.3 million over the revenue requirements included in IGCC-14. The increase is driven by an increase in the amortization amount for additional operating expenses being deferred in the regulatory asset account due to the IGCC-10 rates currently being billed not covering the full level of operating expenses, and the impact of the forecasted staffing increases. Based on the Commission's CPCN Order, the Rate HLF adjustment factor has been developed on a non-coincident peak demand basis for the applicable period. The total jurisdictional revenue requirement for all other rate groups was divided by actual kilowatt-hour sales for the six-month period ending March 31, 2015, to arrive at the revenue adjustment factors per kilowatt-hour.

Similarly to her IGCC-14 testimony discussed above, Ms. Douglas explained the transitioning of certain lighting customers, stating that it does not affect the total retail peak demand or allocation to other customer classes.

Ms. Douglas testified that the rate migration adjustment included in her IGCC-12 testimony was based on the migration of customers and sales from the HLF rate schedule to the LLF rate schedule using data from 2008 through 2012.

Ms. Douglas noted that the reconciliation amounts in Columns F and H on Page 10 of Petitioner's Exhibit B-2 would normally contain an amount representing the reconciliation of amounts collected from customers from October 2014 through March 2015 to actual expenses (or credits) and an additional amount representing the reconciliation of the voluntary credit adjustment provided to HLF customers in IGCC-13 to correct for an IGCC Tracker administration clerical error, which affected the rates that were proposed, approved, and billed to HLF customers under Cause No. 43114 IGCC-4 rates. However, the IGCC-13 rates have not yet been approved, so the expenses and credits included in the IGCC-13 rates have not yet been billed. To avoid double refunds and future refund volatility, Ms. Douglas, on behalf of the Company, proposed to hold all additional reconciliations until the proposed IGCC-13 rates are in effect, after which a cumulative reconciliation will be completed in the next subsequent filing to ensure all costs and credits subject to reconciliation have been fully collected or refunded. As a result, no reconciliation amounts have been included in this filing, and Ms. Douglas, on behalf of the Company, requested that the Commission approve this proposed treatment.

Ms. Douglas next explained when CWIP ratemaking treatment for the IGCC Project will cease. She stated that consistent with 170 IAC 4-6-22 and in accordance with the CPCN Order, the IGCC Project will be deemed to be under construction, and Duke Energy Indiana will continue to receive revenues through Rider 61, until the Commission determines that this Project is used and useful in a proceeding that involves the establishment or investigation of Duke Energy Indiana's retail electric base rates and charges.

Ms. Douglas then stated that Petitioner's Exhibit B-3 shows the impact of the proposed IGCC ratemaking, should the Commission approve it, on the monthly bill of a typical residential customer using 1,000 kilowatt-hours. Upon approval of the proposed factors, the monthly bill of a residential customer using 1,000 kilowatt-hours will increase by $1.78, or approximately 2.0%, from the base bill plus the IGCC factor currently being billed to customers. This would be an increase of $1.51, or approximately 1.7% from the factors pending in IGCC-13, or a decrease of $2.66 or approximately 2.9% from the proposed factors pending in IGCC-14. This decrease is driven by larger than normal residential sales during the IGCC-15 period as compared to residential sales during the IGCC-14 period. Revenue requirements allocated to residential customers in IGCC-15 are higher than in IGCC-14, however, the lower billing determinant in IGCC-14 has resulted in a higher calculated IGCC factor than that proposed in IGCC-15. This increase is not representative of other customer classes. Most other customers will see higher rates for IGCC-15 than IGCC-14. The revenue requirements for IGCC-11 through IGCC-15 all included the full level of operating expenses for Edwardsport, but the IGCC-10 rates currently being billed only included 4/6^{ths} of the operating expenses, so all customers can expect an increase from the IGCC-10 rates currently being paid.

Ms. Douglas concluded by noting that Duke Energy Indiana is proposing to update its Rider 61 Eleventh Revised Sheet No. 61, Pages 1 through 5, should the Commission approve the Company's proposed rates. Upon approval, and upon Duke Energy Indiana's filing of the updated Rider 61 with the Commission's Electricity Division, the proposed factor will be billed to customers for all bills rendered beginning on the effective date of the Commission's Order in this proceeding.

f. 2016 Settlement Agreement: Mr. Esamann provided testimony supporting the 2016 Settlement Agreement. He explained that the Company is requesting that the Commission approve the change in IGCC Rider filings from semi-annual to annual with the next filing to be in the first quarter of 2017; authorize the interim implementation of future Company rates to the extent revenue requirements are lower than revenue requirements used in the rates for the 2017 and 2018 Rider filings; approve the change in amortization schedule for the regulatory asset established for post-in-service operating expenses and the Regulatory Liability created by the terms of the 2012 Settlement Agreement and the 4S1 Order; approve the caps on recoverable O&M and ongoing capital expenditures incurred through calendar year 2017; and approve rider recovery and implementation of revised IGCC-15 rates as presented in the settlement testimony of Mr. Davey.

Mr. Esamann testified that the 2016 Settlement Agreement was the product of extended negotiations conduced on an arms' length basis and is intended to resolve all disputes, claims and issues that have been raised in IGCC-11 through IGCC-15, and Cause No. 38707 FAC 99-S1. He stated that the 2016 Settlement Agreement features are: a cap on recoverable O&M and ongoing capital expenditures; a reduction of $87.5 million in previously-incurred recoverable O&M; extended amortization period for the Regulatory Asset from three years[11] to eight years and a reduced amortization period for the Regulatory Liability from three years to two years.

As explained by Mr. Esamann, the actual O&M expenditures recoverable are capped as follows:

Period	**Cap Amount (Retail)**	**Amount to be Recovered (Retail)**
Calendar Year 2016 (beginning with the issuance	$73.3 million[12]	Lower of retail portion of 2016 actual or cap

[11] Note that the three years was previously agreed to in the 2012 Settlement Agreement that was approved by this Commission in IGCC 4S1.
[12] The cap for 2016 will be prorated based on number of months remaining in 2016 after Commission approval of the 2016 Settlement Agreement and implementation of new revenue requirements. For example, if the Commission approves the Settlement on April 1, 2016, the 2016 cap would be approximately $73.3 million/12 months x 9 months

of a Commission order approving the Settlement or July 1, 2016, whichever occurs earlier)		amount
Calendar Year 2017	$76.8 million	Lower of retail portion of 2017 actual or cap amount

The Settling Parties agreed that only the actual O&M expenses up to the cap applicable to each calendar year are recoverable, *i.e.* customers will pay the lower of the cap amount or actual expenditures, and that the Company will not seek to recover O&M expenses above the settlement cap amounts except in the event of the defined force majeure occurrences. The 2017 rider will reflect the O&M levels at the level of the cap and will include a true-up for actual 2016 O&M expenses if lower than the 2016 cap. The 2017 O&M level will be trued up in the next filing if actual O&M levels are below the cap. The 2016 Settlement Agreement also provides that the O&M expense level increases in 2017 to the 2017 O&M cap amount regardless of whether the Company's actual O&M expenses are less than the capped amount in 2016.

Mr. Esamann testified that the Settling Parties have agreed that they will not challenge or otherwise oppose the recovery of O&M expenditures in 2016 and 2017 up to the applicable cap amounts and have further agreed that the rates will result from the approval and implementation are just, reasonable and necessary. In the Company's 2018 filing and beyond, and in its next base rate case, the Company may request recovery of its reasonable and necessary O&M expenses and the non-Duke Energy Settling Parties have retained all rights to argue against the recovery of O&M.

Mr. Esamann also testified that the Settling Parties agreed to cap post-in-service ongoing capital, with the exception of defined force majeure events, through calendar year 2017 as follows:

Period	**Cap Amount of Ongoing Capital Additions (Retail)**	**Incremental Ongoing Capital Additions to be Recovered (Retail)**
Balance at 3/31/15 (to be implemented upon approval of the Settlement)		$24.6 million
4/1/15 through Calendar Year 2016	$36.1 million[13]	Lower of retail portion of 2015/2016 actual expenditures or cap

= approximately $54.97 million, which would be compared to actual expenditures from April through December 2016.

[13] Note that this amount appears higher because it includes ongoing capital additions from April 1, 2015 through December 31, 2016 – not just one year like the 2017 cap amount.

		amount
Calendar Year 2017	$16.9 million	Lower of retail portion of 2017 actual expenditures or cap amount

Again, the Settling Parties agreed that the Company will recover the lower of its actual ongoing capital expenditures and the applicable cap amounts. In addition, the non-Duke Settling Parties agreed that they will not challenge or oppose the Company's recovery of ongoing capital expenditures in 2016 and 2017 up to the applicable cap amounts and have further agreed that the rates that will result from the approval and implementation of the Settlement are just, reasonable and necessary. In the 2018 annual rider filing, the Company may propose rates be set on its projected reasonable and necessary O&M expenses (which will then be reconciled to actual O&M expenses in the 2019 annual rider filing) and on its actual 2017 ongoing capital expenditures. The non-Duke Settling Parties may challenge the Company's proposed, projected O&M recovery in the 2018 annual rider filing, but not the ongoing capital expenditures. In the 2019 annual filing, all parties have all respective rights to either propose rates based on reasonable and necessary forecasted O&M and actual ongoing capital expenditures or to make arguments regarding the proposed O&M and ongoing capital.

Mr. Esamann testified that the Company agreed to fund $87.5 million of previously incurred O&M and will reduce the size of the retail Regulatory Asset at the time of approval of the 2016 Settlement Agreement by $80.3 million, thus providing a credit to customers of a significant portion of the O&M expenses that have been deferred in the Regulatory Asset since in-service. He stated that this credit is viewed by the Settling Parties as resolving the issues about the June 7, 2013 in-service determination, including fuel-related issues.

Next, Mr. Esamann testified that the Settling Parties have agreed to extend the amortization of the Regulatory Asset from three years[14] to eight years, which along with the $80.3 million reduction, helps to mitigate the rate impact. Thus, customer rates will be what they would have been if IGCC-10 rates had included a full six months of O&M and depreciation.

Mr. Esamann explained that the other Edwardsport related provisions of the Settlement provide that the Edwardsport in-service date shall remain June 7, 2013 for ratemaking and accounting purposes; the non-Duke Settling Parties will only challenge or raise issues with the Plant's operations through December 31, 2017 to the extent its performance is substantially different than the historical Edwardsport performance over the twelve months ended August 2015; if the Settlement isn't approved by July 1, 2016, the Company will treat the agreed-upon O&M cap as if were effective and will apply it to expenses incurred after that date; if the Settlement isn't approved in time for new rates to into effect by July 1, 2016, the Company will reduce the Regulatory Asset account balance by the difference in the revenue requirement associated with the return under the Settlement and the currently-in-effect IGCC-10 return revenue requirement[15]; in lieu of JIs request to add 8% interest to the Commission-ordered Regulatory Liability, the Company agreed to shorten the amortization period from three to two years and that no carrying

[14] As was set in the 2012 Settlement Agreement.
[15] This results in a reduction of $2.46 million/month until rates are in effect after an Order approving this Settlement.

costs will be added to either the Commission-ordered Regulatory Liability or the Regulatory Asset; if the Company's filing in either 2017 or 2018 has a lower revenue requirement than was included in the rates in effect at that time, the Company will file within a week of the 2017 or 2018 Rider filing with the Electricity Division of the Commission for approval of an updated tariff to implement the lower rates on an interim basis; the Company will file its next Rider filing in the first quarter of 2017 and annually until the Commission issues an order in Duke Energy Indiana's next base rate case; and the Settling Parties agree that any "subject-to-refund" designations or similar language in the Company's FAC proceedings, Cause Nos. 38707 FAC 99, FAC 100, or FAC 101, should be removed once the Settlement is approved as well as all issues reserved for consideration in FAC subdocket FAC 99S1.

Further, Mr. Esamann explained the non-Edwardsport related provisions in the 2016 Settlement Agreement provide: An agreement regarding JIs future efforts to seek attorney fees and expenses from the $87.5 million common fund that will be created by the approval of this Settlement; the agreement by the Company to retire or cease burning coal at Gallagher Station Units 2 and 4 by December 31, 2022 and that ratemaking for retirement will be consistent with normal retirement accounting; the Company agreed to share certain information relating to Gallagher Station with the Settling Parties relating to its low income and residential customers; and the Settling Parties also agreed to work collaboratively for two years following the date of a final order approving the Settlement to consider programs or options to assist low income customers and for increasing solar-powered generating facilities in Duke Energy Indiana's service territory.

In addition, Duke Energy Indiana agreed to funding commitments out of shareholder funds, including: a payment to the attorneys representing the Industrial Group in the amount of $2.5 million and expenses in the amount of $41,000; a payment to Nucor Steel-Indiana of $100,000. The OUCC and Duke Energy Indiana will work together to use $1.859 million as follows: $1.009 million retail rate credit to residential customers to be reflected in the next regional transmission organization rider, Rider 68, filed after the Commission's order approving the Settlement; $250,000 to fund OUCC staff development, consultants, and experts in the areas of power hedging and other matters of current interest in the industry; $500,000 contribution to the Battery Innovation Center to further develop battery storage systems in Duke Energy Indiana's service territory; $100,000 contribution to the Indiana Low Income Home Energy Assistance Program ("LIHEAP") fund to be used for Duke Energy Indiana retail customers; lastly JI and Duke Energy Indiana agree to cooperate to fund $500,000 to LIHEAP to be used solely for Duke Energy Indiana retail customers; and $500,000 contribution to the SUN solar energy grant program to develop solar energy projects for Duke Energy Indiana customers in its service territory.

Mr. Esamann concluded his testimony by stating that although the Company considers its actions concerning Edwardsport during the period to be prudent, reasonable and necessary, the Company has engaged in good faith negotiations with the non-Duke Settling Parties in an attempt to resolve the many issues that have been or could have been raised concerning Edwardsport from April 1, 2013 through March 31, 2015. The Settlement results in relative peace in the Edwardsport regulatory proceedings before the Commission through first quarter 2018 and results in many financial benefits for customers. In addition, Mr. Esamann testified that the Company believes that the 2016 Settlement Agreement is supported by substantial evidence and is in the public interest.

Mr. Stultz provided settlement supporting testimony to discuss three specific provisions of the Settlement. He discussed the reasonableness of the proposed O&M, ongoing capital caps, and why the FAC 99S1 subdocket being held in abeyance pending the outcome in IGCC-12/13 has been adequately and appropriately resolved and can be closed.

Mr. Stultz described the O&M cap in the Settlement and that the Settling Parties believed it important that the rates to be implemented upon approval of the Settlement be based on actual, historical O&M from Edwardsport. He opined that the O&M cap amounts, as agreed to by the Settling Parties, are reasonable as reflected in his December 23, 2014 and June 4, 2015 prior testimonies that discussed the issues impacting gasifier availability, the increase in employee labor and expenses, the process safety management program, mechanical integrity efforts, and the facilitation of the station's shift from emergent work to predictive/preventative maintenance.

Mr. Stultz explained that the provision that the Company could only recover the lower of the cap amounts and actual O&M expenditures were a reasonable compromise that reflected the common interest of all in promoting Edwardsport's reliability and availability.

Mr. Stultz testified regarding the cap on ongoing capital at Edwardsport. He stated that the Settling Parties set the ongoing capital cap amounts for the Company's 2017 and 2018 IGCC Rider filings by using the actual figures then-included in the Edwardsport station budget, which included the station's planned capitalized maintenance and plant additions reasonably foreseeable, for the next two years. He believes that the cap on ongoing capital are reasonable and that it reflects an equitable balance between the interests of the parties, while reflecting a common interest in safe and reliable operations.

Next, Mr. Stultz discussed his review of the Commission's order opening and then holding in abeyance the FAC subdocket related to Edwardsport, Cause No. 38797-FAC 99S1. The FAC 99 subdocket was concerned with the underlying causes of periods when Edwardsport was consuming more energy than it was generating with the vast majority of those times during start-up of one or both of the gasifiers and the subdocket would review the reasons for the increased number of gasifier starts during the initial months of Edwardsport operations. Mr. Stultz opined that he suspected that the parties were not concerned with the fact that the gasifiers were starting, but why they had tripped or been shut down in the first place. He testified that his prior testimonies discussed the causes of the gasifier trips and equipment issues and the resolution of those trips and issues, particularly in the IGCC-12/13 proceeding. The provision of the Settlement resolves all disputes, claims and issues from the FAC subdocket and those FAC cases for which rates were approved on an interim basis. Mr. Stultz believes it is reasonable for the Commission to approve the Settlement, close the FAC subdocket, and remove the "subject-to-refund" or similar designation of the FAC 99S1, FAC 100, and FAC 101 proceedings.

Mr. Davey explained how the ratemaking provisions of the 2016 Settlement Agreement impact Rider 61 recovery, including provisions associated with the regulatory asset, regulatory liability, O&M cap, and post-in-service ongoing capital cap. He also briefly discusses the regulatory issues associated with the in-service date and the rate impact of the Settlement relative to Rider 61 rates currently in effect.

Mr. Davey testified that pursuant to the 2016 Settlement Agreement, the company will make its next Rider 61 filing in the first quarter of 2017 and will file in the first quarter of every year thereafter until the Commission issues an order in Duke Energy Indiana's next retail base rate case. Now that the plant is in-service, the annual filing provides for a more efficient review of ongoing plant operations. The 2017 filing would address Edwardsport's operations from April 1, 2015 through December 31, 2016 and subsequent annual filings will cover the Plant's operations during the prior calendar year. The investment on which a return is earned will be updated in each annual filing to include the most recent December 31 balance of plant net of accumulated depreciation. In addition, 12 months of kwh sales or demand data will be used to determine rates instead of six months of data.

Mr. Davey continued his testimony discussing the 2016 Settlement Agreement provisions related to Rider 61. He explained that the Settling Parties recognized that now that the plant is in-service, the net book value of the plant will decline over time as depreciation accumulates and that declining net book value may result in a rate decrease for customers. As such, the 2016 Settlement Agreement provides that if the Rider 61 filing in either 2017 or 2018 has a lower revenue requirement than in the rates currently in effect at that time, Duke Energy Indiana will file within a week of the 2017 or 2018 IGCC Rider filing with the Electricity Division of the Commission for its approval of an updated tariff to implement these lower rates, prior to the conclusion of the Rider 61 proceeding. The 2016 Settlement Agreement continues with the Settling Parties requesting that the Commission authorize the interim approval of these lower rates at the time of their filing with the Commission's Electricity Division.

Next, Mr. Davey testified regarding the impact of the Settlement on the IGCC Rider. He explained that the basis for the rates to be implemented upon Commission approval of the Settlement are the revenue requirements in the Company's June 2015 IGCC-15 filing, but that the Settlement provides for the following adjustments to those revenue requirements: reducing the Regulatory Asset amortization amount to $20 million per year, including the impacts of the retail jurisdictional share of $87.5 million shareholder funding of O&M expenses, and a change in amortization schedule for the Regulatory asset from three to approximately eight years and for the Regulatory Liability from three to two years; implementing capped level of O&M expenses by using the actual retail jurisdictional portion of Edwardsport O&M expenses for the 12 months ended March 31, 2015 and increasing it by $3.5 million each year through 2017; post-in-service ongoing capital projects and retirements as of the March 31, 2015 cut off period in IGCC-15 will be included in the rates implemented under the Settlement.[16] For the period of April 2015 through December 2017, post-in-service ongoing capital project amounts included in the Rider are capped per the terms of the Settlement.

Mr. Davey provided background on the Regulatory Asset[17]. Since IGCC-10 rates have been in effect since September 12, 2013 and are still currently in effect, only 2/3 of the plant's

[16] Approximately $25 million in ongoing capital investments and accumulated depreciation.
[17] The Regulatory Asset was established pursuant to the approved 2012 Settlement Agreement wherein the parties agreed to restart certain Rider filings, specially deferring the actual depreciation and O&M costs (and property tax

O&M and depreciation have been included in rates being billed to customers for over two years and the Company has been deferring 1/3 of its O&M and depreciation into the Regulatory Asset, which has led to its increased size of $173.3 million as of the end of July 2015. At the end of March 2016, the Regulatory Asset balance is approximately $228.5 million.

Continuing his testimony, Mr. Davey described the 2016 Settlement Agreement impacts to the Regulatory Asset. Duke Energy shareholders will fully fund $87.5 million of total Company O&M expenses it has incurred at Edwardsport from the June 7, 2013 in-service date. Plus, retail customers will be credited with the retail jurisdiction share, $80.3 million, by reducing the balance of deferred O&M expenses that have accumulated in the Regulatory Asset. The Company will continue to defer in the Regulatory Asset actual O&M and depreciation not already in rates until the implementation of rates established pursuant to the 2016 Settlement Agreement. If an order is not received from the Commission in time for new IGCC Rider rates to go into effect by July 1, 2016, the Company will reduce the Regulatory Asset account balance by the difference in the revenue requirement associated with the return under the 2016 Settlement Agreement and the currently in-effect IGCC-10 return revenue requirement, which would be a reduction of approximately $2.46 million/month until rates are in effect approving the 2016 Settlement Agreement. Mr. Davey explained that the Regulatory Asset balance currently includes deferred O&M expenses and deferred depreciation expenses, and that the Settlement proposes that the Regulatory Asset be amortized and recovered through rates in the amount of $20 million per year over eight years without carrying costs, instead of the $53.8 million per year included in the development of rates in the June 2015 IGCC-15 filing. In addition, the Company will amortize the Commission-ordered Regulatory Liability over two years, instead of three years and net it against the Regulatory Asset amortization per the IGCC 4S1 Order and as modified in the IGCC-10 order with no carrying costs added to either the Commission-ordered Regulatory Liability or the Regulatory Asset.

Mr. Davey next explained the O&M cap in the 2016 Settlement Agreement. He testified that the beginning basis of the cap is the actual retail O&M expenses for the 12 months ended March 31, 2015 and it is the total of amounts in Petitioner's Exhibit B-2 in IGCC-14 and D-2 in IGCC-15, plus an annual retail escalator of $3.5 million. The 2016 retail O&M cap is $73.3 million, which is the sum of $67.2 million plus $2.6 million (for the nine months of 2015 following March 31, 2015) plus $3.5 million for calendar year 2016. He explained that under the Settlement, the Company will be able to recover the lower of its actual O&M expenses or the applicable O&M cap from the date of the Commission order approving the 2016 Settlement Agreement through the end of 2016. He also discussed the 2016 and 2017 O&M caps to be included in subsequent annual Rider filings. Mr. Davey continued stating that upon Settlement approval Duke Energy Indiana will use the $73.3 million retail O&M cap to set rates for the remainder of 2016 and will use the 2017 cap amount, $76.8 million, to set rates and restated that only the actual O&M expenses up to the cap applicable to each calendar year are recoverable. Any differences between the calendar year cap amount used to set rates in the annual filings and the actual expenditures for the calendar year will be reconciled in subsequent filings. If the Commission's order approving the Settlement is not issued before July 1, 2016, the Settling

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expenses) incurred for all months from the In-Service Operational Date until the effective date of IGCC-10 rates and will recover the deferred amount (without carrying costs) over a three-year period either through the Rider or through inclusion in base rates.

Parties agree that the O&M cap will be effective on July 1, 2016 and will apply to expenses incurred after that date. In addition, the non-Duke Settling Parties have agreed that: they will not challenge or otherwise oppose the Company's recovery of O&M expenditures in 2016 and 2017 up to the applicable cap amount; and they will only raise issues with Edwardsport's operations through December 31, 2017 to the extent its performance is substantially different than the historical Edwardsport performance over the 12 months ended August 2015. The Settling Parties agreed that the cap amounts for 2016 and 2017 are for the term of the Settlement only and that the Company may request recovery of actual O&M expenses in its 2018 and subsequent IGCC Rider filings and that non-Duke Settling Parties retain all retain all rights to argue against recovery.

Mr. Davey next discussed the post-in-service ongoing capital provision of the Settlement. Upon approval of the Settlement, Duke Energy Indiana will use its actual post-in-service ongoing capital project amounts and accumulated depreciation, $24.6 million, as reflected on Petitioner's Exhibit D-2 in its June 2015 IGCC filing to set rates for 2016. For April 1, 2015 through December 31, 2015, calendar year 2016 and calendar year 2017, the Settlement provides that the Company is entitled to recover the lower of its actual ongoing capital expenditures or the cap amounts. Because the Rider did not use forecasted ongoing capital expenditures in the 2017 annual filing, the Company proposed rates based on actual ongoing capital expenditures from April 1, 2015 through December 31, 2016 being added to the March 31, 2015 balance. For the 2018 annual filing, the Company proposed rates based on the actual ongoing capital expenditures from January 1, 2017 through December 31, 2017 being added to the December 31, 2016 balance. In consideration, the non-Duke Settling Parties agreed not to challenge Duke Energy Indiana's recovery of ongoing capital expenditures between April 2015 and December 2017 up to the cap amount and that the cap amounts are for the term of the Settlement only and that Duke Energy Indiana may request recovery of actual capital expenditures incurred in calendar year 2018 forward and in its next rate case. The only exception to these cap amounts are defined acts of force majeure events.

Continuing his testimony, Mr. Davey discussed the in-service date and that the Settling Parties agreed that the in-service date of the Plant shall be June 7, 2013 for accounting and ratemaking purposes. He stated that this is the date that the Plant was put into service and the date has not changed. Mr. Davey explained that the Settling Parties attempted to provide financial value to customers in order to recognize the operational challenges that Edwardsport had for the first 10 months that it was in-service without changing the actual in-service date, and decided that the best way to do this was a reduction in the Regulatory Asset.

Mr. Davey next discussed the retail rate impacts. He explained that Ms. Douglas' exhibit D-2 in IGCC-15 was revised to reflect the terms of the Settlement as well as the Commission's December 9, 2015 order in Cause No. 43114 IGCC 4S3 which required the Company to reduce the Regulatory Liability. Mr. Davey then stated that his Petitioner's Exhibit 3-B shows the impact of the proposed IGCC ratemaking, should the Commission approve the Settlement. He stated that upon approval of the proposed factors, the monthly bill of a typical residential customer using 1,000 kilowatt-hours, relative to the 12 months ended June 2015 revenue is 2.1% comparable to the 3.6% annual retail rate increase if the June 2015 IGCC-15 revenue requirements would have gone into effect. This would be an increase of $1.83 or 1.6% compared to the total bill as of June 2015.

Mr. Davey concluded by noting that Duke Energy Indiana is proposing to replace its current rates, which were approved in IGCC-10, with the rates shown on updated Rider 61 Eighth Revised Sheet No. 61, Pages 1 through 5[18]. Upon Commission approval and upon Duke Energy Indiana's filing of the updated Rider 61 with the Commission's Electricity Division, the proposed factor will be billed to customers for all bills rendered beginning on the effective date of the Commission's Order in this proceeding.

5. **OUCC's Consolidated Testimony.**

a. IURC Cause No. 43114 IGCC-11: OUCC witness Mr. Wes R. Blakley, Senior Utility Analyst, testified concerning the IGCC-11 Rider rates contained in Ms. Douglas' direct and supplemental testimonies. Mr. Blakley described the rate mitigation measures included in the 2012 Settlement Agreement. He explained that the two corrections made in Ms. Douglas' supplemental testimony relating to HLF allocations and the deferred income tax credit results in a reduction in rates from $14.22 per 1000 kWh to $13.97 per 1000 kWh for residential customers and that the OUCC supports the inclusion of the deferred income tax credit in IGCC-11 because it provides immediate rate relief for ratepayers.

Mr. Blakley also confirmed that the figures used in the calculation of the Company's IGCC-11 adjustments factors, including the rate mitigations per the 2012 Settlement Agreement are supported by the testimony, exhibits, and workpapers filed by the Petitioner.

b. IURC Cause No. 43114 IGCC-12/13: Mr. Blakley testified to his opinion regarding Duke Energy Indiana's request for recovery of costs. Referring to the testimony of OUCC witness Mr. Alvarez, Mr. Blakley noted that the OUCC recommends that the Commission order a refund for all costs related to "start-up, testing, validation and commissioning" from the time IGCC-10 rates were instituted until March 31, 2014. The OUCC recommended that the Commission deny recovery related to IGCC-12 and -13 on these grounds. The OUCC further recommended that the revenue requirement billed to customers under IGCC-10 from the approved order date of September 11, 2013, through March 31, 2014, should be refunded to customers.

He testified that the OUCC believes that depreciation and O&M costs billed to customers in IGCC-10 should be refunded because the Plant was not complete and operational until March 31, 2014. On this basis, Mr. Blakley opined that $51,636,396 should be refunded as the approximate amount that customers have paid through rates for the operation of the IGCC Plant while it was not operational. Mr. Blakley further opined that Duke Energy Indiana should not recover the approximately $63.2 million in O&M and depreciation costs associated with IGCC-11 for the period October 2013 through March 2014.

In sum, Mr. Blakley testified that the OUCC recommends (1) that the Company refund $51,636,396 of O&M and depreciation billed from September 12, 2013 to March 31, 2014 in IGCC-10; (2) that O&M and depreciation charges of approximately $63.2 Million included in IGCC-11 for the period October 1, 2013 through March 31, 2014, be treated as subject to the Hard Cap; and (3) that the Commission deny additional recovery related to O&M and depreciation on

[18] *See*, Petitioner's Exhibit 3-B and 3-C.

the IGCC generating facility for IGCC-12 and -13 until all startup, testing, validation and commissioning expenses have been incurred to reach final completion of the IGCC facility.

Mr. Alvarez also testified on behalf of the OUCC. The purpose of his testimony was to describe the issues related to Petitioner's start-up, testing, validating, and commissioning of the IGCC Plant necessary to reach "final completion" as those terms were described in the 2007 Duke-GE Contract ("Duke-GE IGCC Contract"). Mr. Alvarez testified that the OUCC's position is that all costs incurred during "start-up, testing, validating and commissioning" were necessary to reach final completion and are costs that should be borne by Duke Energy Indiana under the Hard Cost Cap of the 2012 Settlement Agreement. Mr. Alvarez testified that an Appendix to his testimony, Public's Exhibit No. 3 contains more chronological detail regarding the IGCC testing and DEI's declaration of "in service."

Mr. Alvarez testified to the definition of the term "startup" in the Duke-GE IGCC Contract and his interpretation of how "startup" relates to the responsibility for construction costs and the Hard Cap under the 2012 Settlement Agreement. Mr. Alvarez also testified to the definition of "performance tests," "validation," "commissioning," and "final completion" in the Duke-GE IGCC Contracts and commented on whether those activities were completed during the IGCC-12 and -13 time periods. Mr. Alvarez opined that despite the Company's "in service" declaration on June 7, 2013, all expenditures that Duke Energy Indiana incurred from April 1, 2013, through March 31, 2014 (the relevant time periods of IGCC-12 and -13) should be deemed subject to the Hard Cost Cap of the 2012 Settlement Agreement, including expenses Duke Energy Indiana identified as O&M, ongoing capital for normal capitalized repairs or maintenance expenditures, or additional plant and equipment for continued operations.

Mr. Alvarez testified to issues the Plant experienced before the in-service date, including certain issues prior to April 1, 2013, which were outside the review period of the consolidated IGCC-12 and 13 proceedings. In particular, he noted the run times of the gasifier trains during the period leading up to May 2013. He also discussed specific incidents at the station prior to in-service relating to oxygen and syngas leaks.

Mr. Alvarez referenced the 46-50 hour start-up process of the gasifiers and opined that because the Company could not run both the gasification island and power block simultaneously during the period leading to the in-service date, it did not demonstrate the Plant's operability and readiness for service. Mr. Alvarez pointed to his calculations of the gasifier run times.

Mr. Alvarez further testified to the OUCC's concerns regarding the IGCC's operability and readiness for service in June 2013 and on the in-service date. Mr. Alvarez testified that both gasifiers were not producing syngas when Duke Energy Indiana declared the Plant in-service. Mr. Alvarez further opined that running the gasifiers together for a few hours does not provide sufficient operational history and experience to support a claim of operability and readiness for service. Specifically, the Company did not have prior experience with dual gasifier train operation.

Mr. Alvarez also referred to the "substantial completion" definition in the 2012 Settlement Agreement, *see* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.E., p. 3, and opined that, as of the "in-service" date, if the performance testing and NPI testing were not complete, and IGCC had not achieved substantial completion, then Duke Energy Indiana could not make a reasonable determination that the IGCC Plant was ready for service. Because none of these requirements were complete, Mr. Alvarez opined that the Company's declaration of in-service was unreasonable.

Mr. Alvarez commented on the impact of Plant outages and gasifier trips on IGCC systems, equipment, and components. He further opined that FERC guidelines do not provide any set of determinative factors for making an in-service declaration.

Mr. Alvarez testified that the OUCC recommends that the Commission (1) reject the June 7, 2013 in-service date declaration by Duke Energy Indiana; (2) find that Duke Energy Indiana did not complete the IGCC startup on June 7, 2013, or anytime during the IGCC-12 and -13 review periods; (3) find that Duke Energy Indiana did not complete the performance tests within the prescribed review periods of this proceeding; (4) find that Duke Energy Indiana did not complete the commissioning of the IGCC within the prescribed review periods of this proceeding; (5) find that Duke Energy Indiana did not achieve the final completion of the IGCC within the prescribed review periods of this proceeding; (6) require Duke Energy Indiana to provide documentation to identify the correct validation completion date of the IGCC, and verify that such completion date was within the prescribed review periods of this proceeding; (7) find that all expenditures incurred by Duke Energy Indiana from April 1, 2013, through March 31, 2014, should be deemed as "identified" during "startup, testing, validation, and commissioning" and necessary to reach "final completion"; and (8) find that all expenditures "identified" during "startup, testing, validation, and commissioning" and necessary to reach "final completion" should be subject to the Hard Cost Cap, borne by Duke Energy Indiana and not passed on to ratepayers.

6. Industrial Group's Consolidated Testimony.

a. IURC Cause No. 43114 IGCC-12/13: Mr. Michael P. Gorman testified on behalf of the Industrial Group. Mr. Gorman testified about Duke's requested relief in light of two key elements of the 2012 Settlement Agreement. First, he testified that Edwardsport was not in-service under FERC guidelines through the relevant period of IGCC-12 and -13, which ended March 31, 2014. Second, he testified about the relief that should be granted to ratepayers under the 2012 Settlement Agreement if the Commission were to find that Edwardsport was in-service during the relevant period. Gorman Direct at 2-3.

Mr. Gorman testified that the Commission is best situated to interpret the 2012 Settlement Agreement and enforce its terms and ensure that the public interest is protected. He testified that whether Edwardsport was in-service on or before March 31, 2014 is an important issue that has a substantial impact on the costs to be borne by ratepayers during this period. Mr. Gorman observed that the 2012 Settlement Agreement does not specify which party has the right to make that determination, but that he believes it is for the Commission to decide if and when Edwardsport is placed in-service. *Id*.

Mr. Gorman examined the in-service guidelines identified as relevant by Duke Energy Indiana in the April 7, 2014 summary judgment affidavit of Mr. Danny Wiles. *Id* at 5-6. In his affidavit, Mr. Wiles testified Duke Energy Indiana's determination that Edwardsport was in-service was based on several FERC guidelines, including ASC 360-10-30-1 and Accounting Release Number 5 ("AR-5"). Mr. Gorman quoted FASB guidance ASC 360-10-30-1 (which interprets Paragraph 835-20-05-1) and states that "the historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use." *Id*. at 7; *see also* Gorman Direct Ex. 2 at ¶ 5. Likewise, Mr. Gorman explained, AR-5 provides that AFUDC capitalization continues as long as capital expenditures are being incurred and activities necessary to get the construction project ready for its intended use are in progress. Gorman Direct at 7. Mr. Gorman testified that neither prong of AR-5 had been met as of March 31, 2014. First, Edwardsport was still incurring capital expenses. *Id*. at 7-8. Second, Edwardsport was not yet capable of providing service to retail customers consistent with its "intended use," and was instead in a testing, tuning, and optimization phase. *Id*. at 7.

Mr. Gorman discussed Edwardsport's intended use, explaining that Edwardsport was approved by the Commission in 43114 and IGCC-4S1 to be a reliable base load generating station. He testified that the plant was designed to be capable of generating energy using either natural gas or syngas, whichever is most economical, but that it is optimized to run on syngas. Mr. Gorman concluded that in order to operate at its intended use, the IGCC must be capable of reliably producing base load energy from syngas at or near its maximum capacity. *Id*. at 8.

Mr. Gorman further explained that in discovery, Duke Energy Indiana indicated that the intended use of Edwardsport is to operate as an IGCC. Duke Energy Indiana had also submitted testimony on Edwardsport's intended use, which indicated that (1) Edwardsport would consistently be among Duke Energy Indiana's first economically dispatched base load generating resources; (2) Edwardsport can operate on natural gas or syngas, whichever is economic, but is designed to run on syngas; and (3) Edwardsport would be offered into MISO based on a minimum and maximum capacity output, with MISO free to economically dispatch the unit above the minimum loading level up to the maximum loading level based on economic dispatch principles. *Id*. at 8-9.

Mr. Gorman testified that Edwardsport was not operated as a base load IGCC through March 31, 2014, and thus that it was not able to operate consistent with its intended use. *Id*. at p. 9. He provided several facts supporting his conclusion. Mr. Gorman pointed out that Duke was not able to operate Edwardsport on syngas during periods of high MISO prices in January and February 2014, when freezing temperatures severely impacted syngas production. Mr. Gorman also testified that there was only one dispatch instruction from MISO during the relevant period, and the plant was unable to meet this instruction due to natural gas restrictions. In fact, through approximately September 2014, Edwardsport had only been dispatched by MISO on an economic basis on one occasion, May 28, 2014, which was outside the relevant time. *Id*. at 10.

In addition, Mr. Gorman supported his conclusion that Edwardsport was not operating consistent with its intended use by explaining that syngas operations for Edwardsport were still in the testing, tuning and optimization phase and were not yet available for Duke Energy Indiana's planned MISO offering until at least September 2014. During this period, Edwardsport was committed to MISO based on a minimum loading capability approximately equal to its expected output. These restrictions limited Duke Energy Indiana's ability to operate Edwardsport as an economic base load generating resource. Mr. Gorman stated that Duke Energy Indiana has indicated that Edwardsport will start to be offered into MISO based on the planned minimum and maximum offering around September 2014 after its most recent outage is complete. *Id*. at 10.

Mr. Gorman further supported his conclusion by testifying that with only one exception of August 9, 2013, Edwardsport did not operate at its seasonal net dependable capacity during the time period of this proceeding. Mr. Gorman observed that the fact that Edwardsport was in a testing, tuning and optimization period was evidenced by the fact that its actual heat rate was substantially higher than the guaranteed heat rate from GE. Edwardsport's net heat rate for June 2013 through March 2014 was as high as 20,981 (Btu/kWh) and as low as 12,402 (Btu/kWh), considerably higher than the guaranteed heat rate of 8,971 (Btu/kWh). He explained that because the heat rate had not yet been optimized consistent with the contract guarantee, Edwardsport was not as economically able to produce energy during this time period as it would have been had it been operating at or consistent with the guaranteed heat rate. *Id*. at 10.

Mr. Gorman also testified to the significance of the fact that Edwardsport was in a startup and testing phase through March 31, 2014. Mr. Gorman explained that under FERC guidelines, the costs of testing or running a plant during experimental or test periods are costs incurred prior to being declared in-service. *Id*. at 11; *see also id.* at 5 (quoting FERC Instruction 9(D)). Mr. Gorman observed that such testing is also an important customer protection. He quoted IGCC-4S1 testimony from Duke Energy Indiana witness Mr. Stultz describing Duke Energy Indiana's efforts to ensure that Edwardsport operated as intended – as a reliable base load generating resource. Mr. Stultz explained that the startup procedures and testing requirements of Edwardsport are designed to ensure that it operates as a reliable facility as intended. Mr. Gorman noted that the reliability of Edwardsport was a significant concern because Edwardsport was a first of its kind large commercial design of an IGCC. *Id*. at 11-12.

Despite its importance, Duke Energy Indiana had not completed testing of Edwardsport as of March 31, 2014, Mr. Gorman testified. Rather, Edwardsport was in a startup and testing phase through this time, relating to a period wherein GE and Duke Energy Indiana were to ensure that the facility operates consistent with its design and meets all reliability requirements. Startup and performance testing were not completed until May 16, 2014, after the relevant time period, and demonstration tests remained uncompleted during the relevant period.[19] In fact, by the end of March 2014, Duke Energy Indiana had not completed preliminary performance tests; final performance testing; or determined whether Minimum Performance Guarantees had been met. Duke Energy Indiana still could not state whether the plant had satisfied the Minimum Performance Guarantees and the Make Right Performance Guarantees as of December 5, 2014. *Id*. at 12-14.

In addition, Mr. Gorman testified that the way Duke Energy Indiana offered Edwardsport into MISO during the relevant period indicated that it was not operating consistent with its intended use. He explained that Duke Energy Indiana has offered Edwardsport as must-run with the minimum and maximum output dictated by the specific schedule and availability of the IGCC and that during these times, the output of the IGCC is coded as testing. In doing this, Mr. Gorman

[19] Duke Energy Indiana acknowledged that ramp demonstration testing was not completed until November 12, 2014. Stultz Rebuttal at 26.

explained, MISO follows the generation of the IGCC and dispatches the rest of its fleet depending on the generation of the IGCC plant. After the testing on Edwardsport is complete, Duke Energy Indiana will continue to offer it into MISO as must-run at a minimum capacity level. However, MISO will be able to dispatch the unit above the minimum generation level up to its maximum net capability in any given hour, based on its generation cost or bid. Mr. Gorman explained that the fact that this type of offer had not yet been utilized during the relevant time demonstrates that the IGCC had not been utilized as intended. *Id*. at 15.

Mr. Gorman also testified that Duke Energy Indiana had expected the in-service and substantial completion dates to be within about 30 to 75 days of each other. *Id*. at 20; MPG Ex. 19. Mr. Gorman explained that substantial completion would mean that all testing would be complete and the IGCC could operate consistent with its intended use. *Id*. at 16. However, Duke Energy Indiana did not achieve substantial completion within a month or two of its declared in-service date, and instead kept pushing the projected substantial completion date further and further back on its progress reports. *Id*. at 16-17. Mr. Gorman testified that Edwardsport was not substantially complete by the end of the relevant period, and still was not substantially complete as of December 5, 2014. *Id*. at 20. In other words, Duke Energy Indiana's June 2013 expectation of an August 2013 substantial completion date was off by over a year. Mr. Gorman testified that the fact that Edwardsport did not meet Duke Energy Indiana's expectations for complying with testing and meeting clear thresholds such as substantial completion and final completion in a timely manner demonstrates that the IGCC was not in a position to operate at a commercial mode and be declared in-service. *Id*. at 18-20.

Mr. Gorman also discussed the poor operating performance of Edwardsport during the relevant period. Though Duke Energy Indiana had submitted testimony predicting a 72% syngas capacity factor and a 75% syngas availability factor during the first 15 months of operation, the actual performance of Edwardsport was far worse during the relevant period. *Id*. at 20-21. Edwardsport's net capacity factor averaged only 29% through March 2014. *Id*. at 22. Its average net capacity factor on syngas alone was a mere 20.6%, far below what could reasonably be considered the generation of a base load IGCC plant. *Id*. at 23. Furthermore, Mr. Gorman disagreed with Duke Energy Indiana that syngas availability factor was an accurate measure of Edwardsport's performance during the relevant time period because of the way Edwardsport had been offered into MISO and its heat rate. However, Mr. Gorman noted that the plant did not even meet its projections under this metric. *Id*. at 23-25. Instead, Duke Energy Indiana's availability factor on syngas averaged only 34.9% during the relevant period. *Id*. at 25-26.

Mr. Gorman testified that Edwardsport's availability factor on syngas was far lower than its availability factor on both natural gas and syngas, which indicates that Edwardsport was not available to operate on syngas a significant amount of time through March 2014. He reiterated that Edwardsport was designed to primarily operate on syngas, and pointed out that dispatch costs on syngas were lower during the relevant period than dispatch costs on natural gas. Mr. Gorman concluded that Edwardsport's limited availability to operate on lower-cost syngas during this time period indicates the constraints of operating it consistent with its intended use, and producing low-cost energy to serve customers. *Id*. at 26-27.

Mr. Gorman testified that Duke Energy Indiana had an economic incentive to declare Edwardsport in-service prematurely. First, O&M is capitalized during construction, and is therefore subject to the Hard Cost Cap of the 2012 Settlement Agreement until the in-service date. Second, Duke cannot begin collecting depreciation expense until the in-service date. *Id*. at 28. Mr. Gorman concluded that because Edwardsport was not in-service through the IGCC-13 period, Duke Energy Indiana should not be permitted to recover O&M or depreciation expense in this Cause (or in the pending IGCC-11). *Id*. at 29. Furthermore, because Duke Energy Indiana has been recovering projected O&M and depreciation since IGCC-10 rates went into effect on September 12, 2013, Duke owes ratepayers a refund. Mr. Gorman testified that Duke has been recovering approximately $8 million a month in O&M and depreciation expense. He calculated his recommended refund by multiplying $8 million times the number of months between September 12, 2013 and date the rates in the present Cause will go into effect. If an Order had issued in this Cause on January 1, 2015, Mr. Gorman would have recommended a refund of approximately $124 million ($8 million X 15.5 months). *Id*. at 30.

Mr. Gorman offered a different recommendation in the alternative if the Commission were to find that Edwardsport was in-service at some point during the relevant proceedings. Mr. Gorman pointed out that Section 2D of the 2012 Settlement Agreement provides that the non-Duke Settling Parties retained all rights under Indiana law to make arguments and seek relief relating to Edwardsport's post-in-service operating performance. *Id*. at 33. He observed that the operating performance of Edwardsport for the period covered by IGCC-12 and -13 was so bad that ratepayers are entitled to relief under 2D. *Id*. at 34. Mr. Gorman noted that 2D does not establish a standard for determining relief, but recommended that either poor performance or used and useful would be appropriate criteria. Mr. Gorman compared Edwardsport's average syngas capacity factor of 20.6% against its projected syngas capacity factor of 72%, and concluded that it operated at about 28.6% of projections. He also compared Edwardsport's average syngas availability factor of 34.9% against its projected syngas availability factor of 75%, and concluded that it operated at 46.5% of projections. Mr. Gorman then averaged the 28.6% and 46.5% figures to calculate a total performance of 37.55%. Mr. Gorman concluded that Duke Energy Indiana should be permitted to retain only 38% of the return after the in-service date, and that it be required to refund 62% of the return previously collected under IGCC-9 and -10 rates. *Id*. at 35-36.

7. <u>Joint Intervenors' Consolidated Testimony</u>.

a. IURC Cause No. 43114 IGCC-11: Mr. Ralph Smith, Senior Regulatory Consultant at Larkin & Associates, provided two recommendations in his testimony: (1) that the Commission direct the Company to accrue interest at the rate of 8% from the date of collection of the Regulatory Liability, July 29, 2010 through the December 2012 billing cycle, pursuant to the Subdocket Order; and (2) that the Commission direct the Company to credit the Regulatory Liability revenues against the revenue requirement in this proceeding, rather than allowing the Company to hold onto ratepayer money for three more years, as proposed by Ms. Douglas in her supplemental testimony. Mr. Smith explained that this could be accomplished by replacing the one-sixth Regulatory Liability amount, $5,121,965 on Pet. Ex. D-5, with the full $30,731,789 Regulatory Liability amount plus interest at the rate of 8% for the period in which the Company has held the money. Mr. Smith further testified that the Regulatory Liability amount should be reduced by the amount determined by the Commission to pay attorneys' fees and litigation expenses due Joint Intervenors (as well as other non-Duke Energy Indiana parties) and their counsel.[20]

b. IURC Cause No. 43114 IGCC-12/13: Mr. Smith testified to his opinions that (1) the evidence does not support the Company's June 7, 2013 in-service declaration as an IGCC Plant; (2) the evidence does not support that the Plant was in-service at any time between June 7, 2013, through March 31, 2014; (3) the Commission should disallow a substantial portion of costs claimed and refund a substantial part of costs projected in prior proceedings for the period of April 1, 2013, through March 31, 2014; (4) the Commission should establish an operating expense cost cap and performance standards for the future commercial operation of the Plant; and (5) the Company's proposal presented in IGCC-11 to amortize over three years the refund or credit to customers associated with the Commission's IGCC 4S1 Order should be rejected in favor of an immediate refund or credit with interest at eight percent.

Mr. Smith claimed that commercial operation of the Plant did not occur during the IGCC-12 and -13 review periods. He referred to the Company's response to a data request in IGCC-8 in which the Company indicated that it would be following FERC's guidance in Electric Plant Instructions 3 and 9 and in Accounting release AR-5, "Capitalization of Allowance for Funds Used During Construction" and FASB's guidance in Accounting Standards Codification ("ASC") section 360-10-30-1, "Property Plant, and Equipment—Overall—Initial Measurement—General—Historical Cost Including Interest" for determining in-service. Mr. Smith noted that ASC section 360-10-30-1 provides that the historical cost of acquiring an asset includes the costs incurred to bring it to the condition and location necessary for its intended use. He identified the intended use of the Plant as an integrated gasification combined cycle generating facility capable of being dispatched economically by MISO and able to produce electricity using gasified coal at a rated capacity of 618 MW from October through May and 586 MW from June through September. Mr. Smith opined that FERC Electric Plant Instructions 3 and 9 were not particularly illuminating as to evaluating whether a plant is in service for its intended use. He further opined that Instruction 9(E) did not permit the Company to declare the Plant in-service before it is operating at levels consistent with commercial operation.

Mr. Smith opined that the Plant was still in the test phase during the IGCC-12 and -13 review periods and was not operating for its intended use. Mr. Smith referenced testimony by Mr. Schlissel as to various tests that the Company had not completed. Mr. Smith claimed that the Company had not met its own criteria for declaring the Plant in service.

Mr. Smith suggested that the concepts of substantial completion and final completion are typically associated with the date of commercial operation. The Company did not accomplish final or substantial completion as of the time testimony was filed in IGCC-13. The Plant was also not operated on MISO economic dispatch during the IGCC-12 and -13 review periods. Mr. Smith

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[20] On October 31, 2013, Joint Intervenors also filed a motion requesting that the Commission set aside, in an interest-bearing account, a part of the refund or credit amount which the Commission determines to be due Duke Energy Indiana customers in order to pay from the "common fund" both the interim and ultimate amounts of attorneys' fees and litigation expenses which the Commission determines to be due to Joint Intervenors, other non-Duke parties, and their counsel. The Commission hereby denies Joint Intervenors' motion as moot.

opined for these reasons that the Plant should not be considered to be in commercial operation during the IGCC-12 and -13 time periods. Mr. Smith identified the following regulatory consequences: (1) depreciation would not be recognized and (2) costs incurred for pre-commercial operation testing and construction would be capitalized as construction costs rather than expensed as operating and maintenance expenses and would be subject to the Hard Cost Cap. Accruals of AFUDC would continue and whether further accruals represent a cost of delay would need to be addressed. Mr. Smith opined that the Plant had not operated consistently at a commercial operating level and that lack of commercial operation was harming customers.

Mr. Smith testified that even if the Plant was "used and useful" as of June 7, 2013, the Company has not demonstrated that the claimed operating expenses are "reasonable and necessary" in their entirety. He suggested that other accounting issues should be separately addressed and recommended that any rate increase be deferred or made subject to refund.

Mr. Smith further testified that there was a need for performance standards and an operating cost cap. He suggested that certain capacity factors should be applied to the IGCC-12 and -13 review period and subsequent periods. He further opined that based on the Plant's performance, customers would pay too much for the Plant's generation. Mr. Smith suggested that the Commission adjust the production plant return and depreciation to reflect the Plant's poor performance and provided an illustrative exhibit to reflect a reduction in revenue requirements. Mr. Smith referred to certain exhibits entered in IGCC-11 as useful in developing an operating cost cap and identified LA-15 as an illustrative calculation of excessive operating costs.

Mr. Smith also expressed concern that the Company's cost classification was inadequately documented, not transparent, and not subject to adequate review. He referenced the Joint Intervenors' discovery requests for work orders, a clear indication of how the Company determines whether costs are subject to the Hard Cost Cap, and a clear indication of how the Company determines whether the costs are an exception to the Hard Cost Cap, and their continued difficulty in evaluating the Company's response. Mr. Smith further expressed concern that the Company is claiming certain repair and related costs as O&M which should be classified as construction costs subject to the Hard Cost Cap. Mr. Smith particularly identified RSC slagging repairs and modifications, and repairs and modifications to other equipment resulting from failures of heat trace and other freeze protection equipment and to liquid nitrogen pumps as potentially misclassified O&M expense. In confidential testimony, Mr. Smith identified six additional O&M projects as potentially misclassified. Mr. Smith testified that Joint Intervenors have not been able to quantify the impact of potential misclassification on IGCC-12 and -13 costs and suggested that the Company make a compliance filing based on a review of expenses classified as O&M.

Mr. Smith referred to the Commission's IGCC 4S1 Order and reiterated Joint Intervenors' position in IGCC-11 that the Commission should order the company to accrue simple interest at the statutory rate of eight percent (8%) per annum from the date of collection on the $30,731,789 Commission-ordered regulatory liability and that the Company should be directed to credit the $30,731,789 in revenues against the revenue requirement in the IGCC-12 and -13 proceeding rather than allow the Company to amortize this amount over three years.

Mr. Schlissel also testified on behalf of Joint Intervenors. Mr. Schlissel testified to the following principal conclusions: (1) the Company's "in-service" declaration as of June 7, 2013, was an attempt to avoid the construction cap because the Plant was not "in service" in a meaningful way between June 7, 2013 and March 31, 2014; (2) the Plant's operating performance between June 7, 2013, and March 31, 2014 was poor; (3) the poor performance demonstrated that the Plant was not in commercial operation as an IGCC base load power plant at the specified rated capacity or ready for commercial operation during the IGCC-12 and IGCC-13 review periods; (4) the Plant was not available at full load nor economically dispatchable by MISO when the Company declared it in-service on June 7, 2013; (5) the Company declared the Plant in service after the gasifiers had only run in parallel for 53 hours; (6) the Company offered the Plant for economic dispatch for a limited number of hours during the IGCC-12 and -13 review periods; (7) there was only one instance in March 2014 when MISO called on the Plant to operate; however, the Company did not start the unit; (8) the Company was still scheduling the Plant as "must run" with MISO as of the mid-September start of the fall 2014 outage; (9) the Company declared the Plant "in service" prior to the completion of testing; (10) the gasification portion of the Plant was not in-service between June 7, 2013 and March 31, 2014, given incomplete testing, ongoing technical issues, equipment problems, and poor availability, and the Plant cannot be considered to be in service as an "integrated" gasification combined cycle power plant; and (11) the Plant's carbon dioxide emissions were substantially higher during 2013 and 2014 than the Company projected in the IGCC-4S1 proceedings.

Based on these conclusions, Mr. Schlissel recommended that the Commission find (1) that the Plant was not "in service" as defined by the 2012 Settlement Agreement at any time during the period June 7, 2013, through March 31, 2014; (2) adopt a performance standard that requires the Company to bear all costs resulting from the Plant's failure to achieve a 72% capacity factor burning syngas during the Plant's first 15 months of commercial operation; (3) adopt a performance standard that requires the Company to bear costs resulting from the Plant's failure to achieve an 82% capacity factor while burning syngas during each twelve-month period following the end of the Plant's first 15 months of commercial operation; and (4) adopt a performance standard that requires the Company to bear costs resulting from the Plant's failure to achieve and maintain the carbon dioxide emissions rate projected during the CPCN proceedings. Mr. Schlissel also recommended that the Commission disallow costs incurred from June 7, 2013, through March 31, 2014, in whole or in significant part, absent a rate case or further special investigation.

Mr. Schlissel disagreed with Mr. Stultz as to whether availability was a better measurement of performance than capacity. He opined that Mr. Stultz's availability factors overstate the Plant's availability because they combine hours when the Plant was available on syngas and hours available on natural gas rather than just state hours that the Plant was available on syngas. Mr. Schlissel testified that the Company's monthly capacity factors on syngas for the months of June 2013 through September 2014 were worse than the 72% average capacity factor projected in IGCC-4S1. Mr. Schlissel also compared the Plant's power capacity output to its full power capacity output rating, referenced the Plant's heat rates, and compared the Plant's monthly equivalent forced outage rate ("EFOR") to an industry comparison group. Mr. Schlissel disagreed with Mr. Stultz that the Plant had performed about as expected.

Mr. Schlissel took issue with the June 7, 2013 in-service declaration, referring to prior testimony by Company witnesses. Mr. Schlissel noted that testing was not completed at the Plant before the Company declared it to be in-service. Mr. Schlissel also noted that the Company had not achieved "substantial completion" or "final completion" as defined in the GE contract. Mr. Schlissel further noted that MISO did not economically dispatch the Plant during the IGCC-12 and -13 review periods.

Mr. Schlissel expressed concern that customers would be charged excessive rates for the Plant's generation. He recommended that the Commission discount capital costs charged to customers to reflect actual generating performance during the period of actual commercial operation. He indicated that he had related concerns as to fuel costs but would defer testimony on that issue because the FAC proceeding initiated by the Commission in Cause No. 38707-FAC-99-S is stayed. Mr. Schlissel further indicated his belief that O&M costs should be discounted to reflect projections the Company made during IGCC-4S1.

As to O&M expenses, Mr. Schlissel expressed a concern that the Company was claiming certain repair and related costs as O&M that should be classified as construction costs subject to the Hard Cost Cap. He specifically identified (1) costs for repairs and modifications necessary to reach "final completion" identified on or after June 7, 2013, which should have been considered a period of further "testing"; and (2) costs incurred on or after June 7, 2013, for repairs and modifications identified during start-up testing, validation and commissioning prior to June 7, 2013, as necessary to reach "final completion."

As to carbon dioxide emissions, Mr. Schlissel noted that the Company's actual emissions were higher during 2013 and the first nine months of 2014 than what Duke Energy Indiana projected in 2007 would be achieved. Mr. Schlissel suggested that this posed a risk to customers that the Plant would be more expensive for customers and that the Commission should adopt a performance standard that requires the Company to bear costs relating to any failure to achieve the carbon dioxide emissions rate projected during the CPCN proceedings.

Mr. Kanfer testified on behalf of the JIs with respect to carbon emissions at the Plant, the Environmental Protection Agency's ("EPA's") proposed Clean Power Plan and implications for Indiana, and specific recommendations.

Mr. Kanfer noted that the Company premised the Edwardsport Project on anticipated carbon regulation. However, the Plant has not achieved the goal of reducing the carbon footprint. Since the Plant has been declared in-service, it has had a higher average carbon emissions rate than the rest of its coal fleet in Indiana. Mr. Kanfer also referred to the Company's latest IRP with respect to the evaluation of energy efficiency and supply side resources.

Mr. Kanfer testified to the EPA's "Carbon Pollution Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 79 Fed. Reg. 34,830-34,958 (June 18, 2014) ("Clean Power Plan Rule"), published June 2014. Mr. Kanfer explained that through the Clean Power Plan, the EPA has proposed emissions standards for each state to meet by developing plans to reduce carbon pollution from existing EGUs. The proposed regulations require each state to develop an implementation plan to achieve reductions in carbon pollution by the 2020-2029 period (interim target) and by 2030 (final target). EPA has proposed that Indiana lower emissions by 16% (interim target) and 20% (final target). Mr. Kanfer testified that generation facilities will have a legal responsibility to comply with the EPA regulations.

8. **Non-Duke Settling Parties Settlement Supporting Testimony.** Mr. Gorman testified on behalf of IG and briefly discussed the issues that his IGCC-12 and IGCC-13 testimony covered, specifically why Edwardsport was not in-service during the relevant period of IGCC-12 and IGCC-13, including the relief the Commission should grant the ratepayers, and secondly, the relief the Commission should grant ratepayers under the 2012 Settlement due to Edwardsport's poor post-in-service performance if Edwardsport were found to be in-service.

Mr. Gorman testified that the 2016 Settlement Agreement is a reasonable resolution to the highly complex technical issues in this case, that a negotiated settlement is a proper method to resolve these issues for both customers and the Company, and that he recommends that the Commission approve the 2016 Settlement Agreement. He opined that the 2016 Settlement Agreement brings significant value to Indiana ratepayers and that in conjunction with the previous 2012 Settlement, brings almost a billion dollars of Edwardsport costs that Duke Energy Indiana will not pass onto ratepayers.

Mr. Gorman explained the importance of certain provisions in the 2016 Settlement Agreement for ratepayers: the Company will write-off $80.3 million of the Regulatory Asset balance of $116.8 million in deferred O&M, leaving a balance of approximately $36.5 million of deferred O&M. The total remaining balance of the Regulatory Asset (estimated to be $148.2 million including $111.7 million in deferred depreciation) will be amortized over eight years instead of three and there will be no carrying cost on the unamortized balance, which will greatly reduce the impact on rates over the first three years, making rates more competitive. In addition, the Company will amortize the Commission-ordered Regulatory Liability over two years instead of three. He also described the O&M and post-in-service capital caps and that they are a very significant benefit for ratepayers that would not have existed absent the 2016 Settlement Agreement. He noted that Duke Energy Indiana projects that O&M costs will exceed the cap by $21.7 million in 2016 and 2017, producing even greater savings to ratepayers.

Mr. Gorman discussed the 2016 Settlement Agreement benefits to Duke Energy Indiana stating that the non-Duke Settling Parties agreement not to challenge O&M recovery through 2017 or its post-in-service capital cost recover through 2018 allows the Company to continue to work out issues at the plant and achieve the performance that ratepayers are expecting. He explained that a major benefit of the settlement is the certainty of the outcome of the proceeding.

Mr. Olson testified on behalf of JIs supporting the 2016 Settlement Agreement stating that it is a reasonable resolution to highly complex technical issues and achieves a reasonable balance between rate impacts and cost recovery. He also opined that the 2016 Settlement Agreement is in the public interest and should be adopted by the Commission. Mr. Olson explained the major concerns that JIs have had with Edwardsport over time, and that while the 2016 Settlement Agreement does not adopt all of their recommendations, it is a compromise that resolves disputed issues.

Mr. Olson provided testimony supporting the 2016 Settlement Agreement, specifically the provisions relating to the in-service date, the O&M and post-in-service capital caps, the Regulatory Asset and Regulatory Liability, litigation expenses, program funding, funding of the common fund, and the Company's commitment to retire or cease burning coal at Gallagher Units 2 and 4 no later than December 31, 2022.

OUCC witness Mr. Wes R. Blakley provided a review of the ratemaking treatment of the 2016 Settlement Agreement. He testified that the items that directly impact rates that mitigate the revenue requirement impact are: the $87.5 million ($80.3 million retail jurisdictional share) reduction of O&M expenses that will be reflected as a reduction in the Regulatory Asset deferrals; a change in the amortization schedule for the Regulatory Asset from three years to eight years; a cap on both O&M expenses and capital expenditures; and a change in the amortization schedule for the Regulatory Liability from three years to two years.

Mr. Blakley also testified regarding the capped O&M and capital expenditures as well as the other achieved benefits of the 2016 Settlement Agreement.

Concluding, Mr. Blakley stated that he believes the 2016 Settlement Agreement is in the public interest in that it provides material financial concessions to Duke Energy Indiana ratepayers that significantly reduces the revenue requirement related to the Regulatory Asset, provides for a cap on O&M expenses through 2017 and capital expenditures through 2018, and limits the Company to the lower of actual cost up to the cap and that if expenditures go above either cap, Duke Energy Indiana must absorb all of the cost without opportunity of recovery later.

9. <u>Individual Intervenors Testimony in Opposition to the 2016 Settlement Agreement</u>. Mr. Mullett testified on behalf of himself and his wife recommending that the Commission reject the 2016 Settlement Agreement. Mr. Mullett testified that the 2016 Settlement Agreement proposes to raise rates which are already too high in relation to the service being provided by Duke Energy Indiana. In his opinion, rates would be "excessive, extortionate and beyond the value of the services rendered," and as such the rates would be "confiscatory as to the rate payer."

Mr. Mullett explained that approval of the 2016 Settlement Agreement would increase the rates customers are presently paying under Rider 61 by approximately 18% on a revenue requirement basis and as a result the typical residential customer using 1,000 kwh of electricity per month would be paying an additional $15 per month. He relied on the calculations performed by JIs witness Smith in IGCC-12/13 that the average cost of electricity from Edwardsport would be 27 or 28 cents/kwh (exclusive of fuel) and between 30 and 32 cents per kilowatt hour (inclusive of fuel), which is almost three times on a per kwh basis what the typical residential customer paid in 2014 and 2015 for all electric service. In addition, customer rates will further increase in 2017 and 2018 because of the operating cost and operating capital cost caps included in the 2016 Settlement Agreement increase 3.5% per year in both 2016 and 2017. Further increases are also likely because the 2016 Settlement Agreement imposes no cost caps after December 31, 2017. Mr. Mullett described the 2016 Settlement Agreement, as an economic and financial matter as "insupportable and unsustainable," as a regulatory matter, simply "incomprehensible and unacceptable," and "grossly inadequate" and a "bad bargain" for customers.

Mr. Mullett described the Regulatory Asset as a "wolf in sheep's clothing." He stated that to date the Commission has not approved the presently proposed Regulatory Asset in any of its IGCC orders, is not analogous to the one proposed in the 2012 Settlement and that there is simply no basis whatsoever for the Company to claim that it was authorized by the 2012 Settlement Agreement or 4S1 final order. The Regulatory Asset proposed here is not a rate mitigation measure, Mr. Mullett said, but is a retroactive regulatory lag mitigation mechanism intended to significantly benefit the Company financially at great expense to customers. He opined that the $80.3 million reduction of the Regulatory Asset is a grossly inadequate consideration for concessions which non-Duke Settling Parties made. Mr. Mullett relied on his exhibit MAM-6 to support his contention that the 2016 Settlement Agreement is unreasonable. He continued his testimony stating that the Regulatory Asset also accrues for future recovery past operating costs which would be disallowed and depreciation expenses which would be deferred were an appropriate Edwardsport in-service date to be established by the Commission in lieu of the premature June 7, 2013 date declared by the Company. Mr. Mullett also argued that the 2016 Settlement Agreement doesn't recognize that IGCC-10 rates have been in effect since September 2013.

Mr. Mullett opines that the Plant should not have been declared to be in-service by the Company any sooner than the results of the April 2, 2014 performance test which were confirmed on May 17, 2014. He relies on the testimonies of JI witnesses Smith and Schlissel filed in IGCC-12/13 and concludes that his opinion is reinforced by the Plant's poor operating performance between June 7, 2013 and March 31, 2014 and that this raises disturbing questions on the criteria used by the Company to declare Edwardsport in-service.

Next, Mr. Mullett discussed the Regulatory Liability. He discussed issues that were previously litigated in IGCC-11 and IGCC-12/13 and which have been consolidated into this proceeding regarding the Regulatory Liability. He testified that more than five years after it began to accrue and three years after the Regulatory Liability was ordered refunded or credited, customers have not received a single dime of refund or credit, nor has the Company accrued any interest on the amount collected. He continues stating that the 2016 Settlement Agreement adds both insult and further injury to customers by proposing to further defer the credit of the remaining $27 million of the Regulatory Liability for two additional years with no interest added for either the delay to date or the additional delay proposed in the future.

10. Duke Energy Indiana's Consolidated Rebuttal Testimony.

a. IURC Cause No. 43114 IGCC-11: Ms. Douglas provided rebuttal testimony disagreeing with Mr. Smith that the Subdocket Order required the Company to compute interest in determining the amount of Regulatory Liability. Ms. Douglas testified that the $28 million Regulatory Liability estimate presented by Joint Intervenors and referred to by the Commission in the Subdocket Order does not include an estimate for interest, nor did the Commission allow the Company to calculate and receive interest on the deferred operating expenses to be included in the offsetting Regulatory Asset or on the net unamortized balance. Ms. Douglas pointed out that Joint Intervenors made this same recommendation and argument in IGCC-10 and that the Commission's IGCC-10 Order referenced the netting of the Regulatory

Liability against the Regulatory Asset created by the IGCC-9 rate mitigation effort, discussed the assumed timing for the recovery of the net amount, and ordered that it would be appropriate to include the regulatory liability and offsetting regulatory asset, "to the extent there is one," in the development of revenue requirements and rates in IGCC-11. Ms. Douglas explained that the Commission did not order the calculation or inclusion of interest on the Regulatory Liability, the Regulatory Asset, or the net amount to be used in the development of IGCC-11 rates.[21] Ms. Douglas also opined that if the Commission had ordered interest to be accrued, the 8% rate proposed would not be reasonable given the current interest rate environment.[22]

Ms. Douglas responded to Mr. Smith's recommendation that customers should be credited with the full amount of the Regulatory Liability stating that the inclusion of the $5,121,965 credit in developing rates in Pet. Ex. D-4 through D-6 was based on the Company's interpretation of the IGCC-10 Order, read in conjunction with the Subdocket Order and the language in the approved 2012 Settlement Agreement. She explained that the IGCC-10 Order included the netting language, referenced the 2012 Settlement Agreement language, and did not specify that the entire regulatory liability amount (or entire regulatory liability amount plus interest) should be credited to customers in IGCC-11 rates and that the Company believes the Commission intended that one-sixth of the net amount should be included in the development of IGCC-11 rates.

She also stated that Mr. Smith did not question the accuracy of the Company's rate calculations or testify that the rates proposed were not computed in accordance with the Commission's orders in Cause Nos. 43114/43114-S1, IGCC-1, and as modified by the Subdocket Order and IGCC-10 Order. She also concluded that Mr. Blakley testified that the figures used in the Company's IGCC-10 revenue requirement and adjustment factors are supported by the Company's testimony, exhibits, and workpapers.

b. **IURC Cause No. 43114 IGCC-12/13:** Mr. Esamann provided rebuttal testimony in IGCC-12/13 responding to statements from the OUCC, Joint Intervenors, and Industrial Group regarding the 2012 Settlement Agreement. Mr. Esamann also testified regarding the various rate penalty proposals advanced by the parties and explained why the proposals are both unreasonable and unnecessary.

Mr. Esamann attached the 2012 Settlement Agreement to his rebuttal testimony, and explained that in 2012 he provided testimony supporting and describing the 2012 Settlement Agreement. In that testimony, Mr. Esamann discussed the key components of the Hard Cost Cap – the definitions of "Construction Costs" and "In-Service Operational Date" which are at issue in this proceeding. *See* Testimony of D. Esamann, Cause No. 43114 IGCC 4S1, Petitioner's Exhibit HHH at 5-6. He stated that the definitions of 'Construction Costs' and 'In-Service Operational Date' make clear that legitimate O&M and capital costs incurred for the Project that are unrelated to actual construction to complete the Project will be eligible for rate recovery in the normal course of business. *Id*. at 8. This reflects the understanding of the 2012 Settlement Agreement at the time it was considered and approved by the Commission.

[21] *See* IGCC-10 Order, p. 27.
[22] Ms. Douglas testified that short-term debt rates range from 0.378% to 0.461% as shown in the Company's AFUDC calculations (Workpaper 26)), the Company's long-term debt rate is 4.90% and the current overall regulatory cost of capital is 6.68%. See, Pet. Ex. C-5, p. 8 and D-5, p. 8.

Mr. Esamann stated that the parties are now attempting to convince the Commission to read additional conditions and operational milestones into the term "In-Service Operational Date." The parties appear to be using their opinion of the Plant's performance as "poor" to claim that Duke Energy Indiana has not complied with the In-Service Operational Date set forth in the 2012 Settlement Agreement. Under their theory, if the Plant is not in-service, then the Station's O&M and fuel costs are all charged to the Hard Cost Cap and are borne by Duke Energy Indiana's shareholders.

Mr. Esamann noted that "In-Service Operational Date" was a negotiated term in the 2012 Settlement Agreement. It contains only three conditions: (1) placed in operation or ready for service; (2) operated on both natural gas and syngas; and (3) not in-service prior to September 24, 2012. *See* 2012 Settlement Agreement, Petitioner's Exhibit 1-A, at 2.F, p.3. The Company subsequently determined that in order to meet the "intended use" accounting guideline, operating both gasifiers together was an additional milestone for in-service determination. Duke Energy Indiana complied with both the terms of the 2012 Settlement Agreement and the FERC guidelines in its in-service determination. The Company applied the FERC guidelines conservatively and it did not rush the Plant in-service when it was first "ready for service."

Consistent with the 2012 Settlement Agreement and the accounting guidance, Edwardsport was "ready for service" and "in operation," having "operated on both syngas and natural gas" on June 7, 2013. The gasifiers were first lit off on October 25, 2012 and December 8, 2012. The two gasifiers then operated for 368 hours (gasifier 1) and 710 hours (gasifier 2) prior to in-service. Combustion turbine 1 operated 1,821 hours, combustion turbine 2 operated 4,632 hours, and the steam turbine operated for 2,816 hours prior to in-service.

Mr. Esamann stated that the OUCC and the Joint Intervenors are now attempting to add operational conditions and requirements to the in-service declaration. The Joint Intervenors have previously requested in the IGCC 4S1 proceeding that the Commission add the same operational milestones to the definition of "In-Service Operational Date." The Commission rejected this position. The Joint Intervenors are now attempting to re-litigate this issue and impose an interpretation that is not consistent with the 2012 Settlement Agreement.

Mr. Esamann stated that Duke Energy Indiana has been clear with both the parties and the Commission that in-service would precede Substantial Completion of the GE Contract and the 2012 Settlement Agreement makes it clear that these concepts are distinct. The suggestion that the Commission should now interpret In-Service Operational Date to require substantial completion of a vendor contract—especially when the parties did not include this requirement in their 2012 Settlement Agreement—is an attempt to unilaterally amend the 2012 Settlement Agreement's definition of this term.

Mr. Esamann disagreed with the assertion that the Company had an incentive to rush Edwardsport into service. He stated that it would be a greater risk to "rush" in-service of the most closely watched generating facility in Indiana, especially knowing that the Company's determination would be second-guessed by the OUCC and the Intervenors and reviewed by the Commission.

With respect to "Construction Costs," Mr. Esamann stated that the OUCC's position is not consistent with the 2012 Settlement Agreement. Mr. Esamann stated that he believed that Mr. Alvarez's position was that even if the Plant was in-service, all costs and expenses incurred during start-up, testing, validation, and commissioning (in other words, the entire period of this proceeding), should be considered necessary to reach "final completion" under the GE Contract. This is not consistent with the 2012 Settlement Agreement and would render meaningless an entire clause in the definition of "Construction Costs." Mr. Esamann stated that the better interpretation is that there can be normal O&M and normal subsequent ongoing capital expenditures that occur after in-service that are not included in the definition of Construction Costs and are therefore not subject to the Hard Cost Cap. Those are the costs that the Company has requested for recovery in this proceeding.

Mr. Esamann stated that the Company has diligently worked to ensure that "Construction Costs" are not included in the rates proposed for recovery. The costs needed to complete Edwardsport, the costs to replace portions of Edwardsport that were improperly designed or constructed, and the costs originally contemplated under the GE Contract are all considered Construction Costs and they have not been included herein. Due to the 2012 Settlement Agreement and the Hard Cost Cap, Duke Energy Indiana has been even more conservative than it normally would be. Duke Energy Indiana shareholders have borne approximately $900 million of the construction costs for Edwardsport under the terms of the 2012 Settlement Agreement and that number could continue to grow.

Mr. Esamann testified that the 2012 Settlement Agreement did not specifically define "start-up, testing, validation, and commission" as those terms are used in the definition of "Construction Costs." Duke Energy Indiana thought it made sense to refer to the definitions of those terms found in the GE Contract because they are objective and consistent with the 2012 Settlement Agreement's use the contract for other terms. Under the definitions in the GE Contract, start-up occurred on May 15-16, 2014, testing was completed in November 2014, validation occurred in May 2013, and commissioning was completed in approximately September 2012. The final "test" contemplated by the contract, the facility operability demonstration, occurred on November 12, 2014. Mr. Esamann stated that in his opinion, completing start up, testing, validation, and commissioning is not significant to when the Plant was in-service. Achieving these milestones simply moves Edwardsport closer to final completion of the GE Contract.

With respect to the parties' assertion that customers are entitled to various penalties because Edwardsport has not achieved Duke Energy Indiana's expectations, Mr. Esamann stated that these were modeling assumptions—not guarantees. The Commission has repeatedly refused to impose specific performance guarantees on the Plant, and the OUCC and the Intervenors' attempts to now add such guarantees are inappropriate.

Mr. Esamann conceded that during the first nine or ten months of operations, the Plant did not meet the expected 75% average availability. There have, however, been months during this review period where the Plant's performance exceeded the Company's early assumptions. Edwardsport is capable of meeting, and in fact has met, the levels of performance that were expected at the time the Company received approval of the CPCN and CPCN modifications. There are no known equipment or operational issues that will prevent the Plant from performing as expected in the long term.

Mr. Esamann strongly disagreed with the OUCC's and Intervenors' conclusions that the Plant's performance means it is not in-service and that vague references to "poor performance" automatically require a disallowance of O&M expense recovery or a reduction in the Company's return on its investment. A blanket condemnation of "poor performance," without more, does not provide sufficient rationale for the Commission to disallow costs or expenses associated with Edwardsport. There is simply nothing in the statute that provides for a disallowance of costs and expenses because a generating asset did not meet an earlier forecast of certain metrics.

The Company should not be penalized for missing an operations estimate any more than it should be rewarded for performance that exceeds early-stated assumptions. That is simply not the statutory construct for the plant in Indiana.

Mr. Esamann testified that he does not mean to say that the Company should not be held accountable for operations at the Plant. Rather, it means that the Company should be held accountable only when it is deemed to have acted imprudently considering the facts known at the time of such action. No party has provided any evidence of imprudent actions and, in fact, the Company has demonstrated the reasonableness and necessity of its O&M and additional capital projects requested for recovery. Moreover, Mr. Esamann noted that through the 2012 Settlement Agreement, the Company has already been held accountable during this review period. Many of the reasons the Plant has not been available or has been derated during this period are due to equipment or operational issues that were identified by the Company as "Construction Costs" and are being borne by the Company's shareholders. To require a penalty on top of paying for the expenditures required to correct the identified issues would be unduly harsh and unwarranted. Mr. Esamann stated that even if the Commission determined that it did have the authority to implement a performance standard for Edwardsport, it would be inappropriate to impose it now, during the early months of operation.[23] The Company needs time to work through equipment and maintenance issues in a reasonable manner.

In response to the Commission's January 16, 2015 Docket Entry, the Company also submitted Petitioner's Exhibit 11, which addresses the Commission's request for additional information related to page 12 of Mr. Esamann's rebuttal testimony regarding the temporal relationship between the in-service and substantial completion status of Edwardsport and the variation in the temporal relationship between the time of the negotiation of the 2012 Settlement Agreement and March 2014. The Company explained that it has long forecasted that in-service would precede Substantial Completion because the GE NPI testing requires integrated operations of the entire facility. The planned sequence of events—in-service, substantial completion, and final completion—has not varied since October 2010, when the construction schedule had proceeded far enough to project both an in-service and substantial completion date.

[23] In its Order in Cause No. 43114, the Commission found that "there is no statutory basis for limiting the Company's rate recovery based on the plant achieving a certain minimum capacity factor." November 20, 2007 Order at 38-39.

The Company explained that as construction proceeded, the time between milestones was adjusted for different reasons. In the IGCC-9 schedule, substantial completion was projected for nine months after in-service of the power block and seven months after in-service of the gasification island. In IGCC-10 and -11, the schedule revised the gap between in-service and substantial completion down to three months and one month, respectively, because the in-service date had moved out, and other major milestones were projected to occur prior to in-service, requiring less time between in-service and substantial completion. In IGCC-12, the Company's filing reflected the actual in-service date of June 7, 2013, and projected substantial completion approximately four and one-half months after in-service due to changed circumstances known to the Company, specifically, the grey water concentrator fan failure that kept gasification down until resolution in early July 2013 and delayed NPI testing. Another condition that affected substantial completion was completion of the performance tests. Mr. Stultz's testimony in IGCC-12 reflected the anticipated difficulties in scheduling the performance testing, including the wintertime freezing weather. GE ultimately performed the preliminary performance test on April 2, 2014, with the final thermal performance test on May 15-16, 2014. The Company then waited for GE to complete the Documentation and operability demonstrations required under the contract. The Company accepted GE's notice of substantial completion on December 17, 2014.

The Company also referred to prior testimony regarding the Company's aggressive scheduling, knowing that if unexpected delays occurred, the schedule could be extended. The delay in reaching substantial completion was a delay in reaching contractually required milestones, not a delay that impacted operations.

Mr. Wiles testified regarding the Company's in-service determination for the Plant in accordance with normal accounting guidelines, the Company's long-standing practices, and the 2012 Settlement Agreement. He also explained that Duke Energy Indiana followed normal accounting guidance for determining whether a specific cost item should be capitalized to the original IGCC construction project budget, expensed as O&M, or capitalized as an ongoing plant replacement or addition.

Mr. Wiles summarized the following major conclusions of his rebuttal testimony: (1) The definition of In-Service Operational Date was a concept included in the 2012 Settlement Agreement, as to which Mr. Wiles provided testimony, and the Company's declaration of the Plant as "in service" was consistent with the position explained to the Commission in 2012. (2) Major projects regularly have some costs charged to capital project accounts after an in-service declaration and this does not indicate the project was prematurely declared in-service. (3) FERC guidance provides that "testing" can occur post-in service, and this was explained in the 2012 Settlement Agreement proceeding. (4) Accounting guidance indicating that an asset should be "ready for its intended use" prior to in-service means that the cost of acquiring or constructing the asset includes the costs incurred to bring it to the condition for its intended use—because the intended use for the Edwardsport IGCC Plant is as an integrated gasification combined cycle facility, the Company agreed not to place the Plant in service before operating it on both natural gas and syngas. (5) The in-service determination for utility assets does not depend on "substantial completion" of all major project vendor contracts. (6) In the 2012 Settlement Agreement proceedings, the Joint Intervenors attempted to add additional conditions to the in-service declaration, but the Commission did not accept those additional conditions in approving the 2012

Settlement Agreement; in this proceeding, the parties propose adding similar conditions after the fact, which is unfair. (7) The Company's independent external auditors concur with management's in-service declaration, and neither the Securities and Exchange Commission ("SEC") nor FERC have challenged the Company's determination.

Mr. Wiles explained that he testified before the Commission during the 2012 Settlement Agreement proceedings and was cross-examined by Joint Intervenors on the meaning of "In-Service Operational Date." He noted that the 2012 Settlement Agreement specifically defines it as follows:

> "In-Service Operation Date" means the first date by which the Project has both (1) been declared in-service in accordance with FERC guidelines as the earlier of the date the asset is placed in operation or is ready for service; and (2) has operated on both natural gas and syngas; provided however that the In-Service Operational Date shall not be prior to September 24, 2012.

Mr. Wiles explained that by incorporating FERC guidelines and adding additional criteria, the definition was conservatively consistent with traditional utility accounting and ratemaking guidelines for determination of in-service status. Mr. Wiles further explained that the FERC Accounting Release Number 5 ("AR-5") Revised provides: "Capitalization of AFUDC stops when the facilities have been tested and are placed in, or ready for, service. This would include those portions of construction projects completed and put into service although the project is not fully completed." He noted that this guidance indicates that a portion of a project could be completed and put into service even though the project as a whole is not complete. Given this guidance, the Settling Parties agreed to add specific conditions that the Plant would not be placed in service until it was operational on both natural gas and syngas and would not be placed in service before September 24, 2012.[24]

Mr. Wiles noted that he also testified during the Settlement Proceedings to certain operational milestones that the Company anticipated meeting prior to declaring the Plant in service, including swapping out the second instrumented rotor. Mr. Wiles further noted that he also testified in the Settlement Proceedings to the accounting implications of declaring a project in-service. Costs associated with operating the Plant, such as labor and fuel costs are no longer capitalized but are expensed. However, it would be typical for final completion costs associated with construction to continue to be capitalized to the project. Normal O&M incurred after in-service that is not required for final completion would either be expensed or capitalized as maintenance capital.

Mr. Wiles disagreed with Mr. Gorman's assertion that because capital project costs are still being incurred, the Plant is not ready for its intended use. Mr. Wiles indicated that the 2012 Settlement Agreement is functioning as intended because the Company is charging to the original construction capital project the costs incurred for repairs or modifications identified prior to in-

[24] Mr. Wiles also noted as an aside that the Plant must follow income-tax guidelines and rules for in-service determinations for income tax purposes, and therefore, the Company placed the gas portion of Edwardsport in service for income-tax purposes in 2012 and the remainder of the Plant in service for income-tax purposes as of June 7, 2013.

service or during start-up, testing, validation and commissioning of the Plant that are necessary for Final Completion. That circumstance—which was specifically contemplated by the 2012 Settlement Agreement—does not indicate that AFUDC should continue to be incurred or that the Plant is not ready for service.

Mr. Wiles also responded to Mr. Smith's suggestion that the Company is treating as a loophole the Uniform System of Accounts, Electric Plant Instruction 9(E) relating to how the cost of efficiency or other tests should be charged after equipment becomes available for service. He referenced the language of the instruction, which clearly provides that testing can occur subsequent to an asset being declared in service. Mr. Wiles did not agree that the Company views this guidance as a loophole but rather indicated that it is consistent with his understanding and prior testimony regarding FERC AR-5, which provides that capitalization of AFUDC stops when the facilities have been tested and are placed in, or ready for, service. Mr. Wiles further referenced prior testimony in 2012 that addressed pre- and post-in-service testing and the interrelation with the GE NPI testing process that was expected to extend beyond in-service.

Mr. Wiles testified to his understanding that the Company's agreement that in service of the Plant would occur when it is "ready for its intended use as an integrated gasification combined cycle generating facility" essentially had the same meaning as saying that the Plant would not be declared in service until it had operated on both natural gas and syngas. Mr. Wiles testified that he believed that the accounting guidance regarding a plant being ready for its intended use supported and was consistent with that provision in the 2012 Settlement Agreement. Mr. Wiles further testified that the phrase "ready for its intended use" came from the FERC accounting guidance in AR-5 and also appears in Financial Accounting Standards Board's guidance in Accounting Standards Codification section 360-10-30-1, "Property, Plant, and Equipment—Overall—Initial Measurement—General—Historical Cost Including Interest." Mr. Wiles viewed this guidance as indicating that the cost of acquiring an asset, or constructing it, includes the costs incurred to bring it to the condition for its intended use. Because the Company viewed the Plant as an integrated gasification combined cycle facility, it agreed not to place the Plant in service prior to operating it on both natural gas and syngas.

Mr. Wiles rejected Mr. Gorman's suggestion that "ready for its intended use" or "ready for service" require that the Plant be capable of reliably producing baseload energy from syngas at or near its maximum capacity. He testified that there is no basis for this assertion in accounting principles. He further rejected Mr. Gorman's suggestion that the concept of "substantial completion" has any relevance to the in-service determination. Mr. Wiles denied Mr. Schlissel's suggestion that the "in-service" declaration should not occur until the Plant is operated at 100% power while operating on syngas, have achieved "substantial completion," been offered to MISO for economic dispatch while operating on syngas, and completed its preoperational and startup testing. He noted that Mr. Schlissel's testimony adds several factors not contemplated by the accounting guidelines used by utilities for years in determining when an asset is in service. He further noted that Mr. Schlissel had offered similar suggestions in the 2012 Settlement Agreement proceedings, which the Company had opposed at the time because the 2012 Settlement Agreement's definition of "in service" was consistent with traditional accounting practices. Mr. Wiles noted that the Commission did not adopt Mr. Schlissel's recommendations to alter the "in service" criteria in the 2012 Settlement Agreement but approved the 2012 Settlement Agreement as written with respect to this term. Mr. Wiles observed that even though the Commission approved the 2012 Settlement Agreement's specific definition of "In-Service Operational Date," the parties to this proceeding, including the Settling Parties, are attempting to add operational performance standards that were not part of the accounting rules or agreed criteria.

Mr. Wiles testified that the Commission should not add additional operational requirements to the in-service determination. He indicated that in-service is historically determined by utilities pursuant to applicable accounting rules with the ratemaking implications under the purview of the Commission. Mr. Wiles disagreed with Mr. Gorman's suggestion that the Commission is the correct party to determine in service. He noted that the Company management is responsibility for ensuring that the Company's books and records comply with FERC and Generally Accepted Accounting Principles ("GAAP"). The Company is required to file quarterly and annual financial statements and footnotes on relatively short deadlines that require management to assess the status of different matters, including whether projects under construction have met requirements to be placed in service. Filed financial information is not revised unless material errors are determined to have occurred. The timing implications of the quarterly reporting process do not facilitate having outside parties re-assess accounting decisions.

Mr. Wiles noted further support for the Company's in-service declaration. He testified that the external auditors concurred that the timing of the Company's in-service declaration complied with applicable FERC and GAAP requirements. He also noted that an SEC comment letter on the applicable 10-K filing did not question the in-service declaration. Finally, FERC was notified as to the in-service declaration and did not challenge the timing.

Mr. Wiles noted that his 2012 testimony did not identify anything in the 2012 Settlement Agreement that was inconsistent with normal accounting rules or guidance. The 2012 Settlement Agreement includes additional commitments by the Company in the definitions of In-Service Operational Date and Construction Costs that subject more costs to the Hard Cost Cap, not less.

The Company also addressed the Commission's January 16, 2015 request for additional information related to pages 18-19 of Mr. Wiles' rebuttal testimony regarding practical accounting implications if the Commission determined an in-service date for ratemaking purposes distinct from the accounting in-service date. The Company explained that the consequences could not be fully known because other regulatory third parties such as the SEC and the IRS may have issues with a change to the in-service date. The Company theorized that it might be required to restate its books, take additional charges to earnings, and potentially lose or delay all or a portion of tax incentives. If the accounting and tax in-service dates remain unchanged but the Commission determined a different in-service date for ratemaking purposes, then the Company would calculate the economic implications of the different in-service date. That would or could affect the amounts subject to the Hard Cost Cap in the settlement and charges to earnings, depreciation, amounts included in the fuel clause, native/non-native allocations of emission allowances in Rider 63, MISO charges and credits in Rider 68, non-native (off-system) sales profits in Rider 70, all of which would require re-work. The income tax ramifications would need to be assessed and income tax entries booked. There would be ongoing practical implications of additional time, resources, and complexity to track the differing timeframes for recovering depreciation expense from customers versus what is reflected for accounting purposes, essentially requiring a separate set of books to be maintained for the 30-year life of the Plant. Finally, the impact of differences would need to be reflected in the determination of accumulated deferred income tax balances recognized for ratemaking versus accumulated deferred income balances recorded on the Company's books, which would have to be reflected in the capital structure used for ratemaking purposes during the regulatory life of the Plant.

Mr. Swez provided rebuttal testimony explaining dispatch in the MISO markets. He provided background information about MISO and explained that in 2005, MISO began administering markets for electric energy pursuant to its Open Access Transmission, Energy Markets Tariff on file with FERC. Demand bids and supply offers for power are submitted to MISO by market participants, including generator owners (as sellers) and load serving entities (as buyers). The Company functions as both a buyer and a seller in the MISO energy markets.

Mr. Swez stated that MISO uses the offers and bids it receives to arrange a security-constrained, economic commitment and dispatch for the entire MISO region. Once MISO defines a security-constrained economic dispatch solution for a given dispatch interval, it determines market clearing prices in each energy market using the principles of locational marginal pricing ("LMP").

There are five different commit statuses plus the option of Self-Schedule in the MISO energy markets: (1) Must Run; (2) Economic; (3) Outage; (4) Emergency; and (5) Not Participating. Must Run designates the resource as committed per market participant request and available for dispatch. Must Run is a very common status. Most days, over half of all generation committed in MISO is the result of an offer by a market participant as Must Run. As an example, Petitioner's Confidential Exhibit 3-A contains the amount of generation cleared as Must Run in the day-ahead market on January 7, 2015. Must Run is used for periods of unit testing, but also for units for which revenues associated with their dispatch are forecasted to exceed their costs. Economic designates the resource as available for commitment by MISO. Outage designates the resource as not available for consideration because the resource is on generator planned or generator forced outage. Emergency designates that the resource is available for commitment in emergency situations only. Not Participating means that the resource will not participate in the market but is otherwise available. Self-Schedule means that the MW amounts of the unit will be indicated as part of the offer.

A resource can only have one status for each period (i.e., a unit cannot be offered as "Must Run" and "Economic" for the same period). Duke Energy Indiana uses the commit statuses Must Run, Economic, Outage, and Emergency. The Company frequently self-commits its most economic coal-fired generating units, including Gibson, Cayuga, and Edwardsport as Must Run.

Mr. Swez said that when determining an individual unit's offer status, the Company considers various factors such as forecasted LMPs, unit generation production cost, MISO charge type impact, station physical limitations, testing requirements, and the capability and economic impact from cycling the generating unit off-line and on-line.

Mr. Swez stated that the Intervenors are confused about the terms "Economic" and "economic dispatch." "Economic" means that the market participant has designated the resource as available for commitment by MISO, with MISO determining whether the unit will be dispatched and at what level of generation. "Economic dispatch" is an operating procedure used by utilities to supply electricity to their customers using the most cost efficient resources available. It is not true that only units offered to MISO as "Economic" are economically dispatched or are economic to operate. Offering Edwardsport to MISO with a commit status of "Must Run" does not conflict with operating the facility in "economic dispatch."

Mr. Swez testified that being designated as Must Run also does not mean that Edwardsport was performing tests every day. His point in his FAC 101 testimony was to explain how the Company was offering Edwardsport into MISO and why. His purpose was <u>not</u> to provide evidence on whether Edwardsport was "testing" while in a "test phase" producing "test energy." When Mr. Swez coded Edwardsport as "test," it was for internal purposes to reflect that fuel costs would be allocated to native load customers. Moreover, his use of "testing, tuning, and optimization" meant that during the time period in question, Edwardsport was being offered to MISO with a commitment status of Must Run with the minimum and maximum output dictated by the specific test schedule and the units' syngas availability. When no specific testing was occurring, the unit was typically committed and operated at the highest syngas production available. If syngas was unavailable, it was typically offered on natural gas with the commit status of Economic.

Mr. Swez stated that by specifying the minimum and maximum outputs as the same, MISO followed the output of Edwardsport when operating on syngas. Because the minimum and maximum outputs for Edwardsport was relatively close together, there is not much of a difference between the unit's minimum and maximum load. Once Edwardsport is up and running on syngas, the economic choice is to run the unit up to its maximum output.

In Petitioner's Exhibit 11, the Company separately addressed the Commission's 1-16-15 request for additional information related to page 19 of Mr. Swez's rebuttal testimony regarding his belief that the Plant was economically dispatched after June 2013. The Company explained that after June 2013, the Plant was offered to the MISO energy markets in a manner that considered its economic costs and, following submission of that offer, MISO performed a security-constrained economic dispatch of the entire MISO energy market. Specifically, the Company performed a daily forecast of unit revenues and costs to determine the unit's commit status offer; when the unit was offered with a commit status of Economic, MISO could commit and dispatch the unit, and when the unit was offered with a status of Must Run, MISO could dispatch the unit to either the Emergency Maximum or Minimum. The Company explained that it performs a forward-looking analysis each day to determine the offer to MISO. A backward-looking analysis can also be performed to reflect how the Plant's economic costs compared to the MISO energy markets, but this analysis does not reflect the reality of the decision-making process, i.e., the offer must be made on projections and forecasts. If an operational issue affects performance, the backward-looking analysis would suggest the unit was uneconomic, even if the right decision was made in bringing the unit online based on forecasts.

To fully respond to the Commission's request, the Company provided a confidential chart displaying a monthly comparison of the unit's expected cost versus the LMP at the station's node. Both the incremental and average cost of the unit are reflected. The Company explained that it is typical for large coal units to have incremental costs above the Locational Marginal Cost during off-peak. The Company further noted that the production costs are not adjusted to account for a change in the coal contract resolution, which is a recent development that will be addressed in Mr. Swez's FAC 103 testimony.

Mr. Stultz provided rebuttal testimony to discuss Edwardsport's operations including the performance metrics used by Duke Energy Indiana, gasifier starts, the Company's in-service declaration, and Duke Energy Indiana's process for flagging O&M costs and expenses for review under the 2012 Settlement Agreement's definition of "Construction Costs."

As to the performance metrics used by Duke Energy Indiana, Mr. Stultz stated that Duke Energy maintains operational and performance data on all of its units in order to comply with NERC's Generating Availability Data System ("GADS"). GADS specifies both the type of unit operating data that is to be provided, as well as the manner in which the data is collected and calculated. Mr. Stultz stated that a "GADS event" is a record of a change in the generating state of a unit. GADS events are mostly associated with forced losses of generating capacity. Although NERC publishes summarized reports of GADS information, detailed GADS data at the individual generator level is not publicly available.

Mr. Stultz testified that the GADS system was designed around reporting for traditional, conventional generating units that typically use a single primary fuel source and a single generator. For these units, defining "in-service" or "start-up" is straightforward. Edwardsport, however, was designed with extensive operational flexibility. As a result, defining the "unit" for GADS metrics is difficult. Nonetheless, the metrics that Duke Energy Indiana provided as part of Mr. Stultz's testimony were compiled in accordance with GADS instructions. Because Duke Energy Indiana reports its operational metrics in accordance with GADS instructions, Mr. Stultz explained that its availability factor is not, as Mr. Schlissel contends, an "inflated" representation of the unit's availability.

Mr. Stultz reiterated his belief that availability factor is the most important operational factor for a plant operator, however, there is no need to decide on a single performance metric because Duke Energy Indiana will continue to provide a variety of statistics to help the Commission gain a full view into the Plant's operations. *See* Petitioner's Exhibit 4-A (station performance metrics from June 2013 through November 2014).

Mr. Stultz stated that the Plant's ability to run on both natural gas and syngas should not be ignored or discounted. He stated that while the Company built an integrated gasification combined cycle facility, which can run on both fuels, it is optimized to run on syngas, and the Company expects it to run primarily on syngas. Although the Plant has not frequently operated on natural gas only, it could run in that state. The fact that the Plant has not frequently run on natural gas alone means that viewing the Plant as a whole is not skewing or "inflating" the numbers, but is considering the integrated nature of the system. Trying to confine the station's net capacity factor to "syngas only" is not necessary because the station has not frequently run when it is solely available on natural gas. Therefore, the net capacity factor figures are a valid measure of the plant's performance, capturing the actual generation of the station. Edwardsport's average net capacity factor post-in-service through November 2014 is 38.82%, which reflects three maintenance outages, the cold winter months of 2014, the best month of November 2014, and the summer months that range between 58.39% and 67.63%. Edwardsport's net capacity factors can be compared to the GADS five-year average data for combined cycle units of 47.67%. Just like the other NERC average data, the Plant has experienced some months below the NERC averages and some months above the averages.

Mr. Stultz testified that operating the Plant has been challenging due to a series of equipment issues, but characterizing the Plant's performance as "poor" is overly simplistic and unfair. Duke Energy Indiana has been upfront with the Commission and the parties about the fact that the Plant took longer to build than expected and that equipment issues have occurred. However, if the sole standard for judging the Plant's operations is whether or not it had 75% or 85% availability on a monthly basis, then positive outcomes along the way will be overlooked. Mr. Stultz testified that the Plant did meet expectations several months and stated he had no reason to believe that it would not achieve this more regularly going forward.

Mr. Stultz also explained that the Company's O&M costs and budget as presented in this proceeding were reasonable. He stated that, in his opinion, the Company has managed the Plant's O&M budget reasonably and that the O&M costs and additional capital included for recovery in this proceeding are reasonable and necessary. Mr. Stultz identified several reasons that the current O&M estimate is higher than the 2006 estimate: (1) OSHA regulations and other safety-related factors required the Company to hire a larger workforce than originally contemplated; (2) the actual costs of the reagents and chemicals necessary to operate the plant were higher than expected; (3) the cost to insure the Plant against catastrophic property damage was considerably higher than expected; and (4) the GE-recommended outage and maintenance schedule for the major equipment in the plant was different than expected.

With respect to the Plant's heat rate, Mr. Stultz stated that the Company has never expected the Plant to operate at the Net Facility Heat Rate on a daily, or even regular, basis. A number of conditions can impact the heat rate, including ambient conditions, gasifier starts and stops, and periods of time operating on natural gas. Accordingly, the Plant's heat rate, just as with other operational metrics, should be viewed over longer-term operations.

Next, Mr. Stultz testified that Mr. Alvarez's assumption about how Duke Energy Indiana records and reports the start of a gasifier is incorrect. Duke Energy Indiana does not reflect a gasifier "start" when the gasifiers are preheated. Rather, the "start" occurs when syngas is being produced. Accordingly, there is no reason to reduce the number of run hours by 50 hours for every start as Mr. Alvarez suggests.

Mr. Stultz recalled the prior Commission decision in Cause No. 40003 involving whether Wabash River Repowering was "used and useful" for purposes of inclusion in the Company's rate base. He noted that the Wabash River case was a situation in which the Commission considered and addressed a contested used and useful determination, which is instructive in this proceeding. Like Wabash River Repowering, Edwardsport was completed, was operational, had been operated, and had provided electric service to customers prior to its June 7, 2013 in-service date (and continues to do so). In comparison to Wabash River Repowering's synchronization to the grid five months prior to in-service, having produced 58,000 megawatt-hours and 7,924 megawatt-hours from syngas, Edwardsport was first synchronized to the grid in March 2012 (about 15 months prior to in-service) and delivered 953,136 megawatt-hours to the grid prior to in-service, including 238,211.8 gross megawatt-hours from syngas.

Mr. Stultz stated that the October 28, 2013, and November 26, 2013 letters from GE were written to support GE's position that they did not want or need to conduct contractually required performance tests. GE tried to include all issues it could think of to support not running the tests and the letters were written with an eye towards the already known litigation (the arbitration) and towards potential future litigation. As a result, the GE letters are inherently untrustworthy and should not be relied upon to accurately reflect the plant's operational abilities. Using GE's letters as evidence of whether the Plant was ready for service on June 7, 2013, is improper. These letters are filled with commercial posturing and biased, self-serving comments and they should be given little or no weight in assessing the Plant's operations.

Mr. Stultz explained that Edwardsport completed validation under the GE Contract upon replacement of the instrumented rotor with the permanent one. To the extent that "validation" refers to NPI testing, numerous Duke Energy Indiana witnesses have testified that NPI testing would continue after in-service and "it is not necessary or even desirable to complete NPI prior to in-service." Cause No. 43114 IGCC 4S1, Rebuttal Testimony of Mr. Womack, Petitioner's Exhibit LLL, p. 3. In any event, significant testing and validation was performed prior to in-service. *See, e.g.*, Cause No. 43114 IGCC-9, Testimony of Mr. Womack, Petitioner's Exhibit A, p. 3; Cause No. 43114 IGCC-9, Testimony of Mr. Stultz, Petitioner's Exhibit B, pp. 4, 6-7. Mr. Stultz noted that Petitioner's Exhibit 4-B contains copies of the System and Area Turnover Status charts filed in IGCC-9, IGCC-10, and IGCC-11, demonstrating the progress of the Joint Validation Review Board and the start-up and test group in performing the test plans for each system and area in its respective turn-over to the operations group. Mr. Stultz rejected the contention that the Plant should not have been run without completing NPI phases 6-8. Duke Energy Indiana had been forecasting for some time that in-service would occur prior to completing NPI testing, prior to performance testing, and prior to substantial completion of the GE Contract. Petitioner's Exhibit 4-C contains copies of the Startup & Commissioning Major Milestones schedules that Duke Energy Indiana previously filed in Cause Nos. 43114 IGCC-9, IGCC-10, and IGCC-11, which all show that in-service would predate NPI testing completion and substantial completion of the GE Contract.

With respect to "Construction Costs," Mr. Stultz testified that Duke Energy Indiana has gone above and beyond a reasonable, good faith effort aimed at ensuring that no Construction Costs were included as part of the O&M or ongoing capital expenses in this proceeding. In addition to the regular meetings that Mr. Stultz's team convened to ensure that no expenses were presented for recovery in this proceeding that would contravene the Commission's Order in Cause No. 43114 IGCC-4S1, the Company also conducted training at Edwardsport to ensure that employees understood how to charge work and supplies post-in-service.

As to the Maximo maintenance work orders that attracted Mr. Smith's attention, Mr. Stultz stated that Mr. Smith's reliance on these work orders is problematic because they are used primarily for maintenance scheduling and not for accounting purposes. Although Duke Energy Indiana attempted to explain this during the discovery process, confusion apparently continues. Just because a maintenance work ticket is written by plant personnel does not mean that any costs or expenses occur or that any cost or expense for Construction Costs would not be identified and charged to the original construction project. The tickets that Mr. Smith references originated as Maximo work orders, but associated costs were charged to the original construction project as Construction Costs. Again, just because a maintenance ticket was written for a repair in Maximo does not mean that actual costs or expenses arose.

Mr. Stultz addressed each of the Company's ongoing capital projects that Mr. Smith questioned and stated that he and his team have conservatively applied the terms of the 2012 Settlement Agreement related to Construction Costs and they have made a reasonable, good faith effort aimed at ensuring no costs are included in the IGCC Rider that should properly be considered Construction Costs.

Ms. Douglas provided rebuttal testimony to respond to several ratemaking recommendations and assertions included by Mr. Smith. Ms. Douglas also briefly responded to Mr. Gorman's testimony about forecasted operating expenses and to Mr. Smith's and Mr. Gorman's testimony about the use of an operational performance standard in evaluating the amount of cost recovery.

Ms. Douglas stated that, contrary to Mr. Smith's assertions, the Company took appropriate and reasonable steps, in addition to its standard accounting controls, to ensure that the Station's costs were appropriately charged and classified. She explained that key personnel on Mr. Stultz's staff oversaw and reviewed the accounting used at Edwardsport during the IGCC-12 and -13 periods. The referenced meetings were established as a temporary additional control measure while the Plant transferred from construction to operations. The purpose of these meetings was to ensure proper accounting and compliance with the terms of the 2012 Settlement Agreement.

With respect to Mr. Smith's complaints that the workpapers supporting IGCC-12 and -13 were not detailed enough, Ms. Douglas stated that workpapers containing similar detail were provided to support the charges to the original construction project subject to the Hard Cost Cap and for the O&M costs. Moreover, the detail provided is consistent with the detail from the Company's accounting systems, which have been provided in previous Commission filings. Ms. Douglas testified that the level of detail that Mr. Smith is seeking is simply beyond the purpose of workpapers and beyond what is, or can be, reasonably maintained in Duke Energy's financial systems. Ms. Douglas stated that she believes the information that the Company provided reasonably and transparently supports the costs included for recovery in the Rider, especially when reviewed in tandem with the additional detail and discussion provided by Mr. Stultz's testimony.

Ms. Douglas next addressed concerns regarding the use of default O&M accounting. She explained that once a power plant is in-service, costs incurred for items such as labor, chemicals used in processes, and materials and supplies, are properly charged to O&M expense unless there is work involving a retirement unit, in which case the costs are charged to a capital project and capital project account. Costs for operating items are straight-forwardly charged to operating expense accounts. For maintenance work, however, costs may be charged to either maintenance expense or to a capital project, depending on whether the repair involves a retirement unit. The Company uses a maintenance management system to plan, manage, and schedule maintenance work. The system is pre-populated with default accounting for both O&M and capital jobs based on the type of equipment being maintained. This ensures the correct account is charged and it allows the Company to give employees a job number to use when recording their time or when ordering supplies. Because it is not always known when a new maintenance job work order is set up whether the repair will involve a retirement unit, the default is to charge the cost as an O&M expense and then use accounting journal entries to transfer the cost to capital if necessary. Jobs that were known, at the time of establishing the job in the maintenance system, to be major construction project closeout items used the major construction project capital accounting. For previously unidentified jobs, if costs needed to be charged before it was determined that the repair or cost should be considered Construction Costs, the costs were charged to O&M or ongoing capital, and then journal entries were made to transfer the costs to the Hard Cost Cap if appropriate. This use of default accounting is standard practice at all of Duke Energy's stations and enables work to begin quickly.

Ms. Douglas also disagreed with claims that the Company has been evasive regarding the classification of O&M expenses. She stated that in response to various requests for accounting documentation, including work orders, the Company attempted to explain that it did not use work orders as part of its accounting code block in its accounting systems (as it once did), but rather used the project field to account for capital projects in its accounting system. The Company subsequently provided additional information that is contained in the maintenance work management system. This information, however, is part of station records, not part of the Company's accounting systems. Because these records are not part of the official accounting system, there are limitations in using them. However, the Company has reasonable accounting controls in place to ensure that the costs presented for recovery were in compliance with the 2012 Settlement Agreement, the Company was transparent in what was presented to support the costs, and the data that the Company provided reasonably enabled the parties to get a good picture of the costs necessary for operating and maintaining Edwardsport during the IGCC-12 and -13 review periods.

With respect to the Commission-ordered regulatory liability, Ms. Douglas stated that the Order in Cause No. IGCC 4S1 did not require the Company to compute interest in determining the amount of regulatory liability created for the incremental deferred income tax incentive revenues collected via IGCC-4 rates or on the regulatory liability once it was established. The $28 million estimate presented by the Joint Intervenors, and referenced by the Commission in its Order, does not include an estimate for interest, nor did the Commission allow the Company to calculate and receive interest in the deferred operating expenses to be included in the offsetting regulatory asset or on the net unamortized balance. The Joint Intervenors made the same recommendation and argument in IGCC-10 and the Commission did not order the calculation or inclusion of interest on the regulatory liability, the regulatory asset, or the net amount to be used in the development of IGCC-11 rates. Even if the Commission had ordered interest to be accrued on the regulatory liability (and it did not), the 8% amount proposed by Mr. Smith would not be reasonable given the current interest rate environment and current overall regulatory cost of capital. *See, e.g.,* Workpaper 27 in IGCC-12; Workpaper 25 in IGCC-13; Petitioner's IGCC-12 Exhibit C-2 at 10; Petitioner's IGCC-13 Exhibit B-2 at 11.

As to the recommendation that customers should be credited the full amount of the regulatory liability in this proceeding, Ms. Douglas stated that the Company's inclusion of a credit of $5,121,965 was based on its interpretation of the Commission's language in the IGCC-10 Order, read in conjunction with the IGCC-4S1 Order, and the language in the 2012 Settlement Agreement. Based on this language, Ms. Douglas stated that the Company reasonably believed that the Commission intended that one-sixth of the net amount should be included in the development of IGCC rates, rather than providing customers with the entire amount that was billed to customers while IGCC-4 rates were in effect.

Ms. Douglas next addressed Mr. Gorman's recommendation that Duke Energy be prohibited from recovering projected post-in-service O&M and depreciation expenses in this proceeding by stating, first, that the Company disagrees with Mr. Gorman's analysis and conclusion that the Edwardsport IGCC Plant was not in-service during the actual periods covered by the IGCC-12 and -13 filings. The plant was clearly used and useful, producing electricity for the benefit of customers during the period covered by the filings; therefore, the inclusion of operating costs in IGCC-12 and -13 rates is entirely appropriate. Second, the Commission's initial approval of the use of Standard Contract Rider No. 61 for tracking costs associated with the IGCC facility included the concept of including forecasted operating expenses, including depreciation, in the development of Rider 61 rates, with such expenses to be trued up to actuals in a subsequent rider filing. Ms. Douglas stated that Mr. Gorman's recommendation is inconsistent with the Commission's prior approval of Rider 61 and the tariff language in each Rider 61 tariff that has been approved by the Commission. Moreover, the forecast period included in IGCC-12 and -13 period is April 2014 through March 2015. The Edwardsport Plant generated electricity throughout that period and the Company incurred expenses and other costs to operate and maintain the plant during most of this "forecast" period. Finally, removing the forecasted amounts from the IGCC-12 or -13 rates will cause unnecessary rate volatility for customers if the Commission ultimately agrees with the Company that the Plant was in-service during the forecasted months.

Ms. Douglas stated that Mr. Esamann's testimony best discusses the Company's objections to Mr. Gorman's and Mr. Smith's recommendation of an operating performance standard. Ms. Douglas noted that Mr. Gorman's and Mr. Smith's recommendations would deny Duke Energy Indiana the opportunity to recover the portion of its debt financing costs that it is incurring for the IGCC plant, as well as a return on shareholder invested funds used to finance the Plant. Ms. Douglas testified that Company believes that the standards that Mr. Gorman and Mr. Smith recommended are not reasonable and, in fact, seem designed to be punitive. Mr. Smith seems to believe that the Company should not be entitled to recover even the Hard Cost Cap amount. The Commission has approved the Hard Cost Cap amount, including Additional AFUDC, under the 2012 Settlement Agreement and issued the Company a CPCN for that amount. As a result, the typical CPCN protections apply and there is no basis not to allow full recovery of, and on, the Edwardsport IGCC Hard Cost Cap, plus Additional AFUDC amounts. In addition, both the Industrial Group and the Joint Intervenors seek to hold the Company to a forecast developed before and during construction of the Plant. When that early forecast was not met, they now propose a penalty of over half the Company's return on the Plant. Neither party explains why a reduction in return revenue is the proper "penalty" for what they deem as poor performance. Ms. Douglas opined that even if the Commission believed a performance standard was allowable and appropriate, the design and magnitude of the penalty proposed by the intervenor parties is neither reasonable nor fair.

c. 2016 Settlement Agreement Supporting Rebuttal: Mr. Esamann provided rebuttal testimony disagreeing with Mr. Mullett's characterization of the 2016 Settlement Agreement as "insupportable and unsustainable," "incomprehensible and unacceptable." He stated that the Settling Parties worked long and hard over many months to craft an agreement that every party could support and were willing to ask the Commission to approve. Although the negotiations were at times contentious, each party advocated on behalf of their clients' distinct interests and were willing to compromise. Mr. Esamann testified that arms-length negotiations resulted in an agreement and that the overall result is one each party considers to be reasonable. Parties to a settlement must be willing to set aside their litigation positions, understand that a compromise is inherent in the settlement process, and accept that their perceived risks of litigating a particular proceeding may differ from the other parties at the negotiating table. He explained that all parties to a settlement appreciate the increased certainty that comes with settlement and that it is the hope of all Settling Parties that the Commission agree with them that the 2016 Settlement Agreement is just, reasonable, in the public interest and approve it without change. Mr. Esamann stated that while Mr. Mullett may view the 2016 Settlement Agreement as "grossly inadequate" "bad bargain" for customers, the Settling Parties disagree and reached their agreement only after careful consideration of all of the same issues Mr. Mullett raised in his testimony, as well as other considerations he did not raise.

Mr. Esamann continued his rebuttal testimony addressing Mr. Mullett's testimony on the treatment of the Regulatory Asset in the 2016 Settlement Agreement and referring to the Regulatory Asset as a "wolf in sheep's clothing" and "extraordinary". He reiterated that the 2016 Settlement Agreement provides that the Company will fund $87.5 million of previously incurred O&M and reduce the size of the retail Regulatory Asset by $80.3 million, thus providing a credit to customers of a significant portion of the O&M expenses from Edwardsport that have been deferred in the Regulatory Asset since the June 7, 2013 in-service date. These are costs that customers will not have to pay and which will help to mitigate the impact on customer rates of the remainder of the Regulatory Asset. In addition, the remaining Regulatory Asset will be amortized over eight years. The Regulatory Asset simply consists of Edwardsport depreciation and O&M and is common, Commission approved accounting authority to account for regulatory lag.

Mr. Esamann explained that the Regulatory Asset was not directly created by the 2012 Settlement. However, the history and spirit is what led Duke Energy Indiana to propose to defer and recover over a longer period of time O&M and depreciation from in-service until customer rates are updated. Absent this proposal by the company, customer rates would experience volatility. Mr. Mullett is correct that Duke Energy Indiana proposed to voluntarily continue to defer the operating expenses not recovered via IGCC-10 rates as a Regulatory Asset. However, he is incorrect in his assumption that without the Commission approving this treatment, the Company could not defer its O&M and depreciation for future recovery. The approval sought in IGCC-12 (and which the Settling Parties continue to seek now as part of the 2016 Settlement Agreement) was to extend the period of time over which it would recover that O&M and depreciation with the intention of mitigating rate volatility. The tie to the 2012 Settlement Agreement was merely that the Company suggested a three-year amortization period – the same as that contemplated in the 2012 Settlement Agreement.

Mr. Esamann next addressed Mr. Mullett's statement that Duke Energy Indiana has "no basis whatsoever," to be allowed to ever recover the O&M and depreciation expenses incurred since June 7, 2013 over that which was included in IGCC-10 rates because the IGCC-9 and IGCC-10 orders do not explicitly authorize the present Regulatory Asset to even exist. He explained that Mr. Mullett has chosen to overlook that Edwardsport has been 1) previously granted a CPCN under both Indiana Code 8-1-8.5 and 8-1-8.7[25] and 2) previously approved as a "new energy generating facility" eligible for the "timely recover of costs,"[26] specifically "IGCC Project costs, including financing, O&M, depreciation, property taxes, payroll costs and property insurance costs." In addition, the Company was also approved to defer "post-in-service carrying costs and O&M costs on an interim basis until such costs are reflected in Duke Energy Indiana's retail rates."[27] Mr. Esamann opined that it was his understanding that the Commission's 2007 order in Cause No. 43114 and authorization by Indiana Code 8-1-8.8 approved the timely recovery of O&M and depreciation and deferral of those costs on an interim basis until those costs are included in the next rate case and that it is not "unprecedented" for the Commission to approve such treatment.

Mr. Esamann continued addressing Mr. Mullett's testimony regarding the value of the $80.3 million reduction in the Regulatory Asset. He explained that regardless of whether the Plant is declared in-service on June 7, 2013 or on May 17, 2014, as Mr. Mullett advocates, the Edwardsport depreciation expense remains the same because customers will eventually begin to pay depreciation expense in rates, the only difference is one of timing and that the primary importance of the in-service date is how it impact the Company's recovery of O&M expense. To the extent that Edwardsport was not in-service on June 7, 2013, but instead at some later date, O&M expenses would be considered construction costs subject to the 2012 Settlement Hard Cost Cap and become a shareholder cost, but recovery of depreciation expense would simply be delayed.

Mr. Esamann stated that he believes the Commission should assess the overall reasonableness of the 2016 Settlement Agreement and that he disagrees with Mr. Mullett's suggestion that the $80.3 million reduction of the Regulatory Asset is inadequate because customers could "avoid paying" $155 million by changing the in-service date. Only the timing, not the amount, of depreciation expense is impacted by the in-service date and the Settling Parties set aside any contentions regarding the depreciation expense included in the Regulatory Asset. He opined that should the Commission consider the fact that even if it were to adopt Mr. Mullett's position that the in-service date should be moved to May 17, 2014, the 2016 Settlement

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[25] See the Commission's Order in Cause No. 43114 at p. 43 (November 20, 2007). This original CPCN approval has been subsequently adjusted in both Cause Nos. 43114 IGCC-1 and IGCC 4S1.
[26] *Id*. at 57.
[27] *Id.* This approval was previously challenged by Mr. Mullett, but was affirmed on appeal. See *Citizens Action Coalition, Inc. v. PSI Energy, Inc.*, 894 N.E.2d 1055 (Ind. Ct. App. 2008), *reh'g denied*. The Settling Parties acknowledge that the Commission's 2007 Order did not contemplate the size of the present Regulatory Asset, particularly when on page 49 of that Order, it stated that "the Company is proposing to be allowed to continue the accrual of AFUDC and deferral of operating expenses after the in-service date of the IGCC Project, to the extent that costs are not reflected in Duke Energy Indiana's retail electric rates (*i.e.*, through the IGCC Rider or in base rates). The *differential between post-in-service costs recovered in rates and actual costs incurred will be relatively small if the Company's proposed IGCC cost recovery mechanism is utilized*." (emphasis added)

Agreement provides customers with more than Mr. Mullett's own calculated value of moving the in-service date.

Continuing his rebuttal testimony, Mr. Esamann addressed Mr. Mullett's testimony regarding the fact that IGCC-10 rates have been in effect since September 2013. He explained that the Settling Parties recognized that and included it as part of the 2016 Settlement Agreement. However, while Mr. Mullett's testimony notes while the Settling Parties did consider and include it in the 2016 Settlement Agreement, he stated that he would have liked it to have been recognized more.

Mr. Esamann next addressed Mr. Mullett's testimony summarizing JIs testimony from IGCC-12/13 regarding in-service. The Company previously rebutted JI witnesses Smith and Schlissel in IGCC-12/13 and that testimony has been admitted into the record in the IGCC-12/13 evidentiary hearing and consolidated into this proceeding for purposes of considering the 2016 Settling and as such the Company does not believe Mr. Mullett's testimony in this regard needs to be rebutted for a second time. In addition, there is now additional evidence in the record that JIs, who sponsored Smith's and Schlissel's testimonies in IGCC-12/13, have now agreed to the 2016 Settlement Agreement and that it reasonably and adequately resolves their previously raised concerns.

Concluding his rebuttal testimony, Mr. Esamann summarizes that the Commission should strongly weigh the fact that it – setting aside the two Individual Intervenors joining in January 2016 – has a first of a kind unanimous settlement agreement before it for consideration. Mr. Esamann testified that he is proud of the 2016 Settlement Agreement and the fact that all significant parties have been able to find it to be a reasonable resolution of the issues that have been or could have been raised at this time. It is Mr. Esamann's hope that the Commission will see Mr. Mullett's intervention and opposition for what it is – the continued complaints of one person who was outvoted by his own group, the JIs, on whether the 2016 Settling was reasonable. The Settling Parties have worked hard to craft what they believe to be a reasonable resolution – a Settlement that is in the public interest and should be approved without change by this Commission.

Mr. Davey provided rebuttal testimony responding to Mr. Mullett's rate increase calculations and the rate impact that will result from the 2016 Settlement Agreement. Mr. Mullett states, "To be specific, approval of *the Settlement would increase the rates which DEI customers are presently paying for Edwardsport under Rider 61 by approximately 18%* on a revenue requirements basis." (Mullett, p.8., lines 12 -14, *emphasis added*). He makes the point that Rider 61 *revenue requirements* will increase approximately 18% from the amount included in IGCC-10, but, as shown in Petitioner's Exhibit 3-D (BPD), this will result in an approximately *2.1% average rate increase for retail customers* as compared to their <u>total bills</u>. He also mischaracterizes the bill impact that a typical residential customer will see if the Settlement is approved as a 14.4% increase. (Mullett, p.16, line 9 – 11.) As shown in Petitioner's Exhibit 3-E (BPD), if the Settlement is approved, a typical residential customer will see a *$1.83 a month increase (a 1.6% increase in their total bill.*) Anyone involved in this proceeding, knows that IGCC Rider rates will increase from the level in IGCC-10 because the revenue requirements used to develop the rates currently being charged include operating costs for only four out of six months, or about 67% of a full amount of operating expenses.[28]

Mr. Davey also addressed several other issues with rate increase calculation or characterizations in Mr. Mullett's testimony, *e.g.*, the calculations of cost/generation (kWh) under the settlement that were included in Mr. Mullett's testimony on page 8 used *twelve months of costs* divided by net generation for the *less than ten months* the plant was in-service during the IGCC-12/13 period, the first ten months of operation, which inappropriately inflates the cost/generation. A more representative calculation under settlement terms would replace the stale ten-month generation amount with actual calendar year 2015 generation. In either case, the Settling Parties took Edwardsport costs and operations into account when negotiating and reaching the Settlement. In addition, Mr. Mullett also draws inaccurate conclusions, without providing supporting calculations, that, if the Settlement is approved, customer rates will "rise…by 18% immediately and another 3.5% in both 2016 and 2017…" (Mullett, p.17, lines 14 – 16.) As explained above, upon approval of the Settlement, customer rates will rise by approximately 2.1% on average, not 18%. Mr. Mullett does not provide the derivation or any support for the calculation of his additional forecasted 3.5% increases. IGCC rider rate calculations depend on many variables – the net book value on which a return is earned; the capital structure, cost of capital and income tax rates; the levels of O&M and depreciation and other credits applicable to the period; any reconciliations; as well as sales for each rate group. The Commission should disregard Mr. Mullett's unsupported rate increase forecasts. Also, contrary to Mr. Mullett's assumptions that project "further increases in customer rates in 2017 and 2018 because the operating cost and operating capital cost caps included in the Settlement increase 3.5% per year in both 2016 and 2017" (Mullett, p. 16, lines 14 – 17), as Mr. Davey explained in his Settlement Supporting Testimony, due to declining net book value as depreciation accumulates, it is possible that the 2017 and/or 2018 Rider 61 filings may result in an overall rate <u>decrease</u> for customers. The Settling Parties therefore included provisions in the 2016 Settlement Agreement to set up a process to ensure that if the Rider 61 filing in either 2017 or 2018 has a lower revenue requirement than in the rates currently in effect at that time, the proposed rates would be implemented on an interim basis, subject to refund, to ensure that customers get the benefit of the lower revenue requirements in their rates as soon as possible.

Continuing, Mr. Davey next addressed Mr. Mullett's use of Exhibit MAM-6 to support his position that the value of the 2016 Settlement Agreement is unreasonable. Mr. Mullett states on page 34 of his testimony, "I believe that the capital costs "grossed up" for income taxes included in IGCC-10 rates could exceed those included or expected in IGCC-12 through 17 rates by approximately $80 million cumulatively over the three-years involved. See Exhibit MAM-6". However, MAM-6 includes material assumptions that are not reasonable and, therefore, the calculations and exhibit should not be used as supportive evidence. The exhibit assumes that IGCC revenues associated with the return for IGCC-12 – 15 should have been in effect approximately eight months <u>***before***</u> the rates were filed with the Commission. This is not

[28]See the testimony of Diana L. Douglas in Cause Nos. 43114 IGCC-11(Petitioner's Exhibit C, page 23, lines 19-23, and page 24, lines 1-2), IGCC-12 (Petitioner's Exhibit C, page 21, lines 1 – 6), IGCC-13 (Petitioner's Exhibit B, page 20, lines 16 – 21), IGCC-14 (Petitioner's Exhibit B, page 18, lines 14 – 19), and IGCC-15 (Petitioner's Exhibit B, page 19, lines 9 – 14).

reasonable. A more reasonable assumption would be that rates are effective approximately eight months ***after*** they are filed. The Settling Parties took the declining rate base issue Mr. Mullett is concerned about into account when negotiating and reaching the 2016 Settlement Agreement.

Mr. Davey also responded to Mr. Mullett's discussion of issues that were previously litigated in IGCC-11 and IGCC-12/13 regarding the Regulatory Liability, specifically the timing of amortizing and the interest on the regulatory liability, and testified that these issues were considered by the Settling Parties, including the JIs, and resolved as part of the 2016 Settlement Agreement. Mr. Davey opined that Mr. Mullett is wrong that the 2016 Settlement Agreement does not adequately resolve these issues, and the Commission should find the 2016 Settlement Agreement to be reasonable and in the public interest.

11. Non-Duke Settling Parties 2016 Settlement Agreement Supporting Rebuttal Testimony: Mr. Gorman provided rebuttal testimony responding to IIs conclusion that the 2016 Settlement Agreement should not be approved, is not just and reasonable or in the public interest. Mr. Gorman identified what he considered likely errors in the analysis presented by Individual Intervenors. First, when comparing the cost per kwh of energy from Edwardsport to other plants, the Individual Intervenors did not examine more recent information that showed significantly different results. Second, the Individual Intervenors exhibit MAM 6 incorrectly assumes effective dates that certain rates would have gone into effect, producing flawed results. Further, Mr. Gorman notes that the Individual Intervenors fail to recognize that any delay in an in-service date only delays the payment of depreciation dollars, again resulting in a misstatement of the impact on ratepayers. Mr. Gorman testified that the 2016 Settlement Agreement brings significantly greater benefits to ratepayers than the delay in in-service proposed by Individual Intervenors.

Mr. Gorman testified that as he explained in his settlement supporting testimony, he finds the 2016 Settlement Agreement to be reasonable, in the public interest, to provide a balanced outcome for ratepayers, and brings very significant benefits including large reductions to the costs ratepayers could otherwise bear, and yields reasonable rates.

12. <u>Commission Discussion and Findings</u>.

a. Standard for Commission Review of Settlement Agreements. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Ind. Gas. Co., Inc.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather, [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406 (internal citation omitted).

Further, any Commission decision, ruling or order – including the approval of a settlement – must be supported by specific findings of fact and sufficient evidence. *United States Gypsum,* 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Pub. Serv. Co.,* 582 N.E.2d 330, 333 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC § 1-1.1-17(d). Therefore, before the Commission may approve the Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement is reasonable, just, consistent with the purpose of the Indiana Public Service Commission Act (as amended) and the Utility Generation and Clean Coal Technology Act, and serves the public interest.

We have previously observed that Indiana law strongly favors settlement as a means of resolving contested proceedings. *Indianapolis Power & Light Co*., Cause No. 39936, at p. 7 (Ind. Util. Reg. Comm'n, Aug. 24, 1995). This policy is consistent with expressions to the same effect by the Supreme Court of Indiana. *See, e.g., Mendenhall v. Skinner & Broadbent Co., Inc.*, 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and settlement of disputes.") (internal citation omitted); *In re Assignment of Courtrooms, Judge's Offices and Other Facilities of St. Joseph Superior Court*, 715 N.E.2d 372, 376 (Ind. 1999) ("Without question, state judicial policy strongly favors settlement of disputes over litigation.") (internal citations omitted). A settlement that is found based on substantial evidence to establish just and reasonable rates can resolve the merits of the underlying case. *N. Ind. Pub. Serv. Co.*, Cause No. 43969, 2011 Ind. PUC LEXIS 369 at *186 (December 21, 2011) (quoting *Mobil Oil Corp. v. F.P.C.*, 417 U.S. 283, 314 (1974)).

In addition, we have observed in the past, and reaffirm here, that the propriety of regulatory settlements is enhanced when the settlement is supported by the OUCC, and that settlements may be approved even where contested by a party. *S. Ind. Gas and Elec. Co.,* Cause No. 42596, 236 P.U.R.4th 153, 2004 Ind. PUC LEXIS 262 at *32 (2004); *American Suburban Utils*., Cause No. 41254 at p. 4-5 (Ind. Util. Reg. Comm'n, April 14, 1999).

In this case, the Commission has more than sufficient evidence from which to judge the reasonableness of the terms of the 2016 Settlement Agreement. Settling Parties filed testimony supporting the 2016 Settlement Agreement. In addition, Individual Intervenors filed testimony clearly explaining their objection to the 2016 Settlement Agreement, in response to which the Settling Parties filed rebuttal evidence. The Commission has carefully analyzed the evidence presented in this consolidated docket and the proposed Settlement to evaluate whether the proposed outcome is reasonable, just, and properly balances the interests of Duke Energy Indiana, its customers, and the overall public interest.

b. Evaluation of Individual Intervenors' Objections to the 2016 Settlement Agreement. Individual Intervenors raised several objections to the 2016 Settlement Agreement in their prefiled testimony, summarized as follows: (1) the Commission should not approve the 2016 Settlement Agreement because the Settling Parties agreed that the Company should be allowed to amortize the remaining balance of the Regulatory Asset over eight years and the Company deferred post-in-service operating expenses into that Regulatory Asset without Commission approval or legal authority and because those deferrals violated the prohibition against retroactive ratemaking and the filed rate doctrine; (2) the Commission should not approve the 2016 Settlement Agreement because the Settling Parties agreed that Edwardsport's in-service date should remain June 7, 2013 and Individual Intervenors' opinion is that Edwardsport was not in-service until May 17, 2014; and (3) the Commission should not approve the 2016 Settlement

Agreement because the Settling Parties agreed that the Commission-Ordered Regulatory Liability shall be netted against the Regulatory Asset over two years and no interest should be accrued.

1. The Regulatory Asset. Regarding Individual Intervenors' first argument – that the 2016 Settlement Agreement should not be approved because it would allow Duke Energy Indiana to amortize the remaining balance of the Regulatory Asset over eight years – we disagree with Individual Intervenors that the Company's deferrals of post-in-service operating expenses are contrary to law and have not been previously authorized by this Commission.

In our November 20, 2007 Order in Cause No. 43114, we found that Edwardsport was "eligible for the 'timely recovery of costs' incentive under Indiana Code 8-1-8.8." *Duke Energy Ind., Inc.*, Cause No. 43114 Order at p. 57 (Ind. Util. Reg. Comm'n, November 20, 2007). We also found that "Petitioner's proposed IGCC Rider is approved for use and for the recovery of the approved IGCC Project costs, including financing, O&M, depreciation, property taxes, payroll costs and property insurance costs." *Id.* Further, we approved "deferral of post-in-service carrying costs and O&M costs on an interim basis until such costs are reflected in Duke Energy Indiana's retail rates." *Id*. We acknowledge that at the time of approving such deferral treatment, it was not contemplated that the IGCC-10 rates would remain in effect for such an extended period of time and would not be subject to revision every six months based on the assumed semi-annual IGCC Rider filing schedule. However, we find that the build-up of the Regulatory Asset over this period is not a flaw with the 2016 Settlement Agreement. Rather, the Settling Parties have recognized that the build-up of the Regulatory Asset has occurred and have provided for reasonable mitigation through the write-down of the balance by Duke Energy Indiana and by providing for the amortization of the remaining balance over eight years (as opposed to some shorter period) and doing so without carrying costs.

As we stated previously in our July 17, 2013 Order in Cause No. 44182, I&M's life cycle management proceeding, interim deferred accounting treatment goes hand in hand with timely recovery of costs. Without interim deferred accounting treatment, the Company would not be able to fully recover its operating expenses. The same is true in this instance, which is why we previously approved and authorized Duke Energy Indiana to defer its post-in-service expenses until such expenses are reflected in rates. We also recognized this prior approval in our Cause No. 43114 IGCC-4S1 Order when we approved a certain provision of the 2012 Settlement, explaining that it "contemplates that Duke will defer the actual depreciation and O&M costs (and property tax expenses) incurred for all months from the In-Service Operational Date until such costs are included in the Company's rates, *which is consistent with previously authorized deferred accounting treatment granted for the IGCC Project by the Commission.*" *Duke Energy Ind., Inc.*, Cause No. 43114 IGCC-4S1 Order at p. 93 (Ind. Util. Reg. Comm'n December 29, 2012)(emphasis added).

For these reasons, we reject Individual Intervenors' argument that the Regulatory Asset containing incremental operating expenses over those included in the present IGCC-10 rates is contrary to law. We find that Duke Energy Indiana's deferral of Edwardsport's operating expenses until reflected in rates and the inclusion of those costs in a regulatory asset was previously authorized by our November 20, 2007 order, and is consistent with Indiana law, including Indiana Code 8-1-8.8. We also disagree with Individual Intervenors concerning the eight year amortization period and find that the amortization period is appropriate. We find that the eight-year amortization period will provide customer benefits by spreading the remaining Regulatory Asset balance over a longer period without carrying charges.

Individual Intervenors also argue that the Regulatory Asset is contrary to the filed rates doctrine and the prohibition against retroactive ratemaking. We disagree. The filed rate doctrine prohibits a public utility from charging rates other than those filed with and approved by the Commission. Ind. Code § 8-1-2-44. The Settling Parties have requested we allow Duke Energy Indiana to amortize the remaining balance in the Regulatory Asset over eight years, as part of the 2016 Settlement Agreement. Only after we approve the 2016 Settlement Agreement in this order will Duke Energy Indiana file with us revised rate tariffs consistent with this order – and only after we approve those tariffs may Duke Energy Indiana charge rates that include amortization of the Regulatory Asset. Duke Energy Indiana's deferrals of operating expenses into a Regulatory Asset cannot violate the filed rate doctrine because they are deferring expenses not yet included as part of the filed and approved rate tariffs. The fact that the Company has been charging IGCC-10 rates, which included only 2/3 of its estimated operating expenses, is the precise reason why the Regulatory Asset exists today. At least 1/3 of Duke Energy Indiana's operating expenses from Edwardsport have not yet been included in the filed and approved rates, which is why they have been deferred for future recovery. The mere existence of the Regulatory Asset is evidence that Duke Energy Indiana has not violated the filed rate doctrine. The Company has clearly been charging the IGCC-10 rates, which have been filed with and approved by the Commission.

We similarly reject Individual Intervenors' argument that allowing deferrals of post-in-service operating expenses for future recovery violates the prohibition against retroactive ratemaking. This Commission certainly understands that Indiana law does not allow us to cancel or fix rates retroactively, but to only fix rates for the future. However, Individual Intervenors' testimony points out certain exceptions to this prohibition – all of which apply to Edwardsport. Of primary importance is our prior approval of Edwardsport for timely recovery of its operating expenses under Indiana Code 8-1-8.8 and our prior approval to defer for future recovery post-in-service operating expenses until reflected in rates. We believe that prior approval, with its statutory underpinnings, prevents the recovery of deferred operating expenses being considered improper retroactive ratemaking. We have approved this deferral treatment many times for various public utilities since Indiana Code 8-1-8.8 was enacted in 2002 and it has never before been deemed in violation of the prohibition against retroactive ratemaking. Therefore, we reject this argument of Individual Intervenors.

Individual Intervenors also argue that we should reject the 2016 Settlement Agreement because the Regulatory Asset does not reflect accumulated depreciation. However, the Settling Parties expressly stated in the 2016 Settlement Agreement that they "recognize that because IGCC-10 rates have remained in effect for an extended period of time, the IGCC Rider's revenue requirements have not been put into effect to reflect accumulated depreciation and the related lower capital cost revenue requirements" and that "this matter was evaluated in concept and/or qualitatively by each Party in arriving at the agreed-upon amount of reduction to the Regulatory Asset balance . . . ." 2016 Settlement Agreement at 4-5. We also note that the 2016 Settlement Agreement provides for Duke Energy Indiana to reduce the Regulatory Asset balance by the difference in the revenue requirement associated with the return under the 2016 Settlement

Agreement and the IGCC-10 return revenue requirements starting in July 1, 2016, even if the order in this proceeding cannot be issued by such date. 2016 Settlement Agreement at 3. The evidence presented on this issue leads us to the conclusion that the 2016 Settlement Agreement was crafted with an eye toward the very issue Individual Intervenors raise and we find no basis in Individual Intervenors' argument to reject the 2016 Settlement Agreement.

2. The In-Service Date. Regarding Individual Intervenors' next argument – that we should reject the 2016 Settlement Agreement because it does not change Edwardsport's in-service date from June 7, 2013 to a later date (as Individual Intervenors contend) – Individual Intervenors' testimony largely reiterates the testimony previously filed by Joint Intervenors (a Settling Party) in the IGCC-12/13 docket. In addition to restating Joint Intervenors' previous testimony, Individual Intervenors also point to evidence of the contractually-required final performance test, which was performed by General Electric on May 16-17, 2014, as evidence supporting their proposed in-service date. The in-service issue was thoroughly litigated in the IGCC-12/13 docket and was resolved between all parties to that docket through the 2016 Settlement Agreement before us. We find that the 2016 Settlement Agreement reasonably resolves any issue regarding the Company's in-service determination. The significant reduction in the regulatory asset included in the 2016 Settlement Agreement was intended by the Settling Parties to compensate for the initial operation of Edwardsport after the June 2013 in-service date. As Duke Energy Indiana Industrial Group witness, Mr. Gorman, explained in his Settlement Testimony, "Thus, through its agreement to bear $87.5 million in O&M expenses, Duke is essentially absorbing its entire O&M cost during the period involved in the IGCC-12/13 proceeding plus an additional $32.5 million. If the Commission had decided, for ratemaking purposes, to treat Edwardsport as in-service at the end of IGCC 12 and 13 on March 31, 2014, retail ratepayers would have only benefitted by the $51 million." Gorman, p. 4, lines 11-16. Further, evidence presented by the Company in the IGCC-12/13 proceeding supported a June 7, 2013 in-service determination. Given that the 2016 Settlement Agreement resolves this issue between the Settling Parties, we see no reason that the Company's determination should be adjusted for ratemaking purposes. Therefore, we are not persuaded by Individual Intervenors' evidence and argument that we should not approve the 2016 Settlement Agreement on the basis of its agreed-upon in-service date.

3. The Commission-Ordered Regulatory Liability. Third, Individual Intervenors argue that we should reject the 2016 Settlement Agreement because it does not provide for an immediate refund of the Commission-ordered Regulatory Liability, nor does it require Duke Energy Indiana to add 8% interest to the Regulatory Liability amount. In lieu of Joint Intervenors' previously stated position that Duke Energy Indiana should be required to add 8% interest to the Regulatory Liability, the 2016 Settlement Agreement resolves this issue by Duke Energy Indiana agreeing to shorten the amortization period from three to two years. The 2016 Settlement Agreement also provides that the Settling Parties have agreed that no carrying costs will be added to either the Commission-ordered Regulatory Liability or the Regulatory Asset. To the extent that Individual Intervenors seek to revise our December 27, 2012 Cause No. 43114 IGCC-4S1 Order through this argument, we believe this issue would have been appropriately raised during that proceeding or through its subsequent appeals. Additionally, if we had believed requiring Duke Energy Indiana to add 8% interest to the Regulatory Liability was appropriate and warranted, we would have done so in Cause No. 43114 IGCC-4S1 or when this issue was presented through post-hearing briefing in IGCC-10. We declined to adopt Joint Intervenors' position in our IGCC-

10 order, and decline to do so when raised by Individual Intervenors now. When we chose to eliminate the deferred tax incentive in our IGCC-4S1 order, thus creating the Commission-ordered Regulatory Liability, we did so under the same authority that authorized us to grant it in the first place – Indiana Code 8-1-8.8.[29] This is not the same situation as in the *NIPSCO* case cited by Individual Intervenors[30] – in this instance, we were acting within our discretion to remove an incentive previously granted under Indiana Code 8-1-8.8 – there is no requirement under law that interest be added. There are no "illegal charges" as in *NIPSCO*, nor could a customer bring a common law action for funds owed them. Additionally, we must note that at the time of the *NIPSCO* case, the Supreme Court found that 8% interest was "in this instance, a reasonable gauge of a fair return on one's funds when held by another." *Id.* at 161. Assuming without agreeing that interest must be added to the Commission-ordered Regulatory Liability, given the evidence presented by Ms. Douglas regarding current interest rates and Duke Energy Indiana's cost of capital in this consolidated proceeding, 8% is certainly no longer a reasonable fair return that we would order. In conclusion, we were within our discretion under Indiana Code 8-1-8.8 to both grant and remove a financial incentive. We also disagree with Individual Intervenors that the *NIPSCO* case requires interest be added in this instance, which we find distinguishable from that in *NIPSCO*. We therefore find the 2016 Settlement Agreement provisions reasonable and decline to provide for an immediate refund of the Commission-ordered Regulatory Liability or require Duke Energy Indiana to add 8% interest to the Regulatory Liability amount, as suggested by Individual Intervenors.

c. Evaluation of the Reasonableness of the 2016 Settlement Agreement. Having addressed the key issues raised by Individual Intervenors, we turn to our consideration of the reasonableness of the 2016 Settlement Agreement. After hearing and considering the evidence, we conclude that the terms and conditions of the 2016 Settlement Agreement, as a total package, offer a fair, just and reasonable resolution of the matters at issue in this consolidated proceeding. We also find that, as a whole, the 2016 Settlement Agreement will result in just and reasonable rates, will provide significant benefits to customers, and is in the public interest.

It is worth noting that the 2016 Settlement Agreement was entered into by all parties to this proceeding (prior to the later intervention of Individual Intervenors for the purpose of opposing this 2016 Settlement Agreement). Commission proceedings regarding Edwardsport are not typically resolved through a near-unanimous settlement agreement. We commend the parties for reaching an agreement that resolves all disputes, claims and issues that were or could have been raised during Cause Nos. 43114 IGCC-11 through IGCC-15, the FAC subdocket (Cause No. 38707 FAC 99-S1) and the Duke Energy Indiana FAC cases for which rates were approved on an interim basis pending the outcome of Cause No. 43114 IGCC-12/IGCC-13 (Cause Nos. 38707 FAC 99, 100 and 101).

Under the 2016 Settlement Agreement, the Settling Parties have agreed that: Duke Energy Indiana will not propose to recover (absent a *force majeure* situation) Edwardport's O&M and ongoing capital expenditures over certain defined levels through 2017; the balance in the

[29] *See*, Indiana Code § 8-1-8.8-15, which provides that "The commission may revoke any incentive approved in the order if the commission finds that the project no longer complies with the provisions of the order concerning the incentive."
[30] *Northern Ind. Pub. Service Co. v. Citizens Action Coalition of Ind., Inc.*, 548 N.E.2d 153 (Ind. 1989) ("*NIPSCO*").

Regulatory Asset (made up of operating expenses, which were deferred for future recovery) shall be reduced by $80.3 million ($87.5 million total company); and the remaining balance in the Regulatory Asset should be amortized over eight years. We find these provisions fall within the range of positions taken by the parties, are supported by substantial evidence of record, and will result in just and reasonable rates. Together, these provisions benefit customers by reducing the amount of O&M and ongoing capital that Duke Energy Indiana would otherwise seek to include in rates, and also provide for mitigation of the rate impact associated with the recovery of the deferred operating expenses through both reducing the balance in the Regulatory Asset and through the significantly extended amortization period.

The 2016 Settlement Agreement also provides that Duke Energy Indiana will make its IGCC Rider filings annually instead of semi-annually. The 2016 Settlement Agreement further provides that when Duke Energy Indiana makes its 2017 and 2018 filings, if the new rates would be less than those currently in effect, then Duke Energy Indiana will seek approval on an interim basis, subject to adjustment based on our final order. We find both of these provisions to be reasonable and authorize the interim approval of such lower rates by the Energy Division when filed by Duke Energy Indiana consistent with the 2016 Settlement Agreement.

There are also various other provisions in the 2016 Settlement Agreement that reflect compromise between the Settling Parties and also benefit customers, such as the O&M and ongoing capital cost caps. We find such caps provide certainty on IGCC rates for the customers in the near term while providing reasonable cost recovery for Duke Energy Indiana during the initial years of the Plant's operations. The 2016 Settlement Agreement also contains commitments made by the Settling Parties that do not need to be approved by the Commission. Those include agreements to not challenge certain costs through 2017, for certain payments by Duke Energy Indiana shareholders, and for certain information sharing, among others. While we do not need to approve these provisions, we find that none of these provisions alter our conclusion that the 2016 Settlement Agreement will produce just and reasonable rates.

Based on the evidence presented and for the reasons set forth herein, we find that the 2016 Settlement Agreement taken as a whole produces a fair, just and reasonable result that balances the interests of the various stakeholders and the overall public interest.

Although we have provided a discussion and our findings regarding our approval of the 2016 Settlement Agreement, in light of the Indiana Court of Appeals orders in IGCC-9 in which the Court found our order did not adequately address[31] two issues raised by Joint Intervenors, we will also address in this order the key issues raised in IGCC-11 and IGCC-12/13. Given, however, that unlike in IGCC-9, we have been presented with a settlement agreement which resolves between the Settling Parties all issues that were or could have been raised, we can more summarily address those key issues. In addition, we note that the 2016 Settlement Agreement specifically states that "The Settling Parties agree that all pending motions before the Commission related to the relevant proceedings are hereby withdrawn and resolved by this Settlement."

[31] *Citizens Action Coalition of Ind., Inc. v. Duke Energy Ind., Inc.* 44 N.E.3d 98, 110 (Ind. Ct. App. 2015), citing *L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 351 N.E.2d 814, 830 (Ind. Ct. App. 1976) (reversing and remanding for further proceedings where the commission's order did not address a key issue raised by a party or articulate the reasons for its decision).

In IGCC-11, the Industrial Group raised, by way of motion for summary judgment, a claim that applicable statutes and/or Duke Energy Indiana's previously found imprudence preclude Duke Energy Indiana from recovering in this proceeding any O&M expense beyond that contained in the Company's estimate from 2007. The Industrial Group's second argument is that, as an evidentiary matter, the O&M expenses Duke Energy Indiana seeks to recover that exceed its 2007 estimate are due to the Company's imprudence and therefore should not be allowed. After consideration and in light of the 2016 Settlement Agreement, which resolves this issue between the parties for the periods and under the conditions spelled out in the 2016 Settlement Agreement, we deem Industrial Group's motion for summary judgment withdrawn.[32]

In IGCC-11 post-hearing briefing, Joint Intervenors and the Industrial Group urged the Commission to deny recovery of some portion or all of the O&M expenses requested in the IGCC-11 proceeding on the grounds that Duke Energy Indiana should not be allowed under law to change its estimated O&M costs in these ongoing rider proceedings. Again, we note that this dispute has been resolved between the Settling Parties through the 2016 Settlement Agreement.

In the IGCC-12/13 proceeding (before it was consolidated herein for purposes of consideration of the 2016 Settlement Agreement), the primary dispute between the parties was the validity of the Company's June 7, 2013 in-service declaration. The OUCC, Industrial Group and the Joint Intervenors presented evidence that Edwardsport was not in-service at any point during the IGCC-12/13 period under the 2012 IGCC-4S1 Settlement Agreement. In response, Duke Energy Indiana presented evidence that Edwardsport's in-service date complied with the definition of "In-Service Operational Date" provided in the 2012 IGCC-4S1 Settlement Agreement. Individual Intervenors have reiterated the arguments raised in the IGCC-12/13 proceeding and argued that we should reject the 2016 Settlement Agreement because the Settling Parties have agreed that the June 7, 2013 in-service date should remain the same. As discussed above, we reject Individual Intervenors' argument that Edwardsport's in-service date should be adjusted for ratemaking purposes to May 17, 2014. Instead, we find that the 2016 Settlement Agreement reasonably resolves this dispute and disagree with Individual Intervenors that their additional evidence on this issue requires us to adjust the Company's in-service determination.

In IGCC-12/13, the Joint Intervenors and the Industrial Group presented evidence that if the Commission did not modify the in-service date, it should nonetheless adjust the Company's rates downwards based on the performance of Edwardsport after it was declared in-service. Duke Energy Indiana presented evidence that while the Company should be held accountable for operations, it should not be financially penalized unless it is found to have acted imprudently. Once again, we find the 2016 Settlement Agreement reasonably resolves this dispute. We have rejected previous recommendations for setting a performance standard for Edwardsport[33] and, given the 2016 Settlement Agreement, see no need to set one now. Although we decline to impose a performance penalty based on the station's early years of operation, we do intend to keep close watch on the station's performance. To that end, the Commission requires Duke Energy

[32] We recognize that the 2016 Settlement Agreement specifically allows the Industrial Group and other non-Duke Settling Parties to renew their previous arguments following the term of the 2016 Settlement Agreement.
[33] *Duke Energy Ind., Inc.*, Cause No. 43114 at p. 38-39 (Ind. Util. Reg. Comm'n, Nov. 20, 2007).

Indiana to provide in future IGCC Rider proceedings the same breadth of operational metrics it submitted with Mr. Stultz's IGCC-14 and IGCC-15 testimonies.

In IGCC-12/13, the Industrial Group filed a motion to incorporate its IGCC-11 motion for summary judgment. Duke Energy Indiana again opposed this motion. We discussed this motion previously and again deem it withdrawn at this time.

In IGCC-12/13, Joint Intervenors and the Industrial Group filed a motion for judgment on the pleadings arguing that the Company's request to recover ongoing capitalized O&M through Rider 61 should be denied. Duke Energy Indiana responded stating that Indiana Code 8-1-8.8 provides for "[t]he timely recovery of costs and expenses incurred during . . . operation of projects" and argued that it does not matter whether or not the operating costs are treated by accounting rules as capital or expensed. Again, this is another dispute resolved by the 2016 Settlement Agreement. The 2016 Settlement Agreement includes caps on the amount of ongoing capital which may be included in the Company's IGCC Rider through 2017. We think the 2016 Settlement Agreement is a reasonable resolution of this issue and note that should the Settling Parties want to re-raise this issue after the 2016 Settlement Agreement has run its course, we will consider it then. At this time, however, we deem the motion for judgment on the pleadings withdrawn.

Joint Intervenors also challenged the Company's method of classifying expenses as O&M rather than construction costs subject to the 2012 IGCC-4S1 Settlement Agreement's Hard Cost Cap. Mr. Stultz's and Ms. Douglas's testimony indicates that the Company took appropriate and adequate measures to ensure that costs were accurately classified. In particular, the Company held regular meetings to evaluate costs and their classification, and employees were trained how to charge work and supplies post-in-service. The Company explained that the work orders referenced by the Joint Intervenors are not part of the accounting system and no misclassified expense has been identified. Further, this dispute has been resolved between the Settling Parties as part of the 2016 Settlement Agreement. We therefore do not see the need to take additional action regarding this issue at this time and instead accept the Settlement as a reasonable resolution.

Finally, Joint Intervenors raised the same arguments regarding interest on the Commission-ordered Regulatory Liability in both IGCC-11 and IGCC-12/13. Individual Intervenors have reiterated those same arguments even though the 2016 Settlement Agreement resolved this issue amongst the Settling Parties. We therefore do not see the need to take additional action regarding this issue at this time and instead accept the Settlement as a reasonable resolution.

In addition, there are several other findings for us to make as part of the approval of this 2016 Settlement Agreement. First, we find that the Company has adequately satisfied the information reporting requirements to the Commission for purposes of these review proceedings as specified in our orders in IGCC-1 and IGCC-2, and subsequently amended in IGCC-8. Accordingly, we find and conclude that the Company's ongoing review progress reports on the IGCC Project should be approved. We also find that the Company's proposal, as described by Mr. Stultz, to report certain Edwardsport operating information to the Commission in future proceedings, due to previously requested information becoming stale, is hereby approved.

Second, we find that the IGCC Project costs, including the actual Project investment through June 7, 2013, up to the amount of the Hard Cost Cap and Additional AFUDC, as defined by the 2012 IGCC-4S1 Settlement Agreement and reflected in the testimony and exhibits of Duke Energy Indiana witness Ms. Douglas, are hereby approved consistent with our findings herein.

Third, we find the O&M costs Duke Energy Indiana will recover under the terms of and as part of the 2016 Settlement Agreement, reasonable.

Therefore, the Commission hereby approves (1) the 2016 Settlement Agreement; (2) recovery of incremental fees and expenses of Black & Veatch incurred by the Company through March 2014; and (3) adjustment of Petitioner's retail electric rates, via Rider 61, to reflect the revenue effect of such Settlement, as described in the testimony of Duke Energy Indiana's witnesses Diana L. Douglas and Brian P. Davey. We also find that the FAC subdocket (Cause No. 38707 FAC 99S1) previously initiated and held in abeyance pending the outcome of this proceeding has been reasonably resolved by the 2016 Settlement Agreement. We therefore close the FAC subdocket and remove the subject to refund provisions for the FAC orders (Cause Nos. 38707 FAC 99, 100 and 101).

13. <u>Petitioner's Request for Confidential Treatment</u>. a. IURC Cause No. 43114 IGCC-11: On July 3, 2013 in IGCC-11, Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") in this Cause. In its Motion, Duke Energy Indiana requested that certain details of various pricing and operating characteristic information for the IGCC Project (*e.g.* project cost estimates, details of forecasted operation and maintenance expenses of the IGCC Project, the detailed project schedules, operations staffing and training schedules, safety training, test and startup plans and procedures, quality control information, commodity curves), confidential information provided to Duke Energy Indiana by its two primary contractors, GE and Bechtel Power Corporation ("Bechtel"), and confidential information provided to Duke Energy Indiana by other IGCC contractors and vendors, be treated as confidential and a trade secret and not subject to public disclosure (collectively referred to as "Confidential Information"). In support of its Motion, the Petitioner included sworn Affidavits supporting the Petitioner's request for confidential treatment from Mr. Thompson and from GE and Bechtel representatives.

In a July 17, 2013 Docket Entry, the Presiding Officers made preliminary findings that the Confidential Information should be subject to confidential treatment. There has been no disagreement among the parties as to the confidential and proprietary nature of the information submitted under seal in this proceeding. The Commission now finds that the confidential information submitted by Duke Energy Indiana and Joint Intervenors should continue to be held as confidential by the Commission.

b. IURC Cause No. 43114 IGCC-12/13: On December 23, 2013, with respect to IGCC-12, Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("IGCC-12/13 Motion"). In its IGCC-12/13 Motion, Duke Energy Indiana requested that certain details of various pricing and operating characteristic information for the IGCC Project (*e.g.* project cost estimates, details of forecasted operation and maintenance expenses of the IGCC Project, the detailed project schedules, operations staffing and training schedules, safety training, test and startup plans and procedures, quality control information, commodity curves), confidential information provided to Duke Energy Indiana by its two primary contractors, GE and Bechtel Power Corporation ("Bechtel"), and confidential information provided to Duke Energy Indiana by other IGCC contractors and vendors, be treated as confidential and a trade secret and not subject to public disclosure. In support of its IGCC-12/13 Motion, the Petitioner included sworn Affidavits supporting the Petitioner's request for confidential treatment from Mr. Thompson and from GE and Bechtel representatives.

In a January 29, 2014 Docket Entry, the Presiding Officers made preliminary findings that the Confidential Information should be subject to confidential treatment. On June 12, 2014, Petitioner filed a motion to apply the preliminary determination of confidential treatment to the confidential materials filed in the then-consolidated IGCC-12 and IGCC-13 proceeding. There was no objection to that motion, and the Commission granted it on July 3, 2014.

c. IURC Cause No. 43114 IGCC-14/15 and Consolidated Cause No. 43114 IGCC-15:
On December 23, 2014, Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("IGCC-14 Motion"). In its IGCC-14 Motion, Duke Energy Indiana requested that certain details of various pricing and operating characteristic information for the IGCC Project (*e.g.* project cost estimates and expenditures, details of forecasted and actual operations and maintenance expenses of Edwardsport and certain detailed plant operational statistics), be treated as confidential and a trade secret and not subject to public disclosure. In a January 5, 2015 Docket Entry, the Presiding Officers made preliminary findings that the Confidential Information should be subject to confidential treatment.

On June 4, 2015, Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("IGCC-15 Motion"). In its IGCC-15 Motion, Duke Energy Indiana requested that certain details of various pricing and operating characteristic information for the IGCC Project (*e.g.* project cost estimates, details of forecasted operations and maintenance expenses of the IGCC Project, and certain detailed operational statistics), be treated as confidential and a trade secret and not subject to public disclosure. In a June 17, 2015 Docket Entry, the Presiding Officers made preliminary findings that the Confidential Information should be subject to confidential treatment.

There has been no disagreement among the parties as to the confidential and proprietary nature of the information submitted under seal in the consolidated proceeding. The Commission now finds that the confidential information submitted by Duke Energy Indiana, the non-Duke Settling Parties, and the Individual Intervenors should continue to be held as confidential by the Commission.

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

1. The 2016 Settlement Agreement is in the public interest, results in just and reasonable rates and is approved in its entirety as outlined above.

2. Duke Energy Indiana's ongoing progress reports are hereby approved.

3. The interim and subject to refund provisions of our orders in Cause Nos. 38707 FAC 99, 100 and 101 shall be removed consistent with the implementation of the 2016 Settlement Agreement and this Order.

4. Duke Energy Indiana is directed to modify its tariffs consistent with the findings herein and file copies with the Commission for its approval.

5. The confidential information presented in this proceeding is found to be confidential and trade secret, excepted from public access, and will continue to be held as confidential by the Commission.

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

STEPHAN, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED:

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

____

Brenda Howe
Secretary to the Commission