ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL TO REFLECT COSTS INCURRED FOR THE PLANT 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** **) APPROVED:** AUG 24 2016

ORDER OF THE COMMISSION

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

On May 29, 2013, Duke Energy Indiana, LLC ("DEI") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") in Cause No. 43114 IGCC 11. In its Petition, DEI requested: (1) approval of DEI's updated ongoing progress report associated with its Plant Generating Facility ("Plant" or "Station"); and (2) authority to reflect costs incurred with respect to the construction of the Plant through March 31, 2013, and other related costs and credits and applicable reconciliation amounts and credits, in its retail electric rates through DEI'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.

On December 20, 2013, DEI 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, DEI 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.

On December 23, 2014, DEI 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 Allowance for Funds Used During Construction ("AFUDC"), the 2012 Settlement Agreement regulatory asset, and Commission-ordered Regulatory Liability. On June 4, 2015, DEI 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, DEI, Nucor Steel-Indiana ("Nucor"), the Duke Energy Indiana Industrial Group ("Industrial Group"), and the Indiana Office of Utility Consumer Counselor ("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 99 S1 along with IGCC 14 and IGCC 15 in order to provide for administrative efficiency. On January 18, 2016, DEI; the Industrial Group; the OUCC; Nucor; and the Citizens Action Coalition of Indiana, Inc., Save the Valley, Inc., Valley Watch, Inc., and the Sierra Club (collectively "Joint Intervenors") (collectively referred to herein as "Settling Parties") submitted to the Commission a 2016 Settlement Agreement ("2016 Settlement Agreement"). On January 14, 2016, Michael Mullett and Patricia Marsh (collectively "Individual Intervenors") 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.

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

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published by the Commission as required by law. DEI 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. In its November 2007 Order in Cause Nos. 43114 and 43114 S1 ("CPCN Order"), the Commission issued certificates of public convenience and necessity ("CPCN") and clean coal technology. Under Indiana Code chapters 8-1-8.5, 8.7, and 8.8, the Commission has jurisdiction to approve ongoing review progress reports and associated cost recovery of a public utility's capital investment. Accordingly, the Commission has jurisdiction over DEI and the subject matter of this proceeding.

2. **DEI's Characteristics.** DEI is an Indiana corporation with its principal office located at 1000 East Main Street, Plainfield, Indiana. DEI is engaged in the business of supplying electric utility service to the public in the State of Indiana. DEI 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. DEI 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. DEI 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 DEI.

3. **Relief Requested.** In its Verified Petition in IGCC 11, DEI requested: (1) approval of an ongoing review progress report pursuant to Indiana 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 Plant costs incurred through March 31, 2013, and authority to recover certain other applicable costs and credits via DEI's IGCC Rider and such reconciliation of charges or credits to actual amounts as are applicable.

In its Verified Petition in IGCC 12, DEI requested: (1) approval of DEI's final updated ongoing review progress report pursuant to Indiana 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 Plant costs, including post-in-service normal capitalized repairs and maintenance expenditures, incurred through September 30, 2013, (3) authority to recover certain other Plant-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 Operations and Maintenance ("O&M"), fringe benefits, payroll taxes, property insurance and property taxes, tax credits, and including applicable reconciliation amounts, related to The Plant 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 DEI's High Load Factor ("HLF") and Low Load

Factor ("LLF") customers; and (6) authority to amortize post-in-service AFUDC and to amortize the settlement agreement regulatory asset and Commission-ordered regulatory liability.

In its Verified Petition in IGCC 13, DEI requested similar relief for the next six-month period: (1) authority to reflect costs incurred through March 31, 2014 for The Plant, 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 The Plant 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 DEI's HLF and LLF 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, DEI 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, DEI 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. DEI's Case-in-Chief Evidence.

A. Cause No. 43114 IGCC 11. DEI witness Jack L. Stultz, General Manager II, Regulated Fossil Stations provided the Commission with an ongoing review progress report concerning the Plant. 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 five of General Electric's ("GE") New Product Introduction ("NPI") Testing. Both gasifiers were successfully commissioned with the train one gasifier lit off and operating for approximately three hours on October 25, 2012. Train two 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 two 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 three testing, and running the power block on natural gas, syngas and mixtures of each at different loads as part of NPI Phase five.

Mr. Stultz explained that the NPI Phase five testing of the power block has been completed, which allowed GE to provide a technical release of the power block to DEI operations. Remaining are NPI Phases six through eight, which will be completed during the coming months and involve the tuning and optimizing of performance of the 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 two gasifier was lit off on May 31, 2013. Once the slag crusher packing was repaired and stack testing performed, the train one 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 Plant 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 six 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 Midcontinent Independent System Operator ("MISO") were charged and credited to the capital budget of the Plant.

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 number one 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 Plant 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 DEI to complete start-up activities and commence commercial operation of the Plant.

Mr. Stultz explained that since the Plant began commercial operation, DEI 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, National Pollutant Discharge Elimination System ("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 Plant 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 Plant. 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 Plant. 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 Plant. 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 presented the Commission with additional Plant information, as requested by the Commission in its IGCC 1 and IGCC 2 Orders. As noted in Mr. Womack's IGCC 8 testimony, much of this information pertained to the design and construction phases of the Plant, which are now essentially complete, and accordingly, Mr. Stultz 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.

Gary S. Thompson, Senior Project Manager, The Plant, IGCC provided a high level update on the construction status of the Plant. 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 Plant involved testing of various components, commissioning of the Plant, and significant portions of GE's NPI testing. As of the filing of Mr. Thompson's direct testimony, the remaining construction activities were Phases six through eight of GE's NPI testing.

Mr. Thompson provided an update on the status of the Plant's schedule and cost. He stated that the Plant reached the in-service milestone on June 7, 2013. He continued stating that the Plant 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 DEI's Confidential Exhibit B-1.

In IGCC 11, Diana L. Douglas, Director of Rates for DEI, explained that the purpose of her testimony was to explain DEI's request for timely recovery of costs in connection with the Plant, including Construction Work in Progress ("CWIP") ratemaking treatment for retail jurisdictional Plant 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 DEI, Ms. Douglas requested that the Commission approve the following: (1) the value of the Plant upon which DEI is requesting authorization to earn a return; (2) the amount of DEI's expenditures for the IGCC facility incurred through March 31, 2013; (3) recovery of incremental fees and expenses of Black & Veatch incurred by DEI 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 DEI's retail electric rates, via Rider 61 to reflect the revenue effect of such investment and cost recovery.

Ms. Douglas described DEI's Exhibit C-1, DEI's Rider 61, of which DEI is requesting approval. DEI'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 DEI'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. DEI'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 Plant rather than tying depreciation rates to the original estimated 30-year life of the plant.

Her testimony also explained DEI'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 Plant 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; Plant expenditures as of March 31, 2013, subject to CWIP ratemaking treatment; Plant 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 Plant as of March 31, 2013; and the total amount of AFUDC included in the Plant.

Ms. Douglas also explained the ratemaking treatment for the costs of four Plant-related transmission projects, which are in-service and were included in the $2.35 billion approved Plant 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, DEI 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 DEI would seek cost recovery for such project (or portion of a project) through the IGCC Rider. The projects are in-service, and DEI expects a 50% reimbursement for such RECB projects; therefore, DEI has included 50% of the value of the projects in its Plant valuation for CWIP ratemaking purposes (representing the 50% of the projects that are not expected to receive MISO RECB reimbursement). Accordingly, Page 1 of DEI's Exhibit C-2 shows the expenditures for the two RECB projects, including the reduction in Plant expenses by the 50% amount for which DEI expects to be reimbursed by MISO through the RECB process.

Ms. Douglas continued her testimony stating that Page 2 of DEI's Ex. C-2 shows the amount of accumulated depreciation as of March 31, 2013, applicable to the Plant investment. As of March 31, 2013, the only portions of the Plant that have been placed in-service and are being depreciated are the four transmission projects. The jurisdictional accumulated depreciation applicable to the jurisdictional Plant 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, DEI limited the amount of Plant 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 Plant-related operating expenses, including depreciation expense, and tax credits. These operating expenses included: expenses incurred by DEI 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.

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

Ms. Douglas stated that DEI forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the 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 DEI forecasts retail jurisdictional depreciation expense of $51,572,002 for the October 2013 through March 2014 period. 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 Plant-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.

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 Plant 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 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.

Page 7 of DEI'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 DEI 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, DEI 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 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 DEI's weighted average cost of capital as of March 31, 2013, as shown on DEI'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 Plant 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 DEI'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 Plant will cease. She stated that consistent with 170 IAC 4-6-22 and in accordance with the Commission's CPCN Order, the Plant will be deemed to be under construction, and DEI will continue to receive revenues through Rider 61, until the Commission determines that the Plant is used and useful in a proceeding that involves the establishment or investigation of DEI'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.

Ms. Douglas also stated that the impact of the proposed Plant ratemaking treatment, under the terms of the 2012 Settlement Agreement and assuming approval of the IGCC 10 proposed factor, 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 Plant 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 the voluntary HLF credit reconciliation error. She explained that the revenue requirements under the new revised DEI'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 DEI's Exhibits C-1 through C-3 do not reflect any amortization for the net amount of the Regulatory Liability and Regulatory Asset because DEI 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, DEI's Exhibit D-1 through D-3, to reflect DEI'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 include amortization of the Regulatory Liability. 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, DEI 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.

DEI'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 DEI'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. 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.

B. Cause No. 43114 IGCC 12. In direct testimony in IGCC 12, DEI witnesses Mr. Stultz and Mr. Thompson provided the Commission with the final ongoing review progress report under Indiana Code chapter 8-1-8.5 concerning the Station construction 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 DEI 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. DEI then lit off the train two and train one gasifiers on May 31, 2013, and June 5, 2013, respectively, and declared the Plant in-service and commercially available on June 7, 2013. DEI made this determination pursuant to Federal Energy Regulatory Commission ("FERC") accounting guidance and subject to consultation with the Plant 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, DEI 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 one operated a consecutive 585 hours or 24.4 days and gasifiers one and two operated at the same time for 394 hours or 16.4 days.

Mr. Stultz testified that the Plant completed GE's NPI testing program in September 2013. DEI and GE have been working on the conditions necessary to complete the performance testing so that the Plant 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 Plant experienced one of its longest dual train runs until tripping in late October 2013. DEI 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 DEI 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. DEI 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 DEI 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 DEI 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) 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 the Station were resolved by a settlement between DEI 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. DEI 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 O&M forecast. He explained that the Plant will incur fixed costs, such as labor costs, and variable costs, such as chemical costs. DEI 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 DEI-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 DEI has reached an agreement with GE for GE to provide required parts for the combustion turbines for eight years at a base discounted price. DEI 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 Plant 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 DEI's Exhibits A-1, Confidential A-1, B-1, Confidential Exhibit B-1, B-2, and Confidential B-2. Mr. Stultz further explained that DEI 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 Plant. 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 Plant 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 DEI's final ongoing review report of station construction.

Mr. Thompson testified that the Plant'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 DEI's Confidential Exhibit B-1.

In IGCC 12, Ms. Douglas testified on behalf of DEI with respect to ratemaking issues. She explained that the purpose of her testimony was to explain DEI's request for timely recovery of costs in connection with DEI's Plant, including CWIP ratemaking treatment for retail jurisdictional Plant 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 which was included in the proposed rates presented for Commission approval in DEI'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 DEI, Ms. Douglas requested that the Commission approve the following: (1) the value of the Plant upon which DEI is requesting authorization to earn a return; (2) the amount of DEI's expenditures for the Plant incurred through September 30, 2013; (3) recovery of incremental fees and expenses of Black & Veatch incurred by DEI 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 DEI'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 DEI'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 Plant 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; Plant expenditures as of September 30, 2013, subject to CWIP ratemaking treatment; Plant 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 Plant; and the total amount of AFUDC included in the Plant.

Ms. Douglas continued her testimony stating that Page 2 of DEI's Ex. C-2 shows the amount of accumulated depreciation as of September 30, 2013, applicable to the recoverable in-service Plant investment. The jurisdictional accumulated depreciation applicable to the jurisdictional Plant 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 Plant. DEI 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, DEI's Exhibit 1-A, at 2.E., p. 3)

The jurisdictional balance of DEI'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. DEI 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, DEI limited the amount of Plant 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 Plant 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 Plant-related operating expenses, including depreciation expense, and tax credits. These operating expenses included: expenses incurred by DEI 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; 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.

Ms. Douglas stated that DEI incurred $55,222 between April and September 2013 for Black & Veatch Project-related oversight services. She also testified DEI forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Station 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. DEI 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. 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. 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. 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.

Ms. Douglas testified that in the spirit of the 2012 Settlement Agreement, DEI 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 DEI 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 Rider 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 Plant 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 DEI'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 DEI'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 Plant 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 Plant will cease. She stated that consistent with 170 IAC 4-6-22 and in accordance with the Commission's CPCN Order, the Plant will be deemed to be under construction, and DEI will continue to receive revenues through Rider 61, until the Commission determines that the Plant is used and useful in a proceeding that involves the establishment or investigation of DEI's retail electric base rates and charges.

Ms. Douglas also stated that the impact of the proposed Plant 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, DEI is proposing a rate migration adjustment. DEI has seen a net migration of customers and load from Rate HLF to Rate LLF. To account for this change and better align the Rider with costs and customer loads, DEI proposes to adjust the allocation for the net migration between the two rate classes by approximately 1%. DEI 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. DEI proposes to use this adjustment on a going-forward basis and will continue to monitor rate migrations each year.

C. 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, the Station 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, the Station 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, DEI decided to move up the fall outage. During the outage, DEI 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 the Station's syngas-operated turbines were originally set conservatively at 8,000-hour maintenance intervals. Mr. Stultz stated that DEI 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, DEI 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. DEI ordered and subsequently installed a new burner. Gasifier one was lit off on November 20, 2013, and Gasifier two 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, DEI 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 DEI has previously found inadequately designed and installed heat tracing at the Station. Although DEI 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, DEI 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, DEI 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 DEI 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. DEI 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 two 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. DEI 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, DEI has not seen a reoccurrence of this issue. Gasifier one 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 two tripped on January 23, 2014 due to a loss in feedwater. DEI lit off Gasifier two 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, DEI discovered that the entire sulfur recovery unit was blocked by ammonia salts. DEI 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. DEI 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 DEI 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, DEI moved its previously scheduled spring outage forward to take advantage of the station downtime. This worked well because while a portion of DEI'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, DEI takes advantage of unexpected downtime to perform necessary outage and maintenance work. Because DEI 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, DEI inspected both the gasifiers and the combustion turbines and replaced nine rows of refractory brick in the throat of gasifier one. DEI 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 one ran from its light off after the spring outage on March 13, through March and into April. Also following the spring outage, Gasifier two 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 the Plant, 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 DEI has focused on operating the Plant as reliably and consistently as possible. Mr. Stultz stated that he believed the Plant had operated about where DEI expected it to in the early months of operation because DEI 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, DEI 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 the Station's availability had not yet reached 85%, nor had it reached the 75% DEI 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 DEI still had more than 30 years of the Station operations ahead of it. He also noted that following the spring outage, DEI saw steadily improving reliability from the gasifiers—May 2014 represented DEI'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 DEI 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 DEI hopes to receive the final results from GE shortly.

Mr. Stultz explained that in order for the Station 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 DEI. When the performance test data is fully analyzed and reported to DEI, 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 DEI 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 the Station 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 the Station 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 DEI 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, DEI does not anticipate receiving and installing them until 2015. Until these new pumps are installed, the Station 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. The Station has also increased the capacity of the pumps and believes that these will resolve the concern DEI has had that the nitrogen capacity of the ASU is insufficient to meet the plant's demands. Through work with Burns and McDonnell, DEI 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 DEI 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 DEI incurred to operate the Station from September 2013 through March 2014 are the types of expenses that all DEI 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 DEI 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, DEI 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 DEI 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. 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. DEI 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 DEI 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 DEI 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 DEI'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 Plant'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, DEI updated its forecast of the expected O&M expenses involved in operating the 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. DEI's maintenance strategy will influence a variety of costs, such as the use of contractors or use of DEI 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 DEI'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 Plant-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. DEI's current budget includes labor for identified and planned outage work.

Ms. Douglas testified on behalf of DEI with respect to ratemaking issues relevant to the IGCC 13 time period. She explained that the purpose of her testimony was to explain DEI's request for timely recovery of costs in connection with DEI's Plant, including CWIP ratemaking treatment for jurisdictional Plant expenditures. Her testimony also shows the calculations used to develop DEI's proposed IGCC revenue adjustment factor and includes an updated set of retail electric tariff pages applicable to the IGCC Rider.

Ms. Douglas noted that her calculations were based on data recorded on DEI's books and in DEI'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 DEI is requesting authorization to earn a return; (2) the amount of DEI'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 DEI 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 Subdocket 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 DEI'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 DEI's Exhibit B-1, DEI's Rider 61, of which DEI 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 DEI'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. DEI'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 DEI's Exhibit B-2, which sets forth schedules for the Plant 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 Plant as of March 31, 2014, subject to CWIP ratemaking treatment; Plant 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 Plant; and, the total amount of AFUDC included in the cost of the Plant.

Ms. Douglas explained the ratemaking treatment for the costs of four Plant-related transmission projects that were included in the approved cost estimate for the Plant in DEI'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, DEI 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 DEI will seek cost recovery for such project (or portion of a project) through the IGCC Rider. MISO will provide a 50% reimbursement for the two IGCC related RECB projects, therefore, DEI 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 DEI's Exhibit B-2 shows the expenditures for the two RECB projects, including the reduction in Plant costs by the 50% amount for which DEI 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 DEI's Exhibit B-2, and the full costs for these projects have been considered in IGCC Rider ratemaking.

Ms. Douglas stated that Page 2 of DEI's Exhibit B-2 shows the amount of accumulated depreciation as of March 31, 2014, applicable to the recoverable in-service Plant 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 Plant 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 DEI's Exhibit B-2 includes the total expenditures as of March 31, 2014, for certain ongoing capital projects related to the IGCC facility. DEI 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 Plant 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. 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 DEI'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 Rider 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 DEI 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 DEI 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, DEI's Exhibit 1-A, at 2.C., p.3. Because the first costs were incurred during the period covered by IGCC 12, DEI 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 DEI'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 DEI 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. DEI 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 DEI'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 DEI's Exhibit B-2 develops the jurisdictional revenue requirements for the return on the net jurisdictional investment in the 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, DEI 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 Plant investment and the ongoing capital projects was multiplied by DEI'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 DEI'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 DEI 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 DEI incurred between October 2013 and March 2014 for services from Black & Veatch was $49,644. She stated that DEI forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Station's 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 DEI 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 DEI 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, DEI'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.

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, DEI 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 DEI 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 Rider filing (and the subsequent one, if needed). On behalf of DEI, Ms. Douglas requested that the Commission approve this treatment. She noted that the additional deferrals will cease if the Commission approves DEI'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.

According to Ms. Douglas, DEI'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 DEI'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 the Plant as a Tax Increment Financing District.

Ms. Douglas stated that Page 10 of DEI'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, DEI 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. DEI has completed the 2013 monitoring and it resulted in an additional migration of approximately 26 MW, therefore, DEI 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 DEI's Exhibits B-1, B-2, and B-4.

According to Ms. Douglas, these rate migrations are not one-time adjustments and DEI proposes to use both of these adjustments on a going-forward basis in this, and other riders, using historical demand allocations. In addition, DEI 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, DEI 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 DEI'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 DEI, 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 DEI, requested that the Commission approve this proposed treatment.

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

Ms. Douglas then stated that DEI'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 DEI is proposing to update its Rider 61 Ninth Revised Sheet No. 61, Pages 1 through 5, should the Commission approve DEI's proposed rates. Upon approval, and upon DEI'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. 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.

The Plant 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 Plant 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 the Plant to be substantially complete, 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 one. Gasifier two also came down on September 12, 2014 due to a RSC blow down leak, and ultimately the station decided to make CT one 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 the scheduled maintenance and repair work was completed in order to mitigate the issue. Gasifier two was re-lit on October 18, with gasifier one 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 DEI'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, DEI received the final certificate of substantial completion from GE which indicates that the Plant has reached Substantial Completion, 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, DEI 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 DEI 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, DEI 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 DEI with respect to ratemaking issues relevant to the IGCC 14 time period. She explained that the purpose of her testimony was to explain DEI's request for timely recovery of costs in connection with DEI's Plant, including CWIP ratemaking treatment for jurisdictional Plant expenditures. Her testimony also shows the calculations used to develop DEI's proposed IGCC Revenue Adjustment Factor and includes an updated set of retail electric tariff pages applicable to the IGCC Rider.

Ms. Douglas noted that her calculations were based on data recorded on DEI's books and in DEI's records as of September 30, 2014. Her testimony requested that the Commission approve: (1) the value of the Plant, including the value of related post-in-service ongoing capital project expenditures, upon which DEI is requesting authorization to earn a return; (2) the amount of DEI'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 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 DEI'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 DEI's Exhibit B-1, DEI's Rider 61, of which DEI 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 DEI'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. DEI'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 DEI's Exhibit B-2, which sets forth schedules for the Plant 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 Plant as of September 30, 2014, subject to CWIP ratemaking treatment; Plant 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 Plant; and, the total amount of AFUDC included in the cost of the Plant.

Ms. Douglas explained the ratemaking treatment for the costs of four Plant-related transmission projects that were included in the approved cost estimate for the Plant in DEI'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, DEI 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 DEI 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, DEI 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 DEI'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 DEI 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 DEI'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 DEI's Exhibit B-2 shows the amount of accumulated depreciation as of September 30, 2014, applicable to the recoverable in-service Plant 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 Plant 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 DEI's Exhibit B-2 includes the total expenditures as of September 30, 2014, for certain ongoing capital projects related to the IGCC facility. DEI 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 Plant 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. 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 DEI's investment in these post-in-service ongoing capital projects at the Plant 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 DEI 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 DEI 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, DEI's Exhibit 1-A, at 2.C., p.3. Because the first costs were incurred during the period covered by IGCC 12, DEI 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 DEI'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 Rider. 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 DEI 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. DEI 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 DEI'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 DEI's Exhibit B-2 develops the jurisdictional revenue requirements for the return on the net jurisdictional investment in the 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, DEI 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 Plant investment and the Ongoing Capital Projects was multiplied by DEI'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 DEI'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 DEI 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 DEI forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Station's 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 DEI forecasts retail jurisdictional depreciation expense of $50,770,240 for the April through September 2015 period. 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 DEI 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. 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, DEI 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 DEI 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 DEI, Ms. Douglas requested that the Commission approve this treatment. She noted that the additional deferrals will cease if the Commission approves DEI'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.

According to Ms. Douglas, DEI'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 DEI'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 the Plant as a Tax Increment Financing District.

Ms. Douglas stated that Page 10 of DEI'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 DEI'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 DEI, 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 DEI, requested that the Commission approve this proposed treatment.

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

Ms. Douglas then stated that DEI'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 Plant, but the IGCC 10 rates currently being billed only included 4/6ths 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 DEI is proposing to update its Rider 61 Tenth Revised Sheet No. 61, Pages 1 through 5, should the Commission approve DEI's proposed rates. Upon approval, and upon DEI'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. 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 one gasifier began on April 4 and on gasifier unit two 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 one 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 two 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 DEI'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, 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 DEI with respect to ratemaking issues relevant to the IGCC 15 time period. She explained that the purpose of her testimony was to explain DEI's request for timely recovery of costs in connection with DEI's Plant, including CWIP ratemaking treatment for jurisdictional Plant expenditures. Her testimony also shows the calculations used to develop DEI'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 DEI's books and in DEI'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 DEI is requesting authorization to earn a return; (2) the amount of DEI'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 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 DEI'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 DEI's Exhibit B-1, DEI's Rider 61, of which DEI 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 DEI'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. DEI'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 DEI's Exhibit D-2, which sets forth schedules for the Plant 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 Plant as of March 31, 2015, subject to CWIP ratemaking treatment; Plant expenditures applicable to the wholesale jurisdiction; retail Plant investment as of March 31, 2015; the amount of retail AFUDC included in the cost of the Plant; and, the total amount of AFUDC included in the cost of the Plant.

Ms. Douglas explained the ratemaking treatment for the costs of four Plant-related transmission projects that were included in the approved cost estimate for the Plant in DEI'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, DEI 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 DEI will seek cost recovery for such project (or portion of a project) through the IGCC Rider. MISO will provide a 50% reimbursement for the two IGCC related RECB projects, therefore, DEI 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 DEI's Exhibit D-2 shows the expenditures for the two RECB projects, including the reduction in Plant costs by the 50% amount for which DEI 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 DEI'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 DEI's Exhibit D-2 shows the amount of accumulated depreciation as of March 31, 2015, applicable to the recoverable in-service Plant 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 Plant 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 DEI's Exhibit D-2 includes the total expenditures as of March 31, 2015, for certain ongoing capital projects related to the Plant. DEI 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. 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 DEI'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 Rider 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 DEI 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 DEI 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, DEI's Exhibit 1-A, at 2.C., p.3. Because the first costs were incurred during the period covered by IGCC 12, DEI 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 DEI'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 Rider. 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 DEI 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. DEI 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 DEI'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 DEI's Exhibit D-2 develops the jurisdictional revenue requirements for the return on the net jurisdictional investment in the 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, DEI has limited the amount of Plant 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 Plant investment and the Ongoing Capital Projects was multiplied by DEI'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 DEI'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 Subdocket 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 DEI forecasts a total of the retail jurisdictional operating expenses, net of a credit to reflect costs applicable to the Plant 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 the Plant as a Tax Increment Financing District. She testified DEI forecasts retail jurisdictional depreciation expense of $54,545,595 for the October 2015 through March 2016 period. 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 DEI forecasts retail jurisdictional depreciation expense on the Plant 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 Subdocket 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. 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 Rider via amortization over a three-year period) of operating expenses, including depreciation, from the In-Service Operational Date of the Plant 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, DEI 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 Rider 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 DEI 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 DEI, Ms. Douglas requested that the Commission approve this treatment. She noted that the additional deferrals will cease if the Commission approves DEI'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.

According to Ms. Douglas, DEI'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 DEI'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 1/12th 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 the Plant as a Tax Increment Financing District.

Ms. Douglas stated that Page 10 of DEI'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 DEI'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 DEI, 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 DEI, requested that the Commission approve this proposed treatment.

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

Ms. Douglas then stated that DEI'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 the Plant, but the IGCC 10 rates currently being billed only included $4/6^{\text{ths}}$ 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 DEI is proposing to update its Rider 61 Eleventh Revised Sheet No. 61, Pages 1 through 5, should the Commission approve DEI's proposed rates. Upon approval, and upon DEI'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 Case-In-Chief Evidence.

A. 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 DEI'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 DEI.

B. Cause No. 43114 IGCC 12 and 13. Mr. Blakley testified to his opinion regarding DEI'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 Plant while it was not operational. Mr. Blakley further opined that DEI 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 DEI 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 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 Plant.

Mr. Alvarez also testified on behalf of the OUCC. The purpose of his testimony was to describe the issues related to DEI'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 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 DEI 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 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 Contracts and commented on whether those activities were completed during the IGCC 12 and 13 time periods. Mr. Alvarez opined that despite DEI's "in service" declaration on June 7, 2013, all expenditures that DEI 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 DEI 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 DEI 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 Plant'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 DEI 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, DEI did not have prior experience with dual gasifier train operation.

Mr. Alvarez also referred to the "substantial completion" definition in the 2012 Settlement Agreement, and opined that, as of the "in-service" date, if the performance testing and NPI testing were not complete, and the Plant had not achieved substantial completion, then DEI could not make a reasonable determination that the Plant was ready for service. Because none of these requirements were complete, Mr. Alvarez opined that DEI'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 DEI; (2) find that DEI did not complete the IGCC startup on June 7, 2013, or anytime during the IGCC 12 and -13 review periods; (3) find that DEI did not complete the performance tests within the prescribed review periods of this proceeding; (4) find that DEI did not complete the commissioning of the Plant within the prescribed review periods of this proceeding; (5) find that DEI did not achieve the final completion of the Plant within the prescribed review periods of this proceeding; (6) require DEI to provide documentation to identify the correct validation completion date of the Plant, and verify that such completion date was within the prescribed review periods of this proceeding; (7) find that all expenditures incurred by DEI 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 DEI and not passed on to ratepayers.

6. Industrial Group's Case-In-Chief Evidence.

A. Cause No. 43114 IGCC 12 and 13. Mr. Michael P. Gorman testified on behalf of the Industrial Group. Mr. Gorman testified about DEI's requested relief in light of two key elements of the 2012 Settlement Agreement. First, he testified that the Plant 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 the Plant was in-service during the relevant period.

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 the Plant 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 the Plant is placed in-service.

Mr. Gorman examined the in-service guidelines identified as relevant by DEI in the April 7, 2014 summary judgment affidavit of Mr. Danny Wiles. In his affidavit, Mr. Wiles testified DEI's determination that the Plant 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. 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. Mr. Gorman testified that neither prong of AR-5 had been met as of March 31, 2014. First, the Plant was still incurring capital expenses. Second, the Plant 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.

Mr. Gorman discussed the Plant's intended use, explaining that the Plant 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.

Mr. Gorman further explained that in discovery, DEI indicated that the intended use of the Plant is to operate as an IGCC. DEI had also submitted testimony on the Plant's intended use, which indicated that (1) the Plant would consistently be among DEI's first economically dispatched base load generating resources; (2) the Plant can operate on natural gas or syngas, whichever is economic, but is designed to run on syngas; and (3) the Plant 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.

Mr. Gorman testified that the Plant was not operated as a base load Plant through March 31, 2014, and thus that it was not able to operate consistent with its intended use. He provided several facts supporting his conclusion. Mr. Gorman pointed out that DEI was not able to operate the Plant 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, the Plant had only been dispatched by MISO on an economic basis on one occasion, May 28, 2014, which was outside the relevant time.

In addition, Mr. Gorman supported his conclusion that the Plant was not operating consistent with its intended use by explaining that syngas operations for the Plant were still in the testing, tuning and optimization phase and were not yet available for DEI's planned MISO offering until at least September 2014. During this period, the Plant was committed to MISO based on a minimum loading capability approximately equal to its expected output. These restrictions limited DEI's ability to operate the Plant as an economic base load generating resource. Mr. Gorman stated that DEI has indicated that the Plant 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.

Mr. Gorman further supported his conclusion by testifying that with only one exception of August 9, 2013, The Plant did not operate at its seasonal net dependable capacity during the time period of this proceeding. Mr. Gorman observed that the fact that the Plant 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. The Plant'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, the Plant 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.

Mr. Gorman also testified to the significance of the fact that the Plant 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. Mr. Gorman observed that such testing is also an important customer protection. He quoted IGCC 4S1 testimony from DEI witness Mr. Stultz describing DEI's efforts to ensure that the Plant operated as intended – as a reliable base load generating resource. Mr. Stultz explained that the startup procedures and testing requirements of the Plant are designed to ensure that it operates as a reliable facility as intended. Mr. Gorman noted that the reliability of the Plant was a significant concern because the Plant was a first of its kind large commercial design of an IGCC plant.

Despite its importance, DEI had not completed testing of the Plant as of March 31, 2014, Mr. Gorman testified. Rather, The Plant was in a startup and testing phase through this time, relating to a period wherein GE and DEI 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. In fact, by the end of March 2014, DEI had not completed preliminary performance tests; final performance testing; or determined whether minimum performance guarantees had been met. DEI still could not state whether the plant had satisfied the minimum performance guarantees and the make right performance guarantees as of December 5, 2014.

In addition, Mr. Gorman testified that the way DEI offered the Plant into MISO during the relevant period indicated that it was not operating consistent with its intended use. He explained that DEI has offered the Plant 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 explained, MISO follows the generation of the IGCC and dispatches the rest of its fleet depending on the generation of the Plant. After the testing on the Plant is complete, DEI 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 Plant had not been utilized as intended.

Mr. Gorman also testified that DEI had expected the in-service and substantial completion dates to be within about 30 to 75 days of each other. Mr. Gorman explained that substantial completion would mean that all testing would be complete and the Plant could operate consistent with its intended use. However, DEI 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. Mr. Gorman testified that the Plant was not substantially complete by the end of the relevant period, and still was not substantially complete as of December 5, 2014. In other words, DEI's June 2013 expectation of an August 2013 substantial completion date was off by over a year. Mr. Gorman testified that the fact that the

Plant did not meet DEI's expectations for complying with testing and meeting clear thresholds such as substantial completion and final completion in a timely manner demonstrates that the Plant was not in a position to operate at a commercial mode and be declared in-service.

Mr. Gorman also discussed the poor operating performance of the Plant during the relevant period. Though DEI 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 the Plant was far worse during the relevant period. The Plant's net capacity factor averaged only 29% through March 2014. 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. Furthermore, Mr. Gorman disagreed with DEI that syngas availability factor was an accurate measure of the Plant's performance during the relevant time period because of the way the Plant 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. Instead, DEI's availability factor on syngas averaged only 34.9% during the relevant period.

Mr. Gorman testified that the Plant's availability factor on syngas was far lower than its availability factor on both natural gas and syngas, which indicates that the Plant was not available to operate on syngas a significant amount of time through March 2014. He reiterated that the Plant 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 the Plant'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.

Mr. Gorman testified that DEI had an economic incentive to declare the Plant 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, DEI cannot begin collecting depreciation expense until the in-service date. Mr. Gorman concluded that because the Plant was not in-service through the IGCC 13 period, DEI should not be permitted to recover O&M or depreciation expense in this Cause (or in the pending IGCC 11). Furthermore, because DEI has been recovering projected O&M and depreciation since IGCC 10 rates went into effect on September 12, 2013, DEI owes ratepayers a refund. Mr. Gorman testified that DEI 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).

Mr. Gorman offered a different recommendation in the alternative if the Commission were to find that the Plant 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 the Plant's post-in-service operating performance. He observed that the operating performance of the Plant for the period covered by IGCC 12 and 13 was so bad that ratepayers are entitled to relief under 2D. 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 the Plant'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 the Plant'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 DEI 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.

7. **Joint Intervenors' Case-In-Chief Evidence.**

A. Cause No. 43114 IGCC 11. Mr. Smith provided two recommendations in his testimony: (1) that the Commission direct DEI 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 DEI to credit the Regulatory Liability revenues against the revenue requirement in this proceeding, rather than allowing DEI 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 DEI 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-DEI parties) and their counsel.

B. Cause No. 43114 IGCC 12 and 13. Mr. Smith testified to his opinions that (1) the evidence does not support DEI'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) DEI's proposal presented in IGCC 11 to amortize over three years the refund or credit to customers associated with the Commission's Subdocket 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 DEI's response to a data request in IGCC 8 in which DEI 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 DEI 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 DEI had not completed. Mr. Smith claimed that DEI 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. DEI 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 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, DEI 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 DEI'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 DEI determines whether costs are subject to the hard cost cap, and a clear indication of how DEI determines whether the costs are an exception to the hard cost cap, and their continued difficulty in evaluating DEI's response. Mr. Smith further expressed concern that DEI 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 DEI 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 DEI to accrue simple interest at the statutory rate of eight percent per annum from the date of collection on the $30,731,789 Commission-ordered regulatory liability and that DEI 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 DEI 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) DEI'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 DEI declared it in-service on June 7, 2013; (5) DEI declared the Plant in service after the gasifiers had only run in parallel for 53 hours; (6) DEI 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, DEI did not start the unit; (8) DEI was still scheduling the Plant as "must run" with MISO as of the mid-September start of the fall 2014 outage; (9) DEI 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 DEI 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 DEI 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 DEI 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 DEI 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 DEI'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 DEI witnesses. Mr. Schlissel noted that testing was not completed at the Plant before DEI declared it to be in-service. Mr. Schlissel also noted that DEI 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 S1 is stayed. Mr. Schlissel further indicated his belief that O&M costs should be discounted to reflect projections DEI made during IGCC 4S1.

As to O&M expenses, Mr. Schlissel expressed a concern that DEI 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 DEI's actual emissions were higher during 2013 and the first nine months of 2014 than what DEI 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 DEI 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 Joint Intervenors 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 DEI premised the Plant 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 DEI'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. <u>DEI's Rebuttal Testimony for Cause Nos. 43114 IGCC 11, 12 and 13</u>.

A. <u>Cause No. 43114 IGCC 11</u>. Ms. Douglas provided rebuttal testimony disagreeing with Mr. Smith that the Subdocket Order required DEI 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 DEI 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. 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.

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 DEI'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 DEI 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 DEI's rate calculations or testify that the rates proposed were not computed in accordance with the Commission's orders in Cause Nos. 43114 and 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 DEI's IGCC 10 revenue requirement and adjustment factors are supported by DEI's testimony, exhibits, and workpapers.

B. Cause No. 43114 IGCC 12 and 13. Mr. Esamann provided rebuttal testimony in IGCC 12 and 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. 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 Plant that are unrelated to actual construction to complete the Plant will be eligible for rate recovery in the normal course of business. This reflects the understanding of the 2012 Settlement Agreement at the time it was considered and approved by the Commission.

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 DEI 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 DEI'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. DEI subsequently determined that in order to meet the "intended use" accounting guideline, operating both gasifiers together was an additional milestone for in-service determination. DEI complied with both the terms of the 2012 Settlement Agreement and the FERC guidelines in its in-service determination. DEI 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, the Plant 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 one) and 710 hours (gasifier two) 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 DEI 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 DEI had an incentive to rush the Plant 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 DEI'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 DEI has requested for recovery in this proceeding.

Mr. Esamann stated that DEI has diligently worked to ensure that "Construction Costs" are not included in the rates proposed for recovery. The costs needed to complete the Plant, the costs to replace portions of the Plant 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, DEI has been even more conservative than it normally would be. DEI shareholders have borne approximately $900 million of the construction costs for the Plant 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." DEI 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 the Plant closer to final completion of the GE Contract.

With respect to the parties' assertion that customers are entitled to various penalties because the Plant has not achieved DEI'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 DEI's early assumptions. The Plant is capable of meeting, and in fact has met, the levels of performance that were expected at the time DEI 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 DEI'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 the Plant. 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.

DEI 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 DEI should not be held accountable for operations at the Plant. Rather, it means that DEI 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, DEI 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, DEI 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 DEI as "Construction Costs" and are being borne by DEI'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 the Plant, it would be inappropriate to impose it now, during the early months of operation. DEI needs time to work through equipment and maintenance issues in a reasonable manner.

In response to the Commission's January 16, 2015 Docket Entry, DEI also submitted DEI'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 the Plant and the variation in the temporal relationship between the time of the negotiation of the 2012 Settlement Agreement and March 2014. DEI 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.

DEI 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, DEI'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 DEI, 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. DEI then waited for GE to complete the documentation and operability demonstrations required under the contract. DEI accepted GE's notice of substantial completion on December 17, 2014.

DEI also referred to prior testimony regarding DEI'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 DEI's in-service determination for the Plant in accordance with normal accounting guidelines, DEI's long-standing practices, and the 2012 Settlement Agreement. He also explained that DEI 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 DEI'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 IGCC Plant is as an integrated gasification combined cycle facility, DEI 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) DEI's independent external auditors concur with management's in-service declaration, and neither the Securities and Exchange Commission ("SEC") nor FERC have challenged DEI'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 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.

Mr. Wiles noted that he also testified during the settlement proceedings to certain operational milestones that DEI 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 DEI is charging to the original construction capital project the costs incurred for repairs or modifications identified prior to in-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 DEI 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 DEI 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 DEI'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 DEI 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 DEI 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 DEI management is responsibility for ensuring that DEI's books and records comply with FERC and Generally Accepted Accounting Principles ("GAAP"). DEI 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 DEI's in-service declaration. He testified that the external auditors concurred that the timing of DEI'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 DEI in the definitions of In-Service Operational Date and Construction Costs that subject more costs to the hard cost cap, not less.

DEI 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. DEI 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. DEI 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 DEI 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 DEI'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). DEI 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, DEI'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). DEI uses the commit statuses Must Run, Economic, Outage, and Emergency. DEI frequently self-commits its most economic coal-fired generating units, including Gibson, Cayuga, and the Plant as Must Run.

Mr. Swez said that when determining an individual unit's offer status, DEI 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 the Plant 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 the Plant was performing tests every day. His point in his FAC 101 testimony was to explain how DEI was offering the Plant into MISO and why. His purpose was not to provide evidence on whether the Plant was "testing" while in a "test phase" producing "test energy." When Mr. Swez coded the Plant 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, the Plant 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 the Plant when operating on syngas. Because the minimum and maximum outputs for the Plant was relatively close together, there is not much of a difference between the unit's minimum and maximum load. Once the Plant is up and running on syngas, the economic choice is to run the unit up to its maximum output.

In DEI's Exhibit 11, DEI 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. DEI 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, DEI 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. DEI 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, DEI 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. DEI explained that it is typical for large coal units to have incremental costs above the Locational Marginal Cost during off-peak. DEI 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 the Plant's operations including the performance metrics used by DEI, gasifier starts, DEI's in-service declaration, and DEI'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 DEI, 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. The Plant, however, was designed with extensive operational flexibility. As a result, defining the "unit" for GADS metrics is difficult. Nonetheless, the metrics that DEI provided as part of Mr. Stultz's testimony were compiled in accordance with GADS instructions. Because DEI 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 DEI will continue to provide a variety of statistics to help the Commission gain a full view into the Plant's operations.

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 DEI built an integrated gasification combined cycle facility, which can run on both fuels, it is optimized to run on syngas, and DEI 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. The Plant'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%. The Plant'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. DEI 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 DEI's O&M costs and budget as presented in this proceeding were reasonable. He stated that, in his opinion, DEI 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 DEI 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 DEI 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 DEI records and reports the start of a gasifier is incorrect. DEI 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 DEI'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, The Plant 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, the Plant 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 the Plant 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 DEI 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. In any event, significant testing and validation was performed prior to in-service. Mr. Stultz noted that DEI'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 six through eight DEI 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. DEI's Exhibit 4-C contains copies of the Startup & Commissioning Major Milestones schedules that DEI 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 DEI 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, DEI also conducted training at the Plant 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 DEI 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 DEI'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, DEI 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 the Plant 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 DEI'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 DEI 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. DEI 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 DEI 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 DEI has been evasive regarding the classification of O&M expenses. She stated that in response to various requests for accounting documentation, including work orders, DEI 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. DEI subsequently provided additional information that is contained in the maintenance work management system. This information, however, is part of station records, not part of DEI's accounting systems. Because these records are not part of the official accounting system, there are limitations in using them. However, DEI has reasonable accounting controls in place to ensure that the costs presented for recovery were in compliance with the 2012 Settlement Agreement, DEI was transparent in what was presented to support the costs, and the data that DEI provided reasonably enabled the parties to get a good picture of the costs necessary for operating and maintaining the Plant during the IGCC 12 and 13 review periods.

With respect to the Commission-ordered regulatory liability, Ms. Douglas stated that the Subdocket Order did not require DEI 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 DEI 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.

As to the recommendation that customers should be credited the full amount of the regulatory liability in this proceeding, Ms. Douglas stated that DEI'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 Subdocket Order, and the language in the 2012 Settlement Agreement. Based on this language, Ms. Douglas stated that DEI 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 DEI disagrees with Mr. Gorman's analysis and conclusion that the 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 Plant generated electricity throughout that period and DEI 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 DEI that the Plant was in-service during the forecasted months.

Ms. Douglas stated that Mr. Esamann's testimony best discusses DEI'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 DEI 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 DEI 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 DEI 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 DEI 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 IGCC hard cost cap, plus Additional AFUDC amounts. In addition, both the Industrial Group and the Joint Intervenors seek to hold DEI 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 DEI'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.

9. <u>Testimony In Support of 2016 Settlement Agreement</u>. Douglas F. Esamann provided testimony supporting the 2016 Settlement Agreement. He explained that DEI 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 DEI 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 Subdocket 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 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 of a Commission order approving the Settlement or July 1, 2016, whichever occurs earlier)	$73.3 million	Lower of retail portion of 2016 actual or cap 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 DEI 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 DEI'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 the rates that will result from the approval and implementation are just, reasonable and necessary. In DEI's 2018 filing and beyond, and in its next base rate case, DEI 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	Lower of retail portion of 2015/2016 actual expenditures or cap amount
Calendar Year 2017	$16.9 million	Lower of retail portion of 2017 actual expenditures or cap amount

Again, the Settling Parties agreed that DEI 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 DEI'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, DEI 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 DEI'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 DEI 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 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 Plant related provisions of the Settlement provide that the Plant 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 Plant performance over the twelve months ended August 2015; if the Settlement isn't approved by July 1, 2016, DEI will treat the agreed-upon O&M cap as if it were effective and will apply it to expenses incurred after that date; if the Settlement isn't approved in time for new rates to go into effect by July 1, 2016, DEI 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; in lieu of Joint Intervenors request to add 8% interest to the Commission-ordered Regulatory Liability, DEI agreed to shorten the amortization period from three to two years and that no carrying costs will be added to either the Commission-ordered Regulatory Liability or the Regulatory Asset; if DEI's filing in either 2017 or 2018 has a lower revenue requirement than was included in the rates in effect at that time, DEI 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; DEI will file its next Rider filing in the first quarter of 2017 and annually until the Commission issues an order in DEI's next base rate case; and the Settling Parties agree that any "subject-to-refund" designations or similar language in DEI'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 99 S1.

Further, Mr. Esamann explained the non-Plant related provisions in the 2016 Settlement Agreement provide: An agreement regarding Joint Intervenors 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 DEI 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; DEI 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 DEI's service territory.

In addition, DEI 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 DEI 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 DEI's service territory; $100,000 contribution to the Indiana Low Income Home Energy Assistance Program ("LIHEAP") fund to be used for DEI retail customers;

lastly Joint Intervenors and DEI agree to cooperate to fund $500,000 to LIHEAP to be used solely for DEI retail customers; and $500,000 contribution to the SUN solar energy grant program to develop solar energy projects for DEI customers in its service territory.

Mr. Esamann concluded his testimony by stating that although DEI considers its actions concerning the Plant during the period to be prudent, reasonable and necessary, DEI 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 the Plant from April 1, 2013 through March 31, 2015. The Settlement results in relative peace in the Plant regulatory proceedings before the Commission through first quarter 2018 and results in many financial benefits for customers. In addition, Mr. Esamann testified that DEI 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 99 S1 subdocket being held in abeyance pending the outcome in IGCC 12 and 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 the Plant. 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 DEI 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 the Plant's reliability and availability.

Mr. Stultz testified regarding the cap on ongoing capital at The Plant. He stated that the Settling Parties set the ongoing capital cap amounts for DEI's 2017 and 2018 IGCC Rider filings by using the actual figures then-included in the 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 the Plant, Cause No. 38707 FAC 99 S1. The FAC 99 subdocket was concerned with the underlying causes of periods when the Plant 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 the Plant 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 and 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 99 S1, 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 discussed 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, DEI 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 DEI'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 the Plant'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, DEI 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 DEI'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 the Plant 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. 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. Since IGCC 10 rates have been in effect since September 12, 2013 and are still currently in effect, only two-thirds of the plant's O&M and depreciation have been included in rates being billed to customers for over two years and DEI has been deferring one-third 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 DEI O&M expenses it has incurred at the Plant 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. DEI 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, DEI 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, DEI 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 DEI'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, DEI 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 DEI 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 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 DEI's recovery of O&M expenditures in 2016 and 2017 up to the applicable cap amount; and they will only raise issues with the Plant's operations through December 31, 2017 to the extent its performance is substantially different than the historical Plant 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 DEI may request recovery of actual O&M expenses in its 2018 and subsequent IGCC Rider filings and that non-Duke Settling Parties 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, DEI will use its actual post-in-service ongoing capital project amounts and accumulated depreciation, \$24.6 million, as reflected on DEI'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 DEI is entitled to recover the lower of its actual ongoing capital expenditures or the cap amounts. Because the IGCC Rider did not use forecasted ongoing capital expenditures in the 2017 annual filing, DEI 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, DEI 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 DEI'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 DEI 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 the Plant 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 DEI to reduce the Regulatory Liability. Mr. Davey then stated that his DEI'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% compared 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 DEI 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. Upon Commission approval and upon DEI'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.

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 DEI, 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 the Plant costs that DEI will not pass onto ratepayers.

Mr. Gorman explained the importance of certain provisions in the 2016 Settlement Agreement for ratepayers: DEI 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, DEI 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 DEI 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 DEI 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 DEI 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 Joint Intervenors 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 Joint Intervenors have had with the Plant 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 DEI'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 DEI 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 DEI to the lower of actual cost up to the cap and that if expenditures go above either cap, DEI must absorb all of the cost without opportunity of recovery later.

10. Individual Intervenors Testimony in Opposition to the 2016 Settlement Agreement. 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 DEI. 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 Joint Intervenors witness Smith in IGCC 12 and 13 that the average cost of electricity from the Plant 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 for DEI 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 DEI 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 Plant in-service date to be established by the Commission in lieu of the premature June 7, 2013 date declared by DEI. 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 DEI 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 Joint Intervenors witnesses Smith and Schlissel filed in IGCC 12 and 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 DEI to declare the Plant in-service.

Next, Mr. Mullett discussed the Regulatory Liability. He discussed issues that were previously litigated in IGCC 11 and IGCC 12 and 13, 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 DEI 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.

11. <u>Rebuttal Testimony In Support of the 2016 Settlement Agreement</u>. 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" and a "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 DEI 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 the Plant 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 the Plant 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 DEI 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 DEI, customer rates would experience volatility. Mr. Mullett is correct that DEI 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, DEI 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 DEI 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 DEI 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 the Plant has been 1) previously granted a CPCN under both Indiana Code chapters 8-1-8.5 and 8-1-8.7 and 2) previously approved as a "new energy generating facility" eligible for the "timely recover of costs," specifically "IGCC Project costs, including financing, O&M, depreciation, property taxes, payroll costs and property insurance costs." In addition, DEI 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." Mr. Esamann opined that it was his understanding that the Commission's 2007 order in Cause No. 43114 and authorization by Indiana Code chapter 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 Plant 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 impacts DEI's recovery of O&M expense. To the extent that the Plant 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 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.

Mr. Esamann next addressed Mr. Mullett's testimony summarizing Joint Intervenors testimony from IGCC 12 and 13 regarding in-service. DEI previously rebutted Joint Intervenors witnesses Smith and Schlissel in IGCC 12 and 13 and that testimony has been admitted into the record in the IGCC 12 and 13 evidentiary hearing and consolidated into this proceeding for purposes of considering the 2016 Settlement Agreement and as such DEI 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 Joint Intervenors, who sponsored Smith's and Schlissel's testimonies in IGCC 12 and 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 Joint Intervenors, on whether the 2016 Settlement Agreement 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. Davey also addressed several other issues with rate increase calculation or characterizations in Mr. Mullett's testimony, e.g., the calculations of cost/generation 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 and 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 the Plant costs and operations into account when negotiating and reaching the Settlement.

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 before the rates were filed with the Commission. This is not 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 and 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 Joint Intervenors, 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.

Mr. Gorman provided rebuttal testimony responding to Individual Intervenors 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 the Plant 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. Commission Discussion and Findings. 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).

A. The Settlement Agreement. Before we address the overall reasonableness of the 2016 Settlement Agreement, we find it is important to address the Individual Intervenors key arguments in opposition to the 2016 Settlement Agreement.

(1) The Regulatory Asset. Individual Intervenors' first argument is that the 2016 Settlement Agreement should not be approved because it would allow DEI to utilize what was intended to be a one-time deferral and recovery mechanism as an extraordinary and unwarranted regulatory lag mitigation mechanism. We disagree with Individual Intervenors

underlying premise that DEI'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 the Plant was eligible for the timely recovery of costs incentive under Indiana Code chapter 8-1-8.8. *Duke Energy Ind., Inc.*, Cause No. 43114, 2007 WL4150583 (IURC, Nov. 20, 2007). We also found that DEI's proposed IGCC Rider is approved for use and for the recovery of the approved Plant costs, including financing, O&M, depreciation, property taxes, payroll costs and property insurance costs. Further, we approved deferral of post-in-service carrying costs and O&M costs on an interim basis until such costs are reflected in DEI's retail rates. 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, it is effectively an amount reflective of the pending, but not yet reflected in rates, reconciliation of actual to forecasted costs.[1] The Settling Parties have recognized that the larger than reasonably anticipated build-up of the Regulatory Asset has occurred and have provided for reasonable mitigation through the write-down of the balance by DEI and by providing for the amortization of the remaining balance over eight years (as opposed to some shorter period, namely the nominal 6-month IGCC rider periodicity) 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. *Verified Petition of Indiana Michigan Power Co.*, 2013 WL 3817468, *62 (IURC July 17, 2013). Without interim deferred accounting treatment, I&M would not be able to fully recover its approved operating expenses. The same is true in this instance, which is why we previously approved and authorized DEI to defer its post-in-service expenses until such expenses are reflected in rates. We also recognized this prior approval in our Subdocket Order when we approved the 2012 Settlement Agreement, explaining that DEI will defer the collection of allowable costs for later recovery, which is consistent with previously authorized deferred accounting treatment granted for the Plant by the Commission. *Duke Energy Ind., Inc.*, 2012 WL 6759528 (IURC Dec. 27, 2012).

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 DEI's deferral of the Plant'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 chapter 8-1-8.8. We find that the eight-year amortization period will provide customer benefits by spreading the remaining Regulatory Asset balance over an extended period without carrying charges.

Individual Intervenors also argue that the Regulatory Asset is contrary to the filed rate 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. Indiana Code § 8-1-2-44. The Settling Parties have requested we allow DEI to

[1] Indiana Code § 8-1-8.8-12(f).

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 DEI file with us revised rate tariffs consistent with this order and only after we approve those tariffs may DEI charge rates that include amortization of the Regulatory Asset. DEI'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 DEI has been charging IGCC 10 rates, which included only two-thirds of its estimated operating expenses, is the reason why the scale of the Regulatory Asset is what it is today. At least one-third of DEI's operating expenses from the Plant 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 DEI has not violated the filed rate doctrine. It is undisputed that DEI has 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. Of primary importance is our prior approval of the Plant for timely recovery of its operating expenses under Indiana Code chapter 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 chapter 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 the effect of 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 DEI 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) <u>The In-Service Date</u>. Regarding Individual Intervenors' next argument – that we should reject the 2016 Settlement Agreement because it does not change the Plant'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 and 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 GE on May 16-17, 2014, as evidence supporting their proposed in-service date. The in-service issue was thoroughly litigated in the IGCC 12 and 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 DEI's in-service determination. The reduction in the regulatory asset included in the 2016 Settlement Agreement represents the Settling Parties position on reasonable compensation for the initial operation of the Plant after the June 2013 in-service date. As Industrial Group witness, Mr. Gorman, explained in his Settlement Testimony, "[t]hus, 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 and 13 proceeding plus an additional $32.5 million. If the Commission had decided, for ratemaking purposes, to treat the Plant 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. DEI presented substantial evidence in IGCC 12 and 13 in support of a June 7, 2013 in-service determination and that differentiating the in-service date for ratemaking, accounting and tax purposes would create administrative challenges. Given that the 2016 Settlement Agreement resolves this issue between the Settling Parties, we see no reason that DEI'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 DEI to add 8% interest to the Regulatory Liability amount. In lieu of Joint Intervenors' previously stated position that DEI should be required to add 8% interest to the Regulatory Liability, the 2016 Settlement Agreement resolves this issue by DEI 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 DEI 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 chapter 8-1-8.8. We find the 2016 Settlement Agreement provisions reasonable and decline to provide for an immediate refund of the Commission-ordered Regulatory Liability or require DEI to add 8% interest to the Regulatory Liability amount, as suggested by Individual Intervenors.

B. <u>Evaluation of the Reasonableness of the 2016 Settlement Agreement</u>. 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.

Under the 2016 Settlement Agreement, the Settling Parties have agreed that: DEI will not propose to recover (absent a *force majeure* situation) the Plant's O&M and ongoing capital expenditures over certain defined levels through 2017; the balance in the 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 DEI 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 DEI will make its IGCC Rider filings annually instead of semi-annually. The 2016 Settlement Agreement further provides that when DEI makes its 2017 and 2018 filings, if the new rates would be less than those currently in effect, then DEI 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 DEI 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 DEI 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 DEI 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[2] two issues raised by Joint Intervenors, we will also address in this order the key issues raised in IGCC 11 and IGCC 12 and 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 "[t]he Settling Parties agree that all pending motions before the Commission related to the relevant proceedings are hereby withdrawn and resolved by this Settlement."

In IGCC 11, the Industrial Group raised, by way of motion for summary judgment, a claim that applicable statutes and/or DEI's previously found imprudence preclude DEI from recovering in this proceeding any O&M expense beyond that contained in DEI's estimate from 2007. The Industrial Group's second argument is that, as an evidentiary matter, the O&M expenses DEI seeks to recover that exceed its 2007 estimate are due to DEI'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.

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 DEI 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 and 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 DEI's June 7, 2013 in-service declaration. The OUCC, Industrial Group and the Joint Intervenors presented evidence that the Plant was not in-service at any point during the IGCC 12 and 13 period under the 2012 IGCC 4S1 Settlement Agreement. In response, DEI presented evidence that the Plant'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 and 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 the Plant's in-service date should be adjusted for ratemaking purposes to May 17, 2014, or any other date. 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 DEI's in-service determination.

In IGCC 12 and 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 DEI's rates downwards based on the performance of the Plant after it was declared in-service. DEI presented evidence that while DEI should be held accountable for operations, it should not be financially

[2] *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).

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 the Plant and, given the 2016 Settlement Agreement, see no need to set one now. Although we decline to impose a performance penalty based on the Plant's early years of operation, we do intend to keep close watch on the Plant's performance. To that end, the Commission requires DEI 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 and 13, the Industrial Group filed a motion to incorporate its IGCC 11 motion for summary judgment. DEI again opposed this motion. We discussed this motion previously and again deem it withdrawn at this time.

In IGCC 12 and 13, Joint Intervenors and the Industrial Group filed a motion for judgment on the pleadings arguing that DEI's request to recover ongoing capitalized O&M through Rider 61 should be denied. DEI 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 DEI's IGCC Rider through 2017. We find 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 DEI'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 DEI took appropriate and adequate measures to ensure that costs were accurately classified. In particular, DEI held regular meetings to evaluate costs and their classification, and employees were trained how to charge work and supplies post-in-service. DEI 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 2016 Settlement Agreement as a reasonable resolution.

Finally, Joint Intervenors raised the argument regarding interest on the Commission-ordered Regulatory Liability in both IGCC 11 and IGCC 12 and 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 2016 Settlement Agreement as a reasonable resolution.

In addition, there are several other findings for us to make as part of the approval of the 2016 Settlement Agreement. First, we find that DEI 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 DEI's ongoing review progress reports on the Plant should be approved.

We also find that DEI's proposal, as described by Mr. Stultz, to report certain operating information to the Commission in future proceedings, due to previously requested information becoming stale, is hereby approved.

Second, we find that the Plant costs, including the actual Plant 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 DEI witness Ms. Douglas, are approved consistent with our findings herein.

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

Therefore, the Commission approves (1) the 2016 Settlement Agreement; (2) recovery of incremental fees and expenses of Black & Veatch incurred by DEI through March 2014; and (3) adjustment of DEI's retail electric rates, via Rider 61, to reflect the revenue effect of such Settlement, as described in the testimony of DEI's witnesses Diana L. Douglas and Brian P. Davey, specifically Petitioner's Exhibit 3-B (BPD). We also find that the FAC subdocket (Cause No. 38707 FAC 99 S1) 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. DEI's Requests for Confidential Treatment. On July 3, 2013 in IGCC 11, DEI filed a Motion for Protection of Confidential and Proprietary Information ("Motion") in this Cause. In its Motion, DEI requested that certain details of various pricing and operating characteristic information for the Plant (*e.g.* project cost estimates, details of forecasted operation and maintenance expenses of the Plant, 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 DEI by its two primary contractors, GE and Bechtel Power Corporation ("Bechtel"), and confidential information provided to DEI 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 DEI included sworn Affidavits supporting the DEI'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 DEI and Joint Intervenors should continue to be held as confidential by the Commission.

On December 23, 2013, with respect to IGCC 12, DEI filed a Motion for Protection of Confidential and Proprietary Information ("IGCC 12 and 13 Motion"). In its IGCC 12 and 13 Motion, DEI requested that certain details of various pricing and operating characteristic information for the Plant (*e.g.* project cost estimates, details of forecasted operation and maintenance expenses of the Plant, 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 DEI by its two primary contractors, GE and Bechtel, and confidential information provided to DEI 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 and 13 Motion, the DEI included sworn Affidavits supporting the DEI'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, DEI 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.

On December 23, 2014, DEI filed a Motion for Protection of Confidential and Proprietary Information ("IGCC 14 Motion"). In its IGCC 14 Motion, DEI requested that certain details of various pricing and operating characteristic information for the Plant (*e.g.* project cost estimates and expenditures, details of forecasted and actual operations and maintenance expenses of the Plant 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, DEI filed a Motion for Protection of Confidential and Proprietary Information ("IGCC 15 Motion"). In its IGCC 15 Motion, DEI requested that certain details of various pricing and operating characteristic information for the Plant (*e.g.* project cost estimates, details of forecasted operations and maintenance expenses of the Plant, 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 DEI, 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 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. The Cause No. 38707 FAC 99 S1 subdocket is closed.

5. Duke Energy Indiana is directed to modify its tariffs consistent with the findings herein and file the applicable rate schedules for the first billing cycle after the effective date of this Order, under this Cause for approval by the Commission's Energy Division.

6. 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.

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

STEPHAN, HUSTON, WEBER AND ZIEGNER CONCUR:

APPROVED: AUG 24 2016

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

Mary Becerra
Secretary of the Commission

2016 Edwardsport Settlement Agreement

1. Introduction

This Settlement Agreement ("Settlement" or "2016 Edwardsport Settlement") is entered into by and between Duke Energy Indiana, LLC (and its successors), the Indiana Office of Utility Consumer Counselor ("OUCC"), the Duke Energy Indiana Industrial Group, Joint Intervenors (comprised of the Citizens Action Coalition of Indiana, Inc., Sierra Club, Save the Valley and Valley Watch), and Nucor Steel-Indiana (collectively, the "Settling Parties") solely for purposes of compromise and settlement. The 2016 Edwardsport Settlement amends, supersedes and replaces in its entirety the 2015 Edwardsport Settlement entered into by Duke Energy Indiana, Inc., the OUCC, Duke Energy Indiana Industrial Group and Nucor Steel-Indiana dated September 18, 2015. The Settling Parties agree that this Settlement resolves all disputes, claims and issues from the following Indiana Utility Regulatory Commission ("Commission") proceedings regarding Duke Energy Indiana's Edwardsport IGCC Generating Facility: Commission 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 (specifically, Cause Nos. 38707 FAC 99, 100 and 101).

Included in this Settlement is an $87.5 million reduction in recoverable previously incurred operating and maintenance expenses (as defined for purposes of the Settlement to include operating and maintenance expenses, payroll taxes, property taxes, property insurance and net of the credit for old Edwardsport operating expenses (but not fuel and depreciation), hereinafter referred to as "O&M"), a $5.5 million shareholder funded commitment for attorney fees, trusts and programs, as detailed herein, a cap on recoverable O&M incurred through calendar year 2017, a cap on recoverable post-in-service ongoing capital expenditures incurred through calendar year 2017, and an extended amortization period for the regulatory asset established for post-in-service Edwardsport operating expenses under the terms of the 2012 Settlement Agreement[1] and the Commission's Cause No. 43114 IGCC-4S1 Order ("Regulatory Asset") from three years (as was agreed to in the 2012 Settlement Agreement) to eight years. The jurisdictional portion of the $87.5 million reduction in O&M expenses will be credited to customers via a reduction of the Regulatory Asset. In consideration of the above commitments, the Settling Parties agree that the in-service date of the Edwardsport Generating Facility shall be June 7, 2013 for accounting and ratemaking purposes.

[1] The IURC Cause No. 43114 IGCC-4S1 Phase I and Phase II Settlement Agreement, approved by the Commission on December 27, 2012 – referred to herein as the "2012 Settlement Agreement."

The Settling Parties desire to fully settle all disputes, claims and issues among them arising out of or relating to these proceedings, and do so, among other reasons, to avoid the continued time and expense of further proceedings and the inherent uncertainties and potential outcomes associated with such proceedings. The Settling Parties agree that the rates that will result from approval and implementation of this Settlement are just, reasonable and necessary. The Settling Parties further agree that this Settlement is a reasonable compromise and that each Settling Party that filed testimony previously in the resolved proceedings will file testimony with the Commission in support of this Settlement, and in such testimony, each such party will explain to the Commission how, in that Settling Party's view, the Settlement is just and reasonable and in the public interest, based on substantial evidence of record.

The Settling Parties agree to work together to achieve approval of this Settlement by April 1, 2016.

2. <u>IGCC Rider Filing Schedule and Rate Implementation</u>

Duke Energy Indiana will file its next IGCC Rider filing in the first quarter of 2017 and annually (*instead of every six months*) thereafter until the Commission issues an order in Duke Energy Indiana's next retail base rate case. Upon approval, the rates established pursuant to this Settlement will be implemented and will remain in effect until rates from the first subsequent annual filing (the 2017 filing) are implemented.

The annual filings will be made in the first quarter of each year beginning in 2017. The 2017 filing would address Edwardsport's operations from April 1, 2015 through December 31, 2016. Subsequent annual filings will cover Edwardsport's operations during the prior calendar year (*i.e.*, the filing made in the first quarter of 2018 would address Edwardsport's operations during calendar year 2017).

The actual kwh for the twelve months ended March 31, 2015, divided by two, will be used to develop the rates, as reflected on Petitioner's Exhibit B-2 page 10 in IGCC-14 and D-2 page 10 in IGCC-15. This reflects an annual period consistent with how the rates will be billed rather than the six month period originally used in IGCC-15. Subsequent filings will use the sales for the 12 months ended December 31 of the prior calendar year to develop rates and use twelve months of revenue requirements. IGCC Rider reconciliations will be performed pursuant to the IGCC Rider, as in previous IGCC Rider proceedings.

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 (subject to the post-in-service ongoing capital cap provisions in Section 3. C.), and of accumulated depreciation.

If the Settlement order is not issued before July 1, 2016, the O&M cap will be effective on July 1, 2016 and will apply to expenses incurred after that date. The difference between O&M expenses that are included in rates and the lower of the O&M cap or actual O&M expenses will be deferred into the Regulatory Asset. In addition, in the event that an order from the Commission is not obtained in time for new IGCC Rider rates to go into effect by July 1, 2016, Duke Energy Indiana will reduce the Regulatory Asset account balance by the difference in the revenue requirement associated with the return under this Settlement and the currently-in-effect IGCC-10 return revenue requirement. This would be a reduction of approximately $2.46 million/month (on a pro rata basis) until rates are in effect after an order approving this Settlement Agreement. This Regulatory Asset balance currently includes deferred O&M expenses and deferred depreciation expenses, and the Settlement proposes that the Regulatory Asset is to be amortized in the amount of $20,000,000 per year over approximately eight years.

If Duke Energy Indiana's IGCC Rider 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. These rates, once approved, will be interim and subject to adjustment based on the Commission's final order in that proceeding. As part of this Settlement, the Settling Parties request that the Commission authorize the interim approval of these lower rates at the time of their filing.

3. <u>IGCC Rider Recovery – Rates to be Established Pursuant to this Settlement</u>

The basis for the rates to be approved under this Settlement are the revenue requirements included in Duke Energy Indiana's June 2015 IGCC-15 filing, as adjusted for:

- The lower Regulatory Asset amortization amount of $20 million per year as set forth in this Settlement, including the impacts of the retail jurisdictional share of $87.5 million shareholder funding of O&M expenses;
- A change in amortization schedule for the Regulatory Asset from three to approximately eight years;
- Implementing the capped level of O&M expenses by using the actual retail jurisdictional portion of Edwardsport O&M expenses for the twelve months ended March 31, 2015 and increasing it by $3.5 million each year (approximately $67.2 million (actual O&M expenses for the twelve months ended March 31, 2015) plus $2.6 million (for the 9 months of 2015 following March 31, 2015) plus $3.5 million (for calendar year 2016), resulting in a capped retail jurisdictional level of O&M expenses of $73.3 million). For the period after the issuance of the Commission's order approving this Settlement, O&M expenses includable in the IGCC Rider are

capped at the lower of Duke Energy Indiana's actual O&M expenses or the cap amount, as detailed below; and

- 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 this Settlement (approximately $25 million in such ongoing capital investments and accumulated depreciation). For the period of April 2015 through December 2017, post-in-service ongoing capital project amounts includable in the rider are capped at the lower of Duke Energy Indiana's actual post-in-service ongoing capital project amounts or the cap amounts, as detailed below.

A. Regulatory Asset. In resolution of these issues, Duke Energy Indiana agrees that Duke Energy shareholders will fully fund $87.5 million of total Company O&M expenses it has incurred at Edwardsport from its June 7, 2013 in-service date through the implementation of new rates under the terms of this Settlement and will not seek recovery of those costs from its customers.

Retail customers will be credited with the retail jurisdictional share of the shareholder funded $87.5 million of O&M expenses (*i.e.,* $80.3 million) by reducing the balance of deferred O&M expenses that have been accumulated in the Regulatory Asset. Reducing the balance of the Regulatory Asset will reduce the amounts retail customers will pay over time as the amortization of these deferred costs are included in rates.

Duke Energy Indiana 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 this Settlement (subject to Section 2 above). The Regulatory Asset balance as of the time of the Commission's order approving this Settlement will be amortized and recovered through rates over approximately eight years (rather than the three years originally agreed to under the 2012 Settlement Agreement). The actual amortization period may vary depending on factors such as the Commission's order date, the actual Regulatory Asset amount at the time rates are implemented pursuant to this Settlement, and actual sales.

The Settling Parties recognize Joint Intervenors' contribution to achieving the reduction in the Regulatory Asset in lieu of a later in-service date and interest on the Commission-ordered Regulatory Liability. The Settling Parties also 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, as Duke Energy Indiana has proposed in its IGCC-11, 12, 13, 14 and 15 filings. The Settling Parties acknowledge that this matter was evaluated in concept and/or quantitatively by each Party in arriving at the agreed-upon amount of reduction to the Regulatory Asset balance noted above.

Duke Energy Indiana will amortize the Commission-ordered Regulatory Liability[2] over two years and net it against the Regulatory Asset amortization. The Commission's Cause No. 43114 IGCC-4S1 order (modified in the Cause No. 43114 IGCC-10 order) has ordered a three year amortization. However, in lieu of the Joint Intervenors' request that the Commission order Duke Energy Indiana to add 8% interest to the Regulatory Liability amount, Duke Energy Indiana has agreed to shorten the amortization period from three to two years. No carrying costs will be added to either the Commission-ordered Regulatory Liability or the Regulatory Asset.

The Settling Parties agree that they will not challenge or otherwise oppose Duke Energy Indiana's amortization and recovery through rates of the actual balance of the recoverable Regulatory Asset as of the date of the Commission order approving this Settlement and the implementation of rates pursuant to the Settlement. The recoverable Regulatory Asset is net of the retail jurisdictional share of the shareholder funded $87.5 million of O&M expenses (*i.e.,* $80.3 million). As described in the above paragraph, the agreed upon two-year amortization of the Commission-ordered Regulatory Liability will be netted against the amortization of the Regulatory Asset.

B. <u>O&M Cap</u>. The beginning basis of the O&M cap is Edwardsport's actual O&M expenses for the twelve months ended March 31, 2015. It is the total of amounts reflected on Petitioner's Exhibit B-2 page 8 in IGCC-14 and D-2 page 8 in IGCC-15 ($67.2 million), plus an escalator of $3.5 million annually. The Settling Parties agree that Duke Energy Indiana shall be entitled to recover the lower of its actual O&M expenses or the applicable O&M cap from the date of the Commission order approving this Settlement Agreement through 2017. The specific cap amounts to be included in the subsequent annual IGCC Rider filings are as follows:

Period	**Base O&M Amount (Retail)**	**Cap Amount (Retail)**	**Amount to be Recovered (Retail)**
12 Months Ended 3/31/15	$67.2 million		
Calendar Year 2016 (beginning with the		$73.3 million[3]	Lower of retail portion of 2016 actual or cap

[2] As ordered by the Commission in Cause No. 43114 IGCC-4S1 at p. 120.

[3] The cap for 2016 will be prorated based on number of months remaining in 2016 after Commission approval of the 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

issuance 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

Upon approval of this Settlement, Duke Energy Indiana will use the $73.3 million O&M cap amount set forth above to set rates for the remainder of 2016. Duke Energy Indiana's first quarter 2017 IGCC Rider filing will use the 2017 cap amount from the table above (*i.e.*, $76.8 million) to set rates. However, only actual O&M expenses up to the cap applicable to each calendar year are recoverable (*i.e.*, customers will not pay more than actual expenses). 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 a subsequent filing.

The O&M expense cap level increases in 2017 to the 2017 O&M cap amount, regardless of whether Duke Energy Indiana's actual O&M expenses are less than the capped amount in 2016 (as prorated).

To the extent that the Commission's order approving this Settlement is delayed beyond June 2016, the Settling Parties agree that regardless of whether an order has been issued or not, the O&M cap will be effective on July 1, 2016.

The Settling Parties agree that they will not challenge or otherwise oppose Duke Energy Indiana's recovery of O&M expenditures in 2016 and 2017 up to the applicable cap amount, as set forth in this Settlement. In consideration of this Settlement's imposition of O&M expense and post-in-service ongoing capital caps through calendar year 2017 and the reduction in the Regulatory Asset, the non-Duke Settling Parties agree that they will only challenge or 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 twelve months ended August 2015. However, the non-Duke Settling Parties have not waived their rights to raise issues concerning Edwardsport's operations for the period after December 31, 2017.

The Settling Parties agree the 2016 and 2017 agreed-upon cap amounts are for the term of this Settlement only and that Duke Energy Indiana may request recovery of actual reasonable and necessary O&M expenses in its 2018 IGCC Rider filing (and subsequent annual

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

IGCC Rider filings) and in its next general base rate case. Duke Energy Indiana will not seek recovery of O&M expenses above the Settlement cap amounts set forth herein. The non-Duke Settling Parties shall retain all rights to make arguments related to Duke Energy Indiana's recovery of Edwardsport O&M starting with the 2018 IGCC Rider filing and afterwards.

The only exceptions to application of these caps shall be for force majeure events beyond the control and without the fault or negligence of Duke Energy Indiana, such as, by way of example, the following: acts of God, the public enemy, or any governmental or military entity. In such case, Duke Energy Indiana may only propose to recover O&M expenditures above the caps set in this Settlement for the periods of time covered by this Settlement in the event of such a force majeure event. To the extent Duke Energy Indiana proposes to recover O&M expenditures over the caps due to a force majeure event, the non-Duke Settling Parties reserve all rights to make arguments in response to Duke Energy Indiana's request.

C. Post-In-Service Ongoing Capital Cap. Upon approval of this Settlement, Duke Energy Indiana will use its actual post-in-service ongoing capital project amounts and accumulated depreciation, as reflected on Petitioner's Exhibits D-2 page 5, as filed in IGCC-15, to set rates for 2016. For April 1, 2015 through December 31, 2015, calendar year 2016 and calendar year 2017, Duke Energy Indiana is entitled to recover the lower of its actual ongoing capital expenditures or the cap amounts. Assuming Duke Energy Indiana spends at or more than the applicable annual ongoing capital caps, the specific cap amounts for use in the 2017 and 2018 annual IGCC Rider filings would be 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[4]	Lower of retail portion of 2015/2016 actual expenditures or cap amount for 2017 filing
Calendar Year 2017	$16.9 million	Lower of retail portion of 2017 actual expenditures or cap amount for 2018 filing

[4] Note that this amount includes ongoing capital additions from April 1, 2015 through December 31, 2016.

Because Duke Energy Indiana's IGCC Rider does not use forecasted ongoing capital expenditures, in the 2017 annual IGCC Rider filing, Duke Energy Indiana will propose rates based on the actual ongoing capital expenditures from April 1, 2015 through December 31, 2016 (or the cap amount if lower) being added to the March 31, 2015 balance. In Duke Energy Indiana's 2018 annual IGCC Rider filing, Duke Energy Indiana will propose rates based on the actual ongoing capital expenditures from January 1, 2017 through December 31, 2017 (or the cap amount if lower) being added to the December 31, 2016 balance.

The Settling Parties agree that they will not challenge or otherwise oppose Duke Energy Indiana's recovery of ongoing capital expenditures incurred in 2016 and 2017 up to the applicable cap amount, as set forth in this Settlement. The Settling Parties agree the 2015, 2016 and 2017 agreed-upon cap amounts are for the term of this Settlement only and that Duke Energy Indiana may request recovery of actual reasonable and necessary ongoing capital expenditures from calendar year 2018 in its 2019 IGCC Rider filing (and subsequent annual IGCC Rider filings) and in its next general base rate case. Duke Energy Indiana will not seek recovery of ongoing capital expenses above the Settlement cap amounts set forth herein. The non-Duke Settling Parties shall retain all rights to make arguments related to Duke Energy Indiana's recovery of Edwardsport ongoing capital expenditures starting with the 2019 IGCC Rider filing and afterwards.

The only exceptions to application of these caps shall be for force majeure events beyond the control and without the fault or negligence of Duke Energy Indiana, such as, by way of example, the following: acts of God, the public enemy, or any governmental or military entity. In such case, Duke Energy Indiana may only propose to recover ongoing capital expenditures above the caps set in this Settlement for the term of this Settlement in event of such a force majeure event. To the extent Duke Energy Indiana proposes to recover ongoing capital expenditures over the caps due to a force majeure event, the non-Duke Settling Parties reserve all rights to make arguments in response to Duke Energy Indiana's request.

4. Notice of Payments. Duke Energy Indiana agrees to make the following payments, out of shareholders' funds, for attorneys' fees, litigation expenses, and other funding commitments, within 30 days of a Commission order approving this Settlement (unless this Settlement is voided in its entirety pursuant to section 5 below):

A. A payment to the attorneys representing the Duke Energy Indiana Industrial Group of attorneys' fees in the amount of $2.5 million and expenses in the amount of $41,000 incurred for the consolidated causes, with implementation details in a separate Attorneys' Fees and Expenses Implementation Agreement.

B. A payment to Nucor Steel-Indiana of $100,000 for certain fees and expenses incurred for the consolidated causes, with implementation details in a separate Attorneys' Fees and Expenses Implementation Agreement.

C. The OUCC and Duke Energy Indiana will cooperate to use $1.859 million as follows:

- $1.009 million retail rate credit to Duke Energy Indiana residential customers to be reflected in Duke Energy Indiana's next regional transmission organization rider ("RTO") filed after the Commission's order approving this 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. Details will be agreed upon by the OUCC and Duke Energy Indiana.
- $100,000 contribution to the Indiana Low Income Home Energy Assistance Program ("LIHEAP") fund to be used solely for Duke Energy Indiana retail customers (*i.e.*, the Helping Hand Fund).

D. The Joint Intervenors and Duke Energy Indiana will cooperate to use $1 million as follows:

- $500,000 contribution to the Indiana LIHEAP fund to be used solely for Duke Energy Indiana retail customers (*i.e.*, the Helping Hand Fund).
- $500,000 contribution to the SUN solar energy grant program to develop solar energy projects for Duke Energy Indiana customers in Duke Energy Indiana's service territory. Joint Intervenors will be the lead contact to the grant administrator, the Indiana Association for Community Economic Development, and will determine the guidelines for participation in the grant program in conjunction with Duke Energy Indiana. Generally, the guidelines will include solar grant funding for installations of less than 0.5 MW for community, educational, religious, and non-profit organizations and/or low income residential customers in Duke Energy Indiana's service territory.

The OUCC, Joint Intervenors and Duke Energy Indiana acknowledge that the programs and contributions identified in Term 4 (C) and (D) may take longer than thirty days to set up and fund.

5. <u>Other.</u>

A. Duke Energy Indiana agrees not to oppose and the OUCC, Industrial Group and Nucor agree to support Joint Intervenors' efforts to seek between $750,000 and $1.25 million in attorney fees and expenses from the common fund created by this Settlement Agreement. This includes all attorneys who represented Joint Intervenors in any of the subject proceedings, and precludes further requests for fees and expenses relating to the Settlement Agreement and subject proceedings. The fees and expense award will be in the form of a supplemental settlement between Joint Intervenors, their attorneys, the OUCC, Duke Energy Indiana Industrial Group and Nucor Steel-Indiana. $500,000 of the fees and expense award will be provided to the Indiana Utility Ratepayer Trust, which would include any amounts owed by Joint Intervenors to reimburse the Indiana Utility Ratepayer Trust for grants received.

B. The Settling Parties agree that any subject to refund designations or similar language in the orders in Duke Energy Indiana's FAC proceedings (IURC Cause Nos. 38707 FAC 99, FAC 100, FAC 101) should be removed once this Settlement is approved and effective. The Settling Parties also agree that this Settlement Agreement resolves all issues reserved for consideration in the pending FAC subdocket, Cause No. 38707 FAC 99-S1.

C. Duke Energy Indiana agrees to retire or cease burning coal at Gallagher Station Units 2 and 4 by December 31, 2022. Ratemaking for the retirement of Gallagher Station Units 2 and 4 will be consistent with normal retirement accounting. Non-Duke Settling Parties may take any position regarding the Gallagher Station Units 2 and 4 retirement accounting in Duke Energy Indiana's next retail base rate case or other proceeding that addresses such retirement to the extent one is filed. The Non-Duke Settling Parties also reserve the right to take any position regarding any issues associated with a decision to convert Gallagher Station Units 2 and 4 from coal to gas-fired. The obligations outlined in this provision shall be subject to the force majeure provisions attached hereto as Exhibit A.

D. Starting in March 2016, Duke Energy Indiana agrees to provide to the Settling Parties information related to Gallagher Units 2 and 4, including plant balances, accumulated depreciation, depreciation expense, tons of coal burned, and expected capital expenditures at Gallagher Station annually through the date that Gallagher Station Units 2 and/or 4 retire or cease burning coal. To the extent confidential information is reviewed, it would be provided only under a non-disclosure agreement.

E. Duke Energy Indiana agrees to provide the following information in its annual IGCC Rider proceedings: (1) planned outage O&M and ongoing capital expenditures; (2) information on causes and costs for major forced outages /derates.

F. Duke Energy Indiana agrees to report the non-confidential monthly low income and residential customers' aggregated data set forth in Exhibit B to this Settlement on an annual basis to the Settling Parties and to the public, in readily accessible spreadsheet format.

G. The Settling Parties agree to work collaboratively for the two years following the date of a final order from the Commission 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. The Settling Parties will meet at least quarterly to discuss these issues. An attendee shall take detailed minutes at any meeting. The minutes will be provided within two weeks of any meeting to all Settling Parties.

H. The Settling Parties agree that the evidence to be submitted in support of this Settlement, along with the evidence of record previously submitted in Cause Nos. 43114 IGCC-11 through IGCC-15 and the applicable FAC dockets, together constitute substantial evidence to support this Settlement and provide a sufficient evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement. The Settling Parties shall prepare and file with the Commission as soon as reasonably possible, testimony and proposed order(s) in support of and consistent with this Settlement. The Settling Parties agree that all pending motions before the Commission related to the relevant proceedings are hereby withdrawn and resolved by this Settlement.

I. This Settlement is a complete and interrelated package that is intended to resolve all issues related to Edwardsport's operations from April 1, 2013 through March 31, 2015 that were or could have been raised, including Duke Energy Indiana's determination of Edwardsport's In-Service date of June 7, 2013. The Settling Parties agree to oppose or not support any attempt to create additional proceedings or phases of Commission proceedings to further examine Edwardsport operations from April 1, 2013 through March 31, 2015 and related expenditures.

J. The Settling Parties will not appeal or seek rehearing, reconsideration or a stay of a Final Order approving this Settlement in its entirety or without change or condition(s) unacceptable to any adversely affected Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement).

K. The Settling Parties agree to support in good faith the terms of this Settlement before the Commission and further agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement before any appellate courts, or on rehearing, reconsideration, remand or subsequent or additional related proceedings before the Commission.

L. The Settling Parties also agree to support or not oppose this Settlement in the event of any request for a stay by a person not a party to this Settlement or if this Settlement is the subject matter of any other state proceeding.

M. The Settling Parties shall remain bound by the terms of this Settlement Agreement and shall continue to support or not oppose all the terms of the Settlement on appeal, remand, reconsideration, etc., even if the Commission rejects the Settlement. However, in the event that the Settlement is rejected by the Commission and such rejection is ultimately upheld on rehearing, reconsideration, and/or appeal, at the point when all such proceedings and appeals are complete, this Settlement Agreement shall become void and of no further effect (except for provisions which have already been fully implemented or which are explicitly stated herein to survive termination/voiding).

N. If the Commission approves the Settlement in its entirety, or approves the Settlement with modifications that are not unacceptable to affected Settling Parties, and such Commission approval is ultimately vacated or reversed on appeal, the Settling Parties agree to support or not oppose the terms of this Settlement in any additional proceedings before the Commission (as well as any subsequent appeals). In such situation, the Settling Parties agree not to take any positions adverse to or inconsistent with the Settlement or any adverse positions against each other with respect to the Settlement or the subject matters herein, on remand or in additional related proceedings before the Commission. To the extent that the Commission and/or appellate courts ultimately and finally reject this Settlement, any provisions of this Settlement that remain to be implemented will then become void and of no further effect, unless explicitly stated herein.

O. The positions taken by the Settling Parties in this Settlement shall not be deemed to be admissions by any of the Settling Parties and shall not be used as precedent, except as necessary to implement the terms of this Settlement. This provision shall survive termination/voiding of this Agreement.

P. It is understood that this Settlement is reflective of a good faith negotiated settlement and neither the making of the Settlement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except as necessary to implement or enforce this Settlement Agreement. It is also understood that each and every term of the Settlement Agreement is in consideration and support of each and every other term.

Q. The Settling Parties will support this Settlement before the Commission and request that the Commission expeditiously accept and approve the Settlement. This Settlement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party.

R. The Settling Parties will file this Settlement and testimony in support of this Settlement. Such supportive testimony will be agreed-upon by the Settling Parties and offered into evidence without objection by any Settling Party and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement and evidence conditionally, and if the Commission fails to approve this Settlement in its entirety without any change or with condition(s) unacceptable to any adversely affected Settling Party, the Settlement and supporting evidence may be withdrawn and the Commission will continue to proceed to decision in the affected proceedings, without regard to the filing of this Settlement.

S. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement all relate to offers of settlement and shall be privileged and confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise. This provision shall survive termination/voiding of this Agreement.

T. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

U. The provisions of this Settlement shall be enforceable by any Settling Party before the Commission and thereafter in any state court of competent jurisdiction as necessary. The obligations outlined in this Settlement shall be subject to the Remedies provision attached hereto in Exhibit A.

V. This Settlement may be executed in two (2) or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED AND AGREED TO THIS 14th DAY of JANUARY 2016:

[signature pages to follow]

For Duke Energy Indiana, LLC

Melody Birmingham-Byrd, President
Duke Energy Indiana, LLC

Kelley A. Karn, Deputy General Counsel
Attorney for Duke Energy Indiana

[This is a signature page for the 2016 Edwardsport Settlement before the Indiana Utility Regulatory Commission. Remainder of page intentionally left blank.]

For the Indiana Office of Utility Consumer Counselor:

A. David Stippler, Consumer Counselor
Indiana Office of Utility Consumer Counselor

Randall C. Helmen, Chief Deputy Consumer Counselor
Indiana Office of Utility Consumer Counselor

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For the Duke Energy Indiana Industrial Group:

Timothy L. Stewart
Attorney for Duke Energy Indiana Industrial Group

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For Nucor Steel-Indiana:

Anne E. Becker
Attorney for Nucor Steel-Indiana

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For Joint Intervenors:

Jennifer Washburn

Jennifer Washburn
Attorney for Joint Intervenors

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EXHIBIT A

Remedies

1. The Settling Parties agree that any obligation(s) to support or not oppose an approval or other action referred to in this Settlement is limited to the specified proceedings before the Commission, except that, in addition, the Settling Parties have also agreed that no Party will appeal or oppose this Settlement on any appeal of a final Commission order that approves this Settlement to Indiana state court.

2. The Settling Parties acknowledge and agree that specific performance (including the payments required under this Settlement) and injunction are the only appropriate remedies for any alleged breach of any obligation in this Settlement, and under no circumstances shall monetary damages be allowed for any breach of any obligation in this Settlement. In addition, no legal action for specific performance or injunction related to any obligation in this Settlement shall be brought or maintained until: (a) the non-breaching Party provides written notice to the breaching Party which explains with particularity the nature of the claimed breach; and (b) within thirty (30) days after receipt of said notice, the breaching Party fails to cure the claimed breach or, in the case of a claimed breach which cannot be reasonably remedied within a thirty (30) day period, the breaching Party fails to commence to cure the claimed breach within such thirty (30) day period, and thereafter diligently complete the activities necessary to remedy the claimed breach. Acceptance of cure shall not be unreasonably withheld. In the event any action should be necessary to enforce the terms and conditions of this Settlement, each Party shall bear their own attorneys' fees and costs, including the fees and costs of enforcing any judgment.

Force Majeure

3. Definition. For purposes of Term 5(C) of this Settlement, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control Duke Energy of one or more of its contractors, or any entity controlled by Duke Energy, that delays or prevents the performance of any obligation under Term 5(C) or otherwise causes a violation of Term 5(C) despite Duke Energy's best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event: (a) as it is occurring; and (b) after it has occurred, such that the delay and/or violation are minimized to the greatest extent possible and the emissions during such event are minimized to the greatest extent possible.

4. Notice of Force Majeure Events. If any event occurs or has occurred that may delay or prevent compliance with or otherwise cause a violation of Duke Energy's obligation under Term 5(C), as to which Duke Energy intends to assert a claim of Force Majeure, Duke Energy shall notify the Settling Parties in writing as soon as practicable, but in no event later than fourteen (14) business days following the date Duke Energy first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, Duke Energy shall reference

this exhibit of the Settlement and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the Force Majeure Event, all measures taken or to be taken by Duke Energy to prevent or minimize the delay or violation, the schedule by which Duke Energy proposes to implement those measures, and Duke Energy's rationale for attributing the failure, delay or violation to a Force Majeure Event. A copy of this Notice shall be sent electronically, as soon as practicable, to the Settling Parties. Duke Energy shall adopt all reasonable measures to avoid or minimize such failures, delays, or violations. Duke Energy shall be deemed to know of any circumstance which it, its contractors, or any entity controlled by Duke Energy, knew or should have known.

5. Failure to Give Notice. If Duke Energy fails to comply with the notice requirements of this Exhibit, the Settling Parties may seek to void such claim for Force Majeure as to the specific event for which Duke Energy failed to comply with such notice requirement.

6. Settling Parties' Response. The Settling Parties shall notify Duke Energy in writing of their response regarding any claim of Force Majeure as soon as reasonably practicable. If Settling Parties agree that a delay in performance has been or will be caused by a Force Majeure Event, the Settling Parties and Duke Energy shall stipulate to an extension of deadline(s) for performance of Term 5(C) by a period equal to the delay actually caused by the event, in which case the delay at issue shall be deemed not to be a violation of Term 5(C) of this Settlement. In such circumstances, an appropriate modification shall be made in a written document that is signed by all Parties and that makes specific reference to this Settlement.

7. Disagreement. If the Settling Parties do not agree with Duke Energy's claim of Force Majeure, or if the Settling Parties and Duke Energy cannot agree on the length of the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Paragraph 2 of this Exhibit.

8. Burden of Proof. In any dispute regarding Force Majeure, Duke Energy shall bear the burden of proving by a preponderance of the evidence that any delay in performance, or any other violation of Term 5(C) of this Settlement, was caused by or will be caused by a Force Majeure Event. Duke Energy shall also bear the burden of proving by a preponderance of the evidence that it gave the notice required by this Exhibit and the anticipated duration and extent of any failure, delay, or violation(s) attributable to a Force Majeure Event. An extension of one compliance date may, but will not necessarily, result in an extension of a subsequent compliance date.

9. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of Duke Energy's obligations under Term 5(C) shall not constitute a Force Majeure Event.

10. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and Duke Energy's response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Exhibit: construction, labor, or equipment delays; acts of God; acts of war or

terrorism; and orders by a government official, government agency, other regulatory authority, or a regional transmission organization *(e.g.,* the MISO), acting under and authorized by applicable law or tariff as accepted by the Federal Energy Regulatory Commission, that directs Duke Energy to supply electricity so long as such order is a response to a state-wide or regional emergency or is necessary to preserve the reliability of the bulk power system. Depending upon the circumstances and Duke Energy's response to such circumstances, failure of a permitting authority or the Indiana Utility Regulatory Commission to issue any necessary permit or order with sufficient time for Duke Energy to achieve compliance with Term 5(C) of this Settlement may constitute a Force Majeure Event where the failure of the authority to act is beyond the control of Duke Energy and Duke Energy has taken all reasonable steps available to it to obtain the necessary permit or order, including, but not limited to: submitting a complete permit application or request; responding to requests for additional information by the authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the authority.

EXHIBIT B

Duke Energy Indiana Residential and Low Income Eligible Customer Reporting

The report will be run annually in the month of July. First report to be provided to the Settling Parties by July 31, 2016 or 30 days after an IURC order in this proceeding, whichever occurs first.

Report will include monthly, aggregated low income eligible and residential customer data for the prior 12 months beginning March (*i.e.,* the first report will cover the twelve months ended March 31, 2016). Report will be made available to the public, in readily accessible spreadsheet format.

IEAP customers are those customers eligible for winter disconnect moratorium as provided to Duke Energy Indiana by Community Action Agencies (*e.g.,* Indiana Energy Assistance Program (IEAP) coded customers).

Reporting Metrics:

General Residential Customers

1. Total Number of Accounts
2. Total Number of Customers Receiving Assistance from Helping Hand
3. Number of Accounts Sent Notice of Disconnection for Nonpayment
4. Number of Service Disconnections for Nonpayment
5. Number of Service Restorations after Disconnection for Nonpayment
6. Number of New Payment Agreements (deferred payment arrangements)
7. Number of Defaulted Payment Agreements (deferred payment agreements)
8. Number of Accounts Written Off as Uncollectible
9. Number of New Budget Billing Plans
10. Number of unpaid accounts 60 days plus in arrears
11. Dollar value of unpaid accounts 60 days plus in arrears

IEAP Customers

1. Total Number of Accounts
2. Total Number of Customers Receiving Assistance from Helping Hand
3. Number of Accounts Sent Notice of Disconnection for Nonpayment
4. Number of Service Disconnections for Nonpayment
5. Number of Service Restorations after Disconnection for Nonpayment
6. Number of New Payment Agreements (deferred payment agreements)
7. Number of Defaulted Payment Agreements (deferred payment agreements)

8. Number of Accounts Written Off as Uncollectible
9. Number of New Budget Billing Plans
10. Number of unpaid accounts 60 days plus in arrears
11. Dollar value of unpaid accounts 60 days plus in arrears