STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT PURSUANT TO IND. CODE §§8-1-8.5 AND 8-1-8.7; (2) AUTHORITY TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") PROPERTY UNDER CONSTRUCTION IN ITS RATES AND AUTHORITY TO RECOVER APPLICABLE RELATED COSTS THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO IND. CODE §§8-1-8.8-11 AND -12; (3) ESTABLISHMENT A SUBDOCKET PROCEEDING TO REVIEW THE COST ESTIMATE FOR THE IGCC PROJECT; AND (4) APPROVAL OF A REQUEST TO UPDATE ITS DEPRECIATION RATES FOR PRODUCTION, TRANSMISSION, DISTRIBUTION AND GENERAL PLANT AND EQUIPMENT	)	**CAUSE NO. 43114 IGCC 4S1**

<u>SUBMISSION OF PROPOSED ORDER</u>

The Settling Parties (Duke Energy Indiana, Inc., the Indiana Office of Utility Consumer Counselor, the Duke Energy Indiana Industrial Group, and Nucor Steel – Indiana, a division of Nucor Corporation) respectfully submit the attached Phase I and Phase II Proposed Order in the above-captioned matter to the Indiana Utility Regulatory Commission.

Respectfully submitted,

By: Kelley A. Karn/scw

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Attorney for Duke Energy Indiana, Inc.
executed on behalf of the Settling Parties*

**The Settling Parties have authorized Kelley A. Karn to sign this submission on their collective behalf.*

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STATE OF INDIANA

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<u>SETTLING PARTIES' SUBMITTAL OF PHASE I AND PHASE II PROPOSED ORDER</u>

TABLE OF CONTENTS

Page

1. Notice and Jurisdiction 8
2. Description of the Edwardsport IGCC Project 8
3. Previous Proceedings Relating to this Project 9
   - A. Original CPCN Case 9
   - B. IGCC 1 Case 11
   - C. IGCC 2 Case 12
   - D. IGCC 3 Case 13
   - E. IGCC 4 Case 14
4. Relief Requested in this Subdocket Proceeding 14
5. Applicable Law; Statutory Framework 15
6. Settlement Agreement and Evidence Presented 20
   - A. The Settlement Agreement Terms 21
     - (1) Hard Cost Cap 22
     - (2) IGCC Rider Implementation 25
     - (3) Retail Electric Rate Case Moratorium 26
     - (4) Updated Depreciation Rates (for all plant except IGCC) 27
     - (5) Move to Non-Accelerated Depreciation Rates for Certain Pollution Control Property/Clean Coal Technology Projects 28
     - (6) Prospective Termination of the Deferred Tax/Capital Structure Incentive 28
     - (7) Potential Recoveries from Vendors/Contractors; Intellectual Property Benefits 29
     - (8) Government Funding and Tax Incentives; Project Byproducts 29
     - (9) Attorney Fees and Reimbursements; Other Funding Commitments 30
     - (10) Other Provisions 30
   - B. Testimony Regarding the Settlement Agreement 31
     - (1) Testimony Supporting the Hard Cost Cap 34

(2) Testimony Opposing the Hard Cost Cap and the Settling Parties' Responses ... 39

(a) Challenges to the Reasonableness of the Hard Cost Cap ... 39

(b) Contentions that the Hard Cost Cap Presumes the "First" $2.319 Billion in Construction Costs Are Prudent ... 41

(c) Contentions Related to Customers' Responsibility for Certain Costs Above the Hard Cost Cap ... 43

(d) Allegations Concerning In-Service Criteria and Effect on Costs ... 46

(3) Testimony Regarding Rider Restart Methodology ... 49

(4) Testimony Regarding Rate Case Moratorium ... 50

(5) Testimony Regarding Updated Depreciation Rates ... 51

(6) Testimony Regarding Move to Non-Accelerated Depreciation ... 52

(7) Testimony Regarding Deferred Taxes ... 52

(8) Testimony Regarding Attorney Fees and Reimbursements; Other Funding Commitments ... 53

C. Joint Intervenors' Additional Objections ... 54

(1) CO_2 mitigation ... 54

(2) Operational Requirements ... 56

(3) Findings on the Merits of Underlying Claims ... 57

(4) Alleged Corruption of the Regulatory Process ... 57

(5) Adequacy of Procedural Schedule ... 59

7. Commission Discussion and Findings ... 60

A. Standard for Commission Review of Settlement Agreements ... 60

B. Evaluation of the Reasonableness of the Proposed Settlement and Whether It Serves the Public Interest ... 62

C. Whether Findings on the Merits of the Underlying Claims are Required ... 66

D. Evaluation of the Joint Intervenors' Objections to the Settlement Agreement ... 68

(1) Adequacy of the Procedural Schedule ... 73

(2) Substantial Evidence Supports the Hard Cost Cap ... 74

(3) Appropriateness of Recovery of the "First" $2.319 billion in Project Costs 81

(4) Objections Concerning Continued Accrual of AFUDC and CWIP 83

(5) Retroactive Termination of Deferred Taxes 84

(6) Whether the Hard Cost Cap is a Floor 85

(7) In-Service Criteria and Construction Costs Incurred After the IGCC Plant is Declared In-Service 86

(8) Operational Requirements 88

(9) CO_2 Mitigation 89

(10) Whether the Regulatory Process was Corrupted 90

(11) Delays in Project Completion 91

(12) Attorney Fees and Contributions 93

E. Guidance for Future Large-Capital-Cost CPCN Proceedings 101

F. Ultimate Findings 104

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FINAL ORDER PHASE I AND PHASE II

<u>BY THE COMMISSION</u>:
James D. Atterholt, Chairman
Kari A. E. Bennett, Commissioner
Larry S. Landis, Commissioner
Carolene R. Mays, Commissioner
David E. Ziegner, Commissioner
David E. Veleta, Administrative Law Judge

On November 24, 2009, Duke Energy Indiana, Inc. ("Duke Energy Indiana," "Petitioner" or "the Company") filed its Verified Petition ("Petition") with the Indiana Utility Regulatory

Commission ("Commission") in Cause No. 43114 IGCC 4. In its Petition, Duke Energy Indiana requested: (1) approval of the Company's ongoing progress report concerning the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC Project," "Edwardsport," "IGCC Plant," or "Project"); (2) authorization to reflect additional actual costs incurred for the IGCC Project under construction in its rates and authorization to recover certain other applicable related costs via the Integrated Coal Gasification Combined Cycle Generating Facility Cost Recovery Adjustment, Standard Contract Rider No. 61 ("Rider 61" or "IGCC Rider"); and (3) establishment of a subdocket proceeding to review a revised cost estimate for the IGCC Project.

Pursuant to a Prehearing Conference Docket Entry issued on January 27, 2010, the Commission granted Duke Energy Indiana's Motion for Subdocket under Cause No. 43114 IGCC 4, thereby establishing this Cause No. 43114 IGCC 4S1.

On July 28, 2010, the Commission issued an order in Cause No. 43114 IGCC 4 ("IGCC 4 Order") approving Duke Energy Indiana's ongoing review progress report on an interim basis pending the outcome of Cause No. 43114 IGCC 4S1. *See* IGCC 4 Order at Ordering Paragraph 1. The Commission also authorized the Company to reflect actual Project costs incurred through September 30, 2009 in its retail electric rates through its IGCC Rider. *See id*. at Ordering Paragraph 2. Consistent with the Commission's ruling, the Company is currently recovering financing costs for capital expenditures incurred through September 30, 2009, on an interim basis, subject to refund.

By Docket Entry dated February 25, 2011, the Commission bifurcated Cause No. 43114 IGCC 4S1 into two phases – Phase I to address the Commission's review of the IGCC 4 progress report, the Project cost estimate increase, the continued need for additional capacity, and the

reasonableness of going forward with the Project; and Phase II to address allegations of fraud, concealment and/or gross mismanagement.

Also on February 25, 2011, the Commission denied the Joint Intervenors' motion to open a new subdocket to investigate allegations of undue influence, improper and *ex parte* communications, conflicts of interest, and other alleged misconduct relating to the regulatory oversight of the Project.[1] In denying the Joint Intervenors' motion, the Commission explained that any such allegations should be the subject of independent investigations by other agencies who have the expertise and the authority to investigate and prosecute such alleged misconduct. The Commission clarified on October 18, 2011, that, with respect to claims of undue influence and alleged improper or *ex parte* communications, any such evidence should be stricken from the record as irrelevant, except that the parties could offer evidence of alleged *ex parte* communications to the extent the evidence relates to cost recovery for the Project.

On August 30, 2011, the Commission precluded the parties from referring to communications made to Black & Veatch[2] and/or the Commission staff as part of the Commission's independent oversight of the IGCC Project.

On March 7, 2011, the Commission issued Docket Entries in Cause Nos. 43114 IGCC 5 and 43114 IGCC 6 providing that the Commission's review of the progress reports submitted in those Causes shall be considered in Phase I of IGCC 4S1, and its review of any allegations of fraud, concealment and/or gross mismanagement relative to the ongoing progress reports presented in IGCC 5 and IGCC 6 shall be considered in Phase II of IGCC 4S1.

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[1] "Joint Intervenors" refers collectively to Citizens Action Coalition of Indiana, Inc. ("CAC"), Save the Valley, Inc., Valley Watch, Inc., and the Sierra Club, Hoosier Chapter.

[2] In 2008, the Commission directed Duke Energy Indiana to engage Black & Veatch to oversee the Project on the Commission's behalf. IGCC 1, Docket Entry dated June 3, 2008.

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 Cause No. 43114 IGCC 4S1 Phase I, beginning on October 26, 2011. An Evidentiary Hearing was also held in Cause No. 43114 IGCC 4S1 Phase II, beginning on November 9, 2011. The hearings for both phases extended over the course of 25 days. The parties to the proceeding, other than Duke Energy Indiana, included the Joint Intervenors, the Indiana Office of Utility Consumer Counselor ("OUCC"), Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), Steel Dynamics, Inc. ("SDI"), and the Indiana Industrial Group ("IG").[3]

During Phase I of the Evidentiary Hearing, Duke Energy Indiana presented the testimony and exhibits of Mr. James E. Rogers, President and Chief Executive Officer, Duke Energy Corporation; Mr. Douglas F. Esamann, President, Duke Energy Indiana; Dr. Kris R. Nielsen, President and Chairman, Pegasus Global Holdings, Inc.; Mr. Richard Haviland, Senior Vice President of Construction and Major Projects, Duke Energy Business Services, LLC; Mr. W. Michael Womack, Vice President, Edwardsport IGCC Project, Duke Energy Business Services, LLC; Dr. Patricia D. Galloway, Chief Executive Officer, Pegasus Global Holdings, Inc.; Mr. Stephen G. De May, Senior Vice President, Investor Relations and Treasurer, Duke Energy Business Services, LLC; Mr. Jack L. Stultz, General Manager II, Regulated Fossil Stations, Duke Energy Business Services, LLC; Mr. Joseph A. Miller, Jr., General Manager, Analytical and Investment Engineering, Duke Energy Business Services, LLC; Mr. Robert J. Burch, Regional Engineering Director, Duke Energy Business Services, LLC; Mr. John L. Stowell, Vice President, Environment, Health & Safety Policy, Duke Energy Business Services, LLC; Dr. Richard G. Stevie, Chief Economist, Strategy and Planning, Duke Energy Business Services,

[3] OUCC, Joint Intervenors, Nucor, SDI, and IG are referred to collectively as the "Non-Duke parties."

LLC; Ms. Janice D. Hager, Vice President, Integrated Resource Planning & Regulated Analytics, Duke Energy Business Services, LLC; Mr. John J. Spanos, Vice President, Valuation and Rate Division, Gannett Fleming, Inc.; Mr. Robert G. Presnak, Senior Vice President, Sargent & Lundy; Mr. Kent K. Freeman, Rate Strategy and Projects Director, Rates for Indiana, Duke Energy Business Services, LLC; and Mr. Kenneth J. Cooper, Senior Engineer and Principal, Petrotek Engineering Corp. All testimony and exhibits pre-filed by Duke Energy Indiana in Phase I on April 16, 2010, September 2, 2010 (as corrected on December 1, 2010), March 10, 2011, and August 3, 2011 were admitted into evidence, subject to the Commission's rulings striking certain testimony. Mr. Womack's Direct Testimonies in IGCC 5 and IGCC 6 were also admitted.

The IG presented the testimony and exhibits of Mr. Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. and Dwight R. Hoenig, President, Turner/Maclane Environmental Consulting, Inc. The OUCC presented the testimony and exhibits of Ms. Barbara A. Smith, Director of the Resource Planning and Communications Division; Mr. Anthony A. Alvarez, Utility Analyst II within the Resource Planning and Communications Division; Mr. Wes R. Blakley, Senior Utility Analyst; and Mr. Robert G. James, Director, Capital Project Management, Accumyn LLC. Joint Intervenors presented the testimony and exhibits of Mr. David A. Schlissel, President, Schlissel Technical Consulting, Inc. The testimony and exhibits pre-filed by the OUCC, the IG, and the Joint Intervenors on June 30, 2011 in Phase I were admitted into evidence, subject to the Commission's rulings to strike.[4] Nucor and SDI did not present any testimony in Phase I of the proceeding.

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[4] The OUCC, IG and Joint Intervenors did not offer into evidence any of the pre-filed testimony and exhibits that they submitted with the Commission in this Cause prior to June 30, 2011 and, thus, all such

(continued...)

During Phase II of the Evidentiary Hearing, Duke Energy Indiana presented the testimony and exhibits of Mr. Steven M. Fetter, President of Regulation, UnFettered; Dr. Galloway; Mr. John J. Roebel, Senior Vice President of Generation Support, Duke Energy Business Services, LLC; Mr. Haviland; Mr. Womack; Ms. Hager; Mr. Burch; Mr. Stultz; Mr. Esamann; Mr. Dennis Zupan, former General Manager in the Major Projects Group, Duke Energy Business Services, LLC; Mr. Richard W. Painter, Professor of Corporate Law at the University of Minnesota Law School; and Mr. Rogers. All testimony and exhibits pre-filed by Duke Energy Indiana in Phase II on September 9, 2011 were admitted into evidence, subject to the Commission's rulings striking certain testimony.

The IG presented the testimony and exhibits of Mr. Gorman; Mr. Hoenig; Mr. Michael Banta, former Commissioner of the IURC; and Mr. William N. D'Onofrio, Principal Consultant and Founder of D'Onofrio and Associates, LLC. The OUCC presented the testimony and exhibits of Mr. Blakley; Mr. Alvarez; Ms. Cynthia Armstrong, Utility Analyst within the Electric Division of the OUCC; Mr. Scott Bayley, Founder and Managing Director of Accumyn LLC; Mr. James; and Ms. Barbara Smith. Joint Intervenors presented the testimony and exhibits of Mr. Schlissel and Mr. Kerwin Olson, Executive Director of CAC. The testimony and exhibits pre-filed by the IG, OUCC, and the Joint Intervenors in Phase II on July 14, 2011 and October 7, 2011 (including corrections to Mr. Banta's testimony filed on August 11, 2011 and November 7, 2011) were admitted into evidence, subject to the Commission's rulings striking certain testimony. Nucor and SDI did not present any testimony in Phase II of the proceeding. The

pre-filed testimony and exhibits are not a part of the record. Oct. 26, 2011 Tr. at A-10:20–11:19 (Pre-hearing matters).

record closed on January 24, 2012, subject to the Commission's determination of the confidentiality of certain exhibits.[5]

On April 30, 2012, subsequent to the close of evidence, Duke Energy Indiana, Nucor, the OUCC and the IG (collectively "the Settling Parties"[6]) submitted a Verified Joint Petition To Reopen The Records In This Cause For The Purpose Of Taking Additional Evidence Relating To A Settlement Agreement Reached By Less Than All Parties And Submission Of Such Settlement Agreement. The Settlement Agreement, if approved and adopted by the Commission, would resolve all issues in Phase I and Phase II of this proceeding.[7] The Joint Intervenors opposed the Settlement, and the matter was set for hearing and heard on July 16-19, 2012.

At the Settlement Hearing, the Settling Parties presented the testimony and exhibits of Mr. Esamann (Duke Energy Indiana); Mr. Freeman (Duke Energy Indiana); Mr. Womack (Duke Energy Indiana); Mr. Danny Wiles, Director of Regulated Accounting, Duke Energy Business Services, LLC; Mr. Gorman (IG); Mr. Blakley (OUCC); and Ms. Barbara Smith (OUCC). All testimony and exhibits pre-filed by the Settling Parties on May 16, 2012 and July 6, 2012 were admitted into evidence.

Joint Intervenors presented the testimony and exhibits of Mr. Schlissel; Mr. Olson; Mr. Ralph C. Smith, Senior Regulatory Consultant at Larkin & Associates, PLLC; and Mr. Nachy Kanfer, Deputy Director for the Central Region of the Beyond Coal to Clean Energy Campaign.

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[5] We opened subdocket Cause No. 43114 IGCC 4 S2 to hear evidence regarding whether certain exhibits and related testimony that Duke Energy Indiana identified as containing trade secret information should continue to be treated as confidential. Upon a careful review of the testimony and exhibits at issue and the evidence submitted regarding Duke Energy Indiana's confidentiality request, we issued an order on July 6, 2012 that determined which of the 328 exhibits, on an individual basis, met the definition of a trade secret under Indiana law and thus should not be subject to disclosure under Indiana's Access to Public Records Act, Indiana Code Ch. 5-14-3.

[6] This Order refers to the OUCC, IG, and Nucor collectively as "the Non-Duke Settling Parties."

[7] The Settlement Agreement is attached hereto as Attachment A.

The testimony and exhibits pre-filed by the Joint Intervenors on June 29, 2012 (as corrected on July 11, 2012), as well as Mr. Olson's supplemental testimony pre-filed on July 13, 2012, were admitted into evidence.

On July 19, 2012, the Commission consolidated the Phase I and Phase II evidentiary records for purposes of consideration of the Settlement Agreement.

SDI did not present testimony or participate in the Settlement Hearing.

A proposed order, exceptions, and replies addressing the Settlement Agreement were submitted by the parties on August 17, 2012, August 31, 2012, and September 14, 2012 respectively.

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

1. <u>Notice and Jurisdiction</u>.

Due, legal, and timely notice of the evidentiary hearing in this Cause was given and published by the Commission as required by law. Duke Energy Indiana is a public utility as defined by Ind. Code § 8-1-2-1, and is subject to regulation by the Commission in the manner and to the extent provided for by the laws of the State of Indiana, including the Public Service Commission Act, as amended. Accordingly, the Commission has jurisdiction over Duke Energy Indiana and the subject matter of this proceeding.

2. <u>Description of the Edwardsport IGCC Project</u>.

The Edwardsport IGCC Project is an approximately 618-MW IGCC facility in Knox County, Indiana located on approximately 220 acres of land adjacent to Duke Energy Indiana's retired Edwardsport Generation Station. It has been under construction since 2008. As of

October 2011, the Project was 96% complete. The Project is designed to use Indiana bituminous coal from the geologic formation known as the Illinois Basin.

The Edwardsport IGCC Project is the first commercial IGCC project of its size in the United States. As we have already found, the Project is a reasonable generating alternative to serve Duke Energy Indiana's load. *See* November 20, 2007, IURC Order in Cause Nos. 43114 and 43114S1 at 22 ("CPCN Order"). Due to the efficient nature of its operations and after consideration of all costs, such as fuel and emission allowance costs, Edwardsport is expected to be consistently among the first units economically committed and dispatched on the Duke Energy Indiana system. *Id.* at 15. The Project will also provide benefits to the State's economy, primarily in the forms of state and federal tax incentives and new jobs. *Id.* at 15, 43. Additionally, the Project will provide environmental benefits as it will reduce SO_2, NO_X, mercury, and particulate emissions well below federal and state standards. *Id.* at 15, 42-43.

3. <u>Previous Proceedings Relating to this Project</u>.

A. <u>Original CPCN Case</u>.

In our November 20, 2007 Order in Cause No. 43114, this Commission approved the construction of the Edwardsport IGCC Project and issued a certificate of public convenience and necessity ("CPCN") and a certificate of clean coal technology for the Project under Ind. Code §§ 8-1-8.5 and 8-1-8.7 (collectively "CPCNs"), respectively, at an approved initial estimated cost of $1.985 billion (including AFUDC[8]). In so doing, we determined that the Petitioner has a need for additional baseload capacity over the next few years to reliably meet its customers' increasing electricity requirements, and that the proposed Edwardsport IGCC Project was

[8] Allowance for Funds Used During Construction, or "AFUDC", means the cost for the period of construction of borrowed and other funds used for the construction of the Project. *See* 170 IAC 4-6-1. In other words, it refers to the costs of financing the construction capital expenditures.

consistent with both the State's generation expansion plan and the Petitioner's integrated resource plan ("IRP"). More specifically, we found that Duke Energy Indiana's load forecasting and IRP processes were reasonable; that the Company had demonstrated a need for 850 MWs to 1000 MWs of additional generation capacity by the 2012 to 2014 timeframe; and that 300 MWs to 600 MWs of this need was a baseload capacity need. We further found that Duke Energy Indiana's cost estimate for the Project ($1.985 billion including future escalation of 4% per year) was reasonable, based on a "Front End Engineering and Design" or "FEED" Study[9] that supported the cost estimate, and in light of the consistency of the cost estimate with the Electric Power Research Institute ("EPRI") range for construction of an IGCC facility of similar size. We also found that Petitioner's IRP analyses supported pursuit of the proposed Edwardsport IGCC Project. We made these findings after consideration of the evidence presented by all parties. *See* CPCN Order at 31-36.

Further, we found that the Edwardsport IGCC Project presented other benefits, as well, such as relative environmental benefits compared to conventional pulverized coal technology (*e.g.*, 90% mercury capture, higher SO_2, NO_x, and particulate emissions removal, utilization of less water and generation of less solid waste), as well as positive impacts on the local and statewide economy. In Cause No. 43114, we also approved certain ratemaking and accounting treatment for the Project, including financial incentives pursuant to Ind. Code § 8-1-8.8. Specifically, we approved Petitioner's request for timely recovery of its construction and operating and maintenance ("O&M") costs through a tracking "Rider" mechanism; we granted Petitioner the authority to defer post-in-service AFUDC and operating expenses to the extent

[9] As we discussed in that Order, the "FEED Study" is an in-depth front-end engineering and design study performed by General Electric ("GE") and Bechtel that developed a cost estimate and schedule for the Project, based on the scope of work proposed by GE and Bechtel, value engineering studies, updated plant performance information, etc. *See* CPCN Order at 6.

such costs are not reflected in Petitioner's retail electric rates; and we approved an incentive for the Project in the form of an exclusion of deferred taxes from the capital structure used in the IGCC cost tracking mechanism (while including the deferred tax balance related to the IGCC Project as an IGCC rate-base offset). Finally, we required ongoing review of the construction of the Project on a semi-annual basis, in conjunction with the semi-annual IGCC Rider rate adjustment proceedings.[10] *See* CPCN Order at 36.

B. <u>IGCC 1 Case</u>.

In our January 7, 2009 Order in Cause No. 43114 IGCC 1 ("IGCC 1 Order"), we considered Duke Energy Indiana's request for an increased cost estimate of $2.35 billion (including AFUDC) for the Project, based on a high demand for construction-related commodities, materials, equipment, engineering services and labor. The evidence presented by the Company indicated that the economics of a resource plan with the IGCC Project (at the increased estimated cost) ranged from 0.9% higher cost to 0.7% lower cost than a resource plan without the IGCC Project, under base case and various scenario and sensitivity analyses. We found that the Project cost estimate increase was in line with other utilities' project costs increases, and in line with EPRI's revised estimate of IGCC project costs. And we found that even with the cost estimate increase, the Project remained reasonable and necessary, and that the Company's overall need for baseload capacity had not changed. With regard to need, we found that even with an updated lower load forecast and additional IRP analysis, the Company had a need for approximately 590 MWs in summer of 2012 and beyond. Accordingly, we approved an updated cost estimate for the Edwardsport IGCC Project of $2.35 billion, and use of a 6% escalation rate. We made these findings after consideration of evidence presented by all parties.

[10] Our CPCN Order was upheld by the Court of Appeals of Indiana on October 16, 2008. *Citizens Action Coalition, Inc. v. PSI Energy, Inc.*, 894 N.E.2d 1055 (Ind. Ct. App. 2008).

However, in our IGCC 1 Order, we limited the incentive treatment of deferred taxes to the initial $1.985 billion of Project costs. Additionally, we approved implementation of Duke Energy Indiana's IGCC Rider, and we directed that Duke Energy Indiana utilize a more formalized reporting and communication process to facilitate the Commission's ongoing review of the Project. *See* IGCC 1 Order at 4-14, 28-29.

C. <u>IGCC 2 Case</u>.

In our May 13, 2009 Order in Cause No. 43114 IGCC 2 ("IGCC 2 Order"), we rejected the Joint Intervenors' recommendations that the Project be put on hold and that a review of the Project be conducted due to, among other things, the decline in electricity use[11] nationally and in the Duke Energy Midwest area. We found that while electricity usage had been impacted by the economic recession, reduction in load was likely to be temporary and load demand will likely resume its upward trend once the recession passes. We noted that planning and constructing new generation capacity must appropriately look to long-term trends and projections to ensure that capacity is planned and constructed in a manner that will result in its timely availability to meet future demand. To stop construction of the Project in response to an economic downturn, without clear projections of a long-term corresponding overall decline in electricity demand, would be inconsistent with this approach. We further found that the Company's overall need for baseload capacity remained, even with a lower load forecast. We concluded that the Project was still needed, and that the public convenience and necessity continued to require the construction and completion of the Project. In this case, we also reviewed the ongoing progress of the

[11] Ind. Code § 8-1-8.5-5.5 states: "When, in the opinion of the commission, changes in the estimate of the probable future growth of the use of electricity so indicate, the commission shall commence a review of any certificate granted under this chapter to determine whether the public convenience and necessity continues to require the facility under construction. If the commission finds that completion of the facility under construction is no longer in the public interest, the commission may modify or revoke the certificate."

Project, approved the Company's ongoing review progress report, and approved updated rates to be implemented through Duke Energy Indiana's IGCC Rider, reflecting construction costs incurred by the Company in connection with the Project. *See* IGCC 2 Order at 14-19. We also directed the Company to provide additional information in its semi-annual IGCC Rider rate adjustment proceedings to further facilitate our ongoing review of the Project. *Id.* at 15.

D. <u>IGCC 3 Case</u>.

In Cause No. 43114 IGCC 3, Joint Intervenors again questioned the continuing need for the IGCC Project, due to the economic recession and the accompanying decline in demand for electricity. As in the IGCC 2 Case, we emphasized that it was necessary to view this Project in terms of long-term needs, and we reiterated our belief that the decline in demand was a temporary phenomenon. We concluded that the Company had demonstrated that the IGCC Project was still needed for baseload capacity, despite the current economic downturn, and that the public convenience and necessity continued to require the construction and completion of the Project.

We also received evidence from the Company concerning cost pressures associated with the Project stemming from quantity increases in various Project components due to both scope additions and design development, the unanticipated need for a grey water disposal system, bid proposals that came in higher than expected, and higher than expected field supervision and overhead costs from bidders. *See* Dec. 2, 2009 Order in Cause No. 43114-IGCC 3 ("IGCC 3 Order"), at 4-7, 16-18.

Also in this case, we reviewed the ongoing progress of the Project, approved the Company's ongoing review progress report, and approved updated rates to be implemented through Duke Energy Indiana's IGCC Rider, reflecting construction costs incurred by the Company in connection with the Project. *See id.* at 20-23.

E. **IGCC 4 Case**.

In Cause No. 43114 IGCC 4, the Company reported on the status of the cost pressures on the Project, particularly in the area of scope growth that it attributed to design development and the increased cost of support services that accompany such growth. The Company also updated the Commission regarding a revised forecasted in-service date. The Joint Intervenors again raised the issue of continuing need for the Project, due to the economic recession. In our IGCC 4 Order, we held that we had previously addressed the issue of continuing need, and that evidence offered on this issue did not support modification of our prior findings on the issue. We also reviewed and approved the Company's ongoing progress review report, but indicated that our findings in this regard were interim, pending the outcome of the Subdocket proceeding on the increased Project costs. Finally, we approved updated rates to be implemented through Duke Energy Indiana's IGCC Rider, reflecting construction costs incurred by the Company in connection with the Project, on an interim and subject to refund basis, pending the outcome of this Subdocket proceeding. *See* IGCC 4 Order at 21.

4. **Relief Requested in this Subdocket Proceeding**.

In this Subdocket proceeding, Petitioner initially requested that the Commission modify the CPCNs previously granted for this Project by approving an increase in the cost estimate for the Edwardsport IGCC Project, from the currently approved estimate of $2.35 billion to a new cost estimate of $2.88 billion including AFUDC.[12] Subsequently, the Company agreed to voluntarily cap the costs that it would seek from customers and sought approval of a Project cost

[12] At the time of its initial request, the Company explained that it may be best to separately track and recover AFUDC, given the variables which can change the amount. *See* Pet. Ex. D at 4, 11-16 (Turner Dir. adopted by Rogers).

estimate of $2.72 billion in direct construction costs, plus all associated AFUDC (financing) costs on the $2.72 billion for a total of approximately $3 billion.[13]

Pursuant to the Settlement Agreement filed in this Cause, the Settling Parties now seek Commission approval of the Settlement Agreement in its entirety, without modification or further conditions that may be unacceptable to any Settling Party. More specifically, the Settling Parties request that the Commission modify the CPCNs for the Project to reflect a Hard Cost Cap and Additional AFUDC agreed to in the Settlement Agreement regarding the overall Project cost estimate, and find that the costs incurred up to the Hard Cost Cap (plus Additional AFUDC), to the extent presented in this Cause (*i.e.*, through the IGCC 6 proceeding), are reasonable and are not affected by imprudence, gross mismanagement, concealment, or fraud. Additionally, the Settling Parties request that the Commission approve the changes to depreciation rates outlined in the Settlement Agreement. The Settling Parties also request that the Commission approve the prospective change in treatment of deferred taxes, as provided for in the Settlement Agreement. The Settling Parties further request confirmation that Duke Energy Indiana has authority to defer, for subsequent recovery over a 3-year period, post-in-service O&M, depreciation, and property tax expenses associated with the Project. Lastly, the Settling Parties request that, to the extent necessary, the Commission approve the litigation expense payments and additional funding commitments in the Settlement Agreement, all of which will be made out of shareholder funds.

5. <u>Applicable Law; Statutory Framework</u>.

We are guided in this Cause primarily by Ind. Code Chapter 8-1-8.5, the Powerplant Construction Act, by Ind. Code Chapter 8-1-8.7, the Clean Coal Technology Act, and Ind. Code

[13] In October 2011, the Company informed the Commission and the Non-Duke Parties that although it would not seek recovery of costs above its $2.72 billion estimate plus applicable AFUDC, on October 19, 2011, the Company's Board of Directors approved a revision to the IGCC Project's cost estimate to approximately $2.98 billion (excluding AFUDC), for a total Project cost of approximately $3.3 billion.

Chapter 8-1-8.8, the Utility Generation and Clean Coal Technology Act. The first two of these statutory chapters require preapproval of new generation and clean coal technology projects and provide certain assurances of cost recovery for preapproved projects. These two statutory chapters also provide for ongoing Commission review of construction of such projects at the utility's option. The third statute encourages the construction of certain coal-fired generating resources, such as an IGCC project, by authorizing financial incentives for such projects, including timely recovery of construction and operating costs through rates. A general overview of these statutes is set forth as follows.

Under Ind. Code § 8-1-8.5-2, a public utility may not begin the construction, purchase, or lease of any facility for the generation of electricity without first obtaining a CPCN from the Commission. Under Ind. Code § 8-1-8.5-5, an application for a CPCN may only be granted after a hearing, if the Commission has: (1) approved the estimated construction, purchase, or lease costs; (2) made a finding that either such construction, purchase, or lease will be consistent with the Commission's plan for expansion of electric generation capacity, or that the construction, purchase, or lease will be consistent with a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility; and (3) made a finding that the public convenience and necessity require or will require the construction, purchase or lease of the facility.[14]

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[14] We recognize that in *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752 (Ind. Ct. App. 1995), the Court of Appeals declared that a portion of Ind. Code § 8-1-2-6.6 relating to Indiana coal violates the Commerce Clause of the United States Constitution. The Court severed the unconstitutional provision from the remainder of the statute which was held to be valid and effective. The Court stated that if a plan "is found by the Commission to be the option best fitting the non-protectionist criteria in the statute, no bar exists to its approval on the basis that it includes the use of Indiana coal . . . ." 654 N.E.2d at 767. Although we find that the IGCC Project will allow Petitioner to continue the use of Indiana and Illinois Basin coal, in accordance with the *General Motors* case, we recognize this factor should not be a prerequisite for Duke Energy Indiana's requested relief in this case.

Once the Commission has granted a CPCN for a project, the utility may either submit to ongoing review of the construction of the project by the Commission, or may defer review of the project construction until the utility's next base rate case. In this case, as referenced above, Duke Energy Indiana submitted to ongoing review of the construction of the IGCC Project by the Commission. With regard to the ongoing review process, Ind. Code § 8-1-8.5-6 provides that:

> (a) . . . the commission shall, at the request of the public utility, maintain an ongoing review of such construction as it proceeds. The applicant shall submit each year during construction, or at such other periods as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction.
>
> (b) If the commission approves the construction and the cost of the portion of the facility under review, the certificate shall remain in full force and effect.
>
> (c) If the commission disapproves of all or part of the construction or cost of the portion of the facility under review, the commission may modify or revoke the certificate.

Ind. Code § 8-1-8.5-6.5 further provides, in part, that "[a]bsent fraud, concealment, or gross mismanagement, a utility shall recover through rates the actual costs the utility has incurred in reliance on a certificate issued under this chapter, and as modified under sections 5.5 and 6 of this chapter as follows: (1) If a facility has been found to be completed and the facility's construction has been subject to ongoing review under section 6(a) of this chapter, the costs of construction approved by the commission during the ongoing review shall be included in the utility's rate base without further commission review."

Similar to the Powerplant Construction Act, Ind. Code § 8-1-8.7-3(a) provides that "a public utility may not use clean coal technology[15] at a new or existing electric generating facility

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[15] "Clean coal technology" is defined as "a technology (including precombustion treatment of coal):

> (1) that is used in a new or existing electric generating facility and directly or indirectly reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal; and
>
> (2) that either:

(continued...)

without first applying for and obtaining from the commission a certificate that states that public convenience and necessity will be served by the use of clean coal technology." Further, "[t]he commission shall issue a certificate of public convenience and necessity under subsection (a) if the commission finds that a clean coal technology project offers substantial potential of reducing sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989." Ind. Code § 8-1-8.7-3(b). After a clean coal technology certificate has been issued, the Commission has authority under Ind. Code § 8-1-8.7-5 to continue to review the project in the context of changes in the estimate of the cost or the need for the technology:

> When, in the opinion of the commission, changes in the estimate of the cost or the need for clean coal technology occur, the commission shall immediately commence a review of the certificate granted under this chapter to determine if public convenience and necessity will be served by the implementation of the technology. If the commission finds that implementation of the technology will not serve the public convenience and necessity, the commission may modify or revoke the certificate.

Finally, similar to the Powerplant Construction Act, the Commission may conduct an ongoing review of the construction of the project pursuant to Ind. Code § 8-1-8.7-7(b) through (d):

> (b) In addition to the review of the continuing need for the clean coal technology system under construction prescribed in section 5 of this chapter, the commission shall at the request of the public utility maintain an ongoing review of that construction as the construction proceeds. The applicant shall submit each year during construction, or at other times as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction. The commission must hold a public hearing before it may approve or deny a proposed increase in the cost estimates for

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(A) is not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or

(B) has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after January 1, 1989."

Ind. Code § 8-1-8.7-1. In the CPCN Order, the Commission found that "the Edwardsport IGCC Project constitutes clean coal technology as defined in Ind. Code 8-1-8.7-1." CPCN Order, at p. 13.

> the implementation, construction, or use of clean coal technology.
>
> (c) If the commission approves the construction and the cost of the part of the clean coal technology system under review, the approval forecloses subsequent challenges to the inclusion of that part of the clean coal technology system in the public utility's rate base on the basis of excessive cost, inadequate quality control, or inability to employ the technology.
>
> (d) If the commission disapproves of all or part of the construction or cost of the part of the clean coal technology system under review, the commission may modify or revoke the certificate. . . .

Rather than a preapproval statute, Ind. Code Chapter 8-1-8.8 encourages the development and construction of certain types of generating facilities, including IGCC projects. In particular, this statute reflects the Indiana General Assembly's determination that "the state should encourage the use of advanced clean coal technology, such as coal gasification." Ind. Code § 8-1-8.8-1(a)(5). Such encouragement takes the form of financial incentives for utilities to develop and construct such projects. Ind. Code § 8-1-8.8-11 (footnote added) provides that:

> (a) The commission shall encourage clean energy projects[16] by creating the following financial incentives for clean energy projects, if the projects are found to be reasonable and necessary:
>
> > (1) The timely recovery of costs and expenses incurred during construction and operation of projects described in section 2(1) or 2(2) of this chapter.
> >
> > * * *
> >
> > (4) Financial incentives for projects to develop alternative energy sources, including renewable energy projects or coal gasification facilities.
> >
> > (5) Other financial incentives the commission considers appropriate.

Further, Ind. Code § 8-1-8.8-12 (footnotes added) provides that:

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[16] "Clean energy projects" include "[p]rojects at new energy production or generating facilities that employ the use of clean coal technology and that produce energy, including substitute natural gas, primarily from coal, or gases derived from coal, from the geological formation known as the Illinois Basin. Ind. Code § 8-1-8.8-2(1)(A). Thus the Edwardsport IGCC Project is a "clean energy project" within the meaning of this statute, as the Commission found in the CPCN Order. *See* CPCN Order at 57.

(a) The commission shall provide financial incentives to eligible businesses for:

(1) new energy production or generating facilities;

* * *

in the form of timely recovery of the costs incurred in connection with the study, analysis, development, siting, design, licensing, permitting, construction, repowering, expansion, life cycle management, operation, or maintenance of the facilities.

* * *

(d) The commission shall allow an eligible business[17] to recover:

(1) the costs associated with qualified utility system property[18]; and

(2) qualified utility system expenses;

if the eligible business provides substantial documentation that the expected costs and expenses and the schedule for incurring those costs and expenses are reasonable and necessary.

6. <u>Settlement Agreement and Evidence Presented</u>.

Prior to the submission of the Settlement Agreement, there were many highly contested, substantial issues in this proceeding, both evidentiary and legal. At the conclusion of the Phase I and Phase II hearings, Duke Energy Indiana and the Non-Duke Parties were still far apart on major issues. These issues included factual questions regarding Duke Energy Indiana's actions, as well as legal questions such as the burdens of proof, the definitions of the statutory terms "concealment" and "gross mismanagement," the statutory remedies for a finding of fraud, concealment, or gross mismanagement, and the standards and remedies regarding potential

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[17] An "eligible business" includes an energy utility (such as Duke Energy Indiana) or other owner of a coal gasification facility that proposes to construct, among other things, a new IGCC powerplant. Ind. Code § 8-1-8.8-6. Thus, Duke Energy Indiana is an "eligible business" under the statute, as the Commission found in the CPCN Order. *See* CPCN Order at 57.

[18] "Qualified utility system property" includes new IGCC powerplants to be used to provide retail electric utility service. Ind. Code §§ 8-1-8.8-9 and -8. "Costs" associated with such property include capital, operation, maintenance, depreciation, tax costs, and financing costs. Ind. Code § 8-1-8.8-5.

imprudence by contractors, many of which are issues of first impression before this Commission. Against this backdrop, the Settling Parties presented the Commission with their proposed settlement to resolve this entire proceeding on the following terms and conditions.

A. **The Settlement Agreement Terms**.

The Settlement Agreement is intended to resolve (1) all disputes, claims, and issues in Phase I and Phase II of this proceeding, (2) all issues relating to the construction and construction costs (including financing costs) associated with the Project, (3) all issues concerning allegations of imprudence, fraud, concealment, and gross mismanagement relating to such construction and construction costs, and (4) all issues between the Settling Parties concerning allegations of *ex parte* communications, improper conduct, undue influence, appearances of impropriety, and related issues involving or allegedly involving the Project.

The primary substantive features of the Settlement are: (1) a "Hard Cost Cap" on the Project Construction Costs; (2) a methodology for restarting the IGCC Rider in a way that gradually increases rates while also avoiding an additional Company write-off, and thus that is workable for both customers and the Company; (3) additional rate mitigation measures to reduce the initial rate impacts of including the Project costs in retail rates (including updated, lower depreciation rates and going-forward inclusion of deferred taxes in the capital structure for Project ratemaking purposes); (4) an additional change in depreciation rates from accelerated depreciation to non-accelerated depreciation for certain of the Company's pollution control property; (5) a retail electric base rate case moratorium; and (6) certain shareholder funding commitments pertaining to low-income heating assistance, the Indiana Ratepayer Trust, a new clean energy initiative, and litigation expenses and attorney fees for the Settling Parties. These primary features of the Settlement Agreement are described in greater detail below. The Settlement Agreement also addresses certain other issues, as set forth below.

(1) Hard Cost Cap.

Provision 2 of the Settlement Agreement sets a "Hard Cost Cap" for the Project of $2.595 billion, plus applicable AFUDC accruing on and after July 1, 2012 (the "Additional AFUDC"). The $2.595 billion Hard Cost Cap consists of an estimated $2.319 billion in direct construction costs and $276 million in estimated retail AFUDC on such direct costs as of June 30, 2012.[19] Under this provision, subject only to a *force majeure* situation as defined in the Settlement Agreement, Duke Energy Indiana may not recover from retail electric customers any Project construction costs above the amounts included in the Hard Cost Cap. The Company may, however, seek recovery of legitimate post-in-service O&M costs as defined in the Settlement Agreement.

Post-July 1, 2012, AFUDC will accrue if and to the extent that the Hard Cost Cap Project costs are not yet reflected in the IGCC Riders and thus are not receiving "construction work in progress" ("CWIP") ratemaking treatment. The Settlement also provides, however, that in the event that (and to the extent that) the Hard Cost Cap Project costs are not receiving CWIP ratemaking treatment as of December 1, 2012, from that date forward, the Company should only be authorized to accrue and add 85% of such accrued AFUDC to the Project cost.

The Settling Parties have agreed, solely for purposes of the Settlement, that the construction costs included in the Hard Cost Cap (plus any Additional AFUDC) are reasonable and necessary and should not be further reduced below that amount because of any issues

[19] At the time of the Settlement, in April 2012, Duke Energy Indiana estimated that the Construction Costs component of the Hard Cost Cap would be approximately $2.319 billion and the AFUDC component would be $276 million. In his rebuttal testimony, Mr. Freeman explained that the Company had agreed upon the Hard Cost Cap of $2.595 billion and based on actual AFUDC rates through the end of May, that equated to a Construction Costs component of $2.322 billion and an AFUDC component of $273 million. Pet. Ex. MMM-S at 9:3-4 and fn.2 (Freeman Reb.). For sake of simplicity, we will generally refer to the $2.319 billion estimate of Construction Costs as the parties did in pre-filed testimony.

relating to imprudence, fraud, concealment, or gross mismanagement, or concerning *ex parte* communications, improper conduct, undue influence, appearances of impropriety, or related issues. In IGCC Rider proceedings up to and including the IGCC 8 proceeding, the Settling Parties and the Joint Intervenors have had the opportunity to review, testify regarding, and participate in multiple hearings on the Construction Costs incurred by the Company on the Project up to and in excess of the Hard Cost Cap,[20] and as between the Settling Parties those costs are resolved as part of the Settlement.

Key components of this Hard Cost Cap are the definitions of Project "Construction Costs" and the "In-Service Operational Date." In order to provide a bright line between construction costs on the one hand (which are subject to the Hard Cost Cap), and legitimate post-construction operational costs (which are not subject to the Hard Cost Cap), construction costs subject to the Hard Cost Cap are defined in provision 2.E of the Settlement Agreement. That provision specifies that Project "Construction Costs" shall be defined consistent with usual utility practices and Federal Energy Regulatory Commission ("FERC") guidelines. The provision specifically provides that "Construction Costs" include all costs required to achieve "final completion," as set forth in a December 20, 2007 contract between Duke Energy Indiana and GE. Such costs include engineering, materials, construction and equipment purchases, capitalized AFUDC (through June 30, 2012), and all start-up and testing, validation and commissioning costs, and costs of repairs and modifications identified during start-up, testing, validation and commissioning. By contrast, normal O&M expenditures on the Project that begin after the Project is in-service, are not Construction Costs; nor does the definition of Construction

[20] As noted in our order in IGCC 8 – issued concurrently with this Order – actual construction costs and AFUDC as of September 30, 2011 exceeded $3.1 billion, more than $500 million more than the Hard Cost Cap.

Costs include ongoing capital spent on the Project after the "In-Service Operational Date" for normal capitalized repairs or maintenance expenditures or additional plant or equipment added to the Project, unless such additions were identified during start-up, testing, validation and commissioning as being necessary to reach "final completion."

The "In-Service Operational Date" is defined in provision 2.F as the first date by which the Project has (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. The Settlement Agreement also provides that the In-Service Operational Date cannot occur prior to September 24, 2012.

Related to the Hard Cost Cap, the Settling Parties have agreed that they will propose and support a return calculation for the Project in future retail rate proceedings that is consistent with the Settlement Agreement terms. More specifically, the Settling Parties agreed that – except for ongoing additions, replacements, and maintenance capital expenditures made separate and apart from and not included in Construction Costs – in future retail electric base rate cases and riders, the portion of revenue requirements attributable to a return on the Project shall equal the original cost of the Project, defined as the Hard Cost Cap Project Costs, including the Additional AFUDC as provided for above, less accumulated depreciation, multiplied by Duke Energy Indiana's authorized weighted cost of capital calculated on an original cost basis. (*See* provision 2.C of the Settlement Agreement.)

Finally, the Settling Parties agreed that the CPCNs for the Project (granted under Ind. Code Chapters 8-1-8.5 and 8-1-8.7) should be modified to reflect an approved Project cost estimate equal to the Hard Cost Cap Project cost of $2.595 billion, plus any Additional AFUDC. Other than as set forth in the Settlement Agreement, the Non-Duke Settling Parties have agreed

that they will seek no further rate or regulatory "penalties" relative to the construction and overall final Construction Costs of the Project (plus Additional AFUDC). All parties, however, retain the right to pursue available remedies concerning post-in-service operating performance of the Project.

(2) IGCC Rider Implementation.

Provision 3 of the Settlement Agreement outlines a methodology for "restarting" IGCC Rider proceedings that have been frozen during the pendency of this proceeding. The last IGCC Rider update approved by the Commission became effective in late July 2010 (on an interim basis) pursuant to the Commission's Order in IGCC 4. The Settling Parties agreed that, upon approval of the Settlement, the IGCC Rider should be "restarted" immediately to consider the prudence of Construction Costs up to the level of the Hard Cost Cap (plus any Additional AFUDC).

The Settlement Agreement provides that, if the Settlement is approved prior to the approval of the IGCC 8 CWIP Rider proceeding, then CWIP recovery shall begin on Construction Cost amounts approved through the IGCC 6 CWIP Rider (which are less than the Hard Cost Cap), and recovery of CWIP for Construction Cost amounts over the IGCC 6 CWIP Rider amount (up to the Hard Cost Cap plus Additional AFUDC) should begin upon approval of the IGCC 7 and IGCC 8 CWIP Rider proceedings.

This "Rider restart" methodology takes into account the uncertainty of the precise in-service completion date for the Project and, as a consequence, results in the Company's retail rates increasing incrementally over time rather than all at once. Specifically, the Settling Parties agreed that the Company's proposed tariffs in IGCC 9 (filed on June 8, 2012) do not include projections of post-in-service operating costs (*e.g.*, estimated depreciation, O&M, and property tax expenses (other than operating costs for items that have been included in previous IGCC

Rider filings)). Rather, the Settlement envisions that post-in-service Project costs will be included in the Company's filing in IGCC 10, which is expected to be filed in November 2012. The Settlement Agreement contemplates that Duke Energy Indiana will defer the actual depreciation and O&M costs (and property tax expenses) incurred for all months from the In-Service Operational Date until such costs are included in the Company's rates, which is consistent with previously authorized deferred accounting treatment granted for the Project by the Commission. Finally, the Settlement provides that Duke Energy Indiana should be authorized to recover deferred expenses (without carrying costs) over a three-year period either through future IGCC Rider proceedings or through inclusion in base retail electric rates.

(3) Retail Electric Rate Case Moratorium.

Under provision 4 of the Settlement Agreement, except in the case of an emergency, Duke Energy Indiana agrees that it will not file for an increase in its retail electric base rates prior to March 2013, and that no increase to its base rates will be implemented prior to April 1, 2014. This base rate case moratorium applies only to retail electric base rate cases, and not to any other requests by Duke Energy Indiana for accounting deferrals, creation of regulatory assets or liabilities, or creation of new or modification of existing retail rate riders.

This provision also states that, in the Company's next retail base rate case, the Non-Duke Settling Parties agree not to oppose any request by Duke Energy Indiana to zero-out the IGCC Rider and include the IGCC Plant (up to the Hard Cost Cap Project costs, plus Additional AFUDC), O&M, depreciation, and property taxes in base rates, consistent with past practice for capital riders. However, the Non-Duke Settling Parties may challenge the reasonableness of specific amounts of O&M, depreciation, and property taxes to be included in base rates.

(4) Updated Depreciation Rates (for all plant except IGCC).

Provision 5.A of the Settlement Agreement provides for the update of Duke Energy Indiana's depreciation rates for non-IGCC production, transmission, distribution, and general plant and equipment (except for certain pollution control property/clean coal technology projects, as discussed in item (5)). The proposed change in depreciation rates will initially benefit retail customers by approximately $35 million annually. The Settling Parties have agreed to these new depreciation rates, including the negative net salvage values. The depreciation rate changes will be made effective upon approval of the Settlement, and retail electric customers will begin receiving the approximately $35 million annual reduction in rates, via the IGCC Rider, beginning with the first full calendar month after the date of this Order. Upon the implementation of new retail base rates that reflect any new depreciation rates (as discussed below), this benefit will be superseded by those new depreciation rates.

To ensure realization of this updated depreciation rate benefit for customers for the near-term, the Settlement Agreement further provides that, if the Company files for an increase in its base retail electric rates prior to the end of 2013, it will request the continued application and approval of the depreciation rates approved in the depreciation study presented in this Cause. The Settlement Agreement permits Duke Energy Indiana, however, to propose updates to these depreciation rates in the event of material changes in law, regulation, or accounting rules, or material changes to the Duke Energy Indiana system as defined in the Settlement Agreement.

The Settling Parties have agreed not to oppose or present evidence regarding the depreciation rates and net salvage values provided in the Settlement in any Duke Energy Indiana retail rate case filed prior to 2014, except that the Non-Duke Settling Parties may present testimony challenging any updates the Company proposed. Duke Energy Indiana reserves the right to file new depreciation rates for any retail rate case filed after 2013, and the Non-Duke

Settling Parties retain the right to object to such new, post-2013 proposed depreciation rates and net salvage values.

(5) Move to Non-Accelerated Depreciation Rates for Certain Pollution Control Property/Clean Coal Technology Projects.

Provision 5.B of the Settlement Agreement provides for a change in depreciation rates – moving from accelerated depreciation to normal depreciation – for certain qualified pollution control and clean coal technology projects that have previously been approved for accelerated depreciation. With respect to this change in depreciation, the Settlement Agreement provides that Duke Energy Indiana's retail rates will not be changed to reflect this accounting adjustment to depreciation rates until the effective date of an Order in the next-filed retail electric base rate case. At the time of the Company's next rate case, Duke Energy Indiana will propose to include in its revenue requirement a depreciation expense that reflects the change from accelerated to normal lives for such qualified pollution control equipment, resulting in an estimated $32 million decrease in annual retail depreciation expense and revenue requirements.

(6) Prospective Termination of the Deferred Tax/Capital Structure Incentive.

Provision 6 of the Settlement Agreement provides that Duke Energy Indiana will prospectively include, consistent with traditional Indiana ratemaking, deferred taxes in the capital structure used in its IGCC Rider, beginning with the effective date of the rider approved by an Order restarting the IGCC Rider. This termination of the deferred tax incentive will benefit customers by approximately $22 million initially. This provision also sets out the Settling Parties' agreement that any "bonus depreciation" treatment applicable to the IGCC Project costs included in retail rates will be accorded normal ratemaking treatment, *i.e.*, any deferred taxes created by such bonus depreciation associated with the Hard Cost Cap amount

will be reflected in Duke Energy Indiana's capital-related rate riders and base rate case filings on an actual basis.

(7) Potential Recoveries from Vendors/Contractors; Intellectual Property Benefits.

Provision 7.A of the Settlement Agreement recognizes that Duke Energy Indiana may have valid causes of action against Bechtel, GE, or other Project vendors or contractors with respect to the Project. In light of this Settlement, Duke Energy Indiana will bear all costs associated with pursuing any such causes of action, and in turn, will be entitled to retain any amounts received from Bechtel, GE, or other Project vendors or contractors associated with the cost and quantity estimates, design, construction, start-up, testing, *etc*. of the Project, whether such benefit stems from agreement, arbitration, mediation, litigation, settlement, or otherwise. The Settling Parties agree not to affirmatively oppose or undermine in any way Duke Energy Indiana's pursuit of claims against GE, Bechtel, or other Project vendors or contractors.

Provision 7.B states that Duke Energy Indiana shall retain any intellectual property benefits related to the Project.

(8) Government Funding and Tax Incentives; Project Byproducts.

Provision 8 of the Settlement Agreement confirms that retail electric customers will receive 100% of the applicable retail jurisdictional share of any Project-specific funding received from federal, state, or local governmental authorities, such as incentive tax credits and property tax credits. In addition, the Settlement confirms that retail electric customers will receive 100% of the applicable retail jurisdictional share of any net byproduct or co-product revenues from the Project.

(9) Attorney Fees and Reimbursements; Other Funding Commitments.

The Settlement contains a number of funding commitments to be made by Duke Energy Indiana out of shareholder funds. These funding commitments include: (1) a total of approximately $13.5 million to be paid to the Non-Duke Settling Parties or their attorneys, for attorney fees and litigation expenses; (2) a contribution of $2 million to the Indiana Utility Ratepayer Trust; (3) a contribution of $3.5 million to the Indiana Low Income Home Energy Assistance Program ("LIHEAP") fund, to be made over a 5-year period and to be used for Duke Energy Indiana retail customers; and (4) a contribution of $1 million to establish a fund to effect the collaborative development of a yet-to-be-determined clean energy initiative by the OUCC and Duke Energy Indiana, and to be administered by a suitable third party for the benefit of Duke Energy Indiana retail customers.

(10) Other Provisions.

Provision 10 of the Settlement Agreement sets forth the understanding of the Settling Parties with respect to certain additional issues. In provision 10.A, the Settling Parties agree that any subject-to-refund designations or similar language in the IGCC 4 Order, and any subsequent IGCC Rider orders approved prior to this Order, should be removed once this Settlement is effective. In provision 10.B, the Settling Parties agree that the evidence submitted in support of the Settlement, along with the evidence previously submitted in this proceeding, together constitute substantial evidence to support the 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 the Settlement. Provision 10.C sets forth the Settling Parties' understanding that the Settlement represents a complete, interrelated package that is intended to resolve all issues related to the IGCC Project Construction Costs (and associated AFUDC)

including without limitation, all issues that were addressed or could have been addressed in Phase I and Phase II of this proceeding. The Settling Parties agree to oppose or not support any attempt to initiate new proceedings before the Commission related to such issues. Further, in provision 10.D, the Settling Parties commit to support the provisions of the Settlement in good faith before the Commission and, if necessary, before appellate courts, in related proceedings, and on remand or reconsideration before this Commission.

B. **Testimony Regarding the Settlement Agreement**.

Witnesses for the Settling Parties explained why, in their view, the Commission should approve the Settlement Agreement as reasonable, equitable, supported by substantial record evidence, and in the public interest. *See, e.g.*, Pet. Ex. HHH-S at 2:6-8 (Esamann Dir.); Pet. Ex. III-S at 4:1-13:13 (Freeman Dir.); IG Ex. MG-D-S at 3:4-10:16 (Gorman Dir.); Pub. Ex. 2S at 2:3-7:5 (Blakley Dir.); Pub. Ex. 1-S at 1:13-9:6 (B. Smith Dir.). The Settling Parties believe that the Settlement Agreement, which resulted from extended, arms'-length negotiations between the parties, represents a reasonable compromise that resolves these lengthy and complex proceedings in a manner that benefits the public interest, customers, and Duke Energy Indiana. *E.g.*, Pet. Ex. HHH-S at 3:10-11; 21:13-16 (Esamann Dir.).

The testimony of the Settling Parties' witnesses indicates that, in their view, the Settlement Agreement, if approved, will provide substantial benefits for Duke Energy Indiana's retail customers. These benefits for customers include:

- The benefits of advanced IGCC technology at a price well below the full cost of the Project;
- Certainty about the rate impacts of this Project with Duke Energy Indiana bearing the risk of additional construction costs above the Hard Cost Cap;

- Restart of the IGCC Rider (and CWIP ratemaking treatment), up to the Hard Cost Cap (plus any Additional AFUDC), (which will reduce AFUDC accrual and reduce the amount of Project costs ultimately in rates), and a Rider restart methodology wherein the full impact of the IGCC Rider will not be included in rates all at once, but the impact will be more gradual and moderate;
- Additional rate mitigation resulting from updated (lower) depreciation rates on the remainder of the Duke Energy Indiana system (approximately $35 million annually) and termination of the currently approved and in-place deferred tax incentive (initially approximately $22 million annually);
- Upon the effective date of new retail base rates, additional rate mitigation resulting from the proposal to move from accelerated depreciation to normal, straight-line depreciation for clean coal technology/qualified pollution control projects that are currently receiving accelerated depreciation (approximately $32 million annually);
- Benefits from a rate case moratorium, which will delay increases in Duke Energy Indiana base retail electric rates (potentially as much as $100 million annually);
- Confirmation of receipt of all byproduct revenues;
- Benefits from Duke Energy Indiana's funding commitments for LIHEAP, the Indiana Ratepayer Trust, and a new Duke Energy Indiana/OUCC clean energy initiative; and
- Reduction in litigation risk and uncertainty.

Id. at 12:1-10, 13:13-14:15, 21:19-22:18; Pub. Ex. 1-S at 6:20-7:3 (B. Smith Dir.).

Despite resulting in a significant impairment and write-off, the Settlement also provides certain benefits for the Company and its shareholders, such as:

- Reduction in litigation risk and uncertainty about the outcome of these proceedings;

- Certainty going forward with this Project, in terms of rate recovery;
- Restart of the IGCC Rider (and CWIP ratemaking treatment) for the Project, up to the Hard Cost Cap plus Additional AFUDC amounts, which will improve the Company's cash flow as it heads toward Project completion; and
- A temporary boost to earnings from the change from accelerated to straight-line depreciation for clean coal technology/qualified pollution control projects, without any immediate corresponding increase to rates.

Pet. Ex. HHH-S at 22:21-23:8 (Esamann Dir.).

If the Settlement is approved, the Settling Parties indicated that customers will receive the benefit of over 600 MWs of new, advanced clean coal baseload capacity, at a cost well below the true cost of constructing this Project – an average peak retail rate impact of 14.5%, compared to 21.7% if the full costs of the Project were included in rates and 19.9% if the previously proposed $2.72 billion plus AFUDC costs were included in rates. While the overall increase of 14.5% is not insignificant, a portion (4.9%) is already included in retail customers' rates, and the increase is about one-quarter less than it might otherwise have been without the Settlement and is spread over an extended period of time. *Id.* at 23:9-15.

OUCC witnesses Barbara Smith and Blakley and IG witness Gorman identified benefits similar to those identified by Mr. Esamann, and summarized the benefits of the Hard Cost Cap to customers as $700 million to $900 million in Project costs being borne by Duke Energy Indiana's shareholders and from $1.7 billion to nearly $2 billion in reduced rates over the life of the Project. They also noted that Duke Energy Indiana will recover only $94 million[21] (or about

[21] As noted previously (*see* fn. 19), at the time the witnesses submitted their pre-filed testimonies, the estimate of the Construction Costs component of the Hard Cost Cap was $2.319 billion. Because the (continued...)

12%) of the currently projected $775 million in construction cost increase above those already approved. Pub. Ex. 1-S at 4:4-15 (B. Smith Dir.); IG Ex. MG-D-S at 4:15–5:14 (Gorman Dir.); July 18 Tr. at FFF-42:6-11 (Blakley).

IG witness Gorman also opined that the Settlement will "bring[] significant value to Indiana customers" and "provides a balanced outcome for customers of the disputed issues," and "the resulting rates produced from the Settlement will be reasonable." IG Ex. MG-D-S at 8:11, 16-18 (Gorman Dir.). Ms. Barbara Smith further testified that the Settlement provides cost certainty in addition to other benefits. July 17 Tr. at EEE-73:21–23 (B. Smith). From the OUCC's perspective, it was more important to obtain the financial benefits of the Settlement for customers "than to prove that Duke [Energy Indiana] was wrong." *Id.* at EEE-73:13–17.

The Parties then addressed certain specific provisions of the Settlement Agreement.

(1) Testimony Supporting the Hard Cost Cap.

Mr. Esamann noted that the record in this proceeding is extensive, and there is a wide spectrum of outcomes represented in the parties' filed and litigated positions. Pet. Ex. HHH-S at 25:14-15 (Esamann Dir.). In Phase I of this proceeding, the parties filed positions that ranged from recommending no increased recovery to the previously-approved $2.35 billion cost estimate for the Project, to permitting recovery up to the Company's recommended increase in the approved cost estimate to $2.72 billion plus associated AFUDC (or approximately $3 billion). *Id.* at 25:15-19. In Phase II, the parties filed positions that ranged from proposals to reduce the $2.35 billion approved cost estimate to the original cost estimate of $1.985 billion or even lower, to the Company's position that no reductions to the approved Project cost should be made. *Id.* at 25:19-22. The Settling Parties noted the previously-approved $2.35 billion Project

actual Construction Costs component is $2.322 billion, the increase is $97 million. This difference does not affect our analysis of the reasonableness of the Settlement Agreement.

cost estimate consisted of $2.225 billion in direct construction costs and $125 million in AFUDC costs (estimated at that point in time and assuming ongoing CWIP treatment). *Id.* at 25:22-26:2. By comparison, the Hard Cost Cap consists of approximately $2.319 billion in direct construction costs and an estimated $276 million in AFUDC (as of June 30, 2012) – an increase of $94 million in direct construction costs. *Id.* at 26:2-5.

Mr. Esamann testified that the Company strongly believes that its actions with respect to the Project have been reasonable and prudent and do not constitute gross mismanagement, concealment, or fraud. *Id.* at 21:9-11. Accordingly, the Company believes that the record in this proceeding supports approval of a new Project cost estimate up to $2.72 billion in direct construction costs plus applicable AFUDC – approximately $3 billion in total – as reasonable, necessary, and prudently incurred. *Id.* at 21:11-13, 26:6-10. In contrast, the Settlement provides for a modified Project cost for ratemaking and CPCN purposes of significantly less – approximately $2.319 billion in direct construction costs plus associated AFUDC to June 30, 2012, up to a Hard Cost Cap of $2.595 billion (plus post-June 2012 AFUDC per the Settlement Agreement's terms). *Id.* at 26:10-14.

Under the Settlement Agreement, the Company and its shareholders will bear a significant portion of the cost of the Project. Specifically, Duke Energy Indiana will absorb the Construction Costs above the Hard Cost Cap plus Additional AFUDC, an estimated impairment of nearly $700 million. *Id.* at 8:11-14. Mr. Esamann further confirmed that Duke Energy Indiana will segregate the Hard Cost Cap costs (plus any Additional AFUDC) from the "unrecoverable" costs on its books and records. *Id.* at 24:13-14. In particular, the Hard Cost Cap (and Additional AFUDC) costs will be accounted for "above-the-line," and the "unrecoverable" or "impairment" costs (*i.e.*, amounts above the Hard Cost Cap and Additional

AFUDC for which the Company's shareholders are responsible) will be accounted for "below-the-line," so that in future rate proceedings, the impairment costs will not be included in the Company's utility plant in service or rate base or cost of service for ratemaking purposes. *Id.* at 24:14-20. Depreciation associated with the impairment costs will also be excluded from the utility cost of service for ratemaking. Similarly, the Company will segregate the tax benefits and detriments associated with the impairment costs, and will separately account for, on a below-the-line basis, the tax impacts associated with the impairment. Additionally, the deferred tax assets and the deferred tax liabilities (including the portion of bonus depreciation attributable to the impairment costs) will be excluded from the capitalization structure for purposes of calculating the rate of return.

Mr. Esamann further testified that, even if one does not accept the Company's analysis of the record, the Hard Cost Cap – reflecting an increase of $94 million in construction costs over the approved Project cost estimate, in comparison to Duke Energy Indiana's proposal of an approximately $500 million increase – is nevertheless supported by substantial evidence in the record. *Id.* at 27:3-7. Thus, although in the Company's view, there is no persuasive evidence of imprudence, gross mismanagement, concealment or fraud in the record, if the Commission were to conclude that some Company actions fall into one of these categories, the impact of any such imprudence, gross mismanagement, concealment, or fraud, would be more than covered by the numerous financial concessions in the Settlement Agreement. *Id.* at 27:17-28:7.

In his testimony supporting the Settlement Agreement, IG witness Mr. Gorman testified that, in Phase I of this proceeding, he was of the view that Duke Energy Indiana's request to modify its certificate to increase its cost estimate from $2.35 billion to $2.88 billion should be denied because the increased costs were unreasonable, unnecessary, and imprudent. In Phase II,

Mr. Gorman expressed the view that the Commission should deny Duke Energy Indiana any recovery in excess of the $1.985 billion estimate due to concealment of significant relevant information and failure to timely disclose that information. IG Ex. MG-D-S at 2:7-19 (Gorman Dir.).

Nevertheless, in his Settlement testimony, Mr. Gorman explained that, given the wide ranging differences in the parties' positions and the substantial uncertainty and litigation/regulatory risk faced by the parties, the Settlement Agreement acceptably resolves the highly complex technical issues presented in the case. *Id.* at 3:4-15. He stated that the Settlement Agreement represents a balanced outcome for customers of the disputed issues and will result in rates that are reasonable. *Id.* at 8:11-18.

Mr. Gorman further testified that the $2.319 billion construction cost cap allows Duke Energy Indiana only $94 million more than the $2.225 billion in construction costs already approved. Of the $775 million increase in construction costs since the Commission approved the estimate in the IGCC 1 Order, Duke Energy Indiana will bear $681 million or almost 88% of the cost increase. *Id.* at 4:15-22. Further, because of the Hard Cost Cap, the Company alone bears the risk of any future cost increases, not customers. *Id.* at 5:3-9. Finally, Mr. Gorman testified that the approximately $700 million in construction costs to be absorbed by Duke Energy Indiana will result in substantial savings to customers in the long term. Because Duke Energy Indiana would have recovered not only the $700 million through depreciation but also a return on that amount, Mr. Gorman estimated that, over 30 years, customers will save approximately $1.7 billion in rate reductions. *Id.* at 5:10-14.

With respect to the AFUDC component of the Hard Cost Cap, Mr. Gorman testified that the increase in direct costs of $94 million had very little impact on the amount of AFUDC. The

amount of AFUDC accrued on the already-approved $2.225 billion in direct costs is about $268 million. More specifically, the AFUDC component of the Hard Cost Cap represents only approximately $8 million more than the AFUDC as of June 30, 2012 on the direct costs approved in IGCC 1. *Id.* at 6:3-17. Mr. Gorman further testified that treating the Hard Cost Cap as the fair value of the IGCC Project will prevent the Company from seeking, in the future, a substantial increase in the Project's revenue requirement. *Id.* at 7:1-11.

OUCC witness Wes Blakley testified that the Hard Cost Cap will result in a reduction to the annual revenue requirement paid by Duke Energy Indiana customers. Specifically, he testified that the $700 million reduction in construction investment results in a reduced revenue requirement of $48.9 million on an annual basis, or approximately $73.4 million annually in year one on a grossed-up basis. Pub. Ex. 2S at 3:12-4:3 (Blakley Dir.). Mr. Blakley also testified that additional savings in depreciation expenses are attributable to the Hard Cost Cap. Assuming a 30-year depreciation period, a $23.3 million reduction in the Project's annual revenue requirement can be calculated for depreciation, resulting in a reduced revenue requirement of approximately $96.7 million on an annual basis. *Id.* at 4:7-14. Over thirty years, the reduced revenue requirements will result in approximately $1.5 to $2 billion in savings for customers. July 18 Tr. at FFF-42:6–11 (Blakley).

OUCC witness Barbara Smith's testimony stated that the Settlement Agreement addresses the concerns raised by the OUCC in this proceeding regarding potential imprudence and gross mismanagement. Pub. Ex. 1-S at 3:3-14 (B. Smith Dir.). She explained that, although the OUCC stands by its previous testimony, the Settlement Agreement puts the OUCC's claims to rest by providing substantial benefits to customers. *Id.* at 5:7-15. Ms. Barbara Smith noted that the amount of the Hard Cost Cap resulted from extensive arms'-length negotiations. *Id.* at

5:17-18. Although the Settling Parties did not attempt to agree as to precisely what individual costs were prudently incurred, by setting the Hard Cost Cap at a level higher than Duke Energy Indiana's currently approved project costs, the Settlement Agreement reflects the fact that there are certain legitimate cost escalations that have occurred and may continue to occur in the future. The Hard Cost Cap is an amount that the Settling Parties agreed was reasonable, supported by the evidence of record and will provide certainty, with regard to costs, for the remainder of the life of the Project. *Id.* at 5:17-6:2.

(2) Testimony Opposing the Hard Cost Cap and the Settling Parties' Responses.

Joint Intervenors' witnesses Mr. Olson, Mr. Ralph Smith, and Mr. Schlissel presented testimony objecting to the Hard Cost Cap aspect of the Settlement on the grounds that (1) it was not shown to be reasonable, (2) it presumes that the first $2.319 billion in costs were reasonable, (3) customers will be responsible for more than the costs below the Hard Cost Cap, and (4) the definition of in-service is vague, thus permitting Duke Energy Indiana to recover costs after the IGCC Plant is declared in-service.

(a) Challenges to the Reasonableness of the Hard Cost Cap.

Joint Intervenors contend that the Hard Cost Cap does not provide for sufficient cost disallowances. JI Ex. KLO-S at 4:15-28 (Olson Dir.). Mr. Olson argued that Edwardsport is an illegitimate power plant that should not have been approved during the CPCN proceeding and that Duke Energy Indiana should not be permitted to rely on the CPCN or the IGCC 1 Orders. *Id.* at 4:17-28. In his view, allowing the Company to recover $610 million dollars above the originally approved $1.985 billion cost estimate is a reward, not a penalty, and thereby does not constitute a significant disallowance. *Id.* at 5:26-28. He recommended revocation of the Project's CPCNs, rescission of the CPCN and IGCC 1 Orders, and zero cost recovery for the

Project. *Id.* at 10:6-8. Mr. Schlissel agreed that the Hard Cost Cap does not provide for sufficient disallowances and that the Commission should not modify the CPCNs to include a higher approved cost estimate. JI Ex. M-S at 18:4-19:7 (Schlissel Dir.). He stated that Mr. Olson's proposal is one way that the Commission could limit cost recovery for the Project, but he also proposed two alternatives: (1) the Commission could hold Duke Energy Indiana to its original cost estimate and preclude the Company from charging customers for any costs above $1.815 billion in direct construction costs plus financing charges accrued over a 47-month schedule, and rescind only the IGCC 1 Order (thereby keeping the CPCN Order and the Project's CPCNs in full effect); or (2) the Commission could hold the Company to its revised cost estimate and preclude it from charging customers for any costs above $2.35 billion (thereby keeping the CPCN Order, the IGCC 1 Order, and the Project's CPCNs in full effect but declining to modify the CPCNs with an even higher cost estimate). *Id.*

Mr. Schlissel and Mr. Ralph Smith further argued that the Settling Parties have not provided sufficient evidence to show that the $2.595 billion Hard Cost Cap is just and reasonable and in the public interest. Specifically, Mr. Schlissel testified that the record evidence shows that $2.595 billion is significantly higher than the reasonable and prudent costs that should be added to rate base when the Project goes into service. *Id.* at 2:20-27, 3:1-5, 14:13-16. He referred to his testimony from Phase I and Phase II of this proceeding as evidence that the Company imprudently and grossly mismanaged the Project, and contends that the Project's cost overruns are a product of such gross mismanagement and mismanagement. *Id.* at 14:17-17:4. Mr. Ralph Smith testified that the Settling Parties have failed to explain why the Project cost estimate of $2.595 billion (plus any additional AFUDC) is reasonable compared to the cost of alternative generation. JI Ex. N-S at 7:22-8:7 (R. Smith Dir.). In addition, he testified that the Settling

Parties' rationale that the $2.595 billion cost estimate falls within the range of prior estimates supported by various parties in the proceeding is not sufficient to show that $2.595 billion is the appropriate number compared to other numbers that fall within the same ranges. *Id*. at 8:21-9:5.

The Settling Parties responded that the Settlement is in fact supported by the evidence. Mr. Esamann described the testimony the Company presented in Phases I and II that addressed both the reasonableness of the increased project costs and the evidence showing that the Company was not guilty of imprudence, gross mismanagement, concealment, or fraud. Mr. Esamann specifically referenced the Company's testimony about (1) the need to alter the approach for disposing of grey water from deep-well injection ("DWI") to zero liquid discharge ("ZLD"), (2) the significant unanticipated increases in bulk commodity quantities, (3) increased labor productivity costs largely associated with the bulk commodity quantity increases, and (4) additional AFUDC accrued due to delays in the CWIP proceedings. Pet. Ex. JJJ-S at 4:14-6:3 (Esamann Reb.). He further reiterated the significant benefits that the Settlement Agreement achieves. *Id.* at 3:9-4:13.

Ms. Barbara Smith further explained that the Non-Duke Settling parties believe that a $2.595 billion Hard Cost Cap – which results in a more than $700 million shareholder impairment – is reasonable and in the public interest. Pub. Ex. 1SR at 3:8–4:8 (B. Smith Reb.). Ms. Barbara Smith explained that, given the evidence submitted in this proceeding, there is a range of reasonable outcomes, and $2.595 billion is within that range. *Id.*

(b) Contentions that the Hard Cost Cap Presumes the "First" $2.319 Billion in Construction Costs Are Prudent.

According to Mr. Schlissel and Mr. Ralph Smith, the Settling Parties are effectively requesting the Commission to find that all of the first $2.319 billion in direct costs incurred and all of the first $276 million in AFUDC accrued on the Project are reasonable, but there is no

evidence demonstrating that these "first" costs were not affected by the Company's "gross mismanagement or mismanagement" of the Project, or by the improper conduct of the Company's contractors or subcontractors. JI Ex. M-S at 3:1-5 (Schlissel Dir.); JI Ex. N-S at 9:15-22 (R. Smith Dir.). Even if there were substantial evidence demonstrating that these "first" costs are reasonable, Mr. Ralph Smith testified that such direct costs and related financing costs should be distributed pro rata or over an "S-curve" characteristic of major construction projects over the full time determined to be reasonably required to complete the Project. JI Ex. N-S at 9:22-27 (R. Smith Dir.).

Mr. Ralph Smith further argued that the Settlement creates a "matching" problem with respect to costs reviewed compared to costs to be recovered. *Id.* at 12:23. He explained that the costs reviewed on the record in IGCC 4S1 extend only to the Company's $2.039 billion total investment through September 30, 2010, which is $556 million less than the $2.595 billion Hard Cost Cap. *Id.* at 12:24-13:2. He testified that the $2.039 billion investment through September 30, 2010 is precisely the amount that the Non-Duke parties challenged when they presented evidence relating to imprudence, gross mismanagement, and concealment during Phases I and II of this proceeding. *Id.* at 10:1-13, 13:3-6. Under the Settlement, however, the Company will be able to recover the $2.039 billion investment that the Non-Duke parties challenged during Phases I and II, plus an additional $556 million. *Id.* at 10:1-13, 12:22-13:7.

In response, Mr. Esamann explained that the Settlement reflects the Settling Parties' agreement that construction costs up to the amount of the Hard Cost Cap are reasonable, prudent, and necessary and should be recovered, but that the Commission, not the Settling Parties, will decide in the IGCC 5, 6, 7, and 8 Rider proceedings whether those costs should in fact be recovered. Pet. Ex. JJJ-S at 6:7-14 (Esamann Reb.). Mr. Esamann and Mr. Womack further

responded that the drivers of the cost increase that were the focus of earlier testimony in this proceeding were back-end loaded so a pro rata or S-curve approach to calculating a disallowance is not appropriate. *Id.* at 18:18-19:18; Pet. Ex. LLL-S at 8:3-9:9 (Womack Reb.). Mr. Freeman modeled the cost estimate implications of altering how the costs are deemed to have been occurred, such as on a pro rata basis. Pet. Ex. MMM-S at 9:5-12:6 (Freeman Reb.). Even if a pro rata approach were appropriate, based on his analysis, using a pro rata method changes the AFUDC/direct cost mix, but the change is not substantial. *Id.* Moreover, Mr. Freeman explained that the Settlement Agreement's breakdown of the Hard Cost Cap into direct construction and AFUDC components was necessary for accounting reasons, but that the Settling Parties reached an agreement as to an overall Project cost cap and impairment amount, not direct cost and AFUDC components. *Id.* at 12:7-17 (Freeman Reb.). Further, Mr. Esamann emphasized that the Company would not have entered into a settlement that resulted in an impairment of greater than the approximately $700 million agreed to in the Settlement. Pet. Ex. JJJ-S at 19:3-5 (Esamann Reb.).

(c) Contentions Related to Customers' Responsibility for Certain Costs Above the Hard Cost Cap.

Mr. Schlissel and Mr. Ralph Smith also took issue with the Hard Cost Cap because they contend that it is actually a "firm floor" that assures the Company of cost recovery through rates for the first $2.319 billion of direct costs and associated AFUDC incurred on the Project, while also allowing the Company to recover additional revenues above the cost cap, *e.g.*, AFUDC accruals, CWIP, and potential post-in-service O&M costs. JI Ex. M-S at 2:1-14, 5:6-6:18 (Schlissel Dir); JI Ex. N-S at 11:1-12:13 (R. Smith Dir.). Specifically, Mr. Schlissel objected to the fact that the in-service criteria together with the rate treatment being requested by the Company in IGCC 8 allows the entire $2.595 billion to be placed into rates as CWIP before the

project is "substantially" completed, or before the gasification island produces any syngas. JI Ex. M-S at 3:6-18 (Schlissel Dir). He stated that although the Company is currently forecasting an in-service date in late 2012, several factors have already led to the delay of the Project's in-service date. *Id.* at 7:1-8:10 (Schlissel Dir). Also, the Company's current forecast for substantial completion of the Project is the first quarter of 2013, but there is evidence that the Company has considered pushing that date past the first quarter of 2013. *Id.* at 6:5-7, 8:4-10. Mr. Schlissel contends that, given the problems that have already been experienced during start-up and testing and considering the potential for further problems down the line, it is conceivable that "the Company would be accruing AFUDC and collecting revenues from its customers related to the $2.595 billion in CWIP-related revenues for perhaps 6 to 9 months (or longer) before the Project is in commercial operation. These costs are above the so-called 'hard cost cap' in the proposed Settlement Agreement." *Id.* at 6:7-12. Mr. Schlissel testified that this could result in an additional $30 to $35 million in AFUDC accrued after June 30, 2012 being included in rates as CWIP before the Project is even operational. JI Ex. M-S at 3:6-18 (Schlissel Dir). Similarly, Mr. Ralph Smith testified that the $2.595 billion provided for in the Settlement is not the total cost to customers to complete the Project, but rather, reflects an amount of direct costs and AFUDC accruals as of June 30, 2012, and customers will be responsible for additional AFUDC and CWIP-related charges after June 30, 2012. JI Ex. N-S at 10:14-21, 13:15-14:25 (R. Smith Dir.). Mr. Ralph Smith further testified that customers will continue to pay financing costs during the remaining construction period as a result of CWIP-related financing charges and that, if the Settlement is approved, the amount of CWIP-related financing charges resulting from the Settlement could exceed $655 million. *Id.* at 14:8-17. He said that such an amount "would appear" to be over and above the hard cost cap. *Id.* at 14:16-17.

Mr. Esamann and Mr. Gorman challenged Mr. Ralph Smith's and Mr. Schlissel's argument that the Hard Cost Cap is actually a firm floor. Pet. Ex. JJJ-S at 6:4-17 (Esamann Reb.); July 16 Tr. at BBB-56:8–60:6 (Esamann); IG Ex. MG-R-S at 3:7-19 (Gorman Reb.). They testified that the Hard Cost Cap, if approved, will constitute the new CPCN cost estimate. *Id.* The Commission will decide in IGCC 5, 6, 7, and 8 whether actual incurred Project costs up to the Hard Cost Cap are prudent and should be recovered. *Id.*

Mr. Esamann further stated that the Hard Cost Cap does not "ignore" CWIP recovery to date, which is calculated based on earlier incurred costs substantially below the Hard Cost Cap. Pet. Ex. JJJ-S at 6:18-23 (Esamann Reb.); July 16 Tr. at BBB-75:17–79:14 (Esamann). Mr. Freeman explained that the IGCC Rider specifically allows the Company to recover construction costs prior to startup testing, commissioning, and in-service status, and that AFUDC is accrued only to the extent that the construction expenditures are not yet receiving CWIP ratemaking treatment. AFUDC accrual ceases once the expenditures begin receiving CWIP ratemaking treatment. Pet. Ex. MMM at 2:7-5:2 (Freeman Reb.). Mr. Freeman also testified that the Settlement reflects the Settling Parties' agreement that direct costs and AFUDC up to the Hard Cost Cap are reasonable, that CWIP and/or AFUDC on such amounts are likewise reasonable, and that the amount of Project costs receiving CWIP ratemaking treatment to date is approximately $963 million on a total Company basis or approximately $887 million on a retail jurisdictional basis, which is well below the Hard Cost Cap of $2.595 billion. *Id.* Mr. Freeman stated that if the Company did not receive CWIP, AFUDC would continue to accrue under traditional Indiana ratemaking principles until the next rate case, so customers would end up paying additional financing costs. *Id.* at 5:3-18. "Consequently, moving from CWIP treatment per the IGCC Rider to rate base treatment in a rate case is [largely a] technical distinction with

virtually no actual impact on rate levels." *Id.* Mr. Freeman responded that Mr. Ralph Smith's analysis ignores that, whether through CWIP, AFUDC accruals, or inclusion in rate base, utility plant investments earn a return/recovery of costs to finance the capital investments. *Id.* at 7:6-8:9. He further explained that the impact of the Settlement Agreement Hard Cost Cap is only about a 6% increase in CWIP recovery over what would have occurred with the previously-approved $2.35 billion cost estimate.

Mr. Gorman stated that the Hard Cost Cap, along with the CWIP provisions, are clearly defined economic conditions of the Settlement, and modification of either would distort the compromise achieved by the Settling Parties. IG Ex. MG-R-S at 4:4-12 (Gorman Reb.). Mr. Esamann and Mr. Gorman also testified that CWIP and AFUDC accruals are permitted by the Indiana legislature and are allowed on the Project's costs that are determined to be reasonable. Pet. Ex. JJJ-S at 7:1-8 (Esamann Reb.); IG Ex. MG-R-S at 6:8-14 (Gorman Reb.). They testified that the Settlement Agreement delineates which types of costs are subject to the Hard Cost Cap. Pet. Ex. JJJ-S at 7:9-11 (Esamann Reb.); IG Ex. MG-R-S at 6:18–7:13 (Gorman Reb.). Therefore, because of the Hard Cost Cap, customers will not pay costs that are properly categorized as construction costs even if such costs are incurred after the Project is declared in-service. Moreover, the Non-Settling Parties have the right to dispute the categorization or prudence of costs, as well as costs related to IGCC Plant operations. Pet. Ex. JJJ-S at 7:11-8:17 (Esamann Reb.).

(d) Allegations Concerning In-Service Criteria and Effect on Costs.

Mr. Schlissel also objected to the in-service date and in-service criteria set forth in the Settlement, contending that these provisions do not adequately protect customers from additional costs. He argued that the in-service criteria are vague as to how long and at what power levels

the Project must operate on both natural gas and syngas before it may be deemed in-service, and that the Project could thereby be declared in service even if it has only operated for short periods of time on either natural gas or syngas and/or at only low power levels on either fuel. JI Ex. M-S at 12:15-26 (Schlissel Dir.). He also contends that the in-service criteria allow the Company to deem the Project in-service before all of the relevant testing and commissioning activities have been completed, and that customers could be responsible for additional costs if the plant is shut down or de-rated for extended periods of time to fix problems that should have been detected through additional testing and commissioning activities. *Id.* at 6:18-23, 12:6-13:17. Mr. Schlissel further argued that the in-service criteria do not protect customers from additional costs resulting from future delays in the final completion of start-up, testing, commissioning and GE New Product Introduction ("NPI") activities, or delays resulting from problems identified after the Project is declared in-service that may stem from the Company's alleged mismanagement or gross mismanagement of the Project, or the mismanagement of its contractors or subcontractors. *Id.* at 2:14-19, 3:19-22, 4:3-7. He points to Mr. Womack's testimony in IGCC 9 to suggest that the Company may be mismanaging the start-up, testing, validation and commissioning program at Edwardsport, although he acknowledged that he did not explore this issue in detail. *Id.* at 11:29-31, 11:33-12:1, 8:11-29. Mr. Schlissel also pointed to his Phase I and Phase II testimony as evidence that the Company mismanaged or grossly mismanaged aspects of the Project.

Mr. Schlissel contends that the Company has accelerated its projected in-service date ahead of the Project's completion date, and that it may be imprudently rushing start-up, testing and commissioning activities in order to "rush Edwardsport into rates as quickly as it can." *Id.* at 6:18-23, 11:29-31, 11:33-12:1, 8:11-29. To ensure that customers are adequately protected from having to pay certain repair costs resulting from the Project being deemed in-service "too soon,"

Mr. Schlissel recommended that the Commission adopt alternative in-service criteria for the Project, specifically: (1) the startup testing, commissioning, validation and GE NPI programs shall be fully and successfully completed, including a successful uninterrupted run of at least 100 hours on syngas during which power is furnished to the grid at levels between 95 percent and 100 percent of the plant's rated power; (2) the plant and associated transmission facilities shall have been tested and found capable of supplying to Duke Energy Indiana's customers their full share of its rated power; (3) the plant shall have demonstrated full compliance with all air permit requirements; and (4) the plant shall be supplying electricity to the grid with the output scheduled by the appropriate load dispatcher. JI *Id.* at 14:1-12. Mr. Schlissel acknowledged, however, that he did not explore the issue of whether the Company has accelerated its projected in-service date to "rush" the Project into rates in detail. *Id.* at 12:2-5. Mr. Ralph Smith also testified that the Project's in-service date has important implications for accounting, tax, and ratemaking purposes. JI Ex. N-S at 15:8-16:12 (R. Smith Dir.). In particular, Mr. Ralph Smith suggested that the Project's eligibility for various tax incentives may be adversely affected if the in-service date is delayed. *Id.*

Mr. Esamann responded that under the Settlement Agreement, any party retains all its rights under Indiana law to make arguments and to seek relief relating to post-in-service operating performance of the Project. Pet. Ex. JJJ-S at 8:18-9:17 (Esamann Reb.). Mr. Womack and Mr. Wiles explained that the in-service criteria are generally consistent with, and indeed slightly more stringent than, traditional practices concerning in-service determinations for major new projects – practices that have been used by utilities across the country for many years. Pet. Ex. LLL-S at 2:16-3:19 (Womack Reb.); Pet. Ex. KKK-S at 3:7-4:20 (Wiles Reb.). *See also* July 16 Tr. at CCC-37:8–39:13 (Esamann); July 18 Tr. at HHH-65:7–20 (Wiles) (Duke Energy

Indiana will continue capitalizing costs to the Project after the IGCC Plant is declared in-service).[22] Mr. Womack further explained why the in-service date should not be tied to GE's NPI – the NPI is not a test to determine operational status, but rather is a GE contractual provision intended to validate GE's design criteria for multiple pieces of equipment in multiple scenarios, some likely and some not. Pet. Ex. LLL-S at 2:16-3:19 (Womack Reb.). The Project will, in fact, be dispatched into the Midwest Independent Transmission System Operator ("MISO") markets long before GE finishes its NPI testing. *Id.*

Mr. Womack further responded that Duke Energy Indiana is proceeding with due diligence and speed to complete the Project and place it in-service for the benefit of customers. Pet. Ex. LLL-S at 3:20-5:6, 6:14-7:13 (Womack Reb.). But the Company is also proceeding carefully to ensure that all necessary testing and validation is done prior to putting the Project in-service. *Id.* The Company expects that the Project should be in-service by the first quarter of 2013 and has no reason to believe that the Project will not be in-service by the end of 2013. Because of this timing, the Company does not expect customers to incur negative impacts related to the tax incentives identified by Mr. Ralph Smith. *Id.* at 5:18-6:13; Pet. Ex. KKK-S at 9:1-10:21 (Wiles Reb.).

(3) Testimony Regarding Rider Restart Methodology.

Mr. Esamann explained that the IGCC Rider restart methodology ensures implementation of the IGCC Rider in an orderly manner, providing for a stepped-in increase for customers and, thus, a rate impact that is more gradual and moderated. Pet. Ex. HHH-S at 10:9-11:5, 22:3-4, 23:23-24:2 (Esamann Dir.). Mr. Freeman further explained the rider implementation proposal in

[22] Mr. Wiles noted that it is possible that a portion of the plant could be declared in-service for tax code purposes (as opposed to accounting and regulatory purposes) in 2012. July 18, 2012 Tr. at HHH-80:10–25 (Wiles).

detail and quantified the estimated rate impact of the Rider proceedings by rate group. Pet Ex. III-S at 9:12-13:13 (Freeman Dir.). According to Mr. Freeman, the estimated average retail rate impacts associated with this IGCC "Rider restart" methodology would be as follows:

- IGCC 4 Rider rates (in effect since July 2010) – 4.9%
- IGCC 8/9 Rider rates (anticipated to go into effect in the third or fourth quarter of 2012) – 3.2% average increase
- IGCC 10 Rider rates (anticipated to go into effect in the second or third quarter of 2013) – 6.4% average increase

Id. at 12:19-13:13.

Mr. Gorman also testified that this graduated approach to implementing the rate increase provides some relief to customers, as opposed to implementing the increase all at once. IG Ex. MG-D-S at 7:19-8:5 (Gorman Dir.).

Joint Intervenors submitted no testimony or evidence opposing this provision.

(4) Testimony Regarding Rate Case Moratorium.

Mr. Esamann testified that, like the Hard Cost Cap, the rate case moratorium was a significant concession by the Company. Duke Energy Indiana's base rates were last changed in 2004, based on 2002 and 2003 financial data. As the Company's fuel adjustment clause ("FAC") filings indicate, the Company's earnings are consistently below its authorized return, and a rate case filing has been on the Company's horizon for some time. The Company estimates that its current revenue requirements need to be increased in order for the Company to earn a reasonable return on its current utility plant in service. Recent FAC filings indicate that the Company's actual annual net operating income has been below the approved net operating income by over $100 million for the last five FAC filings. The flip side of this, of course, is that

this rate case moratorium provides a real benefit to customers because it will delay a rate increase filing and will delay increases in Duke Energy Indiana's base retail electric rates for nearly two years. Pet Ex. HHH-S at 15:13-16:2; 22:12-13 (Esamann Dir.).

Ms. Barbara Smith agreed that the rate case moratorium provides tangible benefits to customers. Although the OUCC does not necessarily place the same value as Duke Energy Indiana does on the moratorium, the OUCC agrees that a two-year rate case moratorium will result in lower rates than customers might otherwise pay without this limitation. Pub. Ex. 1-S at 6:20-7:3 (B. Smith Dir.).

Joint Intervenors submitted no testimony or evidence opposing this provision.

(5) Testimony Regarding Updated Depreciation Rates.

Mr. Esamann testified that, under this provision, customers will realize the benefit of a depreciation rate change credit amounting to approximately $35 million annually, with a commitment to keep this in place at least through any retail base rates filed prior to 2014. Pet. Ex. HHH-S at 12:1-20, 23:18-23 (Esamann Dir.). Mr. Freeman's testimony provides details regarding the depreciation accounting and ratemaking that the Settling Parties request, and quantifies the effects on future rates. Pet. Ex. III-S at 6:10-8:3 (Freeman Dir.).

Mr. Blakley and Ms. Barbara Smith also noted the benefits of the modified depreciation rates in their supporting testimony. In particular, both Mr. Blakley and Ms. Barbara Smith observed that, normally, depreciation rates are only changed in base rate case proceedings, but customers will realize certain benefits from updated depreciation rates immediately upon approval of the Settlement Agreement. Pub. Ex. 2S at 5:15-21 (Blakley Dir.); Pub. Ex. 1-S at 7:4-13 (B. Smith Dir.).

Joint Intervenors submitted no testimony or evidence opposing this provision.

(6) Testimony Regarding Move to Non-Accelerated Depreciation.

Mr. Esamann noted that the proposed move from accelerated to non-accelerated depreciation for certain qualified pollution control property/clean coal technology will provide a near-term cash flow and earnings benefit to the Company and is beneficial to credit quality, but will also result in an additional reduction in depreciation expense in rates at the time of the next rate case, estimated to result in an approximately $32 million annual reduction in revenue requirements for the benefit of customers. Pet. Ex. HHH-S at 13:13-14:9 (Esamann Dir.).

Joint Intervenors submitted no testimony or evidence opposing this provision.

(7) Testimony Regarding Deferred Taxes.

Mr. Esamann explained that the inclusion of deferred taxes in the capital structure used in the Company's IGCC Rider will initially benefit retail customers by initially approximately $22 million annually. Pet Ex. HHH-S at 14:10-15 (Esamann Dir.). Mr. Blakley testified to the same effect. Pub. Ex. 2S at 6:4-18 (Blakley Dir.). Bonus tax depreciation could further reduce the rate impact of the Project by approximately 0.7% in the near term. Pet Ex. HHH-S at 15:1-2 (Esamann Dir.).

Mr. Ralph Smith did not object to the Company's proposal to eliminate the deferred tax incentive prospectively, but argued that the Commission should also terminate the incentive on a retroactive basis. JI Ex. N-S at 21:18-20 (R. Smith Dir.). He contended that the Commission approved the deferred tax incentive to motivate the Company to contain Project costs within the original $1.985 billion cost estimate, and that the Company has known since at least May 2008 that the purpose of the deferred tax incentive would not be achieved. *Id*. at 17:16-20. For these reasons, he recommended that the Commission eliminate the incentive, and that the deferred tax incentive collected in rates as a result of the IGCC 4 Order be refunded to customers. *Id*. at 21:13-20. He further argued that any amount of AFUDC accrued and recovered by the Company

through rates as a result of the deferred tax incentive should be credited back to customers, although he was not sure whether the deferred tax incentive actually affected AFUDC accruals. *Id*. at 21:21-22:2.

Mr. Esamann responded that the Commission's orders did not treat the deferred tax treatment as a cost-control incentive, and he referenced the relevant portions of the Commission's CPCN and IGCC 1 Orders as support. Pet. Ex. JJJ-S at 9:18-11:23 (Esamann Reb.). He further explained that although the Commission's IGCC 1 Order ties the deferred tax incentive to the original cost estimate, it did not eliminate the incentive or require a refund of what had already been collected when the Company presented its increased $2.35 billion estimate. *Id.*

Joint Intervenors also cross-examined Mr. Blakley on this provision during the Settlement Agreement hearing. In response to the Joint Intervenors' questions, Mr. Blakley acknowledged that he had presented testimony on behalf of the OUCC in the CPCN proceeding and in previous IGCC Rider proceedings objecting to the exclusion of deferred taxes from Duke Energy Indiana's capital structure. In the CPCN Order and in subsequent IGCC Rider orders, however, the Commission rejected the OUCC's position. Hence, Mr. Blakley testified that it was reasonable for the Settlement Agreement to make the change to treatment for deferred taxes on a prospective basis only.

(8) Testimony Regarding Attorney Fees and Reimbursements; Other Funding Commitments.

Mr. Esamann testified that the $6.5 million in funding commitments under the Settlement Agreement for LIHEAP, the Indiana Ratepayer Trust, and a new Duke Energy Indiana/OUCC clean energy initiative will benefit customers. Pet. Ex. HHH-S at 22:15-17 (Esamann Dir.). Ms. Barbara Smith further testified that, although the details of the clean energy initiative by OUCC

and Duke Energy Indiana have not been established, the OUCC will ensure that the resulting project(s) will have a positive impact on Indiana customers and the Indiana economy as well as help push market transformation in the clean energy arena.

The Joint Intervenors did not object to this provision in their initial pre-filed testimony, although, in supplemental testimony, Mr. Olson urged the Commission to scrutinize these provisions. *See* JI Ex. P-S at 6:24-26 (Olson Supp.). Additionally, at the evidentiary hearing on July 16, 2012, the Joint Intervenors moved to dismiss these Settlement proceedings on the grounds that insufficient evidence had been offered to support the reasonableness of the attorney fees to be paid by Duke Energy Indiana shareholders to the Non-Duke Settling Parties. We denied that motion before the start of the Settlement Agreement hearings, but we discuss the basis for that determination in the Commission's Findings below, Section 4.C (11).

Joint Intervenors submitted no testimony or evidence opposing the remaining substantive provisions of the Settlement Agreement concerning Duke Energy Indiana's claims against Project vendors or contractors, Duke Energy Indiana's retention of intellectual property benefits, and customers' receipt of 100% of the applicable retail jurisdictional share of Project-specific funding such as incentive tax credits and property tax credits.

C. <u>Joint Intervenors' Additional Objections</u>.

In addition to their objections to specific provisions of the Settlement described above, the Joint Intervenors identified the following additional concerns.

(1) CO_2 mitigation.

Mr. Kanfer testified that the Commission should reject or modify the Settlement because it does not provide for CO_2 mitigation. JI Ex. O-S at 5:2-6 (Corrected Kanfer Dir.). He contends that, because Duke Energy Indiana has opted not to pursue carbon capture and sequestration ("CCS") technology at the present time, and given the amount of CO_2 emissions that

Edwardsport will produce for at least 30 years, there should be an alternative method of CO_2 mitigation for the Project. *Id*. at 7:6-8:20. Although Mr. Kanfer recognized that there are no current regulations or legislation in place that set CO_2 limits for Edwardsport, he asserted that "[t]here is little doubt that a federal carbon management regime – whatever form it ultimately takes – would pose additional cost on carbon-intensive facilities such as Edwardsport IGCC." *Id*. at 5:24-26. He opined that there are foreseeable business and financial risks that: (1) CO_2 permit limits will be set for the Project within the next 20 years, and (2) there will be civil penalties for global damages claimed to result from the Project's CO_2 emissions. *Id*. at 5:8-6:23. He also stated that the Commission's resource planning rules require the Commission to evaluate and address these types of business and financial risks to Duke Energy Indiana and its customers, as well as changes in federal and state energy and environmental policies. *Id*. at 6:25-7:4.

Because the Company has asked the Commission to modify the Project's CPCNs with respect to the cost estimate, Mr. Kanfer believes that this is also an appropriate time for the Commission to modify the CPCNs to impose CO_2 mitigation requirements. *Id*. at 8:21-9:28. He recommended that the Commission require the Company to mitigate approximately 2 million tons of CO_2 emissions per year over the course of the Project's projected 30-year operating life. *Id*. at 11:9-14. He explained that the Commission could achieve this result by requiring Duke Energy Indiana to retire more old coal plants, with retirements occurring sooner than currently planned, and that the retired coal-fired capacity and energy be replaced by significant increases in end-use efficiency and renewable generation, including distributed renewable generation. *Id*. at 10:22-11:3, 11:9-14.

Mr. Esamann responded that the EPA's greenhouse gas regulations do not apply to Edwardsport, and although the EPA could establish new CO_2 emission standards in the future,

they would likely apply to Edwardsport only if any modifications are made to the IGCC Plant. Pet. Ex. JJJ-S at 14:6-17 (Esamann Reb.). He further explained that the Commission's CPCN Order required the Company to initiate a proceeding "regarding further study and potential implementation of partial CO_2 capture at the IGCC project and further study and potential implementation of CO_2 sequestration and for enhanced oil recovery." *Id*. at 12:12-19 (internal citation omitted). The Company complied with the Commission's requirements and filed its Carbon Capture FEED Study Report with the Commission on June 24, 2011. *Id.* at 12:20-13:11. The Company's request for approval of and cost recovery associated with the study of carbon storage is currently pending before the Commission in Cause No. 43653. *Id.* Mr. Esamann believes that it would not be appropriate to modify the CPCNs at this late stage without the necessary evidence and cost analyses that are required to assess the reasonableness of adding CO_2 mitigation. *Id.* He stressed, however, that Duke Energy Indiana has not abandoned its plans to install CCS at Edwardsport. *Id.* at 13:12-14:5. Mr. Esamann testified that the Company included alternative resource plans similar to the one identified by Mr. Kanfer in its IRP analysis and determined that such a plan would actually be more costly for customers. *Id.* at 14:18-15:11. He further explained the additional factors that Duke Energy Indiana considered in its IRP analyses related to minimizing environmental effects. *Id.* at 15:12-17:15.

(2) Operational Requirements.

Mr. Schlissel also objected to the Settlement Agreement − as he has previously in this subdocket, in the CPCN proceeding, and in earlier IGCC Rider proceedings − because there is no provision that protects customers against a possibility that Edwardsport will not operate at or near its projected availability and capacity factors. JI Ex. M-S at 5:1-5 (Schlissel Dir.). Mr. Esamann responded that, although the Settlement Agreement does not specifically address this issue, all parties retain the right under the Settlement Agreement to present arguments and seek

relief concerning the post-in-service operating performance of the Project. Pet. Ex. JJJ-S at 8:18-9:11 (Esamann Reb). *See also* Pub. Ex. 1SR at 6:4-10 (B. Smith Reb) (same). Further, Mr. Stultz explained in Phases I and II of the proceeding why guarantees of this nature are not necessary or reasonable. *See, e.g.*, Nov. 7, 2011 Tr. at P-44:2–45:23 (Stultz).

(3) Findings on the Merits of Underlying Claims.

Additionally, Mr. Schlissel objected to the Settlement claiming that the Company has requested the Commission to approve the Settlement without making any findings on evidence of imprudence, fraud, concealment and/or gross mismanagement or mismanagement, and that any such ruling would make it difficult for any Non-Duke party to prove that post in-service costs were the result of Duke Energy Indiana's gross mismanagement or mismanagement of the Project or that of the Company's contractors. JI Ex. M-S at 4:17-28 (Schlissel Dir). In response, Ms. Barbara Smith testified that, although the Settling Parties did not come to a common conclusion regarding imprudence, concealment, fraud, and gross mismanagement, to the extent such activities occurred, the Settling Parties agree that the transfer of responsibility for $700 million in costs from customers to the Company's shareholders is sufficient to address any imprudence, concealment, fraud, or gross mismanagement that may have occurred. Pub. Ex. 1SR at 5:15-18 (B. Smith Reb.).

(4) Alleged Corruption of the Regulatory Process.

Mr. Olson testified that the Commission should reject the Settlement as a whole because it does not address Duke Energy Indiana's alleged corruption of the regulatory process. JI Ex. KLO-S at 2:26-28 (Olson Dir.). He expressed concern that, if approved, all allegations against the Company concerning imprudence, fraud, concealment and gross mismanagement would "just 'go away.'" *Id*. at 4:1-4 (internal citation omitted). He also testified that the Commission should immediately open a Phase III investigation into whether improper communications, undue

influence, conflicts of interest or other misconduct impacted the regulatory oversight of the Project, caused administrative due process violations, or constituted fraud on the tribunal. *Id*. at 10:3-13. He believes it is "incomprehensible" that the Commission has not granted the Joint Intervenors' prior requests to initiate a Phase III investigation concerning such issues, particularly considering that the Commission has dismissed and reversed other cases based on the same events that would be the subject matter of a Phase III investigation. *Id*. at 6:26-9:30. Mr. Olson also expressed concern that the Settlement purports to resolve all issues concerning *ex parte* communications, improper conduct, and undue influence with respect to the Project even though the Commission has never investigated such issues. *Id*. at 5:29-6:25.

In supplemental testimony, Mr. Olson testified that Duke Energy Indiana's course of conduct regarding a change in leadership and related events arising from the Company's merger with Progress Energy shows a pattern of Duke Energy Indiana corporate misconduct under the leadership of its CEO, Mr. Rogers. JI Ex. P-S at 2:10-3:25 (Olson Supp.). He contends that Mr. Rogers' testimony highlights the Company's employment of "loophole lawyering," and that it is therefore critical for the Commission to closely review and scrutinize the fine print in the Settlement in order to find and properly evaluate the "devil in the details." *Id*. at 3:20-25. He believes that a pattern of Duke Energy Indiana corporate misconduct under Mr. Rogers' leadership is further exemplified by the allegations of concealment, ex parte communications, improper conduct, undue influence, conflicts of interest, and other misconduct that have been previously raised in this proceeding. *Id*. at 3:8-13; *see also id*. at 4:12-5:4. He argued that a repudiation of past misconduct regarding regulatory review of the Project, and a concrete commitment by the Company that any such misconduct will not be repeated should be an essential part of any settlement in this proceeding. *Id*. at 2:10-20.

The Company's witnesses did not specifically address Mr. Olson's allegations in the settlement phase of this proceeding on the grounds that (1) the Commission has, on numerous occasions, denied Joint Intervenors' attempts to include allegations of *ex parte* communications, improper communications, conflicts of interest, undue influence, *etc*., in this proceeding, (2) Duke Energy Indiana had previously addressed such concerns, and (3) Mr. Olson's allegations are beyond the scope of the Settlement Agreement testimony. Pet Ex. JJJ-S at 12:1-5 (Esamann Reb.).

(5) Adequacy of Procedural Schedule.

Mr. Olson further testified that the procedural schedule approved by the Commission for consideration of the Settlement Agreement did not give the Joint Intervenors adequate time to complete their review and analyze the impact of the Settlement terms. JI Ex. KLO-S at 3:2-17 (Olson Dir.). He stated that the expedited procedural schedule hurt the Joint Intervenors' ability to prepare their case, and that in establishing the accelerated schedule, the Commission ignored the Joint Intervenors' previously filed verified statements explaining that they reasonably required up to and including July 27, 2012, to prepare their case. *Id*. at 3:9-17. Mr. Ralph Smith stated more specifically that he needed more time to prepare his testimony due to the complexity of the accounting, tax, and ratemaking issues implicated by the Settlement, as well as his previous commitments to other clients. JI Ex. N-S at 6:9-7:21 (R. Smith Dir.). Mr. Schlissel echoed similar sentiments, stating that he had insufficient time to explore all issues raised in his testimony in greater detail and to coordinate his testimony with that of Mr. Ralph Smith. JI Ex. M-S at 1:17-23; 12:2-5 (Schlissel Dir.).

Ms. Barbara Smith responded to Mr. Olson's claim that the procedural schedule did not provide the Joint Intervenors adequate time to prepare their case. She testified that Duke Energy Indiana filed its request for CPCNs for the Project in September 2006, and that since that time,

there have been extensive proceedings, including discovery and public evidentiary hearings, in which OUCC and Joint Intervenors have participated. Pub. Ex. 1SR at 2:9-3:3 (B. Smith Reb.).

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

A. <u>Standard for Commission Review of Settlement Agreements</u>.

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), the Powerplant Construction Act, the Clean Coal Technology Act, 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, even where the settlement is not supported by all parties. *Indianapolis Power & Light Co*., Cause No. 39936, at p. 7 (Ind. Util. Reg. Comm'n, Aug. 24, 1995); *Indianapolis Power & Light Co.*, Cause No. 43960, 2011 Ind. PUC LEXIS 344 at *114 (Nov. 22, 2011) (quoting *Penn. Gas & Water Co. v. F.P.C.*, 463 F.2d 1242, 1246 (D.C. Cir. 1972)). 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. *S. Ind. Gas and Elec. Co.*, Cause No. 42596, 236 P.U.R.4th 153, 2004 Ind. PUC LEXIS 262 at *32 (2004).

In this case, the Commission has more than sufficient evidence from which to judge the reasonableness of the terms of the Settlement. All Settling Parties except Nucor filed testimony supporting the Settlement. In addition, the Non-Settling Parties filed testimony clearly explaining their objection to the Settlement, in response to which the Settling Parties filed rebuttal evidence. The Commission has carefully analyzed the evidence – including particularly

the evidence presented in Phase I and Phase II of the proceedings – and the proposed Settlement to evaluate whether the proposed outcome is reasonable, just, and properly balances the interests of Duke Energy Indiana, its customers, and the overall public interest.

B. Evaluation of the Reasonableness of the Proposed Settlement and Whether It Serves the Public Interest.

Having heard and considered the evidence, for the reasons summarized in the following paragraphs the Commission concludes that the terms and conditions of the Settlement Agreement as a total package offer a fair, just, and reasonable resolution of the complex and highly contested matters pending in this subdocket, and we find that as a whole the Settlement Agreement meets the standard of public convenience and necessity, is fair, will result in just and reasonable rates, will provide significant benefits to customers, and is in the public interest.

Under the Settlement Agreement, Duke Energy Indiana shareholders assume the burden of approximately $700 million of the Edwardsport Construction Costs – resulting in approximately $1.7 billion in reduced rates over the life of the Project – and customers will pay less than 80% of the capital construction and financing costs for a plant that is needed to ensure reliability.[23] That IGCC Plant will operate for approximately 30 years and will provide customers with the benefits of reliable, clean coal generation to meet the future energy demand of Indiana at low operating costs thereby making it one of the first plants expected to be dispatched on the Duke Energy Indiana system. As our state legislature has recognized, the need for clean coal technology is particularly important in a coal-rich state like Indiana. This view is reinforced by new EPA regulations that are expected to require Duke Energy Indiana to retire Wabash River Units 2, 3, 4, and 5 and possibly Wabash River Unit 6 and Gibson Unit 5.

[23] The construction costs and AFUDC the Company has incurred through IGCC 8, as noted in the order we are issuing concurrently with this Order, already exceed the amount of the Hard Cost Cap by over $500 million.

Customers will, therefore, receive the needed generation and benefits of advanced IGCC technology while Duke Energy Indiana shareholders pay for more than 20% of the costs of building the IGCC Plant.

In this regard, we find that the Project remains needed and that it is in the public interest for the Project to be completed. In its pre-filed testimony in Phase I, Duke Energy Indiana presented substantial evidence that the Company is in significant need of additional baseload capacity on its system, and thus, the Project remains reasonable and necessary.[24] Also, the record evidence demonstrates that the Project will have extremely low SO_2, NO_x, and mercury emissions, and thereby offers substantial potential of reducing sulfur and nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989.[25] Thus, based on record evidence, we find that the Company is in need of additional baseload capacity on its system, the Project's use of clean coal technology continues to serve the public convenience and necessity and, thereby, it is in the public interest for the Project to be completed. Notably, no party in this proceeding challenged Duke Energy Indiana's load forecasts and the need for the Project's baseload capacity, nor did any party by the latter phase of these proceedings contend that Duke Energy Indiana should have stopped construction of the

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[24] *See, e.g.*, Pet. Ex. N at 8:9–17, 9:12–15 (Stevie Sept. 2010 Reb.) (presenting the Company's 2010 summer load forecast, which projected at least a 1.4% growth rate in retail energy sales in Duke Energy Indiana's system for the period of 2010 to 2020 before reduction for energy efficiency impacts, and 0.7% after energy efficiency impacts); Pet Ex. QQ at 3:1–5 (Stevie Mar. 2011 Supp.) (presenting the Company's fall 2010 load forecast, which projected even higher level energy sales, as well as higher summer peaks than the summer 2010 forecast); Pet. Ex. G at 17:17–19 (Hager Apr. 2010 Dir.) (testifying that the Company's IRP analyses have consistently shown that Duke Energy Indiana has a continuing need for the IGCC Project's baseload capacity); Pet. Ex. L at 11:11 (Hager Corrected Sept. 2010 Reb.) (explaining that intermittent resources are not an appropriate substitute for the IGCC Project's baseload capacity).

[25] Nov. 9, 2011 Tr. at R-6:20–R-9:9 (Stowell) (explaining that even with the myriad environmental regulations that could impact coal-fired generating plants in the United States, the IGCC Project will continue to be a robust option because, among other things, it will have extremely low SO_2, NO_x, and mercury emissions in comparison to conventional coal-fired facilities); Pet. Ex. RR at 13:1–15 (Stowell Mar. 2011 Supp.) (same); Pet. Ex. O at 12:10–22 (Stowell Sept. 2010 Reb.) (same); Pet. Ex. LL at 15:7–16:2, 17:1–5 (Esamann Mar. 2011 Supp.) (same); Pet. Ex. D at 9:16–10:2 (Turner Apr. 2010 Dir.) (same).

IGCC Project. Accordingly, the evidence presented in this matter does not support modification of our prior findings on this issue.[26]

The Settlement Agreement also provides rate certainty. The Hard Cost Cap limits the amount of construction costs Duke Energy Indiana can recover. While post-June 2012 additional AFUDC will accrue and CWIP recovery will continue on the construction costs under the cap, those costs can be reasonably calculated and do not materially affect the price certainty for customers. The reduction in litigation risk provides further rate certainty. Furthermore, Duke Energy Indiana agreed to a number of measures that will mitigate the rate increases, including: (1) a rider restart methodology that will result in graduated rate increases, (2) lower depreciation rates on the remainder of the Duke Energy Indiana system (excluding qualified pollution control projects discussed below), (3) termination of the deferred tax incentive previously authorized for the Project, (4) a rate case moratorium, and (5) use of normal, straight-line depreciation for clean coal technology qualified pollution control projects that currently are being depreciated on an accelerated basis (which will be implemented for ratemaking purposes with the Company's next retail rate case order).

All of these agreed-to measures, including the Hard Cost Cap, will mitigate the rate effects of the Edwardsport Project, so that customers will see an average peak retail rate increase of 14.5%, rather than 19.9% as it would have otherwise occurred under Duke Energy Indiana's $3 billion estimate ($2.72 billion of direct costs and $280 million of AFUDC). While this rate impact is significant, this is not a situation where doing nothing is acceptable. Any replacement

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[26] Although in his Phase I testimony Mr. Schlissel presumably challenged the need for the Project's clean coal capacity, JI Ex. DAS at 56:15–24 (Schlissel June 2011 Supp. Reb.), he offered no new information about the Project's use of clean coal technology and anticipated regulation of CO_2 that we have not already considered in prior proceedings. His contentions are a collateral attack on our previous findings that, even without CCS, the public convenience and necessity will be served by the Project's use of clean coal technology. CPCN Order at 47; IGCC 2 at 13; IGCC 3 at 19; IGCC 4 Order at 15-16.

baseload generation – which we have previously determined is needed – will significantly affect rates, and the Settlement provisions will have the real impact of mitigating the burdens on customers' rates. Specifically, the Hard Cost Cap will result in annual revenue requirements approximately $96.7 million less than if the $3.3 billion estimate (construction costs plus AFUDC) were included in rates. *See* Pub. Ex. 2S at 4:7-14 (Blakley Dir.). Moreover, the termination of the deferred tax incentive will decrease rates by initially approximately $22 million annually, the updated depreciation rates will decrease rates by $35 million annually, and moving to non-accelerated depreciation will decrease rates by $32 million annually at the time of Duke Energy Indiana's next retail base rate case. Additionally, customers will realize real (albeit more difficult to quantify) value from the rate case moratorium.

Duke Energy Indiana also agreed to a funding commitment for the Indiana LIHEAP and for a new Duke Energy Indiana/OUCC clean energy initiative, which will provide additional benefits to customers. Finally, the Company (rather than customers) has the responsibility to pursue and fund litigation against Bechtel and/or GE in order to try to recover any disallowed costs.

In sum, the Settlement Agreement provides a significant decrease in construction costs that will be charged to customers, the benefits of over 600 MWs of baseload clean coal capacity with low operating costs, and additional rate mitigation provisions and funding provisions that will provide benefits to customers beyond the scope of the matters set for hearing in this Cause. Therefore, based on all the evidence presented and for the reasons set out herein and in the following sections of this Order, we find that the Settlement taken as a whole produces a fair, just, and reasonable result that balances the interests of the various stakeholders and the overall public interest and results in just and reasonable rates.

C. **Whether Findings on the Merits of the Underlying Claims are Required**.

The subdocket that is the subject of this Settlement was created to review a revised cost estimate for the IGCC Project. Later the Commission bifurcated the subdocket into two phases – Phase I to address the Commission's review of the IGCC 4 progress report, the Project cost estimate increase, the continued need for additional capacity, and the reasonableness of going forward with the Project; and Phase II to address allegations of fraud, concealment, and gross mismanagement. On those issues, the parties presented more than 3,000 pages of detailed pre-filed testimony from 34 witnesses, engaged in extensive cross-examinations and redirect examinations over the course of 25 days – resulting in more than 6,500 pages of hearing transcripts – and introduced more than 1,300 exhibits.

The Commission has thoroughly reviewed and considered all of this evidence in this decision to approve the Settlement. But the Commission declines to draw ultimate conclusions on each of the disputed issues raised in this subdocket as if no settlement had been tendered, because it is not necessary to do so to thoroughly evaluate the Settlement Agreement. Our task in evaluating the Settlement Agreement – to determine whether it is reasonable, just, consistent with the purpose of the applicable statutes, and serves the public interest – does not require that we reach detailed, point-by-point conclusions on each of the underlying claims of imprudence, fraud, concealment, or gross mismanagement, in the manner that we would in the absence of a settlement. Rather, we need only determine whether the amount of Project costs that will ultimately be eligible for recovery in retail rates pursuant to the terms of the Settlement Agreement represents a reasonable resolution based on the record as a whole. We will undertake such analysis and make such findings below.

Moreover, it has long been settled both in Indiana and before the United States Supreme Court that a commission can adopt a settlement agreement as "'a resolution *on the merits* if [the Commission] makes an independent finding, supported by substantial evidence on the record as a whole that the proposal will establish 'just and reasonable' rates.'" *N. Ind. Pub. Serv. Co.*, Cause No. 43969, 2011 Ind. PUC LEXIS 369 at *186 (Dec. 21, 2011) (quoting *Mobil Oil Corp. v. FPC*, 417 US 283, 314 (1974)) (emphasis in *Mobil Oil*). We described previously the substantial evidence that supports the reasonableness of the Settlement. Furthermore, as part of the Settlement, Duke Energy Indiana agreed to rate-mitigation proposals that would not necessarily have resulted from a litigated resolution of the underlying merits.

Finally, in light of our finding that the Settlement is fair, just and reasonable, and in the public interest, it is unnecessary to address the large number of complex factual and legal issues. Each such issue would be susceptible to appeal, and customers would lose the key benefit of rate impact certainty during the entire pendency of the appeal and possible remand, thereby removing one of the benefits of the Settlement Agreement. While it is likely that every party would appeal a Commission order on the merits of the underlying claims, any appeal from this Order will be more limited than an order on the merits in such a large and complex case like this Cause and less disruptive of the benefits that will flow to customers. Moreover, there is no certainty that customers would receive a greater benefit at the conclusion of an appeal of a litigated resolution.

We disagree with Mr. Olson's contention that we should revoke the Edwardsport CPCNs and rescind the CPCN Order and IGCC 1 Order and thereby allow recovery through rates of zero dollars. *See* JI Ex. KLO-S at 10:6-8 (Olson Dir.). To the contrary, as we indicate above, there is substantial record evidence that the Project remains reasonable and necessary, and that it is in the public interest for the Project to be completed. Moreover, as we have previously found, the

Project is a reasonable generating alternative to serve Duke Energy Indiana's load, it will provide many benefits to the environment, and it will benefit the State's economy in the forms of state and federal tax incentives and new jobs. CPCN Order at 15, 22, 42-43. Further, we agree with the Settling Parties that the $2.595 billion Hard Cost Cap – which results in a more than $700 million shareholder impairment – results in a reasonable price for the Project and is in the public interest. Accordingly, because we find that: (1) the Project remains needed; (2) it is in the public interest to complete construction of the plant; (3) the Settlement Agreement is fair, just and reasonable, and satisfies the standard of public convenience and necessity; and (4) the Settlement will produce just and reasonable rates, we will not revoke the Edwardsport CPCNs, rescind the CPCN Order or the IGCC 1 Order, or limit the Company's recovery through rates to zero dollars.

D. **Evaluation of the Joint Intervenors' Objections to the Settlement Agreement**.

The Joint Intervenors' objections do not alter our finding that the Settlement Agreement as a whole is fair, just, reasonable, and in the public interest. While the Joint Intervenors dispute individual components of the Settlement Agreement and argue that it should have included additional elements or that the costs assumed by Duke Energy Indiana's shareholders should have been greater, they did not show that the sum of the customer benefits is unreasonable, is unsupported by the record, or that it is not in the public interest. Furthermore, the terms of the Settlement Agreement must not be evaluated as individual independent components, but must be evaluated as a whole unit which reflects both benefits for and concessions by all participating parties. The evidence in this case demonstrates that the Settling Parties evaluated the substantial risk and uncertainty faced by all parties in this case, and arrived at a compromise solution that is fair, just, reasonable and in the public interest.

The OUCC, IG and Joint Intervenors presented testimony and evidence in Phase I supporting their allegations that:

- Duke Energy Indiana used inadequate management controls and insufficiently experienced staff for the Project and were consequently unable to react to and contain cost increases on a first-of-a-kind-at-this-size project;

- The Company imprudently underestimated the quantities of bulk materials that would be required for the Project, failed to timely identify the increases that became apparent in the second half of 2009, and took inadequate and untimely steps to control the cost consequences of those quantity increases;

- The Company failed to take reasonable and necessary steps to prevent and to recover from lower-than-expected labor productivity;

- The Company imprudently adopted a DWI system for disposal of grey water based on inadequate information, failed to take reasonable steps in response to notification from GE of the hazardous composition of the expected grey water, and unreasonably delayed the adoption of a ZLD system for grey water disposal;

- The Company did not reasonably manage or control its major contractors, Bechtel and GE, and instead caused the relationships with those contractors to deteriorate and to become detrimental to the Project; and

- The Company imprudently produced cost reports to the Commission that did not permit consistent or comprehensive tracking of cost increases.

Duke Energy Indiana responded to these issues with substantial testimony and exhibits supporting its position that:

- The Company reasonably assigned qualified managers for each of the evolving stages of the Project, regularly involved senior management and the Board of Directors in Project oversight, and either conducted or commissioned internal and external audits to proactively identify areas of the Project's management that could be further enhanced;

- The Company could not have reasonably foreseen the necessary bulk commodity quantity increases, but instead, it reasonably relied on Bechtel's expert estimates during the FEED Study of the required bulk commodity quantities, and reasonably accepted Bechtel's quantity forecasts through the first half of 2009, which matched the FEED Study estimates;

- Once the increases in necessary bulk commodity quantity became apparent, the Company reasonably identified, managed and mitigated the necessary increases as

evidenced by the fact that it took reasonable steps to manage quantity increases as detailed engineering progressed and as Bechtel identified those increases;

- The Company reasonably managed lower-than-expected labor productivity that was caused by factors it could not have reasonably anticipated or controlled (*e.g.*, abnormally severe weather and the follow-on consequences of quantity increases);

- The Company acted reasonably and prudently to address evolving requirements for grey water disposal: (a) it based its original decision to use a DWI system on expert advice from GE that the Company reasonably used to pursue a lower-cost alternative, (b) it reasonably continued to develop the lower-cost option so long as there was a plausible possibility of success, (c) it reasonably evaluated alternatives and moved to a ZLD system after pursuing an EPA exemption that would have permitted installation of the DWI system, and (d) regardless of the timing of the grey water decision, the ZLD system that the Company installed is essential for plant operation; and

- The Company reasonably and prudently modified and enhanced its cost reporting systems during each phase of the Project in order to control costs, and it was always able to identify and justify its costs internally and to the Commission.

In Phase II, relying on both the Phase I and the Phase II records, the OUCC, IG and Joint Intervenors presented testimony and evidence alleging that:

- Duke Energy Indiana concealed or grossly mismanaged its consideration of "first mover" risks and thereby understated the possibility of cost and schedule overruns;

- The Company grossly mismanaged the FEED Study and the development of the initial cost estimate or concealed the extent to which that Study and estimate were still incomplete or had been modified;

- The Company concealed its consideration of and preference for certain contracting approaches and delivery methodologies for the Project − including the alleged availability of a lump-sum, turnkey engineering and construction execution contract − and the associated risks of the contracting approach that it adopted and that the Company grossly mismanaged the chosen contracting approach and delivery methodology;

- The Company grossly mismanaged the Project's organization and controls by beginning the project with inadequate schedule and cost measurement tools and by repeatedly modifying the Project's management organization;

- The Company grossly mismanaged its analysis of the need for the Edwardsport IGCC Project by delaying IRP studies and using unreasonable assumptions for those studies;

- The Company concealed Project-related information from the Commission that would have disclosed cost overruns, schedule delays, and evolving management problems;

- The Company fraudulently misrepresented certain project risks to the Commission, and certain communications between the Company and former-Chairman Hardy constituted fraud on the Commission;

- The Company's cost reports to the Commission concealed cost increases and misrepresented the Company's gross mismanagement of essential project cost controls; and

- Duke Energy Indiana failed to timely inform the Commission and the Parties about issues associated with the feasibility of its DWI plan and with the chemical composition of its grey water.

In response, Duke Energy Indiana presented substantial testimony and evidence that it contends demonstrates that:

- The Company reasonably (a) assessed first-mover risks based on the information known in the industry at the time through the preparation of an in-depth FEED study, and its disclosures to the Commission were consistent with the knowledge in the industry at the time, (b) recognized that the Project was not a first-of-a-kind technology, but that it was the first time the technology was being used at this scale, and (c) took steps to mitigate the risks associated with the Project, including through the preparation of an in-depth FEED study, as well as the contracting structure it adopted;

- The Company acted reasonably in preparing and relying on the FEED Study and cost estimate by: (a) achieving the objectives of the FEED Study and completing the study before completing the cost estimate, (b) contracting with two world-renowned experts to develop the FEED Study and cost estimate, and reasonably overseeing those experts' work, including conducting its own internal review of the cost estimate using an outside estimating expert, (c) reasonably relying on a reference plant and the FEED study for the development of the cost estimate, (d) completing a reasonable amount of design and engineering work before completing the estimate, (e) properly commencing construction before the engineering work was complete, and (f) informing the Commission and other parties with information the Company deemed relevant and requested by the Commission, as well as responding to discovery requests and other requests for information throughout prior proceedings concerning the Project;

- The Company reasonably performed its analyses of the need for the Project by: (a) using reasonable and reliable assumptions in its IRP analysis, (b) reasonably opting not to use high-capital cost sensitivities when detailed cost estimates had been undertaken, (c) reasonably identifying when the project could no longer be completed under the approved estimate, and (d) completing an updated cost estimate and IRP analyses in a timely manner;

- The Company reasonably assessed the pros and cons of different contracting approaches and delivery methods and acted reasonably in executing its contracts with GE and Bechtel by: (a) engaging in extensive negotiations with Bechtel and GE, (b) achieving concessions from Bechtel, (c) entering into the best contract available in light of contemporaneous market conditions, (d) maintaining an industry-standard flexible contracting approach that could be reassessed as the needs of the Project evolved, and (e) timely informing the Commission of its selected contracting approach and delivery method;

- The Company instituted reasonable project management and project controls by: (a) placing experienced managers on the Project based on the needs of each phase of the Project, (b) implementing reasonable project controls as needed for each phase of the Project, (c) reasonably overseeing and challenging its contractors, and (d) providing the Commission with information regarding the major issues as they developed on the Project;

- The Company (a) reported extensively to the Commission through its twice-yearly progress reports, including about issues associated with the feasibility of its DWI plan and with the chemical composition of its grey water, (b) accurately and comprehensively described the status of the Project's costs and schedule in regular reports to the Commission, and (c) reasonably and appropriately evolved Project reports so that they would meet changing Project needs to assure adequate cost and schedule controls;

- The Company's contacts with former-Chairman Hardy did not relate to issues that were pending with the Commission, and the communications did not divulge information that was not being shared with intervenors or the OUCC; and

- With regard to allegations that conduct in Phase I also constituted gross mismanagement, because the Company's management of those issues was prudent, its management could not constitute gross mismanagement.

We find that, on the basis of the competing evidence presented in Phases I and II and in the settlement testimonies, the $700 million in IGCC costs that Duke Energy Indiana shareholders will assume is a reasonable resolution of those claims in order to achieve the customer benefits that the Settlement Agreement will bring. While it is always possible to argue

that the allocation of costs between shareholders and Duke Energy Indiana's customers should be different, and that the costs borne by shareholders should be even greater, we find that the Settlement Agreement as a whole − including the other rate mitigation measures that Duke Energy Indiana will take − is well within the range of reasonable outcomes based on all of the evidence in this voluminous record and is, in fact, reasonable. The Settlement Agreement provides a sizeable customer benefit, caps the costs that customers will bear, expedites the delivery of benefits, and serves the public interest. Given the considerable litigation risk for all the parties, the Settlement Agreement is a reasonable compromise of contested issues and will produce reasonable rates. Given our review of the extensive testimony in Phases I and II of this proceedings and our assessment of the credibility of witnesses in this proceeding, we find that Project costs that are eligible for recovery in retail rates under the Settlement Agreement are not tainted by the impact, if any, of imprudence, gross mismanagement, concealment, or fraud.

In opposing the Settlement Agreement, the Joint Intervenors have raised a number of specific claims. As we discuss below, we do not find those claims to be persuasive in light of the substantial benefits that the Settlement Agreement will bring.

(1) Adequacy of the Procedural Schedule.

The Joint Intervenors had two months – from April 30, 2012 to June 29, 2012 – between the date the Settlement Agreement was filed with the Commission and the date when their testimony was due, and an additional two weeks thereafter to prepare for the hearing. We further accepted into evidence Joint Intervenors' corrected testimony and supplemental testimony, submitted more than ten days after the date when their pre-filed testimony was due. Finally, the Joint Intervenors conducted extensive cross-examination over the course of four days of settlement hearings. This procedural schedule was ample considering that the Settlement Agreement was preceded by more than 18 months of discovery and extensive pre-filed testimony

and cross-examination related to the underlying dispute. Moreover, all but four of the provisions of the Settlement Agreement are similar to proposals that had been made previously in this proceeding – (1) the move from accelerated to non-accelerated depreciation for certain clean coal technology equipment, (2) the rate case moratorium, (3) the rider restart proposal to more gradually increase the rate impacts, and (4) the shareholder funding commitments. Joint Intervenors did not contest the first three of these provisions. We therefore find that the procedural schedule provided ample time for the Joint Intervenors to assess the Settlement Agreement and prepare opposing testimony and cross-examination.

(2) Substantial Evidence Supports the Hard Cost Cap.

The Joint Intervenors contend that the testimony in support of the Settlement does not contain evidence supporting the amount of the Hard Cost Cap. Specifically, Mr. Schlissel repeats the following arguments from his Phases I and II testimonies: (1) the Company grossly mismanaged the Project from the earliest stages regarding the planning and regulatory review and approval for the Project; (2) although the Company knew it was exposed to first-mover and megaproject risks and that there were significant technology risks and potential for additional construction costs, it grossly mismanaged resource planning for the Project and failed to disclose to the Commission the risks of higher construction costs; (3) the Company refused to consider the potential for further cost increases; (4) the Company refused to consider or acknowledge the possibility that the Project might not achieve its estimated 85% availability; (5) the Company continued to report to the Commission that the risks were manageable and costs were under control when they were not; (6) the Company refused to consider that dramatically increasing Project costs meant alternatives to completing the Project (*e.g.*, energy efficiency and renewables) should once again be considered; and (7) the Company concealed and fraudulently misrepresented to the Commission and the parties critical Project information and imprudently

failed to re-examine Project economics on a timely basis or using reasonable planning assumptions.

Mr. Schlissel does not address, however, the substantial testimony Duke Energy Indiana submitted in response to both his arguments and the allegations and arguments of other witnesses in Phases I and II of this proceeding. Specifically Ms. Hager, Mr. Roebel, and Mr. Zupan responded to issues related to the IRP analyses, the original planning and regulatory review and approval for the Project, the assessment of known and unknown risks at the beginning of the Project, the reasonableness of the initial cost estimates, and the reasonableness of the contracting strategy ultimately employed for the Project. Mr. Haviland and Mr. Womack responded to issues regarding the causes of the increases, how the Company handled the challenges that arose on the Project and how it managed its contractors when the Company knew that it would no longer be able to complete the Project within the approved estimate, and the timeliness and completeness of the Company's updated cost estimate and IRP analyses. Mr. Haviland, Mr. Roebel, Mr. Womack, and Mr. Zupan also testified that Mr. Schlissel misinterpreted a number of documents on which he relied for his conclusions. Mr. Stultz testified that it would be imprudent and unwise to adopt Mr. Schlissel's proposal to impose an operations requirement that the IGCC Plant achieve at least 85% availability. Mr. Burch and Mr. Cooper responded to issues regarding the decisions related to the grey water disposal system. Finally, Duke Energy Indiana presented the testimony of an outside expert project management auditor – Dr. Patricia Galloway – who assessed Duke Energy Indiana's Project management and decision-making from the time it decided to consider an IGCC Plant until it submitted its $2.72 billion estimate and concluded that, except in regard to one issue, all of Duke Energy Indiana's actions were prudent. She

quantified the effect of that imprudence to be approximately $12 million, well within the $700 million amount that Duke Energy Indiana shareholders will assume.

In Phase I of this proceeding, the Parties' filed positions varied from recommending no increase to the previously-approved $2.35 billion cost estimate for this Project, to the Company's recommendation that we increase the approved cost estimate to $2.72 billion plus associated AFUDC (or approximately $3 billion). In Phase II, the Parties' filed positions varied from proposals to reduce the $2.35 billion approved cost estimate to the original cost estimate of $1.985 billion or even lower, to the Company's position that no reductions to the approved Project cost should be made. Notably, the previously-approved $2.35 billion Project cost estimate consisted of $2.225 billion in direct construction costs and $125 million in AFUDC costs (estimated at that point in time and assuming ongoing CWIP treatment). In comparison, the Hard Cost Cap in the 2012 Settlement Agreement consists of approximately $2.322 billion in direct construction costs, and approximately $273 million in AFUDC (as of June 30, 2012) – an increase of $97 million in direct construction costs over the previously approved Project cost estimate of $2.35 billion.

With regard to the 2012 Settlement Agreement's Hard Cost Cap and the proposal to modify the CPCNs consistent with the Settlement, in the Company's view the record in this case supports Commission approval of a new Project cost estimate up to $2.72 billion in direct construction costs plus applicable AFUDC as reasonable, necessary, and prudently incurred. In contrast, the Settlement provides for a modified Project cost for ratemaking and CPCN purposes of significantly less − $2.322 billion in direct construction costs plus associated AFUDC through June 30, 2012 (plus post-June 2012 AFUDC per the 2012 Settlement Agreement terms).

The Company emphasized there were three main drivers of the cost increase at issue in Phase I of this proceeding: (1) the need for a ZLD system for grey water (approximately $100 million); (2) the increase in required bulk commodity quantities (approximately $400 million) stemming from underestimations by the contractor; and (3) lower-than-anticipated labor productivity (and therefore higher labor costs), largely driven by the need for installation of substantially more bulk commodities.[27]

In the Company's view, there is substantial evidence to support up to $2.72 billion (plus AFUDC), totaling approximately $3 billion. Thus, there is certainly substantial evidence of record to support the significantly lower agreed-upon Hard Cost Cap (plus Additional AFUDC). While we do not adopt the Company's view of the evidence, we believe the record supports a finding that at least a portion of the requested increase in the Project cost estimate above the previously-approved Project cost estimate of $2.35 billion is reasonable and necessary, as the Settling Parties have agreed in the Settlement Agreement. Our review of the record leads us to the conclusion that at least a portion of the increased costs associated with the growth in bulk quantities, the ZLD grey water system, the increase in labor expenses associated in part with the growth in bulk quantities, and the growth in AFUDC, are reasonable and necessary and that the Company should be allowed to recover that portion of the increased costs.

Stated differently, the Commission does not have to accept the Company's analysis of the record, to conclude as we do that the Hard Cost Cap is nevertheless supported by substantial evidence. By way of example, it may be helpful to view the Hard Cost Cap in the Settlement in terms of the specific items that drove up the costs. The Hard Cost Cap could be seen to reflect inclusion of most of the ZLD costs ($97 million), plus AFUDC, but none of the increased bulk

[27] Plus additional AFUDC primarily related to the extended IGCC Rider proceedings.

commodity costs. Or it could be seen to reflect approximately 25% of the increased bulk commodity costs (again, $97 million), plus AFUDC, but none of the ZLD costs.

In Phase I, we must also ask ourselves whether imprudence affected any of the costs incurred and presented to the Commission in IGCC 4, IGCC 5 or IGCC 6; or when viewed from a different perspective, whether the approximately $700 million in disallowed costs covers any such imprudence.[28] We can conclude that customers will not pay for any imprudent costs – to the extent that any were incurred – based in part upon the following evidence of record: (a) the Company's resource planning processes are reasonable and consistent with its historical processes, which we have previously found to be reasonable (s*ee, e.g.*, CPCN Order at 31 (finding the Company's IRP methodologies to be "sound" and "reasonable")); (b) the increased bulk commodity quantities are needed for the Project and were driven by factors to some degree outside the control of the Company (*i.e.*, the bulk commodity quantity estimates were contractually the responsibility of its expert contractor, Bechtel, not Duke Energy Indiana); (c) the ZLD grey water system is also needed for the Project; and (d) the lower than expected labor productivity was largely driven by the need to install additional bulk commodities.

The issue in Phase II is whether the Company's actions at any point constituted gross mismanagement, concealment, or fraud. In the Company's view, there is no persuasive evidence of gross mismanagement, concealment, or fraud, and therefore, by definition there is substantial evidence that the recoverable Project cost up to at least the $2.595 Hard Cost Cap (plus Additional AFUDC) provided for in the Settlement should not be further reduced. While we, again, do not adopt the Company's position, the question presented to us in this proceeding by the Settlement Agreement is as follows: if there was any gross mismanagement, concealment, or

[28] We will ask this same question in IGCC 7 and IGCC 8.

fraud, is the impact of such adequately covered by the numerous financial concessions in the 2012 Settlement Agreement? In other words, based on the substantial evidence of record, can we conclude that there has been no gross mismanagement, concealment, or fraud with respect to any Project costs ($1.88 billion incurred through IGCC 6 on a retail jurisdictional basis)[29] that have been or will be recovered in rates? We can reach that conclusion, based in part upon the following evidence of record: (a) the Company engaged in a thirteen-month in-depth FEED Study in order to assess the risks and costs of the Project prior to proceeding; (b) the Company employed two world-renowned experts to prepare the FEED Study at the outset of the Project and also employed an independent estimating expert to review the FEED study estimate; (c) the changes made by the Company to the GE/Bechtel FEED study estimate were in areas other than the core areas of the Plant (*i.e.*, other than the power block and the gasification island), and were in areas not materially related to the major drivers of the cost increase; (d) the Company had previous experience with the development and construction of an IGCC powerplant (the Wabash River Repowering Project); (e) the Company had previously and successfully used similar contracting strategies and fully disclosed to the Commission and Parties its proposed contracting strategy for this Project; and (f) the Company regularly analyzed and re-analyzed the resource planning implications of Project cost estimate changes and presented those analyses to the Commission and parties.

In sum, it is clear from the comprehensive record in this Cause that the parties' filed and litigated positions represented a wide spectrum of outcomes, and the Settlement Agreement falls well within the realm of reasonable conclusions based on the evidence. While we will not totally adopt the Company's positions in either Phase I or Phase II, we also are not persuaded that the

[29] We will make similar inquiries in the IGCC 7 and IGCC 8 proceedings.

Company's positions in either Phase are totally without merit, as outlined above. Accordingly, the evidence of record supports a compromise position, such as that reflected in the Settlement Agreement.

In addition, the Settling Parties, including the OUCC, were well aware of the evidence of record in this proceeding. The Settling Parties reached the conclusion, as expressed in the Settlement and their testimony supporting the Settlement, that the increase in costs reflected in the Hard Cost Cap is reasonable and necessary and supported by the evidentiary record. Further, the Settling Parties reached agreement that the Settlement addresses any imprudence, fraud, concealment and gross mismanagement that might have existed, and testified to that effect. Our review of the entirety of the record leads us to the same conclusions, namely that the Hard Cost Cap reflects costs that are reasonable and necessary, and that the $700 million plus in Project costs that Duke Energy Indiana will be responsible for funding under the Settlement adequately addresses any imprudence, fraud, concealment or gross mismanagement that may have existed.

More specifically, the previously approved cost estimate included $2.225 billion in direct construction costs, and Duke Energy Indiana's April 2010 updated cost estimate increased the direct construction costs to $2.72 billion, an approximately $495 million increase. Over the course of the proceedings, the parties presented various estimates of the amount of disallowable costs ranging from Duke Energy Indiana's belief that all costs are recoverable, to the other parties' positions that all construction costs above $2.225 billion are due to imprudence and that fraud, concealment, or gross mismanagement should decrease Duke Energy Indiana's recoverable costs to $1.985 billion or lower. The Settlement Agreement permits recovery of only approximately $97 million in direct construction costs above the previously approved amount of $2.225 billion, and requires Duke Energy Indiana to shoulder at least $700 million in

costs. This reduction in the amount of the approved cost estimate falls within the proposed ranges that could be supported by the evidentiary record, is a reasonable resolution of the issues raised in Phases I and II, and will provide Indiana customers with a complete IGCC facility at just and reasonable rates. We find that substantial evidence supports the Hard Cost Cap in the Settlement Agreement, notwithstanding the Joint Intervenors' contentions to the contrary.

(3) Appropriateness of Recovery of the "First" $2.319 billion in Project Costs.

Joint Intervenors argue that the Settlement Agreement effectively treats the last dollars expended on the Project as the disallowed dollars, and therefore assumes that all of the earliest-in-time dollars expended on the Project up to the Hard Cost Cap are reasonable. Stated differently, the Joint Intervenors complain that the Settlement Agreement assumes that every dollar expended from the beginning of the Project up until construction costs reached $2.319 billion was prudent, thereby resulting in beneficial rate treatment to Duke Energy Indiana with respect to the timing of when those costs and associated CWIP and AFUDC are recovered. Joint Intervenors contend that the excluded or disallowed dollars should be considered to have occurred over the life of the Project – on an "S" curve or pro rata basis. Joint Intervenors, however, did not offer any specifics as to what such an "S" curve would look like.

As mentioned above, the evidence in this proceeding has focused largely on the three Project components that have driven costs above the approved $2.35 billion: (1) the need for a ZLD system; (2) significant increases in bulk commodity quantities; and (3) labor productivity costs associated largely with the bulk commodity quantity increases. These three factors, along with associated AFUDC, account for virtually all of the increase in the Project cost estimate above $2.35 billion. As Mr. Womack's settlement rebuttal testimony demonstrates, the pattern of expenditures for these three cost elements is not front-loaded, nor is it evenly spread over the

life of the Project. Rather, expenditures to address these developments are significantly backloaded, which caused most of the costs to be incurred late in the Project. Thus, Joint Intervenors' proposed "S" curve or *pro rata* methodology does not comport with the facts before us, and for this reason alone, Joint Intervenors' argument can be rejected.

However, even if one were to adopt the Joint Intervenors' *pro rata* calculation methodology, Mr. Freeman's settlement rebuttal testimony demonstrates that using such a *pro rata* methodology as compared to the Settlement Agreement's methodology would not produce a substantial change in the amount of disallowance.[30] Significantly, the differences these different timing methodologies produce is not substantial. We believe there is ample evidence in the record to conclude that the Settlement Agreement's disallowance of approximately $700 million in construction costs and AFUDC combined is reasonable, whether a backend loaded or a pro rata analysis is used. In other words, we agree with the Settling Parties that regardless of the precise breakdown between direct construction costs and AFUDC, there is ample evidence to conclude that a disallowance of almost $700 million and a resulting Hard Cost Cap of $2.595 billion is reasonable.[31]

These are the quintessential types of issues that, as we described above, represent the give-and-take and, ultimately, the balancing of interests necessary to achieve a settlement. If we

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[30] For example, Mr. Freeman's analysis – which analyzed the change in breakdown between construction costs and AFUDC while keeping the overall impairment amount at $700 million – resulted in a change from the Settlement Agreement's approximately $2.322 billion in direct costs plus approximately $273 million in AFUDC, to $2.353 billion in direct costs plus $242 million in AFUDC – an increase of $31 million in direct costs, and a concomitant decrease of $31 million in AFUDC costs. And if a backend-loaded analysis were used, in line with Mr. Womack's testimony concerning the actual pattern of expenditures for the drivers of the Project cost increase, would simply change the breakdown between construction costs and AFUDC from approximately $2.322 billion in direct costs plus approximately $273 million in AFUDC to $2.355 billion in direct costs plus approximately $240 million in AFUDC.

[31] As indicated by Mr. Freeman, the Settling Parties did not negotiate a specific breakdown between construction costs and AFUDC. Rather, they negotiated a specific hard cost cap/impairment amount, but for accounting reasons they specified a breakdown.

were to find that one such element was not reasonable, it would not necessarily render the settlement as a whole unreasonable. Specifically, the Settling Parties agreed to $2.595 billion as an overall amount of reasonable direct construction costs and AFUDC through June 30, 2012 that would be approved in this subdocket. They did not set a specific amount for AFUDC or construction costs. Stated differently, the Settling Parties agreed that Duke Energy Indiana shareholder responsibility for approximately $700 million of the costs of the IGCC Plant is a reasonable resolution of the issues presented in this proceeding. Any material change to the amount of AFUDC or direct construction costs the Company can recover would require a commensurate change to a different factor to maintain the agreed-upon balance. We thus find that Joint Intervenors' objections about whether Duke Energy Indiana is recovering the "first" $2.319 billion do not affect the overall reasonableness of the Settlement.

(4) Objections Concerning Continued Accrual of AFUDC and CWIP.

Joint Intervenors also object, without providing a legal basis, to the continuance of CWIP and to continued AFUDC accruals above the $2.595 billion Hard Cost Cap. However, recovery of financing costs on reasonable utility investments, whether through CWIP ratemaking or through AFUDC accruals, is consistent with traditional ratemaking and Indiana law. Under Ind. Code Chapter 8-1-8.8, this Project is eligible for CWIP ratemaking treatment, which necessarily results in recovery of financing costs while projects are under construction. Similarly, Ind. Code § 8-1-2-6(b) provides that interest (or financing) charges on projects under construction shall be included in rate base – in other words, that AFUDC should be accrued on projects while they are under construction and that such accrued AFUDC should be capitalized to the project's rate base. Thus, there is nothing unreasonable in allowing Duke Energy Indiana to continue accruing these legislatively allowed financing costs to the extent permitted under the Settlement Agreement, so

long as we find, as we have here, that the underlying capital costs to be recovered are reasonable and necessary.

(5) Retroactive Termination of Deferred Taxes.

Joint Intervenors assert that the deferred tax incentive was granted in order to motivate the Company to control Project costs, but this position is not supported by the language of the Commission's CPCN Order. Our CPCN Order indicates that we granted the deferred tax treatment as an incentive to undertake the Project and to maintain credit quality, consistent with Indiana statutory law which contemplates the authorization of financial incentives for IGCC Projects:

> Furthermore, the Commission generally considers credit quality to relate strongly to the availability of funds to pay debt capital cost. The ordinary treatment of deferred taxes could understate the project specific financing cost as noted by Mr. Farmer (Pet. Ex. 28, pg. 6). The treatment proposed by Duke [Energy Indiana] in its rebuttal testimony would appear to reduce this bias and serve as a financial incentive for the project . . . .
>
> An increased rate of return early in the life of the project provides for the availability of additional funds to pay debt capital costs and is supportive of credit quality. As project life passes, the accumulation of project specific deferred income taxes reduce rate base faster than under the ordinary approach, providing for a reduced revenue requirement in the future. The Commission recognizes that this treatment of deferred income taxes acts as an additional incentive that serves to maintain credit quality and is consistent with the provisions set forth in IC 8-1-8.8-11(a)(5). Considering this benefit and the cost of attaining it, we find that excluding deferred income taxes from the capital structure and instead applying them as an off-set to rate base to be reasonable treatment in the conditions specific to this proceeding.

CPCN Order at 58. Our order reflects that, rather than tying the incentive to cost control, we granted the incentive pursuant to Ind. Code Chapter 8-1-8.8-11, which authorizes a number of financial incentives for IGCC projects, including "other financial incentives the Commission considers appropriate." Subsequently, when the Company presented its $2.350 billion estimate for approval, we declined to extend the deferred tax treatment beyond the initially approved

$1.985 billion estimate and also declined to retroactively revoke the deferred tax treatment for the $1.985 billion estimate. IGCC 1 Order at 21, 28-29.

We have therefore already limited the deferred tax treatment to the original $1.985 billion estimate and we decline to retroactively revoke the deferred taxes provision because the incentive is allowable for a project like Edwardsport and Joint Intervenors have not shown that it is unreasonable. Moreover, any such change would materially affect the balancing of interests achieved by the Settlement Agreement. Of course, the Settlement Agreement does provide a further customer benefit by eliminating these deferred tax incentives prospectively, and the Company will recover no additional revenue from the deferred tax incentive once this provision of the Settlement Agreement is implemented in the IGCC Rider proceedings.

(6) Whether the Hard Cost Cap is a Floor.

Joint Intervenors' contention that the $2.595 billion is a floor, not a hard cap, is similarly misguided. As Mr. Esamann recognized, the Commission will decide in IGCC 5, 6,[32] 7, and 8 whether actual incurred Project costs up to the Hard Cost Cap are prudent and should be recovered. Pet. Ex. JJJ-S at 6:7–23 (Esamann Reb.). The Settlement Agreement submitted in this Cause simply fixes the maximum amount of Project costs that will be eligible for recovery in the applicable IGCC Rider proceedings, and reflects the Settling Parties' agreement among themselves that they consider those costs to be reasonable, prudent, and necessary and that they should be recovered in such applicable IGCC Rider proceedings. The Hard Cost Cap does represent the maximum amount the Company will recover for AFUDC through June 30, 2012, and all direct construction costs. It is true that recovery of CWIP and some Additional AFUDC

[32] Note that the ongoing review portions of IGCC 5 and IGCC 6 have been incorporated into this proceeding, and we have found that costs incurred through IGCC 6, which are below the Hard Cost Cap, are recoverable.

will take place with respect to the Hard Cost Cap amounts, if approved in separate IGCC Rider proceedings, but, as discussed above, the Company is entitled to recover those financing-type costs on underlying costs found to be reasonable. Moreover, as both Mr. Freeman and Mr. Gorman testified, the amount of Project Costs receiving CWIP ratemaking treatment to date is approximately $887 million, well below the Hard Cost Cap; Project cost estimates under the CPCN statute never reflect ongoing CWIP recoveries; and the total estimated amount of CWIP charges customers will pay pursuant to the Settlement Agreement ($663 million) is not substantially different from what customers would have paid under the previously approved $2.35 billion Project cost estimate ($627 million).

(7) In-Service Criteria and Construction Costs Incurred After the IGCC Plant is Declared In-Service.

We decline to impose the additional requirements Mr. Schlissel proposes before the plant can be declared "in-service." The Settlement Agreement provides that the Project will be declared in-service in accordance with FERC guidelines – *i.e.*, when the facilities have been tested and are placed in, or are ready for, service – and on a date after September 24, 2012 when it has operated on both natural gas and syngas. Settlement at 3; *see also* Pet. Ex. KKK-S at 3:22–4:20 (Wiles Reb.). The FERC guidelines also comport with guidance provided by the Indiana Court of Appeals, which defined the test for determining a plant's used and useful status, *i.e.*, if it is in-service, as requiring "(1) that the utility plant be actually devoted to providing utility service, and (2) that the plant utilization be reasonably necessary to the provision of utility service." *City of Evansville v. S. Ind. Gas and Elec. Co.*, 339 N.E.2d 562, 589 (Ind. Ct. App. 1975); *see also In re PSI Energy, Inc.*, Cause No. 40003, 1996 Ind. PUC LEXIS 411 at *18-24; 172 P.U.R.4th 393 (Sept. 27, 1996). Because the Settlement Agreement's in-service requirement

is at least as stringent as FERC's guidelines and our precedent, it is reasonable, and Mr. Schlissel has not provided any basis to deviate from industry standards.

Similarly, we reject Mr. Schlissel's proposal that we require the IGCC Plant to operate for a specific amount of time before it can be deemed "in-service." We rejected just such a proposal in a previous case involving the in-service determination for another coal gasification plant. *See In re PSI Energy, Inc.*, 1996 Ind. PUC LEXIS 411 at *18-23. In that 1996 case, we rejected a proposal that the project achieve 100 hours of continuous operation of the entire integrated project to be considered "in service." We noted that, "as an approved 'clean coal technology' project pursuant to Ind. Code 8-1-8.7 [the project] may be entitled to a lower than normal standard." *Id.* at *21. We reiterate that holding here. Finally, Mr. Schlissel's attempt to tie the in-service requirement to completion of GE's NPI program is misplaced. GE's NPI program is a contractual requirement – conducted at least partially for GE's purposes and benefit (Pet. Ex. LLL-S at 2:16-3:19 (Womack Reb.) – intended to validate design criteria for multiple pieces of equipment in multiple scenarios, some likely and some not, and has no relevance to whether the plant is operating and providing benefits to customers. Edwardsport will in fact be dispatching energy into the MISO markets long before GE completes its contractual NPI testing, and there is no reasonable basis to delay declaring the plant in-service when it is already providing benefits to customers.

We similarly find Joint Intervenors' contention that the Company will be able to seek recovery of Construction Costs beyond the Hard Cost Cap once the plant is declared in-service to be unfounded. The Settlement contains detailed guidelines for what types of costs must be capitalized as construction costs – and, therefore, be subject to the Hard Cost Cap – in accordance with FERC guidelines and "includes all costs required to achieve 'final completion'"

as defined in Duke Energy Indiana's contract with GE. Conversely, costs that are truly unrelated to the completion of the Project – *i.e.*, normal post-in-service O&M costs, as well as post-in-service capital for normal capitalized repairs or maintenance expenditures or additional plant and equipment necessary for the continued operation of the Project (unless identified during start-up, testing, validation, and commissioning as being necessary to reach "final completion") – will properly be excluded from Construction Costs subject to the Hard Cost Cap. As with most large construction projects, some Construction Costs will be incurred after the in-service date, but because they will be above the Hard Cost Cap, Duke Energy Indiana will not be able to seek recovery of those costs. Any party will, of course, have the opportunity to raise objections in future proceedings if they believe Duke Energy Indiana is seeking recovery of costs that should be categorized as Construction Costs. Such concerns are properly raised at that time. We decline to impose requirements based on speculation about what might happen in the future, especially where, as here, procedures exist to address any such future concerns.

(8) Operational Requirements.

Similarly, it is premature at this time to impose penalties if the plant does not meet specified levels of operational efficiency, as the Joint Intervenors propose. Such a proposal is outside the bounds of the statutory construct limiting our review to the "estimate of construction, purchase, or lease costs" of the proposed facility. *See* Ind. Code. § 8-1-8.5-5(a). As we recognized in earlier proceedings, we have no statutory basis to limit the Company's rate recovery as Mr. Schlissel proposes. *See* CPCN Order at 38-39 ("The contention that an 82% capacity factor is the minimum capacity factor needed to make the plant commercially reasonable was effectively rebutted and *there is no statutory basis for limiting the Company's rate recovery based on the plant achieving a certain minimum capacity factor*.") (emphasis

added). Furthermore, the record supports a conclusion that it would be inappropriate and possibly detrimental to emphasize one performance measurement metric – *e.g.*, availability – to the potential detriment or negative impact on other metrics like safety or environmental impact. *See, e.g.*, Nov. 7, 2011 Tr. at P-44:2–45:23 (Stultz).

Furthermore, we find that this request to include performance guarantees as part of the capital cost cap is premature and speculative. If issues arise after the plant begins operations then those issues can be dealt with at that time. We will not speculate now about possible challenges that might arise in the future and whether they might be caused by Duke Energy Indiana's imprudent conduct. To the extent any party has a legitimate concern about the prudence of the IGCC Plant's operations and future costs, we have adequate processes and procedures in place to address the prudence of the Company's expenditures relating to those future events. Indeed, the Settlement Agreement specifically preserves the right of the Parties to make arguments and seek relief concerning the post-in-service operating performance of the Project. For all of these reasons, we will not set operational requirements for the IGCC Plant.

(9) CO_2 Mitigation.

Consistent with our prior orders concerning the Project, we decline Joint Intervenors' request – raised for the first time in this Cause in Settlement testimony – to require Duke Energy Indiana to address CO_2 mitigation. The Company has complied with all of the Commission's orders that required a study of CCS and provision at Edwardsport for possible implementation of CCS in the future, but we did not impose any other steps when we approved the CPCNs, and no party raised this issue previously in this Cause. Duke Energy Indiana might have agreed to such a requirement as part of an overarching settlement, but we are not in a position to impose such a requirement because it would alter the economic balance of the Settlement. Further, there is no

reason to impose CO_2 mitigation at this time because there are no current regulations or legislation requiring CCS, there is no carbon tax in the offing, and there is no mandated participation in a carbon emissions allowance market. It arguably would be imprudent to require such a requirement without having performed further cost analyses based on current conditions and because deferring any potential implementation plans will preserve Duke Energy Indiana's ability to incorporate any advancements in technology that may occur before CO_2 mitigation becomes required by regulation or legislation. As the OUCC's witness, Ms. Barbara Smith, testified, under the circumstances today, there is no basis or economic justification for requiring additional CCS measures for Edwardsport.

Further, we find that Duke Energy Indiana has adequately considered renewable and energy efficiency options in its resource planning and has demonstrated that an IRP plan that considers alternatives similar to those Mr. Kanfer suggested would be more costly for customers.

(10) Whether the Regulatory Process was Corrupted.

We once again decline the Joint Intervenors' request to consider allegations that the regulatory process was corrupted. We have on numerous occasions, both in writing and during the hearings, denied Joint Intervenors' attempts to add allegations of *ex parte* communications, improper communications, conflicts of interest, undue influence, or other misconduct except to the extent that such allegations were relevant to the issues of fraud, concealment and gross mismanagement.. *See, e.g.*, Feb. 25, 2011 IURC Docket Entry at 2; Oct. 18, 2011 IURC Docket Entry at 3; Mar. 23, 2012 IURC Docket Entry at 2. To the extent that OUCC, IG, or Joint Intervenors have presented evidence of *ex parte* communications that is relevant to the cost recovery issue of Phase II, these allegations have been adequately addressed by the $700 million disallowance of the Settlement Agreement. We re-emphasize here, as we have in the past, that

the investigation of any alleged undue influence unrelated to the issues in this Cause should be the subject of independent investigations by other agencies that have both the expertise and the authority to investigate and prosecute such alleged misconduct.

(11) Delays in Project Completion.

Joint Intervenors' witness Schlissel testified that the forecast dates for "project in-service" and for "substantial completion" have slipped from earlier estimates with the result "that the Company would be accruing AFUDC and collecting revenues from its customers related to the $2.595 billion in CWIP-related revenues for perhaps 6 to 9 months (or longer) before the Project is in commercial operation," and all of these costs would be above the Settlement Agreement's Hard Cost Cap. JI Ex. M-S at 6:5-12 (Schlissel Dir.) (internal citations omitted). Mr. Schlissel then recited various "issues and problems in the start-up and testing phase," including what he believed "to be a significant dispute between GE and Duke [Energy Indiana] regarding the scheduling and progress being made in start-up testing, validation and commissioning activities." *Id.* at 7:5, 8:13-15. Based on these reports, Mr. Schlissel concluded that

> [t]his information suggests (1) that the actual start of sustained commercial operations at Edwardsport may occur significantly later than Duke [Energy Indiana] has so far acknowledged to the Commission; (2) that Duke [Energy Indiana] may be seriously mismanaging the start-up testing, validation and commissioning program at Edwardsport; and (3) that Duke [Energy Indiana] may be imprudently rushing start-up, testing and commissioning activities in order to try to get Edwardsport into service as soon as possible.

Id. at 11:29-12:1.

In response, Mr. Womack testified that Duke Energy Indiana has consistently updated the Commission in its IGCC Rider proceedings about the forecasted schedule, including any schedule extensions that were caused by the need to install additional quantities of bulk

commodities or unusually adverse weather. Pet. Ex. LLL-S at 7:18-21 (Womack Reb.). According to Mr. Womack, all of the required schedule extensions have been reasonable given the circumstances of the Project, have been disclosed as they became known, and were caused largely by circumstances outside of the Company's control. *Id.* at 7:21-8:1. Moreover, Mr. Womack emphasized that the original schedule estimate, developed in 2007, was just that – an estimate, subject to change as conditions have changed. *Id.* at 8:1-2.

The Joint Intervenors' arguments are unpersuasive for three primary reasons. First, Mr. Schlissel's testimony is in large part speculative and premature. He posits "that Duke [Energy Indiana] *may* be seriously mismanaging the start-up testing, validation and commissioning program," and "that Duke [Energy Indiana] *may* be imprudently rushing start-up, testing and commissioning activities." JI Ex. M-S at 11:31-12:1 (Schlissel Dir.) (emphasis added). The Company's or GE's observations about problems currently being encountered and addressed are not probative evidence of imprudence or of what might occur in the future. In other words, without more, the fact that the Project encountered a problem or that there was a disagreement with a contractor does not mean that the Company or the contractor acted imprudently or that the problem might not be resolved as the Project start-up proceeds. Moreover, any contentions about future schedule delays or the Company's ongoing management of start-up and testing will be appropriately addressed in the individual IGCC Rider proceedings covering those activities. Mr. Schlissel's conjecture is not probative evidence relevant to this Settlement Agreement.

Second, to the extent that Mr. Schlissel challenges the Settlement Agreement based on the absence of any provision to account for a delay in the scheduled Project in-service date, the Settlement Agreement makes clear that the Settling Parties considered delays that have occurred to date as part of their settlement package. As an example, provision 2.F. of the Settlement

Agreement discusses the In-Service Operational Date, and provision 3 explicitly recognizes the "uncertainty as to the actual In-Service Operational Date." Accordingly, schedule delays were factored into the Settling Parties' agreement as to a Hard Cost Cap that produces a disallowance of at least $700 million. Furthermore, if there are subsequent delays in Edwardsport's commercial operations that increase Project Construction Costs, the Company will bear those costs because they will exceed the agreed upon Hard Cost Cap. Indeed, under the Settlement Agreement, the Company will also recover only 85% of its actual AFUDC costs if the Project's in-service date is delayed beyond November 30, 2012 − a clear assignment of this portion of the delay risk to Duke Energy Indiana, not to customers. We conclude that the risk of future schedule delays is adequately and appropriately addressed in the Settlement Agreement, and no change is warranted.

Third, the record demonstrates that the delay in the scheduled Project in-service date when compared with the originally estimated date is largely driven by the same factors that caused costs to increase − the increase in required bulk commodity quantities and the related lower-than-expected labor productivity. As we have concluded, the Hard Cost Cap and the limitations on Duke Energy Indiana's cost recovery reasonably account for those factors, including the resulting schedule delay.

(12) Attorney Fees and Contributions.

Finally, there is no evidence that the settlement negotiations were conducted in bad faith or were corrupted in any way by Duke Energy Indiana's shareholders' payment of attorney fees and costs. Under provision 9 of the Settlement, Duke Energy Indiana has agreed to pay, out of shareholders' funds, a total of $20 million associated with the fees and expenses of the other Settling Parties and contributions to specified customer-benefiting programs. The sums include

$11.7 million in attorney fees and $600,000 in expenses to the IG, between $800,000 and $1 million for fees and expenses to Nucor, up to $300,000 for reimbursement of expert consulting fees of the OUCC, $2 million to the Indiana Utility Ratepayer Trust, $3.5 million to Indiana LIHEAP and a $1 million contribution to a clean energy initiative to be collaboratively developed by Duke Energy Indiana and the OUCC.

The sums provided for in provision 9 are to be paid by Duke Energy Indiana from shareholders' funds, and therefore represent financial commitments to be borne solely by the Company, separate and apart from the rate and regulatory provisions in the Settlement. The payments by Duke Energy Indiana of fees, expenses and contributions and the specified amounts were negotiated and agreed to by the Settling Parties through arms'-length bargaining, by duly informed and knowledgeable representatives familiar with all the relevant circumstances. *See* Pet. Ex. HHH-S at 3:10-19 (Esamann Dir.); Pub. Ex. 1-S at 2 (B. Smith Dir.); July 16 Tr. at CCC-17:3–11 (Esamann). Because the payments are coming from shareholders' funds, Duke Energy Indiana had direct financial incentive to negotiate for no more than amounts that it deemed to be reasonable and justified. In addition, the OUCC, as statutory advocate for ratepayers, has endorsed the provisions of the Settlement, including the provisions of provision 9, as being reasonable and in the public interest.

Insofar as the payments and contributions under provision 9 are voluntary commitments agreed to by Duke Energy Indiana to be funded by its shareholders, the terms of provision 9 do not affect the customer rates, charges and terms of service over which the Commission exercises regulatory authority. The situation here is thus distinct from cases involving common fund awards, by which, for example, the amount of a utility refund may be reduced so that a portion of a ratepayer recovery can be used to pay attorney fees and litigation expenses associated with the

creation of the common fund. In that instance, the award has the effect of diminishing the net financial benefits realized by ratepayers, and the Commission accordingly applies appropriate scrutiny to ensure that the amounts funded by ratepayers are reasonable. Here, by contrast, Duke Energy Indiana will be paying amounts that the Company has agreed to pay. The Commission has little need to protect the Company's shareholders from the funding commitments negotiated by Duke Energy Indiana's authorized representatives.

The Settling Parties properly disclosed the commitments set forth in provision 9 as terms agreed to as part of the Settlement, even though the payments and contributions will be made from shareholder rather than customer funds. In their evidentiary submission opposing the Settlement, the Joint Intervenors did not identify in any respect which terms of provision 9 were supposedly unreasonable, excessive or inappropriate, or otherwise caused the Settlement as a whole to be unjust, unreasonable or contrary to the public interest. The only reference in this regard was contained in the Supplemental Responsive Testimony of Kerwin L. Olson, at p. 6, which proposed Commission scrutiny of the payment of fees and expenses by the Company . However, that testimony did not allege that the amounts were substantively inappropriate and did not identify any alleged impropriety in the Settlement negotiation. Counsel for Joint Intervenors, furthermore, expressly clarified that collusion was not being alleged. *See* July 16 Tr. at FF-35:16–17 (Agnew, Motion to Dismiss). In light of the undisputed record that the commitments of provision 9 will be entirely funded by Duke Energy Indiana shareholders, the extensive ratepayer benefits arising from the Settlement are unaffected by those payments, and no party has introduced any evidence challenging the amounts Duke Energy Indiana has agreed to pay, the Commission finds the terms of provision 9 are consistent with the determination that the Settlement is reasonable and in the public interest and should be approved.

Notwithstanding that context, at the outset of the evidentiary hearing on July 16, 2012, Joint Intervenors submitted a Motion to Dismiss for Insufficiency of Evidence, alleging the Settling Parties had not presented evidence to demonstrate that the amount of attorney fees and litigation expenses to be paid under provision 9 was reasonable. Following oral argument, the motion was denied by the presiding Judge. Joint Intervenors appealed that ruling to the full Commission, which affirmed. Counsel for Joint Intervenors renewed the motion at the close of the hearing. The motion was again denied.

The prefiling schedule established by the Commission for the presentation of evidence bearing on the Settlement provided Joint Intervenors with opportunity to raise in their evidentiary submission any issues or concerns relating to the Settlement that they wished the Commission to consider. The schedule further afforded the Settling Parties an opportunity to address in their prefiled rebuttal evidence any issues raised by Joint Intervenors. By waiting until the opening of the evidentiary hearing to assert an alleged concern relating to the payments that Duke Energy Indiana agreed to make, Joint Intervenors ignored the schedule set by the Commission and procedurally prejudiced the Settling Parties by raising the potential concern after the rebuttal filing date had already passed. Any issues that Joint Intervenors wished to assert regarding the terms of provision 9 could and should have been raised in accordance with the procedural schedule established by the Commission. The Motion to Dismiss was properly denied, therefore, as untimely and contrary to the intended purpose of prefiling requirements.

Joint Intervenors contend that the Settlement must be reviewed by the Commission applying the same standards and principles used by federal courts in connection with settlements in class actions. Most of the authorities cited in support of the motion involved federal class action settlements. The Indiana Court of Appeals, however, expressly rejected the proposition

advanced by Joint Intervenors in *Citizens Action Coalition v. Northern Indiana Public Service Co.*, 796 N.E.2d 1264, 1267-68 (Ind. Ct. App. 2003), *transfer denied*, 812 N.E.2d 799 (Ind. 2004). With specific reference to a challenge to an attorney fee provision in the settlement of a rate proceeding, the Court explained the material differences between federal class actions as opposed to regulatory settlements in which the Commission makes independent determinations of the public interest and the OUCC performs the function of representing ratepayers. The Court concluded: "Consequently, the concerns inherent in class action litigation simply do not exist in utility rate cases. As a result, Joint Intervenors' contention that class action principles must be used in approving a settlement must fail." *Id.* at 1268. Notably, while arguing federal class action standards should be applied and relying on such decisions, Joint Intervenors here did not cite to or attempt to distinguish the Indiana Court of Appeals decision expressly rejecting the same position.

Joint Intervenors cite *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401 (Ind. Ct. App. 1996), which involved a common fund award from a utility refund, and hence involved a reduction in the amounts being credited to ratepayers in compensation for prior utility overcharges. Similarly, most of the federal class action cases cited by Joint Intervenors involved common fund awards reducing the amount of the recovery to the class of beneficiaries. In this case, by contrast, the amounts provided for in provision 9 are being paid by Duke Energy Indiana out of shareholders' funds, without any reduction, offset or adverse impact on the ratepayer benefits arising from the Settlement. The concerns arising from requested awards that would be funded by ratepayers are not present here, where shareholders will cover payments that the Company has agreed to make.

The Motion to Dismiss, nevertheless, raised a theoretical concern that a fee provision in a class settlement might be the product of improper "collusion," by which the defendant in a class action could potentially secure agreement to an unreasonably low settlement on the merits in exchange for an unreasonably high payment of fees and expenses. The Joint Intervenors did not present any evidence, however, that any such improper collusion actually occurred in connection with the negotiation of this Settlement. To the contrary, counsel for Joint Intervenors was explicit in stating: "Just to be clear, I'm not alleging collusion." *See* July 16 Tr. at FF-35:16–17 (Agnew, Motion to Dismiss). And the record is also clear that all provisions of the Settlement Agreement, including provision 9, were negotiated on an arms'-length basis. *See* Tr. at GG-16.The position of Joint Intervenors rests on an unfounded theory of potential collusion which there is no basis here to infer or presume, and which counsel for Joint Intervenors expressly disclaimed. The Commission will not assume without proof that the Settling Parties acted in bad faith, where the resulting Settlement produces very substantial results for ratepayers and the record substantiates the conclusion that the Settling Parties engaged in arms'-length, bona fide negotiations and did so specifically with regard to the agreed payment of fees and expenses. *See* July 16 Tr. at CCC-17:3–11 (Esamann). Joint Intervenors have not demonstrated that the Settling Parties, in addition to presenting a Settlement that has been shown to be entirely reasonable and in the public interest, had a further burden to prove a negative with affirmative evidence that each particular provision was not the product of improper collusion. Even if evidence negating collusion were needed, the Settling Parties provided it with unrebutted, sworn testimony confirming that the Settlement was the product of diligent, arms'-length negotiations. *See* Pet. Ex. HHH-S at 3:10-19 (Esamann Dir.); Pub. Ex. 1-S at 2 (B. Smith Dir.); July 16 Tr. at CCC-17:3–11 (Esamann).

To the extent that the Motion to Dismiss nevertheless suggests the record is insufficient here to support the conclusion that the terms of provision 9 are reasonable in the context of the Settlement as a whole, the Commission disagrees. Even in cases where a fee award comes out of a common fund and thereby diminishes a financial recovery to ratepayers, the Court of Appeals has held that the reasonableness of the amount is appropriately determined by reference to the magnitude of the tangible economic benefits achieved through the litigation, in addition to consideration of the amount of effort expended by the litigants to produce the results. *See CAC*, 664 N.E.2d at 406-08 (holding Commission has wide discretion in computing fee awards, and may base an award on a percentage of a utility refund cross-checked with a lodestar calculation). Joint Intervenors are mistaken in describing the lodestar approach as the "preferred" method in common fund cases. *See* Motion to Dismiss at 8. *Compare CAC*, 664 N.E.2d at 407-08 (noting the prevailing trend in federal law favoring percentage method).

In this case, the amounts that Duke Energy Indiana has agreed to pay out of shareholders' funds for the fees and expenses of the Settling Parties are commensurate with the stakes of the litigation and the magnitude of ratepayer benefits realized through the Settlement. The resulting rate benefits are projected to be on the order of $1.7 billion over the life of the plant. *See* IG Ex. MG-D-S at 4:15-5:14 (Gorman Dir.). In relation to that level of financial results on behalf of ratepayers, the fees and expenses provided for in provision 9 are not excessive.[33]

While Joint Intervenors expressed a desire to pursue additional discovery, there is no indication that they even requested supplemental discovery informally, and they certainly did not seek relief through the ordinary process of a motion to compel. *See* Ind. Trial Rules 26(F),

[33] Compare *CAC*, 664 N.E.2d at 410 (noting fee awards in common fund cases involving recoveries of $100 to $200 million typically range from 4%-10%). Notably, the total amount of attorney fees and litigation expenses payable by Duke under Paragraph 9 in this case is less than the award at issue in the Marble Hill case, which nearly twenty years ago was $14.25 million. *See* 664 N.E.2d at 410.

37(A). Insofar as they were seeking disclosure as to the substance of the settlement negotiations underlying provision 9, the asserted objections in any event were properly lodged. *See Citizens Action Coalition v. Northern Indiana Public Service Co.*, 812 N.E.2d 814, 819-20 (Ind. Ct. App. 2004) (affirming denial by Commission of discovery and cross-examination relating to negotiation of fee provision in settlement).

The Commission has great familiarity with the history of this dispute, the complexity of the issues and the extensive level of resources and effort brought to bear by the Settling Parties representing ratepayers in successfully bringing it to the resolution set forth in the Settlement. In addition to the presiding Administrative Law Judge, all five members of the Commission attended the hearings in this matter and personally observed the evidentiary presentations and the performance of the litigants and counsel. The Commission therefore is able to draw on direct firsthand experience in assessing the suggestion by Joint Intervenors that provision 9 might potentially overstate the value of the services performed by the ratepayer Settling Parties in such a way as to give rise to an inference of improper collusion. The Commission finds such an inference is unwarranted here. Throughout the hotly contested and extraordinarily complicated litigation, Duke Energy Indiana was vigorously represented by skilled counsel and devoted considerable resources to presenting its positions with intensive determination. Counsel for the other Settling Parties, in turn, brought a corresponding dedication to the proceedings and represented ratepayer interests with skill and energy, reflecting a wealth of experience in the specialized practice of utility regulation and diligent breadth in addressing the diverse scope of issues effectively. The services for which compensation is provided in provision 9 were skillfully performed and effective both in the conduct of contested litigation against a determined

institutional adversary, as well as in the negotiation of a Settlement resolving extraordinarily complex and difficult litigation on terms highly advantageous to ratepayer interests.

Regardless of whether our approval of shareholder funding commitments is necessary, the Commission concludes that the terms of provision 9, in light of the record in this case and the underlying circumstances, are reasonably scaled to the stakes of the dispute, the magnitude of the litigation, the extent of the benefits achieved for ratepayers, and the level of effort required to reach the settled resolution. Given the agreement by Duke Energy Indiana to make the payments under provision 9 out of shareholders' funds, the active involvement by the OUCC in negotiating the Settlement and its endorsement of provision 9, and the absence of any evidence by Joint Intervenors that the agreed payments are substantively excessive or the product of any improper collusion, the Commission finds the provisions of provision 9 to be reasonable and consistent with the determination that the Settlement as a whole is in the public interest and should be approved.

E. <u>Guidance for Future Large-Capital-Cost CPCN Proceedings</u>.

Although we approve the Settlement Agreement, all of the participants − including the Commission − have also learned useful lessons from their experiences with Edwardsport. The Edwardsport Project is one of the largest, if not the largest, construction project ever undertaken in the State. Moreover, as we noted, this case raised several important legal issues for which there is no precedent before this Commission or in Indiana. Importantly, as we heard throughout this proceeding from all the parties, Edwardsport is the first IGCC plant at this size in the United States. Finally, in terms of the volume of documentary and testimonial evidence, this is among the very largest proceedings ever before this Commission. Each of the Commissioners themselves has devoted substantial time and resources in hearing and analyzing the enormous

evidentiary record. Given the groundbreaking nature of this Project and this case, therefore, it is not surprising that there are important lessons that can be learned.

Based on what we have learned, and with the benefit of hindsight, we provide the following guidance for future CPCN proceedings. We do not imply any fault, but we emphasize these principles for similar future CPCN proceedings involving utilities' large capital projects.

First, we recognize that the Company has provided the Commission and parties with a significant amount of information about the Project, beginning with the CPCN case in 2006-2007, and throughout the IGCC ongoing review filings at subsequent six-month intervals. This information included responses to specific Commission requests for information. Nevertheless, and in hindsight, this information did not necessarily prove to be sufficient in this case. Accordingly, in the future, we will expect a utility seeking a CPCN for a large capital project to provide greater detail about the nature of the cost estimate, the degree of confidence it has in the estimate, the accuracy associated with the estimate, and the probability of achieving the cost estimate. We realize, as we have said before, that an estimate cannot be expected to be perfect, and we do not expect utilities to be able to foresee every eventuality in a complex project that may be subject to myriad outside influences that are beyond the utility's control (*e.g.*, greater than anticipated commodity price inflation). Nevertheless, we do expect a utility to identify what it does not know as well as what it does know, including the reasonably anticipated risks that the project estimate could be wrong. The availability of this information at the earliest planning stages will better permit the Commission to evaluate the proposed project in light of available alternatives.

Second, utilities should also identify, to the extent possible, the greatest risks to the project costs and schedule based on the expected execution plan. It is not enough to hire

experienced contractors or experts, because a project may still go awry, particularly at the interfaces between the utility and the contractor or between contractors. Once the risks to project execution have been identified, the utility should specify the steps it is taking to mitigate and control those risks. With this information, the Commission will be better able to monitor and evaluate the project as it progresses.

Third, to the extent it is cost effective to do so under the circumstances, we expect utilities to conduct benchmarking studies, to collect market intelligence, to obtain second-opinion cost estimates when warranted, and to amass an appropriate level of experienced internal project managers to develop accurate cost estimates and to minimize the likelihood of a large cost increase. At the same time, we encourage utilities embarking on large construction projects to seek outside expertise, as well. Indeed whether the project would best be done in-house or purchased from outside providers needs to be reviewed as both a matter of cost and a matter of risk. If the utility decides to manage or execute a project itself, it must be recognized that no utility has sufficient resources in-house to manage or execute a novel project alone, and all utilities could benefit from objective, independent expert advice. The Commission would benefit − as it has in this proceeding − from the views of unbiased experts who are familiar with the project and can offer their impartial assessments.

Finally, we realize that utilities have valid, reasonable reasons for structuring their cost estimates as they do – for example, developing their cost estimates to achieve the lowest price at which they believe they can complete the project so as to provide the greatest value to customers – and we fully support such approaches. Utilities should explain such strategies to us, however, so that we fully understand the context of the cost estimate. Moreover, although we understand the need to adapt estimate organization in order to use it for control purposes, we expect the cost

estimates submitted to the Commission to be prepared in a consistent manner over time so that we can track changes and identify the causes for any cost increase. While the utility may be able to trace costs through its own sophisticated accounting system, the Commission needs a more consistent estimate formatting and cost reporting mechanism that will permit it to identify emerging concerns more easily.

We expect utilities seeking CPCN approval for a major project to keep these principles in mind and to address them specifically in their applications. The Commission, interested parties, and the utilities will all benefit from greater transparency and communications so that there are fewer surprises as complex, costly projects proceed through the planning, execution, and commissioning phases. The Edwardsport Project proceedings, while undoubtedly painful for everyone involved, will have proved worthwhile if it marks the initiation of enhanced clarity and predictability in future CPCN proceedings.

F. <u>Ultimate Findings</u>.

Based on the foregoing, we find as follows:

(1) the Settlement Agreement is reasonable, equitable, and in the public interest, and should be approved in its entirety, as outlined above and consistent with our orders in Cause Nos. 43114-IGCC 5, 6, 7 and 8 issued contemporaneously with this Order;

(2) the Edwardsport IGCC Project remains needed, and it is in the public interest for the Project to be completed;

(3) the current best cost estimate for completion of the Edwardsport IGCC Project is $2.98 billion, plus applicable AFUDC (estimated to total approximately $3.3 billion);

(4) the CPCNs for the Edwardsport IGCC Project, issued pursuant to Ind. Code Chapters 8-1-8.5 and 8-1-8.7, should be and are hereby modified to allow the Company to only

recover up to the Settlement Agreement's Hard Cost Cap amount ($2.595 billion) plus Additional AFUDC as specified in the Settlement Agreement;

(5) the Company's ongoing progress review reports presented in Cause Nos. 43114-IGCC 4, 5 and 6 are hereby approved;

(6) Project costs incurred up to the Settlement Agreement's Hard Cost Cap, to the extent presented in this Cause (i.e., the amounts presented through Cause No. 43114-IGCC 6), are reasonable and are not affected by imprudence, gross mismanagement, concealment, or fraud;

(7) the Company is authorized to update and modify its depreciation rates as reflected in provision 5.A of the Settlement Agreement, and to adjust the IGCC Rider accordingly, upon the Commission's Electricity Division's acceptance of tariffs consistent with such provision of the Settlement Agreement;

(8) the Company is further authorized to modify its depreciation rates so as to move from accelerated depreciation to non-accelerated depreciation for certain specified qualified pollution control property/clean coal technology, as specified in provision 5.B of the Settlement Agreement, without making a corresponding adjustment to its base retail electric rates at this time (such base rate adjustment to be made instead at the time of the Company's next retail base rate case);

(9) the Company is authorized to terminate, prospectively, the deferred tax/capital structure financial incentive previously authorized for this Project, consistent with provision 6 of the Settlement Agreement;

(10) the interim and subject to refund provisions of our interim order in Cause No. 43114-IGCC 4 shall be removed consistent with the implementation of the Settlement Agreement;

(11) consistent with the CPCN Order, Petitioner shall have authority to continue to accrue AFUDC after the in-service date of the IGCC Project on the Hard Cost Cap and Additional AFUDC amounts, and to defer operating expenses to the extent that costs are not reflected in Duke Energy Indiana's retail electric rates (*i.e.*, through the IGCC Rider or in base rates

(12) generally consistent with our CPCN Order, but as modified by the Settlement Agreement, the Company shall continue to have authority to defer, for subsequent recovery over a 3-year period, post-in-service O&M, depreciation and property tax expenses associated with the Project, as outlined in the Settlement Agreement;

(13) the Company shall segregate on its books and records the Hard Cost Cap costs (plus Additional AFUDC per the Settlement Agreement) from the impairment costs, so as to ensure that in future retail electric rate proceedings, none of the impairment costs (or impairment benefits, such as tax benefits) will be included in the Company's future retail electric rates; and

(14) the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find that our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, (IURC March 19, 1997).

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

1. The Settlement is hereby approved in its entirety, without change or condition, and the issues in this proceeding are resolved as set forth herein.

2. The CPCNs for the Edwardsport IGCC Project are modified as set forth herein;

3. Duke Energy Indiana is directed to modify its tariffs consistent with the findings herein and file copies with the Commission's Electricity Division.

4. Concurrently with this Order we are also issuing orders in the IGCC 5, 6, 7, and 8 Rider proceedings, allowing the IGCC 8 Rider to go into effect to recover financing costs up to the $2.595 billion Hard Cost Cap amount.

5. This Cause should be, and is hereby, closed.

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT PURSUANT TO IND. CODE §§8-1-8.5 AND 8-1-8.7; (2) AUTHORITY TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") PROPERTY UNDER CONSTRUCTION IN ITS RATES AND AUTHORITY TO RECOVER APPLICABLE RELATED COSTS THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO IND. CODE §§8-1-8.8-11 AND -12; (3) ESTABLISHMENT A SUBDOCKET PROCEEDING TO REVIEW THE COST ESTIMATE FOR THE IGCC PROJECT; AND (4) APPROVAL OF A REQUEST TO UPDATE ITS DEPRECIATION RATES FOR PRODUCTION, TRANSMISSION, DISTRIBUTION AND GENERAL PLANT AND EQUIPMENT	)	CAUSE NO. 43114-IGCC4S1

Settlement Agreement

IURC Cause No. 43114-IGCC4S1 Phase I and Phase II

1. Introduction.

This Settlement Agreement ("Settlement") is entered into by and between Duke Energy Indiana, Inc. (and its successors), the Indiana Office of the Utility Consumer Counselor ("OUCC"), the Duke Energy Indiana Industrial Group,[1] and Nucor Steel-Indiana (collectively the "Settling Parties"). The Settling Parties agree that this Settlement resolves all disputes, claims, and issues in Indiana Utility Regulatory Commission ("IURC") Cause No. 43114-IGCC4S1, Phases I and II, and all issues relating to the construction costs and allowance for funds used during construction ("AFUDC") costs associated with the Edwardsport IGCC Project

[1] Consisting of Buzzi Unicem USA, Chrysler Group, LLC, Lehigh Cement Company, Marathon Petroleum Company, LLC, Rochester Metal Products Corporation, and USG Corporation.

("Project" or "IGCC Project"). The Settling Parties desire to fully settle all disputes, claims, and issues among them arising out of or relating to these proceedings and the construction of the Project, now and in the future,[2] 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, solely for purposes of this Settlement, that the Construction Costs included in the Hard Cost Cap (plus Additional AFUDC) (as such terms are defined below) are reasonable and necessary and should not be reduced because of any claims of imprudence, fraud, concealment, or gross mismanagement, or related claims. The Settling Parties agree that the record in this proceeding includes substantial evidence that this Settlement is reasonable and will result in just and reasonable rates for Duke Energy Indiana's customers. The Settling Parties further agree that this Settlement is a reasonable compromise and that each Settling Party that filed testimony previously in this Cause will file testimony with the IURC in support of this Settlement, and in such testimony, each such party will explain to the IURC 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 July 1, 2012.

2. <u>Hard Cost Cap</u>.

A. The Settling Parties agree that the Construction Costs (defined later in this Section 2) of the Project shall be subject to a "Hard Cost Cap" of $2.595 billion as of June 30, 2012,[3] for all Indiana ratemaking purposes (base rate cases and rider proceedings) ("the Hard Cost Cap Project Costs").

B. The Settling Parties agree that, until the Hard Cost Cap Project Costs are fully reflected in Duke Energy Indiana's electric rates, Duke Energy Indiana shall be allowed to accrue and recover actual AFUDC (or post-in-service AFUDC, whichever is applicable) on the portion of the $2.595 billion that has not been reflected in such rates. From and after July 1, 2012, Duke Energy Indiana shall recover actual AFUDC on the Hard Cost Cap Project Costs as follows: until November 30, 2012, 100% of the AFUDC and thereafter, 85% of the AFUDC incurred after such date ("the Additional AFUDC"). Retail AFUDC on the Hard Cost Cap Project Costs is currently accruing at approximately $9 million per month. There will be no cost recovery from retail electric customers above the retail amounts included in the $2.595 billion Hard Cost Cap, other than the Additional AFUDC as provided for above, and any force majeure events as defined below.

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[2] Except as specifically provided for in this Settlement.

[3] Reflecting approximately $2.319 billion in direct costs on a total Company basis and approximately $276 million in retail jurisdictional (only) AFUDC as of June 30, 2012. The retail jurisdictional portion of these direct costs is approximately $2.129 billion.

C. The Settling Parties agree that, except for ongoing additions, replacements, and maintenance capital expenditures made separate and apart from and not included in Construction Costs, in future retail electric base rate cases and riders, the portion of revenue requirements attributable to a return on the Project shall equal the original cost of the Project, defined as the Hard Cost Cap Project Costs, including the Additional AFUDC as provided for above, less accumulated depreciation, multiplied by Duke Energy Indiana's authorized weighted cost of capital calculated on an original cost basis.

D. The Settling Parties agree that the IURC should modify the Certificates of Public Convenience and Necessity ("CPCNs") for the IGCC Project to reflect an approved Project cost estimate equal to the Hard Cost Cap Project Costs ($2.595 billion as of June 30, 2012) plus Additional AFUDC that accrues on that amount on and after July 1, 2012, as described above. Other than as set forth in this Settlement, the Non-Duke Settling Parties agree that they will seek no further rate or regulatory "penalties" relative to the construction and overall final Construction Costs of the Project (plus AFUDC as allowed above); however, the non-Duke Settling Parties shall retain all rights under Indiana law to make arguments and seek relief concerning post-in-service operating performance of the Project.

E. "Construction Costs" of the Project shall be defined in accordance with usual utility practices and in accordance with FERC guidelines and includes all costs required to achieve "final completion," as that term is defined in the December 20, 2007 contract between Duke Energy Indiana and GE (see Attachment A), such as engineering, materials, construction and equipment purchases, capitalized AFUDC (through June 30, 2012), and all start-up and testing, validation and commissioning costs, and costs of repairs and modifications identified during start-up, testing, validation and commissioning and all such costs required whether actually disbursed or only obligated during such period, as well as any costs subsequently incurred to pay claims disallowed or unpaid during such period; except that: "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.

F. "In-Service Operational 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.

G. The Hard Cost Cap Project Costs and Additional AFUDC may only be increased due to an increase in prudently incurred construction costs for the Project caused by a force majeure event beyond the control and without the fault or negligence of Duke Energy Indiana or its suppliers or contractors involved in the Project, such as, by way of example, the following: acts of God, the public enemy, or any governmental or military entity.

3. <u>IGCC Rider Implementation</u>.

In recognition of some uncertainty as to the actual In-Service Operational Date of the Project and in effort to restart the IGCC Rider in a reasonable manner, the Settling Parties agree as follows:

As part of the approval of this Settlement, the IGCC Construction Work In Progress ("CWIP") Rider (Standard Contract Rider No. 61) will be approved to allow CWIP recovery to begin immediately on and up to the Hard Cost Cap Project Costs, and any Additional AFUDC as provided for in Section 2. In the event this Settlement is approved prior to approval of the IGCC-8 CWIP Rider proceeding, then CWIP recovery shall begin on Construction Costs amounts approved through the IGCC-6 CWIP Rider (which are less than the Hard Cost Cap), and recovery of CWIP for Construction Costs amounts over the IGCC-6 CWIP Rider amount (up to the Hard Cost Cap Project Costs and Additional AFUDC) will begin upon approval of the IGCC-8 CWIP Rider proceeding (expected in the September/October 2012 timeframe).

The Settling Parties agree that in IGCC-9 (to be filed in approximately May 2012), Duke Energy Indiana's proposed tariffs will not include costs of post-in-service Project depreciation or O&M costs (or property taxes) for inclusion in the IGCC-9 Rider (other than operating costs for items that have been included in previous Rider filings). Thus, the IGCC-9 filing will reflect financing costs (CWIP), but no post-in-service depreciation or O&M costs (or property taxes). Rather, in IGCC-10 (to be filed in approximately November 2012), Duke Energy Indiana will begin recovering post-in-service Project depreciation and O&M costs (and property tax expenses) on a projected basis for a six-month period. Duke Energy Indiana will defer the actual depreciation and O&M costs (and property tax expenses) incurred for all months from the In-Service Operational Date until the effective date of IGCC-10 rates. At the time of the next IGCC Rider filing (or general base rate case filing) after the filing of IGCC-10, Duke Energy Indiana will recover the deferred amount (without carrying costs) over a three-year period either through the IGCC Rider or through inclusion in base retail electric rates.

4. <u>Retail Electric Rate Case Moratorium</u>.

Except in the case of an emergency pursuant to Ind. Code § 8-1-8-113, Duke Energy Indiana agrees that it will not file for an increase in its basic rates and charges for retail electric service prior to March 2013, and that no increase to its basic rates and charges for retail electric service as a result of a final order in a retail electric base rate case filing shall be implemented

prior to April 1, 2014. This base rate case moratorium applies only to retail electric base rate cases, and not to other requests by Duke Energy Indiana for accounting deferrals, creation of regulatory assets or liabilities, or creation of new or modification of existing retail rate riders.

The non-Duke Settling Parties agree not to oppose any request by Duke Energy Indiana to zero-out the IGCC Rider and include the IGCC plant (up to the Hard Cost Cap Project Costs, plus Additional AFUDC as permitted by this Settlement), O&M, depreciation, and property taxes in base rates at the time of its next retail electric base rate case, consistent with past practice for capital riders; provided, however, that the Settling Parties may challenge the specific amounts of O&M, depreciation, and property taxes to be included in base rates.

5. Updated Depreciation Rates (plant except IGCC).

A. Plant Other Than IGCC. Duke Energy Indiana agrees to update its non-IGCC depreciation rates for production, transmission, distribution and general plant and equipment as submitted in Cause No. 43114-IGCC4S1 proceeding. The Settling Parties agree not to challenge these new depreciation rates including the negative net salvage values. If the IURC approves this Settlement, the depreciation rate changes as referenced in Petitioner's Exhibits UU, VV, and WW, including sub-exhibits, in IURC Cause No. 43114-IGCC4S1, will be made effective and retail electric customers will begin receiving the approximately $35 million retail jurisdictional annual credit for these depreciation rate changes through the IGCC Rider beginning the first full calendar month after the date of the order in Cause No. 43114-IGCC4S1, and ending upon the implementation of new retail base rates that reflect new depreciation rates, as discussed below.

Duke Energy Indiana agrees that, if it files for an increase in its base retail electric rates prior to the end of 2013, Duke Energy Indiana will request the continued application and approval of the depreciation rates approved in the depreciation study presented in Cause No. 43114-IGCC4S1; provided, however, that in such base rate case, Duke Energy Indiana shall have the right to propose updates to these depreciation rates and its depreciation study for any material changes in law, regulation, or accounting rules, or material changes to the Duke Energy Indiana system, including but not limited to, impacts from any decisions to accelerate the retirement of any generating assets, new environmental rules, new plant additions (including the IGCC Project), and the accelerated depreciation change as addressed below.

The Settling Parties agree not to oppose or present evidence regarding appropriate depreciation rates or net salvage values in any such Duke Energy Indiana retail electric base rate case filed prior to 2014, except as may be necessary to challenge any updates proposed by Duke Energy Indiana. Duke Energy Indiana reserves the right to file new depreciation rates for any retail electric base rate case filed after 2013, and the non-Duke Settling Parties retain the right to object to such new, post-2013 proposed depreciation rates and net salvage values.

B. Qualified Pollution Control Property Subject to Accelerated Depreciation. The Settling Parties agree that as of the first calendar month after the date of an Order approving this Settlement, Duke Energy Indiana may adjust its depreciation rates to reflect the use of normal, straight line depreciation lives for the qualified pollution control equipment, which rates are currently approved on an accelerated basis. Duke Energy Indiana's retail rates will not be changed to reflect this accounting adjustment to depreciation rates until the effective date of an order in the next-filed retail electric base rate case. At that time, revenue requirements will be modified to reflect the change from accelerated to normal lives for such qualified pollution control equipment, resulting in an estimated $32 million decrease in annual retail depreciation expense.

6. Deferred Taxes.

Duke Energy Indiana agrees to include, consistent with traditional Indiana ratemaking, deferred taxes in the capital structure used in its IGCC Rider, on a prospective basis, beginning with the effective date of the rider approved by an IURC Order that restarts the IGCC Rider. The Settling Parties agree that any bonus depreciation treatment applicable to the IGCC Project will be accorded normal ratemaking treatment, *i.e.,* any deferred taxes created by such bonus depreciation will be reflected in Duke Energy Indiana's capital-related rate riders and base rate case filings on an actual basis.

7. Potential Recoveries from Vendors/Contractors; Intellectual Property Benefits.

A. The Settling Parties recognize and agree that Duke Energy Indiana may have rights, claims and valid causes of action against Bechtel, GE, or other Project vendors or contractors with respect to the Project, and agree that in light of this Settlement, Duke Energy Indiana shall be entitled to retain any and all benefit from any amounts received from Bechtel, GE, or other Project vendors or contractors associated with the cost and quantity estimates, design, construction, start-up, testing, etc. of the Project, whether such benefit stems from agreement, arbitration, mediation, litigation, settlement, etc., and Duke Energy Indiana agrees to bear all costs associated with pursuing said causes of action. The Settling Parties agree not to affirmatively oppose or undermine in any way Duke Energy Indiana's pursuit of claims against GE, Bechtel, or other Project vendors or contractors.

B. Duke Energy Indiana shall retain any intellectual property benefits related to the IGCC Project.

8. Government Funding and Tax Incentives; Project Byproducts.

Retail electric customers will receive 100% of the applicable retail jurisdictional share of any Project-specific funding received from federal, state, or local governmental authorities, such as incentive tax credits and property tax credits.

Retail electric customers will receive 100% of the applicable retail jurisdictional share of any net byproduct or co-product revenues from the Project.

9. Attorneys' Fees and Reimbursements; Other Funding Commitments.

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 an IURC order (or as otherwise specified below) approving this Settlement (unless this Settlement is voided in its entirety pursuant to section 10 below):

A. A payment to the attorneys representing the Duke Energy Indiana Industrial Group of attorneys' fees in the amount of $11.7 million and of expenses in the amount of $600,000 for this Cause No. 43114-IGCC4S1, with implementation details in a separate Attorneys Fees and Expenses Implementation Agreement.

B. A payment to Nucor Steel-Indiana of between $800,000 and $1 million for certain fees and expenses incurred for this Cause No. 43114-IGCC4S1, with implementation details in a separate Attorneys Fees and Expenses Implementation Agreement.

C. A payment to the OUCC, not to exceed a total of $300,000, for reimbursement of certain outside litigation expenses related to this Cause No. 43114-IGCC4S1.

D. A contribution of $2 million to the Indiana Utility Ratepayer Trust.

E. A contribution of $3.5 million to the Indiana Low Income Home Energy Assistance Program ("LIHEAP") fund, to be funded over a five-year period and to be used solely for Duke Energy Indiana retail customers (*i.e.*, the Helping Hand Fund).[4]

F. A contribution of $1 million to establish a fund to effect the collaborative development of a clean energy initiative by the OUCC and Duke Energy Indiana, and to be administered by a suitable third party for the benefit of Duke Energy Indiana retail customers. The OUCC and Duke Energy Indiana acknowledge that this contribution may take longer than 30 days to set up and fund.

10. Other.

A. The Settling Parties agree that any subject to refund designations or similar language in the order in Cause No. 43114-IGCC-4 and any subsequent IGCC Rider orders approved prior to the date of an IURC order in this docket should be removed once this Settlement is effective.

[4] For the LIHEAP contributions the first $700,000 installment shall be made within 30 days of an IURC order approving this Settlement, with the four remaining $700,000 installments to be made in 2013, 2014, 2015 and 2016.

B. The Settling Parties agree that the evidence to be submitted in support of this Settlement, along with the evidence of record previously submitted in this Cause, 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, as filed. 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.

C. This Settlement is a complete, interrelated package that is intended to resolve all issues related to the IGCC Project Construction Costs (and associated AFUDC) including without limitation, all issues that were addressed or could have been addressed in Phase I and Phase II of Cause No. 43114-IGCC4S1, including but not limited to all claims of imprudence, fraud, concealment and gross mismanagement, as well as all issues concerning ex parte communications, improper conduct, undue influence, appearances of impropriety, or related issues. The Settling Parties agree to oppose or not support any attempt to create additional proceedings or phases of IURC proceedings to further examine the IGCC Project Construction Costs, associated AFUDC, fraud, concealment, gross mismanagement or ex parte communications, improper conduct, undue influence, appearances of impropriety, or related issues.

D. (1) 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).

(2) The Settling Parties agree to support in good faith the terms of this Settlement before the IURC 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 or the subject matters herein, before any appellate courts, and if necessary, on rehearing, reconsideration, or remand before the IURC.

(3) 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.

(4) The Settling Parties shall remain bound by the terms of this Settlement Agreement and shall continue to support all the terms of the Settlement on appeal, remand, reconsideration, etc., even if the IURC rejects the Settlement. However, in the event that the Settlement is rejected by the IURC 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).

(5) If the IURC approves the Settlement in its entirety, or approves the Settlement with modifications that are not unacceptable to affected Settling Parties, and such

IURC approval is ultimately vacated or reversed on appeal, the Settling Parties agree to support the terms of this Settlement in any remand proceedings before the IURC (as well as any subsequent appeals) to the extent possible under applicable law. 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 before the IURC. To the extent that the IURC 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.

E. 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.

F. The Settling Parties will support this Settlement before the Commission and request that the Commission expeditiously accept and approve the Settlement. As stated above, this Settlement is a complete, interrelated package, and the Settling Parties believe that it should be accepted in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party.

G. The Settling Parties will jointly move for leave to re-open the record in this Cause and to file this Settlement and testimony in support of this Settlement. Such testimony in support will be offered into evidence without objection by any Settling Party and the Settling Parties hereby waive cross-examination of each others' 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 this Cause, without regard to the filing of this Settlement.

H. 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.

I. 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.

J. 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.

K. 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 30th DAY of APRIL 2012:

Douglas F Esamann, President
Duke Energy Indiana

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

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

Abby R. Gray, Executive Director Legal Operations
Indiana Office of Utility Consumer Counselor

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

John F. Wickes, Jr.
Attorney for Duke Energy Indiana Industrial Group

Timothy L. Stewart
Attorney for Duke Energy Indiana Industrial Group

Anne E. Becker
Attorney for Nucor Steel-Indiana

"**Final Completion**" shall be deemed to have occurred upon the satisfaction of all of the following conditions:

(a) Substantial Completion shall have occurred;

(b) the performance of the Work shall be one hundred percent (100%) complete (other than Work that by its nature cannot be completed until after Final Completion (e.g., warranty Work)), including the Punch List Work and delivery of all Documentation that the Seller is required to deliver to the Buyer pursuant to this Contract;

(c) either (i) the Equipment shall have satisfied all Performance Guarantees or (ii) the Seller shall have paid to the Buyer all liquidated damages for failure to satisfy the LD Performance Guarantees as required by Section 2.9;

(d) there shall exist no Event of Default and no event which, with the passage of time or the giving of notice or both, would be an Event of Default; and

(e) the Seller shall have delivered to the Buyer a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied.

"**Substantial Completion**" shall be deemed to have occurred upon the satisfaction of all of the following conditions:

(a) Delivery of all GEP Equipment shall have occurred;

(b) 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;

(c) the Facility shall have satisfied the Minimum Performance Guarantees and the Make-Right Performance Guarantees;

(d) 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;

(e) the Seller shall have provided all training required by Exhibit S, with the exception of the Punch List; and

(f) the Seller shall have delivered to the Buyer a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied.