

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

JOINT PETITION AND APPLICATION OF DUKE ENERGY)
INDIANA ENERGY, INC., D/B/A DUKE ENERGY INDIANA,)
INC., AND SOUTHERN INDIANA GAS AND ELECTRIC)
COMPANY, D/B/A VECTREN ENERGY DELIVERY OF)
INDIANA, INC., PURSUANT TO INDIANA CODE CHAPTERS 8-)
1-8.5, 8-1-8.7, 8-1-8.8, AND SECTIONS 8-1-2-6.8, 8-1-2-6.7, 8-1-2-)
42(a) REQUESTING THAT THE COMMISSION: (1) ISSUE)
APPLICABLE CERTIFICATES OF PUBLIC CONVENIENCE)
AND NECESSITY AND APPLICABLE CERTIFICATES OF)
CLEAN COAL TECHNOLOGY TO EACH JOINT PETITIONER)
FOR THE CONSTRUCTION OF AN INTEGRATED)
GASIFICATION COMBINED CYCLE GENERATING FACILITY)
("IGCC PROJECT") TO BE USED IN THE PROVISION OF)
ELECTRIC UTILITY SERVICE TO THE PUBLIC; (2) APPROVE)
THE ESTIMATED COSTS AND SCHEDULE OF THE IGCC)
PROJECT; (3) AUTHORIZE EACH JOINT PETITIONER TO)
RECOVER ITS CONSTRUCTION AND OPERATING COSTS)
ASSOCIATED WITH THE IGCC PROJECT ON A TIMELY)
BASIS VIA APPLICABLE RATE ADJUSTMENT)
MECHANISMS; (4) AUTHORIZE EACH JOINT PETITIONER)
TO USE ACCELERATED DEPRECIATION FOR THE IGCC)
PROJECT; (5) APPROVE CERTAIN OTHER FINANCIAL)
INCENTIVES FOR EACH JOINT PETITIONER ASSOCIATED)
WITH THE IGCC PROJECT; (6) GRANT EACH JOINT)
PETITIONER THE AUTHORITY TO DEFER ITS PROPERTY)
TAX EXPENSE, POST-IN-SERVICE CARRYING COSTS,)
DEPRECIATION COSTS, AND OPERATION AND)
MAINTENANCE COSTS ASSOCIATED WITH THE IGCC)
PROJECT ON AN INTERIM BASIS UNTIL THE APPLICABLE)
COSTS ARE REFLECTED IN EACH JOINT PETITIONER'S)
RESPECTIVE RETAIL ELECTRIC RATES; (7) AUTHORIZE)
EACH JOINT PETITIONER TO RECOVER ITS OTHER)
RELATED COSTS ASSOCIATED WITH THE IGCC PROJECT;)
AND (8) CONDUCT AN ONGOING REVIEW OF THE)
CONSTRUCTION OF THE IGCC PROJECT)

CAUSE NO. 43114

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. FOR)
AUTHORITY PURSUANT TO AN ALTERNATIVE)
REGULATORY PLAN AUTHORIZED UNDER IND. CODE § 8-)
1-2.5 ET SEQ. AND IND. CODE §§ 8-1-2-6.1, 8-1-8.7, AND 8-1-8.8)
TO DEFER AND SUBSEQUENTLY RECOVER ENGINEERING)
AND PRECONSTRUCTION COSTS ASSOCIATED WITH THE)
CONTINUED INVESTIGATION AND ANALYSIS OF)
CONSTRUCTING AN INTEGRATED COAL GASIFICATION)
COMBINED CYCLE ELECTRIC GENERATING FACILITY)

CAUSE NO. 43114-S1

APPROVED:

BY THE COMMISSION:

Gregory D. Server, Commissioner

David E. Ziegner, Commissioner

Scott R. Storms, Chief Administrative Law Judge

On September 7, 2006, Duke Energy Indiana, Inc. ("Duke Energy Indiana," "Petitioner" or "Company") filed its Verified Petition with the Indiana Utility Regulatory Commission (the "Commission") in this Cause.¹ Therein, Duke Energy Indiana requested: (1) the issuance of applicable certificates of public convenience and necessity and applicable certificates of clean coal technology for the construction of an integrated gasification combined cycle generating facility (the "IGCC Project" or the "Edwardsport IGCC Project") pursuant to Ind. Code ch. 8-1-8.5, 8-1-8.7 and 8-1-8.8; (2) the approval of the estimated costs and schedule of the IGCC Project; (3) the authority to recover its construction and operating costs associated with the IGCC Project on a timely basis via applicable rate adjustment mechanisms; (4) the authority to use accelerated depreciation for the IGCC Project; (5) the approval of certain other financial incentives for Petitioner associated with the IGCC Project; (6) the authority to defer its property tax expense, post-in-service carrying costs, depreciation costs, and operation and maintenance costs associated with the IGCC Project on an interim basis until the applicable costs are reflected in Petitioner's retail electric rates; (7) the authority to recover other related costs associated with the IGCC Project; and (8) the Commission to conduct an ongoing review of the construction of the IGCC Project.

The participants in this proceeding, other than Duke Energy Indiana, are: the Indiana Office of Utility Consumer Counselor ("OUCC"), the Citizens Action Coalition of Indiana, Inc. ("CAC"), Save the Valley, Inc. ("STV"), Valley Watch, Inc. ("Valley Watch"), the Sierra Club, Hoosier Chapter ("Sierra Club"), the Indiana Industrial Group ("IIG"), Nucor Steel, a division of Nucor Corporation ("Nucor"), the Indiana Wildlife Federation ("IWF"), the Clean Air Task Force ("CATF"), and the Indiana Coal Council, Inc. (the "Coal Council"). CAC, IIG, STV, Valley Watch, Sierra Club, Nucor, IWF, CATF and the Coal Council are collectively referred to as "Intervenors." CAC, STV, Valley Watch and Sierra Club are collectively referred to as "CAC, *et al.*"

Pursuant to notice, and as provided for in 170 IAC § 1-1.1-15, a Prehearing Conference was held on November 28, 2006, at 9:30 A.M. in Room CC32 of the Indiana Government Center South, Indianapolis, Indiana. On December 13, 2006, a Prehearing Conference Order was issued setting forth the procedural schedule in this Cause.

¹ The Commission notes that the Verified Petition in this Cause was originally filed jointly with Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren"). Vectren is considering 20% ownership of the IGCC Project. On June 4, 2007, Vectren filed a Motion to Suspend Procedural Schedule as it Relates to Vectren's Requests for Relief, in which it indicated that it is still reviewing the front-end engineering and design study and needed more time to consider whether it will execute its option for 20% ownership of the IGCC Project. Because Duke Energy Indiana has, from the beginning, requested approval of up to 100% ownership of the IGCC Project, we find that consideration of a percentage ownership of Vectren, if any, can be postponed to further proceedings. Therefore, the remainder of this Order will address the requests of Duke Energy Indiana only.

On January 12, 2007, Petitioner filed a motion for a subdocket, in which it requested interim cost recovery of costs associated with the study and development of the IGCC Project that were required to be incurred prior to the estimated date of a final order in this Cause. Pursuant to a Prehearing Conference order issued February 28, 2007, the Commission consolidated the two Causes for filing and hearing purposes. Duke Energy Indiana indicated in its Rebuttal testimony that it was withdrawing its request for interim cost recovery, in return for agreement from the OUCC and Intervenors on an expedited post-hearing briefing schedule that will allow the Commission to issue an order in this Cause by approximately October 1, 2007.

After the pre-filing of testimony by all parties, an Evidentiary Hearing in this proceeding occurred June 18 – 22, 2007, pursuant to notice as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission. At the close of the record, the parties were authorized to file proposed orders and/or exceptions to proposed orders, in accordance with an agreed upon procedural schedule. A Presiding Commissioner and the Chief Administrative Law Judge have attended all of the Evidentiary Hearings in this proceeding, and have thus observed the demeanor and credibility of the witnesses. All proposed findings of the parties not specifically adopted in this Order are hereby rejected. This Commission, having examined the evidence and being duly advised in the premises, now finds that:

1. Notice and Jurisdiction. Due, legal, and timely notice of public hearings herein was given and published by this Commission as required by law. Duke Energy Indiana is a public utility as defined in Ind. Code § 8-1-2-1 and is subject to regulation by this Commission in the manner and to the extent provided for in the Public Service Commission Act, Ind. Code ch. 8-1-2. This Commission has jurisdiction over Duke Energy Indiana and the subject matter of this proceeding.

2. Petitioner's Characteristics. Duke Energy Indiana is an Indiana corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. Its address is 1000 East Main Street, Plainfield, Indiana 46168. It is engaged in the business of supplying electric utility service to the public in the State of Indiana. Duke Energy Indiana owns, operates, manages and controls plants, properties and equipment used and useful for the production, transmission, distribution and furnishing of electric utility service to the public in the State of Indiana. It directly supplies electric energy to over 760,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. It also sells electric energy for resale to municipal utilities, Wabash Valley Power Association, Inc., Indiana Municipal Power Agency and to other public utilities which in turn supply electric utility service to numerous customers in areas not served directly by Duke Energy Indiana.

Duke Energy Indiana's electric generating properties consist of: (1) steam capacity located at five stations comprised of nineteen coal-fired generating units supplied by nineteen coal-fired boilers and one oil-fired boiler; (2) combined cycle capacity located at two stations comprised of one syngas-fired / natural gas-fired Combustion Turbine ("CT") with steam turbine-generator and of three natural gas-fired CTs and two steam turbine-generators; (3) a run-of-river hydroelectric generation facility comprised of three units; (4) peaking capacity

consisting of seven oil-fired diesels located at two stations, eight oil-fired CT units located at two stations, and sixteen natural gas-fired CTs, one of which has oil back-up.

Duke Energy Indiana possesses a diverse portfolio of on-system generation, energy efficiency and demand response programs, and wholesale power purchases. The Company's on-system generating resources include baseload, intermediate and peaking generation and those resources are fuel-diversified, consisting of coal-fired (71%), gas-fired (25%), oil-fired (3.3%), and hydro (less than 1%). The Company has further diversified its portfolio by the addition of a wind energy purchase agreement to begin in 2008. The Company believes in the importance of a portfolio approach to resource planning in order to produce an economic mix of resources while mitigating risk through diversification. Pet. Ex. No. 2, pp. 9-10 (Pashos Direct).

3. Description of the IGCC Project. The IGCC Project will have a capacity of approximately 630 MW and will be located in Knox County, in southwestern Indiana, on approximately 220 acres of land adjacent to Duke Energy Indiana's existing Edwardsport Generation Station. The plant will have a Claus process sulfur removal system and two gasifiers, which will share a Selexol acid gas removal system. Each gasifier train will also include an activated carbon bed for absorption of mercury. The plant will have two GE 7FBJ combustion turbine generators, two heat recovery steam generators ("HRSGs"), each of which will be equipped with selective catalytic reduction ("SCR") for nitrogen oxide ("NO_x") control, one GE 13-33 steam turbine generator, and a multiple cell cooling tower. There will be no thermal discharge into the White River. Pet. Ex. No. 4, p. 4 (Moreland Direct); Shilling cross-examination at hearing.

IGCC technology uses a gasification process to convert coal into a fuel gas and to generate steam for a combined cycle generating facility. Gasification is the conversion of a feedstock, in this case bituminous coal, at high pressure and temperatures in an oxygen-controlled atmosphere into a combustible gas, called synthesis gas or "syngas." This is generally accomplished by finely grinding coal, mixing it with water, and feeding this slurry to a gasifier along with oxygen from a cryogenic air separation unit. The highly pressurized coal slurry and oxygen react to produce raw syngas that consists primarily of hydrogen and carbon monoxide. Inside the gasifier, the syngas is separated from the slag (primarily ash in the coal) and later is further cleaned by removing sulfur and other contaminants. The raw syngas from the gasifier is partially cooled by producing high pressure saturated steam that is then superheated and supplied to a steam turbine to generate power. The syngas itself is used as fuel for combustion turbine generating units to produce electricity. Exhaust heat from the combustion turbine passes through a HRSG to create steam, which, along with steam from the gasification process mentioned above, is used to power a steam turbine to produce additional electricity. *Id.* at 3-4.

The new plant will be designed to use Indiana bituminous coal (Indiana #5 seam) from the geologic formation known as the Illinois Basin. Many of the Indiana coal resources are located within 50 miles of the Edwardsport site and these sources are more than ample to supply the estimated 1.5 to 2 million tons per year needed by the Edwardsport IGCC Project for its useful life. Duke Energy Indiana is evaluating both truck and rail delivery of coal to the Edwardsport site. *Id.* at 9.

The Edwardsport Generating Station is located on the White River, in the town of Edwardsport, Knox County, just north of Vincennes. The station was initially constructed in 1918 with the "old plant" units being retired and dismantled prior to 1960. The existing generating units were constructed predominantly in the 1940s and are of a common header configuration with four boilers feeding steam to any of three turbine-generators. The station has a nominal total 160 megawatt nameplate rating for the three generators. Boiler #6 is an oil-fired steam generator and boilers #7-1, #7-2 and #8 are coal-fired steam generators. The coal burned is Illinois Basin high sulfur coal mined almost entirely in Indiana. Pet. Ex. No. 12, p. 3 (Roebel Direct).

The Edwardsport units will be retired in conjunction with the completion of construction and the start up of the Edwardsport IGCC Project. Shortly thereafter Duke Energy Indiana will begin to salvage any remaining usable equipment, such as machine shop equipment, and materials with a positive salvage value, such as copper. Petitioner expects to promptly demolish the stack and precipitators. Petitioner is currently evaluating whether any of the remaining structures will be useful for the Edwardsport IGCC Project, such as for storage purposes. If not, the remainder of the station will be demolished. The estimated net cost of demolishing the Edwardsport Station is \$12,376,200 in 2002 dollars. *Id.* at 4.

Dr. Norman Shilling, Product Line Leader for GE Energy's Integrated Gasification Combined Cycle Power Block, described the history of coal gasification. He explained that coal gasification is not a new technology, but one with many technological improvements since its inception. By the 1910s, commercial coal gasification was commonly used in the United States and Europe to provide cities with gas for streetlights and domestic consumption. Dr. Shilling explained that two advancements were required before coal gasification could be used with gas turbine power plants (the IGCC technology) – the first was the ability to clean the syngas to extremely low levels of contaminants to avoid corrosion and erosion of the hot gas path and the second was the advancement of turbine technology to be able to combust low Btu IGCC fuels. Pet. Ex. No. 3, pp. 5-6 (Shilling).

Dr. Shilling stated that IGCC's roots trace back to testing in the early 1970s at General Electric Company's ("GE") research facilities. After much testing and refining, the first large commercial coal IGCC was built – the 120 MW Cool Water Plant in California in 1984. He further described advances in technology made in the 1990s with the completion of two more IGCC facilities, the Tampa Electric Company's 250 MW plant in Florida and the 262 MW Wabash River generating station. Dr. Shilling said that GE has sold over 23 IGCC gas turbines and attained over 900,000 gas turbine operating hours on syngas. *Id.*

Dr. Shilling then explained that the gasification piece of IGCC is appropriately viewed as a coal refining process; that is, it generates a clean gas (referred to as synthesis gas) that consists of the basic chemical building blocks of carbon monoxide and hydrogen. This technology can also be used to create a variety of chemical products, such as fertilizer, alcohols, ultra-clean diesel and hydrogen fuels. He stated that this gasification capability provides an alternate pathway away from imported petroleum or natural gas for the production of many of our national economic staples. *Id.* at 6.

Dr. Shilling described the Tampa Electric Company's Polk Power Station near Lakeland, Florida ("Polk"). It has been operating since 1996 and is a part of the Department of Energy ("DOE")'s Clean Coal Technology program. Dr. Shilling stated that this 250 MW facility demonstrated that IGCC is cleaner and more efficient than conventional coal-fired plants. In addition to the environmental benefits, the Polk plant's ability to use a variety of poor, but lower cost fuels have made it the lowest variable cost coal power producer in Tampa Electric Company's system. The Polk plant also generates additional cost offsets by marketing some of the slag from the IGCC gasifier for use in manufacturing roofing and concrete blocks and the sulfuric acid for fertilizer production. *Id.* at 7.

Dr. Shilling also described the work of the GE/Bechtel Corporation ("Bechtel") Alliance in developing the IGCC Reference Plant², the configuration of which he stated is "optimized for cost of electricity, emissions performance, capital cost and availability." He concluded by stating:

The future of IGCC is bright. IGCC's inherent environmental benefits will serve to drive its widespread adoption. Immediate benefits include lower criteria emissions, production of marketable byproduct versus waste, over 90% Mercury capture, and lower water consumption than pulverized coal plants. With its pre-combustion cleanup, IGCC provides the flexibility needed to respond to future tightening regulatory requirements. This flexibility includes more economic carbon capture to deal with the potential for future carbon constraints. Gasification is already very successful and commercially accepted today in the refinery and chemical industries. Currently there are approximately 120 gasification vessels in operation at 62 facilities that are using GE gasification technology. A key factor in success is the product focus and overall responsibility that GE has brought to IGCC. This is a big and positive change. For all of these reasons, I believe that the Edwardsport Project will be a success.

Pet. Ex. No. 3, pp. 8-9 (Shilling).

In addition, Mr. Robert Moreland General Manager, Analytical & Investment Engineering for Duke Energy Shared Services, Inc., described the Company's development in the early 1990s, along with Destec Energy, Inc., of the IGCC demonstration project, partially funded by the Department of Energy, at the Company's Wabash River Generating Station ("the Wabash River Repowering Project"). This project used syngas from the Destec owned and operated coal gasifier³ as fuel for a combustion turbine owned by the Company. A Company owned existing

² At the hearing, Dr. Shilling said the proposed Edwardsport IGCC plant is based on the GE/Bechtel reference plant with certain modification improvements proposed by the Company. He stated that the Duke Energy value engineering work focused on reducing costs and improving reliability and performance.

³ Wabash Valley Power Association, Inc. ("WVPA") acquired a controlling ownership interest in the Destec gasifier facility from a successor company in November 2004. As presented in Cause No. 43210, contingent upon

steam turbine was refurbished and re-powered to use waste heat recovered from the combustion turbine owned by the Company. Mr. Moreland said this plant continues to operate as one of the cleanest solid fuel power plants in the world. Pet. Ex. No. 4, pp. 4-5 (Moreland Direct). The Company's knowledge and experience resulting from the Wabash River Repowering Project are being directly brought to bear in the development of the IGCC Project. During cross examination on his direct testimony, Mr. Moreland testified that Mr. Dennis Zupan (who is the Senior Project Director for the IGCC Project) was the project engineer for the Wabash River Repowering Project. Further, he stated that Mr. Jack Stultz, who will be the plant manager for the completed Edwardsport IGCC plant, was the operations manager for the Wabash River Repowering Project.

Mr. Moreland described how the Company continued its investigation into IGCC technologies when it became apparent that the Company would need additional baseload generating capacity. This included gathering information from the Electric Power Research Institute ("EPRI") and meeting with IGCC technology vendors. In the fall of 2004, the Company undertook a site study for the location of a new baseload plant, which resulted in the selection of the Company's Edwardsport Generating Station as the preferred site location. In January 2005, the Company entered into a Technical Services Agreement with GE and Bechtel (the "Feasibility Study") to study the technical feasibility of building an IGCC plant at the Edwardsport Station. The study included a technical scope description, services to be supplied, projections of plant performance, including heat rate and environmental emissions, as well as a preliminary cost estimate. At the same time the Company also undertook site specific activities related to such matters as availability and cost of natural gas supply, electric system interconnection, land acquisition, and coal handling. *Id.* at 5-9.

The Feasibility Study did not identify any fatal flaws and in the summer of 2005 the Company proceeded with the next phase of its investigation, consisting of the front-end engineering and design study (the "FEED Study")⁴. In addition to further site specific studies aimed at further quantifying the scope and cost of the entire IGCC Project, the Company and Vectren executed a second Technical Services Agreement with GE/Bechtel in February, 2006 (the "FEED Study Agreement"). The FEED Study Agreement required GE/Bechtel to develop a cost estimate for the scope of work proposed by GE and Bechtel, based on engineering documents that identify the scope of work upon which a final contract will be based. The FEED Study Agreement also covered supporting information required to apply for and ultimately obtain the necessary environmental permits, regulatory approvals, a contracting approach for construction of the IGCC Project and information necessary to apply the reference plant design being developed by GE/Bechtel to the Edwardsport site.

Commission approval, the Company and WVPA have entered into an agreement whereby the Company will sell and WVPA will purchase the gas turbine, steam generator and related equipment used in connection with the syngas produced by the WVPA owned gasifier. The Company will continue to operate such turbines and related equipment.

⁴ The Company, together with Vectren, sought cost recovery for the FEED Study in Cause No. 42894. As a result of a Settlement Agreement entered into with the OUCC, the Commission entered an order on July 26, 2006, authorizing, among other matters, the Company and Vectren to fully recover their costs for the FEED Study in the event that a CPCN order is issued and the IGCC plant is built, and authorizing the recovery of 50% of FEED Study costs up to \$15 million of total costs, if the Company and Vectren do not proceed forward with the IGCC Project.

Pursuant to the Commission's Prehearing Conference Order dated December 13, 2006, the Company filed with the Commission its FEED Study Report, supported by the written verification of Mr. Zupan, on April 2, 2007. The FEED Study Report provided a description of the numerous investigations undertaken by the Company and/or GE/Bechtel for the Project (including value engineering studies), updated plant performance information, the Company's updated cost estimate and schedule, and a summary of the Company's going forward contracting approach. Based upon the FEED Study, the Company reached the following conclusion:

The Project is technically feasible and commercially reasonable. The IGCC technology developed to meet Duke Energy Indiana objectives under the GE/Bechtel Alliance work performed in association with this study represents a product that will deliver 630 megawatts of reliable power with superior environmental performance at a thermal efficiency equal to or better than supercritical pulverized coal technology.

Pet. Ex. No. 20-A. The FEED Study Report concluded that "the Edwardsport IGCC Project provides the best option for acquiring baseload generation in a timely manner to meet the needs of our customers." The FEED Study Report, including the confidential pages, was formally introduced Mr. Zupan's rebuttal testimony. Pet. Ex. No. 20-A; Pet. Ex. No. 20 (Zupan Rebuttal).

Duke Energy Indiana witness Ms. Kay Pashos, Vice President, Regulatory Strategy for Duke Energy Shared Services, Inc., testified that because of the estimated 10% to 20% cost differential between a traditional pulverized coal ("PC") plant and an IGCC plant, Duke Energy Indiana aggressively pursued state, local and federal tax incentives to help bridge that financial gap. The Company worked with other interest groups resulting in the passage by the Indiana General Assembly of the Coal Gasification Technology Investment Tax Credit Act. This Act provides tax credits for placing into service an IGCC power plant. This law requires the taxpayer to enter into an agreement with the Indiana Economic Development Corporation to use Indiana coal and satisfy other requirements relating to the operation of the power plant. Pet. Ex. No. 2, pp. 11-13 (Pashos Direct).

Specifically, the law establishes a tax credit against a taxpayer's tax liability arising under the Adjusted Gross Income Tax, Financial Institutions Tax, Insurance Premiums Tax, and the Utility Receipts Tax for qualified investment in an integrated coal gasification power plant. The credit is equal to 10% of the first \$500 million in qualified investment, and 5% of the qualified investment exceeding \$500 million. The taxpayer may take the credit in 10 annual installments beginning with the year in which the taxpayer places the IGCC power plant into service. *Id.* at 13-14.

At the local level in Knox County, Duke Energy Indiana conducted a total of nineteen local meetings over a period of a year and a half to help secure local incentives for the IGCC Project. On April 11, 2006, the final approval for the 10-year real and personal property tax abatement and the tax increment finance ("TIF") district was unanimously approved by the Knox County Council.

The total estimated state and local incentives (based on a project cost of \$1.985 billion) is approximately \$316.5 million. These tax incentives will reduce Duke Energy Indiana's costs of operating the IGCC Project, to the benefit of native load customers. *Id.* at 14-15; Pet. Ex. No. 17, p. 19 (Pashos Rebuttal).

At the federal level, Duke Energy Indiana put together a comprehensive application for DOE certification seeking up to \$133.5 million (the maximum amount allowed) in federal tax credits for this project. The IRS has notified Duke Energy Indiana that it was awarded \$133.5 million in tax credits for this Project. *Id.* at 15-16; Pet. Ex. No. 16, p. 2 (Pashos Supplemental).

4. Applicable Law; Statutory Framework. At the outset, we will summarize the primary Indiana statutes applicable to Petitioner's requests in this Cause, and will examine whether the proposed Edwardsport IGCC Project meets the eligibility requirements under various statutes cited by Petitioner, specifically: (1) the Powerplant Construction Act, (2) the Clean Coal Technology Certificate statute, and (3) "Senate Bill 29".

A. Powerplant Construction Act. Under Ind. Code § 8-1-8.5-2, a public utility may not begin construction, purchase, or lease of any facility for the generation of electricity without first obtaining a certificate of public convenience and necessity ("CPCN") from the Commission. Under Ind. Code § 8-1-8.5-4, when determining whether a CPCN should be issued, the Commission is directed to take into account the utility's current and potential arrangement with other utilities for the interchange of power; the pooling of facilities; the purchase of power; joint ownership of facilities; and other methods for providing reliable, efficient and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration and renewable energy sources.

Under Ind. Code § 8-1-8.5-5, an application for a CPCN may only be granted after a hearing, and 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.

We have indicated in previous CPCN cases that "least-cost planning is an essential component of our Certificate of Need law."⁵ We have defined "least-cost planning" as a "planning approach which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* However, we have emphasized that the CPCN statute does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its

⁵ *In re Petition of PSI Energy, Inc.*, Cause No. 42145, at p. 4 (IURC; Dec. 19, 2002); *In re Petition of Southern Indiana Gas & Electric Co.*, Cause No. 38738, at p. 5 (IURC; Oct. 25, 1989).

obligation to serve. "If an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of Ind. Code § 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service."⁶

The Powerplant Construction Act is clearly applicable to Petitioner's request for approval to construct the Edwardsport IGCC Project, and thus the Commission has subject matter jurisdiction over this case pursuant to Ind. Code 8-1-8.5 *et seq.* We discuss the various alternatives the Commission must take into account in Section 5 of this Order.

B. The Clean Coal Technology Certificate Statute. Ind. Code § 8-1-8.7-1 defines "clean coal technology" as a technology:

- (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:
 - (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.

Therefore, for the Commission to have subject matter jurisdiction over Duke Energy Indiana's Petition for a CPCN pursuant to Ind. Code ch. 8-1-8.7 in this Cause, it must find that Petitioner is seeking authority to employ a technology that reduces airborne emissions of sulfur or nitrogen based pollutants and either was not in general commercial use as of January 1, 1989, or has been selected for funding by the DOE after January 1, 1989.

As we stated in *In Re NIPSCO*⁷, Ind. Code ch. 8-1-8.7 was added to the Commission's responsibilities by the General Assembly to encourage utilities within Indiana to utilize innovative clean coal programs with the possible increased utilization of Indiana coal while, at the same time, providing protection to the ratepaying public. Ind. Code § 8-1-8.7-4(b) provides that the Commission may grant the requested clean coal certificate only if it: (1) finds that the public convenience and necessity is served by the clean coal technology; (2) approves the estimated costs of the project; (3) finds that the clean coal technology will utilize Indiana coal as its primary energy source or, because of economic considerations or governmental

⁶ *In re Petition of PSI Energy, Inc.*, Cause No. 42145, at p. 4 (IURC; Dec. 19, 2002); *In re Petition of PSI Energy, Inc.*, Cause No. 39175, at p. 14 (IURC; May 13, 1992).

⁷ *In Re Petition of NIPSCO*, Cause No. 38849 (IURC; April 11, 1990).

requirements, it was justified in not doing so⁸; and (4) makes a finding as to each factor listed in Ind. Code § 8-1-8.7-3(b).

Ind. Code § 8-1-8.7-3(b) requires the Commission to find that the 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." In making this efficiency finding, the Commission must consider the following factors: (1) the estimated costs of the proposed project versus the estimated costs of conventional emission reduction facilities; (2) whether the project will extend the useful life of the existing generating facility and, if so, the value of that extension; (3) the potential emission reduction of the clean coal technology; (4) the emission reduction that could be achieved by conventional technology; (5) Federal sulfur and nitrogen emission standards; (6) the likelihood (feasibility) of success of the project; (7) the dispatching priority of the facility utilizing the technology considering direct fuel costs, revenues and expenses of the utility, and environmental factors associated with by-products resulting from the utilization of the clean coal technology; and (8) any other factor which the Commission deems relevant. The Commission also must consider the likelihood of success of the proposed project. Ind. Code § 8-1-8.7-3(b)(6).

Mr. Moreland described the IGCC technology and the processes involved in an IGCC plant, as discussed above. Duke Energy Indiana offered the testimony of Dr. Norman Shilling, who is responsible for the heavy-duty turbines applied to IGCC for GE. Dr. Shilling explained that coal gasification technology can deliver cost-effective generation from coal while also playing an important role in meeting the environmental goals of reducing sulfur oxides, nitrogen oxides, mercury and other air pollutants. IGCC technology also generates useful by-products in contrast to the large quantities of waste generated by conventional PC plants. Pet. Ex. No. 3, p. 2 (Shilling).

Dr. Shilling described IGCC as a cleaner coal technology that reduces traditional air emissions and particulate matter by approximately 50% compared to a state of the art PC plant. It also provides 90% higher mercury capture independent of coal type and at a fraction of the cost of pulverized coal. He then explained that with IGCC technology, pollutants are removed from the syngas before they reach the gas turbine, which means that end-of-pipe clean up is not necessary. Further, IGCC technology efficiently removes ash, sulfur compounds, ammonia, mercury, other metals, and particulate matter from plant emissions. *Id.* at 4.

⁸ 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 ("Court") 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. . . ." Although, we find that the proposed IGCC Project will allow Petitioner to continue the use of Indiana and Illinois Basin coal, in accordance with the *General Motors* case, we do not treat this factor as a prerequisite for Duke Energy Indiana's requested relief in this case.

Dr. Shilling provided some examples of the emission reductions achieved by other gasification projects in other locations, such as the 95% mercury removal achieved by a gasification plant in Kingsport, Tennessee and the NO_x emissions of less than 0.1 lb/million Btu achieved by the Tampa Electric Company's Polk and Duke Energy Indiana's Wabash River IGCC facilities. He further explained that sulfur is recovered from the syngas either as elemental sulfur or sulfuric acid in the pre-combustion clean up – both of which are marketable industrial by-products. *Id.*

Mr. John Roebel, Senior Vice President, Engineering and Technical Services for Duke Energy Shared Services, Inc., testified that in his opinion, the Edwardsport IGCC Project meets the definition of "clean coal technology" as used in Ind. Code ch. 8-1-8.7. He said gasification was not in general commercial use for power generation in 1989. He also said the Edwardsport IGCC Project will be equipped with selective catalytic reduction ("SCRs") technology for the reduction of NO_x emissions and such SCRs were not in general commercial use in the United States on large coal-fired facilities in 1989. He also stated that SCRs have not been used on IGCC plants using coal for a feed stock. He said the IGCC technology is capable of removing over 99% of the sulfur and will dramatically reduce NO_x emissions, even without the addition of SCRs. In 1989, Mr. Roebel noted that there was no "conventional technology" for reducing NO_x in general use in the United States. He said that the clean coal technology will not extend the useful life of the Edwardsport generating units because Duke Energy Indiana is planning an entirely new generating project in close proximity to the existing station. Pet. Ex. No. 12, pp. 5-7 (Roebel Direct).

No party has disputed that the Edwardsport IGCC Project falls within the definition of "clean coal technology" as defined in Ind. Code § 8-1-8.7-1, and the Commission so finds. The IGCC technology and the accompanying SCRs were not in general commercial use prior to January 1, 1989, and the IGCC technology used in the Edwardsport IGCC Project received DOE funding since 1989. Also, it is undisputed that this technology will cause substantial reductions in sulfur and nitrogen based pollutants by employing a technology not in general commercial use as of 1989. There is also no question that the Edwardsport IGCC Project will utilize Indiana coal as its primary energy source. Accordingly, the Commission finds that the Edwardsport IGCC Project constitutes clean coal technology as defined in Ind. Code § 8-1-8.7-1.

We now turn to the factors that we must consider in granting a clean coal technology certificate as called for in Ind. Code § 8-1-8.7-3(b).

(1). **The costs for constructing, implementing, and using clean coal technology compared to the cost for conventional emission reduction facilities.** Mr. Roebel testified that the IGCC technology is capable of removing over 99% of the sulfur and will dramatically reduce NO_x emissions, even without the additions of the SCR. The Edwardsport IGCC Project will have a Selexol acid gas removal system and a Claus process sulfur recovery system which removes and collects the sulfur as a salable byproduct. Mr. Roebel estimated the cost of this system to be about \$147/kW (in 2006 dollars), with operating costs of approximately \$0.87/MWh. Mr. Roebel contrasted these costs with the CG&E's Zimmer Station which began operation in 1989 with then state-of-the-art scrubbers. The Zimmer scrubbers could remove 91%

of the sulfur at a capital cost of \$158/kw (in 1990 dollars) and an operating cost of \$2.04/kwh in 1992. Pet. Ex. No. 12, pp. 6-7 (Roebel Direct).

(2). **Extension of the useful life of an existing generating facility.**

The Edwardsport IGCC Project will not extend the useful life of the Edwardsport generating units currently in use at the Edwardsport Generating Station. Mr. Roebel testified that these units will be retired in connection with completion of the construction and startup of the Edwardsport IGCC Project and will be dismantled. Pet. Ex. No. 12, p. 4 (Roebel Direct).

(3). **Potential reduction of sulfur and nitrogen based pollutants and reduction of sulfur and nitrogen based pollutants by conventional technology.** Mr.

Moreland testified that the 630 MW Edwardsport IGCC Project, operating 100% of the time would emit approximately 2200 tons annually of sulfur dioxide (“SO₂”), NO_x and particulates, combined. He said IGCC technology is capable of 0.014 lbs/MMBtu of SO₂ (approximately 99.7% removal). He also said IGCC technology is capable of 0.02 lbs/MMBtu of NO_x with an SCR installed. The IGCC technology particulate rate will be about 0.007 lbs/MMBtu. Finally, IGCC technology can remove over 90% of mercury in coal. Pet. Ex. No. 4, pp. 10-11 (Moreland Direct).

Mr. Moreland testified that the 160 MW Edwardsport Station operating 30% of the time emits approximately 11,000 tons annually of SO₂, NO_x and particulate emissions, combined. *Id.* As already noted, Mr. Roebel stated that the Zimmer generating station removes 91% of the sulfur emissions versus over 99% removal by IGCC technology. Pet. Ex. No. 12, p. 7 (Roebel Direct). The evidence in this proceeding is that the Edwardsport IGCC Project will dramatically reduce SO₂, NO_x and mercury emissions.

(4). **Sulfur and nitrogen emission standards.** The evidence of record is uncontroverted that the Edwardsport IGCC Project will reduce SO₂, NO_x, mercury and particulate emissions well below all Federal standards. The February 2006 New Source Performance Standards (“NSPS”) limits (converted to lbs/MMBtu) for SO₂, NO_x and particulates are approximately 0.16 lbs/MMBtu, 0.12 lbs/MMBtu and 0.15 lbs/MMBtu, respectively. As already stated, the IGCC technology is capable of 0.014 lbs/MMBtu of SO₂, 0.02 lbs/MMBtu of NO_x with a SCR, a particulate rate of 0.007 lbs/MMBtu, and 90+% removal of mercury in coal. Pet. Ex. No. 4, pp. 10-11 (Moreland Direct).

(5). **Likelihood of success of the Edwardsport IGCC Project.** The record demonstrates that there is a likelihood of success for the Edwardsport IGCC Project. Dr. Shilling testified that IGCC technology has been developed since the 1970s and GE has developed a broad IGCC product line of gas turbines with matching steam turbine. He cited the Wabash River 262 MW facility that began operating in 1995. Dr. Shilling believes the future of IGCC is bright with its inherent benefits that will drive its widespread adoption. He said gasification is already very successful and commercially accepted today. In his opinion, the Edwardsport IGCC Project will be successful. Pet. Ex. No. 3, pp. 6-9 (Shilling).

(6). **Dispatching priority.** Due to the efficient nature of its operations and after consideration of all costs, such as fuel and emission allowance costs, the Edwardsport

IGCC Project is expected to economically dispatch often. Ms. Diane Jenner, Director, Integrated Resource Planning for Duke Energy Shared Services, Inc., testified that the STRATEGIST[®] model, a commercially available system expansion model, was used in the Integrated Resource Planning process and the results demonstrate that the Edwardsport IGCC Project is consistently among the first units economically committed and dispatched on the Duke Energy Indiana system. Pet. Ex. No. 5, pp. 3, 25 (Jenner Direct).

(7). **Other factors.** We find that the Edwardsport IGCC Project will provide significant economic and environmental benefits. Many of the economic benefits directly result from the efforts of Duke Energy Indiana to seek state and federal tax incentives. Mr. Noland, on behalf of the Indiana Coal Council, discussed the economic benefits that would result from the use of coal mined in the area of the Edwardsport IGCC Project in terms of permanent and construction jobs. We also find it significant that, in addition to the well documented immediate environmental benefits, the Edwardsport IGCC Project well positions Duke Energy Indiana in the event of carbon regulation. We believe these benefits are factors that should be considered in determining whether the Commission should approve the Edwardsport IGCC Project under the provisions of Ind. Code § 8-1-8.7-3.

C. **“Senate Bill 29.”** Another chapter dealing with clean coal technology is Ind. Code ch. 8-1-8.8 (“Senate Bill 29”). Section 11(b) of Senate Bill 29 provides an “eligible business” must file an application for approval of a “clean coal and energy project”. Under Section 11(d) the Commission, after notice and hearing, shall issue a determination of a project's eligibility for the financial incentives described in Section 11(a). The relevant financial incentives involved in this proceeding are the timely recovery of costs (Section 11(a)(1)), authorization of up to three percentage points on the return on shareholder equity that would be otherwise allowed to be earned on the projects (Section 11(a)(2)), and other financial incentives the Commission considers appropriate (Section 11(a)(5)).

Section 6 of Senate Bill 29 defines “eligible business” as an energy utility as defined in Ind. Code § 8-1-2.5-2 that proposes to construct a new energy generating facility or purchases fuel produced by a coal gasification facility. Section 8(a) defines “new energy generating facility,” in part, as: (1) fueled primarily by coal or gases from coal from the Illinois Basin; (2) newly constructed and dedicated primarily to serve Indiana retail customers; (3) constructed by an Indiana utility after July 1, 2002; and (4) a clean coal and energy project. Section 2 of Senate Bill 29 defines, in part, “clean coal and energy projects” as projects at a new generating facility that employ the use of clean coal technology fueled primarily by Illinois Basin coal or gases and as projects to provide electric transmission facilities to serve a new generating facility. Section 3 defines “clean coal technology” as a technology that is used in a new generating facility and that was either not in general commercial use at the time of the Federal Clean Air Act amendments of 1990 or had been selected by the United States Department of Energy for funding under its innovative clean coal technology program. Finally, Section 4 defines “coal gasification facility” as a facility in Indiana that uses a manufacturing process that converts coal into a clean gas that can be used as a fuel to generate energy.

There is no question, and it is undisputed in the record, that the Edwardsport IGCC Project qualifies for financial incentives as authorized by Section 11(a) of Senate Bill 29.

Duke Energy Indiana is clearly an "eligible business" and the Edwardsport IGCC Project employs clean coal technology as discussed above and constitutes a coal gasification facility as that term is defined in Senate Bill 29. Therefore, the Commission finds that the Edwardsport IGCC Project is eligible for the incentives under Senate Bill 29.

Section 2(1)(c) includes as clean coal projects the electric transmission facilities required to serve a new energy generating facility. Mr. Snead submitted testimony on the transmission facilities that would be required to connect the Edwardsport IGCC Project. He stated that since the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") has assumed responsibility for evaluation of new generator interconnections to the transmission system the Company must submit an energy connection request. Mr. Snead said Duke Energy Indiana submitted this request in June, 2004 for the Midwest ISO to begin evaluating the impact of a 600 megawatt IGCC facility at the Edwardsport site. He testified the interconnection feasibility study indicated that the proposed IGCC project could be accommodated at the Edwardsport site, but that the deliverability study indicated that some facilities may need to be upgraded. The original Midwest ISO studies indicate that the approximate cost for interconnecting the proposed facility to the transmission system would be \$7.2 million - approximately \$5.7 million for a new substation and approximately \$1.5 million for relocating some transmission facilities. Mr. Snead testified that the Midwest ISO estimates were reasonable and that the studies will continue to be updated as the design of the IGCC project becomes finalized. Pet. Ex. No. 9, p. 8 (Snead).

No one disputed Mr. Snead's testimony regarding the necessary transmission facilities and estimated cost with regard to the Edwardsport IGCC Project. Therefore, we find that the investment in these facilities is eligible for incentives under Senate Bill 29.

Section 12 of Senate Bill 29 details the requirements for the granting of the timely recovery of cost incentives called for in Section 11(a). Under Section 12(b), the eligible business seeking timely recovery of its costs must apply to the Commission for approval of a rate adjustment mechanism. The application must include a schedule for completion of the construction of the new generating facility, a copy of the most recent integrated resource plan filed with the Commission, the amount of capital investment in the new energy generating facility and other information deemed necessary by the Commission. Under Section 12(d), the Commission shall allow the timely recovery of costs associated with a qualified utility's system property if the applicant provides substantial documentation that the expected costs associated with qualified utility system property are reasonable and necessary. Under Section 12(f) a retail rate adjustment mechanism may be based on actual or forecasted data.

It is also clear that Duke Energy Indiana's proposed Edwardsport IGCC Project meets the eligibility criteria under Senate Bill 29, and that Duke Energy Indiana has complied with the requirements of Section 12(c) of Senate Bill 29. Duke Energy Indiana has submitted a detailed construction schedule for the construction of the Edwardsport IGCC Project. It has submitted its most recent integrated resource plan. It has provided significant detail as to the capital investment that is required for the Edwardsport IGCC Project. All of which leads to this Commission's conclusion that the Edwardsport IGCC Project meets the eligibility criteria under Senate Bill 29.

5. Consideration of Alternatives Under Ind. Code ch. 8-1-8.5 CPCN

Statute. Ind. Code § 8-1-8.5-4 requires that the Commission, in acting upon any petition for the construction, purchase, or lease of any facility for the generation of electricity, take into account the Petitioner's current and potential arrangement with other electric utilities for: (a) the interchange of power; (b) the purchase of power; (c) the pooling of facilities; (d) joint ownership of facilities; and other methods of providing reliable, efficient, and economical electric service, including; (e) the refurbishment of existing facilities; (f) conservation and load management; and (g) cogeneration and renewable energy sources.

In accordance with Ind. Code § 8-1-8.5-4, a petitioner must fully address the enumerated alternatives in order for the Commission to make an informed decision as to whether a pending proposal is in the public interest. As we noted in *In re Petition of PSI Energy, Inc.*, Cause No. 41924, the statute does not require a utility to exhaust all statutory alternatives before it may request a CPCN for new capacity.⁹ Rather, what is important is that the Commission be given enough information so that the Commission can take into account all of the enumerated alternatives in making its determination. The statute does not limit the Commission's discretion to weigh the importance of each alternative in determining the public interest.¹⁰ We consider the evidence on each of these statutory alternatives as follows:

A. The Interchange of Power. Duke Energy Indiana regularly uses interchange power as it continuously dispatches its generation and makes market purchases to meet its native load customers' demand requirements. In its testimony presented in this Cause, Duke Energy Indiana indicates that it believes that hourly spot purchases are not a good substitute for, and cannot be depended upon to take the place of, firm capacity such as on-system generation and forward reliability purchases. In addition, Ms. Jenner noted that the Midwest ISO does not allow such purchases to be applied towards a company's Module E reserve requirements. Pet. Ex. No. 5, p. 21 (Jenner Direct).

B. The Purchase of Power. Over the past few years, Duke Energy Indiana has relied on forward reliability purchases to help meet its native load customers' peak load requirements. The Company has also considered purchased power in its 2005 Integrated Resource Plan ("IRP"), as was demonstrated by the testimony of both Ms. Jenner and Mr. Judah Rose, Managing Director of ICF International. Ms. Jenner indicated that purchased power will likely continue to be a part of the Company's most economical supply portfolio for several years. Pet. Ex. No. 5, p. 21 (Jenner Direct).

C. The Pooling of Facilities. Duke Energy Indiana presented evidence that the Midwest ISO Day 2 Market, along with East Central Area Reliability Coordination Agreement's ("ECAR") Automatic Reserve Sharing, which will be succeeded by the Midwest Contingency Reserve Sharing Group if approved by FERC, helps to ensure that the use of existing capacity resources is maximized. Ms. Jenner testified that the current Midwest ISO market is very effective at utilizing the existing capacity resources in the region. Because of that,

⁹ *In re Petition of PSI Energy, Inc.*, Cause No. 41924, p. 5 (IURC; Dec. 17, 2001).

¹⁰ *Id.*

the Company does not believe that power pooling would provide any further benefits and therefore, is not a viable alternative to serve Duke Energy Indiana's current capacity needs. Pet. Ex. No. 5, pp. 21-22 (Jenner Direct).

D. Joint Ownership of Facilities. Duke Energy Indiana presented evidence that it has considered joint ownership of the IGCC Project. Ms. Jenner provided that from the early stages of the project, the Company had discussions with many of the other utilities in Indiana regarding potential joint ownership. Further, as discussed above in footnote 1, Vectren is considering ownership of 20% of the IGCC Project. Duke Energy Indiana has included in its IRP analyses 100%, 80% and 50% ownership as alternatives. Pet. Ex. No. 5, p. 22 (Jenner Direct).

E. The Refurbishment of Existing Facilities. Mr. Roebel testified that the Company considered refurbishment of the Edwardsport Generating Station and described the Company's refurbishment or engineering condition assessment program ("ECAP"). The ECAP program is utilized by the Company to assess its existing units and the steps necessary to preserve their existing capacity. Even with this program, Mr. Roebel stated, the Company recognizes that a generating unit life cannot be prolonged forever. Pet. Ex. No. 12, pp. 4-5 (Roebel Direct).

F. Conservation and Load Management. Duke Energy Indiana presented evidence that, given the substantial need for capacity on the Duke Energy Indiana system, additional conservation or load management programs are not a realistic substitute for the construction of the IGCC Project. Mr. James Rogers, President and CEO of Duke Energy, stated that Duke Energy Indiana first launched its comprehensive set of demand-side management programs in 1991 and since then, the Company has invested over \$150 million in energy efficiency. He further stated the programs have saved approximately 654,000 MWhs of energy annually – enough to serve approximately 50,000 homes per year and reducing the demand on the Company's system by about 160 MW. Mr. Rogers said that, according to the DOE Information Administration, Duke Energy Indiana's energy efficiency programs rank number 1 in Indiana, number 4 in ECAR/MAIN (out of 70 utilities) and in the top 6% nationally. He said that approximately 350,000 of the Company's customers have participated over the years and the cumulative bill savings for these participants has been over \$300 million. Pet. Ex. No. 1, pp. 24-26 (Rogers). Dr. Richard Stevie, Managing Director, Customer Market Analytics for Duke Energy Shared Services, Inc., also estimated that the cumulative emissions reductions resulting from the Company's energy efficiency programs equal reductions in SO₂ by 54,000 tons, NO_x by 11,000 tons, carbon dioxide ("CO₂") by 6,850,000 tons, and mercury by 200 lbs. Pet. Ex. No. 8, p. 20 (Stevie Direct).

Dr. Stevie then explained the different demand-side management ("DSM") programs currently in place at Duke Energy Indiana. The Company's current residential programs include: Residential Audit, Residential Low-Income Program, the Smart Saver[®] Program, a Photovoltaic Program, a Refrigeration Replacement Program, Energy Star[®], a Residential Direct Load Control Program, and the newly approved Personal Energy Report Program. The Company's commercial and industrial incentive programs include: Lighting Incentive Plan, Energy Efficient Cooling Systems, and Energy Efficient Motors. *Id.* at 16-19.

Dr. Stevie testified that he prepared three alternate DSM impact forecasts: a high DSM impact case, an ultra high DSM impact case, and a low case. Under the ultra high DSM impact case, which assumed implementation of several new DSM programs, the Company's programs could provide an additional annual reduction of over 800,000 MWh and 179 MW in fifteen years. In sum, Duke Energy Indiana believes it has adequately considered and implemented many conservation and load management options. *Id.* at 21, 24.

CAC, *et al.* witness Mr. Philip Mosenthal testified that cost-effective electric efficiency programs will lower total costs and electric bills for consumers, such investments will boost the state and local economies by leaving consumers with more disposable income, and by reducing electricity demand, the investments will reduce upward pressure of prices due to significant new investments in generation, transmission and distribution infrastructure. RC Ex. D, pp. 13-20 (Mosenthal).

Mr. Mosenthal stated that he would like the Commission to increase the budget for the Duke Energy Indiana efficiency program to take advantage of additional opportunities. He then recommended that Duke Energy Indiana be required to meet a goal of capturing 1% per year of efficiency because it is sufficient to roughly meet load growth for the Company by 2020. He also stated that California, Connecticut, Massachusetts, and Vermont are already currently meeting this level of savings. He maintained that Duke Energy Indiana should have an initial target of capturing savings of 1% of load each year with a budget of around 3% of electric revenue. He recommended that Duke Energy Indiana include the following efficiency programs: residential new construction; residential lighting and appliances; residential low income; residential existing home improvements; C&I new construction; C&I existing construction; and C&I products. *Id.*

CAC, *et al.* witness Mr. Bruce Biewald testified that, according to his calculations, the IGCC Project has a slight cost advantage over gas combined cycle and a PC unit, yet is more expensive than wind or DSM. However, when costs associated with carbon regulations are included in Mr. Biewald's comparison, wind and DSM remain more cost-effective than the IGCC Project and a gas combined cycle unit becomes more cost-effective than the IGCC Project. RC Ex. B, pp. 37-41 (Biewald Direct).

In response to Mr. Mosenthal, Duke Energy Indiana witness Dr. Stevie commented on Mr. Mosenthal's testimony regarding the availability of cost-effective energy efficiency potential sufficient to meet all electric load growth through 2020. Dr. Stevie pointed out that Mr. Mosenthal admits that he has not performed a market potential study for energy efficiency and therefore, the energy efficiency potential in Duke Energy Indiana's service area is merely Mr. Mosenthal's opinion. In addition, Dr. Stevie pointed out that the load forecast already incorporates rising levels of energy efficiency. Relying on the results of a market potential study could result in the double counting of efficiency effects. Dr. Stevie then mentioned the fact that Indiana is characterized in general as having lower energy prices coupled with above average per customer energy consumption. These low prices, he said, do not provide customers with motivation or incentive to reduce consumption and limits customer willingness to invest in energy efficiency. Pet. Ex. No. 23, pp. 3-8 (Stevie Rebuttal). Dr. Stevie testified on cross examination that the states cited by Mr. Mosenthal as having achieved high levels of

energy savings, California, Connecticut, Massachusetts, and Vermont, have high residential rates. In fact, according to the Energy Information Administration, average residential electric rates for the month March, 2007 for these states were 75% higher than the average residential electric rates in Indiana (and more than twice as much in the case of Connecticut and Massachusetts). Commercial and industrial electric rates were similarly listed as much higher than those of Indiana. IIG, CX 1.

Dr. Stevie also pointed out how Mr. Mosenthal erroneously concluded that his recommendation for energy efficiency savings was not very different from the DSM plan the Company proposed in 2004. Mr. Mosenthal mistakenly compared the cumulative impacts over 5 years of over 1 billion kWh in Dr. Stevie's testimony in Cause No. 42612 to Mr. Mosenthal's proposal of an annual savings of 1.47 billion kWh. Dr. Stevie had developed the estimate of 1.1 kWh as a cumulative number to demonstrate the need for recovery of lost revenues net of fuel. The number from Dr. Stevie's testimony in Cause No. 42612 that is comparable to Mr. Mosenthal's is 400 million kWh, which is the projected annual level of load impacts achieved in the fifth year of the proposed programs, not 1 billion kWh. Accordingly, Mr. Mosenthal incorrectly applied numbers from Dr. Stevie's prior testimony to support his claims for a level of achievable potential energy savings.

Dr. Stevie also questioned the conclusion of Mr. Biewald that the levelized cost of DSM would come in at \$40/MWh. The recovery of lost margins, which was not considered by Mr. Biewald, would likely raise the cost to the ratepayer above \$40/MWh. Dr. Stevie also stated that Duke Energy Indiana has been actively involved in the Commission's investigation into DSM and in its own energy efficiency collaborative that includes the OUCC, CAC and industrial customers. He said that the Company plans to file a proceeding seeking to expand its current energy efficiency programs and that discussion of spending on energy efficiency is more appropriate for that proceeding. Ms. Pashos explained that the Company fully expected that its energy efficiency and demand response program offerings in that filing would equate to a spending level of 1% of Duke Energy Indiana's revenues. At the hearing, Dr. Stevie indicated that, in his opinion, the best way to look at spending levels was to start from the bottom up – *i.e.*, start by determining what programs are cost effective and how much savings can be generated from the programs and then determine how much money it will cost to achieve the potential energy and demand savings. *Id.* at 8-10; Pet. Ex. No. 17, p. 6 (Pashos Rebuttal).

Duke Energy Indiana witness Mr. Rose also testified that several of the Intervenor's witnesses overstate the potential for DSM and renewable resources in their testimony. He goes on to explain the reasons why he believes that the elimination of electricity demand growth is very unlikely. He looked at past growth of 2.5% per year from 1980 to 2003 as reported by the SUFG and Midwest ISO reports of peak electricity demand growth between 2004 and 2006 of an average of 7.2% per year. He also reported that no major U.S. region has been able to prevent load growth. Pet. Ex. No. 25, pp. 4, 39-41 (Rose Rebuttal).

G. Cogeneration and Renewable Energy Sources. Duke Energy Indiana presented evidence that cogeneration and renewable energy sources are not adequate alternatives to the construction of the IGCC Project. Duke Energy Indiana witness Mr. Rogers described renewable energy sources as offering the potential for being cost-effective resource options with

proper incentives in place. He stated that renewable energy sources cannot yet make a big enough impact on the Company's capacity to supply its growing baseload needs. Mr. Rogers also indicated that the Company issued a request for proposals ("RFP") in November, 2005 for a supply portfolio of energy and capacity generated by renewable and/or environmentally-friendly sustainable sources of power. Mr. Rogers testified that, after receiving the proposals, Duke Energy Indiana entered into a 20-year agreement to purchase approximately 100 MW of wind power from the Benton County Wind Farm, LLC. Mr. Rogers stated that this agreement demonstrates Duke Energy Indiana's commitment to the environment by providing its customers with stably-priced and emission-free electricity. Further, he said that the Company has installed one wind and 15 solar demonstration projects throughout its service territory at homes, schools and its own customer service centers. The Company also recently committed \$75,000 to begin a feasibility study to use switch grass as a fuel in co-firing a coal-fired unit at Purdue University. Pet. Ex. No. 1, pp. 26-29 (Rogers).

Duke Energy Indiana witness Ms. Jenner also stated that the Company reviewed the available data for a number of other renewable resources, including solar. Based on the information available and the analysis performed, Duke Energy Indiana concluded that, with the current state of technical development and the cost of such technologies, these options were not yet economically attractive on a utility scale within the Duke Energy Indiana territory. Ms. Jenner testified that renewable resources can provide some benefits, but are not appropriate substitutes for the capacity required at this time. Pet. Ex. No. 5, pp. 18-20 (Jenner Direct).

In developing its IRP, Duke Energy Indiana included the cogeneration capacity Duke Energy Indiana expects on its system over the period of the IRP. Duke Energy Indiana's IRP analysis also included a number of renewable resources including wind, solar, fuel cells and other renewables (such as biomass and waste-to-energy). Two of the six plans chosen for further analysis in the Company's IRP process involved wind resources and one of its sensitivities considered a higher level of renewables. Indeed, the resource plan chosen had a placeholder added for a wind purchase power agreement ("PPA") in 2008, which is the start date for a 20-year PPA entered into with the Benton County Wind Farm LLC, as recently approved by the Commission. *Id.* at 11-16.

CAC, *et al.* witness Robert Fagan testified that Indiana has a large, commercially viable wind energy resource with class 3, 4 and 5 wind regimes that could support wind turbine average annual capacity factors exceeding 30%, and up to at least 42% in some regions at 90 meter wind turbine hub heights. Indeed, he said, TrueWind Solutions produced a report for the Indiana Department of Commerce, which demonstrated the geographical distribution of average annual wind speeds across the state. The report indicates that Indiana's best wind resources are located between Indianapolis, Kokomo and Lafayette and in Benton and White counties. Mr. Fagan said that NREL estimates that Indiana's total installed capacity technical potential is 198,000 MW at 100 meter hub heights and 42,000 MW at 70 meter hub heights. RC Ex. C, pp. 6-12 (Fagan).

Mr. Fagan then stated his belief of what the range of cost would be for Duke Energy Indiana to construct additional wind energy. *Id.* at 13-14.

Mr. Fagan also looked to the Midwest ISO queue of wind generators applying to the Midwest ISO for transmission interconnection studies to estimate other sources of wind energy that could be utilized by Duke Energy Indiana. As of April 16, 2007, he indicated that the Midwest ISO queue consisted of almost 49,000 MW of potential wind plans in the Midwest ISO region, with over 3,000 MW in Indiana alone. Mr. Fagan admitted that wind energy could not be used to meet all of Duke Energy Indiana's native load because for many hours of the year, the wind turbine's output will be less than full-rated capacity. Additionally, he said that wind energy is not inherently dispatchable as is more traditional forms of generation, such as gas, oil and coal facilities. *Id.* at 16-19.

Mr. Fagan estimated that with 20% wind penetration by peak load, Duke Energy Indiana could have an additional 1,300 MW of wind installed on its system with no significant operational or reliability constraints. He also explained that 1,300 MW of wind energy would produce 3,986 GWh per year, at a capacity factor of 35%. Mr. Fagan also said that in 2006, the Midwest ISO Transmission Expansion Plan studied the possibility of 20% wind energy in the state of Minnesota and 10% wind energy throughout the Midwest ISO region. *Id.* at 21-22.

Mr. Fagan maintained that the Company does not appear to recognize the vast potential and relatively attractive economics of wind generation resources. Further, he argued that Duke Energy Indiana limited the quantity of wind that could be selected by the STRATEGIST[®] model. According to Mr. Fagan, the Company limits the model by only allowing the cumulative maximum of a single additional 100 MW wind project over the 2006-2028 period, in addition to the 100 MW wind PPA already approved by the Commission. *Id.* at 23-24.

Mr. Fagan then testified regarding combined heat and power ("CHP"), which he described as a form of distributed generation that uses waste heat generated from the production of electricity to supply a portion of the thermal requirements of certain facilities, usually large commercial or industrial facilities. He indicated that a database maintained by Energy and Environmental Analysis shows that Indiana has approximately 2,074 MW of CHP generating capacity. Mr. Fagan also testified that according to a report by the Midwest Combined Heat and Power Application Center at the University of Illinois, Indiana has 30 installations with a total capacity of approximately 2,129 MW. He further identified another study that indicated a market potential of 1,491 MW in Indiana, with much of that potential found in office buildings, schools, hospitals and nursing homes because much of the industrial potential has already been utilized. He recommended that Duke Energy Indiana consider inventive programs to help the best candidate facilities finance and invest in cost-effective CHP systems. *Id.* at 29-33.

Duke Energy Indiana witness Mr. James Lefeld, Director Alternative Energy for Duke Energy Shared Services, Inc., filed rebuttal testimony in response to Mr. Fagan. Mr. Lefeld testified that one must be careful when using technical potential assessments, because they do not take into account economics or other practical realities. He also disagreed with Mr. Fagan's assertion that the Midwest ISO's application process indicates a current *commercial* potential for wind power of over 3,000 MW in Indiana and 45,000 MW in the Midwest ISO's region. He stated that going through the Midwest ISO process does not necessarily equate to either economic or installed projects and many projects in the queue are not ultimately built. Mr.

Lefeld also stated that, based on the Company's experience gained through its RFP for renewable power, the estimated wind price cited by Mr. Fagan is unrealistically low; for one thing, his estimate did not fully consider the delivery costs, which could be substantial, given that the better wind sites are not located in Duke Energy Indiana's service territory. Further, he said that wind prices have only continued to increase from the time of the RFP due to increased competition for wind turbines. On redirect examination, Mr. Lefeld indicated that he did not believe Duke Energy Indiana would be successful in getting additional wind purchases at the same price as it did for the Benton County Wind PPA. Pet. Ex. No. 22, pp. 3-8 (Lefeld Rebuttal).

Mr. Lefeld testified that wind energy is an "as available" energy source that can provide only a limited contribution to capacity in consideration to the amount of capacity installed because it cannot be "turned on" when electricity is needed. The clearest example of wind's inherent limitation, he said, is on a hot, humid, stagnant summer day when electric capacity is most needed and valuable. He also provided that wind speeds are typically lowest at precisely the time of day when peak loads typically occur, making it a less valuable resource for peak periods. On redirect examination, at the hearing Mr. Lefeld explained that the capacity that is available from wind generation at peak times is often lower than the annual capacity factor, and, in fact, it is possible that the wind generation may not be available in the peak hour. *Id.* at pp. 4-6.

Duke Energy Indiana witness Mr. Rose discussed the testimony of Mr. Fagan indicating that large amounts of wind energy could be relied upon by utilities. Mr. Rose argued that Mr. Fagan's testimony overstates the potential for wind development, by extrapolating that by 2030, if wind were to meet 25% of Midwest ISO demand, this would require approximately 85,000 to 95,000 MW of wind. A wind farm of this size, Mr. Rose estimates, would require up to 92% of the land area of the state of Maryland (6,640 to 11,429 square miles). Pet. Ex. No. 25, p. 41 (Rose Rebuttal).

In response to Mr. Fagan's criticism that Duke Energy Indiana used its STRATEGIST[®] model to limit the quantity of wind that can be selected by the model Ms. Jenner explained that Mr. Fagan failed to consider the CO₂ scenarios the Company had analyzed. Even so, in the updated analysis the Company allowed the model to choose up to twelve 100 MW wind projects in addition to the Benton County Wind PPA Project, but the model chose only two projects, and that was in the CO₂ Scenario where wind is more likely to be economic. On cross examination at the hearing, Ms. Jenner explained that her IRP modeling process included wind as a resource, but limited the amount of wind the model could take because, if she had not, the model may not have been able to solve. However, in the new runs for rebuttal, Ms. Jenner allowed the model to choose up to a total of 1300 MW of wind, and it still only choose a total of 300 MW of wind (or 45 MW of capacity value). Pet. Ex. No. 24, p. 11 (Jenner Rebuttal).

Duke Energy Indiana witness Mr. Roebel provided testimony that Duke Energy aggressively pursues economic CHP projects throughout the country, including Indiana. Duke Energy owns or manages 23 projects through the country with 6,514 MW, 84,380 tons of cooling capacity, and 13,210 Mlb/hour of steam capacity. He also indicated that a study cited by Mr. Fagan in support of his testimony listed Cinergy as one of three energy companies leading the way for CHP in Indiana. Pet. Ex. No. 27, p. 5 (Roebel Rebuttal).

Mr. Roebel stated that the data used by Mr. Fagan showing the potential for CHP in Indiana is over seven years old and did not investigate any specific customers. He also said that the data cited is for technical potential, not economic potential. Mr. Roebel reported that Duke Energy's experience is that even when a project appears economic, the customer may well be reluctant to participate. Mr. Roebel also pointed out that the study relied upon by Mr. Fagan specifically mentions that "Relatively low electricity rates and high natural gas prices in Indiana . . . may result in a less attractive environment for CHP in Indiana." Mr. Roebel concluded with his opinion that CHP is not an acceptable substitute for the Edwardsport IGCC Project. *Id.* at 5-6.

H. Commission Discussion and Findings on CPCN Alternatives. As we have previously observed, the CPCN statute "requires public utilities in Indiana to evaluate and consider reasonable alternatives to installing additional generating capacity to meet the utility's forecasted probable future growth of the use of electricity and requires the Commission to consider the utility's evaluation of alternative means of meeting capacity requirements We believe that some deference should be given to a utility's judgment, provided the utility has made a reasonable, good faith effort to evaluate and consider available alternatives. . . ." ¹¹

The statutory alternatives required to be considered are: (a) the interchange of power; (b) the purchase of power; (c) the pooling of facilities; (d) joint ownership of facilities; and other methods of providing reliable, efficient, and economical electric service, including (e) the refurbishment of existing facilities; (f) conservation and load management; and (g) cogeneration and renewable energy sources. Our findings as to the adequacy of Duke Energy Indiana's consideration of these factors are described below.

The evidence shows that Duke Energy Indiana considered interchange of power, pooling of facilities, joint ownership of facilities, and refurbishment of existing facilities, and that Duke Energy Indiana reasonably concluded that none of these alternatives would provide the capacity to be provided by the construction of the IGCC Project. Accordingly, we find that Duke Energy Indiana has adequately considered interchange of power, pooling of facilities, joint ownership of facilities, and refurbishment of existing facilities, and that Duke Energy Indiana's decision to rely on a source of capacity other than these alternatives is reasonable.

The evidence indicates that Duke Energy Indiana adequately considered the purchase of power in its resource planning process. Duke Energy Indiana reasonably concluded that the construction of the IGCC Project was superior to the purchased power alternative in terms of risk and reliability. Further evidence provides that the Company will continue to utilize purchased power as part of its supply portfolio for several years. Accordingly, we find that Duke Energy Indiana has adequately considered the purchase of power, and that its preference for the construction of the IGCC Project in lieu of reliance on imported purchased power is reasonable.

¹¹ *In Re Petition of PSI Energy, Inc.*, Cause No. 39175, at pp. 3-4 (IURC; May 13, 1992); *In re Petition of PSI Energy, Inc.*, Cause No. 41924, at p. 12 (IURC; Dec. 17, 2001); *In re Petition of PSI Energy, Inc.*, Cause No. 42145 at p. 31 (IURC; Dec. 19, 2002).

The evidence also shows that Duke Energy Indiana adequately considered conservation and load management alternatives in its resource planning process, and that Duke Energy Indiana reasonably concluded that conservation and load management cannot be used to substitute for or replace the capacity represented by the IGCC Project. We note that Duke Energy Indiana is currently in a Collaborative with the OUCC and some of the Intervenors wherein an independent market potential study was conducted and the parties are working together toward the goal of increasing the Company's energy efficiency and demand response program offerings, with a planned filing later this summer. We also note that Duke Energy Indiana, along with other utilities in the state and interested parties, is participating in the Commission investigation into DSM. Although evidence was presented by the CAC, *et al.* witnesses that the Company should be required to meet its capacity needs through increased DSM and energy efficiency programs, we find that these other proceedings provide the proper forum to consider Duke Energy Indiana's energy efficiency goals. The Commission finds that Duke Energy Indiana has adequately considered conservation and load management alternatives and has further demonstrated that increased conservation and load management programs alone cannot satisfy Duke Energy Indiana's substantial need for additional capacity.

The evidence also indicates that Duke Energy Indiana adequately considered cogeneration and renewable energy sources in its resource planning process. Duke Energy Indiana demonstrated that, for both technical and economic reasons, cogeneration and renewable energy sources cannot be used as substitutes for the capacity of the IGCC Project. We note that Duke Energy Indiana has entered into renewable energy contracts including the first PPA with the first commercial scale Indiana wind farm, and a mine methane PPA. Duke Energy Indiana adequately considered wind and other renewables, and demonstrated that such resources, though promising, cannot be counted on to fulfill Duke Energy's substantial capacity need, particularly its need for baseload generation. Duke Energy Indiana uses 15% of wind's rated capacity for reserve margin planning purposes, and wind may not be available to serve load when needed the most – on hot summer days. Duke Energy Indiana reasonably concluded that the IGCC project will be a more reliable, and less risky, supply resource than wind for addressing its baseload capacity needs. Mr. Fagan's claim that the Company unduly limited the ability of the STRATEGIST[®] model to select wind options also appears to be unfounded because the model selected far fewer wind projects than were available in the updated analysis. We find that Duke Energy Indiana has adequately considered cogeneration and renewable energy alternatives and that its decision to acquire needed capacity by means other than cogeneration and renewable energy sources is reasonable.

6. Duke Energy Indiana's Need for Additional Capacity.

A. Duke Energy Indiana's Load Forecast.

(1). Petitioner's Evidence. Dr. Stevie described how Duke Energy Indiana's load forecast is developed. Dr. Stevie explained that the econometric forecasting methodology used to create the Duke Energy Indiana 2005 and 2006 load forecasts is basically the same approach as used by the Company in the past with updated economic forecasts and with historic databases revised to reflect the latest available information. Pet. Ex. No. 8, p. 8 (Stevie Direct).

The load forecast begins with an updated Duke Energy Indiana service area economic forecast which was prepared by Moody's Economy.com, and provides detailed projections of many aspects of the economy including: employment, income, wages, industrial production, inflation, prices and population. Using this forecast and historical Duke Energy Indiana load data an energy forecast is prepared with econometric models, which are a means of representing economic behavior through the use of statistical methods such as regression analysis. Finally, using the energy forecast, summer and winter peak demand forecasts are developed using econometric equations where peak demand is a function of economic growth, as measured by energy sales and several key weather factors. Dr. Stevie also explained that the impact of historical DSM programs that have been implemented in Duke Energy Indiana's service territory are reflected in the load forecasts. Dr. Stevie also indicated that nearly all utilities with which he is familiar utilize similar factors in their load forecasting as does Duke Energy Indiana. *Id.* at 5.

The energy forecast projects the load required to serve: (1) Duke Energy Indiana's three retail customer classes – residential, commercial and industrial; (2) wholesale loads of municipals and rural electric membership corporations ("REMCs") served directly by Duke Energy Indiana; and (3) portions of the wholesale load requirements of the Indiana Municipal Power Agency ("IMPA") and Wabash Valley Power Association, Inc. ("WVPA"), as applicable. *Id.*

Dr. Stevie also compared the Company's load forecast with the State Utility Forecast Group's ("SUFG") 2005 load forecast for the Duke Energy Indiana service territory. After making certain adjustments to reflect the difference in treatment of wholesale loads, the SUFG's forecasted growth for Duke Energy Indiana's retail peak load for the period 2006 to 2021 is higher than the Company's by nearly one percent, primarily due to Duke Energy Indiana's lower forecast for economic growth in the service territory. Dr. Stevie also testified that if the Company's service territory economic growth is higher than reflected in the economic forecasts, the electric loads could be significantly higher than currently projected. *Id.* at 10-11.

(2). OUC and Intervenors' Evidence and Petitioner's Response. No one challenged Duke Energy Indiana's load forecasting methodology or the Company's load forecast, although CAC, *et al.* witness Mr. Biewald complained that there were "unexplained differences" between the forecasts described by Dr. Stevie and the forecast used by Ms. Jenner in the Company's planning analyses. Mr. Biewald speculated that the difference related to Duke Energy Indiana's back-up power supply obligations associated with WVPA's and IMPA's

ownership interests in Gibson Unit 5 and questioned Ms. Jenner's modeling of these obligations. Mr. Biewald also expressed concern that if the Company was offering power to new wholesale customers at prices below the all-in cost of the Edwardsport IGCC Project, then retail customers would be enabling off-system sales. RC Ex. B, pp. 23, 26-29 (Biewald Direct).

In rebuttal, Dr. Stevie explained that the 2005 load forecast included in his original testimony did not include certain wholesale loads such as the 70 MW firm contract with WVPA and the backup for IMPA's ownership of Gibson Unit 5. Once those adjustments are made the forecast exactly matches the forecast used for the 2005 IRP. Dr. Stevie also testified that when forecasted wholesale native load sales are added to the 2006 load forecast included in his direct testimony there are only slight differences, due to changes in the economic outlook, between the load forecast used for the 2005 IRP and Dr. Stevie's 2006 load forecast. Pet. Ex. No. 23, pp. 2-3 (Stevie Rebuttal).

Ms. Pashos testified in rebuttal that Petitioner does not, now or in the past, add capacity for off-system, non-native sales opportunities, as Mr. Biewald implied. Ms. Pashos pointed out that wholesale native load customers, (primarily Indiana-based cooperative and municipal wholesale suppliers) as distinguished from off-system opportunity sales, have been an integral part of Duke Energy Indiana's system for many, many years, making up 8% to 11% of the Company's load obligation. In Duke Energy Indiana's last base rate case wholesale native load was approximately 8% to 9% of total load. Accordingly, 8% to 9% of fixed production costs in that case were allocated to wholesale native load customers, not retail customers. Pet. Ex. No. 17, p. 7 (Pashos Rebuttal). As shown on CAC Cross Examination Exhibit 15 Confidential, the new wholesale native load contracts are primarily with Indiana based wholesale suppliers, serving Indiana retail customers. Furthermore, Ms. Jenner testified that the wholesale native load forecast used in her updated analysis is approximately the same as the long-time historical level of Duke Energy Indiana's wholesale native load, and is consistent with the level of wholesale native load that was included in the Company's last rate case. Pet. Ex. No. 24, p. 5 (Jenner Rebuttal).

Ms. Jenner testified on rebuttal that Duke Energy Indiana's total capacity needs in the 2012-2014 timeframe are approximately 850-1000 MW prior to the addition of any new resources, of which the need for baseload capacity is approximately 300 to 600 MWs. Pet. Ex. No. 24, p. 9 (Jenner Rebuttal).

(3). Commission Discussion and Findings Regarding Load

Forecast. This is not the first time that this Commission has reviewed Petitioner's load forecasts and load forecasting methodology and found Petitioner's approach reasonable.¹² As Dr. Stevie explained, the Company's basic approach to load forecasting has not changed. Furthermore, no Party challenged the Company's methodology and we find that Dr. Stevie clearly explained the differences identified by Mr. Biewald. We also note that the Company's forecasted rate of load growth is lower than the latest forecast by the SUFG and that if the Company's service territory

¹² See e.g., *PSI Energy, Inc.*, Cause No. 42145 (IURC; Dec. 19, 2002); *In re Petition of PSI Energy, Inc.*, Cause No. 41924 (IURC; Dec. 17, 2001); *PSI Energy, Inc.*, Cause Nos. 42469 Phase I, 42865, 42866 (IURC; Aug. 3, 2005).

economic growth is higher than forecasted by Moody's Economy.com Duke Energy Indiana could well need even more resources to serve customers.

We are familiar with jurisdictional separation studies performed in general rate cases for the appropriate allocation of fixed costs between retail customers and customers that are non-jurisdictional to this Commission, such as wholesale native load customers. No one challenged the fact that an appropriate portion of Petitioner's fixed costs were allocated to its wholesale native load customers, and not allocated to retail customers, in the Company's last base rate case. And, no one challenged Petitioner's evidence that the current level of wholesale native load is consistent with the level of wholesale native load in the Company's last base rate case. Additionally, we recognize that Duke Energy Indiana has historically planned and built its generating system with the inclusion of these wholesale native load obligations. We therefore, find that as long as Petitioner appropriately allocates costs to its wholesale native load customers as it has done in the past, it is entirely appropriate for Duke Energy Indiana to include such loads in its load forecast and resource planning analyses. We also decline to micro-manage Petitioner's wholesale native load customer contracts. We conclude that Mr. Biewald's concerns with respect to retail customers "enabling" wholesale sales are unfounded. For all the above reasons we find Petitioner's load forecasting methodology and load forecasts presented in this Cause to be reasonable.

B. Duke Energy Indiana's Integrated Resource Planning Process.

(1). **Petitioner's Evidence.** Petitioner's evidence described at length the resource planning process that was used to first identify the range of viable alternatives and then narrow those choices to the best alternative. The initial steps in Duke Energy Indiana's IRP process consisted of the development of planning objectives and assumptions and the preparation of an electric load forecast (discussed above). The major objectives of the Company's IRP process are to: (1) provide adequate, reliable and economical service to customers while meeting all environmental requirements; (2) maintain the flexibility and ability to alter the plan in the future as circumstances change; (3) choose a near-term plan that is robust over a wide variety of possible futures; and (4) minimize risks such as wholesale market risks, reliability risks, *etc.* Pet. Ex. No. 5, p. 8 (Jenner Direct).

Ms. Jenner stated that the goal of the IRP process is to determine an optimal combination of resources that can be used reliably and cost-effectively to meet customers' future electrical service requirements. Duke Energy Indiana's most recent IRP was its 2005 IRP filed with the Commission on June 15, 2006, and was an exhibit to the testimony of Ms. Jenner in this proceeding, Petitioner's Exhibit No. 5-A. Ms. Jenner testified that the Company considers a multitude of options and combinations of options in its IRP process, such as DSM programs, environmental compliance alternatives and supply-side alternatives. As part of the Company's screening process in order to reduce the universe of options to a more manageable number for more detailed analysis, the potential demand-side, supply-side and environmental compliance alternatives are evaluated for their cost-effectiveness, with those resources that are the most viable and cost-effective passed on to the integration process using a commercially available, well accepted system expansion model, STRATEGIST[®] for further analysis. *Id.* at 3-6.

Ms. Jenner stated that the STRATEGIST[®] model uses the load forecast, in concert with data concerning existing generating units, demand-side resources, environmental compliance alternatives and future supply-side resource alternatives, to simulate electric production system operation. The model then dynamically analyzes the cost-effectiveness of a multitude of combinations of the resource alternatives resulting from the screening analyses, ultimately producing a number of resource expansion plans that meet the prescribed reliability criteria. These resource expansion plans are ranked from lowest to highest present value revenue requirements ("PVR") with environmental (emission) constraints reflected as well. Normally, the model analysis produces a number of expansion plans with PVRs that are so close that, for all practical purposes, they are identical. The Company must apply judgment to the raw model results. The resulting combinations are reviewed by the Company in terms of risk, flexibility, availability of equipment, constructability and transmission constraints. *Id.* at 6-7.

Ms. Jenner explained that all of the generating units on the Company's system and their operating characteristics were included in the model, along with a number of parameters including the Company's load forecast, reliability criteria,¹³ forecasted fuel, emission and market prices,¹⁴ demand-side resources, environmental compliance alternatives and supply-side alternatives.¹⁵ The specific supply-side alternatives included simple-cycle CTs, combined cycle units, supercritical pulverized coal units, an IGCC unit at Edwardsport along with the retirement of the existing Edwardsport 6-8 units, greenfield IGCCs, 100 MW block purchases of power from the market, a 100 MW wind purchased power agreement, and 100 MW turnkey wind projects. The wind alternatives were based on the bids received by Duke Energy Indiana in its RFP for renewable resources. The environmental compliance alternatives included in the model were SCRs on Cayuga 1 and 2, 500 MW or 635 MW common scrubbers on Wabash River 2-6, a scrubber on Wabash River 6, precipitator upgrades on Wabash River 2-6, a common baghouse on Wabash River 2-5, and retirements at Wabash River and Gallagher. *Id.* at 10-11.

Ms. Jenner described the major sensitivities that were analyzed under the Base Case conditions on a number of significantly different resource plans: higher gas price forecast, higher load forecast, lower load forecast/higher level of renewables, higher DSM, IGCC with no federal incentives, property tax abatement on supercritical PC unit, lower capital cost of supercritical PC unit, later first in-service date for supercritical PC unit, 17% reserve margin, Clean Air Interstate Rules ("CAIR") / Clean Air Mercury Rules ("CAMR") Plus (assumed stricter emissions caps beginning in 2014), and CAIR/CAMR Plus with CO₂ (assumed the same stricter emissions caps in 2014 along with an assumed level of CO₂ emission allowance prices). Ms. Jenner stated that all of the sensitivity and scenario analyses showed that the plans containing either a 50% or 80% ownership of the IGCC Project appeared to be the most robust over all sensitivities and scenarios. The least cost plan in each sensitivity and scenario contained

¹³ Ms. Jenner testified that the 2005 IRP used a 15-17% reserve margin (as a minimum) along with the same Loss of Load Hours ("LOLH") (annual LOLH less than 175) and Expected Unserved Energy ("EUE") (less than 0.18%) criteria the Company has been using in its past IRPs. Pet. Ex. No. 5, p. 8 (Jenner Direct).

¹⁴ ICF International ("ICF") provided forecasts of fuel, emission allowance and power prices. See Pet. Ex. No. 6 (Rose Direct).

¹⁵ Mr. Moreland provided cost estimates and other operating information for the supply side alternatives. See Pet. Ex. No. 4 (Moreland Direct).

either the 80% or 50% ownership of the IGCC Project, which led to the 80% ownership of the IGCC Project being selected for the 2005 IRP. *Id.* at 12-16.

Ms. Jenner also described the resource plan selected as a result of the IRP analysis. The plan contains the DSM bundle, interruptible contracts, direct load control and PowerShare[®] CallOption programs and special contracts. Ms. Jenner said that the supply-side resources consist of the wind power PPA starting in 2008, the Edwardsport IGCC Project, retiring the existing units at Edwardsport and installing a CT in 2016. Further in the future, the plan consists of another CT in 2027, a 50% natural gas combined cycle unit in 2021, and a supercritical PC unit in 2023. She also indicated that the IRP includes various environmental compliance measures, all of which have been approved by the Commission in Cause Nos. 42622 and 42718. *Id.* at 16-17; Pet. Ex. No. 5-D.

Ms. Jenner also stated that the latest SUFG report shows a growing gap between projected demand and the resources to serve that demand for the state; that over the next five years the SUFG plan calls for a combination of new peaking, cycling, and baseload capacity or purchases from the market, and that by 2011 the baseload need for the state is approximately 40% of the total 3540 MW requirement. She also explained that in her analyses the STRATEGIST[®] model shows that the Edwardsport IGCC Project is consistently among the first units economically committed and dispatched due to its efficient heat rate and low environmental emissions. She also described the various analyses performed regarding the economics of the IGCC plant with a change in tax incentives and if Vectren were to decide not to participate – all of which maintained the economic viability of the Edwardsport IGCC Project. Pet. Ex. No. 5, pp. 24-27 (Jenner Direct).

Ms. Jenner also filed Supplemental Testimony after Duke Energy Indiana learned that the Edwardsport IGCC Project had been awarded federal investment tax credits. She described the additional analysis performed on the IGCC Project to consider the effects of the federal tax credits and the escalation of costs of alternative supply-side generating technologies, specifically supercritical pulverized coal units, natural gas simple cycle combustion units, natural gas combined cycle combustion units, and wind projects. She explained that in the base case scenario, the number 1 plan contained a natural gas combined cycle unit in 2011, but the plan containing the IGCC Project in 2011 was a mere 0.23% higher in Present Value Revenue Requirements ("PVR"). She also indicated that her analyses demonstrate that the economics of the IGCC Project are very sensitive to higher natural gas prices. Pet. Ex. No. 15 (Jenner Supplemental).

(2). OUCC and Intervenors' Evidence and Petitioner's Response.

Mr. Biewald, a witness for Intervenors CAC, *et al.* criticized a number of aspects of Duke Energy Indiana's resource planning. Mr. Biewald claimed that Duke Energy Indiana used unrealistic assumptions about the capital cost and online date for Edwardsport because the Company did not use the cost estimate and schedule developed as a part of the FEED Study which was completed in April 2007 and that the Company failed to include the impacts of its proposed ratemaking in its analysis. He also asserted that the Company inappropriately analyzed its back-up obligations for WVPA's and IMPA's ownership shares of Gibson Unit 5, claiming that the model will not be able to differentiate between back-up power and native load

obligations, will plan to meet the back-up needs as if they were firm, and that the Company could more appropriately meet these obligations with a low cost peaking resource. He stated that the Edwardsport IGCC Project would result in a clear jump in off-system power sales and that Duke Energy Indiana inadequately considered renewable resources such as wind. Mr. Biewald also criticized petitioner for not analyzing a 100% Duke Energy Indiana ownership of the Edwardsport IGCC Project scenario, and claimed that the CO₂ emission allowance prices the Company used to analyze future potential carbon regulation were too low. Finally, using a simple levelized cost analysis, Mr. Biewald estimated that if the Edwardsport IGCC Project would be replaced by a mix of 50% wind and 50% DSM, the cost savings to Indiana customers would be approximately \$1.9 billion cumulative present value dollars over the period 2011-2030. RC Ex. E, pp. 23-29 (Biewald Direct).

Intervenor CAC, *et al.* witness Mr. David Schlissel also criticized the CO₂ emission allowance prices the Company used to analyze future potential carbon regulation, claiming that these prices were too low. Mr. Schlissel testified that Duke Energy Indiana utilized figures from Senator Bingamann's draft legislation as part of its sensitivity analyses, but indicated that these figures do not reasonably capture the possible magnitude of greenhouse gas regulations. This is because of the uncertainty surrounding future CO₂ regulations and because there is really no compelling reason why Senator Bingamann's bill would be passed by Congress over all of the other climate change bills in Congress. Mr. Schlissel also stated that emissions reductions would likely be greater than those required by Senator Bingamann's bill. He believes that the most likely scenario is that as policymakers commit to serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that will serve to lower cost scenarios and technological innovation. Even so, Mr. Schlissel stated that Duke Energy Indiana modeled CO₂ prices well below the modeled prices prepared by other entities. Based on his review of recent studies of greenhouse gas regulations, he believes that the Company is underestimating CO₂ costs associated with regulation. Further, he maintained that higher CO₂ costs would have a material effect on the economics of building and operating the IGCC Project. RC Ex. E, p. 12 (Schlissel).

In rebuttal, Ms. Jenner presented Duke Energy Indiana's updated analysis of the Edwardsport IGCC Project, using the estimated costs and schedule from the FEED Study. Ms. Jenner also explained that even though the STRATEGIST[®] model, as licensed by Duke Energy Indiana is not a ratemaking model, in the updated analysis the Company included the effects of its ratemaking proposals to the extent that the Company was able to do so. The Company also updated other inputs, such as the capital costs of other supply side alternatives supplied by Mr. Moreland¹⁶ and the forecast prices of gas, power and emission allowance prices supplied by Mr. Rose.¹⁷ Ms. Jenner also updated the level of native load to be served in recognition of the fact that the Company has executed additional firm wholesale native load contracts and that the Company's total wholesale native load is now approximately the same as Duke Energy Indiana's historical level of wholesale native load. Pet. Ex. No. 24, pp. 2-5 (Jenner Rebuttal).

¹⁶ See Pet. Ex. No. 19 (Moreland Rebuttal).

¹⁷ See Pet. Ex. No. 25 (Rose Rebuttal).

Ms. Jenner testified that the results of this updated analysis were that in the base case scenario the plan containing the 80% ownership share of the Edwardsport IGCC Project was 0.11% lower in PVRR than the lowest cost plan without the IGCC. She also testified that, under the CO₂ scenario, the IGCC plan was 0.19% lower than the lowest cost plan without the IGCC (a plan that would require 450 MW of natural gas combined cycle capacity in 2011). Ms. Jenner also analyzed the scenario of Duke Energy Indiana assuming 100% ownership of the Edwardsport IGCC Project. In that case the results were that in the base case scenario the plan containing the 100% ownership share of the Edwardsport IGCC Project was 0.24% lower in PVRR than the lowest cost plan without the IGCC. She also testified that, under the CO₂ scenario, the IGCC plan was 0.13% lower than the lowest cost plan without the IGCC. *Id.* at 7.

In response to Mr. Biewald's claim that the Company could more appropriately meet its back-up power supply obligations associated with WVPA's and IMPA's ownership interest in Gibson Unit 5 with a low cost peaking resource rather than model these obligations as firm, Ms. Jenner stated that these obligations *are firm contracts* and have been treated as such in past Duke Energy Indiana IRPs and rate cases. The Company has included IMPA's and WVPA's Gibson 5 capacity shares as well as the load for IMPA and WVPA that corresponds to their shares at 100% load factor. Ms. Jenner also pointed out that this modeling was discussed explicitly in the 2005 IRP. *Id.* at 5.

In response to Mr. Biewald's claim that that the Edwardsport IGCC Project would result in a clear jump in off-system power sales Ms. Jenner testified that she was unable to replicate Figure 19 in Mr. Biewald's testimony showing large increases in off-system sales, that the model is limited to sell only 200 MW into the market, and that the Company's historical level of non-native sales is actually about twice the amount of economy sales shown in the model runs. Ms. Jenner also stated that non-firm off-system sales revenues should be included in the model because of the economies they provide to the Company's customers. *Id.* at 8-9.

Ms. Jenner next addressed Mr. Biewald's suggestion that the IGCC Project could be replaced by 50% wind and 50% DSM. If it is assumed that a wind farm contributes 15% of its nameplate capacity at the time of the summer peak, a conservative assumption, Ms. Jenner estimated that 2060 MW of installed wind capacity (or about twenty 100 MW wind farms) would be required to replace half of the total IGCC Project's capacity. She also cited studies that demonstrated that an even lower level of capacity can be expected from wind and that such resources are subject to significant variability in the capacity value provided. A lower capacity value would require even more wind farms. *Id.* at 10-11.

Ms. Jenner opined that levelized cost analyses as used by Mr. Biewald are simplistic and sometimes misleading. She also stated that they can be useful for screening purposes, but should not be used to make final economic decisions. Ms. Jenner also pointed out a few issues that she had with Mr. Biewald's calculations: (1) the cost of wind used treats the production tax credit as an offset over the entire 30 year period even though the credit is assumed to be extended for only the first 10 years of operation; (2) the analysis ignores the gas price increases associated with CO₂ emission regulations; and (3) it also ignores the decrease in emission allowance prices for SO₂, NO_x and mercury associated with CO₂ emission regulations. She then stated that her biggest issue with Mr. Biewald's levelized cost analysis is that it assumes

all resources are equivalent in their ability to serve customers. She further explained that Mr. Biewald's analysis compares resources on a cost per MWh basis with no regard for the capacity value of a resource, its dispatchability or the time of day when its MWh are provided. Ms. Jenner also pointed out that Mr. Biewald's claim that if the Edwardsport IGCC Project would be replaced by a mix of 50% wind and 50% DSM, the cost savings to Indiana customers would be approximately \$1.9 billion cumulative present value dollars over the period 2011-2030 was based on just such a simplistic spreadsheet levelized cost analysis using understated costs as discussed above, with the potential to leave customers short of power on hot summer afternoons. *Id.* at 11-14.

Mr. John Stowell is Vice President, Environmental, Health and Safety Policy for Duke Energy Shared Services, Inc. and has extensive experience working with the U.S. government and Congress. Mr. Stowell responded to Mr. Schlissel's criticisms of the forecasted CO₂ emission allowance prices the Company used in its analysis of possible future carbon regulation. Mr. Stowell explained that while he believes that legislation regulating CO₂ will be enacted in the future he is of the opinion that Congress will be very careful to do so, particularly in the early years, in such a way as not to shock and disrupt the economy. Pet. Ex. No. 18, p. 4 (Stowell Rebuttal).

Mr. Rose also disagreed with Mr. Schlissel's criticisms of the forecasted CO₂ emission allowance prices used by the Company and with Mr. Schlissel's forecasts of CO₂ emission allowance prices. Mr. Rose indicated that Duke Energy Indiana's CO₂ emission forecasts are reasonable and consistent with ICF's own forecasts. He maintained that the Intervenor's overstate potential CO₂ allowance prices and fail to account for key factors which mitigate the effects of CO₂ controls on the economics of coal plants including higher natural gas prices, lower emission allowance prices for SO₂, NO_x, and mercury, lower coal prices, and the potential for extra allowance allocations. Pet. Ex. No. 25, pp. 15, 17 (Rose Rebuttal).

Mr. Rose stated that the IGCC technology has the potential for lower emissions due to higher thermal efficiency, which is in turn related to the potential for greater ease of carbon capture in IGCC facilities. He then explained how ICF modeled CO₂ allowance prices, developing mild, stringent and expected CO₂ scenarios. *Id.* at 14, 17-24.

Mr. Rose then responded to testimony from Mr. Schlissel that Duke Energy Indiana's CO₂ forecast is unreasonable because it is based on Senator Bingamann's legislation. However, Mr. Rose pointed out that the Company's price trajectory leaves its estimate in 2030 at over three times greater than the allowance price from Senator Bingamann's draft legislation. Further, he stated that EIA has analyzed Senator Bingamann's draft legislation and it does not appear possible that the Company's CO₂ allowance price forecast could be based on that draft. *Id.* at 24-30. Mr. Stowell explained that the CO₂ prices he provided to Ms. Jenner for the IRP analysis followed expected prices from a draft of Senator Bingamann's bill in the early years, but that the Company increased the prices in the later years in recognition of the Company's belief that CO₂ prices would have to increase to a level equal to the estimated cost of carbon capture and sequestration technology. Pet. Ex. No. 18, p. 4 (Stowell Rebuttal); cross examination.

Mr. Rose also described some flaws in the CO₂ studies relied upon by Intervenors. For example, he said that Mr. Schlissel identified three studies of the two versions of the McCain-Lieberman bill with widely different results, but noted that Mr. Schlissel gave equal weight to each, with no view as to which is correct. Mr. Rose also noted that Mr. Schlissel excluded results from some studies without explanation and further failed to explain why one scenario from a study was accepted while others were rejected. Another key flaw of Mr. Schlissel's analysis is that although he seemed to acknowledge that gas prices are important in evaluating power sector economics, he provided no gas forecast associated with his expected higher CO₂ prices. Pet. Ex. No. 25, pp. 24-30 (Rose Rebuttal).

Mr. Rose concluded that Mr. Schlissel's higher CO₂ estimates reaching \$40 to \$50/ton in real dollars represent extreme views and recommends that they be given a low weight by decision makers. *Id.* at 37-38.

(3). Commission Discussion and Findings on Petitioner's IRP

Process. Just as with Petitioner's load forecasting methodology discussed above, this is not the first time that this Commission has reviewed Petitioner's integrated resource planning and found Petitioner's approach reasonable.¹⁸ It is clear from the extensive testimony of Petitioner's witnesses, particularly Ms. Jenner, that the Company has carefully considered a wide range of alternatives using essentially the same methodologies it has used in the past, including the methodologies used in the proceedings cited above. Ms. Jenner's rebuttal testimony clearly answers Mr. Biewald's and Mr. Fagan's criticism of Petitioner's use of the STRATEGIST[®] model. Duke Energy Indiana did analyze the Edwardsport IGCC Project using the updated cost and schedule from the FEED Study and did model its proposed rate treatment to the extent possible. Duke Energy Indiana's modeling of its back-up obligations with respect to IMPA's and WVPA's ownership shares of Gibson Unit 5 is consistent with past treatment of these obligations, both for planning and ratemaking purposes and is proper. Duke Energy Indiana did analyze a 100% ownership of the Edwardsport IGCC Project scenario. Mr. Biewald's criticism of the Company's treatment of off-system power sales appears to be unfounded, especially in light of the limits Petitioner placed on such sales, and the fact that the model's results were significantly lower than historical levels of such sales.

We now turn to Mr. Biewald's and Mr. Fagan's criticism of the forecast of CO₂ emission allowance prices Duke Energy Indiana used in its scenarios analyzing the impact of possible future carbon regulation. While all parties, or nearly all parties, to this proceeding seem to agree that CO₂ emissions will be regulated in the future, the fact is such emissions are not regulated today. We cannot assume that the US Congress, if it does enact carbon regulation, will do so in such a manner as to unduly shock the economy. For this reason, and for the reasons set forth in the rebuttal testimony of Mr. Rose, we do not believe that it would have been reasonable for Petitioner to use the CO₂ emission allowance prices proposed by Mr. Biewald and Mr. Fagan, and find that Petitioner's approach was reasonable.

¹⁸ For instance, see *PSI Energy, Inc.*, Cause No. 42145 (IURC; Dec. 19, 2002); *In re Petition of PSI Energy, Inc.*, Cause No. 41924 (IURC; Dec. 17, 2001); *PSI Energy, Inc.*, Cause Nos. 42469 Phase I, 42865, 42866 (IURC; Aug. 3, 2005); *PSI Energy, Inc.* Cause Nos. 42622/42718 (IURC; May 24, 2006).

In summary, we have found Petitioner's integrated resource planning methodologies to be reasonable in the past. Petitioner has followed the same basic approach in this proceeding and has adequately addressed the criticisms of its planning brought forth in this proceeding. We find Duke Energy Indiana's planning process to be reasonable.

C. Commission Findings on Duke Energy Indiana's Need for Additional Capacity. Duke Energy Indiana's load forecast and IRP process demonstrated a total capacity need in the 2012-2014 timeframe of approximately 850-1000 MW prior to the addition of any new resources. Of that, Duke Energy Indiana's analyses show a need for about 300-600 MW of baseload capacity in the same timeframe. Pet. Ex. No. 24, p. 9 (Jenner Rebuttal). In fact, at least the last two IRPs have shown that Duke Energy Indiana has a need for baseload capacity. Pet. Ex. No. 1, p. 3 (Rogers). We have found that the Petitioner's load forecasting and IRP process are reasonable and we now conclude that Petitioner has a need for 850 to 1000 MWs by the 2012-2014 timeframe, including a need for 300 to 600 MWs of baseload capacity.

Now that we have determined there is a need for additional capacity, we must determine whether the IGCC Project is a reasonable method of meeting that need. We note that Petitioner's analyses demonstrated that the IGCC project is a cost-effective and robust option to meet this increasing need, under many differing sensitivity and scenario analyses. In fact, in the most current IRP runs, the IGCC Project is included in the lowest cost PVRR plan in each scenario, including a scenario with potential carbon regulation. We also agree with Petitioner, that a coal plant, with its attendant low fuel and environmental costs, is a good choice for baseload generation. We agree that Petitioner has a diverse portfolio of supply and demand-side options, and that the IGCC Project is a good fit for Indiana's growing capacity needs. We have found that Petitioner adequately considered alternative options to meet its capacity needs, and we now find that the IGCC Project constitutes a cost-effective and robust choice to meet those needs.

7. IGCC Project Cost Estimate.

A. Petitioner's Evidence. Mr. Moreland described the process by which the Company prepared the cost estimate for the IGCC Project. This estimate, as filed with the Commission (Petitioner's Confidential Exhibit No. 4-D), is based on the indicative cost estimate as produced in the initial feasibility study and also includes estimated costs for portions of the project that are outside the expected scope of GE/Bechtel's work, such as the cost of the land, the cost of the transmission interconnection described by Mr. Snead,¹⁹ a possible rail spur, coal handling equipment, owner's costs, escalation and allowance for funds used during construction ("AFUDC"). Mr. Moreland noted that the estimated cost of demolition of the existing Edwardsport Station, in the amount of about \$12.4 million, is not included in the cost estimate for the IGCC Project. The low end of the Company's confidential cost estimate was used by Ms. Jenner in developing the Company's 2005 IRP. The estimate provided to Ms. Jenner was in

¹⁹ Mr. Snead testified that the total cost of interconnection of the IGCC plant to the transmission system would be approximately \$7.2 million. In addition, he stated that potential upgrade work may be required on IPL's system at a cost of approximately \$200,000. At the hearing, Mr. Snead described the \$20 million "worse case" estimate for potential upgrade work on IPL's system referenced in Petitioner's Exhibit No. 9-A as an "outlier".

2005 dollars and was without escalation and AFUDC. Pet. Ex, No. 4, pp. 13-15 (Moreland Direct).

In addition to the Company's confidential estimate, Mr. Moreland also presented an estimate range based on EPRI estimates in the amount of \$1.6 to \$2.1 billion for an IGCC Project similar to the Edwardsport IGCC Project. *Id.* at 13.

Mr. Moreland stated that the Company anticipated updating the estimate upon completion of the FEED Study in early 2007. He then explained that the Company has been seeing some rapidly escalating costs of certain commodities, such as steel and concrete, along with escalating labor rates. Mr. Moreland said these escalating costs would have a similar effect on other baseload alternatives to an IGCC plant. *Id.* at 14-15. On direct examination at the hearing, Mr. Moreland explained that the cost estimate information for the IGCC Project set forth in his direct testimony had been superseded by the cost estimate resulting from the FEED Study.

Mr. Moreland also sponsored supplemental testimony in which he explained he had provided Ms. Jenner with updated estimated costs for other candidate supply-side technology options, including supercritical pulverized coal units, natural gas-fired simple cycle combustion turbine units, natural gas-fired combined cycle units, and new wind power projects. The new cost estimates were necessary because the escalating costs of commodities and labor would also affect alternatives to the IGCC Project. Mr. Moreland stated that any analysis of the high end of the Company's Edwardsport Project cost estimate range needs to be compared to alternatives that also reflect the recent escalation in construction costs. Pet. Ex. No. 14 (Moreland Supplemental).

In her direct testimony, Ms. Pashos explained that there is an estimated 10 to 20% capital cost differential between an IGCC plant and pulverized coal plant and that because of this the Company has aggressively sought local, state and federal tax incentives in order to reduce the cost of the Project. Ms. Pashos explained the basis for the state and local tax incentives and testified that these incentives, based on a project cost of \$1.985 billion, total about \$316.5 million. Pet. Ex. No. 2, pp. 11-16 (Pashos Direct); Pet. Ex. No. 17, p. 19 (Pashos Rebuttal). In her amended supplemental testimony, Ms. Pashos reported that the Company had been successful in getting an award of \$133.5 million in federal investment tax credits. Pet. Ex. No. 16, p. 2 (Pashos Supplemental). These tax benefits will be used to benefit the Company's native load customers.

The FEED Study Report, which was verified by Mr. Zupan and filed with the Commission on April 2, 2007, sets forth the Company's updated cost estimate of \$1.985 billion for the IGCC Project, including future escalation of 4% per year²⁰. Mr. Zupan formally sponsored the FEED Study Report in his rebuttal testimony, together with a more detailed

²⁰ In his rebuttal testimony, Mr. Rose said that ICF used a general inflation rate of 2.25% for escalation of capital costs for new generation plant costs. Accordingly, he indicated that the Company's use of a 4% escalation rate built conservativeness into the Company's estimate because if ICF's escalation forecast is correct then actual IGCC Project costs will be less than projected. Pet. Ex. No. 25, p.10 (Rose Rebuttal).

breakdown of the cost estimate. Pet. Ex. No. 20-A and Pet. Ex. No. 20-B Confidential and 20-C Confidential. This capital cost estimate is about 5.2% higher than the high end of the range of the Company's cost estimate included with Mr. Moreland's testimony and it is within the range of the \$1.6 to \$2.1 billion EPRI-based estimate included in Mr. Moreland's direct testimony. The FEED Study Report explains how Bechtel used detailed engineering drawings in estimating costs. The estimate is also based on GE prices for equipment it will manufacture or directly procure, as well as pricing information from other vendors who were supplied specifications for the equipment to be supplied. The estimate includes all purchase, supply and construction costs for the Project, including transmission costs associated with the Project, through the assumed commercial operation date in late 2011. Pet. Ex. No. 20-A.

The FEED Study cost estimate assumes that there will not be a lump sum turn key contract with GE/Bechtel for construction of the entire Project, which the Company deemed to be too expensive, due to the substantial amount that would be added by GE/Bechtel to cover contingencies which may never occur. Rather, consistent with the contracting approach taken by the Company on pollution control construction projects of over \$1 billion currently in progress or completed in recent years, the Company will assume more control over construction of the Project. *Id.*

The FEED Study cost estimate of \$1.985 billion does not take into consideration the effect of federal, state and local tax incentives awarded to the Company or for which the Company is eligible, which Ms. Pashos said in her rebuttal testimony is estimated to exceed \$450 million. Pet. Ex. No. 17, p. 19 (Pashos Rebuttal). On cross examination at the hearing, Mr. Rose testified that the net present value of the tax incentives would be approximately \$230 per kW of capacity for the IGCC plant.

B. OUC and Intervenors' Evidence and Petitioner's Response. IIG witness Mr. Nicholas Phillips stated that the IGCC Project's cost is estimated to be \$3,142/kW, which is significantly higher than either a conventional pulverized coal or a nuclear unit. He then explained that Petitioner is relying on local, state and federal incentives to make the IGCC Project an economical choice as compared to a pulverized coal unit. He further commented that although Mr. Rogers had stated that the potential for carbon sequestration was a benefit to the Edwardsport site, Duke Energy Indiana had prepared no detailed cost estimates for carbon capture and sequestration for the proposed IGCC Project. IIG Ex. 1, pp. 3-4.

Mr. Phillips proposed that the construction costs be capped at the latest estimate of \$1.985 billion as an incentive to the Company to efficiently manage construction costs. He mentioned that this is especially important in light of the Company's latest cost revision, which represents a 5.2% increase over the Company's prior high-end forecast. IIG Ex. 1, pp. 11-12.

CAC, *et al.* witness Mr. Schlissel quoted the FEED Study Report as saying that the new cost estimate "assumes that it will not be necessary to pay significant premiums to attract craft labor for the Project, assuming 40 hour work weeks with only occasional overtime." Relying on testimony with respect to a plant in Minnesota, Mr. Schlissel opined that, given the demand for skilled labor, the Company's refusal to recognize a requirement for labor premiums reflects that the Company is underestimating the cost of constructing the IGCC Project. He also

pointed to testimony from Mr. Rose that new coal-fired capital costs have increased approximately 90% to 100% since 2002 due to competition for the resources needed to construct new power plants. According to Mr. Schlissel, this competition makes it reasonable to assume that the IGCC Project will experience additional cost increases before it is completed. He found it imprudent for the Company to pursue a new power plant without considering the potential for higher capital costs. RC Ex. E, pp. 30-35.

Petitioner filed the rebuttal testimony of Mr. Roebel wherein he stated his opinion that the \$1.985 billion cost estimate for the IGCC Project resulting from the FEED Study is reasonable. He further stated that with the completion of the FEED Study, the Company has a significant amount of detailed knowledge about the project, more knowledge than normal for this stage of a major project. He also said that Bechtel was able to perform take offs from engineering drawings, a much more accurate method for estimating quantities. Further, Bechtel was able to obtain current pricing for over 90% of the bulk quantity materials and equipment from vendors. Mr. Roebel noted that the estimate was rigorous and performed by seasoned personnel using accepted estimating techniques. Pet. Ex. No. 27, p. 2 (Roebel Rebuttal).

Mr. Roebel rejected Mr. Schlissel's concerns about the Company's assumption that it would not have to pay significant overtime premiums to attract labor for the Project. Mr. Roebel stated that the Company has constructed (or is in the process of constructing) well over \$1 billion of pollution control equipment on its generating stations in the same general area as the Edwardsport IGCC Project, and frequently meets with local contractors and local unions. Local union officials have indicated that they welcome the IGCC Project as a long term local project without significant travel. Based on its experiences in the area, the Company believes its assumptions are reasonable. *Id.* at 3.

Mr. Roebel also addressed Mr. Phillips and Mr. Schlissel's concerns about whether the Company had made reasonable assumptions with respect to escalating commodity costs. Mr. Roebel stated that the Company's cost estimate is based on very recent quotes and estimates from vendors and suppliers (as recent as March 2007), and the Company has included a 4% escalation rate in the estimate. He affirmed the reasonableness of these assumptions. Further, he stated that if commodity prices do begin rapidly escalating beyond the Company's control, such forces would also impact competing technologies similarly. *Id.*

At the hearing on cross examination Mr. Roebel affirmed his opinion that the Company's updated cost estimate is reasonable. However, he noted there could be circumstances beyond the Company's control that could cause the cost of the IGCC Project to increase. Because of such possibility, he said it would be unfair for the Commission to place a cap of \$1.985 billion in capital costs that the Company could recover from its customers through rates. Likewise, Ms. Pashos testified in rebuttal testimony and at the hearing that due to the potential for circumstances beyond its control, the Company would not agree to forego its rights under the Indiana certificate of need statutes by agreeing to an absolute cost cap for purposes of IGCC Project cost recovery. Pet. Ex. No. 17, pp. 11-12 (Pashos Rebuttal).

C. Commission Discussion and Findings Regarding IGCC Project Cost Estimate. The Company's \$1.985 billion cost estimate for the IGCC Project results from the

extensive engineering and technical work on the Project encompassed within the FEED Study, which was undertaken for a period of over 18 months. The FEED Study effort included the preparation of a Project Scope Book, which will serve as the technical specifications for the Project. In addition to the substantial engineering and other technical services of GE and Bechtel (which, according to the FEED Study Report, involved over 250 GE and Bechtel professionals), the Company undertook numerous site specific studies and activities which are summarized in the FEED Study Report. The detailed engineering drawings produced as a part of the FEED Study provided significant amounts of details about the IGCC Project, which Bechtel used in estimating the quantities of many of the commodities, and cost estimates based on these quantities. GE provided estimates for the equipment that it will manufacture or procure and other vendors provided estimates based on specifications for the equipment to be supplied. The estimate includes all purchase, supply and construction costs for the IGCC Project, based on a commercial operation date in late 2011. Although the various components of the estimate are not fixed, as no supply or construction contracts have been concluded, the cost estimate is based on component estimates that are relatively current, as late as March 2007. Importantly, the estimate includes an escalation rate of 4%, which adds an element of conservativeness to the cost estimate.

The fact that the updated cost estimate is about 5.2% higher than the high end of the estimate range submitted by Mr. Moreland when his direct testimony was filed is not particularly surprising. In Mr. Moreland's direct testimony filed on October 24, 2006, he specifically noted that the costs for certain commodities and labor had been rapidly escalating and that such estimate was based on the feasibility study for the IGCC Project, rather than the more extensive FEED Study, which was not yet complete. He specifically stated the Company anticipated updating its estimate upon completion of the FEED Study. In addition, the Company's FEED Study cost estimate is well within the range of the EPRI based cost estimate (\$1.6 to \$2.1 billion) for an IGCC plant set forth in Mr. Moreland's testimony.

We reject Mr. Schlissel's contention that the Company failed to adequately consider the possibility of labor premiums and overtime. In recent years the Company has been and remains involved in a number of major pollution control construction projects. Mr. Roebel testified that the Company regularly meets with local contractors and labor unions which welcome the prospect of working on a major project relatively close to home. Mr. Roebel said he was comfortable about the Company's assumptions on labor rates and so are we.

We also find that the Company's proposed contracting approach whereby it will actively manage the project to be reasonable. A lump sum turn key approach with one primary contractor or contractors taking on price and other risks necessarily means that the contractor will build in large contingency amounts in the contract to ensure it will cover all possible costs and make a profit. Although such an approach could (assuming the contract is truly all encompassing and provides a fixed price) provide greater certainty of costs to the owner, it would also increase the total Project cost. The Company's proposed contracting approach is consistent with the contracting approach it has used on major pollution control projects, which we find to be reasonable.

We reject the IIG's proposal to place a permanent cap on the cost of the IGCC Project. The CPCN statute provides for assurance of cost recovery for the utility of up to the Commission approved cost and also provides the utility an opportunity to come before the Commission for ongoing review of its construction project. Duke Energy Indiana has elected to be subject to the ongoing review procedure. These ongoing review proceedings are the proper forum for the Commission to review any increases in costs above the initially approved cost estimate. The IIG and any interested Intervenors will have an opportunity to participate in such future proceedings. We will not, and indeed cannot under the CPCN statutes, require a permanent cap on the costs of the project. Rather, we find that the CPCN statutes themselves provide utilities a natural incentive to control costs to remain under the cost estimated approved in the CPCN proceeding.

Finally, we find that the Company is to be commended for aggressively seeking and securing over \$450 million in state, local and federal tax benefits that will inure to the benefit of its native load customers.

For all of the foregoing reasons, we find the Company's \$1.985 billion cost estimate to be reasonable and find that is the best estimate of construction costs based on the evidence of record.

8. IGCC Technology Reliability.

A. Intervenors' Evidence and Petitioner's and Intervenors' Response Regarding Reliability of IGCC Technology. IIG witness Mr. Phillips expressed concern about the reliability of the proposed IGCC plant, based on his review of testimony and filings at various state utility commissions regarding IGCCs and based on the time it took for two demonstration IGCC projects to reach higher capacity factors. He recommended that the Commission require that the Edwardsport IGCC Project operate at a minimum 82% capacity factor in order for Petitioner to recover the plant's cost from ratepayers. Mr. Phillips asserted that the 82% capacity factor is the capacity factor at which Petitioner determined that the IGCC Project will most economically meet customers' demands. He also claimed that ratepayers must be protected from management's decision to construct a plant using technology that has historically demonstrated lower reliability than other generating technologies such as pulverized coal. IIG Ex. 1, p. 13 (Phillips Direct). Mr. Phillips also testified that Consumers Energy in Michigan has also recently expressed concerns with respect to IGCC technology in the context of its application for approval of its "Balanced Energy Initiative." He further said that Consumers Energy presented testimony that "implementing IGCC at this time represents both a reliability and cost risk to customers without any substantial benefit of improved plant technical performance or emissions performance" and such testimony indicated that further research was needed to demonstrate IGCC's effectiveness with carbon capture and sequestration. *Id.* at 7-8.

In response to Mr. Phillips' concern that IGCC plants have questionable reliability, IWF/CATF witness Mr. Douglas Cortez recognized that the early IGCC demonstration plants built over 10 years ago experienced startup problems and required several years to achieve high levels of reliability. However, he said it is a mistake to interpret this experience as proof that IGCC is not a reliable technology. He said a recent study by Higman *et al.* examines the history

of IGCC plants in the U.S. and Europe and comes to a different conclusion. He stated that the study reports that the source of unreliability in some IGCC plants is in areas outside the gasification and gas process sections of the plant. He said the reasons for such reliability issues are well understood and are unlikely to occur in new IGCC plants that apply lessons learned. He further stated that IGCC plants have demonstrated high levels of reliability comparable to conventional coal plants. He said that IGCC technology has completed its pioneer plant stage and the next generation of IGCC plants will perform reliably. CATF/IWF Ex. 2, pp. 1-2 (Cortez Rebuttal).

In response to Mr. Phillips' statement that other utilities have concerns regarding construction of IGCC plants, Mr. Cortez stated that the utility industry is becoming more accepting of IGCC technology and several utilities are aggressively pursuing IGCC projects as the preferred option for clean coal powered generation. He said in November 2006 the DOE and IRS announced winners of about \$1 billion in gasification tax credits. He said over 45 projects were bid and several IGCC projects were awarded credits. The winners included Duke Energy Indiana, Southern Company and TECO Energy. Mr. Cortez stated that Mr. Phillips is attempting to paint a picture of utility rejection of IGCC, whereas, in fact, the industry is moving towards IGCC technology as a viable alternative to address the environmental problems plaguing conventional coal plant technology. *Id.* at 3.

Mr. Moreland similarly rejected Mr. Phillips' concerns about the reliability of the Edwardsport IGCC Project, stating that he was not surprised that it took some time for the two IGCC demonstration plants, the Polk plant and the Wabash River Repowering Project, to reach higher levels of availability. Both plants were part of the U.S. Department of Energy's clean coal program that were required to test a variety of fuels and perform other tasks which would impact availability. Mr. Moreland testified that the industry expected to, and has, learned from these projects. With respect to the Wabash River Repowering Project additional issues arose out of the split ownership between the gasification island (owned by Destec and its successors) and the power generation island (owned by Duke Energy Indiana). This will not be an issue for the Edwardsport Project because GE is designing both the gasification island and the power generation island. Further, the Company will be operating both parts of the IGCC Project. Pet. Ex. No. 19, pp. 3-5 (Moreland Rebuttal).

Mr. Moreland affirmed his belief that the IGCC Project will be very reliable, based, in part, on the significant lessons learned from the IGCC demonstration projects. He also noted that GE has a large database of best practices for gasification design that it has developed based on information from technology licensees. *Id.* at 4-5.

At the hearing on cross examination, Mr. Moreland testified that the reliability of an IGCC plant and a new supercritical pulverized coal plant would be similar over time. Likewise, he said the overall equivalent availability between supercritical pulverized coal and IGCC plants would be similar.

Mr. Roebel also rejected Mr. Phillips' contention that IGCC technology is unproven. Mr. Roebel's view is that IGCC technology involves a merger of two mature technologies: coal gasification, which, as described by Dr. Shilling, has been practiced for many

years; and combined cycle generating plants, which are operating on natural gas throughout the country. Mr. Roebel noted that the industry now has a very good experience base with two operating demonstration IGCC plants, including the Wabash River Repowering Project, with which the Company now has over 10 years of experience operating the combined cycle power plant in conjunction with the gasification plant (which is now operated by WVPA). Further, subject to stringent confidentiality limitations, the Edwardsport IGCC Project team has had unprecedented access to GE's design effort and has observed how GE has incorporated lessons learned from prior IGCC projects. Though he said it would not surprise him if the Company needs to make some modifications early in the operating life of the IGCC Project, which would not be unusual for any new large power plant, Mr. Roebel stated his opinion that the Edwardsport IGCC Project will be reliable, serving the Company's customers well. Pet. Ex. No. 27, p. 4 (Roebel Rebuttal).

At the evidentiary hearing on cross examination, Mr. Roebel described his background with successful major generating projects (including the successful conversion of the Zimmer nuclear plant to a large coal fired plant – the only such conversion in the US) and his role with Duke Energy which includes continuing responsibility for the successful construction of the IGCC Project. He described the extensive work carried out during the FEED Study for the IGCC Project and strongly reaffirmed his opinion that the IGCC Project will be reliable.

Ms. Jenner testified that Mr. Phillips had mischaracterized her testimony when he stated that an 82% capacity factor is the capacity factor Petitioner determined that the proposed IGCC plant will most economically meet customers' demands and that, in fact, Duke Energy Indiana had not done any STRATEGIST[®] model runs to determine the capacity factor at which the IGCC Project must run to be the least cost option. In response to Mr. Phillips' belief that the IGCC Project must run at 82% capacity factor to most economically meet the demands of customers, Ms. Jenner testified that the model runs show the plant running at 82%, not that 82% capacity *is required* for the IGCC Project to be a least cost option. Pet. Ex. No. 24, p. 14 (Jenner Rebuttal). In addition, Mr. Moreland testified that Mr. Phillips' proposed minimum capacity factor requirement gives no recognition that the Edwardsport IGCC Project, just like any other generating plant, will require periodic maintenance outages for such things as turbine overhauls, *etc.* Mr. Moreland also pointed out that the Commission has ample authority to investigate issues and craft appropriate remedies if large operating problems do occur in the future, which Mr. Moreland does not expect. Pet. Ex. No. 19, p. 4 (Moreland Direct).

B. Commission Discussion and Findings on IGCC Project Reliability.

The Company has over 10 years of experience with the Wabash River Repowering Project, one of two currently operating demonstration IGCC plants in the United States. The Company has methodically studied IGCC technology and has worked closely with GE/Bechtel in the adaptation of the GE IGCC reference plant for purposes of the IGCC Project. The record in this case establishes that the Company has extensively studied IGCC technology and the Company has concluded that an IGCC plant is technically feasible and commercially reasonable. Not only have Company witnesses strongly endorsed the expected reliability of the proposed plant, but reliability of IGCC technology has been affirmed by GE's Dr. Shilling and CATF/IWF witness Mr. Cortez.

We do not believe that the fact that certain demonstration projects encountered reliability issues in the early years of their operation is a reliable indicator that the Edwardsport IGCC Project will suffer the same fate. These demonstration projects had to operate somewhat differently as a part of their DOE funding requirements and there is ample evidence that GE has taken account of the lessons learned from these experiences. We find that the IGCC Project is technically feasible and commercially reasonable and is expected to be a reliable baseload generating station.

Furthermore, we agree that this Commission has ample authority to take appropriate action when and if reliability becomes a real problem and the facts can be determined. There is no evidence that an 82% capacity factor is the minimum capacity factor needed to make the plant commercially reasonable. And, there is no statutory basis for limiting the Company's rate recovery based on the plant achieving a certain minimum capacity factor. For the foregoing reasons, we therefore reject IIG's proposal to place a capacity factor limit or goal on the Edwardsport IGCC Project at this time.

9. Environmental and Other Benefits of the Proposed IGCC Project.

A. Continuing and Increasingly Stringent Emissions Reduction Requirements. Duke Energy Indiana presented evidence that electric utilities continue to face continuing and increasingly stringent emissions reduction requirements. For example, the 1990 Clean Air Amendments required Duke Energy Indiana to reduce SO₂ emissions by 50% and NO_x emissions by 25%. As stated in Petitioner's witness Mr. Stowell's testimony, Petitioner complied with these regulations at a cost of over \$540 million in capital. As another example, the United States Environmental Protection Agency ("EPA") and the State of Indiana's NO_x State Implementation Plan required an additional 50% reductions in summertime NO_x emissions by May 2004, with which Petitioner complied at a cost of nearly \$600 million in capital. Pet. Ex. No. 7, pp. 4-8 (Stowell Direct).

This trend of increasingly expensive and stringent emissions reduction requirements continues in the new CAIR and CAMR rules. Mr. Stowell stated that the CAIR made the deepest cuts in SO₂ and NO_x in over a decade. The CAMR represents the first ever federal rules to permanently cap and reduce mercury emissions from coal-fired power plants and requires meeting stringent New Source Performance Standards. *Id.* As Mr. James Rogers discussed, compliance with CAIR/CAMR requires investments in capital of over \$1 billion (Duke Energy Indiana received approval from this Commission for its first phase CAIR/CAMR compliance plan in Cause Nos. 42622 and 42718). Pet. Ex. No. 1, p. 8 (Rogers).

Petitioner is anticipating more stringent SO₂, NO_x, and mercury requirements could be enacted in the future and carbon regulation is highly likely as well. *Id.* at 8-9, 12-15. Petitioner, the OUCC, CAC, *et al.*, and CATF/IWF all expressed the likelihood of future carbon regulation. Petitioner's witness Mr. Rogers cited the example of the nine northeastern states forming the Regional Greenhouse Gas Initiative to develop a regional cap-and-trade plan for CO₂ emissions. Mr. Rogers also presented testimony regarding California's September 2006 AB 32, the nation's first bill to reduce greenhouse gas emissions. According to Mr. Rogers, this bill is especially significant as California is historically a leader in environmental regulations. *Id.* at

16-17. Petitioner's witness Mr. Stowell, the OUCC's Ms. Soller, CAC, *et al.s'* Mr. Biewald and Mr. Schlissel, and the CATF and IWF's witness Mr. Thompson all discussed details of potential carbon regulations and recent Congressional bills proposing carbon regulations, including proposals by Senators McCain, Lieberman, Kerry, and Bingamann.

B. The IGCC Project Environmental Footprint. Petitioner presented evidence demonstrating that the IGCC Project will in many respects have a much smaller environmental impact than other coal-fired plants. Petitioner's witness Mr. Moreland testified that the existing 160 MW Edwardsport plant runs less than 30% of the time and emits approximately 11,000 tons of SO₂, NO_x, and particulates in an average year, whereas the 630 MW IGCC Project, even running 100% of the time, would emit about 2,200 tons of these pollutants annually. Pet. Ex. No. 4, p. 10 (Moreland Direct). Mr. Rogers testified that the IGCC Project will use approximately 30% less water and generate 50% less solid waste than a conventional pulverized coal plant, and the waste products generated - 99%-pure elemental sulfur and slag - are salable by-products. It is Mr. Rogers' belief that with the IGCC Project, Duke Energy Indiana will be able to substantially increase its baseload capacity while simultaneously reducing its environmental footprint. Pet. Ex. No. 1, pp. 6-7 (Rogers).

Similarly, Mr. Moreland testified that the IGCC Project will provide 90% mercury capture independent of coal type and at a fraction of the cost of pulverized coal. Mr. Moreland presented testimony that the IGCC Project will be capable of SO₂ removal to about 0.014 lb/MMBtu (approximately 99.7% removal), NO_x emissions of 0.06 lb/MMBtu, and particulates emissions of about 0.007 lb/MMBtu - all of which exceed the NSPS limits. Pet. Ex. No. 4, pp. 10-11 (Moreland Direct). While IGCC technology is already capable of reducing NO_x emissions to well below the NSPS limit, Mr. Rogers testified that Duke Energy Indiana has committed to installing SCR that will make the Project the cleanest IGCC plant in the nation, with NO_x emissions at 0.02 lb/MMBtu with the SCRs in service. Pet. Ex. No. 1, p. 7 (Rogers); Pet. Ex. No. 4, p. 11 (Moreland Direct). Petitioner maintains that the low emissions of the IGCC Project lessen the likelihood of expensive retrofit environmental compliance equipment becoming necessary, even as future, stricter reductions are mandated.

Intervenors' CATF/IWF witness Mr. Thompson testified that the Edwardsport IGCC Project proposed by the Company will have superior environmental performance relative to coal plants across the nation and even around the world. He stated that SO₂ and NO_x emissions from the plant would be much lower than proposals for pulverized coal plants around the nation. Further, Mr. Thompson stated that the IGCC Project's carbon bed could perform at levels better than the manufacturer's guarantee, and that it could achieve 98% mercury removal or higher. On cross examination at the hearing, Mr. Thompson also testified that the rate of emissions per MWh for all pollutants would be less for the Edwardsport IGCC Project than for pulverized coal, including lead, CO, and VOCs. CATF/IWF Ex. 3, pp. 5-7 (Thompson Direct).

The environmental benefits of the IGCC Project related to potential CO₂ regulations are discussed below in Section 11 of this Order.

C. The IGCC Project's Thermal Efficiency. According to the testimony of Mr. Rogers, IGCC plants are capable of achieving superior thermal efficiencies due to the

combined cycle configuration. Pet. Ex. No. 1, pp. 7 (Rogers). Mr. Roebel testified the IGCC Project is a state-of-the-art, highly efficient generating station. Pet. Ex. No. 12, p. 6 (Roebel Direct). Mr. Rose testified that because more efficient plants combust less coal energy per MWh, the IGCC Project will produce less CO₂ and other emissions than competing coal technologies. Pet. Ex. No. 6, pp. 47 (Rose Direct). According to Petitioner's witness Ms. Jenner, the Company's modeling runs show that the IGCC Project is consistently among the first units economically committed and dispatched on the Duke Energy Indiana system due to its efficient heat rate and low environmental emissions. Pet. Ex. No. 5, p. 25 (Jenner Direct).

D. Tax Benefits of the IGCC Project. Petitioner's witness Ms. Pashos testified that Indiana's legislative leadership is supportive of providing funding for clean coal technology projects such as IGCC through investment tax credits, as is evidenced by Ind. Code ch. 6-3.1-29. Ms. Pashos stated that local support in Knox County is very high, with the Knox County Council unanimously approving a ten-year real and personal property tax abatement and a tax increment finance district. According to Ms. Pashos, the ten-year real and personal property tax abatement represents the maximum allowed by law. Ms. Pashos further represented that under the Clean Coal Facilities Investment of the Energy Policy Act of 2005, the IGCC Project has received the maximum amount of \$133.5 million in federal tax credits, demonstrating the support for and interest in this type of clean coal technology at the national level, for a total of approximately \$450 Million in tax incentives. Pet. Ex. No. 2, pp. 16-18 (Pashos Direct); Pet. Ex. No. 17, p. 19 (Pashos Rebuttal).

The testimony of Ms. Soller addresses why the IGCC Project is attractive in Indiana. Citing the testimony of Petitioner's witness Mr. Rogers in the North Carolina case NC Docket E-7, sub 790, Ms. Soller's testimony presents that there is strong local and state support for an IGCC facility to promote Indiana's coal industry. Public's Ex. 1, p. 17 (Soller).

E. Other Economic Benefits of the IGCC Project. Petitioner's witness Ms. Pashos presented testimony on an Economic Impact Study performed by Ernst and Young which confirmed that the construction of the IGCC Project would have a significant positive impact on both the local and statewide economy. According to Ms. Pashos, the IGCC Project involves a total investment of almost \$2 billion, creating an increased tax base for both state and local economies. Ms. Pashos stated that the IGCC Project will use about 1.5 million tons of locally mined Indiana coal per year, at a value of about \$45-50 million annually. Ms. Pashos further explained that the construction of the IGCC Project will result in large increases in state and local taxes paid. Additional economic benefits of the IGCC Project include the creation of 50 permanent new jobs, the majority of which are high-skilled and high-paying, with estimated payroll of \$4-5 million, and an average of 800-900 construction jobs during the three year construction period, with peak construction seeing the number increase to nearly 2,000. Ms. Pashos also believes that as the IGCC Project will be among the first of its size in the United States, this technological innovation and leadership in clean coal technology reflects positively on the State of Indiana. Pet. Ex. No. 2, pp. 12, 16-18 (Pashos Direct).

The Indiana Coal Council's witness Mr. Noland supports the IGCC Project. Mr. Noland testified that coal, which the IGCC Project will use in a more environmentally friendly way than competing technologies, is Indiana's most abundant natural resource.

Mr. Noland believes that the IGCC Project represents an innovative way to use existing resources. Mr. Noland testified that currently over half of coal consumed in Indiana comes from outside the state, but the IGCC Project is designed to run on Indiana coal. According to Mr. Noland, the IGCC Project will create many more direct mining jobs, and for every direct mining job, approximately 3.5 jobs are created. Additionally, Mr. Noland testified that a project of this scope indirectly spurs the local economy, and he estimates that during construction, increased supplier and consumer purchases could create almost 2,000 additional jobs with \$186 million in personal income. ICC Ex. JNN, pp. 1-10 (Noland).

F. The IGCC Project and the State Energy Plan. Ms. Pashos testified that the IGCC Project is consistent with Indiana's recently unveiled Strategic Energy Plan and the State Utility Forecasting Group's analysis of Indiana's capacity needs. Ms. Pashos characterized the IGCC Project's use of Indiana coal in combination with clean coal technology to produce cost-effective electricity while providing jobs and increased capital investment in the state as a prime example of a "homegrown" energy resource. Pet. Ex. No. 2, p. 18 (Pashos Direct).

ICC witness Mr. Noland addressed the Governor's Energy Plan, noting that it specifically provides for using IGCC technology to make best use of Indiana's coal reserves and to rely less on imported coal. Mr. Noland testified that the IGCC Project will meet the goal of producing energy from Indiana's natural resources and will represent a substantial increase in production from clean coal technology, a central component of the Energy Plan. ICC. Ex. JNN, p. 4 (Noland).

G. Commission Discussion and Findings on the Benefits of the IGCC Project. Based on the evidence presented in this proceeding as well as the continuing and increasing interest in climate change exhibited both by the public and state and federal governments, the Commission finds that planning for the likelihood of more stringent emission reductions and the possibility of carbon regulation is reasonable and prudent in Petitioner's planning process. While there is significant disagreement as to the scope and cost of future carbon emissions reductions, this Commission recognizes the strong possibility that carbon regulations are coming, and it is to the benefit of customers and the State of Indiana that utilities be cognizant of potential regulations and prepare accordingly.

The Commission recognizes that IGCC technology not only has significantly less emissions of SO₂, NO_x, and other harmful pollutants as compared to competing coal technology, but goes above and beyond fulfilling the statutory requirement for clean coal technology, providing the most environmentally sound way to meet Petitioner's future baseload capacity requirements while using local and economic coal as a fuel supply. Even without carbon capture technology, we find that the IGCC Project is an environmentally friendly way to increase Duke Energy Indiana's baseload capacity using lower cost local Indiana coal.

We note that no party disputed that the IGCC Project is expected to have superior thermal efficiency, which will contribute to its low variable costs, including fuel and emission costs. We, therefore, find that one benefit of the IGCC Project is its expected superior thermal efficiency.

The Commission finds that the availability of substantial tax benefits for this project speaks to the support for and interest in the deployment of the IGCC Project at local, state, and national levels. The Commission finds that the tax incentives will inure to the benefit of Duke Energy Indiana's customers, and as such these tax incentives constitute a benefit of the IGCC Project.

The Commission also finds that the IGCC Project would provide attendant benefits to the economy of the State of Indiana in the form of increased jobs related to the plant itself, the coal and related industry, and ripple effects benefiting the economy.

In sum, we find and conclude that: (1) the IGCC Project with SCRs not only fulfills the statutory requirements of clean coal technology, but will also be one of the cleanest coal plants in the country; (2) local, state, and federal tax incentives speak to the support for and interest in IGCC technology, especially in Indiana; (3) the IGCC Project represents a great opportunity for the state not only to receive cost-effective reliable electricity but also because it provides significant economic benefits to the state and local economies; and (4) the IGCC Project is entirely in keeping with the State Energy Plan.

10. Ultimate Findings Regarding Reasonableness and Necessity for Construction of Edwardsport IGCC Project. Based on all of the evidence presented regarding the need for and reasonableness of the proposed Edwardsport IGCC Project, we conclude and find as follows: Petitioner has a need for 300 to 600 MWs of baseload capacity in the next few years (and additional capacity needs beyond that), in order to reliably meet its customers' increasing electricity requirements; the evidence indicates that the proposed Edwardsport IGCC Project will be a reasonable, reliable, cost-effective, diverse and robust addition to Petitioner's resource portfolio; Petitioner has adequately considered alternative means of meeting its customers' demand requirements; the construction of the Edwardsport IGCC Project is consistent with Petitioner's integrated resource plan, and is also consistent with the State's generation expansion plan; the construction of the Edwardsport IGCC Project is consistent with the State's energy plan and will provide other benefits to the State in terms of job creation, increased tax base, *etc.*; and Petitioner has aggressively sought to create and obtain tax credits for this Project for the benefit of its customers. Accordingly, we find that Petitioner should be granted certificates of public convenience and necessity and certificates of clean coal technology for this Project under both Ind. Code ch. 8-1-8.5 and 8-1-8.7. We also find that Petitioner should be granted financial incentives for this Project pursuant to Ind. Code ch. 8-1-8.8, which we discuss in detail later in this Order.

11. Carbon Capture and Sequestration.

A. Petitioner's Evidence. As described by Mr. Moreland, the IGCC Project is designed to be carbon-capture ready, as the design utilizes a Selexol acid gas removal system and includes space designed for carbon capture equipment necessary for carbon capture. As explained by Mr. Moreland, the smaller volume and the concentrated nature of the gas stream make IGCC technology a very promising approach for future capture of CO₂ at less expense than

pulverized coal. Pet. Ex. No. 4, pp. 11-12 (Moreland Direct). According to a study by the National Energy Technology Laboratory cited by Mr. Rogers in this testimony, it is estimated that outfitting an IGCC plant with carbon capture technology will result in an approximate 30% increase in plant electricity costs, as opposed to an estimated 68% cost increase to outfit a supercritical pulverized coal plant. Pet. Ex. No. 1, pp. 12-13 (Rogers). Should carbon restrictions become a reality, this could mean significant cost savings for Duke Energy Indiana and its customers; but as Mr. Moreland cautions, there are both capacity and efficiency penalties associated with the carbon capture process, which will require further study.

As Mr. Moreland points out, carbon capture is only the first step; once capture has been completed, sequestration of the removed CO₂ is also necessary. Duke Energy Indiana has preliminarily studied the possibility for CO₂ sequestration at the Edwardsport site, working with the Midwest Geological Sequestration Consortium to perform a preliminary feasibility study. Mr. Moreland testified that according to that study, there is a good possibility of significant amounts of sequestration potential within an area below and immediately surrounding the site. Pet. Ex. No. 4, pp. 11-12 (Moreland Direct).

B. OUCC and Intervenors' Evidence and Petitioner's Response. Several parties (the OUCC and the CATF/IWF) urged Petitioner to more aggressively pursue carbon capture and sequestration or enhanced oil recovery in conjunction with the Edwardsport IGCC Project.

The OUCC agrees with Petitioner that there is a very strong possibility of carbon regulation in the near future. Ms. Smith testified that the OUCC believes it to be in the economic interest of Indiana ratepayers to plan for carbon regulations, and that the IGCC Project fulfills this interest. In her testimony, Ms. Smith acknowledged that Duke Energy has taken a leadership role in this research and is an active participant in the DOE's Midwest Regional Carbon Sequestration Partnership. Ms. Smith presented independent testimony showing that carbon capture and sequestration ("CCS") is estimated to be significantly less expensive for an IGCC plant as opposed to a PC plant. Ms. Smith presented testimony that the OUCC was not aware of any major technical or knowledge barriers regarding CCS, and believes that the design of the IGCC Project as proposed would allow for the capture of around 20% of the CO₂ without significant impact on the current design or construction schedule. The OUCC supports the building of the IGCC project with 20% carbon capture. Public's Ex. No. 2, pp. 9-14 (Smith). On cross examination, Ms. Smith concurred that it made sense for the Company to further study carbon capture so as to fully understand the impacts to the plant. Ms. Soller testified that IGCC with CSS must be explored if coal is to be part of Indiana's energy future, and that the construction of an IGCC plant provides the state with a unique opportunity to explore CCS. Ms. Soller also emphasized that the OUCC's support of the IGCC Project depended on the inclusion of partial CCS in the design and construction of the plant. Public's Ex. No. 1, pp. 6, 16, 19 (Soller).

The CATF and IWF strongly support the IGCC Project. Witness Mr. Cortez testified that the IGCC technology can economically achieve very low emissions of regulated air pollutants such as SO₂, NO_x, and particulates. Mr. Cortez agreed with Petitioner's description of the IGCC Project as "carbon capture ready." According to Mr. Cortez, the cost and performance

penalties of carbon capture on a Supercritical Pulverized Coal plant ("SCPC") would be much greater than for IGCC, and this technology is commercially unproven in SCPC. Mr. Cortez believes that the cost and performance penalties of carbon capture in IGCC can be partially mitigated if the initial plant is designed for future retrofitting for carbon capture. Mr. Cortez also presented testimony as to additional equipment necessary for capturing and handling CO₂, including a CO₂ absorber, equipment to dehydrate the captured CO₂, and equipment to compress the dehydrated CO₂ for handling and disposal. Mr. Cortez expressed the opinion that the detailed engineering of the added equipment could be carried out after full release of the IGCC Project without delaying the construction schedule. CATF/IWF Ex. 1 pp. 6-13 (Cortez Direct).

CATF/IWF witness Mr. Melzer testified as to potential for sequestration near the IGCC Project, stating that he had ample cause to believe that enhanced oil recovery ("EOR") in particular had great potential near the Edwardsport area. Mr. Melzer presented testimony that the Midwest Geologic Sequestration Consortium estimates potential for 860,000,000-1,300,000,000 barrels of oil while sequestering 140,000,000-440,000,000 tons of CO₂. CATF/IWF Ex. 6, pp. 10-13 (Melzer).

CATF/IWF witness Mr. Thompson expressed that the CATF and IWF strongly support the IGCC Project, but with the addition of the necessary work and equipment to capture and dispose of 15-20% of carbon emissions. Mr. Thompson believes that the IGCC Project offers significant environmental benefits and advantages while offering a valuable opportunity to investigate CCS. Mr. Thompson recognizes that the IGCC technology is inherently cleaner than pulverized coal plants, and that Duke Energy Indiana has already opted to include additional cleaner coal technologies (such as SCRs). Mr. Thompson maintains that it is reasonable to expect mandatory regulatory constraints on carbon emissions for all power producers in the United States, and the IGCC Project is an opportunity to "get ahead of the problem." Mr. Thompson views the IGCC Project as important for gaining experience in sequestering CO₂, and believes the Commission should require carbon capture as part of the CPCN. CATF/IWF Ex. 3, pp. 5, 9, 20-24 (Thompson Direct).

IIG Witness Mr. Phillips pointed out that there are currently no carbon regulations. Additionally, Mr. Phillips testified that carbon sequestration is commercially unproven, and also expressed concern regarding the unknown capacity and efficiency penalties of adding carbon capture equipment to the IGCC Project. IIG Ex. No. 1, pp. 8-9 (Phillips Direct). In his cross-answering testimony addressed at the OUCC and CATF/IWF's support of CCS, Mr. Phillips stated that the current uncertainty of the economic impact of adding CCS to the plant makes it impossible for the Commission to determine whether the IGCC plant with CCS would be an economic means of meeting Duke Energy Indiana's ratepayers' needs. Mr. Phillips further testified that Petitioners are still evaluating the technical feasibility of geologic sequestration, and pointed out that the environmental effects, legal liabilities, and costs of sequestration have not yet been fully studied. Mr. Phillips emphasized that there are many unknowns regarding future carbon regulation, and stated his belief that it would be imprudent to plan on the assumption of strict carbon constraints in a very short time period. IIG Ex. No. 3, pp. 1-10 (Phillips Cross-Answering).

Petitioner responded to the CCS issues concluding that, while the indications are very promising, that there is still much uncertainty with regard to carbon capture and sequestration, and further study is needed. According to Petitioner's witness Mr. Moreland, CATF/IWF witness Mr. Cortez significantly understated the work necessary to accomplish partial carbon capture, and more study is required of both the carbon capture for the plant and the potential sequestration options. Pet. Ex. No. 19, pp. 5-8 (Moreland Rebuttal). Petitioner witness Ms. Radcliffe enumerated the open issues associated with sequestration, including the feasibility and cost of permanent geologic storage, insurance and legal liability, property rights, regulatory issues, and public acceptability, which require further study and possibly state and/or federal government legislation. As Ms. Radcliffe details in her testimony, Duke Energy continues to study the sequestration through the U.S. DOE Regional Carbon Sequestration Partnerships, including through a DOE Phase II project at Duke Energy Kentucky's East Bend coal plant, at which sequestration potential will be tested in geology very similar to that at the Edwardsport site. Additionally, Petitioner has applied to take part in a DOE Phase III project using the CO₂ from the Edwardsport IGCC Project that will test the feasibility of carbon capture and geological sequestration of large volumes of CO₂ over four years. Ms. Radcliffe testified that as a Phase III project participant, Duke Energy Indiana would have access to a broad range of expertise and gain a valuable internal knowledge base. Pet. Ex. No. 21, pp. 3-12 (Radcliffe Rebuttal).

Petitioner's witness Ms. Pashos emphasized that the IGCC Project is first and foremost an environmentally friendly and economic way to meet baseload capacity needs. However, the Company is committed to exploring CCS for the future. Ms. Pashos presented in her testimony Duke Energy Indiana's proposed path forward for CCS at the IGCC Project, including the following commitments, all subject to future Commission approval and cost recovery authorizations:

- To conduct a FEED study specifically targeted at understanding the costs and performance impacts of partial (15-18%) CO₂ capture at the IGCC Plant in the 2008 timeframe.
- To conduct a study (or studies) to determine feasible and acceptable sequestration options through either the DOE Phase III program, EOR, or other sequestration opportunities in the 2008 timeframe.
- To take reasonable steps during the detailed engineering and construction phase of the Project to include infrastructure, as identified in a carbon capture FEED study, to support 15-18% carbon capture.
- To initiate a case before the Commission to address CCS and EOR issues within six months following the granting of CPCNs for the IGCC Project. The purpose of the case will be to provide details to the Commission and other interested parties about the proposed studies, and to seek Commission approval to move forward with the above-mentioned activities.
- To work with interested parties toward state legislation constructively addressing potential liability and land right issues associated with CCS.

- To seek necessary regulatory, environmental, *etc.* permitting for CCS and EOR if all other actions are approved by the Commission.
- To meet with the OUCC, CATF, and IWF to update them on progress.

Ms. Pashos testified that pursuing CCS is beneficial because it is environmentally and economically sound policy to prepare for a carbon constrained future. Pet. Ex. No. 17, pp. 2-5, 13-15 (Pashos Rebuttal).

C. Commission Discussion and Findings on Carbon Capture and Sequestration. Based on the evidence presented in this proceeding, the Commission recognizes that carbon regulations are likely, regardless of disagreements over the scope or cost of those restrictions. Given that probability, the Commission further finds that CCS technology holds the potential for keeping cost-effective, local coal an environmentally responsible and economical fuel source in a carbon constrained future. Nonetheless, the existing liabilities and uncertainties prevent CCS from being currently deployed, and carbon is not currently regulated. The Commission accepts Petitioner's assurances to move forward as research indicates, and asks Petitioner to return within six months of the granting of this CPCN with carbon capture and sequestration study proposals. Given the inherent environmental benefits of IGCC technology as well as the strong potential for CCS, the Commission finds that it is reasonable for Petitioner to move forward as planned.

12. Requested Ratemaking / Accounting Treatment.

A. Petitioner's Requested Ratemaking / Accounting Relief. In its case-in-chief, Duke Energy Indiana sought approval of certain ratemaking and accounting treatment for the IGCC Project, including:

- timely recovery of its construction (financing) and operating and maintenance (including depreciation, property taxes, *etc.*) costs incurred in connection with the IGCC Project;
- the use of accelerated (20-year) depreciation;
- an incentive associated with the IGCC Project equal to an incremental 200 basis points on the return on shareholder equity that would otherwise be earned by the Company over the life of the project;
- deferral of post-in-service carrying costs and O&M costs (including depreciation, property taxes, *etc.*) on an interim basis until such costs are reflected in Duke Energy Indiana's retail rates; and
- recovery of Duke Energy Indiana's external costs related to the development and presentation of the case. Pet. Ex. No. 2, pp. 18-19 (Pashos Direct).

In addition, the Company requested the Commission conduct an ongoing review of the construction of the IGCC Project as it proceeds. The Company initially requested approval of interim cost recovery of costs that needed to be incurred on the IGCC Project prior to the expected date of a Commission Order in the CPCN proceeding. However, the Company subsequently withdrew that request, as was discussed at the outset of this Order.

(1). **IGCC Rider/Accounting Treatment.** Mr. Stephen Farmer, consultant for Duke Energy Indiana, explained the Company's proposed Standard Contract Rider No. 61 (the "IGCC Rider"), which is a combination rate recovery mechanism that incorporates many of the attributes of Duke Energy Indiana's Rider 62 (the Qualified Pollution Control Property Revenue Adjustment) and Rider 71 (the Clean Coal Operating Cost Revenue Adjustment). The IGCC Rider will be used to recover the construction work in progress ("CWIP") financing costs, the operating and maintenance costs, including depreciation and property taxes, and the external costs incurred in connection with the IGCC Project. Table 1 in Mr. Farmer's direct testimony details the costs that would flow through the proposed IGCC Rider. He explained that the O&M expenses would include: (a) increased payroll costs, including payroll taxes and employee benefits, to be determined based on Duke Energy Indiana's payroll tax and fringe benefit loading rates; (b) property insurance applicable to the IGCC Project; and (c) the amortization of external costs relating to the development of regulatory filings associated with the IGCC Project including outside consulting costs relating to this proceeding. Mr. Farmer explained that the Company would reduce O&M expense recovery by the O&M expenses applicable to the retiring Edwardsport steam generating plant that are recovered in base rates (\$5,756,000 on an annual basis, before jurisdictional allocation). Pet. Ex. No. 13, pp.3, 5, 7, 14-16 (Farmer Direct).

Mr. Farmer indicated that the IGCC Rider would recover property tax expense applicable to the IGCC Project as recorded on the Company's books and records, reflecting the property tax abatements and Tax Increment Financing credits. He indicated that customers would receive a credit for retiring Edwardsport steam generating station property taxes included in rates in accordance with the provisions of the Commission's Order in Cause No. 42359, whereby the difference between the *pro forma* level of property tax expense included in the jurisdictional cost of service approved in Cause No. 42359 and actual property taxes paid after jurisdictional allocation, are credited back to customers via Rider 62. *Id.* at 7-10.

Mr. Farmer stated the Company proposed to update its IGCC Rider costs every six months, with supporting testimony and exhibits similar to the type of information typically presented in Rider 62 and 71 proceedings. The IGCC Rider will apply to all retail customers served under the Company's firm power tariff rates and will be billed to individual customers within a retail rate group based on billed kWh sales, except for industrial customers served under Rate HLF. Mr. Farmer indicated that the Company proposed that the allocation of recoverable costs within Rate HLF be based on kW sales as opposed to a kWh basis, which is consistent with the rate design principles approved by the Commission in Cause Nos. 42622 and 42718 (the Company's Phase 1 CAIR/CAMR environmental compliance case). *Id.* at 14-16.

Mr. Farmer testified that the accounting treatment for which the Company is seeking approval is consistent with, if not the same as, those that the Commission has authorized

in the Company's various environmental proceedings. He also testified that the Company has accounting procedures in place that stop the accrual of AFUDC on the portion of environmental project capital costs receiving retail CWIP ratemaking treatment and that these same procedures will be applied to IGCC Project costs. Duke Energy Indiana also has procedures in place that recognize the difference in ratemaking between retail and wholesale jurisdictions with respect to environmental costs, which will be applied to IGCC Project costs. *Id.* at 18-19.

Mr. Farmer explained that the Company is proposing to be allowed to continue the accrual of AFUDC and deferral of operating expenses after the in-service date of the IGCC Project to the extent that costs are not reflected in Duke Energy Indiana's retail electric rates (*i.e.*, through the IGCC Rider or in base rates). The differential between post-in-service costs recovered in rates and actual costs incurred will be relatively small if the Company's proposed IGCC cost recovery mechanism is utilized. The Company will file its initial request for recovery of costs related to the IGCC Project after the Commission's Order is issued – and is requesting that the six-month restriction on filing for CWIP ratemaking treatment applicable to qualified pollution control projects not apply to the IGCC Project. *Id.* at 18.

Mr. Farmer stated that the Company will recover fuel costs applicable to the IGCC Project through its FAC and that emission allowance costs will be recovered through its emission allowance cost recovery mechanism. The IGCC technology will allow the Company to use more high sulfur Illinois Basin coal, which should result in future fuel savings. Mr. Farmer also explained that the recovery of IGCC Project costs will be included in FAC earnings and expense tests calculations in the same manner that the recovery of environmental financing costs and operating expenses are handled. *Id.* at 20-21.

Mr. Farmer described the estimated rate impacts expected from the IGCC Project. Mr. Farmer explained that the rate impacts did not attempt to take any credit for the expected lower fuel and emission allowances costs associated with this plant. After the FEED Study was completed and the Company had a more up to date estimate of the cost of the Project, Mr. Farmer updated the rate impact analysis in rebuttal testimony, demonstrating that the rate impacts from the IGCC Project would be phased in over the construction period and were estimated to result in an overall total class rate impact of approximately 16% if Duke Energy Indiana owns 100% of the plant. Again, this estimate did not attempt to take credit for expected lower fuel and emission allowance costs associated with the Edwardsport IGCC Project. *Id.* at 21-22; Pet. Ex. No. 28-E (Farmer Rebuttal).

(2). **Ratemaking Treatment for Tax Incentives.** Mr. Farmer also explained the Company's proposed ratemaking treatment relating to various state, local and federal tax incentive applicable to the IGCC Project. The Company proposed to credit the reduction in tax expense through the IGCC Rider. He then explained that the Company proposed to credit customers through the IGCC Rider for its reduction in property taxes through the ten-year abatement and the TIF reimbursement, both of which were awarded to the Company by the Knox County Council. Pet. Ex. No. 13, p. 8 (Farmer Direct).

Mr. Farmer testified on how the Company proposed to incorporate the recovery of IGCC Project property taxes in rates while honoring the commitments regarding property taxes

made in the Company's last rate case. The Company proposed that property taxes applicable to the IGCC Project be recovered through the IGCC cost recovery mechanism because by tracking IGCC property taxes, the Company will neither over nor under recover IGCC Project property taxes. The Company's commitment in the rate case (for the Company to bear the risk of increases in property taxes) will remain intact, but will exclude IGCC Project property taxes. *Id.* at 9.

Mr. Farmer then described the federal clean coal investment tax incentives for which the Company has applied. He explained that the primary benefit to the recipient of the tax credit is the fact that by using the investment tax credit to offset federal income tax liabilities that would otherwise be payable, the Company is able to preserve a larger share of internally generated funds that can be used to fund necessary capital expenditures – meaning, the Company's need to fund capital expenses with outside capital is reduced. Mr. Farmer also stated that the tax credit is front-end loaded, which is especially important during the most critical and sensitive financial period for companies – the initial construction period when large sums of new capital must be raised. The Company proposed to amortize the federal clean coal investment tax credits ratably over the proposed regulatory life of the IGCC Project. Duke Energy Indiana proposed to pass the jurisdictional portion of this credit through to retail customers through the IGCC Rider. *Id.* at 10-13.

(3). Incentive Return on Equity / Accelerated Depreciation. As allowable under Ind. Code § 8-1-8.8-11 (a)(2), Duke Energy Indiana initially requested an incentive associated with the IGCC Project equal to an incremental 200 basis points on the return on shareholder equity ("ROE") that would otherwise be earned by the Company over the life of the IGCC Project. In its rebuttal filing, the Company agreed to reduce its request to an incremental 150 basis points on ROE, in consideration of the rate impact on customers. Ms. Pashos explained that the Company's request for incentives was reasonable in light of the General Assembly's encouragement of clean coal technology and coal gasification, Duke Energy Indiana's efforts to obtain benefits for customers in terms of local, state and federal tax incentives, and the economic development benefits the Project is expected to bring to the state. Specifically, Ms. Pashos noted that the proposed Edwardsport IGCC Project falls within the types of projects explicitly encouraged by the General Assembly through the eligibility for financial incentives. In addition, she emphasized that Duke Energy Indiana has worked very hard to create this Project and to create value for its customers through obtaining IGCC Project tax credit incentives at the federal, state and local levels – over \$450 million of tax credit incentives in total, which will flow through Petitioner's rates to benefit customers. Pet. Ex. No. 2, pp. 19-20, 22 (Pashos Direct); Pet. Ex. No. 17, pp. 10-11, 15-20 (Pashos Rebuttal). Additionally, Dr. Shilling noted during cross-examination that Duke Energy Indiana has been actively involved with GE and Bechtel throughout the Project design and engineering process, and has contributed many design and engineering suggestions which will be incorporated into the Project design -- creating more value for customers through improvement of the Project design.

As allowable under Ind. Code § 8-1-2-6.7 and Ind. Code § 8-1-8.8-11, Duke Energy Indiana initially requested the use of accelerated (20-year) depreciation for the IGCC Project; however, as discussed below, Duke Energy Indiana withdrew this request, also in

consideration of the rate impacts on customers, and instead requested approval to use a more standard 30-year depreciation for this Project. Pet. Ex. No. 2, p. 19 (Pashos Direct); Pet. Ex. No. 17, p. 11 (Pashos Rebuttal).

B. Need For and Reasonableness of Requested Ratemaking Relief.

Ms. Pashos testified that the Company's ratemaking request is reasonable and entirely consistent with the intent of the Indiana General Assembly – which has provided both tax incentives and ratemaking and accounting incentives for projects such as the IGCC Project. Pet. Ex. No. 2, pp. 19-20 (Pashos Direct).

Mr. Farmer testified that the cost tracking treatment requested was reasonable and necessary due to the critical nature of timely cost recovery. He explained that timely cost recovery is especially important for capital intensive industries such as the electric utility industry that, out of necessity, must rely heavily on borrowed funds to finance long-lived capital projects whose capital recovery is measured in terms of decades as opposed to months or years. He further stated that the primary benefit of timely cost recovery is the lower incremental borrowing rates on new capital. Pet. Ex. No. 13, p. 3 (Farmer Direct).

Ms. Lynn Good, Vice President and Treasurer of Duke Energy Corporation, explained the importance of the additional 150 basis points on the return on equity for the IGCC Project for providing the strong cash flow generation and retained earnings integral to the financing of these capital expenditures. This incentive will also help maintain the strong credit metrics necessary for cost-effective access to the capital markets. Ms. Good explained that the Company's customers benefit from achieving a high level of credit quality through lower overall financing costs and greater access to the capital markets. Pet. Ex. No. 10, p. 11 (Good).

Ms. Good indicated that recovery of its expenditures related to the IGCC Project and approval of its other ratemaking and accounting relief is of increasing importance to the maintenance of the Company's financial strength during the building cycle, especially in light of the Company's capital commitments for maintenance and environmental compliance. *Id.* at 12.

Mr. Steven Fetter, President of REGULATION UnFETTERED, stated his belief that the Indiana General Assembly enacted its clean coal project incentive legislation because it desired that the Commission use its incentives to encourage clean coal projects. He then said that, in light of this recently enacted legislation, the financial community would have concerns about whether the Commission would continue the constructive regulatory approach for which it is highly regarded if the Commission were to forego use of the clean coal incentives to encourage Duke Energy Indiana's IGCC Project. Pet. Ex. No. 11, pp. 20-21 (Fetter Direct).

He concluded by stating that the major credit rating agencies will track closely the substantial amount of investment that Duke Energy Indiana plans to expend during the next several years, and that strong Commission support for the IGCC Project would help to alleviate credit rating agency concerns that additional unforeseen, but certainly possible, expenditures of capital to meet changing environmental mandates could severely weaken the Company's credit profile. Pet. Ex. No. 11, pp. 22-23 (Fetter Direct).

C. OUCC and Intervenors' Evidence and Petitioner's Response.

(1). Incentive ROE. Witnesses for the OUCC, IIG, and CAC, *et al.* opposed Petitioner's request for an incentive ROE. OUCC witness Mr. Wes Blakley testified that the Company's rate of return is commensurate with peer utilities with similar risk profiles and fairly compensates it for its investments in the IGCC Project, given the current economic climate. Mr. Blakley said that, if approved, customers will bear the financial risk of an unprecedented amount, nearly \$2 billion. Further, he indicated that past requests for enhanced rates of return on shareholder equity have not been approved by the Commission; rather such cases resulted in settlements. Public's Ex. No. 3, pp. 4-5 (Blakley).

Mr. Blakley also reminded the Commission of the significant incentives provided to the Company without an enhanced return. He mentioned the ability to recover investments in Qualified Pollution Control Property through a tracking mechanism, earning a return of and on this capital investment as well as receiving the benefits of accelerated depreciation and tracked O&M expenses. Mr. Blakley stated that the OUCC contends that Indiana's clean coal technology statutes provide adequate financial security for utilities and that any financial risks that arise in the construction of these projects are virtually eliminated by statute. *Id.* at 5-8.

IIG witness Mr. Michael Gorman stated that Duke Energy Indiana's request for a 200 basis point incentive return on equity to its last authorized return on equity should be rejected. Mr. Gorman compared the Company's return on equity with the industry average for integrated electric utility companies in 2006, which was 10.36%, and determined that the Company's return on equity was an above industry average return. He also mentioned that the 10.5% return on equity provides the Company with a premium of around 4.5 percentage points over its current marginal cost of debt (approximately 6.2% or 6.0%). Based on these factors, Mr. Gorman concluded that 10.5% was fair and reasonable compensation for the Company's investment risk and will support the Company's current and targeted bond ratings. IIG Ex. No. 2, p. 3 (Gorman).

Mr. Gorman then said that it would be unfair of the Commission to require customers to pay for an incentive equity return while the IGCC Rider's tracking mechanism shifts the Company's investment risk to customers. Mr. Gorman also stated that the credit rating agencies would consider the proposed IGCC Rider as a positive due to the reduced operating risk to Duke Energy Indiana. *Id.* at 3-4.

Mr. Gorman stated that another factor considered by credit agencies in assessing ratings is the need for the utility to maintain competitive cost structures and retail rates. He said that this factor is critical because a utility's customers must be able to pay for utility service. Otherwise, Mr. Gorman stated, customers will be forced to consider alternative sources of energy or to relocate their production facilities. He stated that an important element in maintaining credit quality is to develop a regulatory mechanism to provide the utility a good probability of full cost recovery, and that will also result in just and reasonable and competitive rates to end-use customers. *Id.* at 4.

CAC, *et al.* witness Mr. Biewald recommended denial of the Company's requested ratemaking treatment, including its requested enhanced return on equity. RC Ex. B, p. 5, 47-49 (Biewald).

Duke Energy Indiana witnesses filed rebuttal testimony defending the Company's request for an incentive ROE. Ms. Pashos testified that Duke Energy Indiana continues to believe that an ROE incentive is appropriate in this case, but is reducing its request from a 200-basis point ROE incentive to a 150-basis point incentive, due to the current increasing rate environment. She reminded the Commission that the requested ROE incentive is entirely consistent with the legislature's authorization and stated intent to "encourage the use of advanced clean coal technology, such as coal gasification." Ind. Code § 8-1-8.8-1. She also noted that the language of the statute indicates that the incentive was designed to encourage certain activities by Indiana utilities and does not require justification in terms of risk profile or credit quality concerns. Ms. Pashos stated that there exist strong policy reasons for a full incentive in this case, but that the Company had reduced its request to a 150-basis point incentive, in order to mitigate the rate impact of the IGCC Project. Pet. Ex. No. 17, pp. 10-11, 15-20 (Pashos Rebuttal). On cross-examination, Ms. Pashos indicated her belief that the Commission retains important discretion in this area – both to determine the reasonableness and necessity of the proposed Project, as well as the amount of any ROE incentive (up to a maximum of 300 basis points additional ROE). But, she also emphasized her belief that the General Assembly clearly intended for Projects that meet the requirements of Senate Bill 29 to receive a meaningful incentive.

Duke Energy Indiana witness Mr. Fetter indicated that Indiana's clean coal legislation does not include a financial integrity test before an incentive ROE can be awarded. Instead, he stated that the law provides a true incentive apart from traditional ratemaking in order to encourage what the legislature views as beneficial utility behavior from a public policy standpoint. He maintained that the legislature intends to have Indiana utilities continue to rely upon the state's coal resources in a forward-thinking environmental manner. Mr. Fetter stated that the IGCC Project is wholly consistent with the legislative findings and policy objectives of the law. Pet. Ex. No. 26, p. 3 (Fetter Rebuttal).

On cross examination, OUCC witness Mr. Blakley indicated that four of the five cases where an incentive ROE has been requested resulted in the Commission approving a fixed rate of return for the environmental projects at issue – a rate of return that would not be subject to adjustment under the normal CWIP rules. He also agreed that in the case of IP&L, there was no separately identifiable return on equity percentage set out in its last rate case, which created difficulties in determining whether the IP&L fixed rate of return for qualified pollution control properties resulted in an incentive ROE, or not; although he did not believe it did.

(2). **Depreciation Issues.** Witnesses for the OUCC and IIG contended that Company's assumption of a 20% negative net salvage for the IGCC Plant was not reasonable and should be rejected. IIG witness Mr. Gorman argued that because the Company has not yet established what its cost of removal of the IGCC Project would be, the proposed 20% net salvage cost is not based on a complete and credible study and should be rejected as not known and reasonably measured. He also explained that a negative net salvage of 20% increases the

depreciation rate on the IGCC Project from 5% to 6%, which has a meaningful impact on the annual revenue requirement of the IGCC Project. Mr. Gorman also stated that the proposed accelerated (20 year) IGCC depreciation would produce credit rating financial metrics that are much stronger than needed to support the Company's current and targeted bond ratings. IIG Ex. No. 2, p. 4 (Gorman).

OUCC witness Mr. Blakley described the OUCC's concerns related to the requested depreciation rate and the 20% net negative salvage value factor, which increases the overall depreciation rate to 6%. He noted that there is no mention of "negative net salvage value" in any of the clean coal technology statutes. Mr. Blakley then explained that the design life of the IGCC Project is 30 years, which means that its rate of depreciation is 3.33% per year. But, he stated that when this amount is grossed up with the 20% negative net salvage value factor, it becomes a depreciation of approximately 4%. The depreciation rate requested by the Company fully compensates it for any negative net salvage value based on the 30 year life of the facility. Mr. Blakley explained that each additional one percent amounts to an additional cost of \$16 million for Duke Energy Indiana's customers. Public's Ex. 3, pp. 7-8 (Blakely).

Duke Energy Indiana filed rebuttal testimony concerning these depreciation issues. Mr. Roebel testified that the Company is not proposing to place depreciation rates into effect until the plant goes into operation, and then only after a depreciation study, including a study of the cost of decommissioning the plant. He stated that depreciation expenses, including decommissioning costs, will be a cost of using the plant to serve our customers and should be considered. However, in light of Intervenor and OUCC questions, the Company reviewed its approach and is now proposing a 10% negative net salvage value. Mr. Roebel indicated that the IGCC Project will have a much lower profile than a pulverized coal plant and that the cost of dismantling should be less costly. Pet. Ex. No. 27, p. 7 (Roebel Rebuttal).

Mr. Farmer explained that the concept of recovering costs relating to negative net salvage, whether they be costs incurred due to interim retirement or replacement of property or whether they be final decommissioning costs incurred at the end of a project's life, is a standard and accepted part of normal ratemaking. He stated that the Company now estimates that a more likely percentage of negative net salvage is closer to 10% than 20% and that he has included this value amount as a placeholder in the rate impact analysis. Pet. Ex. No. 28, p. 2 (Farmer Rebuttal).

Ms. Pashos testified that in order to help mitigate the rate impact, the Company was withdrawing its request for accelerated (20 year) depreciation and seeking a traditional 30-year depreciation life. Mr. Farmer testified that unlike the Company's request related to the negative net salvage value, the Company is proposing that the Commission find and approve a thirty-year depreciation life for the IGCC Project. In other words, whether the depreciation study to be conducted later finds that the actual depreciation period should be shorter than or longer than thirty years, Duke Energy Indiana is requesting that it be authorized to recover its IGCC depreciation costs on a straight-line basis over thirty years for ratemaking purposes. Mr. Farmer also indicated that he included the thirty-year life in his updated rate impact analysis. Pet. Ex. No. 17, p. 11 (Pashos Rebuttal); Pet. Ex. No. 28, p. 3 (Farmer Rebuttal).

(3). **Non-Native Sales / Wholesale Native Load Sales Issues.** OUCC witness Ms. Soller testified that because this plant was not included in the calculation of the target value of non-native sales profits in Duke Energy Indiana's last rate case and because the capital cost of the IGCC plant is substantially higher than the cost of the Company's average production fleet, the Company should be required to credit its ratepayers with 90% of any wholesale power sale margins from generation at the IGCC plant, with the remaining 10% net profits going to shareholders. In the alternative, the OUCC believes wholesale power sales margins from this facility should be subject to the same 50-50 sharing mechanism that was approved in the Company's last base rate case. Public's Ex. No. 1, pp. 10-11 (Soller).

Duke Energy Indiana submitted the testimony of Ms. Pashos to rebut the OUCC's recommendation. Ms. Pashos began by making the assumption that Ms. Soller was referring to non-native, off-system sales profits that may result from the IGCC Project, as opposed to firm wholesale native load sales revenues – which she indicated were quite different in that they receive a full allocation of fixed production costs not borne by retail customers. Ms. Pashos testified that retail customers will share in any non-native, off-system sales profits ultimately created by this Project through the Commission approved Standard Contract Rider No. 70 ("Rider 70") sharing mechanism. Ms. Pashos indicated that to the extent that the OUCC is recommending a different level of non-native off-system sales profits be built into base rates, any such proposal is quite premature. The plant is not even approved or built yet, and there is no fixed, known, or measurable data to support such a proposal. Further, under Rider 70, non-native, off-system sales profits are tracked and shared above the level built into base rates, thus retail customers will participate in any increases (from whatever source) in net non-native sales profits. Ms. Pashos also indicated that Ms. Soller's 90% sharing mechanism may be administratively burdensome to implement and that the IGCC plant is expected to be one of the lowest costs units on the Duke Energy Indiana system, and as such will dispatch toward the bottom of the economic stack and will realistically be used to serve native load customers' needs, and not off-system, non-native sales. Pet. Ex. No. 17, pp. 20-21 (Pashos Rebuttal and testimony at hearing).

On cross examination, Ms. Soller agreed that while the Company has an opportunity to share in off-system sales profits above the level built into base rates, since the implementation of the Rider 70 sharing mechanism, the Company's shareholders have yet to share in any amount of revenues above the level built into base rates, and therefore customers have gotten credit for 100% (or more than 100%) of the actual off-system, non-native sales profits to date.

(4). **Deferred Taxes.** IIG witness Mr. Gorman stated that Duke Energy Indiana's proposed treatment of deferred tax balances related to the IGCC Project was unreasonable because by including the IGCC deferred tax balance in its total company capital structure, the Company will be spreading these deferred tax balances across all of its regulated utility costs of service, not just the IGCC Project cost of service. He stated that this proposal is inconsistent with Duke Energy Indiana's proposal to recover the IGCC Project costs separately through the IGCC Rider. Mr. Gorman believes that all tax costs and benefits should be reflected in the IGCC Rider. IIG Ex. 2 p. 5 (Gorman).

Duke Energy Indiana submitted the rebuttal testimony of Mr. Farmer on this issue. Mr. Farmer ultimately agreed with Mr. Gorman's proposal that IGCC tax costs and benefits be captured separately and specifically within the IGCC Rider and that the accumulated balance of deferred income taxes generated by the IGCC Project be treated as a deduction from the cost of plant when calculating jurisdictional revenue requirement. Mr. Farmer also opined that the calculation of financing costs on a newly constructed plant such as the IGCC Project can be significantly understated when the capital structure used to determine jurisdictional return on investment includes the book balance of accumulated deferred income taxes in the capital structure. Mr. Farmer explained that the IGCC Project will not generate any deferred income taxes during construction period. He provided that the estimated accumulated deferred income tax balance attributable to the IGCC Project does not reach the 12+% included in the Company's calculation of the weighted average cost of capital until 2023. Mr. Farmer concluded that if accumulated deferred income taxes are included in the capital structure used to determine the return requirement applicable to the IGCC investment, then the Company would significantly under-recover the cost of financing the project. Pet. Ex. No. 28, pp.4-6 (Farmer Rebuttal).

On cross examination, Mr. Farmer agreed that the CWIP rules mention the inclusion of deferred taxes as one component of the cost of capital, but noted that the provision provided that the "appropriate amount, ratio, and cost rate" should be used, and in his opinion inclusion of deferred taxes for the IGCC Project is not appropriate.

(5). Investment Tax Credit Ratemaking Treatment. IIG witness Mr. Gorman discussed the two options for treatment of the federal investment tax credits – either credit the deferred balances back to customers using an amortization of the balance, or use of the unamortized balance as an offset to rate base. Mr. Gorman believes that the Company should perform a revenue requirement comparison of these two options and that the Commission should select the option that results in the lower cost revenue requirement. IIG Ex. 2, p. 6 (Gorman).

In its rebuttal testimony, Duke Energy Indiana did perform such comparison. Mr. Farmer explained that the comparison includes an estimate of jurisdictional revenue requirements over the thirty-year regulatory life of the IGCC Project. He indicated that the two methods produce different results when compared on a year-to-year basis. Mr. Farmer further explained that the rate base reduction method results in a larger credit during the first half of the asset's life offset by a smaller credit in the last half of the asset's life. The most obvious consequence of choosing this method is that current customers will benefit to the detriment of future customers. Mr. Farmer stated that a second consequence is a significant reduction in the Company's cash flow (approximately \$60 million during the first half of the IGCC Project's regulatory life). He indicated that the Company believes that the positive benefits of the tax credit would be significantly eroded if the credit is flowed through to customers on an accelerated basis. This method would reduce the cash flow to the utility at just the time the cash flow was most crucial, during the construction phase. For these reasons, Mr. Farmer indicated that the Company is opposed to this change. Pet. Ex. No. 28, p. 9 (Farmer Rebuttal).

(6). Reconciliation of O&M Expenses. IIG witness Mr. Gorman opposed the Company's requested reconciliation adjustment mechanism for O&M costs in its IGCC Rider. He stated that the IGCC Rider would not be in effect for an extended period of

time, and projected operating costs should be reasonably consistent with actual operating costs. Mr. Gorman indicated that the proposed reconciliation adjustment would eliminate incentives to manage costs in between semi-annual rate factor adjustments because all cost increases would be passed on to customers. He also said that he believed the reconciliation adjustments to the proposed factor would only increase rate volatility, resulting in higher costs to retail customers. Mr. Gorman states that the Commission should discourage the Company from overstating IGCC projected operating costs in the IGCC Rider by ensuring that such costs are considered in all earnings tests applicable to other Company rate mechanisms, particularly the fuel mechanism. IIG Ex. 2, pp. 19-20 (Gorman).

Duke Energy Indiana witness Mr. Farmer responded that the reconciliation feature included in the Company's IGCC Rider was included to provide equal protection to customers and the Company. He stated that the reconciliation of costs is commonly used in cost recovery mechanisms and is an accepted form of ratemaking. Mr. Farmer testified that projected operating expenses that are recovered under the provisions of Senate Bill 29 are required to be trued up. See Ind. Code § 8-1-8.8-12(f). Mr. Farmer indicated that the Company's proposal protects customers from being overcharged due to variances between actual and projected costs, and due to differences between actual and estimated kilowatt and/or kilowatt-hour sales used to develop billing factors. The Company is protected from under billing customers for the same reasons. Mr. Farmer then clarified that the Company has always planned to incorporate the recovery of the IGCC Project costs in FAC earnings and expense test calculations. Pet. Ex. No. 28, pp. 10-11 (Farmer Rebuttal).

(7). **IRP costs.** OUCC witness Mr. Blakley testified that the Company appears to request recovery of the costs associated with their 2005 IRPs. He said that, if that is indeed the case, the OUCC contends that IRP studies are part of the normal business operations of a utility and were embedded in base rates during the Company's last rate case. Public's Ex. No. 3, p. 10-11 (Blakley).

Mr. Farmer stated that the Company will agree to forgo the recovery of IGCC-related 2005 IRP costs and will not include them in any future IGCC filings. Mr. Farmer indicated that neither Mr. Blakley nor any other intervening party in this proceeding have objected to the deferral and ultimate recovery of external costs relating to the development and presentation of the Company's case in this proceeding. Pet. Ex. No. 28, p. 12 (Farmer Rebuttal).

On cross examination, Mr. Farmer indicated that these external costs included such costs as expert witnesses and consultants that were associated with the IGCC Project and that these external costs were not already included in base rates.

(8). **Transmission Cost Recovery.** Ms. Soller indicated that to the extent the Commission approves the cost recovery of the IGCC Project transmission costs, and a portion of those costs will ultimately be shared among Midwest ISO members through the Regional Expansion and Criteria Benefits ("RECB") process, Ms. Soller recommends that the Company's recovery be reduced proportionately. Public's Ex. No. 1, pp. 17-18 (Soller).

Mr. Farmer agreed that in the event the IGCC Project costs are paid for in part by other Midwest ISO members as part of the RECB process, then Duke Energy Indiana would proportionately reduce its request for recovery of such costs through its proposed IGCC Rider. Pet. Ex. No. 28, p. 11 (Farmer Rebuttal).

(9). **Rate Impact.** The OUCC and Intervenors contend that there is a large rate impact associated with the IGCC Project. IIG witness Mr. Phillips and OUCC witness Ms. Soller indicate that the rate impact is higher than the increase approved in the Company's last base rate case. IIG Ex. 1, p. 2 (Phillips Direct); Public's Ex. No. 1, p. 5 (Soller). CAC, *et al.* witness Mr. Biewald contended that the Company's analyses did not include all the requested ratemaking and therefore did not provide an accurate picture of the true costs of the IGCC Project. Mr. Biewald also states that the Company did not include the impact on the system of the fuel and emission allowances costs associated with the IGCC Project in its analysis. RA Ex. B, pp. 30-31 (Biewald Direct).

Duke Energy Indiana updated its rate impact analysis in the rebuttal testimony of Mr. Farmer. Mr. Farmer explained that this analysis did include all the updated assumptions for the Company's proposed ratemaking treatment, including 30 year depreciation, 10% negative net salvage value, and the 150 basis point ROE incentive. Pet. Ex. No. 28, pp. 2, 4, 8, 15 (Farmer Rebuttal).

Mr. Farmer indicated that the rate increase associated with the IGCC Rider will be phased in over the construction period to a peak impact of between 15% to 19%, depending on the rate class, with an overall total retail class rate impact of approximately 16% based on 100% ownership of the IGCC plant. The overall total retail class rate impact for 80% ownership of the IGCC plant is estimated to be approximately 13%. *Id.* at 15-16. Pet. Ex. No. 28-D, 28-E.

Mr. Farmer agreed that the rate impact analysis did not include an estimate of how the addition of the IGCC Project will affect fuel costs and/or emission allowance costs. He stated that this only serves to make the Company's rate impact analysis conservative because the IGCC Project is projected to be one of the lowest variable cost units on the Duke Energy Indiana system and therefore the system fuel and EA costs are lower than they otherwise would have been with the alternative plan without the IGCC. *Id.* at 13.

On cross and redirect examination, Mr. Farmer indicated that due to time constraints, the Company has not performed a comprehensive analysis of the fuel and emission allowance savings associated with the IGCC Project, but that he had performed a quick, back-of-the-envelope comparison of fuel costs. He indicated that if one were to compare the expected IGCC fuel costs with the fuel costs of a more expensive coal plant on the Company's system, such as Gallagher Station, the savings would be approximately \$40 million per year. Mr. Farmer stated that this is a conservative assumption, which assumes the IGCC Project would displace Gallagher Station, but that if one compared the IGCC Project cost to Midwest ISO market purchases, the savings would be greater. Mr. Farmer indicated that he believed the Company could prepare an analysis of expected fuel and emission allowance savings to be shared with customers if so desired.

Ms. Pashos testified that while the Company recognizes the rate impact is significant in the peak year (first full year of operation of the plant), the rate impact is generally in line with historical rate increases from previous additions of baseload generating plants in Indiana. Pet. Ex. No. 2, p. 22 (Pashos Direct).

D. Commission Discussion and Findings on Ratemaking and Accounting Requests.

(1). **IGCC Rider.** The Commission is mindful that the IGCC Project is the first proposal to build a baseload generating plant in the State of Indiana since the 1980s, and that with such an undertaking comes significant costs and significant financing and capital needs. However, as stated above, we believe this project constitutes a cost-effective and robust choice for meeting increasing demand for baseload generation to serve Duke Energy Indiana's native load customers. Additionally, the rate increase associated with the IGCC Project is to be expected for a baseload plant and is generally in line with rate increases due to the addition of baseload generation in Indiana in the past.²¹ We also find great benefit in Duke Energy Indiana's proposal to phase-in the rate increase over a number of years while construction is ongoing. Finally, as to the rate impact issues, we find persuasive the Company's contention that there will be fuel and emission allowance savings associated with this plant due to its superior efficiency, its low environmental emissions and its ability to use low cost Indiana coal. We fully understand that baseload units have higher initial capital costs and lower operating costs, resulting in a least cost option over the life of the plant.

We are cognizant of the Indiana General Assembly's encouragement of new generating facilities that utilize Indiana coal and clean coal technology, such as coal gasification (see Ind. Code ch. 8-1-8.8), and of the Governor's Home Grown Energy Plan, which also encourages generation additions to meet Indiana's growing electricity needs. We find that the value of timely cost recovery provided for in Senate Bill 29 is beneficial both to the Company and its customers. We agree that a constructive regulatory environment is important to maintain strong credit quality and that good utility credit ratings benefit customers in terms of lower cost of debt. We acknowledge that the incentives provided by Senate Bill 29 provide a constructive regulatory environment. We have previously found that the IGCC Project constitutes clean coal technology and clean coal and energy projects and is therefore eligible for the statutory incentives available to such projects. We now find that Petitioner's proposed IGCC Rider is approved for use and for the recovery of the IGCC Project costs, including financing (CWIP), O&M, depreciation, property taxes, payroll costs, property insurance costs, *etc.* and external costs associated with the IGCC Project, as proposed by Petitioner. Additionally, we approve Petitioner's request for deferral of post-in-service carrying costs and O&M costs (including depreciation, property taxes, *etc.*) on an interim basis until such costs are reflected in Duke Energy Indiana's retail rates.

²¹ See e.g., *PSI Energy Inc.*, Cause No. 36818 (IURC; Jan. 20, 1983) (18.8% increase after addition of Gibson Generating Station, Unit 5); *In re NIPSCO*, Cause No. 38045 (IURC; July 15, 1987)(request for increase of 23.2% or alternatively phased in annual increases of 3.75%, 3.75%, 3.75%, and 3.27% for addition of Schahfer Generating Station Unit 18).

We will now address the specific issues raised by the Intervenors related to Duke Energy Indiana's IGCC Rider. As to the depreciation issues, we agree with Duke Energy Indiana that a depreciation and cost of removal study will be necessary prior to the IGCC Project going in-service and direct that Duke Energy Indiana conduct such a study and provide the results of such study to the Commission in one of its semi-annual IGCC Rider filings, prior to the IGCC Project going on-line. The proper amount of negative net salvage associated with the IGCC Project should be a determination that comes out of that study and may be reviewed or challenged by the OUCC and any interested Intervenors at that time. We also find reasonable and approve Duke Energy Indiana's revised request for 30-year depreciation for the IGCC Project.

On the issue of whether deferred taxes should be included in the cost of capital attributed to the IGCC Project in the IGCC Rider, we agree with IIG witness Mr. Gorman and Mr. Farmer's rebuttal position, that proper ratemaking would exclude such costs from the capital structure and include the deferred tax balance related to the IGCC Project as an IGCC rate base offset. Because the estimated accumulated deferred income tax balance attributable to the IGCC Project does not reach the level included in the Company's calculation of the weighted average cost of capital until 2023, we agree that reflecting the costs in the IGCC Rider would result in an under-recovery of the costs of financing the project, and would not be appropriate. The CWIP rules provide for a utility to use "the *appropriate* amount, ratio, and cost rate as of the date of valuation of the utility's qualified pollution control property under construction *for such capital structure components as* deferred taxes, customer deposits, and investment tax credits." 170 IAC § 4-6-14 (1)(c) (emphasis supplied). We find the CWIP rules provide sufficient discretion in this regard because the rules recognize that only the appropriate amounts must be included in the capital structure and because the listed components, which include deferred taxes, are illustrative only because they follow the clause "such...as."

On the issue of the proper ratemaking treatment for the federal tax incentives, we agree with the Company's proposal. We agree that the rate base reduction method proposed by IIG witness Mr. Gorman would benefit current customers to the detriment of future customers, and would not provide for a proper match of costs with benefits. Additionally, we are cognizant that the benefit of the federal tax incentive is that under the amortization method, it provides a benefit to the Company when it is needed most, in the first years of construction of the project, when the capital requirements are the highest. We find the Company's proposal to amortize the benefit of the tax credits and to pass such benefits back to customers over the life of the plant in accordance with federal tax laws to be appropriate.

Earlier we found that the costs of transmission related to the IGCC Project was a proper cost to include in the cost estimate and was eligible for financial incentives under Senate Bill 29. We agree with the OUCC's proposal, accepted by the Company, that if such transmission costs are partially reimbursed under the Midwest ISO's Regional Expansion and Criteria Benefits process, any costs recovered from Duke Energy Indiana retail customers associated with such transmission projects shall be proportionately reduced.

Regarding whether to include a reconciliation component to the IGCC Rider for O&M costs, the Commission finds that such feature is a commonly used and beneficial device

that protects both customers and the Company from over- or under-recovery, and should be approved. We find unpersuasive the argument that a true-up leaves the utility no incentive to reduce its costs. Furthermore, we recognize that Senate Bill 29 specifically provides that any forecasted tracking mechanism must include a true-up. Ind. Code § 8-1-8.8-12 (f).

We agree with the OUCC's proposal to exclude recovery of the Company's 2005 IRP costs, which was accepted by the Company. Representative IRP costs may already be included as part of the Company's cost of service included in base rates. We also agree with the Company, that its proposal to recover external costs related to the planning, development and presentation of the IGCC case are incremental costs that would not exist but for the IGCC Project, are not otherwise reflected in base rates, and are therefore a proper cost to include in the IGCC Rider, as proposed by the Company.

We also find that in accordance with its proposal, the Company shall file a docketed proceeding semi-annually for recovery of the costs allowable under the IGCC Rider. Because the Company's requested IGCC Rider is requested under Ind. Code § 8-1-8.8-12, we also find that the Company is not required to wait until the IGCC Project has been under construction for six months before filing its first proceeding to recover the CWIP costs associated with the project.

(2). **Incentive ROE.** We have previously concluded that the IGCC Project qualifies as a clean coal and energy project and that it is reasonable and necessary, and is therefore eligible for Senate Bill 29 incentives, such as "The authorization of up to three (3) percentage points on the return on shareholder equity that would otherwise be allowed to be earned on projects...." Ind. Code § 8-1-8.8-11(a)(2). The Commission is mindful of the General Assembly's intent to encourage the use of Illinois Basin and Indiana coal, and specifically for the encouragement of coal gasification technology. We also recognize the Company's extensive efforts to encourage IGCC technology and to create and take advantage of various state, local and federal tax incentives to mitigate the rate impact on its customers, as well as the Company's extensive efforts to create a viable IGCC Project in Indiana. We believe IGCC technology holds great promise for Indiana and for the continued use of coal in an environmentally benign manner, and acknowledge Duke Energy Indiana's leadership role in this regard.

We conclude that the General Assembly has evidenced a clear intent that as long as we find that the projects in question constitute clean coal and energy projects that are reasonable and necessary, we shall offer certain incentives, including an incremental equity incentive return. We agree with the Company that there is no requirement in the law that the Company prove an increased risk or financial need for the incentive; it is a true incentive meant to encourage companies to pursue clean coal and energy projects to the benefit of the State of Indiana. In approving this request, we recognize that Duke Energy Indiana has voluntarily pursued this clean coal and energy project in reliance on the statutory provisions calling for incentives. We note that in previous cases where utilities requested an enhanced ROE, the utilities at issue were complying with mandatory emission reduction requirements whereas, in this case, Duke Energy Indiana voluntarily pursued an option that was encouraged under Senate Bill 29. We also recognize that the previous requests for an incentive ROE were all settled cases,

and as such should not be used as precedent in this or any other case.²² Nevertheless, we would note that, in four of the five settlement agreements,²³ the parties agreed to and the Commission approved a fixed rate of return that is not subject to adjustment for changes in debt or equity, and that under certain circumstances, such fixed rate of return may actually result in an ROE that is higher than the one approved in the utility's previous base rate case. For all of the foregoing reasons, we therefore find that the IGCC Project is entitled to an incentive return on equity and that Company's latest proposal of 150 basis points incremental return on equity –one half of the maximum amount allowable under the law– provides for a proper balancing of shareholder and customer interests, is reasonable and is hereby approved.

(3). **Non-Native Sales / Wholesale Native Load.** The OUCG has requested that 90% of the non-native sales net profits associated with the Edwardsport IGCC Project be credited to customers and 10% of such net profits be credited to shareholders, or in the alternative that any sales from the Edwardsport IGCC Project be included in the Company's existing non-native sales sharing mechanism under Rider 70. We agree with the Company that there is no reason to single out this plant for different treatment; rather any non-native sales associated with this plant should be subject to the existing Commission-approved sharing mechanism under Rider 70. We find the OUCG's argument that this proposed plant was not included in the amount of non-native sales profits included in Company's base rates to be unpersuasive. One of the significant benefits of a tracking mechanism, such as the Company's non-native sales profit tracking mechanism, is that it is flexible enough to deal with significant changes that occur in between base rate cases, changes such as increases or decreases in generation available to the utility, changes in energy markets and changes in market prices, *etc.* The current tracking mechanism has proven to be a substantial benefit to customers since its inception in 2004, providing customers more than 100% of the net profits received by the Company.²⁴ The Company, too, has benefited through a reduction in the base level of non-native sales profits included in rates when the Company did not achieve its test period level. We also recognize that this plant is expected to dispatch toward the bottom of the economic stack and as such, is expected to be used almost exclusively for native load. We therefore, find no reason to treat non-native sales associated with the plant any differently than the Company's other non-native sales.

(4). **Ongoing Review.** No party disputed the Company's request of ongoing review of its IGCC Project and we hereby approve such request. Duke Energy Indiana is directed to file an ongoing review update, including any updates to the project cost estimate and the project schedule contemporaneous with its semi-annual IGCC Rider filings.

²² *PSI Energy, Inc.*, Cause Nos. 42622/42718 (IURC; May 24, 2006); *SIGECO*, Cause No. 42248 Phase II Order (IURC; Jan. 2, 2003); *SIGECO*, Cause No. 42861 (Feb. 22, 2006); *IP&L*, Cause No. 42170 (Nov. 14, 2002); *IP&L*, Cause No. 42700 (Nov. 30, 2004).

²³ The PSI Energy settlement in Cause Nos. 42622/ 42718 did not provide for any enhanced or incremental return on equity or net operating income adjustment, as proposed by the Company initially.

²⁴ *PSI Energy, Inc.*, Cause No. 42695 (IURC; Sept. 14, 2005); *PSI Energy, Inc.*, Cause No. 42870 (IURC; June 28, 2006); *Duke Energy Indiana, Inc.*, Cause No. 43074 (June 13, 2007).

13. Request for Confidential Treatment. Petitioner filed a Motion for Protection of Confidential and Proprietary Information, with Affidavits of Mr. Zupan, Ms. Jenner and Mr. Rose, on October 24, 2006. In this Motion, Petitioner demonstrated a need for confidential treatment for various pricing and operating characteristic information associated with the IGCC Project and Duke Energy Indiana's IRP presented in this proceeding (*e.g.* project cost estimates, competing cost estimates and commodity price forecasts) and certain forecasts of wholesale power, fuel and emission allowance prices received from ICF International. In a November 1, 2006, Docket Entry, the Presiding Officers made a preliminary finding that such information should be subject to confidential procedures. The Affidavits of Mr. Zupan, Ms. Jenner and Mr. Rose indicate that such confidential information has actual or potential independent economic value to competitors, the disclosure of the confidential information could provide competitors with an unfair advantage, and Petitioner and ICF have taken all reasonable steps to protect the confidential information from disclosure.

In addition, Petitioner filed a Motion for Protection of Confidential and Proprietary Information, with Affidavits of Messrs. John B. Lavelle, Dennis Lear and Dennis Zupan, on March 30, 2007. In this Motion, Petitioner demonstrated a need for confidential treatment for various pricing, technical and operating characteristic information, provided by GE and Bechtel to Petitioner, associated with the IGCC Project, including, in particular, confidential information received by Petitioner in connection with the FEED Study. In an April 17, 2007, Docket Entry, the Presiding Officers made a preliminary finding that such information should be subject to confidential procedures. The Affidavits of Messrs. Lavelle, Lear and Zupan indicate that such confidential information has actual or potential independent economic value to competitors, the disclosure of the confidential information could provide competitors with an unfair advantage, and Petitioner, GE and Bechtel have taken all reasonable steps to protect the confidential information from disclosure.

Accordingly, pursuant to Ind. Code § 5-14-3-4(a)(4), we find that the various pricing and operating characteristic information associated with the IGCC Project and Duke Energy Indiana's IRP presented in this proceeding (*e.g.* project cost estimates, competing cost estimates and commodity price forecasts), certain forecasts of wholesale power, fuel and emission allowance prices received from ICF International, as well as various pricing, technical and operating characteristic information provided by GE and Bechtel to Petitioner, associated with the IGCC Project, including, in particular, confidential information received by Petitioner in connection with the FEED Study, are "trade secrets" and should be afforded confidential treatment. The Commission orders that procedures should be taken so that such information is appropriately secured and made available only to selected members of the Commission Staff who are under an obligation not to publicly disclose such information.

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

1. Petitioner is hereby issued certificates of public convenience and necessity and clean coal technology for the Edwardsport IGCC Project under both Ind. Code ch. 8-1-8.5 and 8-1-8.7.

2. The \$1.985 billion estimated construction cost for the IGCC Project is hereby approved as the best estimate of construction cost based on the evidence of record.

3. Petitioner shall be granted financial incentives for the IGCC Project pursuant to Ind. Code ch. 8-1-8.8, including an incremental 150 basis points on the return on shareholder equity that would otherwise be allowed to be earned on the IGCC Project.

4. Petitioner shall be entitled to timely recovery of its construction (financing) and operating and maintenance costs incurred in connection with the IGCC Project through its Standard Contract Rider No. 61 as discussed below in Ordering Paragraph No. 5.

5. Petitioner's proposed Standard Contract Rider No. 61 ("IGCC Rider") is hereby approved to recover the following categories of costs related to the IGCC Project: (1) financing or CWIP costs; (2) O&M costs, including, but not limited to, depreciation, property taxes, increased payroll costs, property insurance, *etc.*; (3) external costs, excluding IRP costs; and (4) transmission costs, excluding any amounts received in the RECB process, all as proposed by Petitioner. Petitioner's proposal for reconciliation of O&M expenses in the IGCC Rider is approved. Petitioner is directed to reduce O&M expense recovery for the IGCC Project by the O&M expenses applicable to the retiring Edwardsport steam generating plant in the amount of \$5,756,000 on an annual basis, before jurisdictional allocation, as proposed by Petitioner. Petitioner is directed to file the IGCC Rider with the Commission's Electricity Division, including any changes necessitated by our findings herein.

6. Petitioner shall file IGCC Rider proceedings semi-annually and may initiate its first IGCC Rider proceeding under the Cause No. 43114-S2 within 30 days following the issuance of this Order.

7. The Commission shall conduct an ongoing review of the construction of the IGCC Project, as proposed by Petitioner through its semi-annual IGCC Rider proceedings.

8. Petitioner shall be permitted to continue the accrual of AFUDC and deferral of operating expenses after the in-service date of the IGCC Project to the extent that costs are not reflected in Duke Energy Indiana's retail electric rates (*i.e.*, through the IGCC Rider or in base rates).

9. Depreciation of the IGCC Project shall be for a period of 30 years, as proposed by Petitioner. Petitioner shall conduct a depreciation and cost of removal study prior to the IGCC plant going in-service and provide the results of such study, including any amount of negative net salvage value requested, to the Commission in one of its semi-annual IGCC Rider filings, prior to the commercial operation date of the IGCC Project.

10. Petitioner shall credit retail customers with the reduction of tax expense related to Petitioner's receipt of state, local and federal tax incentives. With respect to the federal investment tax credit, Petitioner shall amortize such tax credit ratably over the thirty-year regulatory life of the IGCC Project and pass the jurisdictional portion of this credit through to retail customers through the IGCC Rider.

11. Petitioner shall exclude deferred taxes from the capital structure used in the IGCC Rider and include the deferred tax balance related to the IGCC Project as an IGCC rate base offset.

12. Petitioner shall recover fuel costs applicable to the IGCC Project through its Standard Contract Rider No. 60 FAC proceedings and emission allowance costs through its Standard Contract Rider No. 63.

13. Petitioner shall include any non-native or off-system sales generated from the IGCC Project in its currently approved non-native sales sharing mechanism, Standard Contract Rider No. 70.

14. The Commission agrees with the Petitioner, the OUCC, CATF and IWF that future regulation of carbon emissions is likely, and finds that more study regarding carbon capture and sequestration and enhanced oil recovery is warranted. The Commission therefore accepts Petitioner's proposal to file a proceeding within 6 months of the date of this Order regarding further study and potential implementation of partial CO₂ capture at the IGCC Project and further study and potential implementation of CO₂ sequestration and/or enhanced oil recovery using CO₂ captured from the IGCC Project.

15. The confidential information presented in this proceeding is found to be confidential and trade secret and, therefore, excepted from public access.

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

HARDY, GOLC, LANDIS, SERVER AND ZIEGNER CONCUR:

APPROVED:

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

Brenda A. Howe
Executive Secretary to the Commission