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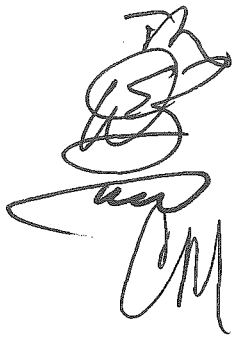

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. REQUESTING THE INDIANA UTILITY REGULATORY COMMISSION TO APPROVE AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-1, *ET SEQ.*, TO THE EXTENT REQUIRED, FOR THE APPROVAL OF AND COST RECOVERY ASSOCIATED WITH THE STUDY OF CARBON STORAGE FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT")	)	CAUSE NO. 43653 APPROVED: JAN 23 2013

BY THE COMMISSION:
David E. Ziegner, Commissioner
Jeffery A. Earl, Administrative Law Judge

On March 6, 2009, Duke Energy Indiana, Inc. ("Duke Energy Indiana," "Petitioner," or "Company") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") in this Cause. On July 17, 2009, Duke Energy Indiana filed a motion in which it requested that the Commission schedule a Technical Conference to generally address technical issues tied to the Petitioner's carbon management, site assessment, and characterization plans proposed in this proceeding. The Presiding Officers granted the request in a July 31, 2009, Docket Entry, and a Technical Conference on these issues was held on August 28, 2009, at 9:30 a.m., in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana.

Pursuant to notice given and published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, an Evidentiary Hearing was held in this Cause on November 9, 2009, at 9:30 a.m., in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. The parties to this proceeding, other than Duke Energy Indiana, included the Indiana Office of Utility Consumer Counselor ("OUCC"); Citizens Action Coalition of Indiana, Inc. ("CAC"); Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"); Indiana Wildlife Federation ("IWF"); the Clean Air Task Force ("CATF"); and the Duke Energy Indiana Industrial Group ("DEIIG"). CAC, Nucor, IWF, CATF and DEIIG are collectively referred to as "Intervenors" throughout this order.

At the Evidentiary Hearing, the Petitioner's case-in-chief consisted of the testimony and exhibits of Mr. Jim L. Stanley, President of Duke Energy Indiana; Mr. Robert D. Moreland, Vice President, Analytical & Investment Engineering; Ms. Darlene S. Radcliffe, Director, Environmental Technology and Fuel Policy; Mr. John Tombari, President, Schlumberger Carbon Services; Mr. David C. Julius, Consulting Engineer, IGCC Project; Mr. John A. Rupp, Assistant Director for Research, Indiana Geological Survey; and Ms. Diana L. Douglas, Director, Rates. In its rebuttal case, Duke Energy Indiana presented the testimony and exhibits of Mr. Jim L. Stanley; Mr. Robert D. Moreland; Ms. Darlene S. Radcliffe; Mr. John Tombari; Mr. John A. Rupp; and Ms. Diana L.

Douglas. All testimony and exhibits offered by Petitioner were admitted into evidence. On December 8, 2009, Petitioner filed a Submission of Late-Filed Notice informing the Commission that the Company's Edwardsport IGCC carbon capture and sequestration project was not selected for funding under the U.S. Department of Energy's ("DOE") Clean Coal Power Initiative ("CCPI") Round 3 funding opportunity.

The OUCC presented the testimony of Ms. Cynthia M. Armstrong, Utility Analyst, and Mr. Wes R. Blakley, Senior Utility Analyst. The CAC presented the testimony of Mr. Kerwin L. Olson, Program Director. The Indiana Wildlife Federation, the Clean Air Task Force, Nucor, and DEIIG did not present testimony in this matter. The pre-filed testimony and exhibits of the OUCC and the CAC were admitted into evidence.

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

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

2. **Petitioner's Characteristics.** Duke Energy Indiana is an Indiana corporation with its principal office located at 1000 East Main Street, Plainfield, Indiana. Duke Energy Indiana is engaged in the business of supplying electric utility service to the public in the State of Indiana. The Company owns, operates, manages, and controls plant, property, and equipment used and useful for the production, transmission, distribution, and furnishing of electric utility service to the public in the State of Indiana. Duke Energy Indiana directly supplies electric energy to approximately 775,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. The Company also sells electric energy for resale to municipal utilities, Wabash Valley Power Association, Inc., Indiana Municipal Power Agency, and to other public utilities that in turn supply electric utility service to numerous customers in areas not served directly by Duke Energy Indiana.

3. **Statutory Framework Referenced by Petitioner.** In its Petition filed in this matter, the Company identified the following Indiana statutes as applicable to its request in this Cause: (1) the Alternative Utility Regulation statutes under Ind. Code ch. 8-1-2.5; (2) Ind. Code § 8-1-2-42(a), which generally prohibits utilities from filing for general rate increases more often than once in a fifteen month period but excepts from this prohibition rates related solely to adjustments in accordance with tracking provisions approved by the Commission; (3) Ind. Code ch. 8-1-8.8, which provides for financial incentives including timely cost recovery and incentive returns for clean coal and energy projects; and (4) Ind. Code § 8-1-2-6.1(c), which allows for recovery (in certain circumstances) of research and development costs designed to increase the use of Indiana coal.[1]

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[1] In *General Motors Corp. v. Indianapolis Power & Light Co.,* 654 N.E.2d 752 (Ind. Ct. App. 1995), the Court of Appeals declared a portion of Indiana Code section 8-1-2-6.6 relating to Indiana coal violated 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. As such, the Commission does not consider the use of "Indiana" or "Illinois Basin" coal as a factor in Duke Energy Indiana's requested relief in this case.

4. **Relief Requested in this Cause and Overview of Prior Proceedings.** Pursuant to the Commission's Order in Cause No. 43114 IGCC-1 regarding the Edwardsport IGCC Project ("IGCC Project"), Duke Energy Indiana received approval to proceed with a carbon capture Front End Engineering Design Study ("FEED Study") and the deferral of costs up to $17 million. *Duke Energy Ind., Inc.*, Cause No. 43114 IGCC-1, 2009 Ind. PUC LEXIS 2, at *81 (IURC Jan. 7, 2009) ("IGCC-1 Order"). Additionally, the Commission indicated that the Company shall initiate a separate proceeding with the Commission regarding carbon sequestration and enhanced oil recovery studies ("Carbon Management Study"), including the Company's proposal for utilization of resources from universities within the State. *Id.* at *82-83. This proceeding was filed in accordance with that Order.

As discussed by Petitioner, geologic sequestration of carbon dioxide ("CO_2") is the technology in which CO_2 that has been captured from a stationary anthropogenic source is injected underground into deep subsurface geological formations for secure confinement with the expectation that the practice will diminish the amount of CO_2 entering the atmosphere. As presented by Duke Energy Indiana, the "site assessment" stage comprises the activities leading up to the selection of a potential site. The "site characterization" stage comprises the work needed to verify the storage capabilities of a site. The "implementation" stage comprises the steps to be performed once a storage site is selected. Duke Energy Indiana proposes to include the initial site assessment and characterization activities in the Carbon Management Study at issue in this proceeding, leaving for a later proceeding the work needed for more detailed characterization activities and implementation.

5. **Direct Testimony Regarding Environmental and Legislative Action Relating to Carbon Emissions and Carbon Storage.**

A. **Testimony Presented by the Petitioner.** Mr. Stanley testified that on June 26, 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act ("ACESA"), which would have established an economy-wide cap on greenhouse gas emissions beginning in 2012. There are numerous other provisions in the bill, including federal renewable electricity and energy efficiency standards and incentives for clean energy technologies including carbon capture and storage. In addition, Duke Energy Indiana believes H.R. 2454 contains important incentives that will accelerate the development and deployment of carbon capture and storage options for coal-fired power plants. In particular, the bonus allowances available may be especially helpful for the IGCC Project if capture and storage are implemented. At the time evidence was filed in this Cause, the bill was awaiting Senate consideration.[2]

Mr. Stanley next discussed how the U.S. Environmental Protection Agency ("EPA") has begun the process of regulating carbon emissions by issuing a proposed endangerment finding on April 17, 2009.[3] In his testimony, Mr. Stanley referenced a recent interview of Ms. Carol Browner, President Obama's special adviser on climate change, in which she indicated that the EPA will move forward with the regulation of CO_2. In the same interview, however, Ms. Browner also

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[2] Ultimately, the Senate did not act upon the bill and it expired at the conclusion of the 111th Congress.

[3] This endangerment finding was in response to the U.S. Supreme Court's decision in *Mass. v. EPA*, 549 U.S. 497 (2007).

indicated that the Obama Administration prefers that Congress draft legislation that could more deftly regulate CO_2 through a cap-and-trade system. Mr. Stanley testified that the President himself has said it is his preference that Congress, and not the EPA, take the lead on regulating greenhouse gases. Mr. Stanley added that climate change involves extremely important public policy issues that absolutely should be the subject of vigorous, public Congressional inquiry and debate by our elected representatives.

Ms. Radcliffe testified regarding the DOE's regional carbon sequestration program and indicated that the DOE established seven regional partnerships of state agencies, universities, private companies, and non-governmental organizations that form the core of a nationwide network to address climate change by assessing the technical and economic viability of various approaches for capturing and permanently storing CO_2 through carbon sequestration. Ms. Radcliffe explained that Duke Energy is a technology coalition partner in three of the seven sequestration partnerships: the Southeast Regional Carbon Partnership, the Midwest Geological Sequestration Consortium ("MGSC"), and the Midwest Regional Carbon Sequestration Partnership ("MRCSP"). According to Ms. Radcliffe, Duke Energy has been the most active in the MRCSP, which is made up of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, West Virginia, New York, and New Jersey.

Ms. Radcliffe explained that partnership activities are divided into three phases. During Phase I, partnerships are formed and an initial assessment of the technical, economic, and social feasibility of carbon sequestration in a region is assessed. In Phase II, the partnerships conduct several small-scale field tests of carbon sequestration opportunities to validate the long-term storage injectivity, containment, and storage effectiveness of various geologic formations. Phase III consists of the initiation of large geologic sequestration demonstration projects.

Ms. Radcliffe noted that Duke Energy is hosting a Phase II project at its East Bend Generation Station in Kentucky, which sits on the Mt. Simon Sandstone formation that is also present near Edwardsport. Ms. Radcliffe also described Phase III of the DOE program and stated that each regional partnership was awarded funding grants. According to Ms. Radcliffe, the DOE is testing the feasibility of geologically sequestering large volumes of CO_2 (at least 1 million tons) into a geologic formation in each region to validate the safety, permanence, and economic feasibility of large volumes of CO_2 being captured, compressed, transported, and stored. She noted that Phase III projects that begin in 2008 will last 10 years.

Ms. Radcliffe further testified that approximately $65 million was made available for each Phase III project and that each project contains a requirement that a minimum of 20% of the costs be borne by the participant. Ms. Radcliffe noted that Edwardsport was selected as an optional Phase III project and awarded $1 million for purposes of site characterization. Ms. Radcliffe stated that of the $1 million that the Company received from the DOE, approximately $50,000 has been spent on geologic testing of the wastewater test well at the Edwardsport IGCC Project site. The remaining dollars will likely be used for other expenditures associated with the Company's carbon sequestration site assessment and characterization plan proposed in this proceeding.

Ms. Radcliffe also discussed the advantages of Duke Energy's participation in the DOE carbon sequestration projects. According to Ms. Radcliffe, aside from the 80% cost share from DOE, participation provides additional benefits including a means to advance the Company's knowledge of CCS with respect to technical, regulatory, legal, and public acceptability issues. Ms.

Radcliffe stated that the Company has been working with the School of Public and Environmental Affairs at Indiana University to evaluate the legal and policy implications of Indiana's development of geologic sequestration programs. In addition, the Company has a representative on the advisory panel of the Indiana Center for Coal Technology Research ("CCTR") located at Purdue University. According to Ms. Radcliffe, the Petitioner is also working with several leading firms and entities including Battelle Memorial Institute, SCS, and the Indiana Geological Survey ("IGS"). In addition, other state geological survey partners are part of the MRCSP. Ms. Radcliffe indicated that Electric Power Research Institute is developing an integrated CO_2 storage demonstration and accelerated post combustion capture development program in which it will construct and test integrated CO_2 capture and storage pilots through the DOE Regional Carbon Sequestration Partnerships.

B. **Testimony Presented by the OUCC.** Cynthia Armstrong testified that there are several pending legislative CO_2 proposals that could impact the need for the Company's proposed Carbon Management Study. Ms. Armstrong stated that since the Company filed its case-in-chief testimony, Senators Kerry and Boxer have introduced the Clean Energy Jobs and American Power Act in Congress. S. 1733, 111th Cong.[4] As proposed, the bill would have established a Carbon Storage Research Corporation to collect $1 billion annually from fossil-fuel based electricity providers for ten years to fund large-scale demonstrations of CCS technologies. The bill also proposed to establish Title VII of the Clean Air Act to establish a greenhouse gas cap and trade program which would require reductions to 97% of 2005 levels by 2012, 80% by 2020, 58% by 2030, and 17% by 2050.

Ms. Armstrong also discussed the proposed Class VI well requirements for the Underground Injection Control ("UIC") program. According to Ms. Armstrong, the proposed rule establishes a new well class for CO_2 injection that would require Class VI UIC wells, similar to Class I UIC wells, to inject CO_2 beneath the lowermost formation that contains an Underground Source of Drinking Water. The Area of Review for a Class VI well is much larger than any other well, and will likely translate into increased monitoring and permitting costs for large scale CO_2 sequestration projects. Ms. Armstrong stated that on August 31, 2009, the EPA issued a Notice of Data Availability for the proposed Class VI UIC rules, which provided a summary of the comments received in the original proposed rulemaking. In this Notice of Data Availability, the EPA acknowledged that permits for several current large scale CO_2 carbon sequestration projects may be impacted by the finalization of the rules, but that any permitting issues with those projects may be able to be handled through a waiver process. According to Ms. Armstrong, State input into the rulemaking process has been important as some states have already taken steps to regulate the sequestration of CO_2.

Ms. Armstrong opined that uncertainty regarding the potential impacts of the proposed regulations places utilities and regulators in a difficult position. Because there are no specific regulations for greenhouse gas emissions from fossil fueled power plants, or a date by which regulations would go into effect, it is difficult to evaluate the benefits that a carbon sequestration study would generate for ratepayers. However, she noted that any large-scale sequestration project will take several years to assess, characterize, and develop. Ms. Armstrong testified that given the uncertainty and magnitude of costs associated with greenhouse gas regulations, as well as

[4] The Senate sent the bill to the Committee on Environment and Public Works, but took no further action, and the bill expired at the conclusion of the 111th Congress.

Petitioner's heavy reliance on coal-fired generation, the OUCC believes it is worthwhile to pursue reasonable carbon sequestration projects.

Ms. Armstrong testified that the National Energy Technology Laboratory ("NETL") has funded several carbon sequestration site assessment and demonstration projects within the last decade and implemented a three-phased approach for the development of carbon sequestration technologies. In Phase I, the DOE initiated regional sequestration characterization and assessment studies under seven regional sequestration partnerships over the 2003-2005 timeframe with the main goal to collect data on CO_2 sources and develop capital to support and enable future carbon sequestration field tests and deployments. During the Phase II validation phase, DOE funded several small scale injection tests over the 2005-2009 timeframe. NETL and the regional partnerships are currently in the process of implementing Phase III large scale sequestration demonstrations in which commercial scale carbon capture and sequestration projects will be developed and tested with the goal of capturing and sequestering at least one million tons per year over a ten year time frame beginning in 2008. DOE would fund up to 80 percent of the overall expenditures for such projects. Ms. Armstrong sponsored Attachment CMA-5 listing the status of the Phase III projects.

C. Testimony Presented by Intervenor CAC. Mr. Olson commented on behalf of Intervenor CAC regarding the Company's climate change lobbying activities and EPA's current and prospective regulation of wells needed for carbon sequestration projects. According to Mr. Olson, the EPA has recognized that CO_2 injection related to geologic sequestration involves different technical issues when compared to enhanced oil recovery ("EOR") and enhanced gas recovery. This is due in part to the volume of CO_2 that will be stored in the subsurface for a long period of time and the fact that any regulation must ensure that the CO_2 will not endanger drinking water sources. Mr. Olson noted that the EPA is evaluating the need for a more comprehensive regulatory framework to manage the geologic sequestration of CO_2.

D. Petitioner's Rebuttal Testimony. In his rebuttal testimony, Mr. Stanley noted Ms. Armstrong's comments regarding the uncertainty of carbon emission regulations, and agreed that this uncertainty makes it difficult to evaluate the benefits of a carbon sequestration study at this time. According to Mr. Stanley, the Company is in a challenging time with a lot of unknowns, but for a utility, like Duke Energy Indiana, that is highly dependent on coal-fired power plants, beginning to study carbon storage options now makes sense, given the long lead time associated with carbon storage site assessment and characterization activities. He additionally noted that although exact carbon regulations are not yet known, there has been much progress at the federal level, including the passage of a climate change bill by the U.S. House of Representatives.

In response to Mr. Olson's testimony regarding Duke Energy's lobbying activities, Mr. Stanley stated that Duke Energy has been at the forefront of climate change legislation in an effort to reduce CO_2 compliance costs for its customers. Mr. Stanley also testified that the Company has been a strong supporter of increased incentives for carbon storage activities for which customers will be the direct beneficiaries.

Ms. Radcliffe stated in her rebuttal testimony that the Company applied for a DOE Clean Coal Power Initiative ("CCPI") Round 3 grant in August 2009 with the goal of offsetting up to 50%

of the allowable costs of carbon capture and storage for the Edwardsport IGCC Project.[5] Ms. Radcliffe indicated that Duke Energy Indiana will continue to actively seek third party funding opportunities. She noted that the proposed American Clean Energy and Security Act included specific incentives for early adopters, such as bonus allowances under a cap and trade program. Similarly, other proposed legislation, specifically, the Clean Energy Jobs and American Power Act introduced by Senators Boxer and Kerry, included a variety of incentives for carbon capture and storage projects, such as investment tax credits and loan guarantees.

6. Site Assessment and Characterization Proposal.

A. Petitioner's Testimony. Mr. Stanley testified that Duke Energy Indiana's proposal entails a three-pronged Carbon Management Study that includes site assessment and characterization, with investigation into deep saline sequestration, EOR options, and sequestration in depleted oil and gas wells. Mr. Stanley stated that while the Company believes deep saline storage will eventually be needed, this option also presents the most challenges and uncertainty and has the longest lead time. Therefore, according to Mr. Stanley, the Company plans to undertake the simultaneous investigation of EOR and depleted oil or gas field storage, as they present a more expedient and cost effective solution regarding CO_2 storage. The Company's initial proposed CO_2 site assessment and characterization plan would take about three years and cost approximately $121 million.

Mr. Stanley explained that the Company's proposal includes activities and costs associated with detailed characterization of storage sites and includes drilling multiple wells and conducting 3D seismic testing. According to Mr. Stanley, the outcome of the site assessment and characterization study will be a fully characterized site ready for implementation. The implementation phase would then include further modeling and drilling and the injection of CO_2. However, Mr. Stanley emphasized that the Company's proposal in this proceeding does not include the activities and costs necessary to implement any of the sequestration options and that the Company will come back to the Commission with implementation proposals once the site assessment and characterization studies are complete.

Mr. Robert D. Moreland explained that the Company is assuming 50%-60% carbon capture at the IGCC Project, even though the Carbon Capture FEED study is studying 20% capture. The Company continues to keep its options open on whether or not to increase capture capability from 20% to 50%-60%. According to Mr. Moreland, a higher level of capture could provide additional incentives and represent a more cost effective option for the Company. In addition, identifying a site area now with greater storage capacity avoids the possibility of additional site assessment and characterization work later.

(1) Deep Saline Sequestration. Mr. Moreland testified regarding the results of geologic data gathered from the drilling of a treated wastewater injection well at the Edwardsport IGCC Project site and indicated that the results were less than optimal due to lower than anticipated porosity and permeability. Based on these results, following review of the wastewater well data and discussions with Mr. Rupp and Mr. Tombari, the Company decided to

[5] The Company informed this Commission on December 8, 2009, through a late-filed notice that it was not selected for funding under the CCPI Round 3 initiative.

expand its assessment activities and target a semi-circular area approximately 50 miles north, east and west from the IGCC Project site.

Mr. Moreland further testified that SCS has begun gathering existing geologic data and two-dimensional ("2D") seismic testing and data gathering for areas where this type of information does not exist. According to Mr. Moreland, SCS will integrate the data into a computer simulated model and evaluate the area's geologic capabilities with respect to carbon sequestration. Once areas are identified, exploratory wells will be drilled to obtain core samples and more detailed three-dimensional ("3D") seismic testing will be performed. Mr. Moreland testified that gathering this data and performing the simulation modeling will allow for detailed engineering and site design at the selected locations during the implementation phase. The end result of the site assessment and characterization will be the selection of a sequestration site area for the CO_2 from Edwardsport based on a detailed model that can be used for risk mitigation and monitoring purposes during implementation and operation.

Mr. Tombari testified that once the top three sites are identified, additional 2D seismic data will be collected at various locations, which will allow SCS to determine the depths of the various layers and form an image of the subsurface. Mr. Tombari explained that 2D seismic data provides an image of the subsurface rock layers that identify CO_2 sequestration formation targets, calculates their size, and estimates their corresponding storage capacity. The images can also be used to help identify potential faults or fractures that could affect the containment of CO_2 and potentially rule out an otherwise promising formation.

Mr. Tombari explained that 3D seismic is different than 2D seismic in that 2D seismic can be thought of as slices of data in two dimensions. In order to incorporate the third dimension, width along the earth, 2D seismic lines are run side by side. The gathering of 3D seismic data allows for the creation of an image that maps the structures and compartments of an entire block in a manner that more fully identifies faults or fractures that may be present. In addition, 3D seismic data provides additional information about rock properties and fluid content.

Mr. Tombari stated that after the data is gathered and analyzed, the Company would take the most promising sites identified and proceed with detailed characterization. During detailed characterization, a test well(s) will be drilled, site-specific subsurface data and samples will be collected and analyzed, seismic data will be acquired and interpreted, and models will be updated. Data would also be collected to confirm the integrity of the cap-rock and the injectivity of the target reservoir. Characterization work would also be done to analyze whether the site has the capacity for commercial development and meets the expected regulatory requirements for commercial sequestration. According to Mr. Tombari, the estimated timeline for completion of the site assessment and characterization is approximately 34 months.

Mr. Julius further testified that SCS and the Company plan to use the model created by SCS to select appropriate sites for further testing and analyses. Once all data has been added to the model, the Company will assess the reservoir capacity, injectivity, and containment strength and run simulations of potential CO_2 injection rates and paths in which the injected CO_2 plume could travel within the storage site. Following identification of the sites, the Company would perform risk assessments associated with the potential sites and identify and obtain the necessary environmental and drilling permits. Around this same time, the Company would perform public outreach to the area neighbors and hire a contractor to drill test wells at the selected locations.

(2) **Non-Saline Options.** Mr. Moreland testified that the Company is investigating other sequestration options in depleted oil and gas fields, as well as possible commercial opportunities for EOR in the Illinois Basin, and monitoring whether an interstate pipeline will be constructed to take CO_2 to the southern oil producing states.

Mr. Moreland testified that Edwardsport is located in an area in which oil and gas fields once operated and continue to operate. Within 150 miles of the IGCC facility, the Company believes that there may be several depleted oil and gas reservoirs suitable for sequestration and operating oil wells for possible EOR opportunities. He testified that non-saline storage options could possibly be implemented sooner than deep saline because the oil and gas fields have already been characterized and EOR permitting in other areas of the country is established. The Company's study proposal would determine whether these non-saline sequestration options are able to be completed sooner and with less cost than deep saline sequestration.

Mr. Moreland continued his testimony by stating that the Company believes exploration and development of a deep saline sequestration site is necessary in order to provide long-term storage of CO_2. One scenario would be to store CO_2 in depleted oil and gas fields for several years while deep saline sequestration is developed. In addition, if the Company is successful in developing EOR, a sequestration site would still be needed when the oil and gas companies no longer need the CO_2 for EOR. Mr. Moreland concluded that it is important to explore all reasonable options with the goal of facilitating the most cost effective CO_2 storage plan for customers.

(3) **Depleted Oil and Gas.** Mr. Julius provided testimony on the Company's proposed assessment of depleted oil and gas fields stating that the requirements of an adequate reservoir and functional seal are generally the same as those for saline aquifer storage. As oil and natural gas have been extracted from the subsurface reservoirs, the formations offer potential storage space for CO_2 in the pore space. In the Illinois Basin, the potential for using saline aquifers underneath the depleted oil and gas reservoirs also exists. According to Mr. Julius, the impermeable cap rock formations that successfully sealed oil and gas in underlying reservoirs for millions of years, could also serve to store CO_2 and prevent its migration. Mr. Julius testified that Apache and Shell have been successfully sequestering about two and a half million metric tons of CO_2 in the Weyburn Field in Saskatchewan, Canada for the last several years. However, sequestering CO_2 in depleted oil and gas reservoirs in the Illinois Basin remains largely unexplored.

Mr. Julius described the Company's proposal for developing CO_2 sequestration options in depleted oil and gas reservoirs as a two pronged approach. First, the Company would identify and screen the top sites based on existing geologic data and assess the amount of CO_2 that can be stored in these sites. Regulatory and permitting issues would be identified and conversations with surface and mineral right owners initiated to ascertain their interest in granting the Company access to the pore space for use in sequestering CO_2. The second part of the process would be to validate the sequestration potential of the target sites by conducting 2D or 3D seismic studies and drilling exploratory wells at potential sites. As part of the second phase, a preliminary engineering assessment of a CO_2 pipeline and compression infrastructure would be developed along with a detailed work plan to execute the selected sequestration option. Mr. Julius stated that the Company is seeking approval and cost recovery of both phases of the site assessment and characterization for carbon storage in depleted oil and gas fields.

(4) **Enhanced Oil Recovery.** Mr. Julius described EOR as a technique that increases the amount of crude oil that can be extracted from an oil field. Using EOR, 30%-60% or more of the reservoir's original oil in place can be extracted compared with 20%-40% using primary and secondary recovery. The most widely used EOR technique involves injecting CO_2 into the oil reservoirs which forces the remaining oil to move upward. Part of the injected CO_2 comes back up with the oil, is separated from the oil, and reinjected into the oil field.

Mr. Julius stated that the risks associated with EOR are similar to geologic sequestration without EOR, and are strongly site dependent. According to Mr. Julius, the best way to reduce risks is to conduct proper site selection, perform detailed site characterization, and organize proper monitoring, mitigation and verification. The major commercial uncertainty regarding EOR is the amount of oil that can be recovered. However, this risk can be mitigated by the simultaneous development of multiple oil reservoirs that can create a steady and significant demand for CO_2. Mr. Julius testified that crude oil prices are another risk that must be considered. Also, EOR has not been performed in the Illinois Basin, so there are some uncertainties related to the regulatory structure and rules for EOR. In addition, oil fields in the Illinois Basin are shallow and fragmented with many owners, which will require more effort to obtain the necessary agreements from mineral rights owners.

According to Mr. Julius, with the use of EOR, CO_2 is sequestered while being used to increase oil production in an oil field that has undergone primary and potentially secondary oil recovery techniques. As a result, CO_2 becomes trapped in the oil field and is considered permanently sequestered. Mr. Julius gave some examples of EOR applications, including a site in LaBarge, Wyoming, where ExxonMobil produced four million metric tons of CO_2 and sent a portion to the Rangley Field in northwestern Colorado for EOR use. He also mentioned the most prominent example of an EOR application, a series of oil fields in the Permian Basin of west Texas, where a thirty year history of CO_2 based EOR yielded significant volumes of incremental oil from depleted fields.

Mr. Julius described the Company's two-pronged approach to its EOR studies. According to Mr. Julius, the first prong is to screen potential oil fields suitable for EOR operations and obtain an estimate of CO_2 storage capacity through reservoir modeling. Infrastructure requirements would also need to be determined and the economic viability would need to be demonstrated in the Illinois Basin. This can be done by reaching out to oil production companies to gauge the level of interest and by identifying the major challenges to implementation of EOR. The second prong of the Company's proposal is to develop a work plan to execute additional drilling, injection testing, and reservoir and fluid characterization necessary to design and implement the enhanced oil recovery system. At the end of the initial scope of work, the Company expects that a specific recommendation will be made which could be the basis of a decision to proceed by the Company.

In support of this issue and the approach outlined by Mr. Julius, Mr. Moreland provided a cost estimate for the investigation of EOR potential and testified that if the economic and practical challenges could be overcome, the Company may pursue commercial contractual arrangements with the oil or gas well owners or a CO_2 marketer for the CO_2 supplied to EOR operations.

(5) **CO_2 Interstate Pipeline.** Mr. Julius provided additional testimony in which he indicated that it is feasible to transport CO_2 via interstate pipeline from multiple sites and/or utilities. In reaching this conclusion, Mr. Julius also recognized that a pipeline does not

currently exist in the Midwest. According to Mr. Julius, the Company has had discussions with entities that have expressed interest in building an interstate CO_2 pipeline from the Midwest to the southern oil producing states for purposes of EOR. Mr. Julius noted, however, that the commercial feasibility of such a pipeline is dependent on a significant minimum supply of CO_2, which the IGCC Project alone cannot supply. The development of multiple large sources of CO_2 could justify the capital expense of building the pipeline, and the Company will continue to monitor this as an option.

(6) Schedule, Cost Estimate, and Implementation. Mr. Moreland sponsored Petitioner's Confidential Exh. B-1, which is a copy of the anticipated schedule for the proposed site assessment and characterization proposal. Mr. Moreland testified that he believes the schedule is reasonable based on current knowledge of the process, but cautioned that the schedule is preliminary and will need to be revised and refined as matters progress. Mr. Moreland also sponsored Petitioner's Confidential Exh. B-2, the current cost estimate for the Company's proposal. Mr. Moreland testified that the cost estimate is also preliminary, and as activities are performed, the cost estimate will be updated and refined.

Mr. Moreland stated that the total cost estimate for the Company's initial site assessment and characterization proposal is $121 million, which includes a 25% contingency. Mr. Moreland indicated that while he believes the cost estimate is reasonable given the facts and circumstances known at the present time, there will be inevitable adjustments and refinements as the site assessment and characterization process proceeds. Mr. Moreland went on to testify that the estimate is based on proposals received from SCS and other consultants, knowledge gained from participation in the DOE carbon sequestration partnerships, and experience gained from the Edwardsport wastewater well testing in 2008.

In his testimony Mr. Moreland described the numerous uncertainties surrounding the implementation schedule such as the potential for state and federal legislation or regulations that will likely shape and affect CO_2 transportation and injection. Mr. Moreland stated that assuming the site assessment and characterization activities lead to the selection of a favorable sequestration site, regulations on CO_2 emissions are implemented, and a carbon sequestration project appears to be a viable, cost-effective carbon compliance option, the Company would return to the Commission to request approval to proceed with implementation of carbon sequestration using CO_2 captured from the Edwardsport IGCC Project. Notwithstanding these uncertainties, for purposes of the request presented in this proceeding, Mr. Moreland provided a cost estimate range and timeline for the implementation of deep saline sequestration with the caveat that the estimate and timeline are preliminary. Mr. Moreland noted that the estimate includes development and implementation of the sequestration area and pipeline construction to transport the CO_2 from Edwardsport to the sequestration site, but does not include the cost of the pore space.

Mr. Tombari also discussed implementation testifying that if the Company is successful at finding an appropriate site for deep saline aquifer sequestration, it will need to obtain permits for the location, engage in public outreach, design, engineer, construct the project, prepare detailed modeling of the expected CO_2 plume, and construct the permanent injection wells and monitoring wells in order to get the sequestration site up and running. In addition, a transportation and distribution piping system will need to be constructed in order to move the captured CO_2 from the Edwardsport IGCC site to the ultimate storage site for injection. Mr. Tombari stated that SCS worked with the Company in developing a preliminary timeline and cost estimate for the

implementation of a sequestration site, but that it could be influenced by a variety of factors and would need to be refined after the initial site assessment and characterization work is completed.

Mr. Julius testified that once a site has been sufficiently characterized, the potential for successful sequestration assessed, and all regulatory and legal issues successfully resolved, the site permitting stage would begin, which would require analysis of local, state, and federal permitting requirements. Mr. Julius explained that the permitting process will include a determination of the composition of the CO_2 that may be injected into the wells and will identify different volume scenarios. Finally, the cost estimate and implementation timelines will be identified for installation and operation activities of the CO_2 sequestration. Once all permits are approved, the site design and construction would begin which would include the drilling of the injector wells and monitoring wells.

B. Testimony Presented by the OUCC. Ms. Armstrong testified that she believes the Company's cost estimate to initially identify a potential exploratory site is reasonable and indicated that the OUCC does not object to Petitioner's sole-source contract with SCS for the preliminary phase of this project. However, Ms. Armstrong testified that the OUCC is concerned that certain line items contained within Petitioner's cost estimate, shown in Petitioner's Confidential Exh. B-2, may be overstated. Ms. Armstrong sponsored a revised cost estimate as OUCC's Confidential Attachment CMA-1.

Ms. Armstrong testified that the OUCC's primary concern relates to the estimates for the 3D seismic survey and the amount listed under the saline portion of Petitioner's Confidential Exh. B-2. According to Ms. Armstrong while there could be some possible explanations none of the Company's witnesses specifically accounted for the difference. Ms. Armstrong indicated that given the uncertainties surrounding carbon sequestration, the OUCC could not support approval of the full study costs and recommended that a more cautious approach to the study be taken. In furtherance of this recommendation, the OUCC supported approval of a phased approach to the Company's Carbon Management Study with certain check points and a capped cost estimate. Ms. Armstrong also indicated that extensive risk assessment activities and public outreach will be necessary at every step of the study.

In her testimony Ms. Armstrong recognized the environmental challenges the power industry will face in a carbon-constrained society and recommended that the Commission approve the activities to be performed under steps 1 and 2 above as appropriate for Duke Energy Indiana's initial site assessment and characterization study. Furthermore, in the event that the initial findings from these steps prove promising, she testified that the OUCC would support drilling and analyzing an exploratory well for deep saline sequestration assessment. Ms. Armstrong further testified that the OUCC supported a cap on study expenditures for non-saline sequestration assessment activities, site characterization, and validation, limited to two wells. According to Ms. Armstrong, capping costs at a retail share of $33.562 million would allow the Company to proceed with its study until the end of 2010. Ms. Armstrong stated that while the OUCC has reservations about the contingency costs for the study, due to the numerous uncertainties, it can support the Company's contingency cost estimates.

In summary, Ms. Armstrong recommended that the Commission deny the Company's plan as proposed. While the OUCC recognizes the potential value of further carbon sequestration research, it can only support a plan that: (1) defers proposed study costs as an operating expense to be recovered

in a subsequent rate case; (2) caps overall study costs at $36.653 million ($33.562 million retail share) and requires additional cost approval contingent on measured progress in finding a suitable sequestration site; and (3) requires the Company to account for and credit ratepayers with any reimbursement or aid it receives from the DOE or other sources.

C. **Testimony Presented by Intervenor CAC.** In his testimony Mr. Olson indicated that there are no U.S. commercial scale projects in existence with respect to storage in saline aquifers. According to Mr. Olson, geologic carbon sequestration is relatively unproven with many technological, economic, regulatory and political challenges to be resolved.

Mr. Olson also discussed the Company's request for approval of an ARP stating that if the Commission were to approve the Company's request, it would be more of a public good and a service to society than a utility service to ratepayers. He also stated that the Company's request does not further "efficiency" which is one of the items that must be approved under an alternative regulatory plan. Mr. Olson further indicated that a Company the size of Duke Energy Indiana has the ability to study carbon capture with or without ratepayer financing and that the Company has confused "efficiency" with risk-shifting. According to Mr. Olson, approval of the Company's ARP would not increase "efficiency" and, in fact, if the study fails to identify a suitable site it may prove to be very inefficient at addressing carbon emissions. Instead, what Duke Energy Indiana has proposed is to shift the risk of cost over-runs, management errors and bad assumptions, and outright failure to ratepayers.

Mr. Olson further noted that the Company's Carbon Management Study will not provide energy or capacity to serve customers and that capture and sequestration creates a penalty on generation which reduces available power and increases the cost of production. Mr. Olson further testified that the Company has not provided any data that monetizes the benefits to ratepayers of performing the study or shows how ratepayers will pay less or have more reliable service.

Finally, Mr. Olson testified that he believes it is inappropriate to include EOR as a CO_2 mitigation tool because only 30-50% of the CO_2 remains in the ground and the carbon content of the oil is increased 77%. Mr. Olson also testified that shallow fields of between 2,500 and 7,000 feet are prone to seal fractures in the event of an earthquake. Accordingly, Mr. Olson testified that EOR in the Illinois Basin would not appear to be a good candidate for CO_2 sequestration.

D. **Petitioner's Rebuttal Testimony.** Mr. Stanley responded to the OUCC's proposal by stating that if the Company is not granted a substantial CCPI Round 3 grant from the DOE,[6] Duke Energy Indiana would agree to a smaller subset of activities and approvals, which entails additional decision points along the way for advice and consultation, and a less costly approach for the initial study scope, similar to that advocated by the OUCC.[7]

Mr. Stanley disagreed with Mr. Olson's claim that utility ratepayers should not pay for the costs of the Company's proposed carbon storage study activities because they are a public good rather than a utility service. According to Mr. Stanley, Mr. Olson failed to recognize that research

[6] The Company notified this Commission on December 8, 2009, through a late-filed notice that it was not selected for funding under the CCPI Round 3 initiative.

[7] Since the Company did not receive funding from CCPI Round 3, this Order only discusses that portion of Petitioner's Rebuttal Testimony regarding the proposed revised carbon management plan.

and development costs are legitimate utility costs that benefit customers. Mr. Stanley testified that if the carbon storage technology is ultimately successful, Duke Energy Indiana customers will benefit through reduced CO_2 emissions.

Mr. Stanley also responded to Mr. Olson's contention that the Company's proposal attempts to shift the risk of cost over-runs, management errors, bad assumptions and outright failure to ratepayers. According to Mr. Stanley, the Company is requesting authority to study carbon storage in a measured and cautious manner and for the inclusion of costs in rates as with any prudently incurred cost. Mr. Stanley also testified that with the approach, the Company does not expect cost over-runs, management errors, bad assumptions or failure. Mr. Stanley pointed out that the CAC simply does not view carbon capture and sequestration as a technology with the potential to allow coal to be used in an environmentally responsible manner.

Mr. Moreland indicated in his rebuttal testimony that indications are that the Mt. Simon Sandstone formation in the Illinois Basin remains a potentially robust storage reservoir for carbon. According to Mr. Moreland, the Company is optimistic that a suitable storage site will be found and is encouraged by recent successful demonstration projects in the Mt. Simon Sandstone at the ADM ethanol plant in Decatur, Illinois, and at Duke Energy's East Bend plant in Kentucky by the MRCSP sponsored by NETL.

Mr. Moreland also testified that while the Petitioner initially requested approximately $121 million for site assessment and characterization, as a result of the Petitioner's failure to obtain DOE funding, the request has been reduced to approximately $42 million, before inclusion of carrying costs. According to Mr. Moreland, the Company's revised Carbon Management Study is generally consistent with the OUCC's timeline focused on activities that could be completed by the end of 2010 (in accordance with Petitioner's original timeline).

Mr. Moreland responded to Mr. Olson's contention that the Company has not provided any data monetizing the benefits to ratepayers. While noting it is difficult to accurately calculate a net present value for the Carbon Management Study, Mr. Moreland indicated that the Company has assessed possible ranges of estimated project net present values using the ACESA Basic Case data from the August 2009 Energy Information Administration report "Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009." According to Mr. Moreland, based on this assessment the cost of the project, including implementation on a stand-alone net present value basis, would be slightly higher than buying CO_2 allowances. Mr. Moreland further testified that there is significant improvement in the project economics when incentives such as the value of early-mover incentives under proposed climate change legislation are considered. However, Mr. Moreland also recognized that any cost benefit analysis is highly dependent on projected CO_2 prices. Mr. Moreland concluded his testimony by indicating that once the studies are complete and the details of climate change legislation are more fully known, the Company would be in a better position to perform more cost benefit analyses.

Mr. Tombari responded to the testimony of Ms. Armstrong in which she referenced the difficulty in assessing the reasonableness of Petitioner's cost estimates. Mr. Tombari indicated that this observation is well founded and is attributable to the lack of publicly available information regarding the costs associated with site characterization and 3D seismic testing for deep saline sequestration. According to Mr. Tombari, a seismic survey is not a generic type of product, but must be properly designed for a specific purpose in a specific area. According to Mr. Tombari, the

two main factors that drive the cost of a 3D seismic survey for sequestration site characterization are the number of square miles surveyed and the quality and resolution designed into the system. Mr. Tombari described a 3D seismic survey as a checkerboard of sensors over an area of the earth and the cost for the survey is driven by the size of the entire checkerboard and by the size of the squares in the checkerboard.

Mr. Tombari testified that SCS estimated the square miles for the 3D seismic survey associated with Edwardsport by considering the maximum square miles based on 200 million tons of CO_2, which is the volume of CO_2 the Company contemplates capturing over the life of the IGCC Project. Mr. Tombari also indicated that the ultimate design will depend upon the results from the exploratory well and that the 3D seismic costs were based on SCS's experience and general knowledge of the Illinois Basin. Mr. Tombari stated that SCS's proposal reflects the use of a resolution from the 3D seismic necessary to allow the seismic images to be used as the baseline of 4D seismic monitoring used to monitor the plume. Mr. Tombari noted that the Sleipner carbon sequestration project in Norway has successfully deployed 4D seismic to monitor the CO_2 plume.

In his rebuttal testimony, Mr. Rupp disagreed with Mr. Olson's statement that EOR should not be considered as a CO_2 mitigation tool. According to Mr. Rupp, CO_2 used in EOR operations is a valuable commodity that is carefully monitored by operators. The portion of the CO_2 that comes up with the oil is recovered and recycled; the portion that stays in the ground is effectively permanently sequestered. Mr. Rupp also rejected Mr. Olson's conclusion that EOR in the Illinois Basin would not appear to be a good candidate for commercial scale CO_2 sequestration. Mr. Rupp referred to his direct testimony in which he indicated that whether or not EOR is implemented in the Illinois Basin is largely a matter of economics, based, among other factors, on the price of oil, the size of the suitable oil fields, the willingness of oil operators to make the necessary capital investment, and the availability and cost of CO_2 delivered to the production site.

7. **Uncertainties Related to Carbon Sequestration.**

A. **Testimony Presented by the Petitioner**. Mr. Rupp stated that from a geological perspective, the primary risks associated with a CO_2 sequestration project include effectively predicting reservoir and seal performance; managing the CO_2 "plume" through drilling and completion technologies; and tracking the migration (monitoring) of the plume. Mr. Rupp also testified that another potential issue is the risk associated with seismic activity that could disrupt the sequestration process or breach a storage reservoir and seal as a result of a naturally occurring earthquake. Mr. Rupp noted that an earthquake could also cause damage to the mechanical components of a sequestration system. Mr. Rupp further testified that if a large volume of CO_2 is emplaced within a shallow reservoir (>2,500 to <7,000 feet) and the injection causes the fluid pressure within the reservoir to approach the fracture pressure of the seal, there is a risk that an earthquake may have the potential to cause the seal to fracture and fail resulting in the movement of the CO_2 out of the reservoir. Although a portion of southwest Indiana lies within the Wabash Valley Seismic Zone, Mr. Rupp testified that generally the locations of the hypocenters (the place within the earth at which breaks occur causing the seismicity) of the recorded earthquakes in this region are well below the depths at which sequestration would take place as earthquakes in this region occur at depths ranging from approximately 45,000 to 100,000 feet.

Mr. Rupp went on to testify that by following proper planning, siting, and operational constraints, geological and other risks of damage to the sequestration system can be minimized. In

addition, the construction of sequestration projects should be undertaken in areas outside of regions that have defined seismic hazards. According to Mr. Rupp, if the precautionary steps he discusses in his testimony are followed and the carbon sequestration project is carefully managed from a technical standpoint, residents need not be concerned about having millions of tons of CO_2 under high pressure stored thousands of feet below their property.

B. <u>OUCC and Intervenor Testimony</u>. Ms. Armstrong testified that she believes Petitioner's initial site assessment and characterization proposal are premature and unreasonable given the uncertainty of outcomes. She further testified that Petitioner's CEO, Mr. James Rogers, has publicly expressed concern over sequestration projects, quoting Mr. Rogers as stating: "I think there's no way we can scale [CCS] in this country ... It's more likely that China will develop and bring CCS to scale. I'd like to be China for a day so we can get CCS done. They're more likely to get it scaled and deployed than we are. We're going to be buying their technology." While the OUCC recognizes the potential value of furthering research for carbon sequestration in Indiana, it believes the costs proposed by Duke Energy Indiana are unreasonable.

In addition, Mr. Olson testified that ratepayers should not be forced to pay for speculative research into unproven technology. Mr. Olson further testified regarding the uncertainties and assumptions surrounding the implementation of carbon capture and storage, indicating that it is not certain that carbon from Edwardsport will ever be sequestered. Mr. Olson testified that he believes southwest Indiana is an area of concern for the location of a carbon sequestration field due to the hazards associated with potential seismic activity. According to Mr. Olson, "shallow fields" between 2,500 and 7,000 feet are prone to seal fractures in the event of an earthquake, making EOR in the Illinois Basin not a good candidate for sequestration. Based on the foregoing, Mr. Olson indicated that benefits to ratepayers from the study are speculative.

C. <u>Petitioner's Responsive Testimony</u>. In response to the issues raised by Mr. Olson regarding the uncertainties surrounding the implementation of carbon capture and storage, Mr. Stanley responded that the Petitioner purposefully listed all the uncertainties about the technology so that all parties would be aware of the uphill battle the Company faces on this issue. Mr. Stanley also indicated that there are uncertainties with any new technology, but that should not prohibit exploration of the technology and the recovery of associated costs of such exploration which could eventually inure to the benefit of customers. According to Mr. Stanley, the carbon storage study plan is designed to identify, reduce, or eliminate risks, and there is every reason to believe the obstacles will be overcome.

Mr. Stanley further addressed testimony presented regarding recent comments made by CEO Jim Rogers concerning carbon capture and storage and the future of coal generation in the U.S. Mr. Stanley testified that Mr. Rogers has made several statements that were meant to be provocative in nature regarding the potential for the continued use of coal for electric generation and the readiness of the U.S. to implement carbon capture and storage technology. Mr. Stanley indicated that these statements were intended as a call to action for the U.S. to do more to promote clean coal technologies, such as carbon capture and storage, and to encourage coal interests to begin supporting a reasonable climate change bill that supports these technologies. According to Mr. Stanley, if we want coal to remain a cost-effective and viable option for electricity in the future, then technologies such as carbon capture and storage need to be developed on a commercial scale.

Ms. Radcliffe also responded to Mr. Olson's observations about the uncertainties associated with geologic carbon sequestration. In her testimony, Ms. Radcliffe stated that too much emphasis on uncertainties obscures the enormous progress that has been made in the development of carbon sequestration projects in recent years. According to Ms. Radcliffe, progress has been documented through DOE carbon sequestration projects, through EPRI, and through dozens of public/private collaboratives and private initiatives. Ms. Radcliffe noted that there are several commercial carbon sequestration projects in operation and that expertise is being developed on numerous aspects of carbon sequestration. Ms. Radcliffe further noted that hundreds of miles of high pressure pipelines for the transport of supercritical CO_2 are currently in use. In addition, techniques for studying subsurface geology, such as the use of 3D seismic technology, have been employed for a number of years in the oil and gas industry.

Mr. Rupp responded on rebuttal to Mr. Olson's concerns about constructing a carbon sequestration project in regions of defined seismicity such as southwest Indiana. In referencing his direct testimony, Mr. Rupp indicated that a geologic sequestration operation should not be undertaken in areas where the hazards are unacceptable and/or technically or operationally unmanageable. According to Mr. Rupp, he did not intend to imply that such operations can only take place where there exists no hazards or risk of any kind of seismic activity, noting that if construction could only take place in areas devoid of any seismic activity very few areas in the United States would have any construction. Mr. Rupp reiterated his direct testimony that seismic activity is one of many risks that must be investigated, planned for, and mitigated in a geologic carbon sequestration project.

According to Mr. Rupp, although the Wabash Valley Seismic Zone ("WVSZ") includes portions of southwestern Indiana, and the 5.4 magnitude earthquake that occurred on April 18, 2008, was within the WVSZ, this does not mean that southwestern Indiana presents an inherently unacceptable risk for a geologic carbon sequestration project. Mr. Rupp further testified that hundreds of oil and gas operations have located in this region and have pumped high volumes of saltwater and other substances underground into deep subsurface reservoirs, employing appropriate and regulated pressures. These operations have produced more oil and have not induced damaging seismic activity, breached the seals of the reservoirs, or contaminated groundwater or other subsurface resources. Further, Mr. Rupp said the surface and subsurface facilities associated with these operations have not sustained any appreciable damages from seismic activity in the WVSZ. Mr. Rupp testified that the DOE's siting criteria for the FutureGen facility (which will include carbon capture and sequestration) requires that the site be located in a zone of no greater than 3.0 (or 30%g) ground acceleration. Examination of the USGS 2008 National Seismic Hazard Maps for the 2% Probability of Exceedence in 50 years shows the 30%g contour to be located to the southwest of the IGCC Project.

Finally, Mr. Rupp responded to Mr. Olson's statement that shallow fields of between 2,500 and 7,000 feet are prone to seal fractures in the event of an earthquake. Mr. Rupp testified that although injection of a large volume of CO_2 in a reservoir would cause the fluid pressure to begin to approach the fracture pressure of the seal, pressure of the CO_2 within the pore system of the reservoir can be monitored and maintained below the pressure exerted by the column of rock. According to Mr. Rupp, regulations for existing injection operations require that the injection pressure be maintained at a value minimally 10% to 20% below the fracture pressure. Mr. Rupp also explained hydrostatic and lithostatic pressures in the subsurface and indicated that it is common practice in the oil and gas industry to exceed the hydrostatic pressures, but not the lithostatic

pressures when injecting fluid into the subsurface. This allows the fluid to move, yet preserves the integrity of the seal system.

8. Ratemaking Issues Presented in this Cause.

A. Testimony Presented by the Petitioner. Ms. Diana Douglas testified that the Company is requesting approval, under an ARP, for the deferral and recovery of costs incurred for the proposed Carbon Management Study, net of any net reimbursement or incentive funds obtained by the Company from the DOE or other government agencies. Ms. Douglas explained the Company's proposal would allow for the recovery of its financing costs associated with the net study expenditures through a new Standard Contract Rider No. 73, Carbon Management Plan Revenue Adjustment ("Carbon Management Rider").

According to Ms. Douglas, under the Company's proposal, subsequent recovery of the net study costs would occur through two possible approaches: first, if a capital project results from the study, the portion of the net study costs applicable to the project would be included in the value of the capital project and subject to the rate recovery approved by the Commission for that capital project; or alternatively, for that portion of the net study costs for which no capital project relates, recovery through the Carbon Management Rider of the net study costs over a 10 year period of amortization, with continued recovery of the Company's financing costs on the unamortized balance of the net study costs until the costs are fully amortized.

Ms. Douglas further stated that Duke Energy Indiana is requesting deferral of the study costs using a regulatory asset account until the inclusion of the costs in the capitalized project cost with associated cost recovery, if Carbon Storage and EOR projects are implemented as a result of the studies, or recovery of such costs in rates via the proposed new Carbon Management Rider. Ms. Douglas stated that the Company will propose the rate treatment for resulting capital projects at a future time.

Ms. Douglas also explained that although the types or amounts of government reimbursements or incentives that may be available to mitigate the costs of the Company's proposed plan are unknown, the Company will ensure that its customers receive the benefits of such reimbursements or incentives received by the Company in its ratemaking, net of costs to comply with the grant rules and regulations. In addition, for grants or reimbursements designed to directly reimburse study costs, the Company proposed to net the grant or reimbursement against actual study costs incurred, which will ensure that customers receive the benefit of the reimbursement in determining the amount of costs to be recovered in rates. If other forms of incentives are received that do not lend themselves to offsetting project costs, the Company will propose rate treatment at that time to ensure customers receive the benefits of the incentive.

B. Testimony Presented by the OUCC. Ms. Armstrong testified that the OUCC does not support the Company's proposed cost recovery method and that the OUCC recommends the Commission treat cost recovery of the Carbon Management Study similarly to the cost recovery approved for the carbon capture study in Cause No. 43114 IGCC-1.

Mr. Blakley of the OUCC provided an overview of the Company's proposal and argued that, although not expressly requested, the Company is actually seeking cost recovery treatment similar to 170 IAC 4-6-1, which relates to qualified pollution control property ("QPCP"), to defer the

carbon sequestration study costs, calculate a return on the deferred balance, and collect a revenue requirement from the customers every 6 months. He stated that since the Company did not specifically request recovery under 170 IAC 4-6-1, Duke Energy Indiana apparently recognizes that its carbon sequestration study is ineligible for cost recovery under this provision as CO_2 is not a pollutant under this rule. Mr. Blakley further noted that the Company would then similarly be precluded from receiving ratemaking treatment provided for in 170 IAC 4-6-9. Mr. Blakley also recommended, based on Mr. Stanley's characterization of the costs of its Carbon Management Study as research and development, that the Commission classify these costs as operating expenses recorded in a deferred account for subsequent recovery in the next general rate case as outlined in the QPCP rules under 170 IAC 4-6-17.

C. **Petitioner's Responsive Testimony.** Ms. Douglas responded to the OUCC's recommendation stating that although the Company still believes that tracker recovery is appropriate and will be necessary for carbon capture and storage implementation, the Company expressed its willingness to forgo cash recovery of financing costs via the Company's originally proposed Carbon Management Rider during this initial study phase. Instead, the Petitioner agreed with the OUCC's proposal on this issue and requested that the Commission approve the same ratemaking treatment and cost recovery assurance that it approved in Cause No. 43114 IGCC-1 for the carbon capture study costs, *i.e.,* deferral of study costs for subsequent recovery, with carrying costs equal to Duke Energy Indiana's AFUDC rates, until such time as the costs are included in rates.

Ms. Douglas explained that deferral of the Carbon Management Study costs until they can be included in rates will minimize the timing difference between cost recognition on the Company's books and cost recovery; however for the Company to defer the expenses and reflect the costs as a regulatory asset, it must be probable that these costs will be recovered through rates and that in order to satisfy the probability standard, the Commission's Order in this proceeding should specifically approve the accounting and ratemaking treatment proposed by the Company. Ms. Douglas also reiterated that the Company will ensure that its customers receive the benefits of any government funding or reimbursements or incentive payments, net of any costs to comply with grant rules and regulations. This would include aid it receives from other non-DOE sources.

9. **Commission Discussion and Findings**. In our November 20, 2007, Order in Cause No. 43114, we recognized that the future regulation of CO_2 emissions appeared likely. *Joint Petition and Application of Duke Energy Ind.*, Cause No. 43114, 2007 Ind. PUC LEXIS 380, at *143 (IURC November 20, 2007). However, we also recognized that carbon emissions are not currently subject to regulation and that existing regulatory and technical uncertainties present obstacles to the short term deployment of CCS technology. *Id.* In light of such regulatory and technical uncertainties and the resulting prudence of moving forward at a deliberate pace, we ordered Petitioner to return to the Commission with a filing that outlined its plans to develop carbon capture and sequestration study proposals. *Id.* at *144. Petitioner complied with this condition through its submission of a proposal to conduct a preliminary FEED study related to partial carbon capture at the Edwardsport IGCC Project.[8] We approved this proposal in our IGCC-1 Order. 2009 Ind. PUC LEXIS 2, at *85-86. In that Order, we further required Petitioner to initiate a new Cause with the Commission that contained a proposal to study carbon sequestration and enhanced oil recovery options related to the Edwardsport IGCC project. *Id.* at *82-83, 85. Consistent with the

[8] Petitioner submitted its Carbon Capture Feed Study report in the IGCC-1 docket on 6/24/11.

obligations in our November 20, 2007 and January 7, 2009 Orders, Petitioner initiated this proceeding in which it proposed a Carbon Management Study that would assess options for the storage of carbon from the IGCC Project.

Petitioner's revised request, as proposed in its rebuttal testimony, differs from the proposal initially filed with the Commission. The changes proposed by the Petitioner not only reduce the amount of the Company's request from $121 million to $42 million, but also impact the method of cost recovery requested by the Petitioner. Based on the revisions outlined by the Company in its rebuttal testimony, we find that the specific statutory provision applicable to the relief requested in this matter can be limited to a request for recovery of research and development costs designed to increase the use of Indiana coal under Ind. Code § 8-1-2-6.1(c), and a request for alternative regulatory treatment under Ind. Code ch. 8-1-2.5. As the Petitioner has revised its initial proposal, in which it requested approval to track costs associated with the Carbon Management Study, to a request to defer proposed study costs as an operating expense to be recovered in a subsequent rate case, we do not find the additional statutory provisions cited by the Company to be applicable to the request presented in this Cause.

Ind. Code § 8-1-2.5-6(e) allows the Commission to approve, reject, or modify an energy utility's proposed alternative regulatory plan if the Commission finds such action is consistent with the public interest. Under the circumstances presented to us in this case, we believe approval of Petitioner's proposed alternative regulatory plan is not in the public interest at this time. As we noted in our Orders that led to the filing presented in this Cause, the Commission recognizes there are many uncertainties related to the long-term management of CO_2, including the potential development of a CO_2 interstate pipeline as an alternative to local sequestration. The exact nature of carbon regulations and the date they might take effect is uncertain. Congress has not passed any definitive legislation requiring the limitation of carbon emissions. Further, while the EPA has proposed restrictions on carbon emissions from new power plants, any potential regulations concerning existing power plants is speculative in terms of both timing and result. Also, uncertainties exist regarding the technological feasibility of local carbon sequestration and pipeline transport of CO_2. Finally, Duke Energy Indiana was not selected to receive additional federal funding to support its study. Therefore, we conclude that the evidence does not sufficiently support a finding that the measurable benefits of the carbon sequestration study merit the material cost to ratepayers at this time.

Accordingly, although we find Petitioner complied with the requirements of the IGCC-1 Order by submitting a proposal regarding carbon sequestration and enhanced oil recovery studies, we find that the provisions of the Alternative Regulatory Statute, coupled with the general provision of Indiana Code § 8-1-2-6.1(c)(1) and 170 IAC 4-6-17 do not support our approval of Petitioner's proposed alternative regulatory plan for the recovery of costs associated with its Carbon Management Study at this time. Petitioner is nonetheless encouraged to continue its carbon sequestration studies and may resubmit its proposal for alternative or other appropriate regulatory treatment to the Commission at a later date when the uncertainties discussed above can be more fully addressed.

10. **Petitioner's Request for Confidential Treatment.** On July 2, 2009, Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion"), supported by the affidavit of Robert D. Moreland, Vice President Analytical & Investment Engineering, and an additional supportive affidavit of John Tombari, President Schlumberger Carbon Services, filed on

July 6, 2009. The affidavits of Messrs. Moreland and Tombari indicate that such confidential information ("Confidential Information") constitutes a trade secret and that Petitioner and SCS have taken all reasonable steps to protect the confidential information from disclosure. On July 9, 2009, the Presiding Officers issued a Docket Entry in which they granted confidential treatment to the Confidential Information on a preliminary basis.

Based on the foregoing, pursuant to Indiana Code section 5-14-3-4(a)(4), we find that the Carbon Management Study cost estimate and schedule set forth in Petitioner's Confidential Exh. B, page 10, B-1, B-2, and Petitioner's Confidential Exh. D, pages 12 and 17 presented in this proceeding constitute a "trade secret" and should continue to be afforded confidential treatment. In addition, we find that the cost estimate to implement a carbon sequestration project set forth in Petitioner's Confidential B, page 15 constitute "trade secrets" and should continue to be afforded confidential treatment. Accordingly, this information is exempted from public disclosure and will continue to be held as confidential by the Commission.

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

1. Duke Energy Indiana's request for alternative regulatory treatment of its study of carbon storage for the IGCC Project as set forth in its revised Carbon Management Study and discussed in this Order is DENIED.

2. The Confidential Information submitted in this proceeding, and found to be confidential on a preliminary basis, shall continue to be held as confidential by the Commission consistent with the findings in this Order.

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

ATTERHOLT, LANDIS, MAYS AND ZIEGNER CONCUR; BENNETT NOT PARTICIPATING:

APPROVED: JAN 23 2013

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission