RC EXHIBIT B (BEB)

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

JOINT PETITION AND APPLICATION OF PSI 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 I.C. 8-1-2.5 ET SEQ. AND I.C. 8-1-6.1,8-1-8.7, 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**

DIRECT TESTIMONY OF BRUCE E. BIEWALD
ON BEHALF OF THE
CITIZENS ACTION COALITION OF INDIANA
SAVE THE VALLEY
VALLEY WATCH
SIERRA CLUB
May 15, 2007

PUBLIC (REDACTED) VERSION

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1. INTRODUCTION AND QUALIFICATIONS

Q. What is your name, position and business address?

A. My name is Bruce Biewald. I am the President of Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. Please describe your experience in the area of electric utility regulation and system planning.

A. I graduated from the Massachusetts Institute of Technology in 1981, where I studied energy use in buildings. I was employed for 15 years at the Tellus Institute, where I was Manager of the Electricity Program, responsible for studies on a broad range of electric system regulatory and policy issues. I have testified on energy issues in more than eighty regulatory proceedings in twenty-five states and two Canadian provinces. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, and the National Association of Regulatory Utility Commissioners. My papers have been published in the *Electricity Journal*, *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and numerous conference proceedings, and I have made presentations on the economic and environmental dimensions of energy throughout the United States and internationally. I also have consulted for federal agencies, including the Department of Energy, the Department of Justice, the Environmental Protection Agency, and the Federal Trade Commission. Details of my experience are provided in Exhibit BEB-1.

Q. Have you testified previously in Indiana?

A. Yes. I testified before the Commission on several occasions, including in March 2005 in Cause Nos. 42622/42718 involving the Indiana utility PSI's environmental compliance planning and Cause No. 42861 involving Vectren's environmental compliance filing. Previously, I testified in August 2003 in PSI's rate case and in July 2002, regarding a proposed settlement of a pending NIPSCO rate investigation (Cause No. 41746). Prior to that, I testified before the Commission regarding NIPSCO system reliability and excess capacity in Cause No. 38045 in November 1986. I made a presentation regarding stranded costs in the Commission's Forum on Electric Industry Competition in November 1996. I also made presentations regarding various aspects of electric utility restructuring before the Indiana Energy Conference in October 1996, and the Regulatory Flexibility Committee of the Indiana General Assembly in September 1997. I also prepared and filed testimony regarding the proposed termination of the operating agreement between PSI Energy, Inc. and Cincinnati Gas & Electric Company in Cause No. 41954 in June 2001, but the case was settled before my testimony was admitted.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Citizens Action Coalition of Indiana, Valley Watch, Save the Valley and the Sierra Club – Hoosier Chapter.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and comment on the modeling and planning analyses that Vectren Energy Delivery of Indiana ("Vectren") and Duke Energy Indiana ("Duke") relied upon in this case. I address the costs and risks of resource options available to the Companies, and reach conclusions with regard to the proposed Edwardsport IGCC project.

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and qualifications.
2. Summary of conclusions and recommendations.

3. Computer modeling and resource planning
4. Review of Vectren's modeling and planning for the Edwardsport IGCC
5. Review of Duke's modeling and planning for the Edwardsport IGCC
6. Resource cost comparisons
7. Electric rates and ratemaking issues

My testimony was prepared in coordination with several other witnesses. Specifically, I draw upon the analyses and conclusions of Mr. Phil Mosenthal who addresses demand-side management, Mr. Robert Fagan who addresses renewable resources and combined heat and power, and Mr. David Schlissel who addresses carbon dioxide regulations and power plant construction costs.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. My primary conclusion is that the analyses upon which the Companies base their support for the Edwardsport IGCC project are deficient. Specifically:

- The Companies fail to include the current cost estimate for the project in their modeling.
- The Companies use an unrealistic and overly optimistic date for the Edwardsport IGCC project to being operating.
- The Companies fail to include the impacts upon customers of their proposed ratemaking treatment in their analyses.
- The Companies conduct much of their planning analysis under the unrealistic assumption that carbon dioxide emissions will not be regulated.

- The Companies fail to use a realistic range of carbon dioxide emission prices in their analyses.
- The Companies fail to adequately consider resource alternatives including demand-side management, combined heat and power, and renewable resources. These resources are feasible, plentiful, and economic.
- The Companies fail to analyze risks to shareholders and to customers in a comprehensive and prudent manner.
- For both systems, the addition of the Edwardsport IGCC project to the system serves to support large increases in the amount of off-system sales, the revenues from which may not occur or accrue to the benefit of customers.
- Levelized cost calculations for the Duke and Vectren resource options show that the coal-fired options (conventional and IGCC) are higher cost than a natural gas combined cycle unit, even under the Companies' modest forecast of carbon dioxide prices. Wind generation and DSM are even more attractive.
- With Synapse's mid-case carbon dioxide price forecast the coal-fired options have an even wider cost gap relative to natural gas generation, wind, and DSM.
- The untapped potential for wind generation and DSM is great, and if Duke and Vectren were to actively develop these resources the amounts of capacity and energy could more than replace the amount of capacity and energy from the proposed Edwardsport IGCC facility.
- I estimate that over the period through 2030 pursuing the Edwardsport project will cost about $1.9 billion (in cumulative present value) more than a mix of wind generation and DSM to replace the project. This waste hurts Indiana's electricity consumers and the State's economy.
- Duke and Vectren shareholders, on the other hand, would benefit greatly from the project, particularly if the Commission allows the ratemaking treatement requested by the Companies in this case. The Commission need not and should not allow a bonus return to be earned on a project such as Edwardsport that is neither reasonable nor necessary.

Taken together these deficiencies mean that the analyses presented by the Companies do not provide an adequate basis for proceeding with a $2 billion project that will increase dependence upon coal for electricity generation and subject the Companies' customers to unnecessary costs and increased risks.

Q. Please summarize your primary recommendations.

A. I recommend that the Commission reject the Companies' request for approval of the proposal to construct and own the Edwardsport IGCC project. The Commission should not approve the cost estimate for the project or the requested ratemaking and accounting treatment. Rather the Commission should require the Companies to do complete planning analyses that should include: (1) up-to-date construction cost estimates for IGCC and other resources; (2) analysis of the cost impacts on customers that reflect the Companies' requested ratemaking treatment; (3) use of a realistic range of low, mid, and high case projections for future carbon dioxide prices; (4) full consideration of cost-effective demand-side management, combined heat and power, and renewable resources; and (5) a proper risk analysis that recognizes a range of risks including but not limited to construction cost overruns and project delays as well as fuel prices and environmental compliance requirements.

3. COMPUTER MODELING AND RESOURCE PLANNING

Q. Please describe how you approach the evaluation of utility modeling for purposes of a certificate of need or siting permit proceeding.

A. The selection of a particular unit, whether it be a fossil-fired unit or a renewable generating facility must be predicated on an analysis which weighs major risks to a utility system as well as the best possible information about the cost and availability of resource options. That is, resource options should be evaluated in the context of "Integrated Electric System Planning."

Q. Can risks vary from one utility system to another?

A. Yes, the nature of the key risks depends to some extent upon the utility system one is examining. For example, a utility with 5% natural gas generation would generally be less concerned about the volatility of natural gas prices than a utility with, as an example, 50% of its generation from gas-fired facilities. Similarly, a utility depending primarily on coal-fired generation should be concerned about the risk of greenhouse gas regulation. Keep in mind, risk exposures have to do with the existing system as well as the incremental additions under consideration. Generally, the resource options that a comprehensive integrated planning analysis considers include various types of gas, coal, renewables, and demand side resources such as energy efficiency and peak demand reductions. We have described resource planning and risk analysis in some detail in two reports that we wrote for the Regulatory Assistance Project and for the National Association of Regulatory Utility Commissioners, and others in 2003 and 2006, respectively. They are:

> ***Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers***, a Synapse Energy Economics, Inc. report prepared for the Regulatory Assistance Project and the Energy Foundation, October 10, 2003.

and

> ***Energy Portfolio Management: Tools & Resources for State Public Utility Commissions,*** a Synapse Energy Economics, Inc. report prepared for consideration by NARUC, The Energy Foundation, the Department of Energy, and NYSERDA, October 2006.

These reports are available on our website.

Ultimately, a good electric system resource plan is one that provides reliable service at reasonable cost, and is robust under a range of scenarios or sensitivity cases representing different future conditions.

Q. What are the basic principles and methods of electric system integrated planning?

A. Broadly speaking, the steps in such an integrated planning process include the following:

1. Load forecasts are prepared that represent the utility's best estimate of the demand of generation, transmission and distribution services in the long-term.

2. Opportunities to meet this demand through cost-effective energy efficiency resources are assessed.

3. Supply-side options are evaluated including building power plants, purchases from the wholesale market, purchasing short-term and long-term forward energy contracts, purchasing derivatives as a hedge against risk, developing distributed generation, building or purchasing renewable resources, and expanding transmission and distribution facilities.

4. Finally, the utility develops the optimal portfolio that will achieve objectives identified both by the utility and regulators.

Screening analysis, using levelized costs, can play a useful role in identifying the more attractive resource options and the impact of key uncertainties upon their relative costs.

Q. Does the planning as conducted by Duke and Vectren appropriately consider a broad range of available resource options, and adequately address risks?

A. No. Vectren and Duke both conducted integrated resource plans, and both use computer simulation models in their planning. However, both systems are predominantly coal-fired and this large reliance on a single fuel exposes shareholders and customers to significant risks. Coal-fired generation is subject to now, and will be subject in the future, to significant regulations governing air emissions. For example, it is simply a matter of time before carbon dioxide emissions are regulated at the federal level. The Companies must engage in environmental compliance planning that is forward-looking and recognizes likely future costs. Resource planning is, by its nature, a long-term process and Vectren and Duke shareholders and customers are not served by planning that understates the magnitude of future air emissions regulations and overlooks opportunities to develop lower emitting resources.

Q. Can something be done to rectify the Companies' overdependence upon coal?

A. Yes, there are several options. For example, there are other fossil fuels available for electric power generation, most notably natural gas, which has been the fuel of choice for new fossil fuel-fired power generation in recent years. Gas is higher cost per MMbtu than coal and is subject to significant price volatility, but relative to coal, gas generation has several advantages including: (1) gas plants typically cost less to build, (2) gas tends to be converted more efficiently (e.g., in combined-cycle applications with conversion efficiencies in the 50 to 60 percent range as compared with coal steam plants which have conversion efficiencies in the low 30s), and (3) gas has generally lower air emissions values (particularly sulfur, particulates, mercury, and carbon dioxide). Balancing the costs and risks of different fossil fuel types is one aspect of utility resource planning.

Renewable generating resources can also play a very important role in reducing overdependence upon coal. For example, generating options such as wind should be incorporated into Vectren's system, in order to reduce that Company's overdependence upon coal and the degree to which it will be exposed to the costs of future climate change policies that will limit carbon dioxide emissions from power plants.

Likewise, energy efficiency will reduce dependence upon coal and exposure to the costs of future carbon regulation. Energy efficiency is generally cost-effective on a direct expected cost basis. In addition, energy efficiency can offer benefits of resource diversity and reduced exposure to the environmental regulatory risks associated with fossil fuel-fired generation.

Q. Does the Edwardsport IGCC project proposed by Duke and Vectren in this case help to diversify the Companies resource mix?

A. No. The IGCC technology differs from the traditional pulverized coal technology that makes up the bulk of both Companies' generation mix. However, the Edwardsport IGCC facility is, simply put, another large coal facility added to a system that is already overly reliant upon coal. Its addition in 2011 would increase the annual coal use and annual carbon dioxide emissions of both of the co-owners. The Edwardsport project increases the Companies' risk exposure related to the use of coal.

4. REVIEW OF VECTREN'S MODELING AND PLANNING FOR EDWARDSPORT IGCC

Overview of Vectren's Modeling

Q. Please describe how you approached your analysis of Vectren's modeling.

A. The generic framework I laid out in the beginning of my testimony is the general approach. Specifically, I examined the modeling files from the 2006 Update to Vectren's IRP as well as the modeling files described in Eric Robeson's Supplemental Testimony. The direct testimony of Eric Robeson indicates that this modeling is the most reflective of Vectren's system since it includes "(1) a revised gas price forecast, (2) a revised estimate of the cost of the IGCC Project based upon more detailed estimates from the Edwardsport FEED Study, (3) revised assumptions regarding municipal customers, (4) revised assumptions related to wholesale proceeds, and (5) revised assumptions related to DSM and renewable resources."[1] This review primarily involved analysis of the STRATEGIST model reports delivered by Vectren in response to Questions 15 and 18 of CAC's First Data Request and Question 6 of CAC's Fourth Data Request.

Q. Can you explain why your review centered primarily on the modeling by Vectren as opposed to other information sources?

A. The STRATEGIST model has the capability to compare both supply-side and demand-side resource choices on the basis of cost with the constraint that the resource portfolio meets the energy and load requirements of the utility system. This type of modeling is the primary analytical tool that permits the weighing of risks and resource options.

Q. What did you find in your review of Vectren's STRATEGIST modeling?

A. I found several major problems with Vectren's modeling. These included:

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1 Testimony of Eric Robeson, page 7, lines 13-17.

- A low and out-of-date capital cost assumption for the Edwardsport IGCC,
- Unrealistic and overly constrained assumptions for DSM and renewables,
- Unrealistic and overly optimistic online date assumed for Edwardsport IGCC, and
- Incomplete analysis of greenhouse gas regulation.

I also found additional, pertinent information to bring to the Commission's attention, including:

- The Company's own analysis shows that Edwardsport is an uneconomic resource choice for its system under a range of gas and CO_2 price assumptions.
- As Mr. Robeson indicates in his direct and supplemental testimony,[2] the No IGCC plan and IGCC plan come out close in terms of present value revenue requirements (PVRR), however, it appears that this is largely a result of the additional off-system sales enabled by the IGCC unit.
- This IGCC plan is particularly uneconomic if one focuses on the "planning period" (through 2025 in Vectren's modeling).
- The No IGCC plan has the benefit of lower system CO_2 emissions in addition to a lower cost.
- Annual natural gas generation is, at a maximum, only 5% higher in the No IGCC plan than in the IGCC plan, indicating that additional risk exposure to natural gas price volatility associated with the No IGCC plan would be relatively small compared to other risks such as those related to coal use.

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[2] See page 10, lines 15-23 of the direct testimony and page 3, lines 1-18 of the supplemental testimony.

Capital Cost for Edwardsport Project

Q. Please explain why you believe Vectren used a low capital cost for the Edwardsport IGCC in its modeling.

A. We asked Vectren to supply information on the resources available to the STRATEGIST model. Vectren provided as part of its response to CAC's Fourth Data Request, Question 3 the following information:

Table 1. Resource Information Used in Vectren Modeling

Resource Name	Resource Type	Summer Capability (MW)	Years Available	Construction Costs (2005$/kW)
IGCC	New coal (IGCC)	125	2011	2,327
Coal	New coal (PC)	125	2013>	2,212
CC E	Combined cycle small	115.5	2011>	869
CC F	Combined cycle large	230.9	2011>	773
CT E	Simple cycle small	73.7	2011>	565
CT F	Simple cycle large	152.4	2011>	472

Additional purchases were made available, but are not shown in the table above.

As David Schlissel describes in his testimony, the modeled cost of the IGCC unit is about 5.2% below the current cost estimate in the front end engineering and design (FEED) study.

Renewables and Energy Efficiency

Q. Please describe Vectren's approach to analyzing renewable and energy efficiency options.

A. Vectren limited its consideration of renewable and energy efficiency options to a very small amount of these resources that was "fixed" in the model runs. That is, the amount was specified as an input, and additional amounts of renewable capacity and energy efficiency were not allowed to be selected by the model in its construction of resource plans. Indeed, renewables and energy efficiency were both represented by Vectren as a single placeholder "transaction" with an unspecified mix of renewables and energy efficiency, and unsupported size limit. Because this "placeholder resource" is fixed in ***all*** of Vectren's model runs, any cost input for it is irrelevant to the resource planning decisions.

Q. What were the characteristics of the transaction?

A. Table 2 shows the details of the transaction. After 2012, these impacts were held constant through the end of the planning period.

Table 2. Details of the Transaction Representing Renewables and EE3

Year	Capacity (MW)	Firm	Firm Cap (MW)	Capacity Factor	Energy (GWh)
2008	4	75%	3	60%	21.0
2009	8	75%	6	60%	42.0
2010	12	75%	9	60%	63.1
2011	16	75%	12	60%	84.1
2012	20	75%	15	60%	105.1

The cost of the transaction was $75/MWh (2005$) escalated, but as mentioned above, the cost has no effect on the differences between any plans because this "placeholder resource" is fixed.

Q. Are the costs and size for this transaction reasonable?

A. Not at all. CAC witnesses Fagan and Mosenthal explain that Vectren's assumptions for renewables and demand-side management do not recognize the real potential of those resources to contribute to Vectren's resource mix. They also provide numbers for the costs of renewables and DSM that are much lower than the numbers used by Vectren in its modeling in this case.

[3] Response to Q. 16 of CAC's First Data Request

Edwardsport Online Date

Q. Did Vectren correctly model the online date for the Edwardsport IGCC facility?

A. No, it did not. Vectren assumed in its modeling that the facility would come online in January 2011. According to the FEED Study summary at page 2, the level 3 Project schedule assumes a "substantial completion date 47 months after full notice to proceed." It notes that while Duke and Vectren would like the project to come online by the summer of 2011, the current projected commercial operation date is October 2011. If 47 months (less than 4 years) are required to complete the Edwardsport facility, it is difficult to see how the plant could come online by the summer of 2011. Even the projected COD of October 2011 seems to assume that everything goes as planned.

In order to achieve a COD of January 2011, Duke and Vectren would have had to begin construction this past February.

Q. Why does it matter whether Vectren assumed a COD of January 2011, summer 2011 or October 2011?

A. Capacity and energy needs (though not in proportion to the IGCC's capacity) will have to be met in the interim period until the facility comes online. This could tend to raise the total cost of the plan with the IGCC facility since other resources, a purchase, a CT, etc. will have to be acquired. The delay in the online date also allows more time for demand-side resources to ramp up to levels which can meet or exceed the deficit in capacity and energy needs.

Carbon Dioxide Emissions

Q. Please continue with your discussion of the problems in Vectren's modeling.

A. Vectren's analysis of greenhouse gas emissions regulation does not go beyond the single CO_2 price trajectory developed by Duke Energy. This price trajectory rests upon a draft bill by Senator Jeff Bingaman of New Mexico that was never introduced in the U.S. Senate. Senator Bingaman's draft bill contained provisions that would cap the CO_2 allowance price at $7/ton, escalating every year thereafter. Senator Bingaman's draft was also the only GHG intensity draft that received much attention. GHG intensity is a measure of greenhouse gas emissions per unit of GDP so a reduction in GHG intensity does not necessarily translate into a reduction in greenhouse gas emissions.

Q. Why does this represent a problem in Vectren's modeling?

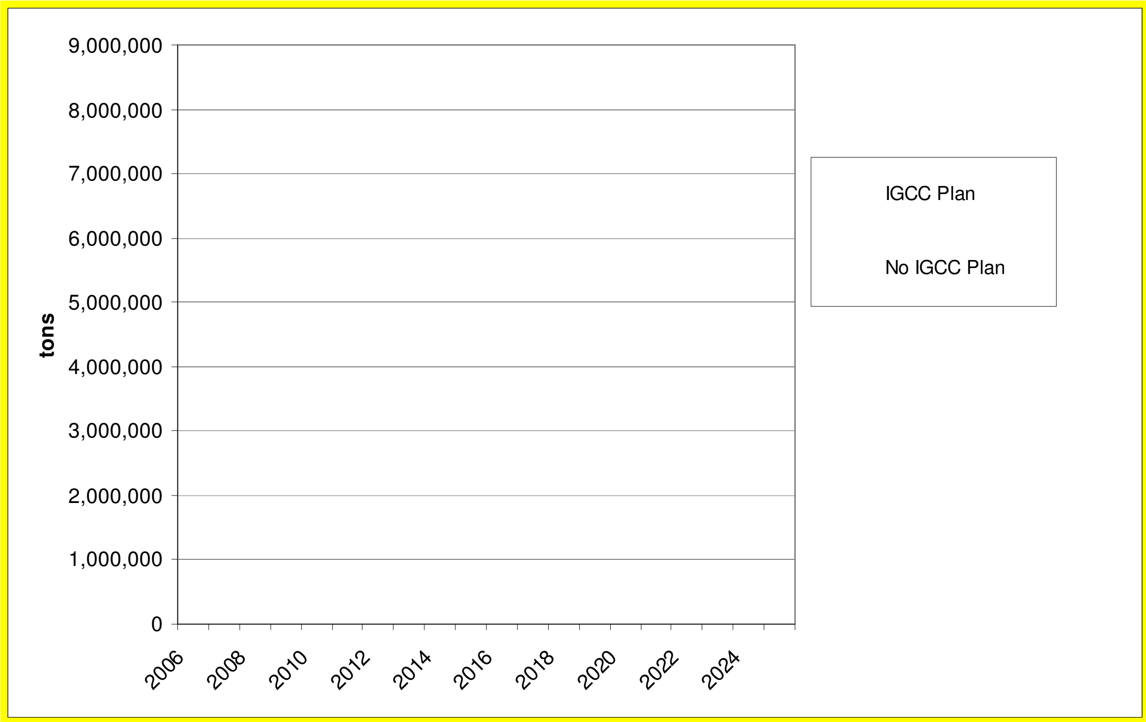
A. All else equal, the biggest driver of the price of CO_2 allowances will likely be the level of reduction required. That is, a minor reduction would be expected to result in a small allowance price and a major reduction would be expected to result in a significant allowance price. Vectren (and Duke's) price trajectory is predicated on a single draft bill that does not mandate a reduction in greenhouse gas emissions in sufficient quantity to do the U.S.'s part to stabilize atmospheric concentrations of GHGs. This is a *very* important consideration in resource planning that contemplates the addition of a coal plant. The Edwardsport IGCC facility could potentially operate for 30 years or more and ought to be analyzed *and* economic under *multiple* greenhouse gas regulation scenarios.

Q. What evidence is there that the Bingaman draft bill would not result in the reduction of greenhouse gas emissions in sufficient quantity to stabilize atmospheric concentrations of GHGs?

A. The first piece of evidence is Vectren's own modeling. Graph X shows the Company's CO_2 emissions assuming Duke's CO_2 price trajectory in its IGCC and No-IGCC Plans from its 2006 Update to the 2005 IRP.[4]

[4] Because the Edwardsport IGCC was not part of the least cost plan in any of Vectren's supplemental modeling, data on CO_2 emissions, generation, transactions, etc. had to be taken from the 2006 Update runs in which the IGCC unit was forced in to the model.

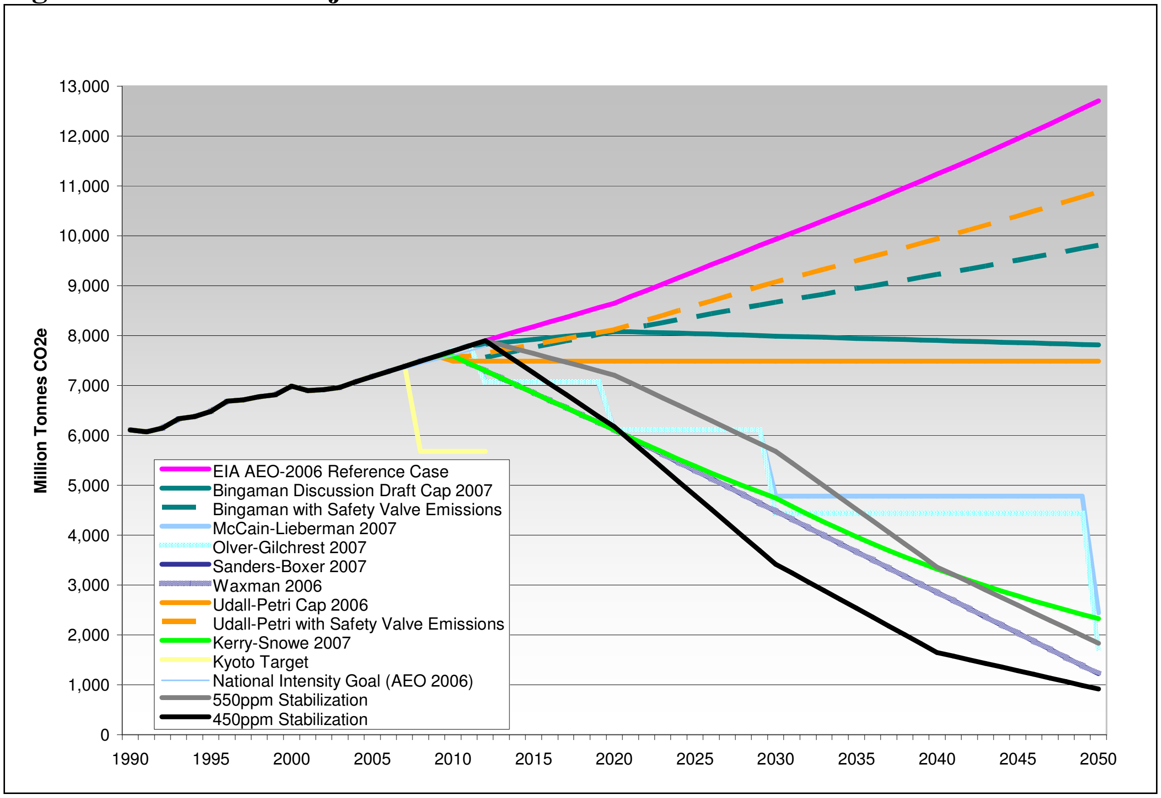
Figure 3. Vectren's Projected CO2 Emissions



In neither scenario are CO_2 emissions reduced significantly from current levels as would likely be necessary to tackle the problem of climate change. Also note that in the No IGCC Plan, Vectren's CO_2 emissions are *lower* than with the IGCC Plan.

Second, modeling, done primarily by the Energy Information Administration, shows that the CO_2 price level that would result from the adoption of the Bingaman proposal can be expected to have minimal impact on greenhouse gas emissions. The emissions trajectories projected from several bills introduced over the past year in the U.S. Congress plus Senator's Bingaman's draft bill are shown in Figure 4.

Figure 4. Emissions Trajectories Based on Recent GHG Bills



The difference between the solid green line and the dotted green line representing Senator Bingaman's draft bill is the difference between the effect of including the cap or "safety valve" price and not including it; the dotted line representing the former and the solid line the latter. The emissions trajectories that result in stabilization of atmospheric concentrations at the 550 ppm and 450 ppm levels are represented by the black and grey lines. As you can see, a number of other bills would mandate far deeper cuts than Senator Bingaman's draft bill and would reasonably be expected to result in higher allowance prices.

Q. How would you expect a GHG allowance price trajectory based on one of the other bills in the chart to affect Vectren's modeling?

A. As Mr. Schlissel explains in his testimony we would expect higher CO_2 emissions allowance prices from the steeper reduction that would be required under other bills being considered in Congress. If Vectren were to model these higher CO_2 prices and to amend its non-carbon emitting resource assumptions, specifically those for renewable energy and demand-side management, we would expect that those resources would be even more economic than they already are and Vectren's CO_2 emissions would decrease significantly below the levels projected in Figure 3.

Q. Wouldn't a higher price trajectory for CO_2 just make the addition of carbon capture and sequestration equipment to the Edwardsport IGCC more economic?

A. No, not necessarily. Just because the unit may be operating does not mean that it will be economic to capture and sequester carbon dioxide emissions. It's very important to remember that neither Duke nor Vectren have submitted any economic analysis that projects the CO_2 allowance price at which the sequestration of carbon dioxide from the Edwardsport unit will be economic rather than simply paying to emit carbon dioxide. It's entirely plausible that carbon dioxide will never be captured at the Edwardsport unit.

Also, any decision to add CCS equipment will not be made in an economic vacuum, rather Duke and Vectren will have to weigh the cost of CCS against other emission reduction options like renewables and energy efficiency. These alternatives also become more cost-effective as the carbon price rises.

Edwardsport Serves to Increase Off-system Sales

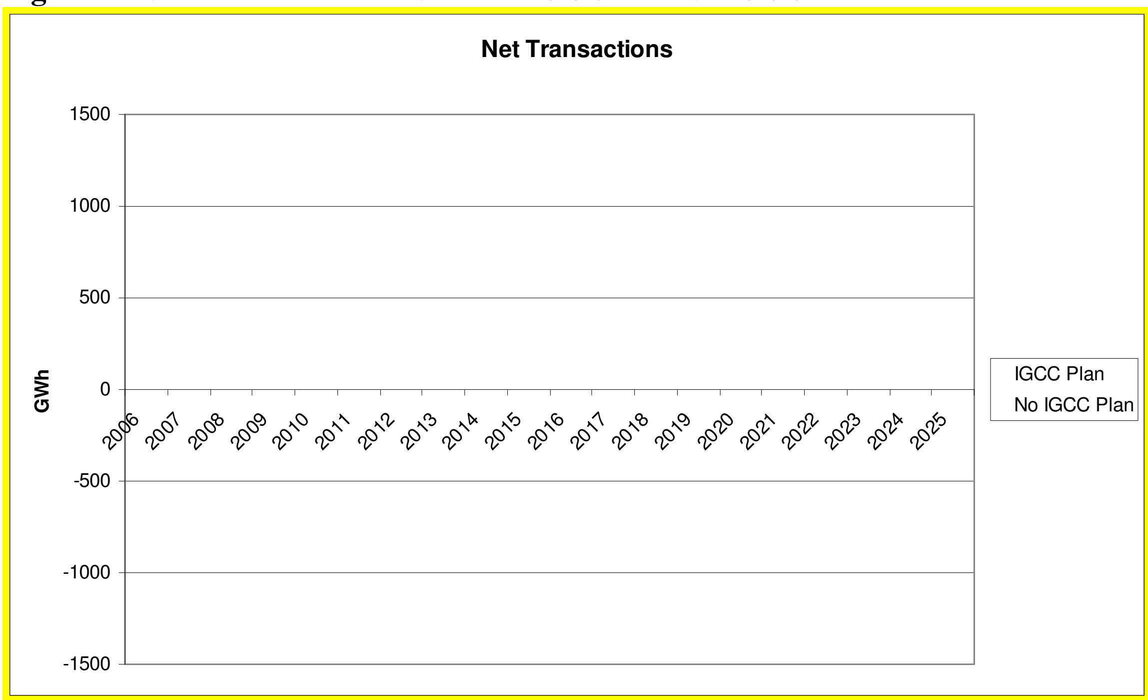
Q. What additional information would you like to bring to the Commission's attention?

A. First, it is important to understand what is driving the results of Vectren's modeling. Simply presenting the present value revenue requirements (PVRR) of various resource portfolios does not tell the whole story. The PVRRs of the No IGCC plan and IGCC plan modeled by Vectren are quite similar, however this seems to be driven primarily by the revenue from sales made because of the addition of the IGCC unit. The No IGCC Plan adds 377 MW of CTs over the period 2011-2025 and the IGCC Plan adds 299 MW of CTs in addition to 125 MW of IGCC over the same period. At a capital cost difference of at least $1,762/kW (between the CTs and the IGCC based on Table 1), clearly some other factor must be driving the closeness in PVRR between the IGCC Plan and the No IGCC Plan.

Q. How do you know that this difference is because of sales enabled by the IGCC addition?

A. Figure 5 compares the net transactions in Vectren's No IGCC and IGCC Plans, based on modeling information provided by the Company.

Figure 5. Net Transactions in Vectren IGCC and No IGCC Plans



A negative number means that Vectren is selling more energy than it is buying. A positive number means that Vectren is buying more energy than it is selling. When the IGCC unit is added in 2011 you can see a big jump in net sales compared to the No IGCC Plan. When the CO_2 allowance price begins in 2015, coal generation at both the new and existing units trends downward so Vectren makes fewer sales.

Planning Period Costs and End-Effects

Q. You said previously in your testimony that the difference in PVRR between the IGCC and No IGCC Plans is magnified depending on the period one is examining. Can you please explain what you meant?

A. Yes. The STRATEGIST model calculates PVRRs over two periods. The first is the planning period. The planning period is the period over which the model optimizes resource additions and dispatch. In Vectren's case, the planning period is the years 2006-2025. Following the planning period, the modeler has the option of modeling an end-effects period. STRATEGIST does not optimize resource additions and dispatch over this period, rather it bases the cost of the system during the end-effects period on the costs of the system through the planning period. Vectren assumed an infinite end-effects period. The combination of planning period and end-effects is called the study period. Eric Robeson, in his supplemental testimony, reported the differences in PVRRs between the IGCC and No-IGCC plans using the study period values.

Q. Why use the planning period PVRR as opposed to the study period PVRR?

A. The advantage of the study period PVRR is that the end effects period can capture benefits from resource choices with high up-front costs, so that they are not disadvantaged in a PVRR comparison over a timeframe less than their operational lives. However, those benefits must be considered potentially speculative. For example, Mr. Robeson seems to be suggesting that the IGCC and No IGCC Plans are essentially break-even over the study period. However, if that situation comes about largely because adding an *infinite* end-effects period makes it so, that result should be considered speculative.

Q. How do the planning period PVRRs of the IGCC and No IGCC Plans compare?

A. The PVRRs are shown in Table 6.

Table 6. PVRRs from Vectren's Supplemental Modeling

	IGCC Planning Period PVRR ($000s)	No-IGCC Planning Period PVRR ($000s)	Planning Period Difference ($000s)	Planning Period Difference	Study Period Difference
Base Case				3.24%	0.76%
Base W CO_2				4.87%	3.74%
Base W Hi Gas				3.79%	0.64%
Base W Hi Gas, CO_2				3.58%	1.31%

In his supplemental testimony, Eric Robeson cited the right most column of this table as evidence that the two plans are essentially break even. However, over the planning period, according to Vectren's analysis, Vectren customers stand to pay as much as $86.9 million more if it moves forward with the IGCC plan in return for a plant that won't result in net benefits even over an *infinite* period.

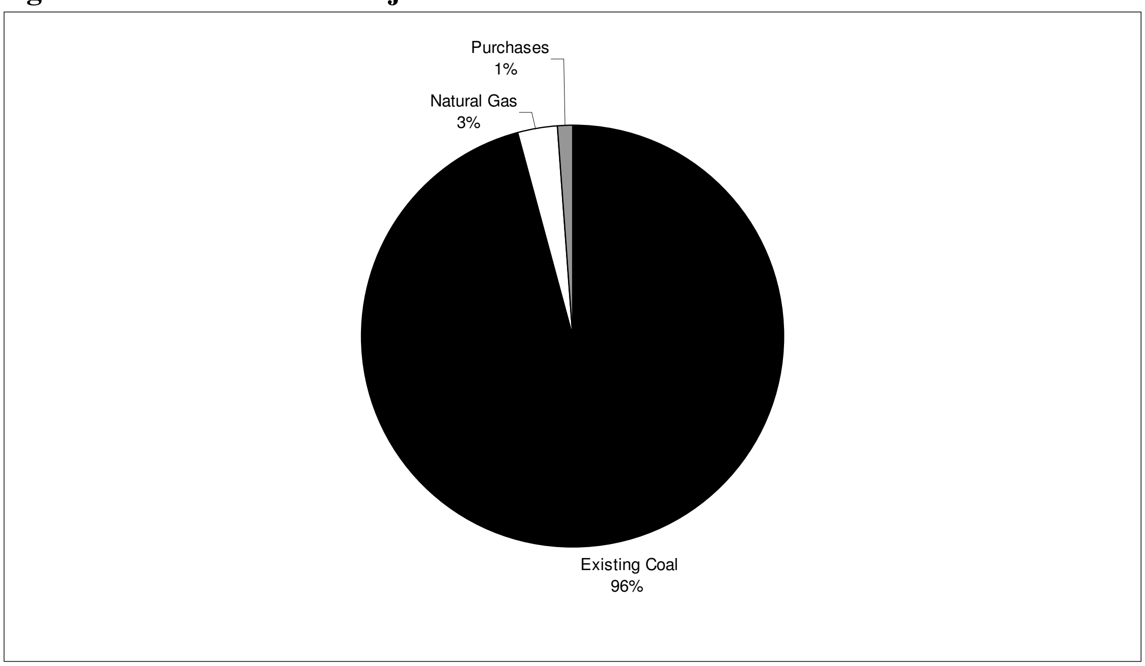
Resource Diversity and Risks

Q. Vectren's No IGCC Plan substitutes natural gas generation for the IGCC plant, but isn't there a tradeoff between natural gas price risk and greenhouse gas regulation risk that ought to examined?

A. All else equal when weighing a portfolio of gas versus coal resources that's certainly true. As discussed at the beginning of this section, however, utility risks will vary in magnitude depending on the individual utility's system.

In the year 2007, Vectren projects that its generation mix will breakdown as shown in Figure 7.

Figure 7. Vectren's 2007 Projected Generation Mix



In the year 2016, Vectren projects that its generation mix under the No IGCC and IGCC Plans will be as follows in Figures 8 and 9.

Figure 8. Vectren's Projected Generation Mix in 2016 – IGCC Plan

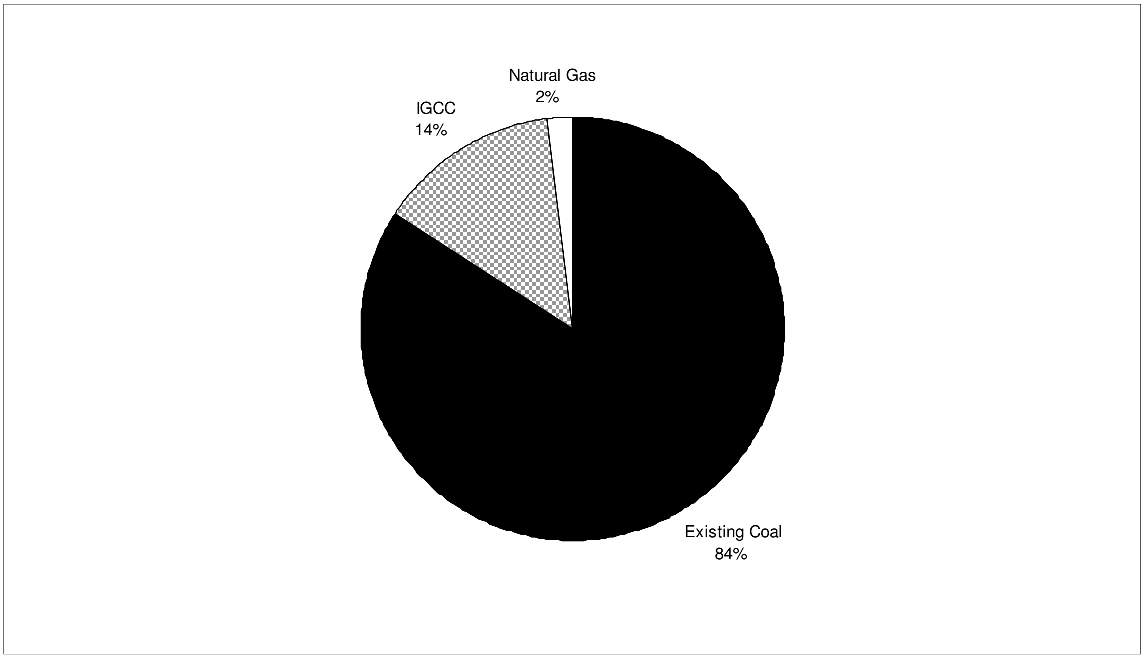
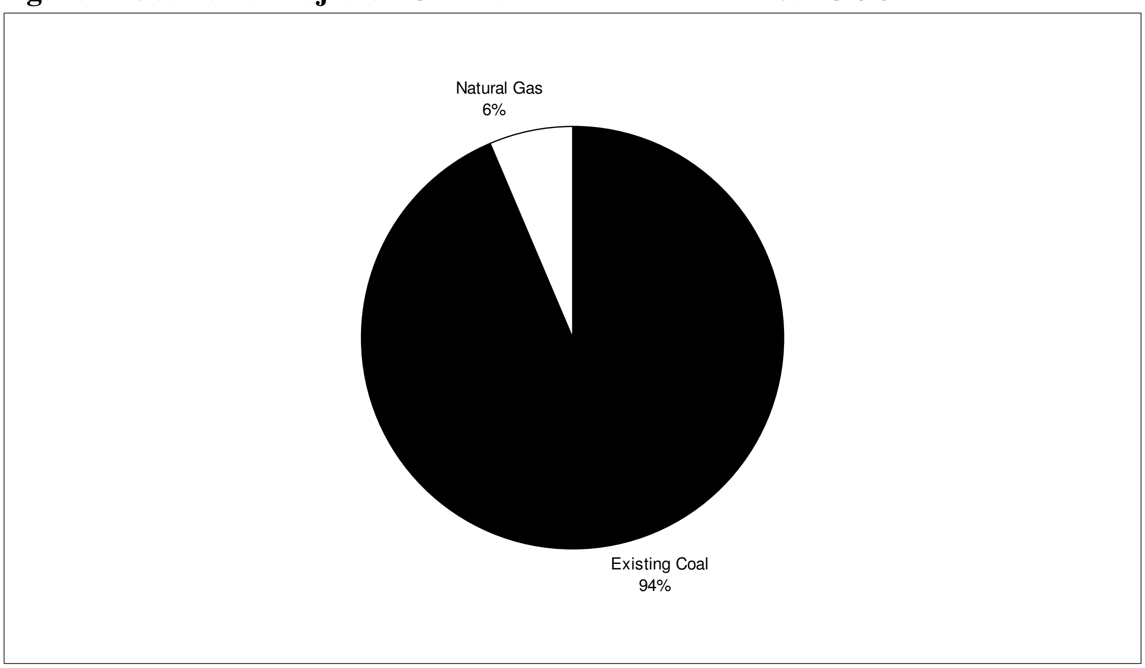


Figure 9. Vectren's Projected Generation Mix in 2016 – No IGCC Plan



With a difference in natural gas generation between the two plans of 4% and total natural gas generation reaching just 6% of the total, even in the No IGCC plan, it seems obvious that GHG regulation is the risk that Vectren and its ratepayers ought to be more concerned about. Since Vectren's modeling also underestimates the cost of the Edwardsport IGCC and the cost difference between the IGCC and No IGCC Plans seems to be driven primarily by off-system sales, the No IGCC Plan really appears to be the better, less risky choice. It is important to note that non-natural gas alternatives have a role to play in Vectren's energy mix which can mitigate both natural gas price volatility and greenhouse gas regulation risks. These alternatives are discussed in the testimonies of Mssrs. Fagan and Mosenthal.

Q. Is there any additional evidence supporting your assertion that greenhouse gas regulation will be a bigger risk to Vectren than gas prices?

A. Yes. Vectren's modeling actually shows that with higher gas prices, Vectren has ***lower*** net total system costs. This is because with the higher gas prices Vectren is modeled as making more off-system sales. The net revenues from these sales reduce Vectren's total costs, resulting in a lower PVRR with high gas prices than with base gas prices.

5. REVIEW OF DUKE'S MODELING AND PLANNING FOR EDWARDSPORT IGCC

Overview of Duke's Modeling

Q. Please describe the analysis you undertook of Duke's modeling.

A. My analysis focused on the modeling files associated with the supplemental modeling described in Diane Jenner's amended supplemental testimony. Ms. Jenner's testimony indicates that this modeling contains Duke's most updated cost estimates for supply-side resources. The general framework for my analysis is very similar to my analysis of Vectren's modeling. That is, I am looking for a thorough weighing of the risks and costs of *both* supply-side and demand-side options.

Q. Please describe the modeling files you examined.

A. The modeling files I examined were the inputs and outputs from the two scenarios that Duke ran in support of its prefiled supplemental testimony, Scenario I (SCI) and Scenario IV (SCIV). The major difference between these two is the inclusion of a CAIR/CAMR Plus requirement and Duke's CO_2 price forecast in Scenario IV, but not in Scenario I.

Q. Please describe the results of your analysis.

A. I found the following major problems with Duke's modeling:

- A low and out-of-date capital cost assumption for the Edwardsport IGCC,
- Unrealistic and overly constrained assumptions for DSM and renewables, and
- Incomplete analysis of greenhouse gas regulation.

I also found additional, pertinent information to bring to the Commission's attention, including:

- There are large, unexplained differences between the energy requirements forecast used in Duke's STRATEGIST model runs and prior documented forecasts (i.e., Duke's 2005 IRP energy forecast and the 2006 energy forecast).

- Duke's system is more than 90 percent coal, in terms of fuel mix, and so the Company's concerns about natural gas price risk, while legitimate, are overstated. Indeed, Duke's customers and shareholders are much more exposed to risks associated with coal use (such as carbon dioxide emissions regulation) and the Company should be actively diversifying its resource mix as a risk management strategy. Instead, Duke's plan understates the possible role of non-coal resources such as natural gas, renewable generation, and DSM, in order to pursue a capacity expansion plan that increases coal dependence and risk exposure.

- In the Company's model, the Edwardsport project enables Duke to increase off-system sales in large amounts (as much as 25% of the output of the facility). This raises issues of appropriate allocation of costs and risks. For customers paying Duke's regulated rates and bearing the burden of construction costs for the project, it is not at all clear that counting on speculative revenues from future off-system sales is a prudent arrangement. The off-system sales may not occur, may not be priced as in the Company's analysis, or may not have the net revenues fully passed through in rates to customers.

Capital Cost and Online Date for Edwardsport

Q. What does Duke assume with regard to the capital cost and operation date for the Edwardsport IGCC project?

A. Duke makes the same unrealistic assumption that Vectren does about the capital cost and online date for Edwardsport. Specifically, both companies assume in their modeling that the plant will be operating at the beginning of calendar year 2011, and both companies use a cost estimate for the project that is below the current cost estimate in the front end engineering and design (FEED) study. I discuss the problems with these assumption above in the context of Vectren's modeling, and will not repeat those points here.

Renewables and Energy Efficiency

Q. Why is Duke's assessment of renewables inadequate?

A. First, as the testimony of Robert Fagan discusses, there is significant potential for wind and CHP in Indiana. The modeling undertaken by Duke limited these options to a few wind power projects in selected years. It appears that the model could select from wind resources as described in Table 10.

Table 10. Wind Resource Options in Duke Modeling

Year Available	Increment to Select in Scenario IV (MW)	Increment to Select in Scenario I (MW)	Cumulative Maximum in Scenario IV (MW)	Cumulative Maximum in Scenario I (MW)

In both scenarios, the Benton county wind farm in 2008 was a fixed resource. Apart from that resource, if a year is not listed in the table, the model could not add any wind capacity. In Scenario I, the increment to select and the cumulative maximum are the same, meaning that only an additional MW could be added either in , , or . In Scenario IV, additional wind capacity could be added in , , and for a total of MW by 2027.

Q. Did the STRATEGIST model select the full MW in Scenario IV?

A. Yes. Duke apparently, did not, however, test whether additional wind resources would also be cost-effective.

Q. You've said that Duke also gave inadequate consideration to energy efficiency. Please explain.

A. As Mr. Mosenthal describes in his testimony, there are significant energy efficiency resources available in Duke's service territory. The DSM cases developed by Witness Stevie do not even begin to approach the level of savings that could be achieved from an aggressive set of programs.

Table 11. Duke DSM Cases for Strategist Modeling

	Low DSM Impact		Base Case		High/Aggressive DSM Impact		Ultra High DSM Impact	
Year	MWH	MW	MWH	MW (1)	MWH	MW (1)	MWH	MW (1)
2005	0	0	4,144	1	21,591	5	30,943	8
2006	0	0	12,122	3	61,882	12	89,569	21
2007	0	0	20,100	5	102,172	19	148,196	34
2008	0	0	28,078	7	142,462	26	206,823	46
2009	0	0	36,056	9	182,753	34	265,450	59
2010	0	0	44,034	11	223,043	41	324,077	72
2011	0	0	52,012	13	263,333	48	382,704	84
2012	0	0	59,991	15	303,623	55	441,331	97
2013	0	0	67,969	17	343,914	62	499,958	110
2014	0	0	75,947	18	384,204	70	558,584	122
2015	0	0	83,925	20	424,494	77	617,211	135
2016	0	0	91,903	22	464,785	84	675,838	148
2017	0	0	99,881	24	505,075	91	734,465	160
2018	0	0	107,859	26	545,365	99	793,092	173
2019	0	0	115,837	28	585,655	106	851,719	186
2020	0	0	123,815	30	625,946	113	910,346	198
2021	0	0	131,794	32	666,236	120	968,973	211
2022	0	0	139,772	34	706,526	127	1,027,599	224
2023	0	0	147,750	36	746,817	135	1,086,226	236
2024	0	0	155,728	38	787,107	142	1,144,853	249
2025	0	0	163,706	40	827,397	149	1,203,480	262

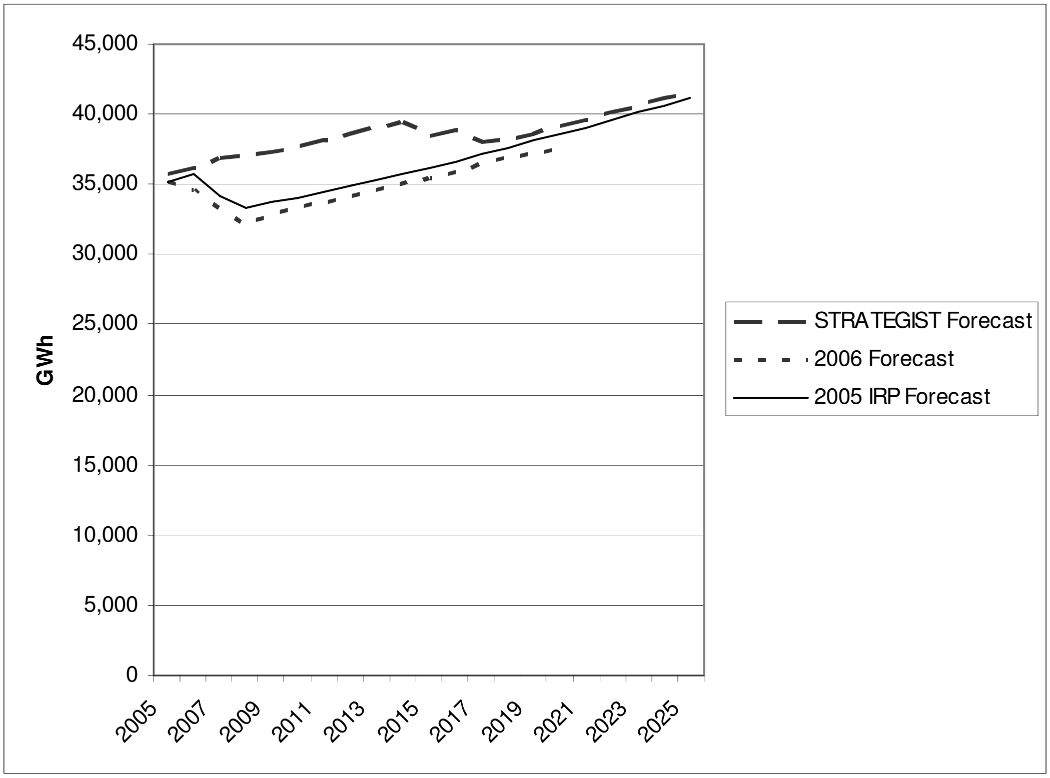
Duke's ultra-high DSM case, at its maximum, represents 0.3% or less of Duke's energy needs. As discussed in the testimony of Phil Mosenthal, much greater potential exists for cost-effective DSM on Duke's system.

Duke's Forecast of System Energy Requirements

Q. What evidence is there that the energy forecast used in Duke's modeling is significantly different than the forecast from its 2005 IRP and 2006 forecasts?

A. Figure 12 compares the three forecasts.

Figure 12. Comparison of Duke Energy Forecasts



What first jumps out from this figure is the shape of the forecasts. Duke is losing wholesale load in 2007, so it is reasonable to expect its energy requirements to drop as they do in the bottom two forecasts. The 2005 IRP Forecast and the 2006 Forecast are directly from Richard Stevie's testimony, Exhibit No. 8-C, and Duke's 2005 IRP. Dr. Stevie testifies that he provided the 2005 IRP and 2006 forecasts along with high and low load growth forecasts based on the 2005 IRP forecast to Ms. Jenner for STRATEGIST analysis.[5] He states that the 2006 Forecast is "the most recent," so the source of the STRATEGIST forecast and the difference in that forecast remain unexplained.

5 Testimony of Richard Stevie, page 15, lines 16-21.

Q. Is it possible that interactions with wholesale load somehow account for this difference?

A. Dr. Stevie does say "The Company's forecast reflects the fact that it will not continue serving the wholesale customer load of IMPA after its contract expires. However, the WVPA and IMPA shares of Gibson 5 would still be a load requirement for resource planning."[6] Ms. Jenner testifies "the 2005 load forecast that [Dr. Stevie] provided me included IMPA's load only through the end of the current contract, which expires on May 31, 2007. The forecast also included…WVPA's load corresponding to its ownership share of Gibson 5 due to Duke Energy Indiana's back-up power contract obligations." It is simply not clear to me whether the IMPA and WVPA loads are part of the forecast despite the expiration of those contracts.

Ms. Jenner's testimony seems to indicate that Duke has a back-up power obligation associated with these customers. If that is the case, however, Duke should either *not* include those loads in its STRATEGIST modeling or somehow appropriately reflect this back-up power obligation so that the model is not adding a baseload coal resource when a low-cost peaking resource would be more appropriate to meet backup power needs.

Q. Is it possible Duke has signed contracts for new wholesale load?

The STRATEGIST modeling does assume that "Duke Energy Indiana would sell an additional 100 MW for ten years starting in 2007 [in order to mitigate the loss of some of its wholesale load]."[7] Even if this 100 MW were at a 100% load factor, though, , i.e., 876 GWh out of about GWh.

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[6] Testimony of Richard Stevie, page 11, lines 11-13.

[7] Testimony of Diane Jenner at page 9, lines 11-14.

Q. How are these issues of the energy forecast relevant to this proceeding?

A. First, the model will not be able to differentiate between back-up power and native load obligations and so will plan to meet back-up needs as if they were firm. This will tend to make the addition of baseload power plants more desirable than peaking units.

Second, there is a concern that Duke is offering power to new wholesale customers at prices that are below the all-in cost of the IGCC unit, thus using captive ratepayers to enable off-system sales.

Q. Have you attempted to clarify this issue?

A. Yes, regarding Ms. Jenner's testimony, CAC asked the following discovery question of Duke:[8]

> Refer to the testimony of Diane Jenner, page 9, lines 11-14. To the best of Duke Energy Indiana's current knowledge, at what price and terms would it sell the 100 MW of firm load? In Duke Energy Indiana's best judgment, who are the potential customers for this load?

Duke responded:

> Subsequent to the filing of the testimony, Duke Energy Indiana has signed 285 MW of firm native load wholesale contracts (in addition to the 100 MW contract with Hoosier Energy referenced in testimony) with 3 different entities. Duke Energy Indiana objects to providing the pricing, terms, and customers since these agreements are subject to confidentiality agreement with the other parties to the agreements and would require the permission of these parties to release that information.

At a 100% load factor, this 285 MW would represent 2,497 GWh.

It is also unlikely that wholesale load is driving the difference since the date of this request, March 27, 2007, postdates the completion of Duke's modeling both

[8] CAC 4.5

for its direct and supplemental testimonies and the energy forecasts in both sets of modeling are identical.

Q. Is the difference significant enough to affect the results of Duke's modeling?

A. Yes. As a point of comparison, Table 13 shows the forecasted generation from the Edwardsport IGCC facility (Column A, taken directly from Duke's modeling) and the difference between the STRATEGIST forecast (Column B) and the 2006 and 2005 IRP forecasts (Columns C and D, respectively).

Table 13. Duke's Edwardsport IGCC Generation Compared to Energy Forecast Differences

	IGCC Generation (GWh) (A)	Strategist Forecast (B)	2006 Forecast (C)	2005 IRP Forecast (D)	(B) - (C)	(B) - (D)
2005			35,236	35,236		
2006			34,557	35,695		
2007			33,169	34,215		
2008			32,222	33,364		
2009			32,861	33,716		
2010			33,253	34,079		
2011			33,722	34,487		
2012			34,178	34,926		
2013			34,641	35,356		
2014			35,088	35,782		
2015			35,520	36,208		
2016			35,955	36,645		
2017			36,394	37,116		
2018			36,814	37,607		
2019			37,221	38,103		

Through 2015, the difference is comparable to the amount of generation coming from the unit. This suggests that the need for *any* type of supply-side capacity is being driven by this difference.

Q. Does the Commission have the information before it to evaluate whether these wholesale contracts would provide power to wholesale load at a discount relative to the cost of the Edwardsport facility?

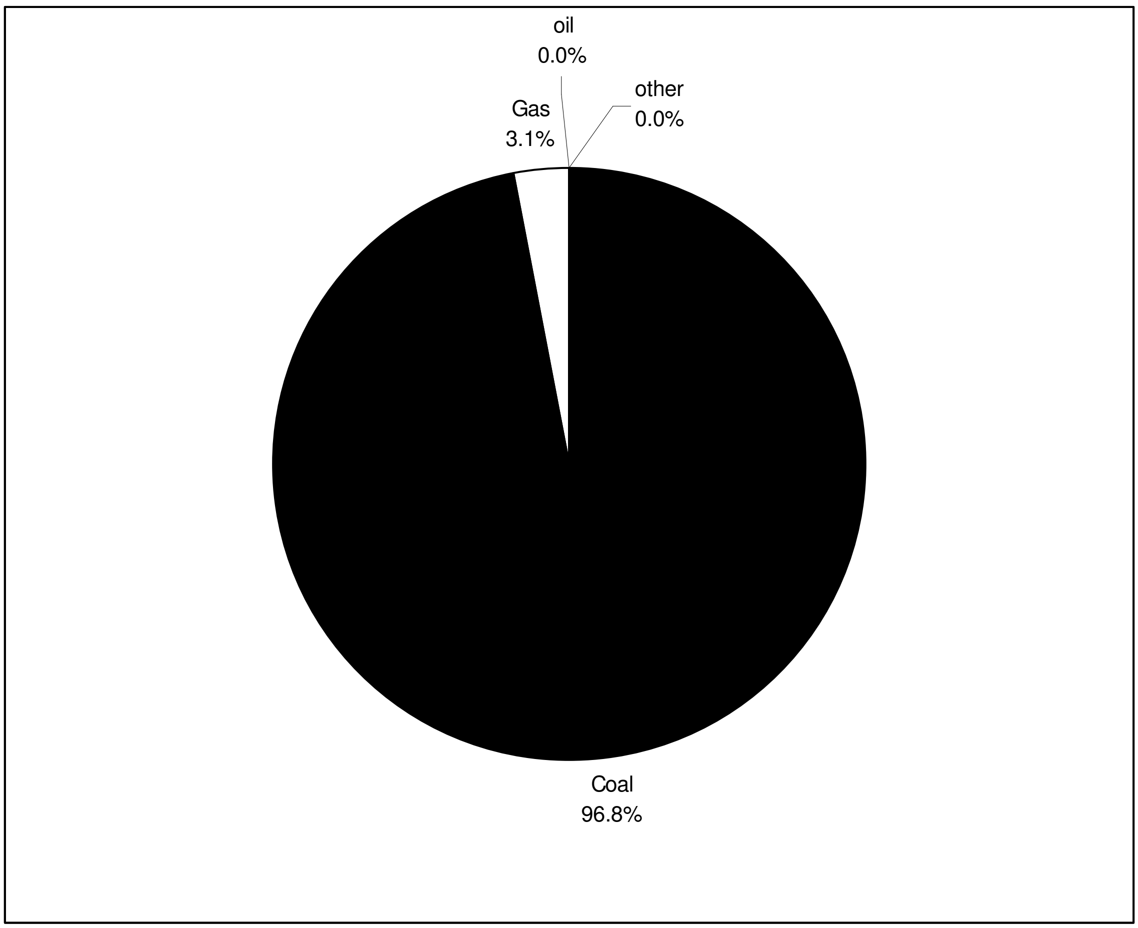
A. Not to my knowledge. As Duke's response above indicates, it has refused to provide the details of those contracts.

Resource Diversity and Risk

Q. In her amended supplemental testimony, Ms. Jenner cautions against not moving forward with the IGCC project because of natural gas price volatility as a result of building a gas CC instead. Shouldn't this risk be weighed against the impacts of greenhouse gas regulation?

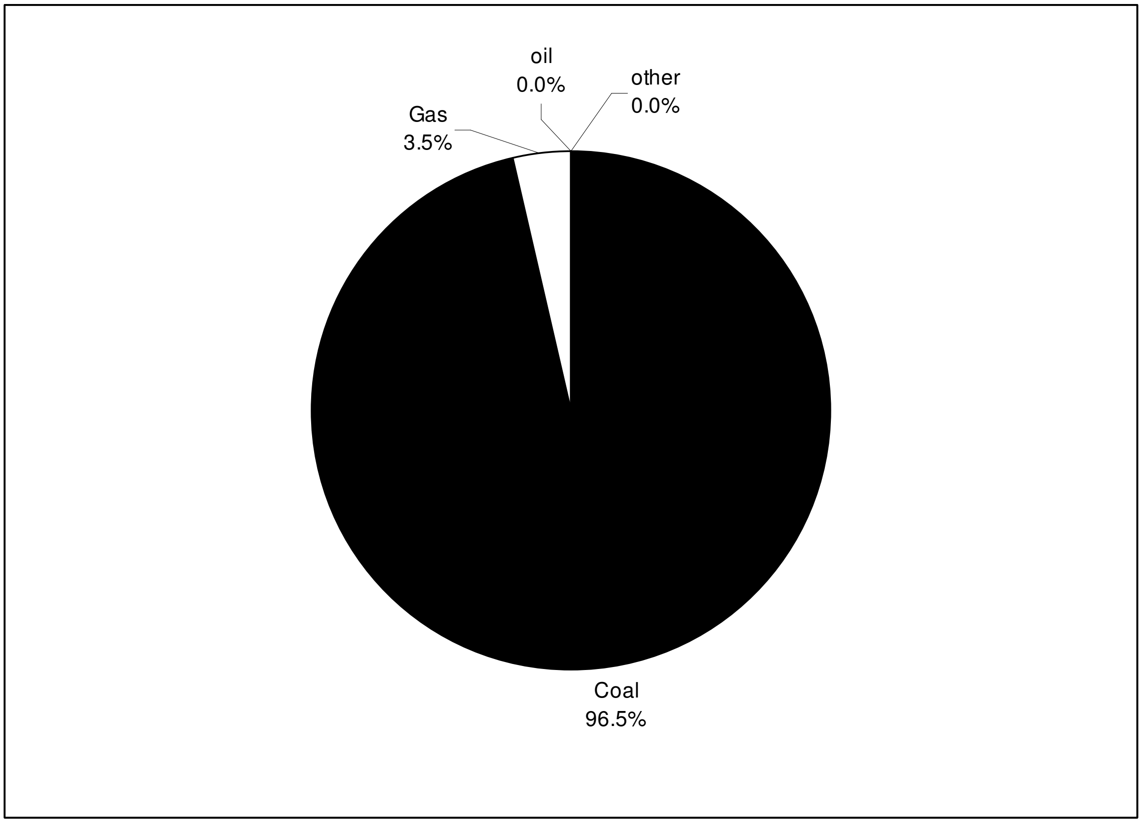
A. Of course. But its consideration should be relative to the magnitude of the problem. In 2007, Duke projects that its system generation will be 96.8% coal and 3.1% natural gas (see Figure 14).

Figure 14. Duke's Projected 2007 Generation Mix



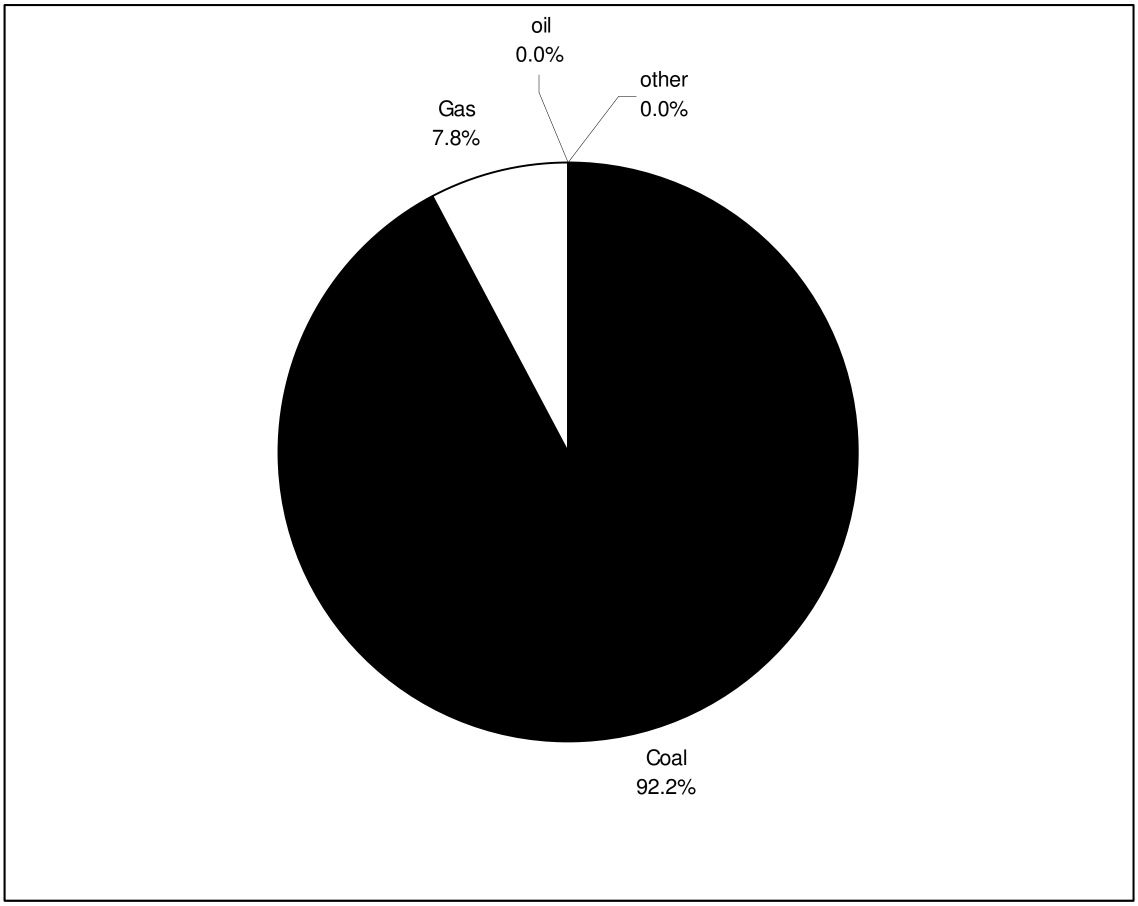
In the plan with 80% ownership of the IGCC unit (and assuming Duke's CO2 price forecast), Duke projects its generation mix will be 96.5% coal and 3.5% gas (see Figure 15).

Figure 15. Duke's Projected 2016 Generation Mix with 80% IGCC



In the plan with a gas combined cycle unit substituted for the IGCC, Duke projects its generation mix will be 92.2% coal and 7.8% natural gas (see Figure 16.)

Figure 16.Duke's Projected 2016 Generation Mix with a CC in 2011



As with Vectren, coal represents such a large portion of Duke's energy mix that greenhouse gas regulation should be paramount among its concerns.

Q. Is there any additional evidence supporting your assertion that greenhouse gas regulation will be a bigger risk to Duke than gas prices?

A. Yes. Duke's own modeling reflects this. The cost of the 50% IGCC Plan under base, high gas and CO_2 price scenarios is shown in Table 17.

Table 17. Study and Planning Period PVRRs of the 50% IGCC Plan in 3 Scenarios

	Planning Period (000s)	Study Period (000s)	Planning Period Delta (000s)	Study Period Delta (000s)
SCI Base			N/A	N/A
SCI Hi Gas				
SCI CO_2				

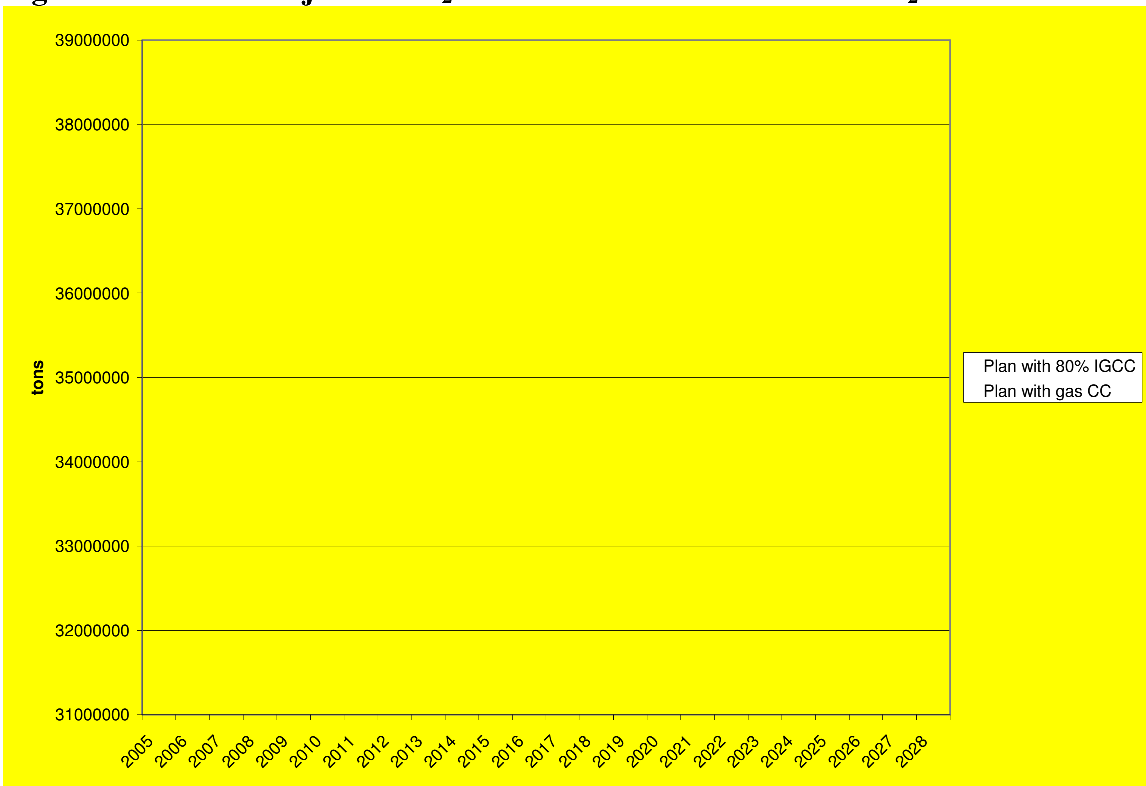
For the "planning period" (i.e., Duke's modeling period through the year 2028), the Company's own model results, with its understated CO_2 forecast, show an increase in costs of billion (cumulative present value). The impact of the high gas price case is only billion, an order of magnitude lower. For the “study period,” which accounts for “end-effects” or costs after the year 2028, the differences are much higher. The exposure to CO_2 prices amounts to almost 20 times the exposure to high gas prices.

Of course there are many important details that would go into a systematic analysis of risks. For example, gas prices could be higher or lower than the reference case forecast. Also, carbon policy could allocate allowances to Duke, softening the total cost impact.

Q. Won’t the IGCC unit result in lower CO_2 emissions on the Duke system?

A. No. Even assuming Duke’s CO_2 price forecast, CO_2 emissions will increase in Duke’s system above the increase resulting from the addition of a gas CC in 2011 instead of the IGCC unit. Duke’s projected CO_2 emissions are shown in Figure 18.

Figure 18. Duke's Projected CO_2 Emissions in Two Plans with CO_2



Edwardsport Serves to Increase Off-System Sales

Q. You stated in your summary that the addition of the IGCC facility enables more off-system sales relative to the addition of a gas CC. What evidence is there to support that?

A. Duke's modeling files reflect this fact. Figure 19 is a comparison of the net transactions from the Gas CC Plan and the 80% IGCC Plan.

Figure 19. Duke Net Transactions in Two Plans with CO_2

A negative number means Duke is selling more that it is buying. A positive number means it is buying more than it is selling. There is a clear jump in sales in 2011, when the IGCC unit comes online. The increase in off-system sales caused by Duke's participation in Edwardsport ranges from about GWh/year to GWh/year. This is quite a large portion of the output of Duke's share of the project. I support Duke taking full advantage of opportunities to decrease costs to customers by selling surplus generation in the wholesale market. I question, however, the wisdom of a plan to overbuild baseload capacity with the burden on customers paying regulated rates, with the intention of increasing the amount of off-system sales. This is a speculative venture with inappropriate allocation of risks and rewards between Duke customers and shareholders. The revenues from these sales influence the PVRR of the different plans so part of the closeness of the PVRRs of the different plans has to do with the ability to make off-system sales.

Q. If Vectren were to decide not to become a partner in the Edwardsport IGCC Project, could Duke reasonably and prudently assume ownership of the full 630 MW facility?

A. No. An economic analysis of full ownership, in light of the capital cost increase of the Edwardsport facility, is not even part of the record in this cause.

6. RESOURCE COST COMPARISONS

Levelized Costs

Q. Have you done any analysis in this case of the comparative costs of resource options available to Duke and to Vectren?

A. Yes, I have developed some cost comparisons, on a levelized basis in order to understand and illustrate the relative costs of Edwardsport and alternatives under a range of assumptions.

Q. What are levelized costs?

A. Costs can be expressed in "levelized" terms in order to make straightforward comparisons. In the case of electricity resource options, it is common to levelize cost streams and to express the results in $ per MWH. The levelized cost in $/MWH typically includes fixed costs such as the annualized capital cost and fixed O&M cost, and variable costs such as fuel, variable O&M, and air emissions allowances. The levelized cost can represent in a single number all of the costs associated with owning and operating a resource, over a long-term period.

The shape of the actual cost (or "revenue requirement") streams over time may vary (e.g., fuel or carbon dioxide emissions costs may, for example, rise faster than inflation, and may not be "smooth") but the levelization calculation expresses them on common terms, such that the cumulative present values of the more complex annual cost streams and the present values of the levelized costs are identical.

Resource Cost Comparison with Duke Data

Q. Please describe the levelized costs in Table 23 and Figure 20.

A. These are levelized costs for a set of resource options, using assumptions based upon Duke's 2006 IRP and the analysis that Duke filed in this case. The costs depicted in the first example, without a carbon dioxide price, correspond closely to what Duke has assumed in its Strategist model runs in this case. In the other cases (Figures 21 – 22), all of the inputs are held constant except for the projected price of carbon dioxide. There are many input assumptions that influence the "all-in levelized resource cost" comparison, but the price for carbon dioxide emissions is perhaps the most important, and is subject to considerable uncertainty.

Figure 20. Duke resource cost comparison without CO2 costs

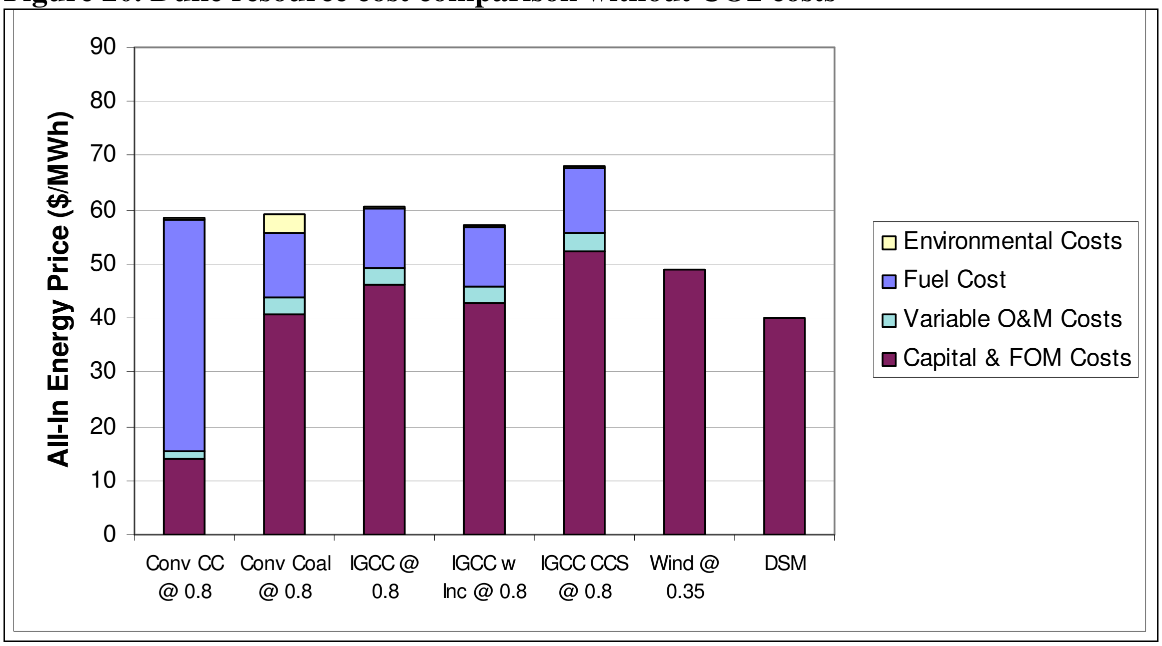


Figure 21.: Duke resource cost comparison with the Companies' CO2 costs

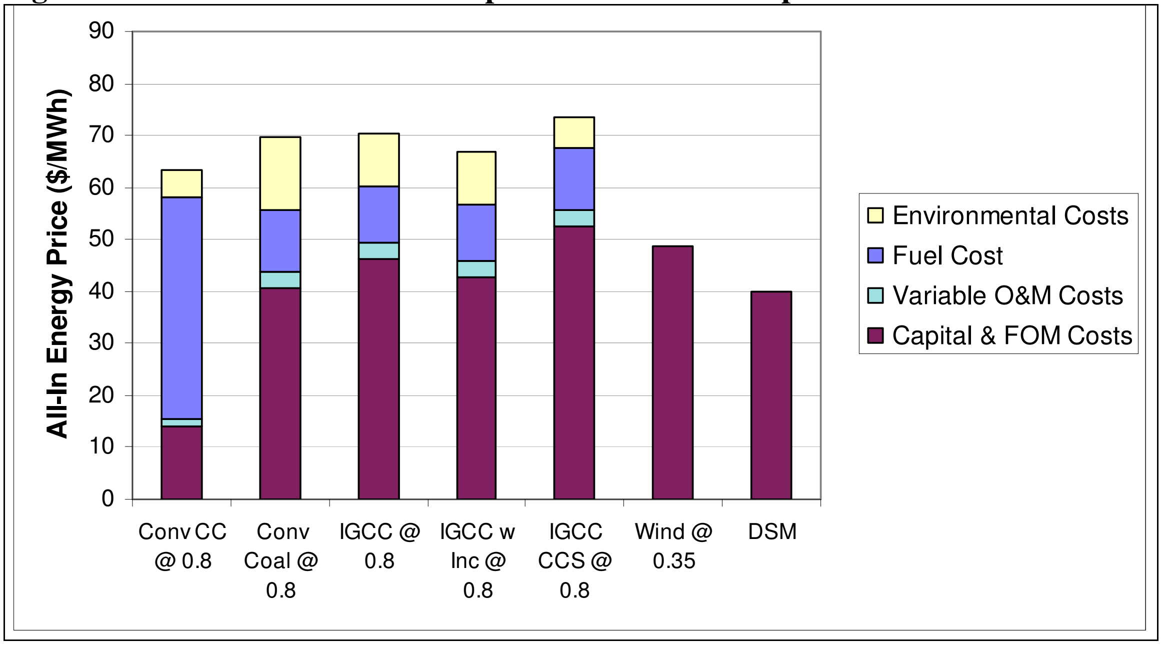


Figure 22.: Duke resource cost comparisons with Synapse's mid-case CO2 costs

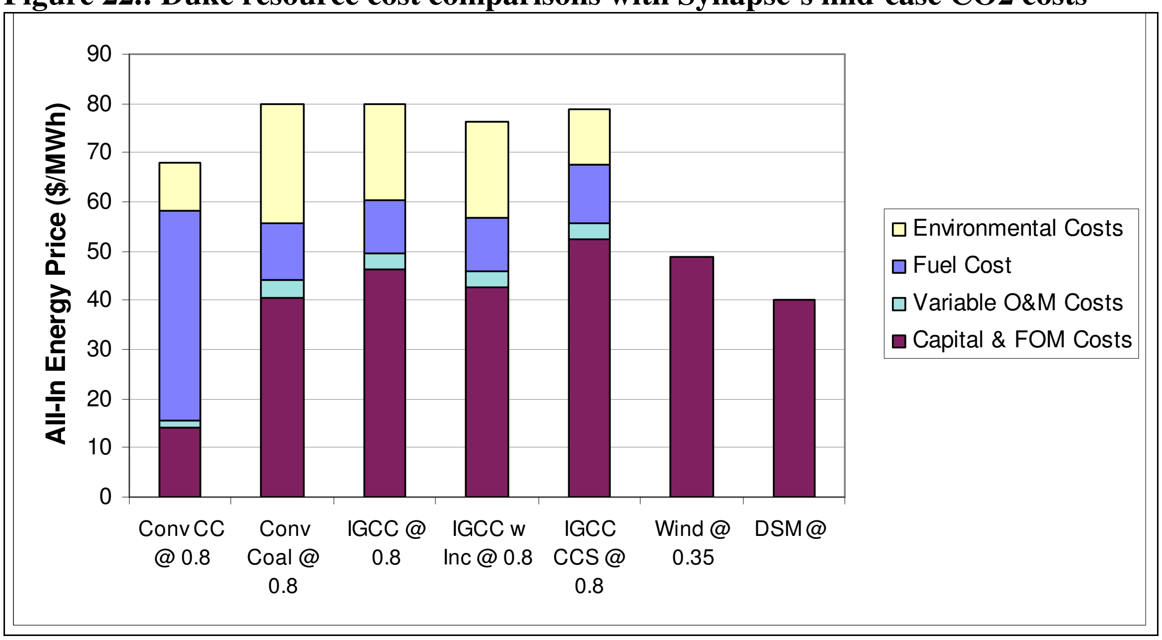


Table 23. Levelized cost summary for Duke resources with different CO2 costs ($/MWh)

Carbon dioxide emissions price	Gas Combined Cycle	Conventional Coal	Integrated Gasification Combined Cycle Coal	Integrated Gasification Combined Cycle Coal Coal with Federal Subsidy	Integrated Gasification Combined Cycle Coal Coal with Carbon Capture Sequestration	Wind	Demand-Side Manage-ment
Zero carbon price	**58.47**	**59.07**	**60.47**	**57.01**	**68.02**	**48.79**	**40.00**
Companies' CO2 price	**63.28**	**69.73**	**70.27**	**66.81**	**73.47**	**48.79**	**40.00**
Synapse's mid-case CO2 price	**67.97**	**80.05**	**79.77**	**76.30**	**78.75**	**48.79**	**40.00**

Q. What do the costs in the three figures and the summary table above show?

A. These cost comparisons show, first, that in the absence of carbon regulations (i.e., carbon dioxide emissions assumed to have no cost for the entire analysis period) that the levelized cost of the gas combined cycle unit, the pulverized coal unit, and the IGCC unit without sequestration are all in a very narrow range, within $58.47/MWh to $60.47/MWh. This is effectively a "break even" situation, given the uncertainties involved in the inputs and calculations. The IGCC plant, with the federal subsidies of more than $100 million from DOE accounted for,[9] has an expected cost of $57.01/MWh, edging out the other fossil technologies. Note that the IGCC cost for this case includes a credit for the federal subsidies, but does not include the cost to customers associated with Indiana ratemaking subsidies.

In this instance, with carbon priced at zero, the IGCC with carbon capture and sequestration ("IGCC CCS") is clearly more expensive than the other resource options. Note that we have, in this table, assumed 50% carbon capture. The costs associated with higher capture rates would be significantly higher still. Note also

[9] According to the Amended Supplemental testimony of Kay Pashos the project was allocated $133.5 million in federal tax credits (page 2).

that the cost and performance assumptions for CCS are from Duke's response to a data request (IWF-CATF 1.3) in this case, and are subject to considerable uncertainty.

In addition, the wind resource option, at a levelized cost just under $50/MWh is preferable to all of the fossil fuel options, even without a carbon price. Similarly, demand-side management would come in at $40/MWh and below, making that the most cost effective of the available resources, even in the absence of carbon regulations. For details supporting the prices for wind and DSM please see the testimony of CAC witnesses Fagan and Mosenthal, respectively.

It is not surprising that the "optimization" algorithm within the Strategist model selects the IGCC option, given the cost comparisons shown in Figure 20.

Q. How do carbon prices influence the resource cost comparisons?

A. In the second and third figures, which include the cost of carbon dioxide, the cost of the gas combined cycle option increases somewhat, and the cost of the coal and IGCC options increases even more so. Even with the Companies' carbon price forecast, the gas combined cycle option is significantly less expensive than all of the coal resource options. With the Synapse mid-case carbon price forecast, these differences grow.

The carbon regulations also make renewables and efficiency, which were cost-effective anyway, significantly more so.

For the reasons described in Mr. David Schlissel's testimony and exhibits, significant carbon dioxide regulations are very likely to be implemented in the timeframe of the Edwardsport project, and the cost implications of those regulations upon the price of carbon dioxide emissions should be considered explicitly and systematically in the planning analysis.

Q. Do you, in fact, accept Duke's input assumptions?

A. No. We have not conducted a comprehensive review of either Company's input assumptions. Our review of the Companies' modeling focused on a few key items including the construction costs of the Edwardsport facility, carbon dioxide prices, and the treatment of renewable generation and DSM.

Q. Figures 20 – 22 show a wind resource option available at $48.79/MWH. Please explain what that is.

A. As described in Robert Fagan's testimony, there is a large wind resource potential available in Indiana. Duke has information from a recent RFP for wind, but has refused to provide that information in this case. Based on assumptions described in Mr. Fagan's testimony he has estimated an all-in cost for wind generation of just under $50/MWH. Actual costs for particular wind project could be above and below this figure.

Q. Figures 20 – 22 also show a DSM resource option available at $40/MWH. Please explain what that is.

A. As described in Phil Mosenthal's testimony, there is a large potential for DSM in Indiana. He puts that cost of that resource at less than 4 cents per kWh (which is $40 per MWH).

Resource Cost Comparisons with Vectren Data

Q. Do the levelized costs based upon Vectren's assumptions differ from those based upon Duke's assumptions?

A. Yes. Analogous figures for Vectren's data on Edwardsport and the alternatives (with different carbon price assumptions) are presented in Figures 24, 25, and 26, and Table 27. The largest differences for Vectren seem to stem from Vectren's higher assumption for the cost of debt and equity. Projects with high construction cost show higher levelized costs because of the higher cost of money. This has a large effect, particularly on the coal and wind resource options.

Figure 24.: Vectren resource cost comparison without CO2 costs

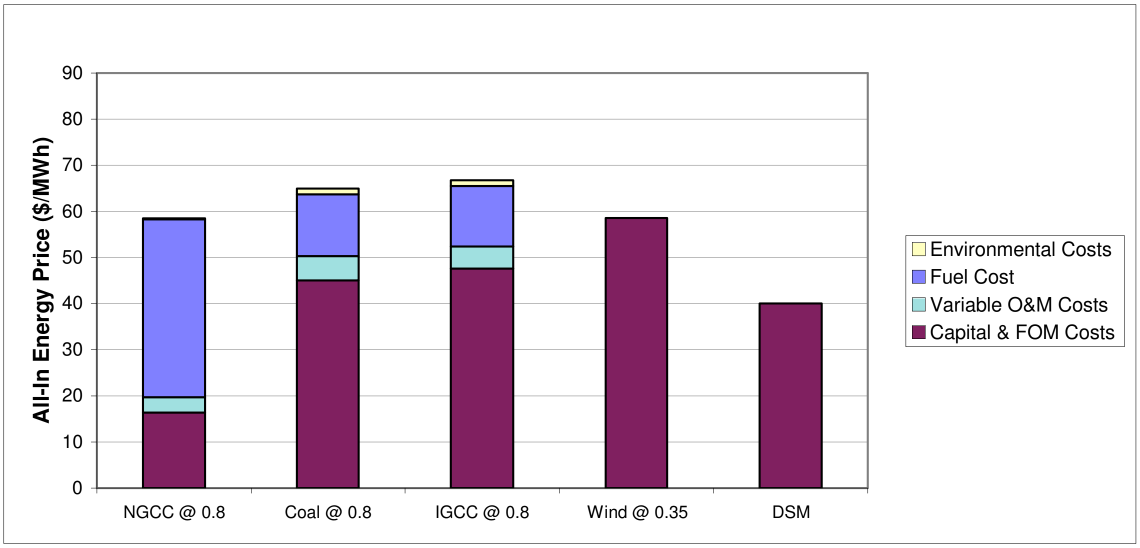


Figure 25.: Vectren resource cost comparison with the Companies' CO2 costs

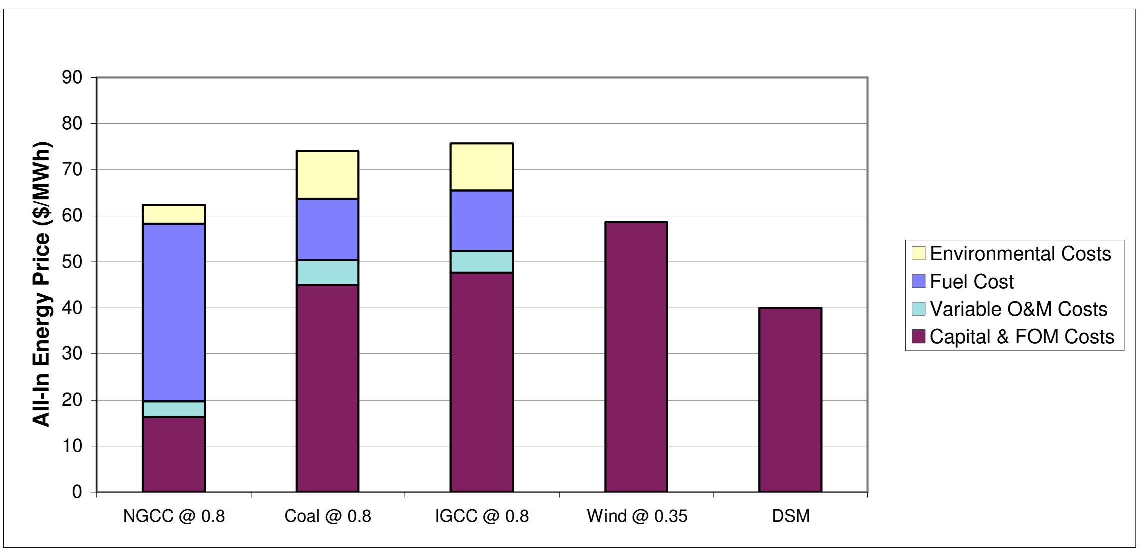


Figure 26.: Vectren resource cost comparisons with Synapse's mid-case CO_2 costs

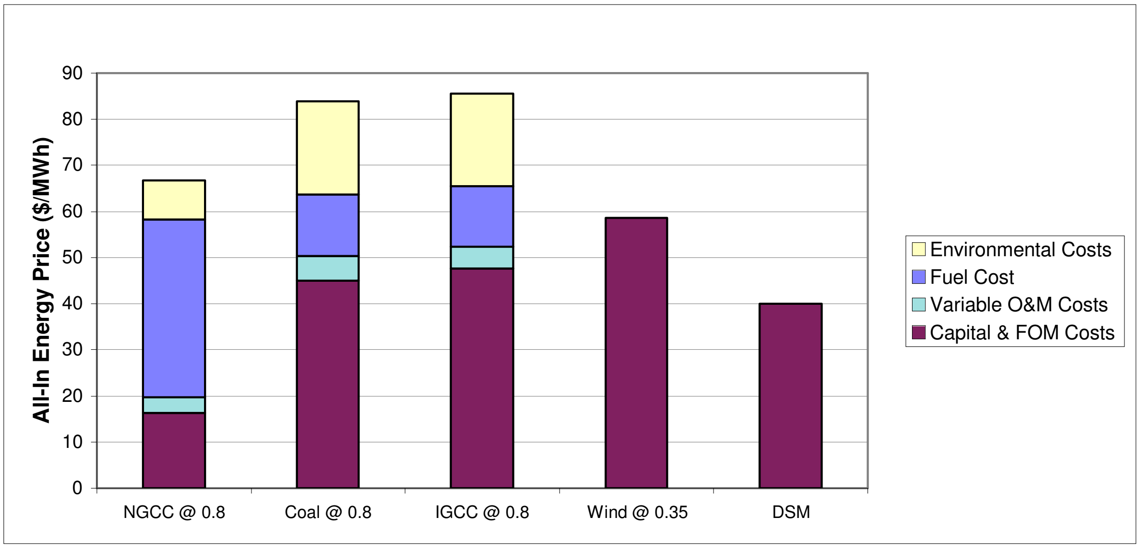


Table 27. Levelized cost summary for Vectren resources with different CO_2 costs ($/MWh)

Carbon dioxide emissions price	Gas Combined Cycle	Conventional Coal	Integrated Gasification Combined Cycle Coal with Federal Subsidy	Wind	Demand-Side Management
Zero carbon price	**58.46**	**64.95**	**66.79**	**58.59**	**40.00**
Companies' CO_2 price	**62.39**	**73.98**	**75.76**	**58.59**	**40.00**
Synapse's mid-case CO_2 price	**66.79**	**83.92**	**85.62**	**58.59**	**40.00**

System Planning and Risk Analysis

Q. What are the aspects of resource planning that are not captured in levelized cost comparisons of this type?

A. Details about the timing of resources are not reflected in levelized cost comparisons. In effect, all of the resources are assumed to be implemented in a similar time period. Also, capacity factors are an input assumption to levelized cost calculations, whereas simulation models would calculate capacity factors over time in the context of the resource mix and system dispatch.

Both of the systems have a considerable amount of existing baseload coal generating capacity, and so in terms of system dispatch the natural gas combined-cycle option has the advantage of being economic at lower capacity factors. In other words, there is a valid need for intermediate or cycling capacity on these systems, and the gas CC resource can, if necessary appropriately play that role. To the extent that natural gas CC capacity is superior to the coal options at 80% capacity factors (as assumed in the levelization calculations) the gas resource will be even more attractive for comparisons at lower capacity factors. In Duke's "Scenario IV Base Case" model run results, there are new gas CCs added to the system, and their capacity factors are in the neighborhood of 30%.

Q. Is peaking capacity also a reasonable option for these systems?

A. Yes, absolutely. Natural gas-fired combustion turbines are relatively expensive to operate, but much less expensive to build than coal plants. The system dispatch simulations show capacity factors generally in the range from 2 percent to 10 percent for Duke's gas fired peaking units. CTs can be an economic resource choice, rather than building new baseload coal (which tends to displace the operating of existing coal generation and increase off-system sales). It is, however, difficult to analyze peakers in the context of the levelized costs per MWh, since so much of the value is in the capacity of the units.

Q. What are the key uncertainties in the planning analysis and how should they be addressed?

A. The major uncertainties for Duke and Vectren's planning are, in my view: construction cost risk, fuel price risk, and environmental regulatory risk. In planning, it is important to consider these risks in a system context. That is, the risk exposure depends upon the portfolio. Duke and Vectren are both very dependant on coal, which represents more than 90% of their energy supply mix. Neither Company is overly exposed to natural gas price risk, but both have a very large exposure to coal price risk and environmental risk (in particular environmental regulatory risk associated with climate change policy and carbon dioxide emissions regulations).

Q. What would a proper risk management analysis entail?

A. A proper risk management analysis would examine ranges for uncertainty in key factors such as plant construction costs, coal prices, gas prices, and carbon dioxide emissions prices, in a systematic way. I believe that the Companies' approach to risk analysis, looking at individual sensitivities for selected assumptions fails to provide a useful assessment of the relative risk exposures and what can usefully be done about them. A reasonable system risk analysis for these coal dominated systems would, I expect, point to greater concern over coal-related risks than to gas price related risks.

Q. You have discussed the prices per kWh for the Edwardsport IGCC project and various other resource options. How does the amount of generation available from those resources compare?

A. The proposed Edwardsport project would be expected to generate roughly 4,400 GWH per year (630 MW at an 80 percent capacity factor). If the project participation is 80% Duke Energy Indiana and 20% Vectren, then their respective shares of the annual generation would be roughly 3,500 GWH and 900 GWH. If carbon capture and sequestration were added to the project at some future date to capture some portion of the carbon dioxide emissions, then the output of Edwardsport would be reduced and the efficiency degraded.

In comparison, the potential for untapped efficiency, combined heat and power, and renewables is vast. For example, with combined energy requirements of nearly 40,000 GWH per year, if the Companies were to ramp up to achieving additional DSM savings of just 1 percent per year, something that Mr. Mosenthal points out is being achieved by other utilities in the United States, the savings would amount to more than 2,000 GWH per year by 2013, and about 4,500 GWH per year by 2018.

In terms of potential for wind generation, according to Mr. Fagan's analysis it would be reasonably feasible to integrate installed wind capacity amounting to 20 percent of peak system demand with reasonable certainty and modest integration costs. Based on MISO analysis, Mr. Fagan testifies that Duke and Vectren can together add about 130 MW per year of new installed wind capacity. This would, by 2013, amount to 2,300 GWH per year of generation, and 4,300 GWH per year by 2018.

Q. What do you conclude from the cost comparisons and resource potential figures described above?

A. It is clear that the Edwardsport facility is not the least cost alternative for Indiana consumers. Indeed, if Edwardsport's output were replaced by a mix of 50% wind generation and 50% DSM, the cost savings to Indiana consumers would amount to roughly $1.9 billion cumulative present value dollars over the period 2011 to 2030. By proceeding with the IGCC project, even with the Federal subsidies, the Companies are wasting a tremendous amount of Indiana citizens' money.

7. RATEMAKING ISSUES

Q. What ratemaking treatment are the Companies asking for with regard to the Edwardsport project?

A. Duke, in the testimony of Ms. Kay Pashos (page 19) and Mr. Stephen Farmer (page 3) explains that it requests specific ratemaking treatment for Edwardsport from the IURC in this proceeding. The requested ratemaking includes (1) "timely recovery" of specific costs; (2) to recover costs via a new mechanism specific to the IGCC project; (3) to receive an incentive of 200 basis points additional return on equity; (4) to capitalize feasibility, engineering, and preconstruction costs; (5) to defer certain costs until they are reflected in retail rates; and (6) to recover external costs associated with regulatory filings.

Vectren requests similar ratemaking treatment for its portion of the costs of the Edwardsport project (testimony of M. Susan Hardwick, page 2).

Q. Have the Companies estimated the cost impacts to customers associated with the requested ratemaking treatment?

A. No. Duke has some projections of the costs to customers associated with the Edwardsport costs and ratemaking. These are presented in Steven Farmer's testimony and specifically in his Confidential Exhibit 13-A (and response to CAC 4.30). These deal just with the cost of the project and do not include its impact on system costs such as fuel or emissions allowances. Also, Duke does not break out the impact of the requested ratemaking. The impact on customers of the requested additional 200 basis points on the ROE, for example, is not broken out. Moreover, the evaluation of resource options in the Strategist model assumes a normal ROE on the Edwardsport (and other) projects. If the IURC allows the additional ROE, it will add significantly to the cost of the Edwardsport project as realized by customers.

Diane Jenner states very plainly in response to CAC 8.18 that Duke did not model the bonus ROE.

Similarly, Eric Robeson, in response to CAC.Q 4.2, states that Vectren did not model the bonus ROE. And like Duke, Vectren Strategist model analysis assumed normal ratemaking for Edwardsport.

Q. How much will the 200 extra basis points, if granted, add to the cost of the Edwardsport project?

A. I have not done a detailed analysis of this. I have, however, plugged a 12.5 percent return on equity into a revenue requirements worksheet, replacing the 10.5 percent return on equity allowed by the IURC in Duke's last rate case. This increases the cost to customers of Duke's share of Edwardsport by about $4 per MWh levelized cost as in Table 27, an increase of 6 percent.

Q. Should the Companies be required to quantify the impact of their requested ratemaking treatment?

A. Yes. The Companies should be required to compute and provide the projected cost impacts on customers associated with the requested ratemaking treatment. In addition, the Companies should be required to conduct planning analyses with the full cost of the project to customers. The planning analyses should be done with an objective of minimizing costs (and risk exposure) to customers. For this reason, it is generally reasonable to account for expected Federal subsidies that reduce the effective cost of the plant for planning purposes. Similarly, however, it also is necessary to account for any other "subsidies" (such as the extra ROE) that would increase the cost of the project to customers.

Q. Do you agree with the Companies' requested rate treatment?

A. Absolutely not. My understanding is that the incentives are strictly for projects that are "found to be reasonable and necessary." Edwardsport is neither.

Moreover, the bonus return on equity is discretionary. It can be "***up to*** three (3) percentage points on the return on shareholder equity that would otherwise be allowed to be earned…" (IC 8-1-8.8-11, emphasis added). The Companies have requested 2 percent points. In the case of Duke, this would apparently raise the ROE on Edwardsport from 10.5% to 12.5%. For Vectren South, which had an ROE of 12.25% approved by the IURC in its 1995 rate case (see Testimony of Jerome A. Benkert, page 6), the 200 basis point requested bonus on Edwardsport would put the ROE at 14.25%. These ROEs are too high and undeserved.

The bonus ROE puts the Companies' returns well beyond what is justified, and should not be provided for a project such as Edwardsport that is already too expensive compared with alternatives, even without the incentive payments associated with the bonus ROE.

Q. What is your ultimate recommendation to the IURC?

A. I recommend that the IURC reject the Joint Petitioners' Application.

Q. Does this conclude your testimony?

A. Yes, it does.