ATTACHMENT D

April 16, 2010 from Sen. Deanna Demuzio, Sen. Kyle McCarter, Rep. Betsy Hannig

For many years, we have supported the Taylorville Energy Center because we believed it would create jobs and revitalize the Illinois coal industry while protecting ratepayers and the environment. We are gratified the comprehensive analysis contained in the Facility Cost Report shows our confidence in this project is justified.

The engineering and cost analysis currently before the ICC was performed over fifteen months by leading independent experts at a cost of more than $20 million. It shows that the Taylorville Energy Center will create more than 2,500 desperately needed construction jobs and hundreds of permanent plant and mining jobs while limiting the impact on residential ratepayers to about 1.8%. While jobs will be created now, ratepayers will see no impact from this project until 2015.

As we all know, our communities in central and southern Illinois were hit particularly hard when high-sulfur Illinois coal fell out of favor with power generators. The Taylorville Energy Center's state-of-the-art gasification technology will show that Illinois coal can again be the fuel of choice.

As members of the General Assembly, our first obligation is to protect our citizens and foster economic growth, but not at the expense of millions of Illinois ratepayers or the environment. Accordingly, the 2008 Clean Coal Portfolio Standards Law demanded that new projects of this type protect residential ratepayers by severely limiting rate increases, even as they were required to meet the nation's most rigorous emissions standards including carbon storage.

Taylorville Energy Center's developer has met the high standards set forth in the legislation and is expected to be a responsible member of our community. We urge the ICC to support moving this project forward.

Senator Deanna Demuzio (D-Carlinville)
Senator Kyle McCarter (R-Lebanon)
Representative Betsy Hannig (D-Litchfield)

April 16, 2010 from Robert J. Finley

The Taylorville Energy Center would be located in an area of Central Illinois that we at the Illinois State Geological Survey believe has significant geological carbon sequestration resources. 2D seismic testing of the injection site has shown no resolvable fault or fracture systems that would be cause for concern with respect to carbon dioxide containment. We are continuing our research on geological carbon sequestration at our test site at Decatur, Illinois and expect that many of the technical results will be applicable to the Taylorville site. Should a pipeline for transporting carbon dioxide to enhanced oil recovery projects not be available, geological carbon sequestration resources are available for testing and development at and near the Taylorville project site.

April 16, 2010 from Ryan Tracy

April 16, 2010

The Honorable Manuel Flores, Acting Chairman

The Honorable Lula M. Ford, Commissioner
The Honorable Erin M. O'Connell-Diaz, Commissioner
The Honorable Sherman J. Elliott, Commissioner
The Honorable John T. Colgan, Acting Commissioner
Mr. Tim Anderson, Executive Director
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, Illinois 62701

Re: Tenaska Clean Coal Facility Comment

Dear Chairman Flores, Commissioners Ford, O'Connell-Diaz, Elliott and Colgan, and Executive Director Anderson,

Thank you for the opportunity to express our strong support of the Taylorville Energy Center (TEC).

As you are aware, the TEC is a proposed 600-megawatt clean coal power plant employing advanced integrated gasification combined-cycle technology. This technology will use an estimated 1.5 million tons per year of Illinois coal to produce substitute natural gas, power more than 500,000 homes, and create more than 2,400 construction jobs and hundreds of permanent power plant and coal mining positions in an economically challenged part of our state.

If constructed, the TEC would capture and store at least 50 percent of the carbon dioxide, would be cleaner than nearly every existing coal-fired power plant in the world and help make our state and nation the leader in clean coal technology. At the same time, TEC will utilize Illinois coal; an abundant, low-cost domestic fuel source.

The TEC enjoys the support of a broad array of organizations including the Illinois AFL-CIO, the American Lung Association of Illinois, the Clean Air Task Force, the Illinois Citizens Utility Board and the Illinois Coal Association. This diverse array of interests, along with Attorney General Lisa Madigan, worked together in support of the Clean Coal Portfolio Standard Act.

Recognizing the importance of the TEC, in July 2009 the U.S. Department of Energy selected the project to proceed into the term-sheet negotiation phase under its loan guarantee program.

Once again, we urge the ICC to support the TEC. We appreciate your years of service for Illinois and thank you for your consideration of our views.

Sincerely,

_________________ __________________
John M. Shimkus Jerry F. Costello
Member of Congress Member of Congress

_________________ __________________
Phil Hare Peter J. Roskam
Member of Congress Member of Congress

_________________ __________________
Melissa L. Bean Mark Kirk
Member of Congress Member of Congress

_________________ __________________
Aaron Schock Bill Foster
Member of Congress Member of Congress

____
Judy Biggert
Member of Congress

April 16, 2010 from Phil Gonet

The Illinois Coal Association supports the Taylorville Energy Center because of its ability to create coal sector jobs and revitalize the Illinois coal industry. Its state of the art coal gasification technology allows this coal-fueled power plant to have emissions as low as a natural gas plant.

There is an abundance of coal in Illinois, with 25% of the nation's bituminous coal reserves which contains more energy than all the oil in Saudi Arabia and Kuwait combined. Unfortunately, this great natural resource has been under-utilized over the past three decades because environmental regulations made high-sulfur Illinois coal difficult to use for power plant operators. The resulting decline in the coal industry has had a devastating effect on communities in Central and Southern Illinois.

The technology proposed for the Taylorville Energy Center is calibrated specifically for Illinois' high energy bituminous coal, making our state's largest natural resource essential for operation of this facility. The Taylorville project will prove that Illinois coal can be used in an environmentally friendly way, which will encourage other developers to return to Illinois coal. Since each mining job supports seven other jobs, every coal industry position created by this and future gasification projects will have a significant positive impact on the state's economy.

The sooner the Taylorville Energy Center begins operations, the sooner good-paying jobs will be created and the coal industry can prosper. Please support this project for the good of the State of Illinois.

Phil Gonet
President
Illinois Coal Association

April 16, 2010 from Siemens Energy Inc.

Tim Anderson
Executive Director
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, IL 62701

Siemens Energy appreciates the opportunity to express to the Illinois Commerce Commission our support for the construction of the Taylorville Energy Center (TEC). This facility incorporates well-proven Siemens technology that has been successfully deployed around the world to enable environmentally responsible coal development -- all while creating jobs and promoting economic development.

Siemens Energy is the world’s leading supplier of services and solutions for the generation, transmission and distribution of power and for the extraction, conversion and transport of oil and gas. Last year our energy business, which has more than 85,000 employees, had worldwide revenues of approximately $ 37.8 billion. In Illinois, Siemens employs over 3,480 people in 35 locations throughout the state.

Incorporating technology from Siemens and other industry-leading suppliers, TEC will be a clean, state-of-the-art power plant with emissions comparable to that of a natural gas facility. The Siemens gasification technology planned for TEC has been in operation in Germany for more than 24 years. Based on Siemens' extensive experience with other coal gasification facilities, we expect TEC will dramatically improve air quality and lower greenhouse emissions as it replaces older, conventional coal plants.

We have worked with Tenaska, Inc., managing partner of the Taylorville Energy Center, on many projects over the years. The company has a well-earned reputation in the industry for developing high-quality projects that benefit the communities they serve. We look forward to expanding our already-extensive work in Illinois with successful and cost-effective development of this project.

Sincerely,

Randy H. Zwrin
Chief Executive Officer
Siemens Energy Inc.

April 15, 2010 from Angela Gaffigan

Hello, last summer I was left a brochure taped to the gate of my driveway regarding an independent study/test being conducted on my ground for geological makeup for CO2. Also, it had been rumored that coal trucks would possibly be traveling down my road. I live on 1700 North Road in Taylorville. I would like to know what plans are in place or could be a possibly be in place that would affect me as a land/homeowner. Did the geological testing prove C02 could be pumped into the ground around me? Are there plans to expand the road which would in turn take some of my property? I work out of town and it makes it hard to catch TENASKA meetings. I did make a few phone calls to ask questions to TENASKA, an IL Reps office as well as the Christian County Township Road. I did not get answers of the results of the testing or if a road expansion was a possibility. I just would like to be informed better on what is going on as a property owner. Finding a brochure taped to my gate 3 days after the project started was rather poor and impersonal. Thanks for your time. Sincerely, Angela Gaffigan

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April 14, 2010 from Louis Laughlin

I live at 1047 E 1700 North Road and understand that the proposed Taylorville Energy Center is planning on upgrading 1700 road to handle 80,000 lb coal trucks. Having worked and retired from IDOT I have seen damage to roadways from continuous heavy truck usage. This will overtime destroy our roadway and make a washboard effect to the roadway in front of my house as they come to a stop at Il 29. Please consider requiring them to use the primary highway system which is designed for heavy traffic and not destroy our township or county roadways. Thank you.

April 14, 2010 from Patricia A. Rykhus

I think that before "we" as taxpayers and consumers decide whether or not we support a project like this, we should look historically at all the other coal gasification plants that are in production.

I challenge you to do some research.

Do not blindly support the TEC project based solely on “jobs” we need to take a long hard look at the industry. Lawmakers, protect your constituents from financial risks.

Taylorville already hosts one Superfund Site due to a power company's inability to contain toxic waste. Let’s not invite another.
Whatever chemicals do not go up a smokestack, have to go somewhere. Where are they going?

Lets take a look at the Great Plains and the Wabash River Coal Gasification Plants.
Great Plains Synfuel Plant in Beulah, ND. Coal Plant Buries U.S. Taxpayers’ $1.5 Billion Along with CO2 - Great Plains was a financial flop. Defaulting on $1.5 Billion in federal loan guarantees before being sold for 4% of its construction costs. In addition to synthetic natural gas, the Great Plains Synfuels Plant produces numerous products from the coal gasification process. Including: ammonium sulfate, anhydrous ammonia, phenol, cresylic acid, liquid nitrogen, methanol, naphtha, krypton and xenon gases. According to their 2008 annual report, Dakota Gasification earned earned $249.1 Million in revenue from the sales of their by-products. Financially, they are dependant on processing their by-products for over 42% of their revenue.

Wabash River Generation Plant – West Terre Haute, Indiana.
Bill disputes idle power plant near Terre Haute – Sept 2004 A state-of-the-art power plant near Terre Haute is sitting idle after natural gas and electricity providers cut service when the owner refused to pay outstanding bills. Their chemical plant – SG Solutions has been plagued with safety and environmental trouble. SG Solutions north of Terre Haute faces a potential $27,000 in fines for serious safety violations in connection with an April 28 explosion that killed two people, according to the Indiana Occupational Safety and Health Administration. According to the Toxic Release Inventory and the Enforcement and Compliance History on-Line at the EPA website- In 2007, in quarters 3 and 4, EPA cited Wabash with “Significant Non-compliance (SNC) effluent violations.” Arsenic limits were exceeded by 589% and Cyanide limiti were exceeded by 20089%. Wabash has been forced to pay $687,500 in penalties for violation of the Clean Air Act and Clean Water Act.

Will the Taylorville Energy Center be a power plant, or a chemical plant masquerading as a power plant?

When considering the "PRICE" that we are paying for the jobs, one must consider the intangible costs, too. We need more answers to the processing of the by-products before this project moves forward.

I urge the ICC to stop this project. The costs are too high.

April 9, 2010 from Monte Cherry

The Sanitary District of Decatur is a strong proponent of the Taylorville Energy Center (TEC) and favors its construction and development. The project is essential in providing all of central Illinois with much needed economic stimulus while having minimal impact on local services and the environment.

Special attention has been given to the design of the TEC to be environmentally-responsible and of minimal impact, including the decision to use a ‘reclaimed’ water source in lieu of depleting existing potable water resources. The Sanitary District of Decatur will provide treated wastewater for the plant’s industrial water needs. TEC incorporates a dry cooling design which uses 70 percent less water than conventional cooling methods and a ‘zero liquid discharge’ process that produces no industrial wastewater further minimizing its environmental impact.

The reclaimed water pipeline capacity will be sized to serve future economic development and other community and agricultural interests revealed through targeted surveys and community meetings.

The Sanitary District has worked closely with Tenaska over the past several years and through that partnership have found them to be highly responsive responsible professionals who are dedicated to forward thinking and environmental stewardship. The TEC is important not only to Illinois, but to our nation as we pioneer new methods to utilize the abundant energy resources found right here in the United Sates. This project will serve as a benchmark for other clean coal facilities to surpass in our efforts to control carbon emissions and improve our air quality.

We believe that every effort should be made to see that this project becomes reality.

March 31, 2010 from John C. Curtin

TO: Illinois Commerce Commission
FROM: John C. Curtin
Christian County Board Chairman

DATE: March 31, 2010

Christian County Generation, LLC is moving toward completion of plans to build and operate one of the first Integrated Gasification Combined-Cycle (IGCC) electric generating stations with carbon capture and managing partner Tenaska has worked closely with the community of Taylorville and Christian County to site and develop the project.

Both national government and electric industry projections state that Illinois needs additional reliable electric generating capacity and central and southern Illinois possess large reserves of high-sulfur coal that would be valued as fuel in an IGCC power plant at a projected rate of $75 million per year (a total of 1.5 million to 1.8 million tons annually).

The Taylorville Energy Center IGCC plant would be among the cleanest power plants in the world, with the ability to remove impurities associated with emissions from coal-fueled power plants, including sulfur, mercury, particulate matter and carbon dioxide and the plant's planners are committed to incorporating cutting-edge technology to capture more than half of the carbon dioxide produced at the plant and prevent it from entering the atmosphere, giving the facility an emissions profile comparable to a natural gas-fueled plant.

Illinois employment would be increased by more than 5,000 jobs during the construction phase of the power project, most of them in the Christian County area, and the electric power generation facility will employ 155 permanent employees and contractors in Christian County, and add indirect employment of an additional 644 full-time and part-time jobs will also be created in the county as a result of electric power generation operations.

As Chairman of the Christian County Board and o0n behalf of the Board, we hereby endorse the Taylorville Energy Center IGCC plant with carbon capture, which provides a new market for the long-struggling Illinois coal industry; incorporates the most advanced emission control technology, including carbon capture, to make it among the cleanest coal-fed power plants in the world; and brings thousands of needed jobs through construction and hundreds more through operation of the facility to Christian County and the surrounding region. We, therefore urge the Illinois Commerce Commission, the State of Illinois and its elected representatives to take swift and positive action to review the Facility Cost Report and approve it to advance the project.

Your attention is sincerely appreciated.

March 31, 2010 from Connie Mitchell

I am in favor of this project!! It can only help the environment and the economy. Most importantly, the money and employment opportunities generated by this undertaking could be just what it takes to save our schools!!

March 31, 2010 from Michael T. Carrigan

The Taylorville Energy Center (TEC) Facility Cost Report confirms what the Illinois AFL-CIO and our member unions have long understood; the TEC will be an economic boon for Central and Southern Illinois.

Especially during these tough economic times, when too many hard-working Illinoisans are out of work, we need to focus on projects that will create jobs.

TEC will create 2,500 good-paying, much-needed construction jobs and hundreds of mining and facility jobs when complete. It will allow Illinoisans to use 1.5 million tons of Illinois coal a year in an efficient and environmentally friendly way. And it will do all of this at a minimal cost to consumers.

It is long past time to move forward with this important project. The state should give this project the green light now!

Michael T. Carrigan, President of the Illinois AFL-CIO

March 30, 2010 from Mary Renner

On March 23, 2010, the Christian County Economic Development Corporation (CCEDC) passed the following Resolution in Support of the Taylorville Energy Center project:

Christian County Economic Development Corporation (CCEDC) Resolution of Support

Whereas, Christian County Generation, LLC is moving toward completion of plans to build and operate one of the first Integrated Gasification Combined-Cycle (IGCC) electric generating stations with carbon capture, and

Whereas, managing partner Tenaska has worked closely with the community of Taylorville, Illinois, and Christian County to site and develop the project, and

Whereas, both national government and electric industry projections state that Illinois needs additional reliable electric generating capacity, and

Whereas, central and southern Illinois possess large reserves of high-sulfur coal that would be valued as fuel in an IGCC power plant at a projected rate of $75 million per year (a total of 1.5 million to 1.8 million tons annually), and

Whereas, the Taylorville Energy Center IGCC plant would be among the first power plants in the world with the ability to remove fuel impurities associated with emissions from coal-fueled power plants, including sulfur, mercury, and particulate matter, and

Whereas, the plant's planners are committed to incorporating cutting-edge technology to capture more than half of the carbon dioxide produced at the plant and prevent it from entering the atmosphere, giving the facility an emissions profile comparable to a natural gas-fueled plant, and

Whereas, Illinois employment would be increased by more than 5,000 jobs during the construction phase of the power project, most of them in the Christian County area, and

Whereas, the electric power generation facility will employ 155 permanent employees and contractors in Christian County, and add indirect employment of an additional 644 full-time and part-time jobs will also be created in the county as a result of electric power generation operations, and

Whereas, an added 238 long-term workers would be employed in coal mining in support of the plant's operations, which would create an additional 297 permanent indirect jobs, and

Whereas, local economic activity would increase by approximately $126 million annually during commercial operation.

Now therefore, Christian County Economic Development Corporation hereby endorses the Taylorville Energy Center IGCC plant with carbon capture, which provides a new market for the long-struggling Illinois coal industry; incorporates the most advanced emission control technology, including carbon capture, to make it among the cleanest coal-fed power plants in the world; and brings thousands of needed jobs through construction and hundreds more through operation of the facility to Christian County and the surrounding region. We further urge the State of Illinois and its elected representatives to take swift and positive action to review the Facility Cost Report and approve it to advance the project.

Jeff Copley, Christian County Integrated Services
John Curtin, Chairman Christian County Board
Greg Brotherton, Mayor City of Taylorville
Dick Adams, First National Bank of Pana
Dr. Gregg Fuerstenau, Superintendent Taylorville Schools
Dr. David Lett, Superintendent Pana Schools
Fred Ronnow, Greater Taylorville Chamber of Commerce
Jim Hahn, Palmer Bank
John Lawrence, CPA
Pam Crisman, Lake Land College
Larry Peterson, Domino Engineering
Roland Carlson, Pana Community Hospital
Brian Atwood, The GSI Group
John Livesay, First National Bank of Pana

Jim Deere, City of Pana
George Heintz, Peoples Bank & Trust
Randy Miller, Miller Media
Bob Gibbs, Ameren
Karen Yeaman, Peoples Bank & Trust

March 24, 2010 from Patricia Rykhus

I think that before “we” as taxpayers and consumers decide whether or not we support a project like this, we should look historically at all the other coal gasification plants that are in production. I challenge you to do some research.
Do not blindly support the TEC project based solely on “jobs”. Do your research and take a long hard look at the industry. Lawmakers, protect your constituents from a toxic waste site in your community.
Taylorville already hosts one Superfund Site due to a power company’s inability to contain toxic waste. Let’s not invite another.
Whatever chemicals do not go up a smokestack, have to go somewhere. Where are they going?

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Is this a power plant, or a chemical plant masquerading as a power plant?

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Bill disputes idle power plant near Terre Haute – Sept 2004 A state-of-the-art power plant near Terre Haute is sitting idle after natural gas and electricity providers cut service when the owner refused to pay outstanding bills.
Their chemical plant – SG Solutions has been plagued with safety and environmental trouble.
SG Solutions cited for safety violations TERRE HAUTE — A coal gasification plant north of Terre Haute faces a potential $27,000 in fines for serious safety violations in connection with an April 28 explosion that killed two people, according to the Indiana Occupational Safety and Health Administration. According to the Toxic Release Inventory and the Enforcement and Compliance History on-Line at the EPA website- In 2007, in quarters 3 and 4, EPA cited Wabash with "Significant Non-compliance (SNC) effluent violations." Arsenic limits were exceeded by 589% and Cyanide limiti were exceeded by 20089%. Wabash has been forced to pay $687,500 in penalties for violation of the Clean Air Act and Clean Water Act.

Personally, I am in favor of bringing jobs to central Illinois. However, I am concerned about the waste products of coal gasification. I have stringently attempted to get responses from City, County and Corporate Officials, to little or no avail. The best I got was that they were initially going to be processing the sulfur, and that other by-products were going to be stored either on or off site. And that they were not in control of by products once they "crossed their fence".

The Chinese at least have the respect to refer to this industry (gasification) and the Coal/Chemical Industry.

Before this project gets the go-ahead, we need to have better answers about the disposition of its by-products.

Right now, with the information at hand, the jobs are not worth the risks.

March 14, 2010 from Robert J. Sargent

Electric commission, With electric rates on the rise anyway and the plants in the area are old and needing to be shutdown this decision is a simple one. We need the jobs so bad the price tag and this point doesnt mean a thing. It will just go up if not started soon! The price of steel and copper is going higher with the growth of China, please dont let this state get left behind anymore. Pass this as soon as possible, we need the jobs and the tax base! Please advise the General Assembly to act on this right now.Thank you for your time. Robert J. Sargent

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March 14, 2010 from James Johnson

With these economic times I believe it is impairative that this Power Plant be built now.
Jobs are needed. Also, with the power grid being bombarded by comsumers the power needs to be available when needed. If we keep waiting for the right time it will never come,the time is now. Remember years ago when the Norteast had a major power outage on the grid, do we want that here? Every Tradesman out there needs to voice their opinions and comments now before

it's to late. Build it NOW!

Thank You,
James Johnson

March 10, 2010 from Gary Hickey

First of all I want to thank the Illinois Commerce Commission for holding an open process for determining the benefits of the Taylorville Energy Center (TEC) Integrated Gasification Combined Cycle (IGCC) plant.

Let me preface my comments with my background. I have over 33 years of experience in the electric power industry, ten of which are in power plant development. I hold both bachelors and masters degrees in electrical engineering from the University of Illinois, where I specialized in power engineering. I am a registered professional engineer in the State of Illinois.

It is my professional opinion that the TEC project should be terminated as soon as possible, based on its lack of value as a demonstration project and its devastating economic impact to Illinois consumers. Although the TEC project is estimated to create a total of 385 jobs in the electric, mining and trucking industries, each permanent job will cost $730,943 per year (or a total of $281,420,040 per year) in higher electric rates for almost all Illinois energy consumers. In today’s tough economic times, this is unconscionable.

In my opinion, the TEC plant has no redeeming value as a demonstration project. The all-in cost of the TEC plant is $3.52 billion. The summertime rating of this air-cooled plant is 533 MW (footnote from Exhibit 2 of the Pace Rate Impact Analysis). This works out to be $6,604 per kilowatt. (This also presumes the TEC plant will be prudently managed and there will be no cost overruns.) As a point of reference, the actual cost of the Clinton Nuclear Station is $4.25 billion for 933 MW, or $4,555 per kilowatt. Consequently, the estimated cost of TEC plant is already 45% more than the Clinton Nuclear Power Station. Given this extraordinarily high cost, it is unlikely that any utility with a least-cost mandate will ever voluntarily build an IGCC plant.

The true economic impact of the TEC plant is masked by how the proposal is packaged. The Pace rate impact study shows that the first year revenue requirement for the TEC plant in 2010 dollars is $150.18/MWh. Assuming a 75% capacity factor and a 533 MW summer rating yields a total first year revenue requirement of $520,901,825.

Assuming a new base-load plant is even needed, the least cost base-load capacity alternative to an IGCC facility is a combined cycle natural gas plant. Assuming an installed cost of $1000/kW, a 75% capacity factor, a 15% levelized carrying charge rate, a natural gas cost of $ 4.59 per million Btu, a gas transportation cost of $0.49 per million Btu, a heat hate of 7000 Btu/MWh and an O&M cost of $10/MWh yields an annual revenue requirement of $68.39/MWh or $239,488,785 per year. Thus the TEC plant would cost a premium of $281,414,040 per year as compared to a lower cost base-load alternative. This de facto energy tax works out to be $730,943 per year for each of the 385 permanent jobs.

I am not a geologist, but as an engineer I also have grave concerns about sequestering CO2 underground near populated areas. Unfortunately, underground storage, seems like a more likely commercial option than a CO2 pipeline. Underground storage fields can leak. CO2 is an odorless gas that displaces oxygen. If I were a resident anywhere near the TEC, plant I would insist upon monitoring equipment in every home and a fund to compensate any future victims.

It is my professional opinion that the TEC project should be terminated as soon as possible based on its lack of value as a demonstration project and its devastating economic impact to Illinois consumers.

Gary L. Hickey
Forsyth, Illinois

March 10, 2010 from John Stephens

Dear Sir, This is a great opportunity for our state of Illinois to lead the nation in development of clean, affordable and domestically produced power. It is a win-win for all . We need to move this forward. Thank you. John Stephens

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Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions

April 16, 2010

Illinois Commerce Commission
527 East Capitol Avenue
Springfield, IL 62701

Re: Tenaska/Taylorville Energy Center Facility Cost Report

Dear Commission:

The Union of Concerned Scientists (UCS) appreciates the opportunity to submit these comments on the Taylorville Energy Center Facility Cost Report submitted by Tenaska. UCS is the leading science-based nonprofit working for a healthy environment and safer world. We represent more than 250,000 activists and members, and have a Midwestern office located in Chicago, of which I am the director.

In 2008 UCS called for public financing of 5 to 10 commercial-scale carbon capture and storage (CCS) demonstration projects in our report, *Coal Power in a Warming World: A Sensible Transition to Cleaner Energy Options*[1], along with adopting stronger laws and regulations to reduce the environmental and social costs of coal use throughout the fuel cycle. While analyses by UCS[2] and others have shown that increasing energy efficiency and renewable energy are important and cost-effective near-term options for reducing carbon emissions, we recognize that CCS technology may be needed over the long-term to help us reduce emissions to levels that are necessary for avoiding the most dangerous impacts of climate change.

The Taylorville facility could be a useful step forward in our understanding of CCS technology. However, the demonstration benefits of this project must be weighed against the fact that renewable electricity and energy efficiency offer proven, lower costs options than the proposed facility. Moreover, Illinois ratepayers appear to be poorly protected from higher-than-projected costs while Tenaska bears relatively little risk.

In addition, the Report raises questions about whether assumptions were made that understate costs and overstate income. Many of these questions are set forth in the analysis prepared by David Schlissel and submitted by the Sierra Club, and we raise a few additional issues below. We encourage the Commission to seek out the answers to these questions so that Illinois policymakers can more fully weigh the costs and benefits of this particular project, and consider any corrections that might better protect ratepayers and the environment.

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[1] http://www.ucsusa.org/assets/documents/clean_energy/Coal-power-in-a-warming-world.pdf
[2] *Climate 2030: A National Blueprint for a Clean Energy Economy*. Union of Concerned Scientists, 2009. http://www.ucsusa.org/global_warming/solutions/big_picture_solutions/climate-2030-blueprint.html

www.ucsusa.org
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One North LaSalle Street • Suite 1904 • Chicago, IL 60602-4064 • TEL: 312.57831750 • FAX: 312.578.1751

COMMENT ONE: Tenaska should more clearly specify the role of federal subsidies in its cost analysis, and how these were calculated, particularly the $156 million/year in bonus allowances under future climate legislation.

On pages 11 and 12 of the Facility Cost Report, Tenaska lists three categories of federal subsidies that it is pursuing, including a Department of Energy loan guarantee of up to $2.579 billion (worth $60 million/year in interest savings), 45Q tax credits (worth $22.3 million/year), and bonus allowances under a future cap and trade bill (worth $156 million/year). The Commission should ask Tenaska to clearly state whether the cost of power set forth in this report includes these subsidies or not, and to state what the costs would be without them. These subsidies seem to be a major variable in the cost analysis, and understanding whether or not they are reflected in the bottom line is central to understanding how much of the project's costs will fall on Illinois ratepayers and how much would be born at the federal level.

The role of future bonus allowances is of particular interest given their size. On page 12 of the Facility Cost Report, Tenaska states that the project could receive $156 million in nominal dollars per year in the project's first ten years of operation if a federal cap and trade bill should pass. Assuming 1.9 million tons sequestered/year, Tenaska appears to be assuming it will receive bonus allowances worth $82/ton. However, to qualify for subsidies this large under the Waxman/Markey or Kerry/Boxer bills, the facility would likely have to achieve a higher capture rate than it is currently projected to achieve. On page 18, the capture of 1.9 million tons of CO2 is described as "more than 50% of the CO2 that would otherwise be emitted from the Facility." The value of bonus allowances for 50% capture (the minimum to receive support under the federal bills) is specified as $50/ton, with a $10/ton additional subsidy for facilities online by 2017. At that rate ($60/ton), the Facility would only receive about $114 million/year for ten years, not $156 million/year (presuming, of course, that a climate bill passes with these subsidy provisions intact).

Tenaska should explain how it calculated the $156 million support it might get under a future climate bill. In particular, what does it assume for the value of bonus allowances per ton of CO2 sequestered? It should also specify what capture rate it believes it would achieve (i.e., how much "more than" 50%) under the pending legislation, since the higher the capture rate under these bills, the higher the support per ton of CO2.

COMMENT TWO: Tenaska should specify its projected sequestration costs in dollars/ton, explain why the feasibility study assumes sequestration of more CO2 than the Facility Cost Report, and explain why sequestration costs are apparently a few times below the $5-10/ton range cited as typical.

The Schlumberger Carbon Services Cost Report for the Taylorville Energy Center refers to a likely "typical" cost of CO2 sequestration of $5-10/ton stored, noting that the costs for this project are lower than this range due to favorable conditions. (Exh. 13.2.b, p.1) However, the report does not state what project sequestration costs will be in dollars/ton, making it hard to know precisely how far this project's cost estimate falls below the $5-10/ton projected range.

The sequestration cost report, building on the sequestration feasibility analysis (Exh. 13.2.a), looks at both a larger and smaller sequestration project. The larger project would involve three injection wells designed to store 3.41 million tons of CO_2 per year. The smaller project would involve two injection wells designed to store 2.27 million tons of CO_2 per year. Tenaska should explain why these feasibility and cost analyses are considering higher volumes of CO_2 than the Facility Cost Report, which states that the Facility "is expected to capture 1.9 million MT of CO_2 per year." (Facility Cost Report, p. 17).

Exhibit 13.2.b states that the total costs for the three-well case would be $116.7 million. If we simply divide this by 102.3 million tons of CO_2 (3.41 million tons x 30 years), the cost per ton is a remarkably low $1.14/ton. If we take the cost of the two-well case of $88 million and divide by the smaller amount of CO_2 taken from the Facility Cost Report (1.9 million tons x 30 years, or 57 million tons) the cost per ton is still only $1.54/ton. Both of these cost estimates are well below the $5-10/ton range Schlumberger cites as the typical estimate.

Tenaska should more clearly specify what it expects the cost/ton of CO_2 sequestered will be, as well as providing the total number of tons of CO_2 it projects to sequester over the thirty year life of the project. If, indeed, it projects sequestration costs/ton to be far lower than the range of typical projections, it should explain why it believes costs will be so much lower than for other projects.

Thank you for considering our comments regarding this project.

Sincerely,

Ron Burke
Midwest Office Director

Union of Concerned Scientists
Citizens and Scientists for Environmental Solutions

April 16, 2010

Illinois Commerce Commission
527 East Capitol Avenue
Springfield, IL 62701

Re: Tenaska/Taylorville Energy Center Facility Cost Report

Dear Commission:

The Union of Concerned Scientists (UCS) appreciates the opportunity to submit these comments on the Taylorville Energy Center Facility Cost Report submitted by Tenaska. UCS is the leading science-based nonprofit working for a healthy environment and safer world. We represent more than 250,000 activists and members, and have a Midwestern office located in Chicago, of which I am the director.

In 2008 UCS called for public financing of 5 to 10 commercial-scale carbon capture and storage (CCS) demonstration projects in our report, *Coal Power in a Warming World: A Sensible Transition to Cleaner Energy Options*[1], along with adopting stronger laws and regulations to reduce the environmental and social costs of coal use throughout the fuel cycle. While analyses by UCS[2] and others have shown that increasing energy efficiency and renewable energy are important and cost-effective near-term options for reducing carbon emissions, we recognize that CCS technology may be needed over the long-term to help us reduce emissions to levels that are necessary for avoiding the most dangerous impacts of climate change.

The Taylorville facility could be a useful step forward in our understanding of CCS technology. However, the demonstration benefits of this project must be weighed against the fact that renewable electricity and energy efficiency offer proven, lower costs options than the proposed facility. Moreover, Illinois ratepayers appear to be poorly protected from higher-than-projected costs while Tenaska bears relatively little risk.

In addition, the Report raises questions about whether assumptions were made that understate costs and overstate income. Many of these questions are set forth in the analysis prepared by David Schlissel and submitted by the Sierra Club, and we raise a few additional issues below. We encourage the Commission to seek out the answers to these questions so that Illinois policymakers can more fully weigh the costs and benefits of this particular project, and consider any corrections that might better protect ratepayers and the environment.

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[1] http://www.ucsusa.org/assets/documents/clean_energy/Coal-power-in-a-warming-world.pdf
[2] *Climate 2030: A National Blueprint for a Clean Energy Economy*. Union of Concerned Scientists, 2009. http://www.ucsusa.org/global_warming/solutions/big_picture_solutions/climate-2030-blueprint.html

COMMENT ONE: Tenaska should more clearly specify the role of federal subsidies in its cost analysis, and how these were calculated, particularly the $156 million/year in bonus allowances under future climate legislation.

On pages 11 and 12 of the Facility Cost Report, Tenaska lists three categories of federal subsidies that it is pursuing, including a Department of Energy loan guarantee of up to $2.579 billion (worth $60 million/year in interest savings), 45Q tax credits (worth $22.3 million/year), and bonus allowances under a future cap and trade bill (worth $156 million/year). The Commission should ask Tenaska to clearly state whether the cost of power set forth in this report includes these subsidies or not, and to state what the costs would be without them. These subsidies seem to be a major variable in the cost analysis, and understanding whether or not they are reflected in the bottom line is central to understanding how much of the project's costs will fall on Illinois ratepayers and how much would be born at the federal level.

The role of future bonus allowances is of particular interest given their size. On page 12 of the Facility Cost Report, Tenaska states that the project could receive $156 million in nominal dollars per year in the project's first ten years of operation if a federal cap and trade bill should pass. Assuming 1.9 million tons sequestered/year, Tenaska appears to be assuming it will receive bonus allowances worth $82/ton. However, to qualify for subsidies this large under the Waxman/Markey or Kerry/Boxer bills, the facility would likely have to achieve a higher capture rate than it is currently projected to achieve. On page 18, the capture of 1.9 million tons of CO2 is described as "more than 50% of the CO2 that would otherwise be emitted from the Facility." The value of bonus allowances for 50% capture (the minimum to receive support under the federal bills) is specified as $50/ton, with a $10/ton additional subsidy for facilities online by 2017. At that rate ($60/ton), the Facility would only receive about $114 million/year for ten years, not $156 million/year (presuming, of course, that a climate bill passes with these subsidy provisions intact).

Tenaska should explain how it calculated the $156 million support it might get under a future climate bill. In particular, what does it assume for the value of bonus allowances per ton of CO2 sequestered? It should also specify what capture rate it believes it would achieve (i.e., how much "more than" 50%) under the pending legislation, since the higher the capture rate under these bills, the higher the support per ton of CO2.

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Thank you for considering our comments regarding this project.

Sincerely,

Ron Burke
Midwest Office Director

COMMENTS OF BOMA CHICAGO

TO: ILLINOIS COMMERCE COMMISSION

FROM: BUILDING OWNERS AND MANAGERS ASSOCIATION OF CHICAGO

SUBJECT: TENASKA FACILITY COST REPORT

DATE: APRIL 16, 2010

Executive Summary

The Building Owners and Managers Association of Chicago ("BOMA/Chicago") is pleased that the Illinois Commerce Commission ("ICC") has provided the ability of interested parties to provide comments addressing the Tenaska Facility Cost Report ("Tenaska Report"). BOMA/Chicago is very supportive of innovative, market-based technologies that create jobs, provide for a cleaner environment, and lower the costs of doing business in the State of Illinois. However, the Tenaska Report demonstrates substantially negative economic consequences to Illinois consumers, and it only begins to foretell the costs to be borne from the implementation of this particular technology at the expense of sound energy policy. Stated simply, the enormous costs imposed on Illinois ratepayers do not justify the construction of this facility as additional generating capacity in Illinois. BOMA/Chicago estimates its members alone will pay what amount to a "tax" of over $10 million annually and hundreds of millions of dollars over 30 years in the form of unnecessary surcharges on top of what they would pay for power and energy actually delivered and consumed. The Tenaska Report does not present a convincing case or provide appropriate justification for this extraordinarily costly venture. Accordingly, BOMA/Chicago supports the Stop Tenaska's Overpriced Power Coalition ("STOP") comments submitted separately and provides these supplemental comments for consideration.

Background of BOMA/Chicago

BOMA/Chicago's members represent over 260 office buildings in Chicago and over 150 companies that provide services to the commercial real estate industry. Member buildings make up more than 80 percent of downtown Chicago's rentable building area and play a vital role in ensuring the economic viability of the region by housing more than 250,000 jobs and nearly 8,000 local, national and international companies. Member buildings also support local schools and public services through more than $650 million in annual property taxes.

From an energy policy perspective, BOMA/Chicago has assisted in the promotion and the development of an effectively competitive electricity market that operates efficiently and is equitable to all consumers.[1] From the advent of electric retail competition and throughout the mandatory transition period in Illinois, member buildings purchased power in the deregulated energy marketplace, reimbursed the incumbent electric utility through a transition charge,[2] and assisted in market development from a large consumer perspective. Today, virtually all of BOMA/Chicago members purchase electricity from competitive retail electric suppliers and are leaders in implementing sustainability measures and energy efficiency programs along with other BOMA chapters locally, regionally and nationally. BOMA/Chicago estimates that its member buildings account for 5 percent of Commonwealth Edison Company's peak load.

Impact of Proposed Project on the Competitive Market

As demonstrated in the Tenaska Report, forecasting future world states is as much an art as it is a science. Locking in thirty-year cost increases to consumers, in the form of sourcing contracts, does not provide an adequate cost-benefit analysis for this state to require its consumers to guarantee the costs of this new technology, particularly in the case of escalating, non-capped price increases that may become inevitable in future years. If the Tenaska facility is ultimately approved, the decision would contradict this State's edict of promoting the development of an equitable, efficient and effective competitive electricity market in Illinois as codified in Section 16-101A(d) of the Illinois Public Utilities Act ("PUA").[3]

On January 2, 2007, many non-residential electric customers, including all BOMA/Chicago member buildings, were *required* to take competitive retail electric service pursuant to PUA Section 16-111.[4] Ostensibly, by requiring all Illinois consumers to fund the costs of the Tenaska facility, Illinois effectively ushers in a return to a regulated environment, but without the safeguards in place to determine what costs are just and reasonable, and what services are deemed competitive.[5] Mandating cost recovery for the Tenaska facility effectively establishes monopoly power to an unregulated entity without the legal standards attendant to protect consumers. The State of Illinois has an interest in providing consumer safeguards, and mandating cost of service from a new market entrant circumvents regulatory maxims that require

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[1] *See* 220 ILL. COMP. STAT. 16-101A(d).
[2] 220 ILL. COMP. STAT. 16-111.
[3] "A competitive wholesale and retail market must benefit all Illinois citizens. The Illinois Commerce Commission should act to promote the development of an effectively competitive electricity market that operates efficiently and is equitable to all consumers. Consumer protections must be in place to ensure that all customers continue to receive safe, reliable, affordable, and environmentally safe electric service." 220 ILL. COMP. STAT. 16-101A(d).
[4] *Id.*
[5] *See* 220 ILL. COMP. STAT. 5/16-111.5(l).

investments be deemed just and reasonable,[6] and that costs borne by ratepayers be subject to a "used-and-useful" standard, and prudently incurred.[7]

The Tenaska Report, taken alone and at face value, does not satisfy the principles of public utility regulation and retail electric deregulation set forth by the State Legislature. When viewed in tandem with Comments provided by the STOP Coalition, the Tenaska Report's only certain outcome is severe cost increase to consumers—particularly to non-eligible electric customers like BOMA/Chicago member buildings.

Economic Impact on BOMA/Chicago Member Buildings

A simple metric of expected cost increases to BOMA/Chicago buildings in the aggregate over the next 30 years is provided below. Under all scenarios, the annual cost increases are substantial, ranging between $10 and $17 million. Extrapolating out 30 years, BOMA/Chicago buildings will incur nearly half a billion dollars in extra added expense to subsidize the proposed Tenaska facility. Even more troubling are the potential or likely escalating cost increases above and beyond the initial forecasts without protection of caps afforded to eligible retail customers. A growth rate for BOMA/Chicago building load was not factored in due to the uncertainty regarding escalating operating costs having a negative effect on business development in downtown Chicago.

Using an estimate of 1,000 MW for aggregate peak electric demand, and an average load factor of 35%, BOMA/Chicago member buildings currently consume 3,066,000 MWh annually.[8] Using the cost per MWh supplied in the Pace study of $114.92,[9] BOMA/Chicago members currently pay $352,344,720 annually for electricity. According to the Comments of the STOP Coalition, non-residential retail customers will likely experience rate increases attributable to Tenaska between 3 percent and 4.75 percent over 30 years of the project.[10]

BOMA/Chicago Cost Increase

	Annual Cost	Annual Increase
Current Cost	$352,344,720.00	N/A
3% Increase	$362,915,061.00	**$10,570,341.60**
4.75% Increase	$369,081,094.20	**$16,736,374.20**

[6] 220 ILL. COMP. STAT. 5/16-111.5(l)
[7] 220 ILL. COMP. STAT. 5/9-211; *see also Schafer v. Exelon Corp.*, 619 F. Supp. 2d 507 (N.D. Ill. 2007) (holding that costs of procuring electric supply shall be prudently incurred).
[8] (1,000 MW) (0.35) (24 hours) (365 days)
[9] *See* Pace Study, Reference Case spreadsheet screen shot, p. 63.
[10] *See* Comments of the STOP Coalition, p. 29.

BOMA/Chicago Cost Increase (Over 30-Years)

	30-Year Cost	30-Year Increase
Current Cost	$10,570,341,600.00	N/A
3% Increase	$10,887,451,848.00	**$317,110,248.00**
4.75 Increase	$11,072,432,826.00	**$502,091,226.00**

Accordingly, our analysis shows that approval of the Tenaska Project will result in BOMA/Chicago member buildings paying between $317,110,248 to $502,091,226 extra for electric energy to subsidize the project over 30 years.

Conclusion

The Tenaska Report is not convincing in building a business case for project approval. Discounting the revenue streams to subsidize development of the project at Commonwealth Edison Company's cost of capital would mean 260 BOMA/Chicago building members would collectively pay a present value of between $112 million to $180 million dollars today, or between $10 million to $17 million dollars annually for 30 years. The Tenaska Facility Cost Report does not justify the enormity of these expenses to a subset of consumers, let alone similar cost increases to every single ratepayer in Illinois.

Comments of Commonwealth Edison Company on the Taylorville Energy Center Facility Cost Report

Commonwealth Edison Company ("ComEd") appreciates the opportunity to submit comments on the Taylorville Energy Center ("TEC") Facility Cost Report ("Report"). ComEd supports the development of clean coal, and supported the enactment of the Illinois Clean Coal Portfolio Standard Law ("Clean Coal Act"), pursuant to which Tenaska Taylorville, LLC ("Tenaska") filed the Report. The development of clean coal is important to Illinois and to our nation, and Illinois is fortunate to have several clean coal projects under development. Since there are limits on the amount of the costs from these projects that can be passed on to customers, it is important for the Illinois Commerce Commission ("Commission") and the Illinois General Assembly ("General Assembly") to carefully consider all of its options and choose those projects which will more clearly advance the goals and purposes of the Clean Coal Act.[1]

I. Executive Summary

The Clean Coal Act was designed to advance environmental protection goals and to demonstrate the viability of coal in a carbon-constrained economy,[2] while at the same time protecting utility customers from paying unreasonable amounts for the energy from clean coal facilities. TEC does not promote these goals. In fact, TEC is a step backward in the attainment of the state's environmental goals, will not appreciably advance the goal of demonstrating the viability of coal since it depends so heavily upon purchased natural gas and fails to protect consumers from the risk of paying exorbitant amounts for the energy from the facility.

[1] In reviewing the Tenaska Report and preparing these comments, ComEd obtained the assistance of the NorthBridge Group ("NorthBridge). A copy of the NorthBridge report is Attachment A to these comments.
[2] 20 ILCS 3855/1-5(8)

The Clean Coal Act contemplates that the emissions from a clean coal facility should generally be comparable to that of a similarly sized and located natural gas-fired combined-cycle facility ("CCGT Facility").[3] However, TEC will emit 50% more carbon dioxide ("CO2") and displace 50% fewer net CO2 emissions from other generating facilities than a CCGT facility.[4] That is not moving toward attainment of the environmental goals of the Clean Coal Act.

Moreover, more than a third of the energy output of TEC that will be sold to Illinois consumers will be generated using natural gas that TEC purchases from the market.[5] The use of such a large quantity of purchased natural gas in the generation of energy from TEC clearly undercuts the ability of TEC to contribute to the goal of demonstrating the viability of coal in a carbon-constrained economy. In addition, the proposed sale of energy generated by purchased natural gas at a huge clean coal premium is inconsistent with the Clean Coal Act, which requires only that utilities buy "clean coal energy."[6]

On top of these shortcomings, TEC will be an extremely expensive source of energy (Report, P. 69). At a projected $163 per MWH (in 2015), the cost from TEC is more than twice the expected future cost of comparable supply procured from the PJM market ($76 MWH) and more than 50% higher than the expected future cost of energy from a CCGT Facility ($96 MWH).[7] Even this elevated price is subject to significant uncertainty and risk.

It is the Illinois consumer who ultimately must bear the cost of this very expensive source of energy and who bears all the risk that the price could rise significantly higher. For this reason, the Clean Coal Act contains a number of provisions designed to protect consumers from much of this risk. Despite these legislatively mandated protections, the sourcing agreement that Tenaska has proposed ignores each

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[3] 20 ILCS 3855/1-10, definition of "Clean coal facility."
[4] NorthBridge, pp. 4, 10-14.
[5] NorthBridge, pp. 4, 11, 15.
[6] 20 ILCS 3855/1-75(d)(3)(B)(iii)
[7] NorthBridge, pp. 1, 3.

and every one of these protections and guarantees Tenaska full cost recovery regardless of the final cost of the project and regardless of whether or not TEC ever generates a single kilowatt-hour of energy.

The price for energy from TEC is extremely high for a project that contributes so little, if at all, to achieving the goals of the Clean Coal Act and that is inconsistent with numerous other provisions. Fortunately, the Commission and the General Assembly have options. There are other clean coal projects underway in Illinois. However, if approved, TEC will use up all of the available funding for clean coal facilities under the Clean Coal Act.[8] Therefore, prior to approving TEC, the General Assembly should consider all projects and choose the one which advances the goals of the Clean Coal Act at the least cost to customers.

II. TEC Does Not Advance the Goals of the Clean Coal Act

The Clean Coal Act provides that the State of Illinois should encourage clean coal technologies in order "to advance environmental protection goals and to demonstrate the viability of coal and coal-derived fuels in a carbon-constrained world."[9] TEC fails to advance these goals.

A. TEC Will Emit 50% More Carbon Dioxide Than a Comparable CCGT Facility

The Clean Coal Act contemplates that the emissions from a clean coal facility should be generally comparable to that of a similarly sized and located CCGT Facility.[10] This is what one would expect as it hardly seems reasonable to require consumers to pay a huge premium for a generating technology that would emit more pollutants than other,

[8] 20 ILCS 3855/1-75(d)(2).
[9] 20 ILCS 3855/1-5(8).
[10] 20 ILCS 3855/1-10 (definition of "Clean Coal Facility").

far less expensive, technologies. However, TEC will emit 50% more carbon dioxide ("CO2") than a CCGT Facility.

While the Report submitted by Tenaska states that TEC will have CO2 emissions that are comparable to a CCGT Facility,[11] that analysis is based on a number of flaws. First, a more appropriate estimate of CO2 emissions can be found in the Federal Energy Regulatory Commission ("FERC") filing made by TEC in December 2009. That filing indicates that CO2 emissions from TEC will in fact be 50% higher than a CCGT Facility.[12] The difference between these vastly different claims appears to be the emissions associated with the Air Separation Unit ("ASU") used by TEC.[13] The December study showed that the electricity used to power the ASU would be self-supplied, and hence the associated emissions were included in the CO2 calculation. In the more recent Report, the ASU is proposed to be owned and operated by a third party and the electricity used by the ASU is apparently purchased rather than self-supplied, and the associated emissions are excluded. While the ASU may be owned and operated by a third party, it is integral to the TEC design and its emissions should be included in the TEC emissions assessment because those emissions would not have occurred absent the production of synthetic natural gas ("SNG") to fuel TEC. The FERC filing does this and the results, as noted previously, are emissions that are 50% greater than a conventional CCGT Facility even though consumers would be paying a 70% premium over a CCGT Facility for this "clean" technology.

Second, in addition to excluding the emissions from the ASU, Tenaska further reduced its estimated emissions per MWH from TEC by using a substantial amount of purchased natural gas.[14] In fact, more than a third of the energy output of TEC is

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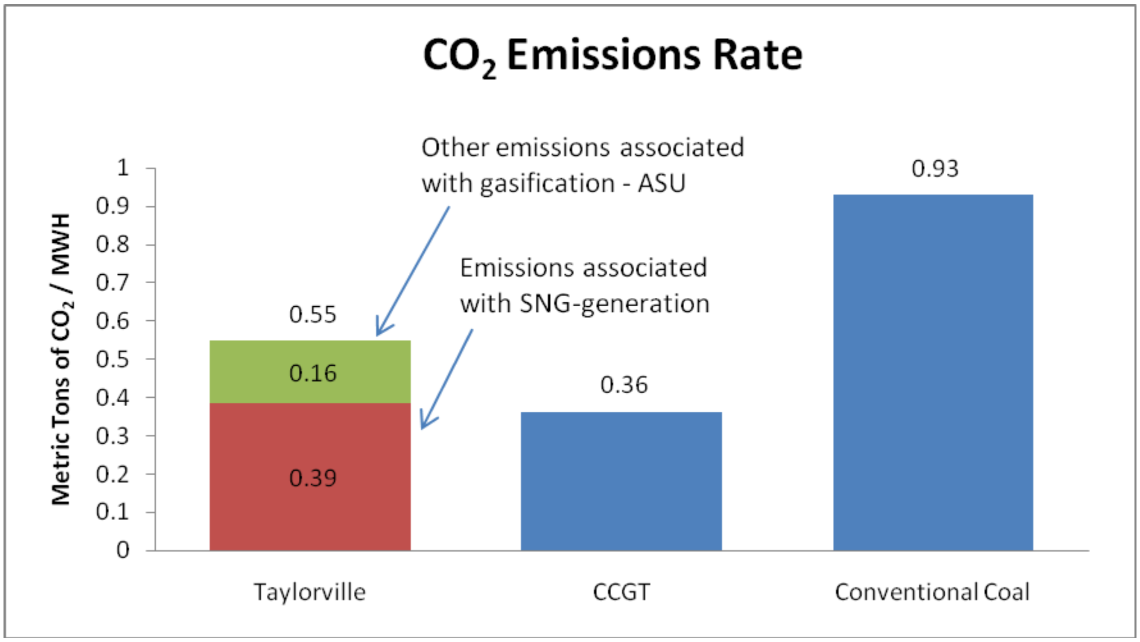
[11] Report, p. 76.
[12] Petition for Declaratory Order, December 23, 2009, FERC Docket No. EL10-27-000.
[13] Exhibit CCG-3 of Tenaska's December 2009 FERC filing, i.e. the Secondary CO2 Emissions Analysis, included a description of an earlier Taylorville design in footnote 2 on page 3, which indicates that Taylorville will self-supply the load for the Air Separation Unit, as well as the SNG island and the CO_2 compression. In Exhibit 12.0 to the Front End Engineering and Design ("FEED") study that Tenaska submitted to the Commission, i.e. the Secondary CO2 Emissions Analysis, footnote 2 on page 3, is nearly identical to the footnote in the FERC filing, except that the FEED footnote omits the Air Separation Unit from the list of auxiliary loads that will be self-supplied.
[14] This fact is discussed in greater detail below.

assumed to be generated using natural gas that TEC purchases from the market. A CCGT Facility burning natural gas has the lowest emissions rate of all fossil-fueled generators, but this is not a benefit of clean-coal technology. If TEC were to use clean coal to produce a comparable amount of energy, emissions for the plant would again increase substantially.

Accounting for all direct and indirect emissions (including the ASU) and excluding emissions associated with generation from purchased natural gas reveals that the TEC emissions' profile is far inferior to a conventional gas plant and just modestly better than a conventional coal plant.[15] The following chart depicts the CO2 emission analysis:

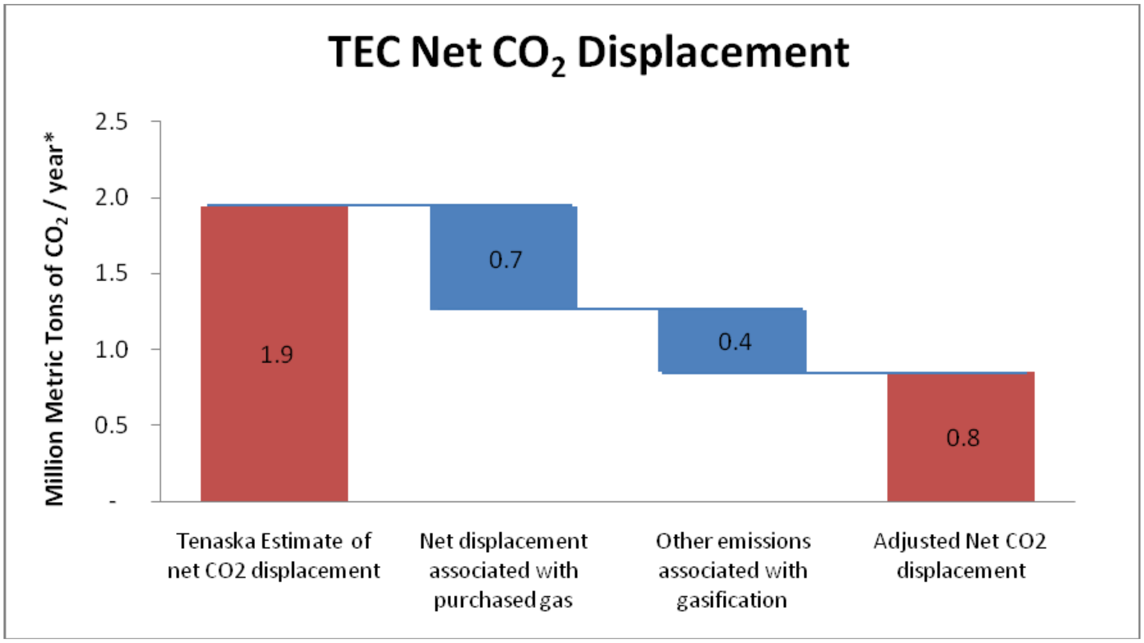


B. A CCGT Facility Would Displace 50% More CO2 Than TEC

Tenaska estimated that TEC would displace almost 2 million metric tons of CO2.[16] However, this analysis is based on the same two flaws discussed above, i.e. it

[15] NorthBridge, pp. 10-14.
[16] Report, Exhibit 12.0.

includes the emission reductions associated with generation using purchased natural gas and it excludes the emissions associated with the operation of the ASU. When these two factors are accounted for, the amount of CO2 displaced by SNG-fueled generation from TEC is far less, as shown on the chart below:[17]



** Tenaska has provided results for 2017 which are assumed to be representative of the project life*

A MWH of energy generated by a CCGT facility will displace the same amount of energy and the same gross amount of associated CO2 as a MWH of energy generated by TEC. Any difference in the net amount of CO2 displaced by the two types of facilities is simply a factor of which facility emits the greater amount of CO2 in the generation process. As described in the section above, TEC emits 50% more CO2. As a result, a CCGT facility will displace 50% more CO2 than TEC on a net basis, or approximately 1.2 million metric tons of CO2 annually.[18]

[17] NorthBridge, pp. 4, 10-14.
[18] Northbridge, p. 14.

C. 35% of the Energy Generated by TEC Will be Fueled by Ordinary Purchased Natural Gas

TEC is essentially composed of two process islands:

(1) substitute natural gas (SNG) production, and

(2) a combined cycle power plant.

The two process islands are co-located, but operate independently for the most part. In fact, the power plant can be operated using pipeline natural gas when the SNG island is shut down. Likewise, the SNG island can be operated using purchased power instead of the onsite generation.[19]

Tenaska, as noted above, made a December 2009 filing at FERC that included a detailed description of the operating characteristics of TEC. Curiously, the plant capabilities described in the FERC filing are dramatically different from the Report filed just two months later. The total capital costs were identical ($3.5 Billion), but the SNG production capacity declined from 28 million mmbtu per year in the FERC filing, to 19 million mmbtu per year in the Report. Likewise, the coal input declined from 48 million mmbtu (FERC) to 33 million mmbtu (Report). Meanwhile, the electricity sales doubled from roughly 2,000 GWH per year (FERC) to 4,000 GWH per year (Report). While a portion of the increased sales appears to be associated with the differing treatment of the ASU power described above, most of the additional energy in the Report (about 1400 GWH) is generated using purchased natural gas.[20]

It is not clear whether TEC even meets the definition of a "Clean Coal Facility" due to its significant dependence on natural gas as a fuel.[21] What is clear is that the use of purchased natural gas to generate energy does not demonstrate the viability of coal in a carbon-constrained economy.

[19] NorthBridge, p. 15.
[20] NorthBridge, pp. 11, 15.
[21] 20 ILCS 3855/1-10 (definition of "Clean Coal Facility"). The Clean Coal Act requires that a coal be the primary fuel of a clean coal facility.

In addition, it appears that Tenaska is intending to require customers to pay the huge clean coal premium (about 70%) for all of this energy that is generated from ordinary, purchased natural gas. This is not consistent with, or even allowed by, the Clean Coal Act. The Clean Coal Act requires utilities to buy "all clean coal energy made available from the initial clean coal facility[.]"[22] Nothing in the Clean Coal Act requires the utilities to purchase energy generated from purchased natural gas. Such energy should be treated the same as capacity from the plant. Tenaska should seek to sell the energy on the open market and treat the proceeds as an additional source of revenue.

The large quantity of TEC generation fueled by purchased natural gas also influences the unit cost of the TEC output. Tenaska's 2015 projected cost of $163/MWH is a weighted average of the cost of the SNG-fueled generation and the generation fueled with purchased natural gas. The cost of the SNG-fueled generation is estimated to be about $215/MWH.[23]

III. Tenaska's Proposed Sourcing Agreement Ignores the Consumer Protections Contained in the Clean Coal Act

A. TEC is Extremely Expensive – With Lifetime Above-Market Costs Projected at $8.7 Billion – and Its Costs are Uncertain

TEC will be an extremely expensive source of energy, as the Report indicates (Report, P. 69). At a projected $163/MWH (in 2010 dollars),[24] the cost from TEC is more than twice the cost of comparable supply procured from the PJM market ($76 MWH) and more than 50% higher than the cost of energy from a CCGT Facility ($96 MWH).[25] This results in above market costs averaging $300 million per year for

[22] 20 ILCS 3855/1-75(d)(3)(B)(iii).
[23] NorthBridge, p. 11.
[24] This is the blended price for TEC generation. As described above, the cost of the SNG-fueled generation is closer to $215/MWH.
[25] NorthBridge, p. 3.

consumers or over $8.7 billion over the life of the project.[26] Even this elevated price is subject to significant risk of being substantially higher given the "cost plus" nature of the TEC proposal.

The $163/MWH price was also based on several assumptions such as the passage of a climate bill setting a price for carbon at around $23/ton and a natural gas price forecast 20-25% higher than the current forward market.[27] In addition, this projected price assumes that TEC will be able to obtain a certain amount of revenue from the sale of various other commodities and components related to the facility such as synthetic natural gas ("SNG"), sulfur and NOX, to offset the costs of the facility. But the markets for these commodities are inherently volatile and unpredictable, as all markets are. Similarly, the projected price is based on other assumptions, such as a 75% capacity factor for an untested facility and receiving governmental loan guarantees, all of which are uncertain.

B. The Clean Coal Act Contains a Number of Provisions Designed to Protect Consumers From Uncertain and Unreasonable Costs

The General Assembly was well aware of the very high and uncertain cost for clean coal facilities. To protect consumers, the General Assembly incorporated a number of consumer protections into the Clean Coal Act. The General Assembly provided that before any proposed sourcing agreement for electricity from a clean coal facility could take effect the General Assembly would need to enact legislation approving the price, stated in cents per kilowatt-hour, that is proposed to be charged for output from the facility.[28] The General Assembly recognized that the costs of such a project were uncertain and therefore allowed for changes to be made to this legislatively-approved price. However, the General Assembly provided that "prior" to any change in the price charged for electricity under the sourcing agreement, a clean coal facility would need to

[26] NorthBridge, pp. 2, 6-8.
[27] NorthBridge, pp. 2, 8.
[28] Section 1-75(d)(4)(iii), (20 ILCS 3855/1-75(d)(4)(iii)).

obtain Commission review and approval for such change.[29] This process ensures that the cents per kilowatt-hour price that is being charged for electricity from a clean coal facility is always one that is specifically approved by either the General Assembly or the Commission.

In addition to these protections, the General Assembly capped the amount that retail customers' rates could be increased in any one year due to the cost for electricity from clean coal facilities. The amount of the cap phased in beginning in 2010 and by 2014 the cap reached its maximum amount of 2.015%. This cap, along with the price certainty provisions described above, ensure that the impact on customers can be known, measured and approved by the General Assembly, as the Clean Coal Act requires.[30]

C. Tenaska Proposes to Ignore These Protections

Tenaska did not provide a proposed sourcing agreement with its Report. However, Tenaska did circulate a proposed sourcing agreement prior to its filing of the Report.[31] That proposed sourcing agreement ignored each and every one of the consumer protections that the General Assembly had enacted.

The Tenaska sourcing agreement did not propose to incorporate the price, stated in cents per kilowatt-hour, that is to be approved and enacted into law by the General Assembly under the Clean Coal Act. Instead, the sourcing agreement proposed charging an amount based on TEC's costs divided by the amount of energy delivered from the facility.[32] This amount would vary monthly and would not be known in advance. In essence, Tenaska proposed a full cost recovery mechanism, not a per kilowatt-hour price. In fact, Tenaska's cost recovery did not even depend on the generation of energy by TEC. In any month in which TEC failed to generate even a single kilowatt-hour of electricity, it

[29] Section 1-75(d)(3)(D)(vii), (20 ILCS 3855/1-75(d)(3)(D)(vii)).
[30] Section 1-75(d)(4)(iii), (20 ILCS 3855/1-75(d)(4)(iii)).
[31] The document that Tenaska previously circulated consisted of a sourcing tariff, which Tenaska proposed to file with the Federal Energy Regulatory Commission ("FERC"), with a Form of Sourcing Agreement attached to it as Attachment A. For simplicity, we will refer to this group of documents as the Sourcing Agreement.
[32] Sourcing Agreement, Attachment A, section I.1.b.

was to be deemed that one kilowatt-hour was delivered and all of TEC's costs for the month were allocated to that one kilowatt-hour.[33] Thus, whether or not TEC generated a single kilowatt-hour of electricity over the thirty year term of the sourcing agreement, Tenaska was to be guaranteed full cost recovery.

Similarly, the proposed Tenaska sourcing agreement ignores the statutory requirement of obtaining Commission review and approval prior to making any changes in the price for electricity under the sourcing agreement. The proposed sourcing agreement anticipates making annual changes in the price charged for electricity. Attachment D to the sourcing agreement sets out the process for implementing these annual changes. While that process acknowledges the need for Commission approval of the sourcing agreement prior to that agreement becoming effective,[34] the Commission's role in approving any subsequent changes appears to be quite limited and secondary. The process includes providing the Commission's Manager of Accounting with a copy of the proposed changes.[35] However, it does not provide for any Commission review or approval prior to the changes becoming effective. In fact, the process requires that the Commission or some other interested party initiate a proceeding at the FERC if they wish to challenge any of the proposed changes.[36] The process does appear to recognize that the Commission might disallow certain costs as imprudent, but it appears that this would be some after-the-fact review and not the statutorily-required prior approval.[37]

The proposed Tenaska sourcing agreement effectively circumvents the cap on the amount of costs that can be charged to customers. The proposed sourcing agreement does limit the amount that utilities' bundled customers' rates can increase in any year to 2.015%, consistently with the Clean Coal Act.[38] (Of course, other customers have no such price protection). However, any amounts from that year that are over the cap are

[33] Sourcing Agreement, Attachment A, section I.1.a (definition of "Total Retail Sales")
[34] Sourcing Agreement, Attachment D, Section 2.d.
[35] Sourcing Agreement, Attachment D, Section 3.d.
[36] Sourcing Agreement, Attachment D, Section 5.a.
[37] Sourcing Agreement, Attachment D, Section 2.d.
[38] Sourcing Agreement, Schedule CEL-1.

accumulated and deferred for recovery in subsequent years.[39] Then, when the sourcing agreement terminates, it provides that there shall be a final true-up adjustment in order to collect any remaining unrecovered costs.[40] Thus, Tenaska is guaranteed full cost recovery, regardless of the final cost of TEC, and there is effectively no limit on the amount of those costs that customers must pay.

IV. The Commission and the Illinois General Assembly Should Consider All of Their Options Before Approving TEC

TEC is clearly not an attractive option for the Illinois consumer. The price for energy from TEC is extremely high for a project that is a step backward in the attainment of the state's environmental goals and contributes so little, if at all, to demonstrating the viability of clean coal. Fortunately, the Commission and the General Assembly have options. There are other clean coal projects underway in Illinois. However, if approved, TEC will use up all of the available funding for clean coal facilities under the Clean Coal Act.[41] Therefore, prior to approving TEC, the General Assembly should consider all projects and choose the one which advances the goals of the Clean Coal Act at the least cost to customers.

Respectfully submitted,
Commonwealth Edison Company

[39] Sourcing Agreement, Schedule CEL-2.
[40] Sourcing Agreement, Attachment D, Section 7. Final True-Up Adjustment.
[41] Report, p. 67, Table 10.5.a; 20 ILCS 3855/1-75(d)(2). The cost of TEC actually exceeds the cap in the first 6 years of operation. The Clean Coal Act makes clear that the cap applies to the "total amount paid" for energy from all clean coal facilities.

Tenaska Taylorville Energy Center

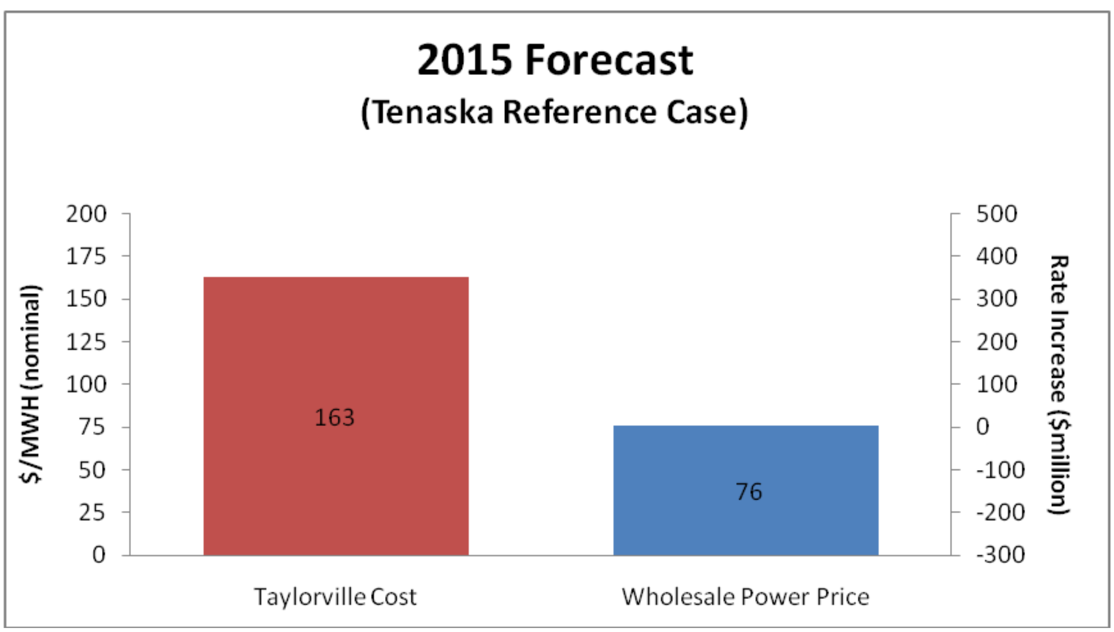
Executive Summary

Christian County Generation, L.L.C. (CCG), a joint venture between Tenaska and MDL Holding Co., proposes to build Taylorville Energy Center (TEC), an approximately 600 MW (net) hybrid IGCC plant near Taylorville, IL, for $3.5 billion with the benefit of $2.58 billion of federal loan guarantees. Tenaska provides details about both the rate impact and the operating characteristics of the TEC project as part of its Facility Cost Report (FCR) filed at the Illinois Commerce Commission (ICC) in February 2010.

The NorthBridge Group (NorthBridge) was asked to review this report and other publicly available information to assess both the economic and environmental costs and benefits associated with the project. We conclude, based on the information provided by Tenaska, that completion of the TEC project would substantially increase the cost of electricity to Illinois consumers. We also conclude, perhaps surprisingly to some, that the completion of the project would **increase**, rather than decrease CO_2 emissions, relative to other less costly alternatives.

Turning first to the rate impacts, Tenaska itself estimates that TEC will cause a rate increase of about $340 million in 2015, relative to Tenaska's Reference case forecast of the wholesale price of power. As shown in the figure below, TEC costs per MWH are projected to be more than twice as high as wholesale power prices.

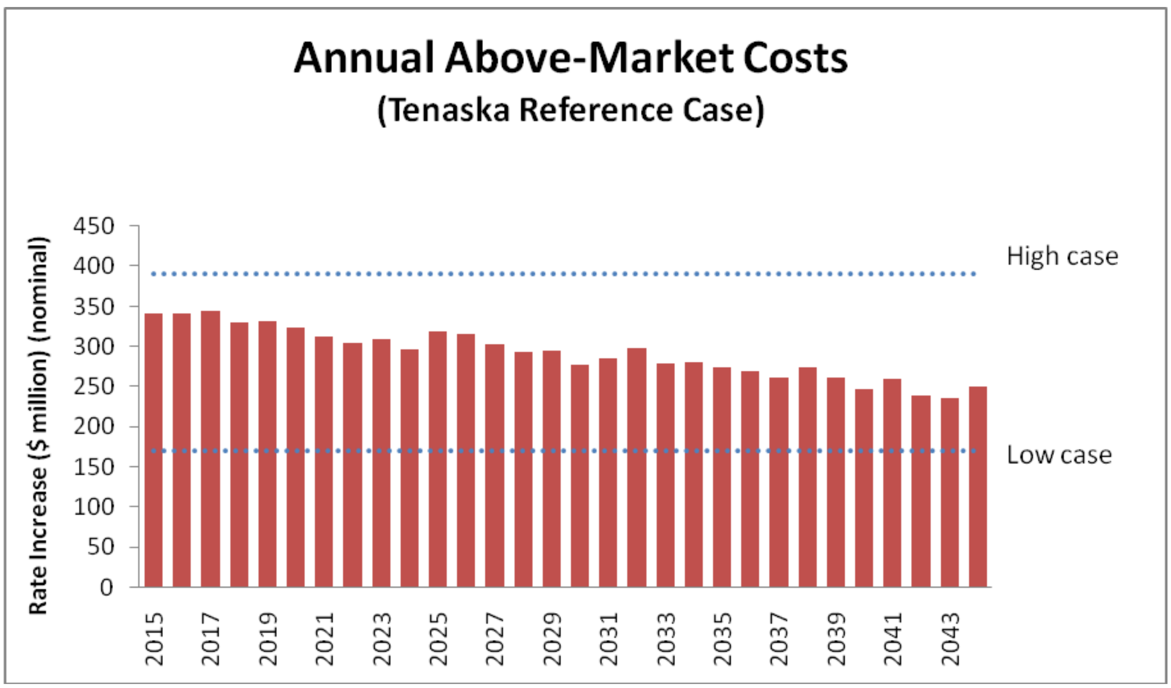
Figure 1



Tenaska expects the above-market costs of the project to average approximately $300 million per year thereafter – for a total of $8.75 billion over the life of the project. Notably, the first six years of the forecast exceed the 2% rate cap.

The commodity price assumptions in the Tenaska Reference case analysis are relatively favorable for the project, with a 2015 natural gas price forecast of $9/mmbtu (compared to current 2015 NYMEX forwards of under $7/mmbtu), and a 2015 CO_2 price of $23/tonne. To test these assumptions, Tenaska also provides a stress test of the rate impact under more and less favorable commodity and policy outcomes. Under the most favorable scenario (reflecting significant new federal subsidies for CCS), Tenaska projects cumulative above-market costs of $5 billion, or $170 million per year. Under the least favorable scenario, Tenaska forecasts cumulative above-market costs of $11.5 billion, or almost $400 million per year. As shown below, not a single year in the Reference Case shows TEC approaching break-even.

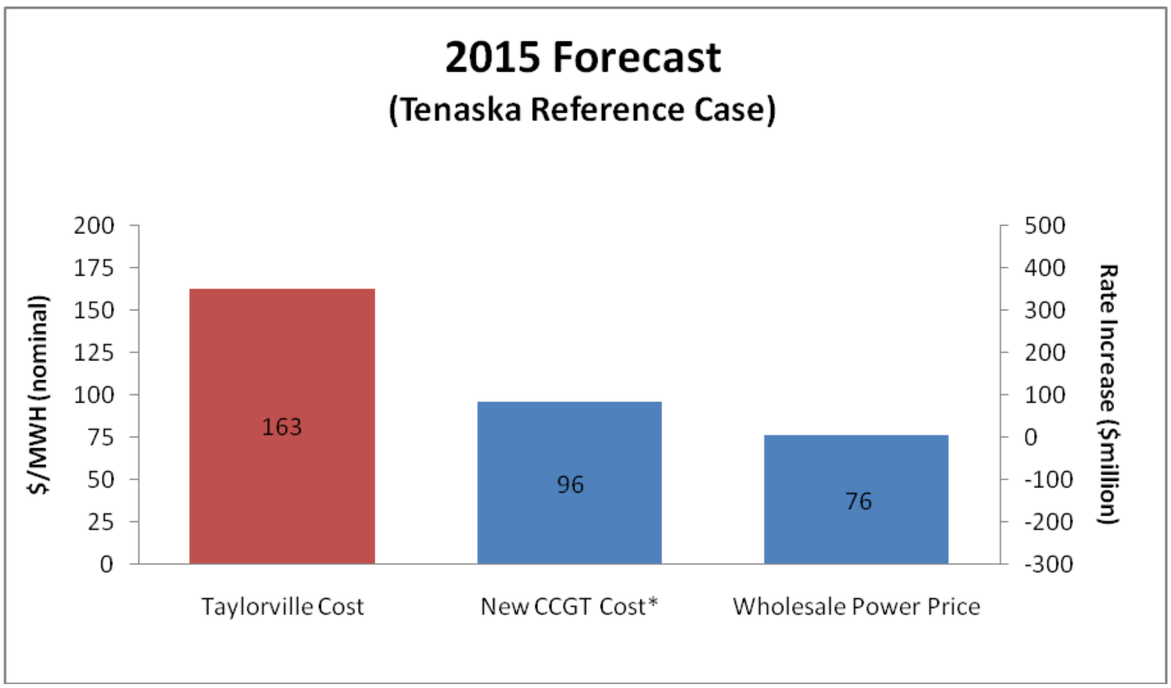
Figure 2



Absent federal bonus allowances (or their equivalent) for CCS, the TEC rate impact seems more likely to fall between the Reference case and the high case shown above – with above-market costs ranging from $8.75 to $11.5 billion over the life of the project.

But, a major justification for the TEC project is the reduction in CO_2 emissions that result. As discussed further below, the information contained in the Facility Cost Report (and the FERC filing which preceded it) indicates that SNG-fueled generation from TEC will reduce CO_2 emissions at an extremely high cost -- approaching $400/metric ton. Given this extremely high cost, it is logical to inquire as to whether there might be less expensive ways to reduce CO_2 emissions than the TEC project. While NorthBridge has not performed a comprehensive analysis of alternatives, one possible alternative is included in the FCR report – gas combined cycle generation fueled by pipeline natural gas rather than SNG. Unsurprisingly, the conventional combined cycle will be far less expensive than TEC, as shown in the figure below. The CCGT first year cost of $96/MWH is above the reference case wholesale power price, but it is much lower than the TEC first year cost of $163/MWH.

Figure 3



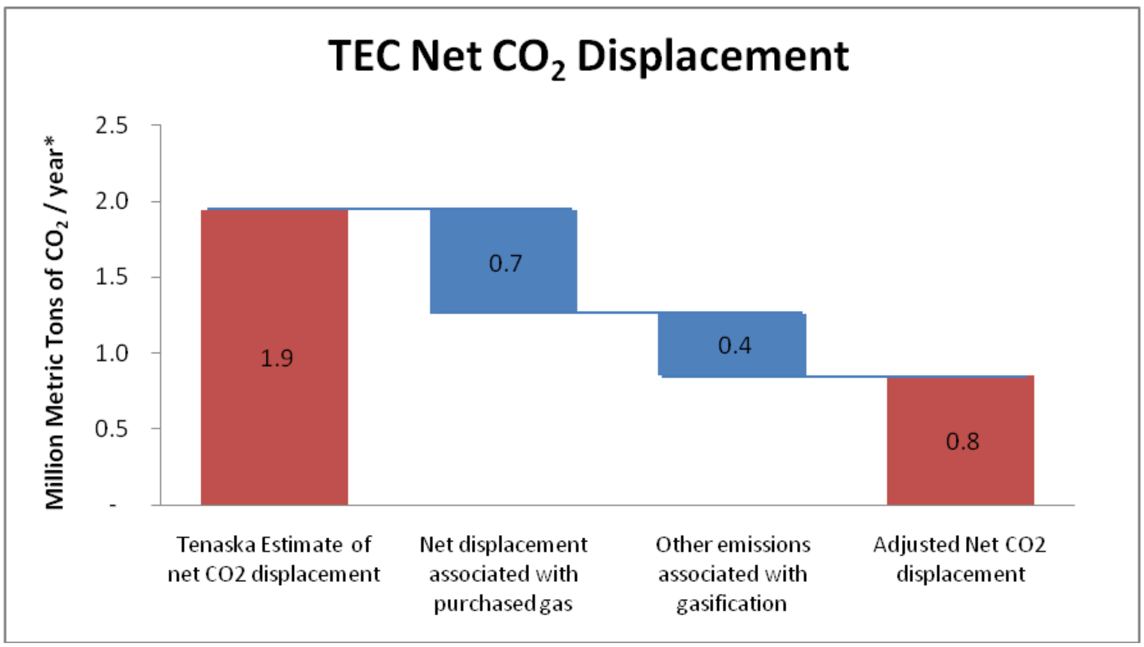
**Note: Tenaska CCGT capital cost estimate was adjusted to reflect a 75% capacity factor.*

The Tenaska analysis suggests that a conventional combined cycle generator, running at the same capacity factor as TEC, would be over $6 billion less costly than the hybrid IGCC under Reference case assumptions. Stated another way, the above-market costs associated with TEC could be reduced by roughly 70%, from $8.7 billion to $2.3 billion by relying on new conventional combined cycle generation instead of the hybrid IGCC.

Turning now to the question of the CO_2 reduction, Tenaska's estimate of the emission reductions associated with TEC are significantly overstated, and their own data suggest that a new CCGT, operated at the same capacity factor as TEC, would provide 50% more CO_2 emission reductions at less than a third of the cost.

The TEC CO_2 analysis suffers from two flaws. First, Tenaska has overstated the emissions reduction resulting from the gasification process by counting not just the emission reductions associated with the SNG-fueled generation at TEC, but also the emission reductions associated with pipeline gas generation at TEC. Approximately 35% of the TEC electricity sold under contract is generated using purchased natural gas, but the associated emissions reductions are not a benefit of "clean-coal" technology, and could be achieved without TEC. Second, as discussed further in the body of this report, Tenaska seems to have ignored a significant portion of the emissions associated with the gasification process[1]. Correcting these two errors reduces the claimed CO_2 emission reductions from 1.9 million metric tons per year to 0.8 tons per year as shown below.

Figure 4



** Tenaska has provided results for 2017 which are assumed to be representative of the project life.*

[1] The Tenaska CO_2 Analysis indicates that TEC will have a direct emissions rate that is just slightly higher than a CCGT, but this seems to ignore the emissions associated with the Air Separation Unit (ASU), which is a co-located third-party facility. The emissions due to the oxygen production should be included in the assessment of TEC because those emissions are a direct result of the SNG production.

An additional challenge associated with the TEC project is the permanent sequestration of the CO_2. Tenaska proposes to sell the Taylorville CO_2 into a to-be-built Denbury pipeline connecting Illinois with Louisiana, where the CO_2 can be used for Enhanced Oil Recovery (EOR). Recent failures in the Kentucky and Indiana legislature to provide eminent domain condemnation power for CO_2 pipeline development suggest that the Denbury project may be in jeopardy. Tenaska's alternative plan is to build a $50-100 million geological storage facility on a site near Taylorville, designed by Schlumberger, which will require its own set of approvals. If neither the Denbury pipeline nor geological storage are brought to fruition, then the CO_2 emissions from the plant will be substantially higher than the estimate in the FCR report – even higher than a conventional coal-fired generator.

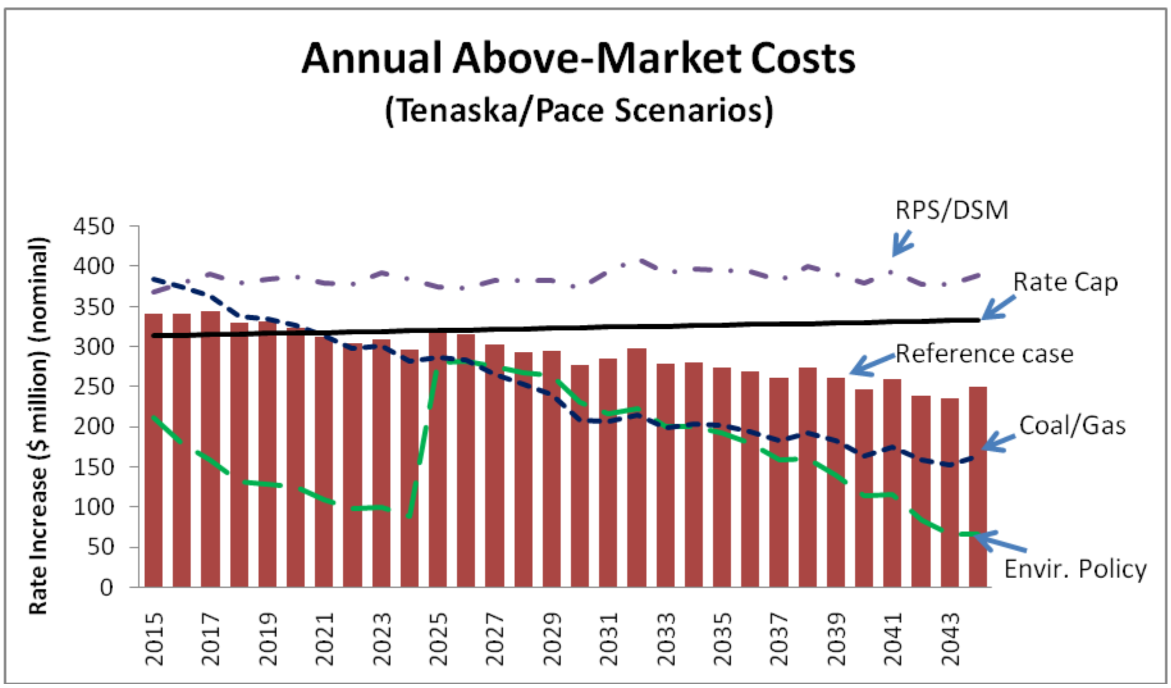
In summary, the TEC facility would result in over three times the above-market costs of a new conventional combined cycle generator with the same operating profile. And CO_2 emissions from SNG generation at TEC are 50% higher than CO_2 emissions from a conventional CCGT. With both higher costs and higher CO_2 emissions, the hybrid IGCC technology is "dominated" by the conventional CCGT – it is not a cost-effective source of reduced CO_2 emissions.

Rate Impact Analysis

For our assessment of the TEC rate impact, we have accepted the cost and revenue forecasts included in Exhibit 10.0 of the Tenaska FCR filing, the Pace Rate Impact Analysis. We have not (nor apparently has Pace) evaluated the impact of a construction cost overrun or operating cost uncertainties. The rate impacts reproduced below are taken directly from the data submitted by Tenaska to the ICC.

The Pace Rate Impact Analysis concludes that the TEC will cause a significant rate increase in every year of the project life. The table (Exhibit 5) on page 6 of their Rate Impact Analysis summarizes their results under four potential future "States of the World" or scenarios. All four scenarios predict significant rate impacts every year. Three of the four scenarios result in rate impacts that are well above the 2% rate cap for at least the first six years. The only scenario that is below the rate cap assumes the creation of a new $150 million per year federal subsidy for TEC. See the figure below for an illustration of the rate impacts reported in the Pace Rate Impact Analysis. Unfortunately, these results may also turn out to be overly-optimistic, as the Pace scenarios do not fully capture the downside risks.

Figure 5



The Pace Analysis results are also summarized in the table below. The Reference case projects that TEC will cause a rate increase of $340 million in 2015, an average annual increase of roughly $300 million per year, and a cumulative rate increase of $8,750 million over the 30 year life of the project.

Table 1

	2015 Rate Impact	Average Annual Increase	Cumulative Rate Increase
	($ millions)	($millions/year)	($ millions)
Reference	340	300	8,750
Gas/Coal	390	250	7,500
Environmental Policy	210	170	5,000
RPS/DSM	370	390	11,500

For each scenario, Pace forecasts the fixed and variable operating costs of the plant (including capital recovery, fuel, O&M, tax credits, etc), and forecasts the market price for the commodities produced by the plant (e.g. energy, capacity, SNG). The annual rate impact is the difference between the plant costs and the market value of the outputs.

Pace developed its four scenarios to evaluate TEC under a range of future commodity price and federal environmental policy outcomes. The key variables that were adjusted in each scenario include CO_2 prices, natural gas prices, and energy demand. Higher outcomes for these variables tend to increase the benefits from TEC; lower outcomes reduce the benefits of TEC, resulting in a higher rate impact. Most of the policy uncertainty is modeled as changes in the variables listed above, but the "Environmental Policy" scenario also reflects the creation of federal bonus allowances specifically allocated to CCS projects. The bonus allowance benefit to TEC is modeled as an $80 per captured ton subsidy for the first 10 years of the project life. The table below summarizes the key features of the four scenarios[2].

[2] Based on Exhibit 10.0 of the FCR study, Pace Rate Impact Analysis, Exhibit 10 on page 13.

Table 2

	Natural Gas Price		CO_2 Price		Demand Growth	CCS Subsidies
	($2010/mmbtu)		($2010/tonne)		CAGR in MWH	($2010/tonne)
	2015*	2030	2015	2030		
Reference	8.1	12.0	21	59	0.2%	
Gas/Coal	8.9	16.8	6	32	0.7%	
Environmental Policy	8.5	9.9	29	80	0.3%	Bonus $80 (2015-2024)
RPS/DSM	7.6	6.0	21	59	-0.3%	

**Note: NYMEX forward price for 2015 delivery (4/13/10 settle) = 6.1 ($2010/mmbtu) or 6.7 (nominal $/mmbtu)*

Pace developed its Reference case "with initial estimates for key market drivers and an assumption of moderate environmental and economic policies"[3]. However, the Reference case forecast turns out to be relatively optimistic compared to current market expectations. For example, the Reference case gas forecast for 2015-2020 is 20-25% higher than current NYMEX gas forward prices[4]. The CO_2 price forecast may also turn out to be too high given the tremendous uncertainty surrounding federal cap-and-trade legislation.

Another issue with the Pace analysis is that the range of rate impact results for the four scenarios may be biased low. The "worst-case" scenario includes a gas price that starts off 10-20% higher than current NYMEX forwards, and has a CO_2 price forecast that is the same as the Reference case. Modifying the Reference case to reflect currently priced natural gas and more modest CO_2 prices may result in a rate impact that is even higher than the "worst-case" Pace scenario.

CCGT Alternative

A major justification for the TEC project is the reduction in CO_2 emissions that result. Given the high level of above market costs described above, it is logical to inquire as to whether there might be less expensive ways to reduce CO_2 emissions than the TEC project. While NorthBridge has not performed a comprehensive analysis of alternatives, one possible alternative is included in the TEC

[3] See Pace Rate Impact Analysis, page 11

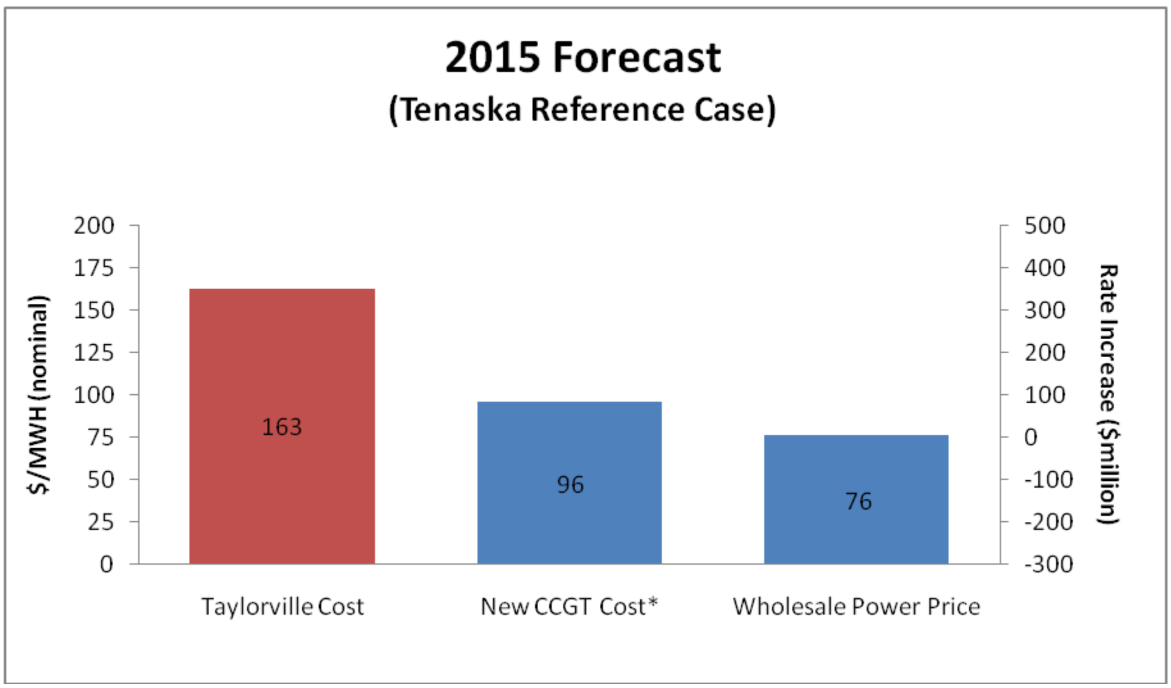
[4] Nominal average annual forward gas prices from NYMEX forwards trading on April 13, 2010 were 6.7, 7.0, 7.4, 7.7, 8.0, 8.2 $/mmbtu, respectively for years 2015-2020.

report – gas combined cycle generation fueled by pipeline natural gas rather than SNG. Comparing the costs of TEC to a conventional combined cycle will put the rate impact into context.

Pace provides a comparison of the levelized cost of Taylorville, $150 ($2010/MWH), and a conventional CCGT $163 ($2010/MWH) in Exhibits 24 and 25 of its Rate Impact Analysis. Unfortunately, these figures are misleading because the CCGT is modeled with a capacity factor of roughly 20% and Taylorville has a 75% capacity factor – this is clearly not an “apples to apples” comparison[5].

It would be more appropriate to compare the costs of running the CCGT with the same generation profile as the TEC facility – a 75% capacity factor. With a higher capacity factor, the fixed costs of the CCGT are spread over many more operating hours. Making this adjustment reduces the CCGT cost substantially. For example, the 2015 cost of a new CCGT would be $96/MWH, compared to $163/MWH for TEC, as shown below. The weighted-average Wholesale Power Price for the TEC generation would be the same as the CCGT running at a 75% capacity factor[6]. As a result, the CCGT above-market costs are much lower than the TEC above-market costs.

Figure 6



**Note: Tenaska CCGT capital cost estimate was adjusted to reflect a 75% capacity factor.*

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5 See Exhibit 33 on page 37 of the Pace Rate Impact Analysis

6 See the Pace Rate Impact Analysis Appendix pg 63. In 2015, Energy Revenue = $282,457, capacity revenue = $16,645, and the generation is 3,924 GWH. (282,457+16,645)/3924 = $76.22/MWH (nominal)

The details of the $96/MWH calculation are as follows. At a 75% capacity factor, the capital-related fixed charges are roughly $18/MWH ($2010)[7]. Exhibit 32 in the Pace analysis indicates a $9.33/kW-yr FOM estimate. The footnote at the bottom of page 4 of Tenaska's CO_2 Secondary Impact Analysis included in its FCR study indicates a VOM of $3.32/MWH. Assuming a 7,000 btu/kWh average heat-rate and 115 lbs CO_2/mmbtu for natural gas, the fuel cost is a function of the natural gas prices in Exhibit 40 of the Pace analysis and the CO_2 emissions cost is a function of the CO_2 price forecast in Exhibit 46 of the Pace analysis. All told the 2015 CCGT cost is:

2015 CCGT cost = [18 {capital cost recovery} + 9.33*1/(75%*8.76) {fixed O&M} + 3.32 {variable O&M} + 7*8.11 {fuel cost} + 21*(7*115/2200) {CO2 emission cost}] = $87/MWH ($2010) or $96/MWH (nominal)

On a life of plant basis, the levelized cost of the new CCGT, under Pace assumptions, would be about $114 ($2010/MWH), adjusting for a 75% capacity factor[8]. This is significantly lower than the TEC life of plant cost of $150/MWH ($2010). This cost difference between TEC and the CCGT of $36/MWH ($2010) translates to roughly $150 million[9] of savings relative to TEC. On a nominal basis, the difference between the TEC and CCGT costs is almost $300 million per year by 2044[10]. As a result, the above-market costs associated with the CCGT are also much lower than the TEC above-market costs. Under Tenaska's Reference case assumptions, the CCGT running at a 75% capacity factor has cumulative above-market costs of about $2.3 billion, less than a third of the corresponding $8.7 billion in above-market costs for the TEC facility.

Emissions Analysis

For our assessment of the emissions impact of TEC we rely on Exhibit 12.0 of the FCR filing, Tenaska's CO_2 Secondary Emissions Analysis. In its estimation of the CO_2 benefits of Taylorville, Tenaska compares the direct emissions of the facility with the avoided emissions of the generators expected to be displaced by the Taylorville generation. The Tenaska model estimates a gross reduction of 3.5 million metric tons and a net reduction of 1.9 million metric tons of CO_2 in 2017. The TEC CO_2 analysis suffers

[7] Exhibit 25 on page 30 of the Pace Rate Impact Analysis shows the fixed costs of a CCGT at roughly $67/MWH at a 20% capacity factor. At a 75% capacity factor the fixed costs would be 20%/75% * $67 = $18/MWH
[8] See Exhibit 24 in Pace Analysis. Ref case CCGT cost = $163/MWH ($2010); See footnote above. At a 75% CF, Pace cost estimate is reduced by $67-18 = $49/MWH. Adjusted CCGT cost is ($163-49) = $114/MWH
[9] $36/MWH * 4,000 GWH/year = $144 million ($2010), which is $158 million nominal in 2015.
[10] $144 MM * 1.02^(2044-2010) = $282 million (nominal)

from two flaws. First, Tenaska has overstated the emissions reduction resulting from the gasification process by counting not just the emission reductions associated with SNG-fueled generation at TEC, but also the emission reductions associated with pipeline gas generation at TEC. Second, Tenaska seems to have ignored emissions associated with the gasification process itself.

Tenaska calculates the gross CO_2 reductions from displacement based on projected output from the TEC facility of approximately 4,000 GWH per year. But, the projected TEC SNG production can only fuel about 2,600 GWH of electricity per year[11]. Tenaska has supplemented its SNG-fueled output by an additional 1,400 GWH per year using generation fueled by purchased natural gas. Although burning purchased natural gas in the TEC power block will displace other PJM generators, an existing conventional combined cycle can provide exactly those same benefits. In order to isolate the emissions benefits of the "clean coal" aspects of the TEC plant, we have excluded the TEC generation fueled by purchased natural gas. This reduces Tenaska's estimated CO_2 emissions displacement benefits by 1.3 million metric tons per year on a gross basis, and 0.7 million metric tons on a net basis[12].

The large quantity of TEC generation fueled by purchased natural gas also influences the unit cost of the TEC output. Tenaska's 2015 projected cost of $163/MWH is a weighted average of the cost of the SNG-fueled generation and the generation fueled with purchased natural gas. The cost of the SNG-fueled generation is estimated to be about $215/MWH[13].

As to the underestimation of CO2 emissions associated with SNG production, the Tenaska CO_2 report explains that an Aurora model was used to tally the direct emissions related to the power plant operation, and Tenaska completed additional calculations to estimate emissions attributable to the auxiliary loads of the SNG production. Table on page 4 of the CO_2 analysis implies that the sum of the results from Aurora and the Tenaska calculations yields an emissions rate for the TEC facility that is only slightly higher than a conventional combined cycle[14]. However, this information is at odds with a similar filing Tenaska made with the Federal Energy Regulatory Commission (FERC) in December 2009[15]. That filing indicates that the emissions associated with SNG-fueled electricity sales from the TEC facility are

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[11] Pace Rate Impact Study, pg 63; SNG production / Power Block Fuel = 19/28 = 68%; Purchased gas will be burned in lower heat-rate Unit2 resulting in >32% of total MWH from purchased gas.
[12] (1-2600/4000)*1.94 MM mt = 0.68 MM mt
[13] Pace Rate Analysis, Exhibits 2 and 40: Cost of Unit2 generation = $8.11*6,600btu/kwh + $3.32 (VOM) = $56.84 ($2010/MWH) or ~$63 (nominal); SNG-gen: ($163*4,000GWH – $63*1,400GWH) / 2,600GWH = $217/MWH
[14] TEC = 1.55 MM mt / (78%*602*8760) = 0.37 mt/MWH; CCGT = 0.21 MM mt / (11%*602/8760) = 0.36 mt/MWH
[15] Petition for Declaratory Order, December 23, 2009, FERC Docket No. EL10-27-000

50% higher than for a conventional combined cycle facility[16]. One difference between the December study and the FCR study appears to be the treatment of the emissions associated with the Air Separation Unit (ASU). The December study showed the ASU electricity would be self-supplied, and hence the associated emissions were included in the CO_2 accounting. In the FCR study, the electricity used by the ASU is apparently purchased rather than self-supplied, as Tenaska now intends to procure oxygen and industrial gases from a co-located third party facility rather than operate an ASU itself[17]. Regardless of the financing and ownership arrangements for the ASU, the emissions due to the oxygen production should be included in the TEC emissions assessment because those emissions would not have occurred absent the SNG production.

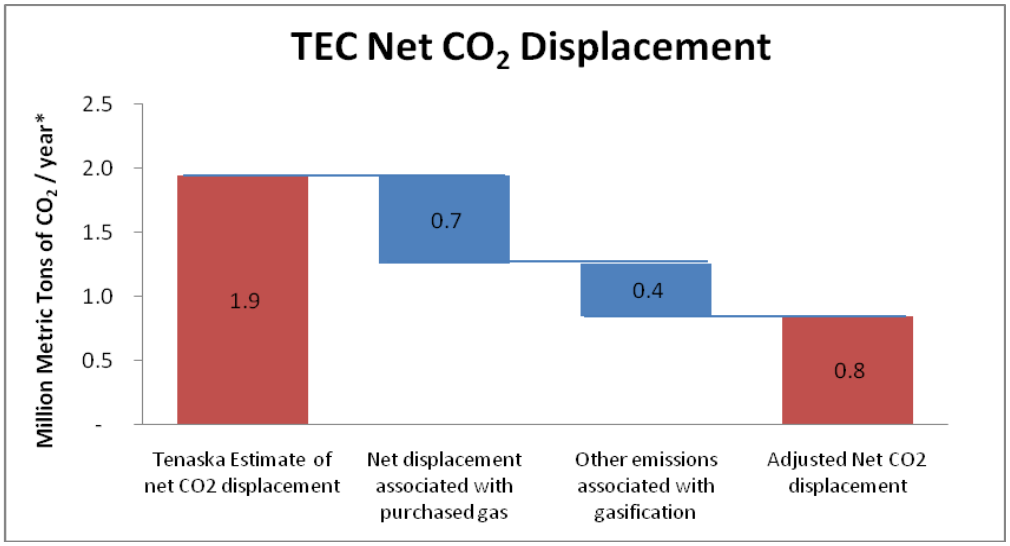
We estimate that the ASU would consume approximately 500 GWH of electricity per year. If this electricity were supplied from a PJM system mix of generators, the CO_2 emissions associated with these purchases would reduce Tenaska's estimate of emissions benefits by roughly 0.4 million metric tons. Our estimate of the ASU load was derived from a comparison of the plant descriptions in the FCR and FERC filings and is further explained in the Appendix.

The net effect of correcting these errors is to significantly reduce the emission reductions attributable to the TEC SNG facility, as shown in the figure below. Tenaska's estimate of 1.9 million metric tons of net CO_2 displacement is reduced by 0.7 million metric tons of displacement associated with the purchased gas, and 0.4 million metric tons of emissions associated with the ASU to yield an adjusted net benefit of just 0.8 million metric tons – less than half of the Tenaska estimate.

[16] Tenaska FERC filing, Exhibit CCG-3: TEC = 1.26 MM tons / (47%*483*8760) = 0.63 tons/MWH; CCGT = .18 MM tons / (10%*483*8760) = 0.42 tons/MWH

[17] Exhibit CCG-3 of Tenaska's December 2009 FERC filing, the CO2 Secondary Emissions Analysis, included a description of an earlier Taylorville design in footnote 2 on page 3, which indicates that Taylorville would self-supply the load for the Air Separation Unit, as well as the SNG island and the CO_2 compression. The FCR study CO_2 Emissions Analysis, footnote 2 on page 3, is nearly identical to the footnote in the FERC filing, except that the FCR footnote omits the Air Separation Unit from the list of auxiliary loads that will be self-supplied.

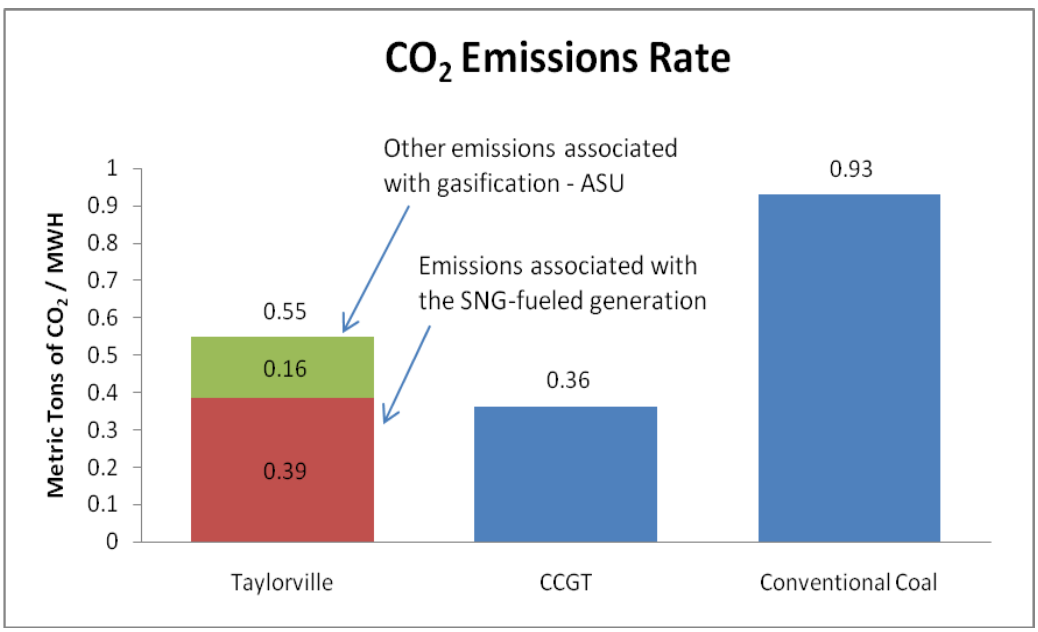
Figure 7



** Tenaska has provided results for 2017 which are assumed to be representative of the project life.*

The figure below compares the CO_2 emissions associated with the SNG-fueled generation from TEC (in tons/MWH) with to the emission rates of a conventional CCGT and a conventional Coal plant[18]. TEC is inferior to the CCGT and somewhat better than the conventional coal.

Figure 8



[18] Taylorville ASU = 480 GWH * (3.5MM mt/4000 GWH) / 2600 GWH; Taylorville SNG-gen = (1.55MM mt/4000 GWH); CCGT = (0.21 MM mt / (11%*602MW*8.76) from Pace Analysis; Coal = (10,000 btu/kwh) *(205 lbs/mmbtu) / (2205 lbs/metric ton) from Industry sources.

Summary

Tenaska claims that "TEC is more effective at reducing CO_2 emissions than a standard combined-cycle unit because it runs more often"[19]. This statement is not correct. The TEC power block is a conventional combined cycle (CCGT). When burning purchased natural gas, TEC produces exactly the same emissions as a conventional CCGT burning pipeline gas. When the gasifier is operating, the auxiliary loads associated with the SNG production (whether self-supplied or not) increase CO_2 emissions. As a result, the TEC emissions rate when it is burning SNG (in CO_2 tons/MWH) is always higher than a conventional CCGT. It would also be far less expensive to build and operate a conventional CCGT at a 75% capacity factor than the Taylorville plant, as the preceding analysis has shown.

The TEC facility has annual above-market costs of about $300 million, most of which is attributable to the SNG production. The annual CO_2 emission reduction attributable to the SNG production is approximately 0.8 million metric tons. The cost of CO_2 reductions, approaching $400 per metric ton[20], is quite high – and much higher than other available options. For example, Tenaska's own analysis suggests that a new CCGT operated at an equivalent capacity factor would have above-market costs of approximately $80 million per year, and emission reductions of 1.2 million metric tons[21]. The average cost of CO2 reductions is $70 per metric ton – a much less expensive option than TEC.

[19] Tenaska CO2 Secondary Emissions Analysis, page 4.
[20] $300 / 0.8 metric tons = $375/ton, on top of the assumed CO2 allowance price of $21-59/ton ($2010).
[21] (96-76)$/MWH*4000 GWH = $80 million; (0.8+0.4 MM tons) = 1.2 MM metric tons {CCGT does not require ASU emissions}

Appendix - Design Overview

The TEC design includes two process islands: (1) substitute natural gas (SNG) production, and (2) combined cycle power plant.

The two process islands are co-located, but operate independently for the most part. In fact, the power block can be operated using pipeline natural gas when the SNG island is shut down. Likewise, the SNG island can be operated using purchased power instead of the onsite generation.

As discussed in the section above, Tenaska made a December 2009 filing at FERC which included a detailed description of the operating characteristics of the Taylorville hybrid IGCC. Curiously, the plant operations described in its FERC filing are dramatically different from the FCR report filed two months later. The total capital costs were identical ($3.5 Billion), but the SNG production declined from 28 million mmbtu per year in the FERC filing, to 19 million mmbtu per year in the FCR report. Likewise, the coal input declined from 48 million mmbtu (FERC) to 33 million mmbtu (FCR) [22]. Meanwhile, the electricity sales doubled from roughly 2,000 GWH per year (FERC) to 4,000 GWH per year (FCR). While a portion of the increased sales appears to be associated with the differing treatment of the ASU power described above, most of the additional energy in the FCR report is generated using purchased natural gas. Unfortunately, Tenaska has not provided any explanation for these significant changes.

The key features of the project are summarized in Table 2 below:

Table 3

	FCR Study (Feb 2010)	**FERC filing (Dec 2009)**
Gasifier Power (Air Separator)	3rd party purchase[23]	Self-supply
Power Block Fuel	Self-supply / 3rd party purchase	Self-supply
2x1 Net/Gross Electric MW	602/716 MW	483/730 MW
1x1 Net/Gross Electric MW	285/395 MW	160/415 MW
Coal Input	33 mm mmbtu	48 mm mmbtu
SNG production	19.3 mm mmbtu	28.1 mm mmbtu
SNG Purch/(Sales)	9.7 / (1.2) mm mmbtu	0 / (7.4) mm mmbtu
Electric Purch/(Sales)	~500 / (4,000) GWH	0 / (2,000) GWH

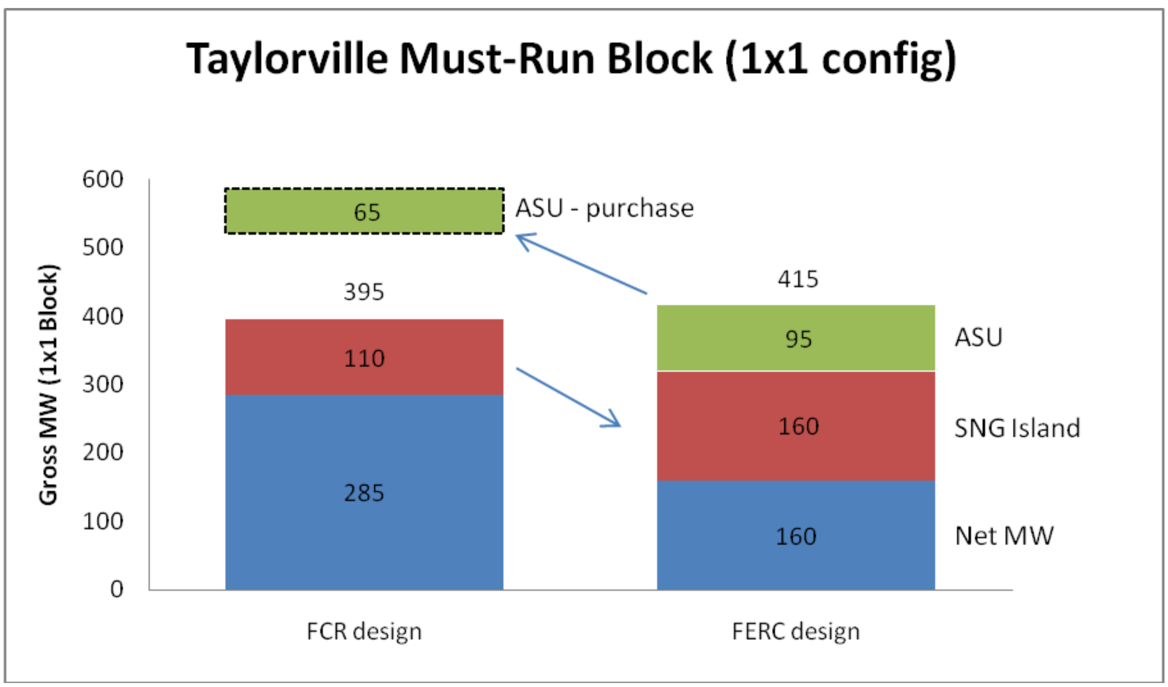
[22] See See Feb 2010 Tenaska Facility Cost Report, Pace Rate Impact Analysis, pg 63. Dec 2009 Tenaska FERC filing, Exhibit CCG-2: TEC Project description, page 27 of 29. Coal input = 4,487,273 tonnes CO_2 / year * 2205 lbs/tonne / 205 lbs CO2 / mmbtu [coal] = 48.2 MM mmbtu

[23] See footnote [14].

Appendix - Air Separation Unit

The Feb 2010 Tenaska Facility Cost Report indicates on page 3-4 that the power block will have a gross electrical generating capacity of 716 MW and net capacity of 602 MW in 2x1 Configuration. In 1x1 Configuration, the facility will have a gross capacity of 395 MW and a net capacity of 285 MW which implies an SNG Island load of 110 MW. The FERC filing described a 1x1 configuration with a gross capacity of 415 MW and a net of 160 MW[24]. Given the difference in the coal input between the FCR and the FERC descriptions, one would expect that FERC SNG load to be roughly 48/33 times greater than the FCR SNG load of 110MW, which would be 160 MW. In fact, the FERC SNG load is (415-160) = 255 MW. Based on Tenaska's description of the ownership of the ASU, it seems apparent that the extra 95 MW of SNG Island load in the FERC design is due to the ASU. This implies that the FCR ASU consumes approximately 33/48*95 MW = 65 MW of electricity during 85% of the hours in the year.

Figure 9



[24] See Dec 2009 Tenaska FERC filing, Exhibit CCG-3, pg 3. See FERC filing testimony of Barton Ford, pg 3 of 14.

A recent EPRI report on IGCC Design Considerations provides context for this interpretation of the ASU load[25]. Table 8-7 of the EPRI report indicates that for a gasifier with a 6,786 mmbtu/hr coal input rate, the ASU consumption would be 128.4 MW. The FCR states that the TEC coal input will be 4,433 mmbtu/hr which implies that the ASU load should be roughly 80 MW. The actual TEC ASU will be somewhat smaller than the EPRI IGCC ASU, because the EPRI report describes a hydrogen-combustion IGCC which has demands for N_2 production from the ASU. The TEC power block does not require N_2, which reduces the requirements for its ASU operations.

Appendix – About Us

The NorthBridge Group is an independent economic and strategic consulting firm serving the electric and natural gas industries, including regulated utilities and companies active in the competitive wholesale and retail markets. NorthBridge has a national practice and long-standing relationships with restructured utilities in Regional Transmission Organization ("RTO") markets, vertically-integrated utilities in non-RTO markets, and other market participants. Before and throughout the restructuring process of the U.S. electricity industry, we have assisted clients with wholesale market design, competitive market analysis and strategy, regulated power supply procurement, state regulatory initiatives and strategy, and mergers and acquisitions.

[25] EPRI, Integrated Gasification Combined Cycle Design Considerations for CCS, Phase 2, R. Schoff, Dec 2009

SIERRA CLUB
FOUNDED 1892

70 E. Lake St., Suite 1500
Chicago, Illinois 60601

April 16, 2010

VIA ELECTRONIC FILING

Tim Anderson
Executive Director
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, Illinois 62701

Re: Comments on Facility Cost Report, Taylorville Energy Center

Dear Mr. Anderson:

On behalf of our approximately 23,000 Illinois members, I am writing to provide Sierra Club's comments on the Facility Cost Report submitted by Tenaska Taylorville, LLC to the Illinois Commerce Commission ("ICC") for the proposed Taylorville Energy Center coal gasification project.

The attached report, prepared by David Schlissel of Schlissel Technical Consulting, identifies many issues and concerns related to the Taylorville project, including—among other things—extremely optimistic assumptions concerning the facility's construction and operating costs, its operating performance, natural gas prices, and the speculative annual revenues Tenaska has packed into the equation.

The ICC and its consultants must dig beneath the smooth veneer of Tenaska's rosy cost report, especially because the company is taking on essentially no risk from this $3.5 billion-plus project. Instead, the ratepayers of the state's investor-owned utilities and alternative electric suppliers will bear the risks and burdens if Tenaska is unable to meet its unrealistic and overly optimistic assumptions.

Illinois ratepayers should not be left holding the bag for an expensive, risky, and unnecessary project. We urge the ICC to take a hard look at the issues identified in Mr. Schlissel's report.

Thank you for the opportunity to comment on this important issue.

Sincerely,

James Gignac

James P. Gignac

Midwest Director
Sierra Club, Beyond Coal Campaign
(312) 251-1680 x147
james.gignac@sierraclub.org

SCHLISSEL
TECHNICAL CONSULTING

Comments on The Taylorville Energy Center Facility Cost Report

David A. Schlissel

April 16, 2010

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Conclusion:

The Facility Cost Report for the proposed Taylorville Energy Center does not reasonably demonstrate that the proposed facility will only have a minor impact on the bills of electric ratepayers in Illinois. The claims and conclusions presented in the Facility Cost Report and its supporting analyses are biased in favor of the proposed Taylorville facility by a number of extremely optimistic assumptions concerning the facility's construction and operating costs, its operating performance, natural gas prices, and the annual revenues that Tenaska will be able to earn through the sale of the SYN gas, carbon dioxide ("CO_2"), sulfur, nitrous oxide ("NOx") allowances and the plant's capacity.

The Facility Cost Report also reveals that Tenaska will not bear any significant risks from the Taylorville Energy Center. Instead, the ratepayers of the state's investor-owned utilities and alternative electric suppliers will bear the main risks and burdens of the project.

Summary of Comments:

Comment No. 1.	We have not had a reasonable opportunity to review the analyses underlying the Facility Cost Report and its supporting exhibits, such as the Pace Rate Impact Analysis and the Tenaska Secondary CO_2 Emission Analysis.
Comment No. 2.	The Taylorville Energy Center will likely be heavily subsidized by the State of Illinois and the Federal government.
Comment No. 3:	Tenaska assumes that the rate impact of the Taylorville Energy Center will be heavily mitigated by revenues from the sale of SYN gas, CO_2, sulfur, NOx allowances and plant capacity. However, Tenaska does not offer any guarantees that these revenues actually will be obtained. Instead, the risks associated with these sales are passed along to the ratepayers of the investor-owned utilities and the alternative retail energy suppliers through the 30 year sourcing agreements.
Comment No. 4.	Despite all of the subsidies and incentives that may be provided by the state and federal governments, the cost of the power generated at the Taylorville Energy Center will be very expensive.
Comment No. 5.	It is unclear what significant risks, if any, Tenaska will bear in the Taylorville Energy Center.
Comment No. 6.	The results of the Rate Impact Analysis are heavily biased by the unrealistic assumption that the proposed Taylorville Energy Center will achieve extremely low heat rates.
Comment No. 7.	There is a significant risk that the actual cost of constructing the proposed Taylorville Energy Center could be substantially higher than Tenaska's current estimate. The economic analyses in the Facility Cost Report should reflect this risk by including scenarios in which the cost of the proposed plant is 20 percent and 40 percent above the currently estimated cost.

Comment No. 8. The results of the Pace Rate Impact Analysis are heavily biased by the assumption that the Taylorville plant will achieve high annual capacity factors which, in turn, is dependent upon (1) the technology performing as well as Tenaska now claims and (2)Tenaska obtaining 'must run' status for the units for a significant portion of the year. If the units are not designed 'must run' as Tenaska has assumed and/or if it is not economic to sell SYN produced at the plant into the natural gas market, the rate impact of Taylorville will be substantially higher than Tenaska has projected because the same fixed costs will have to be recovered over a smaller number of megawatt hours ("MWh") of output.

Comment No.9. The Pace Rate Impact Analysis is distorted by the assumption of high natural gas prices.

Comment No. 10. The Facility Cost Report significantly understates the potential for higher coal prices.

Comment No. 11. The Facility Cost Report is not persuasive in its claim that the proposed Taylorville Energy Center will capture more than 50 percent of the CO_2 that would otherwise be emitted.

Comment No. 12. Tenaska assumes a very low cost for sequestering the CO_2 from the Taylorville Energy Center.

Comment No. 13. The rate impact analyses presented by Tenaska and Pace that assume a 92 percent capacity factor for the Taylorville Energy Center are unrealistic.

Comment No. 14. It appears that the Tenaska Secondary CO_2 Emissions Analysis may significantly overstate the overall reductions in regional CO_2 emissions that would be attributable to the proposed Taylorville Energy Center.

Comment No. 15. It appears that the Pace Market Price Analysis may significantly overstate the overall market cost savings that would be attributable to the proposed Taylorville Energy Center.

Comment No. 1. We have not had a reasonable opportunity to review the analyses underlying the Facility Cost Report and its supporting exhibits, such as the Pace Rate Impact Analysis and the Tenaska Secondary CO_2 Emission Analysis

The Facility Cost Report and its supporting exhibits set forth the results of the various engineering, economic and modeling analyses Tenaska conducted plus conclusory statements regarding the benefits of the proposed Taylorville Energy Center.

As part of our review, we submitted a detailed set of questions and document requests to Tenaska seeking workpapers and computer output files that would reveal the assumptions and methodologies used in the FCR and supporting analyses. Tenaska declined to produce these materials and provided only a few short documents in response to our request. Tenaska did graciously allow us to conduct two phone conversations with their staff. But these phone conversations were not adequate substitutes for having the opportunity to complete detailed reviews of the workpapers, computer output files, and source documents for the substantial number of conclusions that are presented in the FCR and supporting exhibits. Nevertheless, our review of the materials that were made available did identify a number of serious flaws and biases in the Facility Cost Report, the Rate Impact Analysis, and the Secondary CO_2 Emissions Analysis. Our review also raised questions about the validity of the benefits that Tenaska has cited for the Taylorville Energy Center.

Comment No. 2. The Taylorville Energy Center will likely be heavily subsidized by the State of Illinois and the Federal government.

Tenaska assumes it will receive the following subsidies and incentives for the Taylorville Energy Center:

- A loan guarantee from the U.S. Department of Energy for up to $2.579 billion. This will result in interest savings of approximately $60 million per year.[1]
- Carbon sequestration credits under Section 45Q of the Internal Revenue Code.[2]
- The requirement that the investor-owned and alternative retail energy suppliers will have to enter into 30 year sourcing agreements for the power from the Taylorville Energy Center.
- Up to a $50 million cash grant from the Illinois Coal Revival Grant Fund.[3]
- An $18 million grant provided by the state to pay for preparation of the Facility Cost Report that will only be paid back if the Taylorville project "achieves financial closing.[4]

The financing plan for the Taylorville project also may include, in addition to the potential DOE guaranteed loan, debt financing to be provided by Illinois tax exempt solid waste disposal/wastewater treatment bonds, and moral obligation bonds.[5] As noted in the Facility Cost

1 Facility Cost Report, at page 11.
2 Id, at page 12.
3 Id, at page 49.
4 Id, at page 6.
5 Id, at page 50.

Report, the Illinois Finance Authority already has provided a preliminary inducement resolution in 2006 for $350 million of tax exempt solid waste disposal facilities revenue bonds and $149 million of moral obligation bonds financing for the purpose of attracting clean coal generating capacity to the State of Illinois.[6]

Comment No. 3: Tenaska assumes that the rate impact of the Taylorville Energy Center will be heavily mitigated by revenues from the sale of SYN gas, CO_2, sulfur, NOx allowances and plant capacity.[7] However, Tenaska does not offer any guarantees that these revenues actually will be obtained. Instead, the risks associated with these sales are passed along to the ratepayers of the investor-owned utilities and the alternative retail energy suppliers through the 30 year sourcing agreements.

Tenaska makes very optimistic assumptions about its ability to sell the by-products from the Taylorville plant:

- **SNG Revenues –** "Over the first ten years of operation, revenues from SNG sales are projected to average $15.2 million annually in 2010$."
- **CO_2 Revenues –** "It is expected that the TEC will sell approximately 1.9 million [metric tonnes] of CO_2 per year to Denbury Onshore, L.L.C. Over the first 10 years of operation, revenues from CO_2 sales are projected to be approximately $9.0 million annually in 2010$."
- **Sulfur Revenues** – "On average, over the first 10 years of operation, revenues from molten sulfur sales are projected to be $3.6 million annually in 2010$."
- **NOx Allowance Revenues** –"Based on Pace's projected prices for NOx allowances, CCG estimates, on average, over the first 10 years of operation, revenues from the sale of surplus NOx allowances will be approximately $18.1 million annually in 2010$."
- **Electric Capacity Revenues** – "On average, over the first 10 years of operation, revenues from electric capacity sales are projected to be $21.9 million annually in 2010$."[8]

Thus, in total, Tenaska is assuming that it will receive $67.8 million, in 2010$, each year during the plant's first 10 years of operations, from the sales of SYN, CO_2, sulfur, NOx, and electric capacity. However, Tenaska does not bear any risk that these projections will be wrong. Instead, all of the risk will be passed along to the investor owned utilities and alternative retail energy suppliers who must enter into the 30 year sourcing agreements and their ratepayers.

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6 Id, at page 51.

7 Facility Cost Report, at pages 10 and 11.

8 Id.

Comment No. 4. Despite all of the subsidies and incentives that may be provided by the state and federal governments, the cost of the power generated at the Taylorville Energy Center will be very expensive.

The Facility Cost Report notes that the projected cost of power from Taylorville will start at 16.3 cents per kilowatt hour in 2015, increasing to 19.1 cents per kilowatt hour in 2024, 22.6 cents per kilowatt hour in 2030, and 30.6 cents per kilowatt hour in 2045.[9]

These projected costs of power are significantly higher than reasonably estimated costs of implementing aggressive energy efficiency, wind resources, or new natural gas-fired combined cycle capacity. It is more than reasonable to expect that a portfolio of these alternatives could provide reliable electricity at a far lower cost than Taylorville. For example, even the levelized cost study presented in the Pace Rate Impact Analysis shows that energy from wind facilities would cost only $71/MWh, in 2010 dollars, or far less than the $150/MWh levelized price of power from Taylorville.

However, even the costs of generating power at Taylorville that are presented in the Facility Cost Report and Pace Rate Impact Analysis may be far too low as they assume that Taylorville will be able to operate at an average 75 percent annual capacity factor. If the plant does not operate at that high level of performance, the cost per kilowatt hour of generating power will go up, perhaps significantly.

Moreover, the costs of generating power in the Facility Cost Report are based on Tenaska's optimistic assumptions about future plant construction costs, financing costs, and coal prices. If the costs of building and/or operating the plant are higher than Tenaska now acknowledges, then the total cost of power from Taylorville will be even higher than the company now claims.

For example, Tenaska has acknowledged that the costs of power from Taylorville would be significantly higher if it does not obtain the federal credits and the revenues it is anticipating. For example, Tenaska notes that:

> In the event that CCG is not able to store its captured CO_2 either by delivering CO_2 to Denbury or by storing geologically in its own storage field (if, for example, there is a change in law that prevents CCG from obtaining an injection permit), CCG would earn no CO_2 sales revenue and would not receive any production tax credits, and would also incur the cost of purchasing carbon emission allowances (if applicable) for the CO_2 that it is not able to store. However, in this event CCG would not be compressing CO_2, so this cost would be saved. The projected net annual effect of these changes would be an increase in costs (as compared to delivering CO_2 to Denbury under the terms of the Denbury contract) of approximately $63 million per year on average for the first 10 years and $137 million per year on average over 30 years. In the first 10 years, the estimated average rate impact of these changes would be 0.398%. Over the 30-year period, the estimated average rate impact would be 0.838%.[10]

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9 Facility Cost Report, at page 12, and Pace Rate Impact Analysis, Exhibit 6, at page 8.

10 Facility Cost Report, at page 82.

But, according to the proposed plan for Taylorville, ratepayers, not Tenaska, would bear the risks of having to pay these additional CO_2 costs over the life of the Taylorville plant.[11]

Comment No. 5. It is unclear what significant risks, if any, Tenaska will bear in the Taylorville Energy Center.

Tenaska has received and will continue to receive significant incentives and funds from the federal government and the state of Illinois. The investor owned utilities in the state and the Alternate Retail Energy Suppliers will be required to enter into 30 year Source Agreements requiring them to purchase plant's generation. Moreover, as ComEd, the Retail Energy Supply Association, and the Illinois Competitive Energy Association have noted, there is no obligation on Tenaska's part to deliver any power whatsoever, yet the proposed Source Agreements would provide for full payment of the project annual revenue requirements—including costs and profits—whether or not any power is ever generated or delivered over the entire thirty-year term of the agreements. Under these circumstances, Tenaska should not be entitled to earn an 11.5 percent return on equity. Instead, the company's return on equity should be closer to a risk-free cost of long-term debt.

Instead, the state's investor-owned utilities and retail energy suppliers and their ratepayers are at risk that they have will to pay the capital and operating costs of the proposed Taylorville plant without any guarantees as to the output that Tenaska will provide from the plant

The only risk that representatives from Tenaska could cite as being borne by the company was the risk that the ICC would disallow imprudent costs that have been incurred as a result of the mismanagement of construction or operations. Although prudency reviews are important regulatory tools, this means that the state's investor owned utilities, alternative retail energy suppliers and their ratepayers will bear all of the risks that Tenaska is wrong (but not imprudent) about the future costs of building and operating the Taylorville project. Given all of the uncertainties associated with building and operating a new power plant over the next thirty five years (and continuing to operate the fleet of existing plants) it is reasonable to expect that Tenaska's current estimates will not be spot on. Yet Tenaska will reap a relatively high (11.5 percent) annual return on its equity investment whether or not the Taylorville plant provides economic benefits to ratepayers and/or actually reduces greenhouse gas and other air emissions.

Comment No. 6. The results of the Rate Impact Analysis are heavily biased by the unrealistic assumption that the proposed Taylorville Energy Center will achieve extremely low heat rates.

A generating unit's heat rate measures how efficiently it operates. The lower the heat rate, the more efficient the plant. The lower the heat rate, the less fuel a plant will burn and, as a result, the lower its fuel costs and emissions will be.

The heat rates assumed for the proposed Taylorville facility are presented on page 3 of the Pace Rate Impact Analysis:

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11 These risks are particularly noteworthy given that Denbury has not even determined yet whether a 700-mile long CO_2 pipeline from the Midwest to the Gulf Coast could be feasible. See, e.g., http://www.denbury.com/index.php?id=53.

	Units	Unit 1	Unit 2
Net Heat Rate (June-Sep)	Btu/kwh	7,583	6,649
Net Heat Rate (Nov-Feb)	Btu/kwh	7,114	6,487
Net Heat Rate (Mar-May & Oct)	Btu/kwh	7,225	6,476

Thus, Tenaska is claiming that Taylorville Unit 1 will achieve heat rates in the range of 7,114 to 7583 btu/kwh and that Unit 2 will achieve even lower heat rates in the range of 6,476 to 6,649 btu/kwh. These heat rates are not only unreasonably low compared to the heat rates for IGCC plants by other independent sources but are inconsistent with the heat rates projected for the plant in the January 2005 *TEC/IGCC Feasibility Analysis*, as well as the data presented in the Taylorville air permit application.

For example, the following table shows the heat rates projected for future IGCC units by the U.S. Department of Energy's National Energy Technology Laboratory, the *Future of Coal* study from the Massachusetts Institute of Technology, the engineering firm Black & Veatch and a utility that was evaluating coal-fired generating alternatives, Florida Power & Light.

Study	Units	IGCC Heat Rate Without CO_2 Capture	IGCC Heat Rate With CO_2 Capture
DOE/NETL *Cost and Performance Baseline for Fossil Energy Plants* (2007)	Btu/kwh	8,364-8,922	10,505 - 10,757
NETL *Current and Future Technologies for Gasification Based Power Generation (2009)*	Btu/kwh	9,649	11,214
MIT *Future of Coal* (2007)	Btu/kwh	8,891	10,942
Black & Veatch *Energy Market Perspective* (Fall 2009)	Btu/kwh	9,600	12,350
Florida Power & Light *Clean Coal Technology Selection Study* (2007)	Btu/kwh	8,990 - 9,360	

Thus, the heat rates assumed by Tenaska for Taylorville with CO_2 capture for its Facility Cost Report analyses are significantly lower than the heat rates projected for new IGCC facilities without any CO_2 capture.

The heat rates assumed by Tenaska for the Facility Cost Report analyses also are much lower than the 9,039 – 9,099 btu/kwh heat rates projected for the Taylorville plant in the January 2005 *TEC/IGCC Feasibility Analysis* prepared by the ERORA Group.[12] It is significant that this was for a plant without CO_2 capture. As can be seen from the table above, it is reasonable to expect that a plant's heat rate will be substantially higher with CO_2 capture than without.

The heat rates assumed for Taylorville for the Facility Cost Report analyses also are inconsistent with the information presented in Tenaska's air permit application. In that application, Tenaska

[12] At pages 75 and 98.

said that the design heat content of the coal that would be used at Taylorville would be 10,750 btu/lb and that the design coal feed to the gasifiers would be 277 tons per hour. This translates into an HHV heat input to the gasifiers of 5,956 MMbtu/hour and a net heat rate of 9,453 btu/kwh with the designed net output of 630 MW presented in the air permit application.

In conclusion, the heat rates that Tenaska has assumed for the analyses in its Facility Cost Report are inconsistent with the heat rates projected for new IGCC plants by a wide range of government and industry studies, the Taylorville *Feasibility Analysis* and the information presented in Tenaska's air permit application. The use of the very low heat rates biases the results of the analyses in the Facility Cost Report in favor of the proposed plant. Tenaska should be required to redo those analyses with more reasonable heat rates.

Comment No. 7. There is a significant risk that the actual cost of constructing the proposed Taylorville Energy Center could be substantially higher than Tenaska's current estimate. The economic analyses in the Facility Cost Report should reflect this risk by including scenarios in which the cost of the proposed IGCC plant is 20 percent and 40 percent above the currently estimated cost.

Tenaska's currently estimated construction cost for the Taylorville plant is $2.616 billion, excluding financing costs, taxes, insurance and start-up costs.[13] However, none of this cost is currently subject to any cost cap and, it appears, none of the contracts for the project have been signed and no equipment has been purchased.

Coal power plant construction costs have risen dramatically in recent years as a result of a worldwide competition for design and construction resources, equipment, and commodities like concrete, steel, copper and nickel. Terms like "staggering" and "skyrocketing" have been used to describe these cost increases.[14] Coal-fired power plants that were estimated to cost $1500 per kilowatt in 2002 are now projected to cost in excess of $3500 per kilowatt.[15]

Almost all other coal-fired power plants (both those under construction and proposed) have experienced large cost increases in recent years. For example, the estimated per unit construction cost of Duke Energy Carolina's Cliffside Project increased by 80 percent between the summer of 2006 and June 2007. Similarly, AMP-Ohio cancelled its proposed Meigs County coal plant last fall after the estimated cost of the plant increased by 37 percent only 13 months after the previous estimate was issued. Consequently, it is reasonable to expect that the actual cost of building the Taylorville Energy Center will be significantly higher than Tenaska currently estimates.

Duke Energy Indiana's Edwardsport plant is the only IGCC project that is currently under construction in the U.S. This project's construction cost experience illustrates the cost increases that can be expected at Taylorville.

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13 Facility Cost Report, at page 10.

14 Although commodity prices remained flat or fell for a period from late 2008 through much of 2009, prices have rebounded since the 3rd quarter of 2009 and regained some of the ground lost during the preceding year, as Tenaska has noted at page 35 of the Facility Cost Report.

15 See the report, *Coal-Fired Power Plant Construction Costs*., a copy of which is available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.Coal-Plant-Construction-Costs.A0021.pdf.

At the time it requested a certificate from the Indiana Utility Regulatory Commission in the spring of 2007, Duke Energy Indiana estimated that its proposed Edwardsport IGCC unit would cost $1.985 billion. However, in April 2008, just one year later, Duke announced an 18 percent increase in the estimated cost of its proposed IGCC coal plant. Duke indicated that higher than expected costs had been experienced when the Company actually began final procurement of equipment for the plant. Duke also said that "the increase in the cost estimate is driven by factors outside the Company's control, including unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs."[16] Duke also noted in its Petition to the Indiana Utility Regulatory Commission that this projected increase in cost was "consistent with other recent power plant project cost increases across the country."[17]

Then, last fall, Duke announced another 6.4 percent increase in the IGCC unit and warned the Indiana Commission that there may be further increases in the project, which was 44 percent complete:

> The Edwardsport IGCC Project has made considerable progress in the six months since our previous filing. Construction is proceeding at an expected pace and the total project is approximately 44% complete. Yet, despite Petitioner's best efforts to rigorously manage the Edwardsport IGCC Project, we have experienced design modifications and scope growth above what was anticipated from the preliminary engineering design, adding capital costs to the Project. We are currently forecasting that the additional capital cost items will use the remaining contingency and escalation amounts in the current $2.35 billion cost estimate and add approximately $150 million, or about 6.4%, to the estimated cost of the Project. The Company is in the process of determining how this increase in capital costs will impact the total Project cost estimate, including the impact associated with additional contingency. Over the next few months, we will be examining items such as craft labor estimates, final engineering, procurement and start-up estimates to better understand the potential cost increases and how much additional contingency will be needed to complete the Project.[18]

In fact, just today, April 16th, Duke filed an update that increased the estimated cost of the Edwardsport IGCC Project by approximately $530 million, or 23 percent, above the $1.985 billion previous estimate. The new cost estimate is $2.88 billion including escalation and financing costs. This means that the estimated cost of the Edwardsport Project has increased by $895 million, or 45 percent, since the Project was approved by the Indiana Utility Regulatory Commission in the fall of 2007. Duke claims that the Project is now 57 percent complete.

Tenaska says that it intends the Taylorville Energy Center will be constructed through a combination of fixed price equipment purchase contracts (for the gas turbines, steam turbine, other major power block equipment, gasifiers, water treatment plant equipment, and coal handling equipment), fixed price engineering and installation contracts (for the water treatment plant, the power block and the coal handling facilities), and an incentivized cost reimbursable

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16 Verified Petition in Indiana Utility Regulatory Commission Cause No. 43114 IGCC-1, filed on May 1, 2008, at pages 3-4

17 Id, at page 7.

18 *Verified Petition and Motion for Subdocket Proceeding*, Duke Energy Indiana, Indiana Utility Regulatory Commission Cause No. 43114 IGCC-4, November 24, 2009, at page 3.

contract for construction project management and installation of other Core Plant components.[19] However, Tenaska provides absolutely no evidence that it is reasonable to assume that it will be able to obtain such fixed price equipment purchase contracts, fixed price engineering and installation contracts and/or incentivized cost reimbursable contract for construction project management and installation of Core Plant components. In the past, utilities were able to secure fixed-price contracts for their power plant construction projects. It is unclear whether that remains true today. Other proponents of new coal-fired power plants have explained that in recent years (that is, since about 2005) contractors have not been willing to assume the risk that the cost of a multi-year project would escalate significantly and, consequently, have not been willing to fix the price for the entire contract.[20]

A number of other IGCC plants have been proposed but many have been cancelled and, other than Taylorville, the remaining projects have either been formally delayed or are otherwise not moving forward very aggressively. For example, Xcel Energy announced in October 2007 that it was indefinitely deferring its plans to build an IGCC plant in Colorado because the development costs were higher than the utility originally expected.[21] Similarly, Tampa Electric cancelled a proposed IGCC plant in the fall of 2007 due to uncertainty related to CO2 regulations, particularly capture and sequestration issues, and the potential for related project cost increases. According to a press release, "[b]ecause of the economic risk of these factors to customers and investors, Tampa Electric believes it should not proceed with an IGCC project at this time," although it remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation. In addition, the Tondu Corp. announced in June 2007 that it was suspending plans to build a planned 600 MW IGCC facility in Texas citing high costs and other concerns related to technology and construction risks.[22]

In fact, due to cost and technological uncertainties, state regulatory commissions have denied rate recovery for investments in proposed IGCC plants or have refused to allow utilities to enter into a purchase power agreement for the output from a proposed IGCC plant. For example, in August of 2007, the Minnesota Public Utilities Commission refused to require Xcel Energy to enter into an agreement to purchase power from a proposed IGCC plant on the grounds that the terms and conditions of the proposed contract were not consistent with the public interest because they would result in unreasonably high prices for Xcel and unreasonably high rates for Xcel's ratepayers.[23]

Then, in April of 2008, the Virginia State Corporation Commission denied Appalachian Power Company's request to recover costs associated with a proposed IGCC plant from its Virginia ratepayers citing uncertainties of costs, technology, and unknown federal mandates.[24] The

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19 Facility Cost Report at page 24.

20 For example, see the *Consulting Engineer's Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, prepared for the Division of Cleveland Public Power by Burns and Roe Enterprises, Inc., October 2007.

21 Denver Business Journal, October 30, 2007, available at: http://denver.bizjournals.com/denver/stories/2007/10/29/daily26.html

22 http://www.reuters.com/article/companyNewsAndPR/idUSN1526955320070615

23 Order in Docket No. E-6472/M-05-1993, issued on August 30, 2007, at page 17. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={825E0DB0-0D4B-4261-BF18-84643EAC49BD}&documentTitle=4762105.

24 Final Order in Case No. PUE-2007-00068, April 14, 2008. Available at http://scc.virginia.gov/newsrel/e_apfrate_08.aspx.

Commission found that the Company's ("APCo") cost estimate for project was "not credible"—it had not been updated since November 2006.[25]

The Commission also concluded that "… APCo has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in APCo's service territory to assume."[26]

It also noted the uncertainties surrounding federal regulation of carbon emissions and carbon capture and sequestration technology and costs and observed that the Company was asking for a "blank check."[27] On this basis, the Commission concluded that "We cannot ask Virginia ratepayers to bear the enormous costs—and potentially huge costs—of these uncertainties in the context of the specific Application before us."[28]

Tenaska claims that the current KBMD for the overnight construction cost estimate has a level of accuracy of +15%/-10%.[29] It is difficult, if not impossible, to give any credence to such a claim given the significant uncertainties associated with building new coal plants, the fact that Taylorville will be the first-of-a-kind IGCC facility and the substantial cost increases experienced by just about every other coal construction project in recent years (including Duke Energy's Edwardsport IGCC project). If Tenaska wants to proceed with the Taylorville Project, the ICC should require the company to agree that it will not seek recovery of any construction cost investment more than 15 percent above its current construction cost estimate. Then the ICC can determine whether Tenaska really has confidence that the level of accuracy for the overnight construction cost estimate is limited to +15 percent.

Comment No. 8. The results of the Pace Rate Impact Analysis are heavily biased by the assumption that the Taylorville plant will achieve high annual capacity factors which, in turn, is dependent upon (1) the technology performing as well as Tenaska now claims and (2)Tenaska obtaining 'must run' status for the units for a significant portion of the year. If the units are not designed "must run" as Tenaska has assumed and/or if it is not economic to sell SYN produced at the plant into the natural gas market, the rate impact of Taylorville will be substantially higher than Tenaska has projected because the same fixed costs will have to be recovered over a smaller number of megawatt hours ("MWh") of output.

The Pace Rate Impact Analysis modeled a significant share of Taylorville's capacity as having "must-run status," indicating power generation output at full availability of one gas turbine and associated steam turbine. The remaining capacity, associated with the second gas turbine, was modeled with must-run status during peak hours and all hours between June 15 and September 15, but simulated to dispatch competitively in the spot power market during other times.[30]

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[25] Id, at pages 4 to 5.
[26] Id, at page 5.
[27] Id, at page 10.
[28] Id, at page 10.
[29] Facility Cost Report, at page 25.
[30] Pace Rate Impact Analysis, Exhibit 10.0, at page 2.

According to Pace, these parameters were provided by Tenaska based on initial commercial negotiations— but no explanation or justification was provided.

The Rate Impact Analysis also modeled the Taylorville plant as achieving a 92 percent availability. This is a very optimistic assumption for what will be a first-of-its-kind plant with a new mix of technology operating at large electric generating scale for large periods of each year.

Both of these were key assumptions for the Rate Impact Analysis. As a result, the analysis reflected that the Taylorville would operate at a high, 75 percent, average annual capacity factor. The lower the plant's capacity factor, the fewer MWhs of electricity it would be assumed to be generated. This would mean that the very high capital costs of building and financing the plant would have to be spread over fewer units of output. As a result, the price of power from the plant on a per kilowatt hour basis would increase as the capacity factor decreased.

Just how significant an assumption this was can be seen from the levelized cost study presented in the Rate Impact Analysis where Pace assumed that a new gas-fired combined cycle unit would operate at an average 15-22 percent annual capacity factor under reference case assumptions and between 25 percent and 50 percent average annual capacity factors under the three other "states of the world" examined by Pace.[31] This is a very pessimistic assumption for the operating performance of new natural gas-fired combined units and puts the gas-fired plant at a significant disadvantage in an economic comparison with Taylorville. A more appropriate "apples-to-apples" levelized cost comparison would have assumed a higher average annual capacity factor (*e.g.*, in the range of 60 percent to 70 percent) for the gas-fired plant.

Tenaska tells us that the Pace analysis assumed that, unlike Taylorville, the new combined cycle unit would not have "must-run" status and thus would be assumed to be dispatched competitively in the spot power market throughout the year. The per kilowatt hour price of power from Taylorville would be significantly higher if that plant were assumed to have only a 25 percent to 50 percent capacity factor, let alone an even lower 15 percent capacity factor.

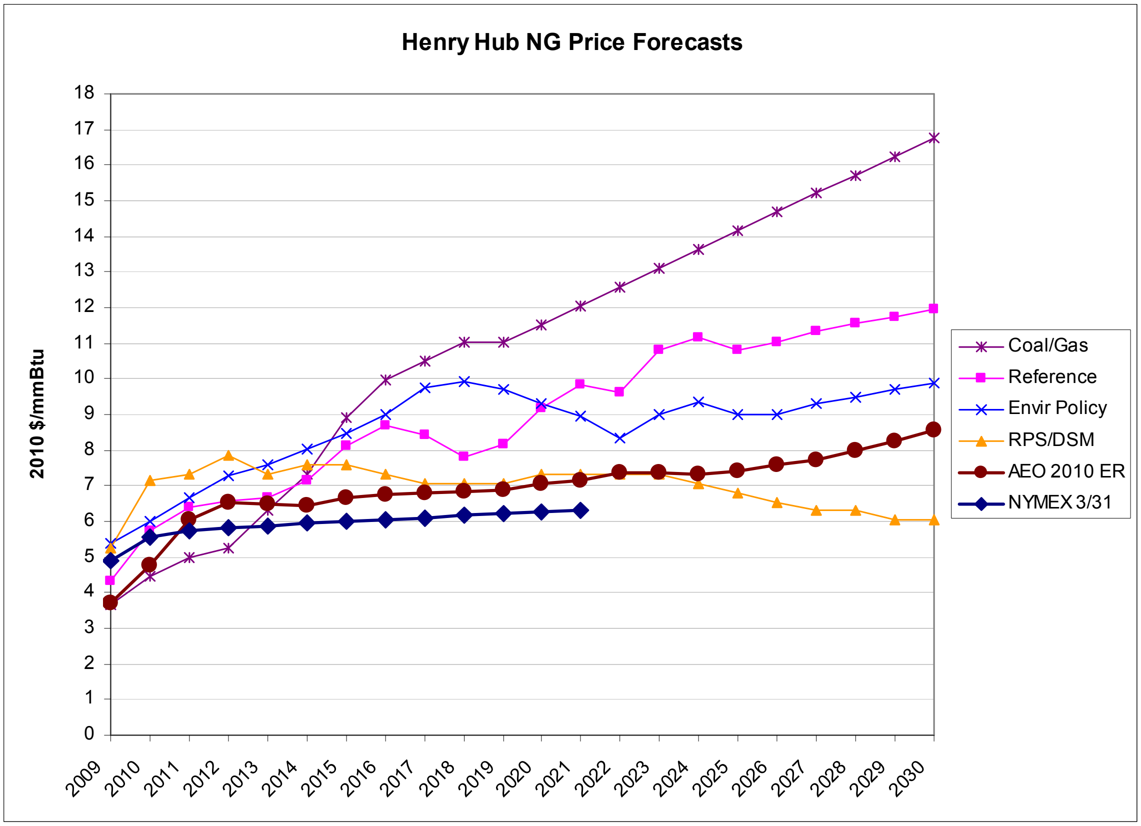
Similarly, the Tenaska Secondary CO_2 Emissions Analysis examined how effective a new natural gas-fired combined cycle plant would be in reducing total CO_2 emissions. This analysis presumably also assumed that the new combined cycle unit was not 'must-run' and instead would be dispatched competitively in the spot power market. As a result, the projected capacity factor for this new combined cycle unit was only 11 percent, much lower than the assumed 78 percent capacity factor assumed for the Taylorville plant.[32] This suggests that Taylorville's annual capacity factor would be significantly lower and its cost of power dramatically higher if it too were assumed to be dispatched competitive in the power market instead of being afforded the benefit of "must-run" status.

Comment No. 9. The Pace Rate Impact Analysis is distorted by the assumption of high natural gas prices.

As can be seen in the following figure, the natural gas prices assumed in three of the four scenarios modeled by Pace ("states of the world") are higher than current NYMEX future prices through 2022 and the most recent long-term price forecast from the Energy Information Administration ("EIA") of the U.S. Department of Energy. In two of the four scenarios,

31 Id, Exhibit 33, at page 37.
32 Exhibit 12.0, at page 4.

"Reference" and "Coal/Gas," the natural gas prices are significantly higher than the current NYMEX prices and EIA forecast.



The lower NYMEX and EIA gas price forecasts are based on new estimates of domestic U.S. natural gas reserves. These increased natural gas supplies can be expected to exert downward pressure on gas prices as shown by the significantly lower NYMEX futures prices in the above figure.

Indeed, Entergy Corporation has described these new supplies of natural gas as a structural change in the natural gas market. This structural change has two important impacts on the resource planning for companies like Mississippi Power. First, as a result of the existing and expected supply glut, current and projected prices of natural gas have been reduced. At the same time, the dramatically larger domestic supplies of natural gas should be able to accommodate any increased demands from any fuel switching due to federal regulation of greenhouse gas emissions without causing significant increases in natural gas prices.

The structural change in the natural gas markets already has had a significant impact on utilities' resource planning. For example, in early April of this year, Entergy Louisiana informed the Louisiana Public Service Commission of its intent to defer (and perhaps cancel) the proposed retirement of an existing gas-fired power plant and its replacement by a new coal-fired unit. Entergy explained that it no longer believed that a new coal plant would provide economic benefits for its customers due to its current expectation that future gas prices would be much lower than previously anticipated:

Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.[33]

4. Recent Natural Gas Developments

Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $131.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.

* * * *

However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas"—so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract—emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. **The recent success of non-conventional gas exploration techniques (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run….**

* * * *

Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels

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33 *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6-8.

> for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods…[34] [Emphasis added]

Entergy's conclusion that there has been a seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the American Gas Association and an independent organization of natural gas experts known as the Potential Gas Committee, the authority on gas supplies. This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[35]

A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to Boom" similarly reported that huge new gas fields have been found in Louisiana, Texas, Arkansas, and Pennsylvania and cited one industry-backed study as estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of current natural gas-demand.[36] It further noted that

> Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
>
> But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand.[37]

The use of high assumed natural gas prices influences the Pace Rate Impact Analysis in several ways, all of which bias that analysis in favor of the proposed Taylorville plant:

- Higher gas prices inflate the cost of power from gas-fired power plants, thereby, improving the relative economics of the Taylorville Energy Center; and
- The higher gas prices also inflate the projected revenues that Tenaska assumes it will receive from the sale of SYN into the market.

Comment No. 10. The Facility Cost Report significantly understates the potential for higher coal prices.

The Taylorville Facility Cost Report contains a *Delivered Price of Coal* study prepared by Wood Mackenzie, who was retained to prepare a 30 year forecast of the delivered price of coal, inclusive of the Illinois Fuel Use Tax for the Taylorville Energy Center (TEC). The plant is required to use coal mined in Illinois for the project period 2015 to 2045. It is expected to consume high sulfur coal at a rate of 2.1 and 2.4 million short tons per year.

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34 Id, at pages 17, 18 and 22.

35 *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009. Available at: http://www.nytimes.com/2009/06/18/business/energy-environment/18gas.html.

36 Available at http://online.wsj.com/article/SB124104598912705 85.html.

37 Id.

The Wood Mackenzie analysis concludes that:

> U.S. power generators are adding environmental equipment to coal plants in response to increasingly stringent emission regulation and the use of this new equipment is having the effect of increasing demand for the higher sulfur Illinois coal. The abundant, accessible and easily mineable Illinois coal supply is expanding to meet this increasing demand. No shortage of Illinois coal is expected over the forecast period from 2015 through 2045. With no looming supply shortage, there is little upward pressure on coal price beyond that normally associated with the cost of mining.[38]

Wood Mackenzie also concludes that:

> While it is possible to determine the expected least cost of coal to TEC from all the sources available to the plant over time, reason and prudence dictate that forecasting a delivered price at TEC should be done by basing the forecast upon the average delivered price of a group of coal sources. The forecast delivered price at TEC is defined as the lowest average delivered price at TEC from one of six subdivisions that represent geographical mining areas of the State of Illinois. The least cost coal, fully evaluated for energy content, sulfur and transportation, is derived from Subdivision 3 (West-Central Illinois). Mining Subdivision 3 (West-Central Illinois) is the mining region geographically closest to TEC wherein transportation costs from mine to TEC will be lower than from other regions.[39]

The Wood Mackenzie total forecast and projection of coal suitable for TEC (Exhibit 14) shows relatively flat production from 2015 through 2018, with a sharp increase through 2023, relatively flat production through 2032, followed by an increase in annual average production levels of almost 20 million tons per ton.

The Wood Mackenzie analysis understates the potential for a supply shortage driven by intensified demand

The Wood Mackenzie analysis makes only passing reference to the rapid depletion of Central Appalachia as an alternative source of low/medium sulfur, high energy content thermal coal. A recent investor analysis by Arch Coal (a leading owner of both CAPP and ILB coal) shows that the 2008-2010 drop-off in CAPP production to be the "largest fall-off in production yet". And, this production decrease is viewed as permanent.[40] Massey Energy, the dominant coal player in the CAPP region, has adopted an aggressive strategy for its remaining reserves as an exporter for the global steel industry.[41] Its assessment of both the domestic and international steel markets and the remaining use of its thermal reserves in the domestic markets is summarized in a recent

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38 *Exhibit 6.0, The Delivered Price of Coal to the Taylorville Energy Center*, at page 8 of 64.

39 Id.

40 Arch Coal, Inc, *Investor Presentation,* March 2010, p. 12. The analysis shows a 70 million drop-off in production and sees this kind of reduction in the historical context as a precursor to a period of sharp price increases. Available at: http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MzcyNjExfENoaWxkSUQ9MzcwMDU0fFR5cGU9MQ==&t=1.

41 Don Blankenship, Chairman and CEO, Massey Energy, *Steel Demand Globally and in the U.S.,* "Go East Young Man, Go East," Slide 2, Coaltrans Americas Conference, January 28, 2010.

investor presentation: "As CAPP depletion, over-regulation and consolidation continue, causing regional production to decline Massey's reserves and production become increasingly more valuable, not less."[42]

The view among utilities that CAPP coal is becoming scarce and more expensive is well known. Utility consumers with historic business relations with CAPP producers are switching to the ILB, and others are looking. Recently, Santee Cooper made market news by settling a deal for a reported 2 million tons per year out of the ILB.[43] Additional utilities currently entertaining deals are Progress Energy, Duke Energy and Southern Company. American Electric Power has also announced its intention of procuring an initial contract of 150,000 tons per month from the ILB (with options for 2 million tons per year for three to five years).[44]

Industry analysts see significant current price differentials between ILB and CAPP coal, and basic market strategies of CAPP owners moving toward the higher end European, Asian and South American met markets in the long term. Even with the relative high sulfur content of ILB coal, the market activity is now. The intention is for long term relationships for coal with qualities that is found in the ILB, and with the dwindling supply from the CAPP region the ILB rises to relative dominance. The risk of price increases in such a climate seems apparent, notwithstanding the statement by Wood Mackenzie that TEC operators can expect "little upward price pressure."

Wood Mackenzie understates the potential for significantly higher mining costs in the region.

Although Wood Mackenzie states that it accounts for mining costs, its overall characterization of the climate for mining in the ILB is at variance with mine owners and detailed federal analysis. The risk is that mining costs may rise beyond those typically considered within the "norm."

For example, Wood Mackenzie says that "Illinois coal is usually easily mined from stable geologies and has high energy content…" Although the United States Geological Survey does characterize the Illinois Basin as a mature mining region with high production costs,[45] Arch Coal's recent investor analysis identifies several production challenges in the ILB: higher mining costs than the PRB, capital investments that are significant, long lead time for permits, and difficult geology in some areas.[46]

Moreover, unlike the PRB Gillette minefields, the ILB has not yet been the subject of an intensive USGS review with regard to stated coal reserves. When such a review of the Gillette minefields was conducted, cost of production considerations substantially reduced the

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42 Massey Energy, *Raymond James 31st Annual Institutional Investors Conference, March 9, 2010.*

43 The deal received extensive coverage in Coal and Energy Price Report, *Market Commentary,* March 19 and 30, 2010.

44 *American Electric Power: American Electric Power Seeks Bids for Coal,* Trading Markets.com, March 23, 2010. Available at: http://www.tradingmarkets.com/news/press-release/aep_american-electric-power-american-electric-power-seeks-bids-for-coal-865577.html.

45 United States Geological Survey, *Coal Resource Availability, Recoverability and Economic Evaluations in the United States—A Summary,* The National Coal Resource Assessment Overview, U.S. Geological Survey Professional Paper 1625-F. Available at: http://pubs.usgs.gov/pp/1625f/downloads/ChapterD.pdf.

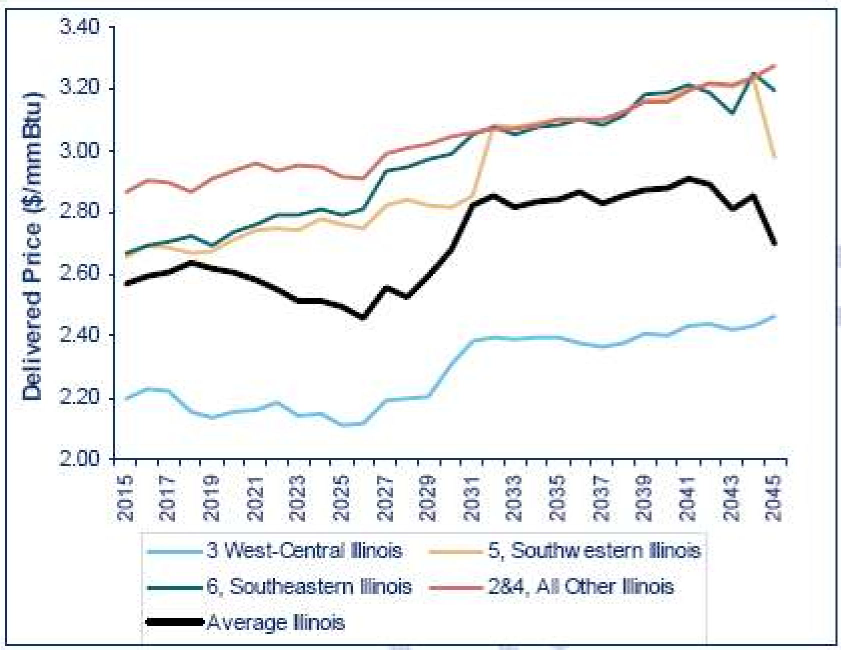
46 Arch Coal, *Op Cit*

economically recoverable reserve figures.[47] If aggressive mining was to take place in the ILB, as Wood Mackenzie anticipates, the price of coal might have to rise precipitously to cover both the higher costs of production and a rate of return sufficient to satisfy investors.

The price of coal will be significantly higher if TEC is unable to purchase coal from Subdivision 3 and/or that supply is disrupted for any reason.

As shown in Exhibit 63 from the Wood Mackenzie Report (Exhibit 6.0 to the Facility Cost Report), the delivered price of coal at TEC would be significantly lower in Subdivision 3 than from the other Subdivisions in the State of Illinois.

Exhibit 63 – Delivered Price of Coal at TEC from All Subdivisions in Illinois, Graph, 2009 $/mmBtu



Consequently, the price of the coal used at TEC could be substantially higher is assumed in the Facility Cost Report, and the supporting Pace Rate Impact Analysis, if the plant is not able to obtain all of its supply from Subdivision 3 and/or if that supply is disrupted for any significant period of time. In fact, as shown in Exhibit 63 from the Wood Mackenzie report, in any particular year, the delivered price of coal from other Subdivisions in Illinois could be between 20 percent and 33 percent higher than the delivered price of coal assumed in the Facility Cost Report and Pace Rate Impact Analysis.

47 United States Geological Survey, *Assessment of Coal Geology, Resources and Reserves in the Gillette Coalfield, Powder River Basin, Wyoming:* Open-File Report 2008-1202. Available at: http://pubs.usgs.gov/of/2008/1202/.

Comment No. 11. The Facility Cost Report is not persuasive in its claim that the proposed Taylorville Energy Center will capture more than 50 percent of the CO_2 that would otherwise be emitted.

The Facility Cost Report says that the Taylorville plant is "expected to capture 1.9 [million metric] tons which is more than 50% of the CO2 that would otherwise be emitted at the facility."[48] In other words, according to Tenaska, the emissions of CO_2 from the Power Island will be the same as the emissions from a similarly sized, highly efficient natural gas power plant.[49]

However, it is not clear from the Facility Cost Report on what basis Tenaska has reached these conclusions. Moreover, it appears that Tenaska has not considered either (a) the CO_2 that would be emitted by the trucks that would be needed to bring the roughly 2.1 to 2.4 million tons of coal that would be processed at Taylorville each year[50] or (b) the CO_2 that would be emitted by the SYN gas that Tenaska plans to sell into the market.

Comment No. 12. Tenaska assumes a very low cost for sequestering the CO_2 from the Taylorville Energy Center.

Tenaska assumes a very low cost for sequestering the CO2 that would otherwise be emitted by the Taylorville plant. This low cost is based on the following conclusion of the Schlumberger analysis that is presented in Exhibit 13.2.b. of the Facility Cost Report:

> Schlumberger found that based on its evaluation and understanding of Project requirements – including pending regulation – costs for *typical* carbon storage projects are likely to be in the range of $5.00 to $10.00/MT of CO_2 stored over the life of the field. However, Schlumberger found the TEC's estimated costs to be lower than this range due to the very favorable geologic setting of the Mt. Simon formation, the assumptions concerning Project requirements, and other conditions for CO_2 injection specific to the TEC.[51] [Emphasis in original]

However, there are no *typical* carbon storage projects operating in the United States so there is no actual experiential basis for the $5.00 to $10.00 per metric tonne cost range identified by Schlumberger. Moreover, given the extremely uncertain nature of future carbon storage practices and costs, it would have been better for Tenaska and Pace to have assumed a wider and higher range of carbon storage prices in the Rate Impact Analysis than the single price they assumed.

Comment No. 13. The rate impact analyses presented by Tenaska and Pace that assume a 92 percent capacity factor for the Taylorville Energy Center are unrealistic.

The Facility Cost and Report and the Pace Rate Impact Analysis present the results of a scenario in which it was assumed that the proposed Taylorville plant would operate at a 92 percent average annual capacity factor.[52] However, there is no reasonable expectation that the new Taylorville plant, with its first-of-a-kind mix of technology operating at electric generation scale,

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48 Facility Cost Report, at page 17.
49 Id, at page 76.
50 Id, at page 18.
51 Id, at page 79.
52 For example, see pages 13, 74 and 75 of the Facility Cost Report.

could operate at such an extremely high level over an entire 30 year period. Even less complicated, new natural gas-fired combined cycle plants are not expected to operate at 92 percent average annual capacity factors. Therefore, the results presented by Tenaska and Pace that are based on an assumed 92 percent capacity factor are completely unrealistic and have no probative value.

Comment No. 14. It appears that the Tenaska Secondary CO_2 Emissions Analysis may significantly overstate the overall reductions in regional CO_2 emissions that would be attributable to the proposed Taylorville Energy Center.

We have not received the workpapers for the Tenaska Secondary CO_2 Emissions Analysis (Exhibit 12.0 to the Facility Cost Report). Therefore, it is impossible to conduct a detailed evaluation of that analysis. However, the results appear to overstate the overall reductions in regional CO_2 emissions that would be attributable to the Taylorville plant.

First, the analysis does not appear to account for the expectation that some, perhaps, many, of the regions existing coal plants will be displaced or retired over the coming decades, even without Taylorville, as a result of the increasing stringency of federal and state air emissions requirements and/or low natural gas prices. Thus, many of the CO_2 emissions reductions that Tenaska claims for Taylorville, can be expected to happen even if the proposed IGCC plant is not built.

Second, as noted above, Tenaska has assumed unreasonably low heat rates for the Taylorville plant. The use of more correct, that is, higher, heat rates would suggest that Taylorville may not displace as many older, more inefficient gas and coal plants as the Tenaska Secondary CO_2 Emissions Analysis has assumed.

Third, it is reasonable to expect that other new generating units will be built in the region in the coming years. They too can be expected to displace generation at, and hence, CO_2 emissions from, existing coal-fired power plants in the region. Again, these reductions in CO_2 emissions can be expected to occur even if the proposed Taylorville plant is not built.

Moreover, it is entirely possible that additional generation at existing natural gas-fired combined cycle units in Illinois could provide a lower cost option for reducing regional CO_2 emissions. As shown in the following table based on 2008 data reported in the U.S. Environmental Protection Agency's Clean Air Markets Database, the existing combined cycle units in the state are operating at very low capacity factors. Increasing the generation at these facilities can be expected to displace significant generation at existing coal-fired units without requiring a three billion dollar investment in a new generating unit.

Unit	County	Unit Type Info	Max Capacity (MW)	Generation in 2008 (MWh)	Capacity Factor
Grand Tower	Jackson	Combined Cycle	244	40,641	1.9%
Grand Tower	Jackson	Combined Cycle	246	45,971	2.1%
Exxonmobil Oil Corporation	Will	Combined Cycle	21	12,301	6.7%
Kendall Energy Facility	Kendall	Combined Cycle	307	211,016	7.8%
Kendall Energy Facility	Kendall	Combined Cycle	309	244,445	9.0%
Kendall Energy Facility	Kendall	Combined Cycle	314	166,569	6.1%
Kendall Energy Facility	Kendall	Combined Cycle	316	445,741	16.1%
Cordova Energy Company	Rock Island	Combined Cycle	281	73,961	3.0%
Cordova Energy Company	Rock Island	Combined Cycle	285	80,238	3.2%
Morris Cogeneration, LLC	Grundy	Combined Cycle	92	137,960	17.1%
Morris Cogeneration, LLC	Grundy	Combined Cycle	95	71,467	8.6%
Morris Cogeneration, LLC	Grundy	Combined Cycle	93	80,484	9.9%
Holland Energy Facility	Shelby	Combined Cycle	338	90,370	3.1%
Holland Energy Facility	Shelby	Combined Cycle	338	106,195	3.6%

Comment No. 15. It appears that the Pace Market Price Analysis may significantly overstate the overall market cost savings that would be attributable to the proposed Taylorville Energy Center.

We have not received the workpapers for the Pace Rate Impact Analysis (Exhibit 10.0 to the Facility Cost Report). Therefore, it is impossible to conduct a detailed evaluation of any portion of that analysis, including Tenaska's claim that the proposed Taylorville plant would lead to lower regional market energy and capacity prices. However, several factors suggest that the results of the analyses overstate the overall reductions in regional energy and capacity prices that would be attributable to the Taylorville plant.

First, as noted above, the unreasonably low heat rates assumed for the Taylorville Energy Project will reduce its expect operating costs, inflate its expected operating performance and, consequently, improve its impact on regional prices.

Second, new energy efficiency and new renewable resources also will work to reduce regional energy and capacity prices and perhaps at a lower cost than Taylorville. These alternatives should have been modeled as part of alternative resource portfolios to the proposed Taylorville plant.[53]

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53 In fact, although we have not had an opportunity to review the workpapers for the Rate Impact Analysis, it appears that Pace has modeled only very low levels of energy efficiency savings (in both MW and MWh).

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CLEAN AIR TASK FORCE

Mr. Manuel Flores, Acting Chairman
Illinois Commerce Commission
527 East Capitol Avenue
Springfield, IL 62701

April 16, 2010

Re: Taylorville Energy Center Facility Cost Report

Dear Mr. Flores:

The Clean Air Task Force (CATF) is pleased to submit these comments to Illinois Commerce Commission (ICC) in the matter of the Tenaska's submission of the Taylorville Energy Center Facility Cost Report. The Taylorville Energy Center (TEC) will produce substitute natural gas (SNG) from gasified coal, capture and sequester the carbon dioxide (CO_2) from the gasification process, and produce electricity by burning the SNG in a combined cycle natural gas plant. Overall, the CO_2 emissions from the project represent at least a 50% reduction from a traditional coal-fired power plant.

CATF is a non-profit organization dedicated to reducing atmospheric pollution through research, legal advocacy, and private sector collaboration. We have offices in Boston, Massachusetts, Washington, D.C., around the Midwestern and Northeastern United States, and in Beijing, China. We receive no funding from either industry or government.

CATF supports the development of the pioneering Taylorville Energy Center project because it transitions energy generation from coal to much lower CO_2 impacts. The project uses proven SNG technology with carbon capture and sequestration in conjunction with a natural gas combined cycle plant. As described below, advancing these kinds of projects is essential to our country's ability to combat climate change.

The United States Environmental Protection Agency has determined that CO_2 emissions and other greenhouse gases endanger public health and welfare in the United States, and that "the body of scientific evidence compellingly supports this finding."[1] According to the United States Department of Energy ("DOE"), energy sector CO_2 emissions world-wide will total some 31 billion metric tons this year, of which 13 billion metric tons will come from coal utilization, the majority of it from electric power plants.[2] China alone has built close to the equivalent of the entire

[1] See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule, 74 Fed. Reg. 66,496, 66,497-66,499 (Dec. 15, 2009).
[2] DOE/EIA International Energy Outlook 2009, Tables A10, A13 and F1.

United States coal power plant fleet in the past several years, and is expected to add many hundreds more coal power plants in the next two decades.[3]

Carbon capture and sequestration technology allows the removal of CO_2 from a power plant before it is emitted to the atmosphere (termed "CO_2 capture") and the injection of the CO_2 into appropriate geologic formations, where it is expected to remain indefinitely.[4] Building coal plants with carbon capture and sequestration is critical to achieving significant reductions from coal's CO_2 emissions.

CATF's technical staff has reviewed TEC's Facility Cost Report, and we offer the following comments:

- In general, we conclude that design of TEC is based on proven technology and the selection of Siemens gasifiers, turbines, Air Liquide Lurgi syngas processing technology and other features that are both reasonable and prudent.

- We conclude, based upon the reports provided, that the FEED package is similar to FEED packages typically developed for projects of this complexity. It is as detailed as what other utilities develop for CPCN determinations before state regulatory commissions. The public versions of these reports, however, do not contain detailed data on plant performance, heat and material balances, and operating modes using in the economic analysis. We hope that you have received these important details have been provided to the ICC as confidential information for your review, and if not, we suggest you ask for them.

- Without access to the confidential details of the Facility Cost Report, it is not possible for CATF to offer detailed opinions on each cost category, but we make the following general observations and urge the ICC to give careful consideration to the following areas:

    - Cost escalation seems low based on the rates discussed in the report.
    - Although the owner's contingency is expected to be about 10%, no detailed explanations are provided.
    - Financing costs are high and not explained, but much cost could be capitalized interest.

[3] DOE/EIA International Energy Outlook 2009, Table H4 and DOE/IEA International Energy Outlook 2007, Table H4.
[4] According to the Intergovernmental Panel on Climate Change ("IPCC"): "For large-scale operational CO_2 storage projects, assuming sites are well selected, designed, operated and appropriately monitored, the balance of available evidence suggests the following: It is very likely the fraction of stored CO_2 retained is more than 99% over the first 100 years; It is likely the fraction of stored CO_2 retained is more than 99% over the first 1000 years". IPCC Special Report on Carbon Dioxide Capture and Storage, page 246.

- Capitalized start-up costs (which could cover a six-month or more start up period) are not itemized. This raises concerns about how start-up risks are addressed.

In summary, we urge the ICC to consider the unique role that TEC can play in advancing the public interest by addressing climate concerns through carbon capture and sequestration. We believe that cost risks exist in a project of this scale and complexity, but that these risks can be satisfactorily addressed. We urge the ICC to give a favorable recommendation to the General Assembly concerning TEC, and hope that it can begin construction on an early schedule.

Sincerely,

John Thompson
Director, Coal Transition Project

<u>Comments of the STOP Coalition</u>
<u>on the Taylorville Energy Center Facility Cost Report</u>

INTRODUCTION

In response to the information presented in Taylorville Energy Center's ("TEC") Facility Cost Report ("Cost Report"), a broad-based and diverse group of businesses, energy suppliers, and some of the most prominent trade associations in the State of Illinois have come together to form the Stop Tenaska's Overpriced Power ("STOP") Coalition. We respectfully submit these Comments to the Illinois Commerce Commission ("Commission") for consideration as the Commission and its experts prepare the analysis of the Cost Report as statutorily required by the Illinois General Assembly.

The companies and organizations that form the STOP Coalition include:

- The Building Owners and Managers Association of Chicago – BOMA Chicago
- The Chicagoland Chamber of Commerce
- The Chemical Industry Council of Illinois
- The Illinois Competitive Energy Association
- The Illinois Industrial Energy Consumers
- The Illinois Manufacturers' Association
- The Illinois Retail Merchants Association
- The Illinois State Chamber of Commerce
- Mid-American Energy Company's Unregulated Retail Services Division
- PROactive Strategies, Inc.

The STOP Coalition members have participated actively in the regulatory and legislative process in matters related to Illinois' competitive electric market. They represent alternative retail electric suppliers ("ARES") and their end-use customers who will be directly impacted by any decision of the Illinois General Assembly mandating ARES to enter into long-term, above-market contracts such as those proposed by the developers of TEC.

To independently assess the impact of approving Tenaska's proposal to mandate long-term purchases of energy from the TEC, the STOP Coalition commissioned Dr. Mat Morey of the nationally renowned economic and engineering consulting firm, Christensen Associates Energy Consulting ("Christensen Associates"), to prepare a comprehensive analysis and study of the TEC Cost Report. A copy of that detailed analysis is attached hereto as Exhibit A. As discussed below, Dr. Morey's analysis reveals serious and significant flaws in the TEC Cost Report, which underestimate the massive adverse electric rate impact of TEC on Illinois consumers, the Illinois economy, and the Illinois environment.

BACKGROUND

As the Commission is aware, the Illinois General Assembly has mandated that ARES and electric utilities enter into long-term power purchase agreements ("PPAs") of up to 30 years, to purchase the output of the proposed TEC if the General Assembly approves the plant. A mandate to require ARES to purchase power over a period of 30 years from a specific power plant is unprecedented. It runs contrary to market-based principles where retail electric suppliers procure power to secure the lowest possible costs for their customers

Because of its serious concerns about the adverse impact of the mandated PPAs on residential and small business customers, however, the General Assembly has also provided that the PPAs with the TEC will not take effect until it approves them in a new statute.[1]

Further, the Illinois statute caps the amount of TEC energy Illinois utilities must buy for their "eligible retail customers" (i.e., their residential and small commercial customers) at an amount that will increase their rates by no more than 2.015% per year.[2] Unfortunately, however, the statute provides no such cost cap protection for ARES' customers. On the contrary, all of the ARES must buy the entire remainder of the output under PPAs, no matter how much it would increase charges to their customers, such as schools, government agencies, hospitals, businesses, and manufacturers, and no matter how much above market those charges are. ARES provide more than half of all electricity consumed in Illinois and serve over 74 percent of non-residential electric load.[3] The state's largest commercial and industrial customers procure 97 percent of their electricity from ARES.[4] ARES provide more than half of all electricity consumed in Illinois and serve over 74 percent of non-residential electric load.[5] The state's largest commercial and industrial customers procure 97 percent of their electricity from ARES.[6]

The stark disparity between the TEC purchase obligations of the utilities and the ARES is significant, both in terms of its inequity and in actual dollar impact, resulting in both a disproportionate impact on ARES' customers and potentially irreparable harm to the competitive

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[1] 29 ILCS 3855/1-75(d)(4)(iii).
[2] The statute limits the average net increase for utility customers to "2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009. . ." 20 ILCS 3855/1-75(d)(2).
[3] Office of Retail Market Development, Illinois Commerce Commission, Annual Report, July 1, 2009 at 4-7.
[4] Retail and Wholesale Competition in the Illinois Electric Industry: Fourth Triennial Report, Illinois Commerce Commission, November 13, 2009 at 2-5, 16-17, 23-25.
[5] Office of Retail Market Development, Illinois Commerce Commission, Annual Report, July 1, 2009 at 4-7.
[6] Retail and Wholesale Competition in the Illinois Electric Industry: Fourth Triennial Report, Illinois Commerce Commission, November 13, 2009 at 2-5, 16-17, 23-25.

electric market in Illinois. These are the primary reasons that this diverse and broad-based group is devoting considerable resources towards this critical issue.

The inequality of the Illinois statute aside, it is necessary to understand the statute to see how the Illinois General Assembly will impact the ratemaking process.

EXPERT ANALYSIS FROM CHRISTENSEN ASSOCIATES

As discussed in detail in Dr. Morey's analysis, the relative impact of TEC on electric rates will be much greater than assumed in the TEC Cost Report. Flawed and unsupported assumptions in the report also make it very likely that the costs for TEC energy will likely be much higher than estimated. As a result, the eligible retail customer cap will be reached and a much larger proportion of TEC's overall above-market costs will be borne by manufacturers, retail establishments, small and medium-sized businesses, schools, hospitals, religious institutions, and units of government – the vital businesses and organizations that fuel Illinois' economy. Specifically, in his analysis, Dr. Morey identifies:

- TEC, as projected in its own Cost Report, will cost consumers **several hundreds of millions** of dollars more each year for electricity than what they would pay for electricity from other available sources.
- This terrible business burden could constrain new employment growth, resulting in a potential **annual average loss of 15,000 to 35,000 jobs for decades,** with devastating impacts to the Illinois economy through loss of earnings and income tax revenues.
- Far more realistic, yet still conservative, estimates of TEC's costs show consumers could **pay $100 million more annually in addition to the excessively high costs**

projected by the Cost Report, as noted above. And, this is before even considering the risk of failure to sequester the required CO_2.

- If TEC were unable to deliver its captured CO_2 through the yet-to-be-built and troubled Denbury pipeline project, or store it underground on-site, those **costs will increase yet an additional $137 million per year on average for 30 years**.
- The supposed **environmental benefits** of TEC are highly **speculative** at best. The proposed pipeline is in grave legislative trouble and underground storage of CO_2 is controversial and as yet unproven.

A. TEC Will Result in Significant Electric Rate Increases for Illinois' Electric Customers

According to Dr. Morey's analysis, the TEC project could increase Illinois customers' rates substantially more than estimated by the Cost Report. The Cost Report concludes that even if TEC were built on time and on budget (a highly unlikely scenario for an unproven technology) the project could still cost Illinois electricity customers an average of $386 million more per year, for the first thirty years of TEC's life, over power from other resources. However, in the far more likely scenario, if the costs of building and operating TEC are higher than expected, and if certain revenues are lower than the Cost Report forecasts, Illinois electricity customers could plausibly **pay an <u>additional</u> $100 million per year over the thirty years** above and beyond what the Cost Report projects under certain scenarios.

Incredibly, it could get significantly worse for Illinois consumers. The Cost Report itself states that in the event that TEC were unable to store its captured CO_2 either by delivering it through the proposed Denbury pipeline or by storing it in its own storage field, it could cost consumers an additional $137 million per year on average over 30 years, above and beyond what

Pace projected.[7] This is not an unlikely scenario as the Denbury pipeline has faced serious legislative challenges in Kentucky and Indiana and underground storage of CO_2 is controversial and its large-scale feasibility is as yet unproven.

So even if TEC were able to provide its promised CO_2-reduction benefits Illinois customers will pay $292 million to $396 million in extra costs per year over and above what they would otherwise pay for electricity. Of that above-market amount, residential and small commercial customers are guaranteed to pay an average of $152 million per year regardless of future uncertainties. The remaining $140 million to $244 million of this annual burden will be imposed on all others consumers -- businesses and other entities that provide jobs and services vital to the Illinois economy. This burden on business will result in a potential **annual average loss of about 15,000 to 16,000 jobs (and the earnings, and income tax revenues that go with them) for decades**.

Even using the Cost Report's conservative and self-serving assumptions, the electric rate impacts on Illinois consumers are significant. But the reality is the Cost Report's numerous flawed assumptions in fact mask the actual rate impacts on Illinois' consumers. The Cost Report not only relies on assumptions that are more favorable to TEC than they are realistic but also conveniently ignores uncertainties that have major impacts on Illinois rates, including core plant capital costs, interest rates, construction costs, fuel costs, and revenue offsets. When these uncertainties are appropriately considered, far worse rate impacts become highly plausible. For example, if TEC can neither deliver its CO_2 to the proposed Denbury pipeline (a project that appears to be near death or at best on "life support") nor sequester it "on-site", WorleyParsons, one of TEC's own consultants, finds that the average additional per-year costs are **$137 million**

[7] *See* Cost Report, pp. 81-82.

annually over the entire 30-year period – a whopping $4.1 billion increase over the life of the project.

Furthermore, the Cost Report has other flaws that undercut its conclusions, including incorrectly applying the benchmark 2009 rate for residential and small commercial customers to all load served by the utilities and ARES. This had the effect of significantly understating the rate impact on non-eligible customers (i.e., customers served by ARES such as hospitals, schools, government agencies, businesses and manufacturers).

B. TEC's "Green" Benefit Is Speculative At Best

There is no certainty at all about how the CO_2 will be sequestered. First, Illinois depends on the kindness of neighboring states to permit the proposed (and now what appears to be dead) Denbury pipeline to transport 50% of the CO_2 from TEC to somewhere in the Gulf of Mexico. Thus far, Kentucky has refused to adopt necessary legislation to allow the project to move forward and Indiana has likewise failed to enact similar, necessary legislation. The Commission may recall that in testimony before the Senate Energy Committee, TEC representatives said that such a pipeline project would only make sense if three projects of similar size were to be constructed in the region. Such projects are not on the horizon. Second, alternative mechanisms for sequestration of the CO_2 are just as uncertain. Geologic sequestration costs much more than the pipeline, and its feasibility is still unproven. Absent these two options, CO_2 disposal would cost billions of dollars and significantly increase the cost to Illinois' ratepayers.

C. Net Negative Impact on Jobs and the Illinois Economy

Tenaska promises TEC will create temporary and permanent jobs in the region as a result of construction and operation of TEC. It is undeniable that job creation is critical during these challenging times. Unfortunately, the jobs added to construct and operate the plant are not the relevant outcome that needs to be considered. Rather, the net impact to the Illinois economy from forcing consumers and businesses to purchase high cost, above market generation is the real issue that must be scrutinized. And the unavoidable reality is by significantly increasing electric rates, TEC would not add jobs to Illinois but instead would lead to a net job and income loss for Illinois.

The electricity price increases induced by the TEC project will make Illinois a less attractive place to do business, and will reduce business investment and jobs in Illinois. The extent of the job reductions will depend upon size of the increases in commercial and industrial electricity prices. However, even applying the unrealistically low cost increases estimated in the Cost Report itself, Dr. Morey estimates long-term job losses at 15,000 to 16,000 jobs annually for decades. More realistic assumptions would result in even greater job losses.

The WorleyParsons Study completely ignores the *total* impact of the TEC project on the Illinois economy. Instead, the WorleyParsons Study solely focuses on the fact that the TEC project will create a certain number of jobs. While job creation associated with the TEC project is important, it cannot be considered in a vacuum. It is significantly more important to understand that some of those jobs would be created elsewhere in Illinois if TEC were not built, and that the high costs of the TEC project will siphon dollars and jobs from other sectors of the Illinois economy. When all the resulting consequences, both positive and negative are considered, it becomes clear that the TEC project will result **in a net job and income loss** for Illinois.

CONCLUSION

The General Assembly has tasked the Commission with a major responsibility as it relates to the TEC Project – prepare an analysis of the TEC Cost Report so that the members of the General Assembly can determine whether or not Illinois' ratepayers -- individual homeowners, small businesses, retail establishments, schools, hospitals, units of government, and major manufacturers – should be required to finance the construction of the TEC project. We believe that the General Assembly will demonstrate a high degree of deference to and reliance upon the Commission's Analysis.

As summarized above, and detailed in the Dr. Morey's expert analysis, we believe that the TEC Cost Report profoundly misrepresents the true impact to our State. From rate impacts, to job creation benefits, to environmental outcomes, the Cost Report consistently offers flawed assumptions based on implausible scenarios, all clearly designed to put the project in the best possible light before the General Assembly deliberates the issue. This is why we believe it is so important that the Commission carefully review the TEC Cost Report, Other Expert reports, and the Comments of other interested parties as it prepares its Report and Analysis to the General Assembly.

The STOP Coalition knows that the Commission appreciates the gravity of the task at hand and appreciates this opportunity to submit these Comments and Expert Report.

Respectfully submitted,
THE STOP COALITION

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Dated: April 16, 2010

Exhibit A

TAYLORVILLE ENERGY CENTER PROJECT:
ECONOMIC IMPACTS ON
ILLINOIS RETAIL ELECTRICITY RATES AND ECONOMY

prepared by

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Laurence D. Kirsch

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Christensen Associates Energy Consulting LLC

prepared for

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April 16, 2010

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Executive Summary

At the request of the STOP Coalition, Christensen Associates Energy Consulting, LLC assessed the economic study prepared by Pace Global Energy Services (the Pace Study) for the Taylorville Energy Center (TEC) – a proposed hybrid integrated gasification combined cycle power plant. The objective of the assessment was to: a) determine the reasonableness of the retail electricity rate impact estimates provided by the Pace Study; and b) provide preliminary estimates of the impacts of TEC upon the Illinois economy over the period of the rate impact estimates.

Overview of Findings

Based upon our review of the Pace Study and of four companion TEC-sponsored studies, we conclude that the TEC project could increase Illinois customers' rates substantially more than claimed in the Pace Study, and will have a negative net impact on jobs and the Illinois economy.

The Pace Study analyzed the rate impacts of TEC under four distinct cases that varied in their projections for certain assumptions.[8] Under the Pace Study's worst case scenario, the TEC project could cost Illinois electricity customers an average of $386 million more every year, for thirty years, than if they obtained that electricity from other resources.[9] That is a total cost over the 30 years of approximately $11.6 billion. That extraordinary number, if taken on its face, is bad enough. But our analysis suggests that the outcome for Illinois electricity customers may be much worse that $386 million of extra costs every year. When taking into consideration plausible increases in the costs of building and operating the TEC, and plausibly lower revenues than Pace forecasts, the impact could be as much as $100 million **per year** greater than projected by Pace under some scenarios.[10]

Perhaps even more significant, however, is the fact that the Pace Study failed to consider the rate impact of TEC's possible failure to capture and sequester the required CO_2 emissions. According to the WorleyParsons Study, if the TEC plant fails to capture and sequester the required 50% of its CO_2 emissions, the increased cost to Illinois electricity customers would average $137 million per year over the first thirty years of TEC's operations. Thus, TEC's own consultants have identified $4.1 billion of potential costs that Pace did not consider in any of its four rate impact case scenarios. When factoring in the impact of that very real risk, Illinois customers could be required to pay well over $500 million per year for thirty years due to TEC.[11]

[8] *See* Table E-1, which identifies the four Pace case studies as Case Nos. 1-4
[9] See Table E-1, Case No. 4
[10] *See* Table E-1, Case No. 6 and 7
[11] *See* Table E-1 Case No. 8

Regardless of the scenario considered, it is irrefutable that the TEC will substantially increase electricity costs for Illinois customers: every one of Pace's scenarios shows that TEC will increase costs by at least $5 billion over thirty years. The Illinois Clean Coal Portfolio Standard Law (CCPSL) puts a major constraint on how these billions of dollars of extra costs may be recovered from customers. Specifically, CCPSL effectively limits the increases borne by residential and small commercial customers to $152 million per year. That means Illinois' hospitals, government agencies, schools, religious institutions, manufacturers, and businesses vital to the Illinois economy will be saddled with all the remaining above market costs of TEC, which could average as high as $366 million per year for thirty years for those customers.[12] The electricity rate increases induced by the TEC project will make Illinois a less attractive place to do business relative to other states, and will therefore reduce business investment and jobs in Illinois.

While the extent of the job reductions will depend upon the exact size of the increases in commercial and industrial electricity prices, under the Pace Study's own case scenarios – which do not consider the risk of failing to sequester the CO_2 emissions – the increases could result in an average annual loss of about 15,000 to 16,000 jobs for 30 years. Those job losses would bring with them devastating impacts to the Illinois economy through loss of earnings and income tax revenues.

When you add to that the risk that TEC fails to provide any of its promised CO_2-reduction benefits, those costs will increase substantially and could lead to an average loss of between 27,000 and 35,000 jobs a year (along with their associated earnings) over decades.

In short, CCPSL insulates the owner of the TEC plant from that plant's financial and environmental risks; so the worse the plant performs – in its construction, in its operation, and in its environmental benefits – the more that the people and businesses of Illinois will pay in dollars and in jobs.

Detailed Findings

Table E-1 summarizes the average annual dollar impact of TEC over the 30-year period as well as the cumulative dollar cost over that time of the TEC facility. Of the eight cases shown, the first four were developed and estimated by Pace, while the last four were developed and estimated by CA Energy Consulting, though these latter four cases are all based upon the Pace Reference Case.

All figures in Table E-1 are relative to the case in which there is no TEC facility. In Case No. 1 (the Pace Reference Case), for example, TEC will cost Illinois electricity consumers $8.76 billion extra over 30 years relative to what power would have cost without TEC. In Case No. 8 (the Pace Reference Case with higher TEC construction and operating costs and with a failure to sequester CO_2), TEC will cost Illinois electricity consumers $15.53 billion extra over 30 years relative to what power would have cost without TEC. From the table, it is apparent that the TEC plant will cost the people of Illinois at least $5 billion

[12] *See* Table E-1, Case No. 8 which sets forth a total cost of $518 annually, less the $152 attributable to eligible customers.

over and above what they would pay for electricity if the TEC plant were never built; and it may cost the people of Illinois as much as $15 billion over what they would otherwise pay for electricity.

Table E-1
Net Costs of the TEC Project Relative to Alternative Power Resources
(millions of dollars)

Case No.	Case Name	Annual	Total 30 Years
1	Pace Reference	292	8,760
2	Pace Environmental Policy	168	5,052
3	Pace Gas/Coal	249	7,464
4	Pace RPS/DSM	386	11,568
5	WorleyParsons - No CO_2 Capture + Pace Reference	429	12,870
6	Pace Reference + Cost Escalation	381	11,421
7	Pace Reference + Cost Escalation + Revenue Reductions	397	11,895
8	Pace Reference + Cost Escalation + No CO_2 Capture	518	15,534

Table E-2 summarizes the percentage rate impacts of various cases considered in the Pace Study and in this report. In analyzing its four cases, Pace did not consider the rate impacts on eligible customers (ECs) separately from non-eligible customers (Non ECs) and made an error in calculating the percentage rate impact on all customers; so the figures shown for Cases Nos. 1 through 4 are our corrections of Pace's calculation for all customers plus our split between the EC and Non EC groups.

The rate impacts of Table E-2 are all relative to the case in which there is no TEC facility. For all customers, the TEC facility will raise rates by an average of between 1.39% and 4.08% for thirty years or more. For the EC group, CCPSL effectively caps the rate increase at 2.02%. For the Non EC group, the TEC facility will raise rates by at least 1.50% and as much as 7.10%. For both customer groups, these rate increases will persist for thirty years or more.

Table E-2
30-Year Average Percentage Rate Impacts of the TEC Project on Customers

Case No.	Case Name	All Customers	EC Group	Non EC Group
1	Pace Reference	2.30%	2.02%	2.76%
2	Pace Environmental Policy	1.39%	1.31%	1.50%
3	Pace Gas/Coal	1.96%	1.72%	2.33%
4	Pace RPS/DSM	3.12%	2.02%	4.25%

5	WorleyParsons - No CO_2 Capture + Pace Reference	3.38%	2.02%	5.38%
6	Pace Reference + Cost Escalation	3.00%	2.02%	4.45%
7	Pace Reference + Cost Escalation + Revenue Reductions	3.13%	2.02%	4.75%
8	Pace Reference + Cost Escalation + No CO_2 Capture	4.08%	2.02%	7.10%

The question of whether the Illinois legislature should give the green light to TEC hinges on how the plant affects the state economy, including retail electricity rates. The Pace analysis of the rate impacts considered four "states of the world" that varied in their projections of U.S. economic growth rates, carbon control and carbon tax policies, NOx regulations, renewable portfolio standards, energy efficiency and demand-side management policy, and natural gas demand. These factors are entirely outside the control of TEC owners and operators.

Unfortunately, the four states of the world address only some of the uncertainties that impact Illinois' retail electricity rates and the Illinois economy. Pace does not analyze some of the uncertainties that pose significant risks to the people of Illinois, namely those about the ultimate costs to construct and operate the TEC plant as well as those associated with the process of extracting and sequestering CO_2. Our analysis shows that variations in these factors, about which there is substantial uncertainty, have significant impacts on Illinois rates and on the broader Illinois economy. When uncertainties in these factors are appropriately considered, the range of plausible rate impacts includes outcomes that are much more adverse than found by Pace. For example, in the event TEC can neither use its CO_2 for enhanced oil recovery nor sequester it "on-site," the added costs of mitigating the effects of the CO_2 will average $137 million *per year* over a 30-year period, which are costs that are not considered by the Pace analysis.

In addition, the Pace Study presents its rate impact conclusions in a misleading fashion. Specifically, Pace computed the percentage rate impacts by applying the 2009 rate for residential and small commercial customers to all load served by the utilities and alternative retail electric suppliers (ARES) even though CCPSL specifically mandates that eligible customers (e.g., residential and small commercial customers) will be treated differently than non-eligible customers (e.g., customers served by ARES such as hospitals, schools, government agencies, businesses and manufacturers). This has the effect of significantly understating the rate impact on non-eligible customers. When we use Pace's own assumptions to consider the separate rate impacts on eligible and non-eligible customers, it is evident that the latter will bear a significantly larger electricity rate impact relative to 2009 rates – ranging between 3% and 7% for the entire 30-year period.

Another TEC-sponsored study, authored by WorleyParsons, reaches implausible conclusions about the impacts of TEC on the Illinois economy. WorleyParsons finds that the TEC facility will create local jobs and increase local expenditures because it looks only at the jobs required to build and run the TEC plant. It fails to consider the fact that jobs would be created at some other power plant if TEC were not built; and more importantly, it overlooks the impacts of an increase in electricity rates on the broader Illinois economy. The billions of dollars that Illinois electricity customers will pay to the owners of the TEC plant, over and above what they would pay for electricity from other resources, will be billions of dollars that will be drained from the Illinois economy; and this drain will continue for decades. Illinois electricity consumers will have billions fewer dollars to spend on goods and services other than electricity, and so jobs will be destroyed in other sectors of the Illinois economy. Furthermore, the higher electricity rates induced by the TEC plant will dissuade some businesses from investing in Illinois, will induce some businesses to switch some operations and production to other jurisdictions, and will cost jobs. The key flaw of the WorleyParsons study is that it looks at the *gross* impacts of the TEC plant when what really matters to the Illinois economy, and to the people of Illinois, is the *net* impact of that project. The fact that the TEC project will create a certain number of jobs is important; but it is significantly more important to understand that some of those jobs would be created elsewhere if TEC is not built, and that the high costs of the TEC project will divert dollars and jobs from other sectors of the Illinois economy. Our research indicates that, when the Pace Study results are modified to account for these adverse economic impacts, it is very likely that the TEC project will result in a significant net job and income *loss* for Illinois.

Figures E-1 and E-2 summarize, for the 30-year period, the average percentage rate and average annual dollar impacts of TEC on All Customers, the EC Group and the Non EC Group. The scenarios considered includes the Pace Reference Case (Pace Reference), a Cost Escalation scenario (Cost Escalation), Cost Escalation plus Revenue Offset Adjustments (Cost Esc + Rev Adj), the Pace Reference Case with No Carbon Sequestration (Pace Ref + No Sequestration), and Cost Escalation with No Carbon Sequestration (Cost Esc + No Sequestration).

All five scenarios demonstrate that the impacts of TEC on Illinois electricity customers will be significant. The differences between the Pace Reference Case and the other cases show that the risks of TEC for the Illinois economy arise not only from the uncertainties considered by Pace but also from the uncertainties associated with TEC's costs and with CCPSL's explicitly acknowledged risk that TEC will be unable to deliver its promised CO_2 reductions. What is clear from these figures is that the TEC project will drain the Illinois economy an average of $292 million to $518 million *per year* for the next thirty or more years; and that in subsidizing the TEC plant, Illinois is betting its economic future on a "roll of the dice" that is sure to cost lots of money and many jobs.

Figure E-1
Average Annual Percentage Rate Increases for TEC Cost Scenarios

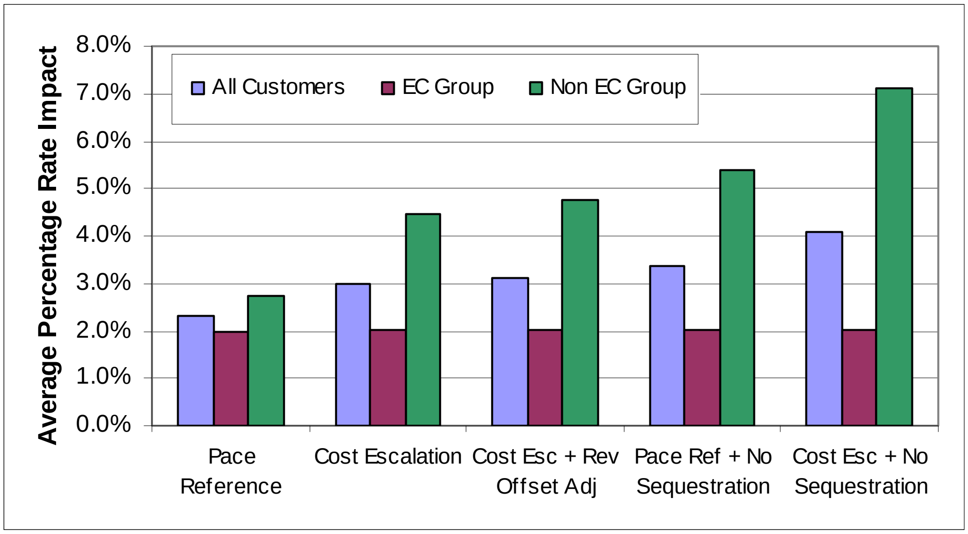
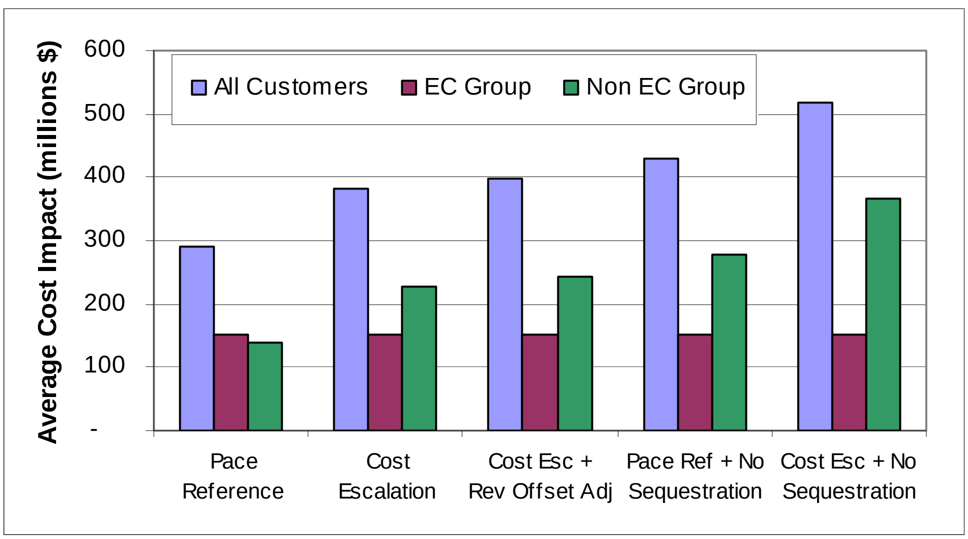


Figure E-2
Average Annual Total Dollar Impact for TEC Cost Scenarios



**TAYLORVILLE ENERGY CENTER PROJECT:
ECONOMIC IMPACTS ON
ILLINOIS RETAIL ELECTRICITY RATES AND ECONOMY**

Introduction

This report assesses a recent economic study prepared by and for the Taylorville Energy Center (TEC) – a proposed hybrid integrated gasification combined cycle power plant. This study is:

- Pace Global Energy Services, *Rate Impact Analysis for Taylorville Energy Center*, February 21, 2010 (the Pace Study).

To perform this assessment, five companion studies prepared by and for TEC were also reviewed. These studies are:

- KBMD Partners, *FEED Study Summary*, February 22, 2010 (the KBMD Study);[13]
- Nexant, Inc., *U.S. Sulfur/Sulfuric Acid Market Analysis: Supply/Demand and Pricing*, June 2009 (the Nexant Study);
- Schlumberger Carbon Services, *Cost Report for the Taylorville Energy Center*, (the Schlumberger Study), February 18, 2010;
- Wood MacKenzie, *The Delivered Price of Coal to the Taylorville Energy Center*, October 2009 (the Wood MacKenzie Study); and
- WorleyParsons Group, Inc., *Facility Cost Report*, February 26, 2010 (the WorleyParsons Study).

The objectives of the assessment are: a) to determine the reasonableness of the rate impact estimates provided by the Pace Study; and b) to provide preliminary estimates of the impacts of TEC upon the Illinois' economy over the period of the rate impact estimates.

This report is organized as follows. Section 2 provides brief descriptions of the TEC project's physical characteristics and of the Illinois law that provides substantial subsidies for the project. Section 3 summarizes the findings of the KBMD Study and the Pace Study with respect to the costs, revenues, and rate impacts of the TEC project. Section 4 presents our alternative assumptions and findings regarding rate impacts on electricity customers and economic impacts on the overall Illinois economy. Section 5 provides conclusions and recommendations. Additional supporting material is provided in an appendix.

Background

This section describes the TEC project, and then describes the law that provides substantial subsidies to the project.

[13] Three additional studies are appended to the KBMD Partners study. They are: KBMD Partners, *Basis of Estimate*, February 22, 2010; KBMD Partners and Christian County Generation, *Project Execution Plan*, February 2, 2010; and Bigge Crane and Rigging Company, *Transportation Survey*, September 18, 2009.

Physical Description of the Taylorville Energy Center[14]

TEC is designed to convert coal to substitute natural gas (SNG), and then to produce electricity from the SNG. TEC will therefore prospectively be comprised of two main operational "islands":

- *The SNG island* will use two Siemens dry feed quench gasifiers to convert coal to SNG. An acid gas and CO_2 removal unit will strip unwanted elements from the gas, particularly sulfur and CO_2. Table 1 summarizes SNG production and coal consumption by the SNG island.
- *The power island* will be a conventional 760-MW combined-cycle power plant that includes two combustion turbine generator sets, two heat recovery steam generators, and one steam turbine generator. Table 2 summarizes the power island's prospective characteristics. Unit 1 will be a must-run unit, while unit 2 will be discretionary.

When the SNG island produces more SNG than is required by the power island, TEC will compress and inject the excess SNG into the natural gas pipeline system for sale. When the power island requires more gas than can be provided by the SNG island, the power island will procure pipeline natural gas to make up for the shortfall. The sulfur and CO_2 byproducts will be available for sale if suitable buyers can be found.

Table 1
Summary of Expected SNG Production and Coal Consumption[15]

Category	MMBtu/Hour
Total Coal Consumption	4,433
Total SNG Production from Gasifier	2,592

Table 2
Summary of Operating Characteristics and Costs of the Power Island (2010\$)[16]

Category	Units	Period	Unit 1	Unit 2
Net Capacity	MW	June-September	262	299
		November-February	304	333
		Other months	285	318
Net Heat Rate	Btu/kWh	June-September	7,583	6,649
		November-February	7,114	6,487
		Other months	7,225	6,476
CO_2 Emission Rate	lbs/MMBtu		115.4	115.4
Variable O&M	$/MWh	2010	2.82	2.82

[14] A more detailed description of the TEC facility and an assessment of the implications of the design in terms of operational issues are contained in KBMD Partners, *Basis of Estimate*, p. 7.
[15] Pace Study, Exhibit 2.
[16] *Ibid.*

For the analysis that follows, it is important to note that the KBMD Study implies that the power island cannot operate at a 75% or higher capacity factor without burning some natural gas purchased at market prices. This implication follows from the prospective TEC design by which the SNG island will be unable to produce sufficient SNG to fully serve the power island when the latter operates at a 75% capacity factor.[17]

Illinois' Clean Coal Portfolio Standard Law

SB 1987, the Clean Coal Portfolio Standard Law (CCPSL), was signed into law on January 12, 2009.[18] Among other things, this legislation defines a "clean coal facility" as

> "an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters… at least 50% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation before 2016, at least 70% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation during 2016 or 2017, and at least 90% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation after 2017."[19]

With the goal "that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities,"[20] Illinois appears to be the first state to establish a goal for producing electricity from coal-fueled power plants with carbon capture and storage (CCS). To support the commercial development of CCS technology and the use of coal mined in Illinois, the legislation requires each utility and alternative retail electric supplier (ARES) in the state to procure at least 5% of its "eligible" retail load from the "initial clean coal facility" in 2015 and each year thereafter.[21] "Eligible" retail load is that of residential and small commercial customers with loads of 100 kW or less in the planning year immediately preceding the commencement of the sourcing contract. The "initial clean coal facility" is defined as a clean coal facility "that will have a nameplate capacity of at least 500 MW when commercial operation commences… [and] that has a final Clean Air Act permit on the effective date of this amendatory Act…"[22] Payments to the initial clean coal facility are to be based upon that facility's cost of service, subject to review by the Illinois Commerce Commission (ICC) and the Federal Energy Regulatory Commission (FERC). All miscellaneous revenue, favorable financing cost impacts, and tax credits earned by the initial clean coal facility, such as revenue from the sale of SNG, is required to reduce dollar-for-dollar payments by the utilities and ARES under the Sourcing Agreements. At the time of the passage of the legislation, as well as at the present, the common expectation was and is that the TEC facility will be the initial clean coal facility.

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[17] This result is implied by the fact that the Pace Study shows the TEC plant buying $149 million worth of natural gas per year over the 30-year period analyzed in the Reference Case scenario.
[18] Public Act 09-1027 (S.B. 1987 Enrolled).
[19] Illinois General Assembly, *Clean Coal Portfolio Standard Law*, SB1987 Enrolled, Public Act 095-1027, p. 4.
[20] *Ibid*., p. 20.
[21] *Ibid*., pp. 19-20.
[22] *Ibid*., pp. 23-24.

Notwithstanding the foregoing cost-of-service calculation, the amounts paid by "eligible retail customers" are subject to the following cap:

> "the total amount paid under sourcing agreements with clean coal facilities … for any single year shall be reduced by an amount necessary to limit the estimated average net increase due to the cost of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of (i) 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009 or (ii) the incremental amount per kilowatthour paid for these resources in 2013."[23]

where "the total amount paid for electric service includes without limitation amounts paid for supply, transmission, distribution, surcharges, and add-on taxes."[24] The rate cap on eligible retail customers means that the costs of power from TEC that would be borne by Illinois utilities and their eligible customers will be limited in absolute amount. However, the remainder of the costs of the power supplied by TEC for eligible retail customers will be borne by ARES, according to CCPSL.[25]

Because 5% of total MWh sold by utilities and ARES will be approximately equal to the output of the TEC facility regardless of the capacity factor assumed, the CCPSL implicitly requires 100% of the TEC facility output to be purchased by Illinois utilities and ARES. Given that the 2.015% limit protects eligible retail customers (i.e., residential and small commercial customers) from even higher rate impacts, the remainder of any power purchase costs must be absorbed by the ARES (i.e., their shareholders) or passed on in rates to all other customers they serve (e.g., schools, hospitals, government agencies, businesses, and manufacturers).

Findings of the TEC Reports

This section begins by describing the key assumptions of the KBMD Study and the Pace Study, and then summarizes the rate impact and economic impact estimates provided by the Pace Study.

Key Assumptions

The TEC reports depend upon numerous assumptions pertinent to the cost, revenue, and other impacts of the TEC project. The key assumptions concern the following:

- TEC project availability and output;
- TEC project capital costs;
- TEC project operating costs;
- TEC project revenue offsets; and
- electricity market conditions.

[23] *Ibid*., pp. 22-23. As a practical matter, condition ii is irrelevant.
[24] *Ibid*., pp. 16-17.
[25] CCPSL, Section 16-115(d)(5)(iv).

Each of these is discussed below.

TEC Project Availability and Output

Table 3 summarizes the Pace Study presentation of the estimates of the availability of the SNG and power islands, which are "in accordance with parameters supplied by Tenaska."[26] As indicated in the table, the SNG island availability is projected to rise dramatically after an initial two-year "shakedown" period. Based on the historical performance and maintenance characteristics of natural gas combined-cycle power plants, the Pace Study, for purposes of estimating revenues from sales of energy from the plant and computing rate impacts, sets the expected availability of the power island at 92% from the outset.[27]

Table 3
Summary of Availability Estimates for TEC SNG Island and Power Island[28]

Availability	SNG Island	Power Island
Year 1	65%	92%
Year 2	80%	92%
Year 3 to Year 12	85%	92%

We note that for purposes of estimating the cost of TEC power, the Pace Study finds that the TEC plant will be dispatched at annual capacity factors of between 75% and 86% during all 30 years of the analysis for all four states of the world that it examined.[29] The Pace Study also estimates the cost of TEC power under an assumption of a 92% annual capacity factor. Given the plant characteristics presented in Table 2 and the capacity factors determined by the Pace Study, this translates into an average annual output of approximately 3,968 GWh of electricity, all of which would be purchased by Illinois utilities and ARES under the CCPSL requirements.

TEC Project Capital Costs

Table 4 presents the KBMD Study's estimated capital costs. Total construction costs are estimated to be $2.82 billion, of which $0.26 billion are a contingency for a 10% cost overrun. Various financing and other non-construction costs are estimated to be $0.70 billion, bringing the total cost to $3.52 billion.

[26] Pace Study, p. 2. Tenaska is an Omaha-based independent power developer that is one of the joint developers of the TEC project.
[27] Pace Study, p. 3.
[28] Pace Study, Exhibit 2.
[29] The range of capacity factors is deduced from the results presented in the Pace Study, pp. 63-66.

Table 4
Capital Costs of TEC Plant (000's of 2010 $)[30]

Core Plant	$2,407,612	
Balance of Plant	154,300	
Owner's Contingency	257,000	
Total Construction Costs		$2,818,912
Process License and Fees	$ 21,418	
Catalysts	26,625	
Worker's Compensation Insurance	28,104	
Land and Mineral Rights	14,146	
Development Costs	106,272	
Owner's Project Management	55,000	
Financing Costs	353,192	
Builder's Risk Insurance	19,500	
Pre-Operation Cost	28,981	
Spare Parts	24,189	
Coal Inventory	2,447	
Sales Tax	22,864	
Financing, Startup and Owner's Costs		702,738
Total Capital Costs		$3,521,650

TEC Project Operating Costs

Table 5 summarizes the WorleyParsons Study's estimated average annual operating and maintenance costs for the TEC facility. Over 90% of the $67 million annual cost is comprised of the first four items in the table.

[30] WorleyParsons Study, p. 56, Exhibit 10.1.1a. Note that there are two $18,000,000 addition errors in the source that are corrected in the table that appears herein.

Table 5
Summary of Annual Average O&M Costs (000's of 2010 $)[31]

Maintenance	$28,551
Yard Contract Labor	14,449
Insurance	9,950
Consumables	8,640
Capital Improvement Allowance	1,500
Plant Management	1,374
Slag & Sludge Disposal	860
Administrative & Facility Support	752
Utilities	638
Plant Materials	443
345 kV Switch Yard	117
Total	$67,274

Neither Table 4 nor Table 5 includes the costs of the air separation unit that the TEC-sponsored studies assume will be provided through a third-party contract. Neither Table 4 nor Table 5 includes the capital and operating costs of CO_2 sequestration by means of well injection, the costs of which would be incurred in the event that CO_2 cannot be sold to Denbury for EOR.[32]

Delivered Coal Prices

The Pace Study determined the total delivered cost of coal used according to the Wood MacKenzie Study's 30-year forecast of delivered coal. The delivered price estimated by Wood MacKenzie represents the lowest average delivered price of coal to TEC from "one of six subdivisions that represent the geographical mining areas of the State of Illinois."[33] Table 6 presents that forecast for the first ten years of TEC's operation as well as the total cost of delivered coal.[34]

[31] WorleyParsons Study, p. 41, Table 5.6.
[32] Nonetheless, the value of the capital recovery requirement used in the Pace Study was set at $439.5 million in 2015, which is 46% higher than the amortized capital cost of $300 million to recover $3.5 billion at a WACC of 7.53% over 30 years. This higher level of capital recovery requirement would be adequate to recover both the capital and fixed operating costs of the air separation unit and the CO_2 well sequestration system.
[33] Wood MacKenzie, p. 8.
[34] The Wood MacKenzie Study, at p. 9, states that the Btu content of the coal used at the TEC plant is 10,450 Btu/lb. From this, the delivered price of coal ($/MMBtu), and the total cost of delivered coal presented by Pace, we infer that the total coal use during the 30-year period ranges from 1.3 million short tons in 2015 to about 3.0 million tons in 2044.

Table 6
Forecast Delivered Price and Estimated Total Cost of Coal (2010 $)

Year	Delivered Coal Price (2010$ per MMBtu)[35]	Total Cost of Delivered Coal (000s of 2010$)[36]
2015	2.21	60,470
2016	2.24	77,015
2017	2.24	83,147
2018	2.17	82,156
2019	2.15	83,122
2020	2.17	85,431
2021	2.18	87,524
2022	2.20	90,207
2023	2.16	90,178
2024	2.16	92,250

Pace used the coal price forecast prepared by Wood MacKenzie for the 30-year rate impact analysis.

Variable O&M Costs

The Pace Study of retail rate impacts uses the variable operations and maintenance (VOM) costs of $2.82 (2010 dollars) per MWh.[37]

Carbon Sequestration Costs

If the sale of CO_2 to Denbury for EOR does not materialize, the TEC project's CO_2 will have to be sequestered by injection into wells in Illinois. The Pace Study appears to have used a capital recovery requirement to account for the costs of carbon sequestration by a well injection system. According to the Schlumberger Study, the costs of carbon sequestration for TEC will average between $5 and $10 per metric ton.[38]

Table 7 summarizes the Schlumberger Study's estimates of the costs of developing a three-injection well system locally for the TEC. According to Schlumberger, $63.4 million will be spent building the system during the construction phase of the project (i.e., before 2015). Refurbishing (i.e., seismic and well workovers) will cost $19.2 million and will occur at ten-year intervals, in 2024 and 2034. Aside from refurbishing, O&M will cost either $182,090 per year (in six years) or $112,000 per year (in twenty-three years) after 2014, for an annual average of $126,501 over the years 2015-2043 inclusive. Decommissioning will run a total of $30.3 million over the years 2044-2054.

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[35] WorleyParsons Study, p. 45, Table 6.0. The Pace Study used the full 30-year forecast of delivered coal prices that is presented in the Wood MacKenzie Study, p. 8, Exhibit 1.
[36] Pace Study, p. 63. The total delivered cost of coal does not vary across the four states of the world analyzed by Pace.
[37] Pace Study, p. 3, Exhibit 2.
[38] Schlumberger Study, p. 1.

Table 7
CO_2 Sequestration – Three-Injection Well Case[39]

	Initial Capital Costs	Seismic & Well Workovers	O&M	Decommissioning	Total
Development	1,100,000				1,100,000
Capital	54,351,980				54,351,980
Seismic Work		19,198,650		15,030,480	34,229,130
Water Sampling + Wellhead O&M			3,799,540	106,090	3,905,630
Contingency	7,994,369			15,136,570	23,130,939
	63,446,349	19,198,650	3,799,540	30,273,140	116,717,679

Commercial Operation Date

Both the KBMD Study and the Pace Study assume that TEC's commercial operations will commence in 2015. The KBMD Study acknowledges significant obstacles in construction, but assumes that all bridge, barge, electrical wire, and road upgrades will be permitted and accomplished on time.

TEC Project Revenue Offsets

The KBMD Study and the Pace Study both assume that the TEC facility will be able to sell certain commodities other than electricity, the revenues from which will offset some of the costs of the TEC facility. Table 8 presents the average annual revenues that the studies forecast for each revenue source for each of the first ten years of TEC's operation.

Although Table 8 includes six items, it appears that the Pace Study's rate impact analysis considers only the revenues from the last two of those items: the sale of capacity in the PJM capacity market; and the Q45 CO_2 tax credits.

[39] Schlumberger Study, Table C-3, p. 4.

Table 8
Average Annual Revenues Reported in the KBMD Study and Pace Study (2010 $)[40]

Commodity	Revenues
SNG	$15,200,000
CO_2 (for Enhanced Oil Recovery)	9,000,000
Sulfur	3,600,000
NOx Allowances	18,100,000
Electric Generating Capacity (for PJM)	21,900,000
IRS Q45 CO_2 Tax Credits	18,300,000

SNG Sales

It is not clear whether the Pace Study includes a revenue offset from SNG sales in its rate impact analysis, as no explicit revenue stream associated with SNG sales is reported in Pace's state of the world analysis. It is clear, however, the gasifier facility alone will not provide sufficient SNG to enable the power plant to run at a 75% (or higher) capacity factor, so that the TEC project will very likely be a net purchaser, rather than a net seller, of gas. The Pace Study accounts for natural gas purchase costs in its rate impact analysis.

CO_2 Sales for Enhanced Oil Recovery

The WorleyParsons Study expects "that the TEC will capture and permanently store geologically more than 50% of the CO_2 that otherwise would have been emitted from the Facility, totaling approximately 1.9 million MT per year… [T]he primary plan for geologic storage is the sale of CO_2 to Denbury for transmission through a pipeline to be used in EOR in Mississippi or other Gulf Coast states. On average, over the first 10 years of operation, CO_2 purchase payments from Denbury are projected to be approximately $8.9 million annually in 2010$."[41]

Sulfur Sales

Sulfur will be removed from coal in the process of its conversion to SNG. The KBMD Study and the Pace Study both state that revenue will arise from the sale of molten sulfur; but, this revenue is not considered in any of the rate impact states of the world analyzed by Pace that we can see.

NOx Allowance Sales

The WorleyParsons Study claims that "TEC's low emissions profile will enable it to be eligible for additional Clean Air Set-Aside and Early Adopter nitrogen oxides (NOx) allowances as set forth in Illinois regulations implementing the Clean Air Interstate Rule. Based on Pace's projected prices for NOx allowances and on CCG's estimate of surplus NOx allowances… as shown in Table 10.1.8, CCG estimates, on average, over the first 10 years of operation, revenues from the sale of surplus NOx allowances will

[40] The first five figures are from the WorleyParsons Study, pp. 10-11. The $18,312,000 figure is a CA Energy computation for the first ten years of operations.
[41] WorleyParsons Study, p. 59.

be approximately $18.1 million annually in 2010$."[42] It appears that the Pace Study does not use this revenue stream in its rate impact analysis.

Electricity Market Conditions

The KBMD Study and the Pace Study anticipate revenues from the sale of the TEC's capacity into PJM's three-year forward capacity market. According to the KBMD Study, "Capacity revenues are estimated based on Pace's projection of capacity market clearing prices multiplied by the TEC summer capacity rating. On average, over the first 10 years of operation, revenues from electric capacity sales are projected to be $21.9 million annually in 2010$."[43]

PJM capacity market prices are very volatile and difficult to forecast. In the ComEd zone of PJM, these prices recently fell sharply as a result of the significant increase in the participation by demand response resources in the 2012/2013 Base Residual Auction (BRA).[44] The participation of demand response is expected to continue to grow in the PJM market, with the effect that capacity prices will be kept down for the foreseeable future.

Other Savings and Credits

Table 9 lists additional potential savings and credits mentioned in the KBMD Study and Pace Study.[45]

[42] WorleyParsons Study, p. 60. "CCG" is Christian County Generation, which is the developer of TEC.
[43] WorleyParsons Study, p. 11. The WorleyParsons Study estimate of revenues from the PJM capacity market are based on the Pace Study projects of capacity market prices in the Northern Illinois zone of PJM (i.e., the ComEd zone) as presented in the Pace Study, p. 21, Exhibit 17.
[44] The elimination of Interruptible Load for Reliability (ILR) category of demand response for the 2012/2013 Delivery Year, and reclassification of that load as Demand Response increased the participation of that category from 1,365 MW in the 2011/2012 BRA to 7,047 MW in the 2012/2013 BRA. The ILR category had not been included in the determination of capacity market clearing prices prior to the 2012/2013 BRA. Consequently, the capacity market clearing prices were driven lower.
[45] These credits do not appear to have been taken into consideration by Pace in determining rate impacts.

Table 9
Additional Revenue Credits Mentioned in the KBMD Study and Pace Study
(millions of nominal dollars per year)

Item	Amount
Interest cost savings from U.S. DOE loan guarantee	$ 60
45Q Tax Credits	22
Cap & Trade Incentives	156
PJM Market Savings for reduction in PJM market prices	120

Interest Cost Savings

The KBMD Study states that it expects the U.S. DOE loan guarantee to save $60 million on interest costs associated with borrowing to cover the capital costs of the TEC. The interest cost savings will be realized only if the forecast interest rate differentials (between conventional and guaranteed bonds) are realized. With interest rates now on the rise, these differentials may change.

IRS 45Q CO_2 Tax Credits

The CO_2 revenues presented in Table 8 reflect a CO_2 tax credit of $10 per ton as per Section 45Q of the Internal Revenue Code, which "serves as the basis of Pace's Reference Case CO_2 tax credit estimate for the TEC."[46] This tax credit reduces Pace's estimated costs of emissions from the TEC plant.

The KBMD Study and Pace Study also mention the potential of CO_2 revenues associated with the implementation of some kind of cap-and-trade system (e.g., as defined under the Waxman-Markey draft legislation). However, the Pace Study does not appear to take the CO_2 revenues associated with a cap-and-trade system into account in its analysis of the rate impacts.

Levelized Cost Analysis

The Pace Study reports the levelized costs of various technologies that could compete with the technology employed for the TEC facility. Table 10 summarizes these costs for Pace's Reference Case, with technologies listed in descending order of costs. Natural gas combustion turbines (CTs) have the highest cost due to their low load factors, while solar photovoltaics (PV) have the second highest cost due to their high capital costs. Pace claims that TEC will be cheaper than natural gas combined cycle (CC) units. Two coal technologies, nuclear, and wind are all significantly cheaper than TEC. Pace indicates that Coal with CCS will have a per-MWh cost essentially identical to that of Pulverized Coal, which implausibly implies that CCS will be costless.

[46] Pace Study, p. 57. Pace adjusts this value by its assumed general inflation rate of 2% per annum for the reference case.

Table 10
Levelized Cost Results by Technology (2010$/MWh)[47]

Technology	Cost		
	Average	**High**	**Low**
Natural Gas CT	690	981	417
Solar PV	351	443	205
Natural Gas CC	163	203	125
Taylorville (TEC)	*150*		
Pulverized Coal	119	152	102
Coal with CCS	119	140	101
Nuclear	115	188	73
Wind	71	100	54

Estimated Impacts on Illinois Electricity Rates

States of the World

To estimate the impacts of the TEC facility operations on Illinois retail rates, the Pace Study developed four states of the world representing different sets of assumptions about macroeconomic drivers and public policy initiatives that could affect the electricity markets over the period 2015 to 2044. The four states are as follows:

- *The Reference Case state* assumes that future environmental and economic policies continue present trends.
- *The Gas/Coal Future state* assumes that future environmental and economic policies are oriented more toward economic growth and less toward environmental protection than is assumed by the Reference Case.
- *The Environmental Policy state* assumes that future environmental and economic policies are oriented less toward economic growth and more toward environmental protection than is assumed by the Reference Case.
- *The RPM/DSM Case state* assumes an even more aggressive pro-environmental policy than is assumed by the Environmental Policy state.

Table 11 summarizes the assumptions underlying each of the four states.

[47] Pace Study, p. 28, Exhibit 23.

Table 11
Pace Study Assumptions Driving Four States of the World[48]

Assumption Category	State of the World			
	Reference Case	**Gas/Coal Future**	**Environmental Policy**	**RPS/DSM**
GDP Growth	Moderate recession; recovery by 2010	Longer deeper recession, but stronger recovery	Quick recovery from current recession	Relatively short recession; strong recovery by 2010
Carbon Control	Widespread carbon control measures	Lax CO_2 requirements; economic growth policies trump environmental protection	Strict CO_2 cap-and-trade policy; no new conventional coal plants; closure of many existing coal plants.	Widespread CO_2 control measures
CO_2 Tax Policy	CO_2 sequestration tax credit of $10/ton			
NOx Regulations	NOx market regulations similar to CAIR			
Renewable Portfolio Standards	Federal RPS: 17% by 2020. Rapid development of zero-emission resources	Lower RPS		Aggressive Federal/State RPS
Energy Efficiency/Demand Side Management	Moderate deployment EE/DSM			Aggressive federal/state DSM reduces load
Natural Gas Demand	North America is largely self-sufficient natural gas supply	Gas-fired capacity dominates as the fuel of choice, nationwide increasing gas demand		

Pace's analysis thus focuses on: a) variations in the main economic and public policy drivers that might impact market prices for power and capacity; b) fuel prices (i.e., natural gas, coal and oil prices); c) load growth; and d) various revenue sources (e.g., NOx allowance prices). Pace's analysis of the four states shows that rate impacts over the 30-year projected life of TEC do not vary significantly across the states. In other words, Pace has focused on variables that generally have little impact on Illinois retail rates. The exceptions are the energy and capacity market prices applied to sales in the PJM market.

Table 12 summarizes the values that Pace has given to key drivers of the four states of the world.

[48] Pace Study, pp. 11-13.

Table 12
Summary of Key Electricity Market Drivers Across States of the World[49]

Market Driver	State of the World			
	Reference Case	Gas/Coal Future	Environmental Policy	RPS/DSM
Gas Price in 2030 (2010$/MMBtu)	11.95	16.77	9.90	6.03
Annual MWh Demand Growth Rate (2015-2030)	0.20%	0.70%	0.30%	-0.30%
CO_2 Price in 2030 (2010$/ton)	59	32	80	59

Rate Impact Estimates

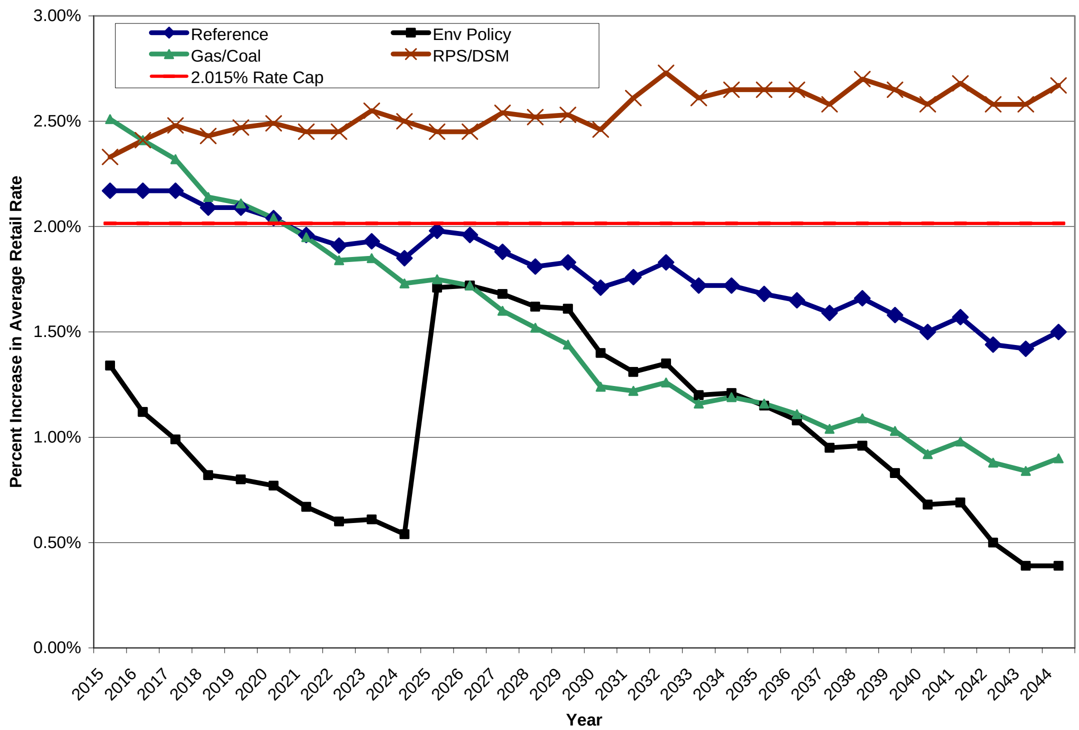
Figure 1 shows Pace's estimated percentage increases in average retail rates under each of the four states of the world relative to what retail rates would have been in the absence of the TEC project. From Figure 1, it would appear that the rate impacts under the Reference, Gas/Coal and RPS/DSM states will violate the 2.015% rate impact cap in the first six years of TEC's operations (i.e., from 2015 to 2020) unless payments to the TEC project owners are reduced below cost-of-service levels or, as the CCPSL requires, the ARES pick up the excess costs and pass those costs on to the non-eligible retail customers (i.e., hospitals, schools, government agencies, businesses, and manufacturers). Beyond 2020, the percentage rate impacts under the Reference and Gas/Coal states fall below the cap, while the RPS/DSM state remains above the cap for the entire 30-year period. The Environmental Policy state falls below the cap for the entire 30-year forecast period.[50]

The retail rate impacts on "eligible" customers in Illinois will be significant, even when the rate impact is held to only 2.015% relative to 2009 levels. The average annual cost of TEC to residential and small commercial customers in Illinois will be about $152 million (nominal), not a trivial sum of money. In other words, to support the TEC facility's reducing carbon output by 1.9 million tons per year, residential and small commercial customers will be paying $80 per ton of CO_2 sequestered, which is significantly higher than the likely cost of carbon reduction that is available and will be available through other means.[51] For the sake of spending inefficiently large amounts of money on CO_2 reduction, Illinois consumers will have $152 million per year less in discretionary income to spend on other goods and services in the state, which will be a drag on the state economy. In addition, the net incremental cost of TEC that is not borne by "eligible" customers will be borne by all other customers, including commercial

[49] Pace Study, p. 13, Exhibit 10.
[50] The significant jump in the percentage impact under the Environmental Policy scenario in 2025 is due to the assumption that the IRS Section 45Q CO_2 tax credits end in 2024.
[51] Official U.S. government projections of CO_2 allowance prices appear in Energy Information Administration, *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*, Report No. SR-OIAF/2009-05, August 4, 2009, http://www.eia.doe.gov/oiaf/servicerpt/hr2454/execsummary.html, Figure ES-3. In 2007 dollars per metric ton, prices for the "basic" scenario are $22 in 2015 and $65 in 2030.

and industrial customers as well as small- and medium-sized customers taking competitive supply such as condominium associations, churches, small retail businesses, and small office buildings. According to our correction of the error in the Pace Reference Case, the average annual burden of TEC on these customers under is about $140 million.

Figure 1
Pace's Estimated Percentage Increases in Average Illinois Retail Rates from TEC, 2015 – 2044



The Pace Study's presentation of the overall rate impacts of the TEC is misleading for two reasons.

First, the percentage rate impact is computed by dividing the annual net cost of the TEC facility by the sum of the projected total revenue collected from all Illinois retail customers served by ComEd, Ameren, and ARES at 2009 average rates, which Pace reports as $0.11492 per kWh.[52] This spreads the net cost over sales of all MWh, which is inconsistent with what the law requires. The rate Pace uses may be reasonable for residential and small commercial customers (similar to the "eligible" retail customer designation in the CCPSL), but it is not reasonably applied to large commercial, industrial, and other customers served by Illinois utilities and ARES because such classes of customers do not fall under the CCPSL's definition of an "eligible" retail customer. Consequently, when the rate impact of the TEC

[52] Pace Study, Reference Case spreadsheet screen shot, p. 63.

facility for non-eligible customers is computed, the appropriate 2009 reference price is about $0.0684 per kWh, and the resulting percentage impact of the excess cost is significantly higher than 2.015%.

Second, in estimating the revenues that TEC will receive from the PJM capacity markets, Pace did not consider the institutional implications of TEC's sales to Illinois utilities and ARES that are located in the footprint of the Midwest Independent Transmission System Operator (MISO). It will be difficult or impossible for TEC to commit to sell into the PJM market the capacity that is used to support energy sales in MISO. Under the CCPSL's mandated sourcing contracts to sell to ComEd and ARES, such capacity will implicitly be committed to the MISO market. Thus, given PJM's capacity market requirements, TEC will be able to commit only a part of its capacity to the PJM capacity market.

Estimated Impacts on the Illinois Economy

The WorleyParsons Study estimates that, during the construction period, 2,470 workers will be employed on site, with an estimated 9.6 million man hours required over the four-year construction period.[53] That study also projects that, after construction, TEC will employ 155 persons full-time on site, and the purchase of Illinois coal will sustain 175 mining jobs and 75 trucking jobs (for hauling the coal).[54] The study does not estimate the dollar impact of these employment levels.

The WorleyParsons Study indicated that once the TEC facility became operational, total local (i.e., Illinois) expenditures were estimated to be $126 million per year.[55] This estimate includes the cost of coal purchased, which according to the Wood MacKenzie forecast of coal prices over the 30-year life of TEC, would average $111 million per year. Thus, not counting coal purchases, the TEC facility is expected to add $15 million per year in local expenditures.

It should be noted that the WorleyParsons Study describes the *gross* impacts of the TEC project, not the *net* impacts. For example, if a conventional power plant were built instead of TEC, that conventional power plant would also create jobs: the net job benefit of the TEC project is the difference between the job impacts without the TEC plant less the job impacts without the conventional plant. As another example, the TEC plant will have substantially higher costs than electricity from other sources; and those higher costs will be paid by Illinois consumers who will then have less to spend on other goods and services. The effect of TEC's high costs will be to destroy jobs, reduce incomes, and reduce tax receipts elsewhere in the Illinois economy.

Alternative Projections of TEC Project Impacts

To develop alterative projections of TEC rate impacts, we created a spreadsheet model that replicates the results of the Pace Study, and then we modified some of the key assumptions to see how the rate impact results change with different assumptions. This allows us to determine how uncertainties in project outcomes and future economic conditions can affect rate impacts, and to provide alternative

[53] WorleyParsons Study, p. 4.
[54] *Ibid.*, p. 5.
[55] *Ibid.*

estimates of rate impacts under plausible conditions that are not as favorable to the TEC facility as assumed under Pace's Reference Case scenario.

Based upon the rate impacts, we then estimate some specific impacts on the Illinois economy. The increases in retail rates, especially significant for Illinois' non-eligible customers, translate into reductions in employment and earnings, which lead to lower tax revenues for the state.

We begin by discussing alternatives to the assumptions that underlie the Pace Study. We then discuss both the plausibility of the assumptions made by Pace in its Reference Case and the plausibility of claims made in the KBMD Study about potential revenue offsets that do not appear to be considered in the Pace analysis. Finally, we quantify rate impacts for assumptions that we believe are plausible alternatives to those that appear the Pace Reference Case. While we do not claim that our rate impact estimates are *better* than those presented by Pace, we do claim that there is a significant possibility that the rate impacts will be worse than those found by Pace and that the adverse impacts on Illinois electricity consumers and on the Illinois economy may be worse than implied by the Pace Study. Based upon our estimated rate impacts, we infer impacts for the overall state economy.

Alternative Assumptions

The alternative assumptions that we make in conducting our analysis of the rate impacts of the TEC facility center on two issues: the fundamental cost drivers of the TEC facility and the appropriate 2009 benchmark prices for eligible and non-eligible customers.

Regarding the fundamental cost drivers, we note Pace's rate impact results do not vary widely across its four states of the world. The reason that Pace did not find much variation among states is that it did not analyze the rate impacts of changes in the fundamental drivers of the TEC costs. These fundamental drivers are core plant capital costs, interest rates, construction costs, fuel costs, and revenue offsets. Pace did not consider higher plant costs in any of the scenarios it examined. Although we use Pace's assumptions and scenarios as the starting point for our analysis, we make alternative assumptions about the values of these fundamental cost drivers.

Regarding the 2009 benchmark prices, we note that when Pace computed the percentage rate impacts, it incorrectly applied the 2009 rate for residential and small commercial customers to all load served by the utilities and ARES. This had the effect of significantly understating the rate impact on non-eligible customers served by ARES. Therefore, we correct this error when we compute the rate impacts for eligible and non-eligible customers.

Table 13 summarizes the alternative scenarios that we consider. In brief, we allow construction costs to be 15% higher than assumed by Pace, and operating costs and Illinois coal costs to each be 10% higher.

We limit the number of years that CO_2 tax credits will be available, and consider the effects of lower capacity prices in the PJM capacity market. [56]

Table 13
Alternative Scenarios Considered
(Relative to KBMD Study/Pace Study Analysis)

	Case 1: Cost Escalation Case	**Case 2: Case 1 + Revenue Offsets**
Plant Costs		
Core + Balance of Plant Costs	15% higher	15% higher
Operating & Maintenance Costs	10% higher	10% higher
Illinois Coal Costs	10% higher	10% higher
Revenue Offsets		
IRS Q45 CO_2 tax credits	same as Pace	first 5 years only
Electric Capacity Prices	same as Pace	50% Lower

Section 0 discusses the bases for our alternative assumptions about plant costs. Section 0 discusses the bases for our alternative assumptions about revenue offsets. Section 0 discusses other issues that seem to be excluded from the Pace Study, and which we also exclude, but which we discuss for the sake of completeness.

Plant Cost Assumptions

If plant costs turn out to be higher than assumed by the Pace Study, the rate impacts of the TEC project will be worse than estimated by that study. Because electric generating plant construction is often subject to serious cost overruns, because electric generating plants often have unforeseen operating problems, and because fuel markets are volatile, the risks of higher-than-expected costs should be seriously considered.

Core Plant Costs

For Cases 1 and 2, we assume that Core Plant Costs and Balance of Plant Costs are 15% higher than assumed in the Pace Reference Case.[57] An increase of 15% in Core Plant Costs and Balance of Plant Costs is within reason. We note that the total annual revenue requirement of the TEC facility was estimated at approximately $540 million in the filing Tenaska made to FERC in December 2009. The KBMD Study and Pace Study filed just three months later, in March 2010, places the annual revenue requirement at about $640 million, which is an increase of 18.5%. It is quite possible that between

[56] We do not assume that the TEC capacity bid into the PJM capacity market will be less than that assumed by Pace in its Reference Case scenario, but it is likely that TEC will not succeed in bidding all of its rated capacity into that market.
[57] Since Pace did not consider higher plant costs in any of the scenarios it examined, our Case 1 assumptions also depart from the plant cost assumptions used in Pace's three other scenarios.

March 2010 and December 2015, costs could increase another 15%. Consistent with such concerns, the WorleyParsons Study indicates that its estimate of core plant capital costs could be low by 15%.[58]

Pace itself has acknowledged – even emphasized – that generation cost forecasts can change very significantly over time. In a discussion of the future of IGCC made back in 2007, Pace stated the following:

> "Project proposals as recently as 5 years ago were estimated to cost as little as $1100-$1300 per kW for engineering, procurement, and construction ('ECP') without CCS. Owners' costs (land, engineering services, insurance, facilities, fuel inventory, spare parts and others) would add about 10%-20% to the cost. But capital cost projections have risen dramatically in recent years, with recent estimates for total costs ranging from $1700 to $3550 per kW, depending on technical and fuel specifications and without carbon capture or sequestration… The increase in IGCC construction costs is no surprise, [because] U.S. prices for various construction and industrial materials have risen rapidly from 2001 to 2006… These underlying increases in input costs affect the entire industry, but appear to have a strong impact on IGCC. The unknown factor is whether these price increases are cyclical or permanent. Clearly, power plants to be built within the next few years will be markedly more expensive than expected when first proposed, and the cost of IGCC, even without CCS, is not competitive at this time with pulverized coal-based technologies…
>
> "Perhaps more significant is that the early public excitement about IGCC was often missing an important element… the additional cost of CCS. Notwithstanding questions about where the CO_2 would be pumped and whether that form of storage would be 'permanent', CCS raises the overall capital cost of a power project. Further, its associated internal demand for energy decreases the generating plant's overall fuel efficiency by significant amounts, whether the CCS is added to a coal IGCC, a pulverized coal plant, or a natural gas combined cycle plant. For example, reports that were recently released by EPRI and by the (NETL) estimate that CCS will increase the installed costs of IGCC by about 32% to 50%, depending on the technology selection and type of coal burned. Also, the fuel utilization efficiency will decline by about 15% to 30%. Non-fuel O&M costs are also higher when capture and sequestration are added. In short, capture and sequestration inflate both the fixed costs and the short-run marginal cost."[59]

This discussion by Pace illustrates how tenuous the estimates of capital and operating costs can be for technology such as IGCC with CCS, particularly when such technology does not have a track record. The lesson is to be cautious in formulating projections of the costs of IGCC with CCS, and to allow significant margins for cost escalation in both capital and O&M costs.

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[58] WorleyParsons Study, p. 25.
[59] Pace Global Energy Services, *IGCC Outlook, Second Quarter 2007*, pp. 2-3.

Operating and Maintenance Costs

For Cases 1 and 2, we assume that operating and maintenance (O&M) costs could be 10% higher than assumed in the Pace Reference Case due to the possibility of higher rates of escalation in various cost categories, such as labor and materials. In the Pace Study, the escalation rate for variable O&M costs was assumed to equal the inflation rate of 2% per annum. No sensitivity analysis was conducted with regard to O&M costs.

In its Annual Energy Outlook 2009, the Energy Information Administration projected that, for IGCC with CCS, variable O&M costs would be $4.54 per MWh in 2008 dollars, which is $5.01 per MWh in 2015 dollars assuming an annual inflation rate of 2%. The Pace Study, by contrast, starts its variable O&M cost series at $3.06 per MWh in 2015 (in 2015 dollars). Consequently, EIA has projected variable O&M costs to be 64% higher than assumed by the Pace Study, leaving considerable room to examine the sensitivity of rate impacts to differences in the variable O&M costs of the TEC plant. Our 10% increase in variable O&M is therefore conservative.

Fuel Costs

For Cases 1 and 2, we assume that Illinois coal costs are 10% higher than assumed in the Pace Reference Case. This contrasts with Pace's procedure, which used in all of its states of the world a single 30-year coal price series projection developed by Wood MacKenzie.

The price of Illinois coal is uncertain for several reasons. First, as the history of the past few decades demonstrates, fuel prices, including coal prices, are volatile. Second, Illinois coal prices can be subject to their own uncertainties. The CCPSL partially decouples Illinois coal from the larger national coal market: because CCPSL mandates that TEC must purchase Illinois coal, there is a possibility that TEC, as a captive coal customer, will be subject to price-gouging by Illinois coal producers. Third, there are uncertainties in the coal delivery costs that TEC will face. According to the KBMD Study, "Illinois bituminous coal will be delivered to the Facility by truck" although the Facility's site layout will allow space for the receipt of coal by rail "in the event that competitive conditions make it advantageous to deliver coal by rail."[60] Coal delivery costs are thus subject to uncertainties in trucking and rail shipping rates.

Revenue Offset Assumptions

Pace's rate impact estimates are reduced by its assumptions that the TEC facility will be able to obtain certain credits and revenues. If those credits and revenues are smaller than assumed, then the rate impacts will be higher than those found by the Pace Study.

IRS Q45 CO_2 Tax Credits

The Pace Study includes IRS Section 45Q CO_2 tax credits as an offset to emissions costs in the rate impact analysis. From society's perspective, this is not a benefit at all: it is merely a transfer of income from federal taxpayers to Illinois electricity customers; and Illinois taxpayers pay a part of that bill. But Pace is correct in recognizing that Illinois electricity customers will benefit from this tax subsidy (at the expense of other states' taxpayers).

[60] KBMD Study, p. 17-18.

As Pace also recognizes, however, the credits are capped at 75 million tons and could be exhausted before the end of ten years. Thus, there is some doubt about the total value of the Section 45Q credits assumed as offsets to emissions costs in the Pace analysis. The development of several integrated gasification combined cycle generation facilities around the country that will include CCS technology suggests that a plausible scenario could have these credits exhausted within five years, rather than the full ten assumed by Pace. This is the scenario that we consider in our Case 2.

Electric Capacity Prices

There are four reasons to doubt that TEC will be able to earn revenues in the PJM capacity market at the level projected by the KBMD and Pace Studies.

First, TEC must comply with PJM rules that will make the quantity of capacity salable in the PJM market substantially smaller than the net physical capacity of TEC. These rules impose specific obligations on generators offering capacity into the PJM capacity market. The obligations include: 1) offering the energy of the unit into the Day-Ahead Market; 2) permitting PJM to recall the energy from the unit under emergency procedures; 3) providing outage data to PJM; 4) providing energy during the defined high-demand hours each year; and 5) assuring that the energy output from the resource is deliverable to PJM load. Because the CCPSL requires the Illinois utilities and ARES to enter 30-year Sourcing Agreements with TEC, and because TEC must therefore sell a significant part of its energy to utilities and ARES that are serving loads within the Midwest ISO market (e.g., Ameren and ARES supplying in the Ameren service territories), the TEC cannot offer its entire net capacity into the PJM capacity market. Selling capacity into the PJM market would require TEC to develop complex arrangements to deal with the inevitability that its capacity will sometimes be called by PJM during emergencies or high-demand hours. At the very least, TEC would have to substantially derate its capacity offered to PJM to account for its contractual commitments to non-PJM Illinois utilities and ARES.

Second, Pace's capacity price projections are far above the most recent results of the capacity market auction, for the 2012/2013 delivery year.[61] For this auction, RTO-wide prices were $16.46 per MW-day.[62] If such prices prevailed for the first ten years of the TEC's operations, capacity revenue would be roughly half what Pace has predicted even if TEC offered its entire capacity into the PJM market, which it cannot do.

Third, for the TEC facility to secure any revenues from the PJM capacity market in the first couple of years of operation (2015 and 2016), it would have to satisfy all of the resource requirements to qualify as a capacity resource prior to and be able to commit its capacity in the auction held in May 2011 for the 2014-2015 delivery year and in May 2012 for the 2015-2016 delivery year. In May 2011, assuming the TEC project was to get the green light from the Illinois legislature in late 2010, construction would have only just begun on the facility. It would be extremely risky to commit any capacity in the PJM market from the facility that early in the construction phase of the project. Likewise, 2012 will be two and a half years away from completion, if the project is on schedule. Furthermore, it would be risky to commit

[61] The PJM capacity market delivery year is defined as the period starting June 1 and ending May 31.
[62] For the auction results, see PJM Interconnection, *2012/2013 Base Residual Auction Results*, http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item06.

capacity for the 2015-2016 delivery year when the facility will only just be "warming" up in 2015. Because of these risks, Pace's capacity revenues for the earliest years of TEC's life are doubtful.

Fourth, Pace's forecast of PJM capacity prices is too high because of expected growth in demand-side participation. The recent history of PJM's capacity market indicates that demand-side provision of capacity can drastically reduce capacity prices.

Other Issues

The KBMD Study and the Pace Study identify several benefits of the TEC project that do not appear to enter Pace's estimates of rate impacts. If, in particular, revenues from SNG sales, sulfur sales, and NOx allowance credit sales were taken into consideration in the Pace analysis, the revenue offsets from these would lower the overall rate impact of TEC and the economic impact on the Non EC group would be reduced accordingly. Because these benefits are a part of the public discussion of the TEC project, a brief examination of these benefits is warranted in spite of their apparent exclusion from Pace's rate impact analysis.

SNG Sales

In considering the possibility that the TEC project may sometimes sell gas to other entities, neither the KBMD Study nor the Pace Study seems to have explored the availability of firm pipeline transportation capacity. The Panhandle Eastern Pipeline (PEPL) website[63] suggests that there is limited firm capacity available at the present time. In addition, PEPL has limited storage capability. Consequently, it is not clear how TEC will be able to get the market price for SNG in peak periods if it cannot get it to market. The utilities served by PEPL will have their peak-period supplies lined up ahead of time, so firm transportation service on behalf of TEC's SNG sales likely will be limited.

CO_2 Sales for Enhanced Oil Recovery

The \$8.9 million of annual CO_2 revenues identified by the WorleyParsons Study are very speculative. The CO_2 sales would supposedly be made to Denbury Onshore, L.L.C., which has entered into a "conditional offtake agreement" that is subject to Denbury determining it is financially feasible to construct a 700-mile pipeline to transport the CO_2 captured at TEC to the Gulf Coast. This determination may depend upon whether Denbury finds other CO_2 sources in the Midwest that it could transport via this possible new pipeline. For a variety of reasons, Denbury may determine that it is not economically viable to build the pipeline infrastructure necessary to buy the CO_2 captured by TEC. In fact, both the Kentucky and Indiana legislatures have this year have failed to give Denbury the condemnation power that it needs to site its pipeline: the Indiana bill died in early March; and the Kentucky legislature adjourned its spring session without acting on its bill.

Furthermore, the potential use of CO_2 for enhanced oil recovery (EOR) is subject to at least two uncertainties. First, lower oil prices would make the use of CO_2 for EOR less viable. Second, the use of CO_2 for EOR may not meet federal rules for use of best available control technologies as specified by EPA.

[63] http://infopost.panhandleenergy.com/InfoPost/jsp/frameSet.jsp?pipe=pepl

Sulfur Sales

Sulfur is a byproduct of the gasification process. The KBMD Study mentions that it may be possible to obtain revenues from the sale of this sulfur. It seems doubtful that the TEC facility would be able to generate significant revenue flows from the sale of sulfur, however, because, as noted by the Nexant Study, "the marketing of sulfuric acid is complicated due to the highly fragmented nature of the market. Tenaska would need to retain an experienced sulfuric acid marketer to perform this task."[64] The Nexant Study also notes that the area in which TEC is located is a net exporter of sulfur, both currently and for the foreseeable future. This suggests that TEC would find itself in a competitive market if it attempts to sell the molten sulfur to local sulfuric acid producers. The speculative nature of these sulfur revenues may explain why they were apparently not considered as part of the rate impact study, and suggests that they should not be considered in any future analysis. It is possible that, instead of enjoying revenues from sulfur sales, TEC will have to pay to have sulfur removed from its site.

NOx Allowance Sales

The WorleyParsons Study identifies revenues from NOx allowance credit sales as one of the revenues that could be expected for the TEC facility. Although the Pace Study does not use the NOx allowance sales revenue stream in its rate impact analysis, it does project NOx allowance prices based on an assumption that the NOx rules in place for the first ten years of TEC operations are equivalent to what was in place prior to the introduction of the NOx Budget Trading Program under the NOx SIP call in 2003.[65,66] As Pace apparently recognizes, however, the current and future NOx allowance market has little resemblance to the earlier market. With increasing compliance and a significant downward trend in NOx emissions, NOx allowance prices are expected to continue to decline from their present levels. Projections of NOx annual allowance prices are in the neighborhood of $1000, compared to $4000 range predicted by Pace.[67] The revenue from the NOx allowance market would at best be a fraction of the $18.1 million annual figure claimed by WorleyParsons.

Commercial Operation Date

Commercial operation is supposed to begin in early 2015; but many things can go wrong between here and there. Plant construction will require coordination among numerous independent firms, which may or may not go smoothly. The delivery of major components of the plant require widening roads, reinforcing bridges, raising various utility wires, modifying barge landings, and other measures that could be delayed and thereby add months to the completion of various phases of the construction process. Responsibility for resolving problems may not always be clear, thus delaying resolution. Some of the TEC project's technologies are new and unproven, testing and synchronization may also take longer than projected.

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[64] Nextant Study, p. 29, Exhibit 10.1.7.
[65] Pace Study, p. 57, Exhibit 47.
[66] The very high NOx allowance prices that occurred in the 2003 to 2004 period were attributable (among other factors) to market participants adjusting to meet new, tougher requirements and to new fundamentals affecting the expected marginal costs of abatement. The temporarily higher prices reflected market uncertainties as firms evaluated information on control installations, energy demand, and other factors that would affect compliance decisions and overall cost of control under the NOx Budget Trading Program.
[67] ICAP Energy, *Environmental Markets Brief*, Volume 1, Issue 3, March 2009.

Estimated Impacts on Illinois Electricity Rates

In contrast to Pace's approach, we present rate impact estimates that distinguish between "eligible" retail customers (ECs) (i.e., residential and small commercial customers with demand of 100 kW or less) that are served by the utilities and non-eligible customers (Non ECs) (i.e., all other customers, including commercial customers, industrial customers, churches, and condominium associations) that are mostly served by ARES. This distinction is important because the annual incremental cost of the TEC facility must be allocated between these two groups of customers (and their respective suppliers) in such a way as to limit the increase in costs to the EC group to 2.015%, while there is no limit to the increase in cost to the Non EC group served by the ARES. It is also important because the initial retail rates for the EC group and the Non EC group differ significantly, with the rates for the latter being sharply lower. Pace makes no such distinctions in its analysis.

Figure 2 shows the percentage rate impacts for Pace's Reference Case when the TEC-induced electricity cost increase is appropriately parsed between the EC and Non EC groups. The figure plots three series:

- The "Pct Change for All Customers" shows the overall rate impact of TEC on all customers relative to 2009 prices.
- The "Pct Change EC Group" series shows the rate impact on the EC group (i.e., small residential and commercial customers) given that this group has the benefit of a 2.015% cap on the rate impact.
- The "Pct Change Non EC Group" series represents the rate impact on Non EC customers, again considering that EC customers enjoy a 2.015% cap.

Figure 2 shows that, under the Pace Reference Case, the overall rate impact on all Illinois customers is about 2.75% in the early years of the TEC project's life and gradually falls to the 2% level over the course of a quarter of a century. The EC group is partly insulated from this rate impact by the 2.015% cap, which is binding until about 2040, when the overall rate impact finally falls below the cap level. The Non EC group ends up picking up the costs that the cap helps the EC group avoid. In the early years of TEC's life, the Non EC group suffers of 4% rate impact, which gradually falls to the 2% level over the next quarter century. In summary, the EC group faces an average rate impact of 2% over the first 30 years of the TEC project life, while the Non EC group faces an average 3% impact over those years.

Figure 2
Pace Reference Case – Percentage Impacts

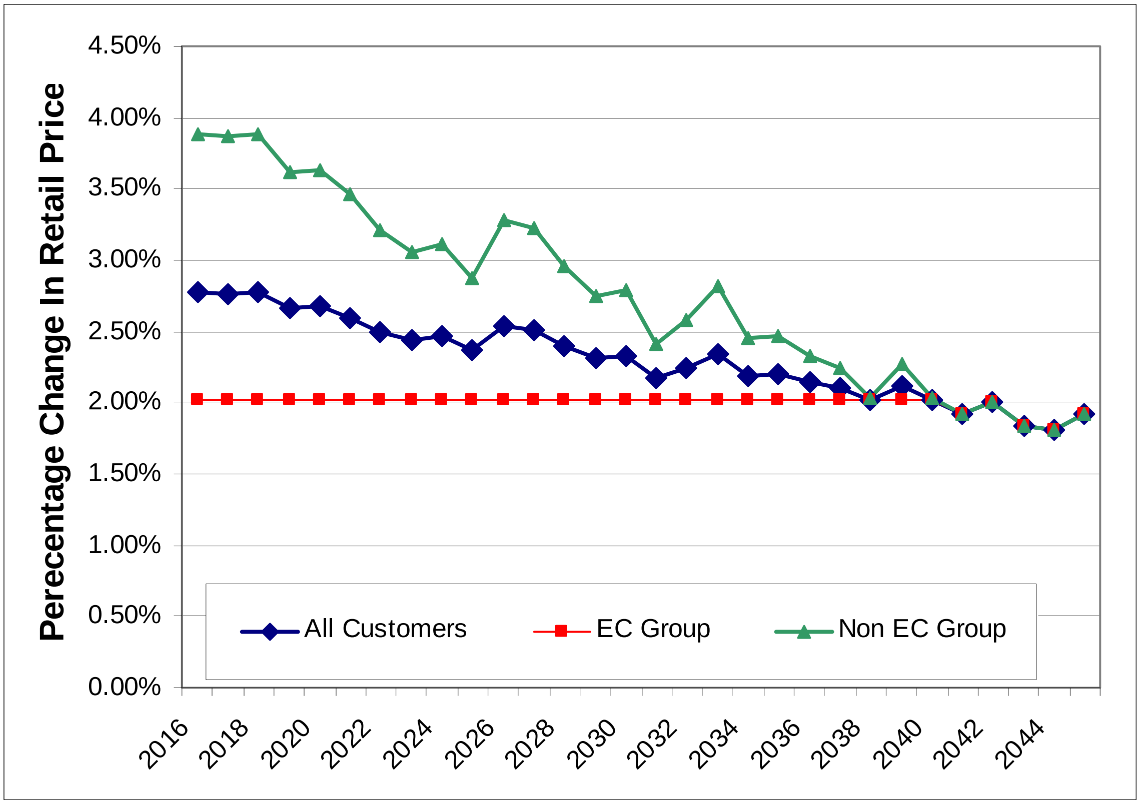
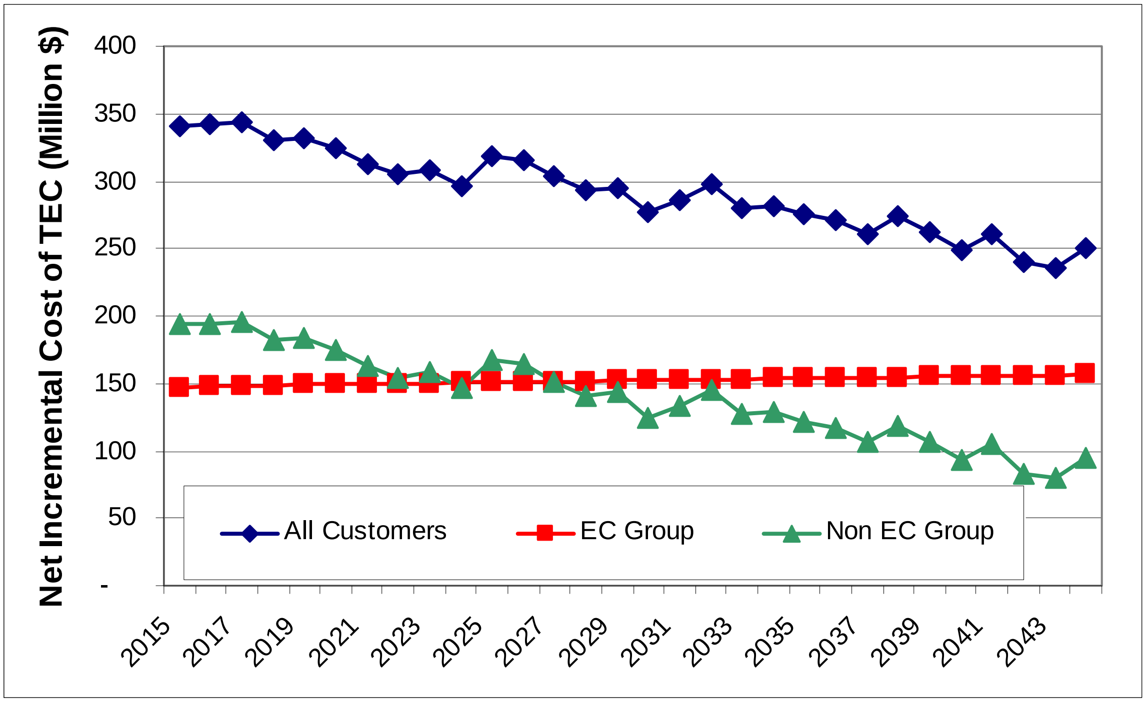


Figure 3 shows the nominal dollar impacts under the Pace Reference case for the EC and Non EC groups. The "All Customers" curve shows the Pace result that an average of about $292 million per year extra would be spent on electricity by Illinois consumers if the TEC facility comes into being, with this impact ranging between a high of $344 million per year (in 2017) and a low of $236 million per year (in 2043). Because of the 2.015% cap, the extra charges to the EC group would average $152 million per year over the 30-year period. The excess costs that are passed on to ARES and their customers, would average $140 million per year over the 30 years.

Figure 3
Pace Reference Case – Dollar Impacts



In the remainder of this section, we present the rate impacts for each of the alternative sets of assumptions defined in Table 13 of Section 0.

Cost Escalation Case

The Cost Escalation Case takes the Pace Reference Case and, as discussed in Section 4.1, assumes that various cost elements of the TEC facility are higher than have been assumed in the Pace analysis. Figure 4 shows that, for this case, the overall rate impact is significantly higher than in the Pace Reference Case, averaging 3% for the entire period. Again, the EC group is partly protected from higher prices, with the CCPSL law restricting the rate increase for EC's to 2.015% for the whole 30 years of the analysis. Consequently, the higher excess costs of the TEC project under this Cost Escalation Case go entirely to the ARES and their Non EC customers, imposing on these customers a rate impact that averages nearly 4.5% for the entire 30-year period.

Figure 4
Cost Escalation Case – Percentage Impacts

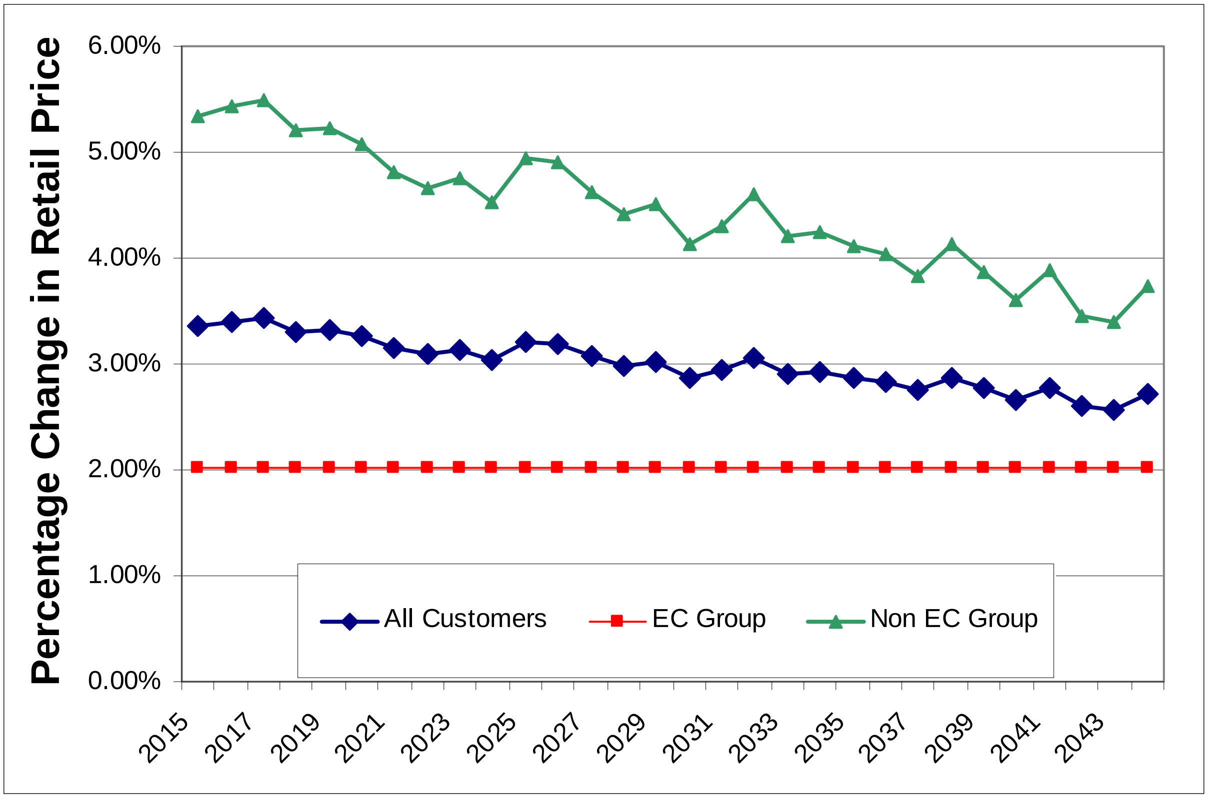
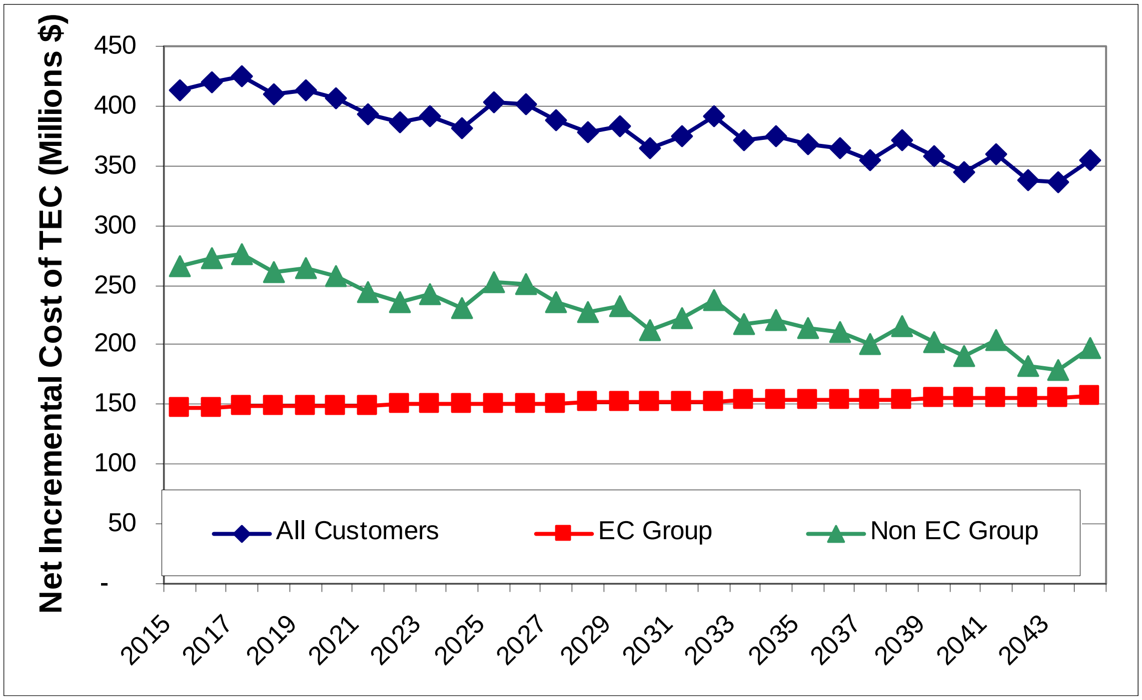


Figure 5 shows that, for the Cost Escalation Case, "All Customers" will pay an annual average of $381 million more per year with the TEC plant than they would without that plant, and that they will do so for at least thirty years. These extra payments will range between a high of $425 million (in 2017) per year and a low of $335 per year (in 2043). Of the $381 million, EC group customers will pay an average of $152 million more per year while Non EC group customers will pay an average of $229 million more per year.

Figure 5
Cost Escalation Case – Dollar Impacts



Cost Escalation Plus Revenue Offset Reduction Case

This Case 2 starts with the Cost Escalation Case and reduces or eliminates two of the revenue offsets assumed in the Pace Reference Case:

- Capacity market prices are set 50% below those projected by Pace; and
- Section Q45 CO_2 tax credits are assumed to be exhausted after five years rather than after the ten years assumed by Pace.

Figure 6 presents results for this second case. Compared to the Cost Escalation Case, the impact of the TEC facility on Illinois rates is a bit higher. The "Pct Change for All Customers" series averages about 3% for the entire 30-year period, the EC group faces a price impact that is at the 2.015% cap for the entire period, and the Non EC group experiences rate impacts averaging about 4.75% over the 30 years, relative to 2009 benchmark rates.

Figure 6
Cost Escalation Plus Revenue Offset Adjustment Case – Percentage Impacts

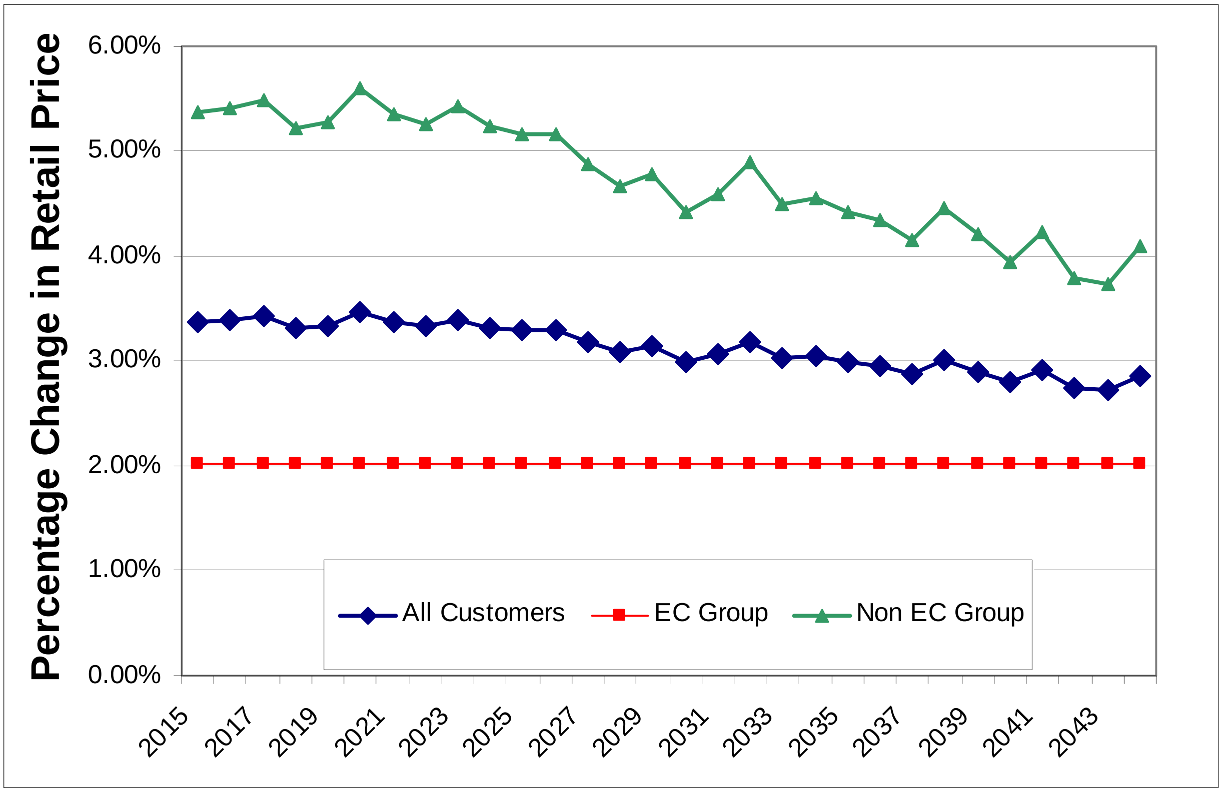
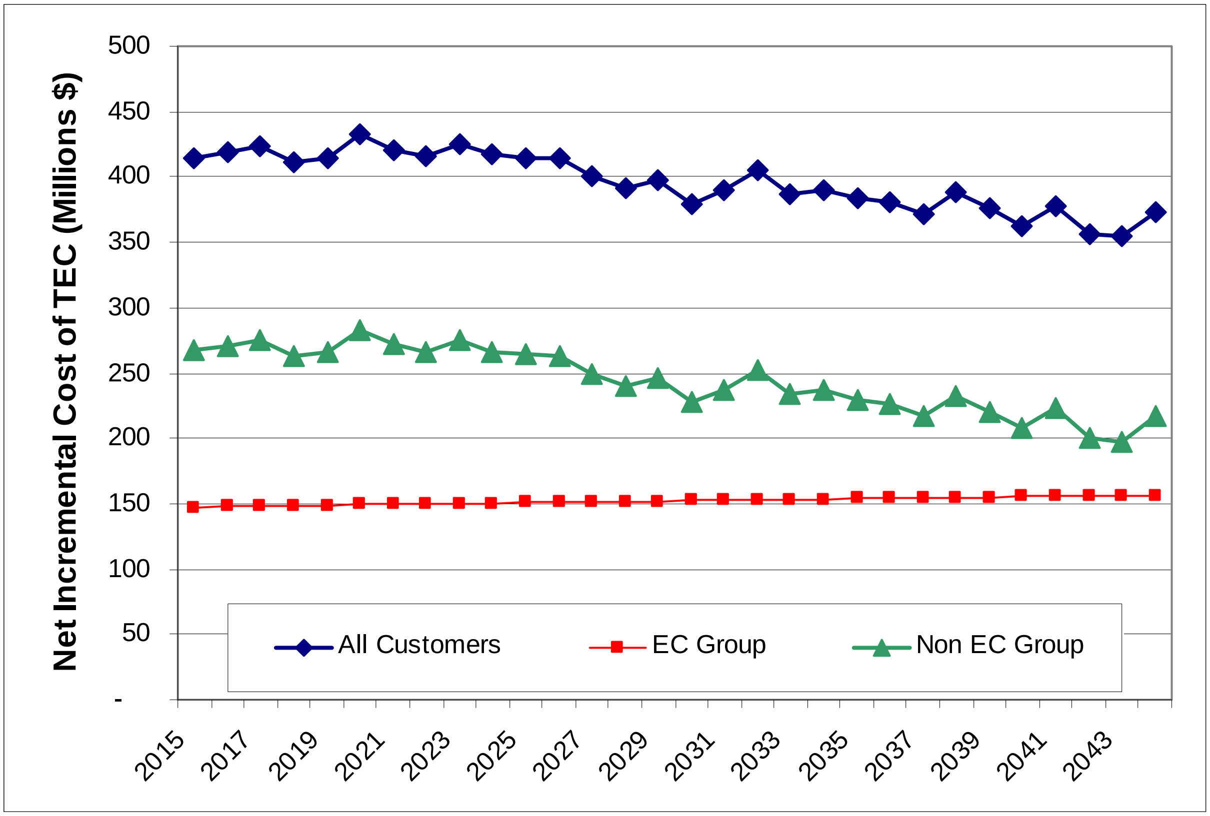


Figure 7 shows that, under this Case 2, the extra costs of the TEC project amount to $396 million per year for All Customers, with the EC group bearing its capped share of $152 million, and the Non EC group absorbing the excess of $244 million per year. The impact in the first ten years of TEC's operations will be the most devastating, with all customers paying extra costs averaging $420 million per year and the ARES' customers bearing an average of $271 million more in electricity costs.

Figure 7
Cost Escalation Plus Revenue Offset Adjustment Case – Dollar Impacts



No Sequestration Case

There is one additional scenario that warrants mention because it would significantly affect the TEC project's economics and would significantly raise the electricity costs of customers in the Non EC group. As acknowledged by the WorleyParsons Study, it is possible that TEC may not be able to store its captured CO_2 through either delivery to Denbury or through geological storage in its own storage field. The WorleyParsons Study notes that, in such an event:

> "[TEC] would earn no CO_2 sales revenue and would not receive any production tax credits, and would also incur the cost of purchasing carbon emission allowances (if applicable) for the CO_2 that it is not able to store. However… [TEC] would not be compressing CO_2, so this cost would be saved. The projected net annual effect of these changes would be an increase in costs… of approximately $63 million per year on average for the first 10 years and $137 million per year on average over 30 years."[68]

Figure 8 and Figure 9 present the percentage rate increases and the total cost impacts of the TEC plant under a "No Sequestration Case," which is based on the Pace Study Reference Case and the incremental cost impacts as stated in the WorleyParsons Study. Figure 8 shows that, if TEC cannot sell its CO_2 to

[68] WorleyParsons Study, p. 82.

Denbury and cannot sequester it, the overall percentage rate impact relative to 2009 prices averages just above 3% for the 30-year period. The impact on ARES customers is worse, averaging 4.71% during the first 10 years of operation and 5.71% over the last 20 years of operation.

Figure 8
No Sequestration Case – Percentage Impacts

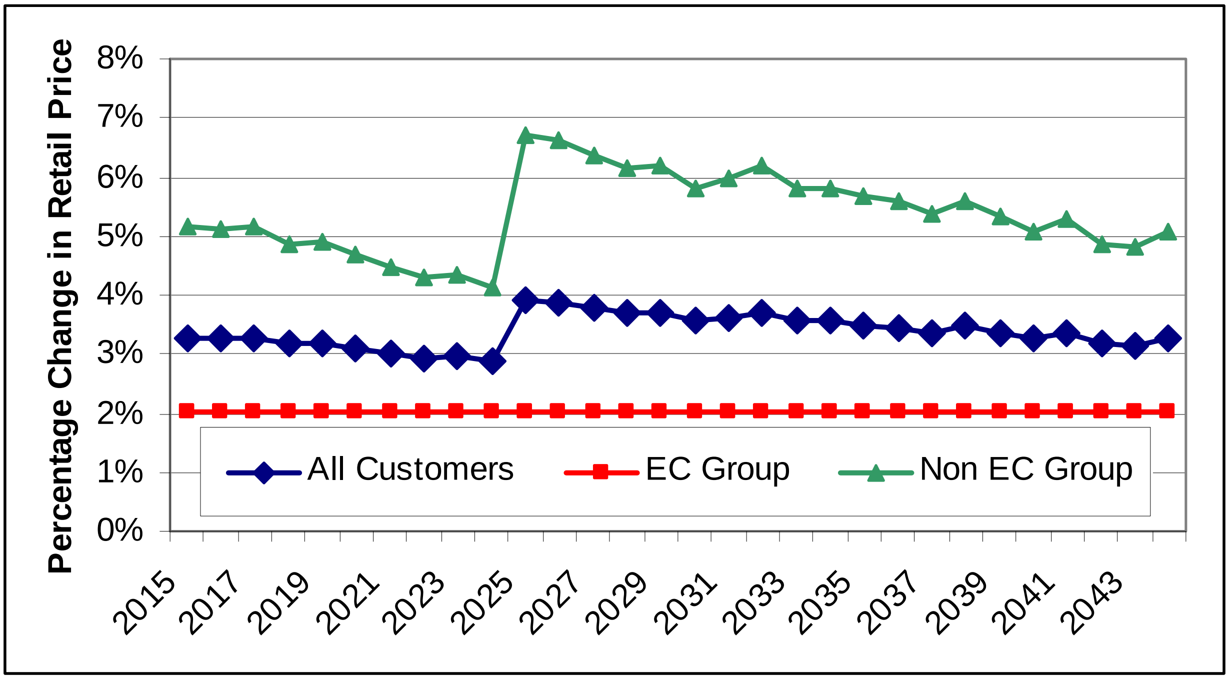
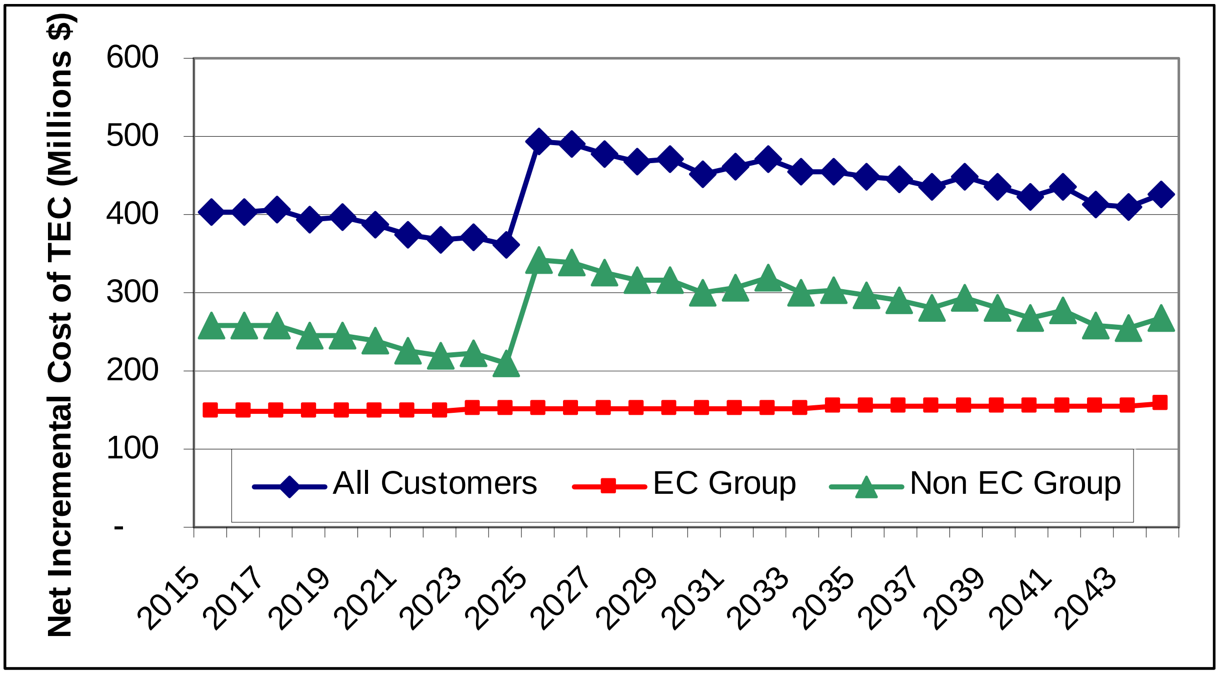


Figure 9 presents the total cost impact under this scenario. The extra payments by All Customers due to the TEC plant range from a low of \$360 million per year (in 2024) to a high of \$493 million per year (in 2025), with an average \$429 million per year. While the EC group is limited to paying an average of \$152 million per year, the Non EC group will pay an average of \$277 million per year due to the TEC plant. Given that the Non EC group will pay an average of \$140 million per year extra in the Pace Reference Case with sequestration, the costs of TEC's failure to sequester CO_2 would be entirely borne by the Non EC group – that is, essentially by Illinois businesses – to the tune of \$137 million per year.[69]

[69] \$106 = \$246 - \$140.

Figure 9
No Sequestration Case – Dollar Impacts



Estimated Impacts on the Illinois Economy

The electricity price increases induced by the TEC project will make Illinois a less attractive place to do business relative to other states, and will therefore reduce business investment and jobs in Illinois. Thus, although the CCPSL may appear to shield "eligible" retail electricity customers from the rate shock that could happen under the various scenarios considered, the residential and small commercial customers who comprise this EC group will nonetheless "feel the pain" indirectly in the form of job losses and/or lower earnings as the TEC project drains the Illinois economy of billions of dollars. State government itself will share in the adverse impacts through lower tax revenues and higher expenditures on social services, as well as in higher electricity bills for state government.

Reduced Demand for Electricity by Large Customers

Price increases for the Non EC group, which includes large commercial and industrial customers, can be translated into estimates of changes in business demand for electricity.[70] This can be accomplished by tying demand changes to price changes through estimated elasticities of demand for electricity.[71] The economic literature provides many estimates of price elasticities of demand for commercial and industrial customers in both the short-run (when demand response is relatively small) and the long-run

[70] We can find no discussion in the Pace Study of the impact of higher retail electricity prices resulting from TEC on the demand for electricity by Illinois customers.
[71] The elasticity of demand for a good is defined as: a) the percentage change in demand for the good that accompanies a small percentage change in the price of the good; divided by b) the small percentage change in the price of the good.

(when demand response is relatively large). Table 14 summarizes the elasticity ranges found in the literature.

Table 14
Estimates of Short-Run and Long-Run Price Elasticity of Demand for Electricity

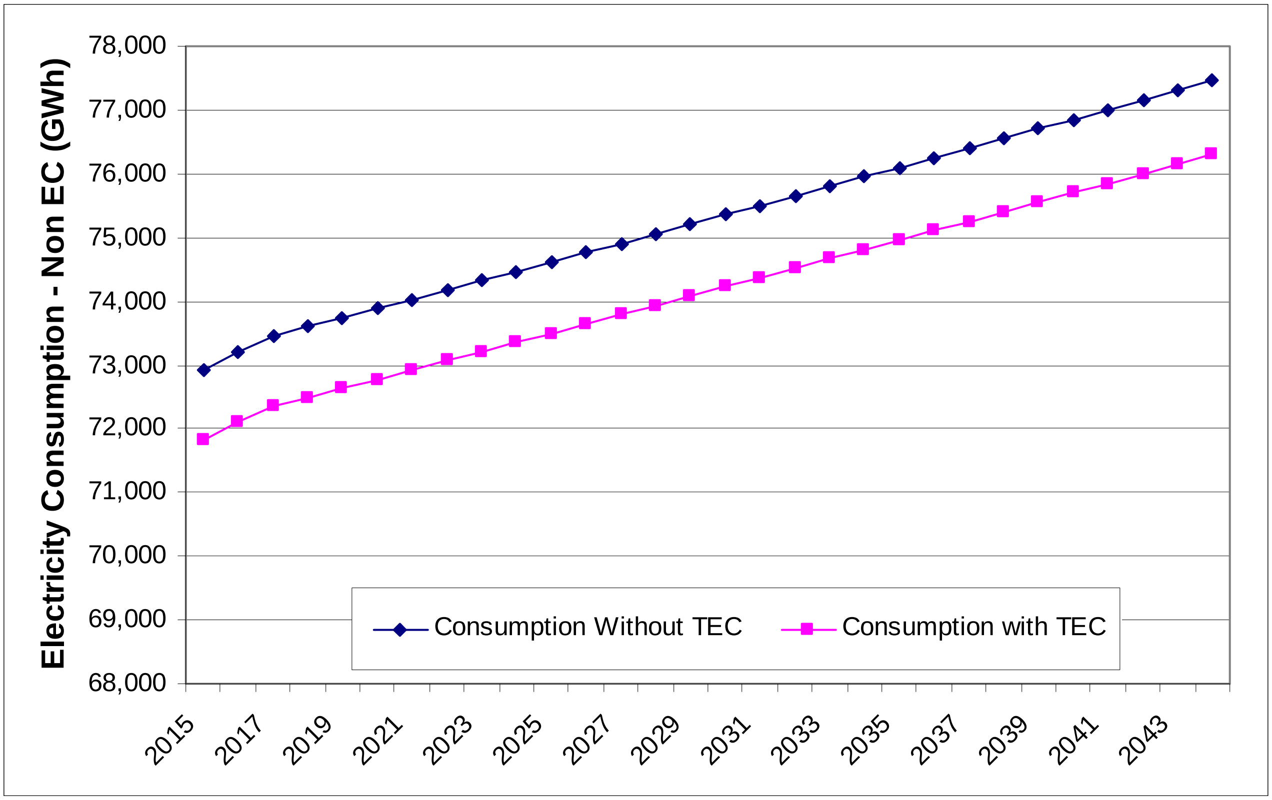
Elasticity Type	Residential	Commercial	Industrial
Short-run	-0.35[72] -0.45 to -1.89[73]		
Long-run	-0.85[74] -0.75 to -0.90[76]	-1.0 to -1.6[75]	-0.51 to -1.82 -0.80 to -1.76[77] -0.85[78] -0.79[79]

To compute the impacts on electricity demand by the Non EC group, we assume that the large commercial and industrial long-run own price elasticities equal -0.5. This elasticity figure is at the (absolute) low end of the commercial and industrial elasticities shown in Table 14 and therefore provides a conservative (low) estimate of the negative impacts of higher retail electricity prices on the Illinois economy.

Figure 10 shows how Illinois' GWh per year of electricity demand for the Non EC group will fall if TEC induces rate increases averaging 3% per year relative to the 2009 benchmark price. With a price elasticity of -0.5, the electricity consumption (GWh) will fall by about 1.5%.[80]

[72] J.A. Espey and M. Espey, "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities," *Journal of Agricultural and Applied Economics*, 36(1): 65-81, April 2004.
[73] D.R. Bohi, *Analyzing Demand Behavior; A Study of Energy Elasticities*, The Johns Hopkins University Press, 1981.
[74] Espey and Espey, *op cit*.
[75] Bohi, *op cit*.
[76] C.A. Dahl, "A Survey of Oil Demand Elasticities for Developing Countries," *OPEC Review*, XVII(4): 399-419, Winter 1993.
[77] J. Roy, A.H. Sanstad, J.A. Santhaye, and R. Khaddaria, *Substitution and price elasticity estimates using inter-country pooled data in a translog cost model*, Lawrence Berkeley National Laboratory, June 1, 2006.
[78] R.S. Pindyck, "Interfuel Substitution and the Industrial Demand for Energy: An International Comparison," *Review of Economics and Statistics*, pp. 169–179, May 1979.
[79] G.M. Griffin and P.R. Gregory, "An Intercountry Translog Model of Energy Substitution Responses," *American Economic Review*, pp. 845–857, December 1976.
[80] The percentage increase in price each year would be less than shown in Figure 2 if the revenue requirement without TEC were permitted to increase with the rate of inflation (i.e., retail rates were permitted to increase at the rate of inflation). In that case, the reduction in electricity consumption by the Non EC group will be slightly less than shown in Figure 10.

Figure 10
Impacts of TEC-Induced Price Increases on Illinois Non EC Electricity Demand



Reduced Jobs and Earnings

If the TEC permanently increases Illinois electricity prices by an average of 3% relative to the 2009 prices, we estimate the number of Illinois jobs lost and earnings reduced in the commercial and industrial sectors of the state economy relative to 2009 employment levels and 2009 average weekly earnings.[81] Table 15 presents the results of our computations.

[81] Illinois Department of Employment Security, Current Employment Statistics Program, Economic Information and Analysis, - I_NSA_CES_Illinois_MSAs_Hours_Earnings_2003_to_Current.xls and I_NSA_CES_Illinois_MSAs_Jobs_1990_to_Current.xls, obtained at http://lmi.ides.state.il.us/cesfiles/cesmenu.htm.

Table 15
Estimate of Job Loss and Earnings Reductions Due to Sustained TEC Retail Rate Impacts

	2009 Employment	Reduction in Jobs	Reduction in Earnings
Industrial Sector			
Construction	219,100	534	$ 34,435,739
Manufacturing	577,600	1,408	$ 49,351,156
Durable Goods	339,400	827	$ 30,043,323
Non-Durable Goods	238,100	580	$ 19,263,166
Sub-Total: Industrial Sector	1,374,200	3,350	$ 133,093,385
Commercial Sector			
Wholesale Trade	291,000	709	$ 26,051,223
Retail Trade	597,000	1,455	$ 27,871,124
Transportation, Warehousing, and Utilities	252,500	615	$ 11,788,038
Information	106,400	259	$ 10,027,327
Financial Activities	371,800	906	$ 35,147,959
Professional and Business Services	784,900	1,913	$ 74,200,197
Educational and Health Services	817,100	1,992	$ 60,164,216
Leisure and Hospitality	516,200	1,258	$ 24,412,517
Other Services	257,400	627	$ 17,092,582
Government	857,400	2,090	$ 40,027,976
Sub-Total: Commercial Sector	4,851,700	11,826	$ 326,783,158
Total	6,225,900	15,176	$ 459,876,542

The projected job losses are derived in the following manner. Based upon the information in Table 14, we conservatively assume an own price elasticity of demand for electricity of -0.5 for both the industrial and commercial sector categories. The percentage change in labor employed in each sector is computed according to the following formula:[82]

$$\%\Delta L_i \quad = \quad \eta_i^{LY} \times \eta_i^{YE} \times \eta_i^{E} \times \%\Delta P_E$$

where $\%\Delta L_i$ is the percentage change in Labor employed in the i[th] sector, η_i^{LY} is the elasticity of demand for labor in sector i with respect to the output of that sector, η_i^{YE} is the elasticity of the output of sector i with respect to the electricity consumption of that sector, η_i^{E} is the own-price elasticity of demand for

[82] This expression for the percentage change in labor demand resulting from a percentage change in the price of electricity can be derived directly from the specification of a general production function involving labor and electricity as inputs. Refer, for example, to H. Varian, *Microeconomic Analysis*, third edition, W.W. Norton & Co., 1992. This formula performs the same type of computation as would be found in an input-output analysis.

electricity by sector i, and $\%\Delta P_E$ is the percentage change in the retail price of delivered electricity. The empirical literature has generally found the first two elasticities to have values less than one.[83] If we assume that all sectors have an output elasticity of labor equal to 0.65, an output elasticity of electricity equal to 0.25, and (based on Table 14) an own-price elasticity of demand for electricity equal to -0.5, and that there is a 3% increase in the retail price of delivered electricity to Non EC customers, the percentage change in employment will be a negative 0.24% in all sectors.[84] The number of annual jobs lost is computed by multiplying the percentage reduction in jobs by the number of persons employed in each industrial or commercial sector in 2009.

These job loss estimates represent the difference between what Illinois jobs would be without the TEC plant and what they would be with the Illinois plant, on average, over a 30-year period. The job losses will occur because businesses will take electricity costs into account when contemplating whether to locate operations in Illinois or someplace else, or whether to schedule production or service at Illinois locations or at their locations elsewhere. Some of the job loss may be existing jobs, but most of the job loss will likely be jobs that will be created elsewhere rather than in Illinois. In other words, the job losses will not occur on the day that the TEC plant begins operation, but will instead occur over time as businesses weigh the long-term higher costs of Illinois electricity in making their locational decisions, implicitly recognizing that the higher electricity costs imposed by TEC on Illinois will persist for decades.

Table 15 indicates that, over three decades, an average of about 3,400 jobs will be lost in the industrial sector, with a reduction in annual earnings of approximately $113 million (2009 dollars). For the commercial sector, the job loss is projected to be about 11,800, with lost annual earnings of about $327 million (2009 dollars). The total potential job loss is projected to be about 15,200, with a reduction in earnings of about $460 million (2009 dollars).

For the cases in which TEC is unable to sequester its CO_2 emissions, the job and economic impacts are even worse. In the Pace Reference Case with no sequestration, the percentage rate increase for the Non EC group is predicted to be an average of about 5.4% over the 30-year period, which would result in a loss of around 27,000 jobs. For the Cost Escalation Case with no sequestration, the percentage increase in electricity rates for the Non EC group is estimated to be 7%, which would lead to about 35,000 in job losses.

[83] See for example, R.H.Rasche and J.A Tatom, *Energy Resources and GNP*, Federal Reserve Bank of St. Louis, 1977.

[84] -0.24% approximates 0.65 times 0.25 times -0.5 times 3%. The 0.24% figure may be biased upward if the first two elasticities actually have values less than those we assume. On the other hand, the 0.24% figure may be biased downward because: a) Table 14 indicates that the own-price elasticity of demand for electricity is likely to have an absolute value greater than 0.5; b) the various figures in Section 4 show that the Non EC group is likely to see price increases larger than 3%; and c) the job impacts are based upon 2009 employment levels, which (because of population growth and economic growth) are likely to be significantly lower than those seen over the next thirty years. On balance, the combination of these considerations implies that the 0.24% figure is more likely to be low rather than high, so that the estimated job losses are more likely to be low rather than high.

Reduced State Income Tax Revenues

The Illinois state personal income tax rate is 3% of federal adjusted gross income (AGI). Assuming that AGI is 75% of gross earnings, based on the estimated reduction in earnings relative to the 2009 level of employment and earnings presented in Table 15, the estimated reduction in personal income tax revenues at the 2009 level are estimated to be about $10.35 million.[85]

Increased Cost of Electricity for State Government

The State of Illinois spends approximately $82 million per year on electricity. A sustained increase in electricity prices of 3% per year relative to 2009 prices, will mean that the State will pay an additional $2.5 million per year for its electricity.

Conclusions and Recommendations

The Pace Study is subject to all of the uncertainties that inevitably complicate forecasts of future economic outcomes. In defining its future states of the world, it has considered only some of the uncertainties that impact Illinois retail rates, and has ignored other uncertainties that have large impacts on Illinois rates. These latter uncertainties include those in core plant capital costs, interest rates, construction costs, fuel costs, and revenue offsets. When the latter uncertainties are considered, the range of plausible rate impacts can be seen to include outcomes that are more adverse than are found by Pace. Furthermore, separate consideration of rate impacts on eligible and non-eligible customers indicates that while the eligible customers would be protected by the 2.015% rate cap, the customers served by ARES will bear a significantly larger electricity rate impact relative to 2009 rates – ranging between 3% and 4.75%, depending upon scenario – for the entire 30-year period.

Contrary to the implicit claims of the WorleyParsons Study, what matters to the Illinois economy, and the people of Illinois, are the *net* impacts of the TEC project, not the *gross* impacts. The fact that the TEC project will create a certain number of jobs is important; but it is also important that some of those jobs will be created elsewhere if TEC is not built, and that the high costs of the TEC project will suck dollars and jobs from other sectors of the Illinois economy. When the adverse economic impacts of TEC project are considered, it turns out the TEC project will result in a net job and income loss for Illinois. Yes, Illinois' coal industry benefits, and it is reasonable to hope that the TEC project can advance a CO_2-reducing technology; but the TEC project is being subsidized, by federal loan guarantees and by the CCPSL's cost guarantees, precisely because the TEC project requires government mandates to obtain the resources that it needs. Those resources will be given to the TEC project at a net cost to the people of Illinois.

[85] $10.35 million equals $459.88 million times 3% times 75%.

About Christensen Associates Energy Consulting LLC

CA Energy Consulting is a wholly owned subsidiary of Laurits R. Christensen Associates, Inc., which has been serving the electric power industry and other infrastructure industries since 1976. CA Energy Consulting's focus on energy markets covers a broad range of technical and policy issues concerning wholesale and retail electricity market restructuring, market design, power supply, franchise license agreements, cost of capital, determination of revenue requirements, asset evaluation, transmission pricing, market power, and retail rate design. Our clients include electric utilities, regulatory agencies, power developers and generation companies, public cooperatives, transmission companies, municipalities, distribution companies, consumer advocates, and industry associations. We have represented clients in numerous state and federal regulatory proceedings focused on revenue requirements, cost allocation, transmission plans, wholesale power supply and contracts, transmission service agreements, market power, market design, RTO participation, cost of capital, cost and performance benchmarking, retail service design, demand response, cost-of-service allocation, and marginal cost estimation.

About the Authors

Mathew J. Morey, Ph.D. (University of Illinois, Urbana-Champaign, 1977) is a Senior Consultant. He specializes in transmission congestion management and pricing systems, market monitoring, market design and incentive regulation. From 2000 to mid-2003, Dr. Morey worked as an independent consultant. Prior to that Dr. Morey served as Chief Economist with the Edison Electric Institute from 1996 to 2000. Dr. Morey has testified before state regulatory agencies and the FERC on a wide range of industry restructuring issues including stranded costs, market power, utility-affiliate transfer pricing rules, regulatory policy regarding the design of distribution standby rates and transmission rates, and the costs and benefits of RTOs. Dr. Morey's clients have included investor-owned utilities, public power entities, electric cooperatives, state regulatory agencies, independent transmission companies, electricity consumer coalitions, and national trade associations. Dr. Morey has published scholarly work in the *Journal of Econometrics*, the *American Economic Review*, the *Southern Economic Journal,* the *Journal of Economic Development and Cultural Change*, the *Proceedings of the American Statistical Association* and *The American Statistician*. His work has also appeared in *Electric Perspectives, Public Utilities Fortnightly* and *The Electricity Journal*.

Laurence D. Kirsch, Ph.D. (University of Wisconsin-Madison, 1982) is a Senior Consultant. He specializes in economic analysis for the electric utility industry, including studies of bulk power markets, power pool operations, electric power system cost structures, and reliability costs. Dr. Kirsch has expertise in the pricing and operating practices of U.S. independent system operators and regional transmission organizations, and has provided comments and testimony to the Federal Energy Regulatory Commission as well as to state commissions. He has developed and applied methods for estimating the real-time marginal energy and reliability costs of both generation and transmission; has developed methods for costing and pricing unbundled ancillary services; has also evaluated the potential for market power in generation service markets, including the interaction of market power with transmission congestion; has participated in the development and implementation of pricing policies for independent power producers; has evaluated the merits of various schemes for auctioning wholesale power; and has assessed a wide variety of utility pricing practices.

Michael P. Welsh, Ph.D. (University of Wisconsin-Madison, 1986) is a Senior Economist. He has over 20 years of experience in the areas of environmental economics and quantitative methods. Past projects have dealt with the assessment of the market values of hydropower and the associated downstream riparian impacts of alternative release regimes, public acceptance of green power programs, and the treatment of renewable energy credits. Prior to working at Christensen Associates, Dr. Welsh managed numerous environmental economics projects at Hagler Bailly and HBRS Inc. His work has been published in the *Journal of Environmental Economics and Management*, *American Journal of Agricultural Economics*, and *Land Economics*.

CITY OF PANA, ILLINOIS
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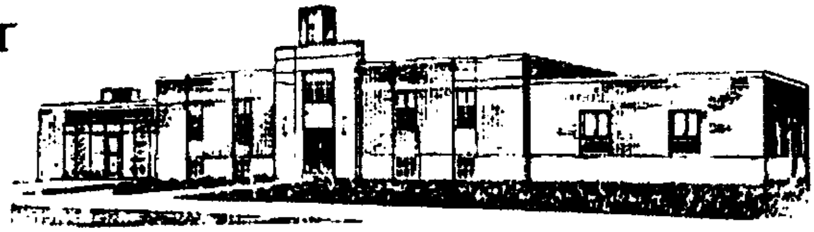

4/13/10

Mr. Tim Anderson, Executive Director
Illinois Commerce Commission
527 East Capital Avenue
Springfield, Illinois 62701

Dear Mr. Anderson;

Enclosed you will find three (3) original, signed resolutions from the City of Pana, Pana Industrial Corporation, and the Pana Chamber of Commerce. These resolutions are in support of the Christian County Generation IGCC Power Plant as being proposed by Tenaska.

Thank You,
CITY OF PANA, ILLINOIS
OFFICE OF DEVELOPMENT

James A. Deere, Director

RESOLUTION #10-05

City of Pana, Illinois - Resolution of Support

Whereas, Christian County Generation, LLC is moving toward completion of plans to build and operate one of the first Integrated Gasification Combined-Cycle (IGCC) electric generating stations with carbon capture, and

Whereas, managing partner Tenaska has worked closely with the communities of Pana, Taylorville, Illinois, and Christian County to site and develop the project, and

Whereas, both national government and electric industry projections state that Illinois needs additional reliable electric generating capacity, and

Whereas, central and southern Illinois possess large reserves of high-sulfur coal that would be valued as fuel in an IGCC power plant at a projected rate of $75 million per year (a total of 1.5 million to 1.8 million tons annually), and

Whereas, the Taylorville Energy Center IGCC plant would be among the first power plants in the world with the ability to remove fuel impurities associated with emissions from coal-fueled power plants, including sulfur, mercury, and particulate matter, and

Whereas, the plant's planners are committed to incorporating cutting-edge technology to capture more than half of the carbon dioxide produced at the plant and prevent it from entering the atmosphere, giving the facility an emissions profile comparable to a natural gas-fueled plant, and

Whereas, Illinois employment would be increased by more than 5,000 jobs during the construction phase of the power project, most of them in the Christian County area, and

Whereas, the electric power generation facility will employ 155 permanent employees and contractors in Christian County, and add indirect employment of an additional 644 full-time and part-time jobs will also be created in the county as a result of electric power generation operations, and

Whereas, an added 238 long-term workers would be employed in coal mining in support of the plant's operations, which would create an additional 297 permanent indirect jobs, and

Whereas, local economic activity would increase by approximately $126 million annually during commercial operation.

Now therefore, *The City of Pana, Illinois and the Pana City Council* hereby endorses the Taylorville Energy Center IGCC plant with carbon capture, which provides a new market for the long-struggling Illinois coal industry; incorporates the most advanced emission control technology, including carbon capture, to make it among the cleanest coal-fed power plants in the world; and brings thousands of needed jobs through construction and hundreds more through operation of the facility to Christian County, Pana, Taylorville and the surrounding region. We further urge the State of Illinois and its elected representatives to take swift and positive action to review the Facility Cost Report and approve it to advance the project.

SIGNED

Steven D. Sipes, Mayor____________________Date__04/12/2010__

Terry Klein, City Clerk____________________Date__04/12/2010__

seal

Pana Industrial Economic Development Corporation (PIDC) Resolution of Support

Whereas, Christian County Generation, LLC is moving toward completion of plans to build and operate one of the first Integrated Gasification Combined-Cycle (IGCC) electric generating stations with carbon capture, and

Whereas, managing partner Tenaska has worked closely with the communities of Pana, Taylorville, Illinois, and Christian County to site and develop the project, and

Whereas, both national government and electric industry projections state that Illinois needs additional reliable electric generating capacity, and

Whereas, central and southern Illinois possess large reserves of high-sulfur coal that would be valued as fuel in an IGCC power plant at a projected rate of $75 million per year (a total of 1.5 million to 1.8 million tons annually), and

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Whereas, an added 238 long-term workers would be employed in coal mining in support of the plant's operations, which would create an additional 297 permanent indirect jobs, and

Whereas, local economic activity would increase by approximately $126 million annually during commercial operation.

Now therefore, *Pana Industrial Development Corporation* hereby endorses the Taylorville Energy Center IGCC plant with carbon capture, which provides a new market for the long-struggling Illinois coal industry; incorporates the most advanced emission control technology, including carbon capture, to make it among the cleanest coal-fed power plants in the world; and brings thousands of needed jobs through construction and hundreds more through operation of the facility to Christian County, Pana, Taylorville and the surrounding region. We further urge the State of Illinois and its elected representatives to take swift and positive action to review the Facility Cost Report and approve it to advance the project.

Pana Industrial Development Corporation

Tom Dean, President	**McCracken Dean Funeral Home**
John Livesay, Vice-Pres.	**First National Bank of Pana**
John Livesay	
Mike Trexler, Treasurer	**Mike Trexler CPA**
Jim Deere, Secretary	**City of Pana – Development Director**
Jim Deere	
Jim Centko, Director	**Centko Construction Co.**
Jim Centko	
David Dorn, Jr. Director	**Dorn Farms, Inc.**
DAVID DORN JR	
Tom Latonis, Director	**Pana News Palladium**
Tom Latonis	
A.J. Wiss, Director	**Pana Iron Company/Bite Size Computers**
AJ Wiss	

Pana Chamber of Commerce Resolution of Support

Whereas, Christian County Generation, LLC is moving toward completion of plans to build and operate one of the first Integrated Gasification Combined-Cycle (IGCC) electric generating stations with carbon capture, and

Whereas, managing partner Tenaska has worked closely with the communities of Pana, Taylorville, Illinois, and Christian County to site and develop the project, and

Whereas, both national government and electric industry projections state that Illinois needs additional reliable electric generating capacity, and

Whereas, central and southern Illinois possess large reserves of high-sulfur coal that would be valued as fuel in an IGCC power plant at a projected rate of $75 million per year (a total of 1.5 million to 1.8 million tons annually), and

Whereas, the Taylorville Energy Center IGCC plant would be among the first power plants in the world with the ability to remove fuel impurities associated with emissions from coal-fueled power plants, including sulfur, mercury, and particulate matter, and

Whereas, the plant's planners are committed to incorporating cutting-edge technology to capture more than half of the carbon dioxide produced at the plant and prevent it from entering the atmosphere, giving the facility an emissions profile comparable to a natural gas-fueled plant, and

Whereas, Illinois employment would be increased by more than 5,000 jobs during the construction phase of the power project, most of them in the Christian County area, and

Whereas, the electric power generation facility will employ 155 permanent employees and contractors in Christian County, and add indirect employment of an additional 644 full-time and part-time jobs will also be created in the county as a result of electric power generation operations, and

Whereas, an added 238 long-term workers would be employed in coal mining in support of the plant's operations, which would create an additional 297 permanent indirect jobs, and

Whereas, local economic activity would increase by approximately $126 million annually during commercial operation.

Now therefore, The ***Pana Chamber of Commerce*** hereby endorses the Taylorville Energy Center IGCC plant with carbon capture, which provides a new market for the long-struggling Illinois coal industry; incorporates the most advanced emission control technology, including carbon capture, to make it among the cleanest coal-fed power plants in the world; and brings thousands of needed jobs through construction and hundreds more through operation of the facility to Christian County, Pana, Taylorville and the surrounding region. We further urge the State of Illinois and its elected representatives to take swift and positive action to review the Facility Cost Report and approve it to advance the project.

PANA CHAMBER OF COMMERCE

Bob Smith, President	George Heintz, Vice President	Jim Deere, Sec.- Tres.
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