TAYLORVILLE ENERGY CENTER

WorleyParsons
resources & energy

Facility Cost Report

February 26, 2010

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Disclaimer

This report has been prepared pursuant to the Illinois Clean Coal Portfolio Standard Law (Public Act 95-1027) and Illinois Department of Economic Opportunity Grant Number 10-481001 on behalf of, and for the exclusive use of, Christian County Generation, L.L.C., and is subject to and issued in accordance with the agreement between Christian County Generation, L.L.C. and WorleyParsons Group Inc. (WorleyParsons).

Taylorville Energy Center

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Table of Acronyms, Abbreviations and Frequently Used Terms

Acronym	Definition
1x1 Configuration	Operating with one combustion turbine generator and one steam turbine generator
2x1 Configuration	Operating with two combustion turbine generators and one steam turbine generator
Air Liquide	Air Liquide Process & Construction, Inc.
ARES	Alternative Retail Electric Suppliers
ASU	Air Separation Unit
BOP	Balance of Plant – includes all off-Site infrastructure upgrades and interconnections. It does not include any facilities located on the Site,as those are included in the Core Plant
Burns & McDonnell	Burns & McDonnell Engineering Company
CCG	Christian County Generation, L.L.C.
CO_2	Carbon dioxide
Core Plant	All equipment, materials and work required for the SNG Island, the Power Island and shared facilities for the TEC located on the Site.
Denbury	Denbury Onshore, L.L.C.
DOE	U.S. Department of Energy
Electric Utilities	Illinois investor-owned electric utilities
EPC	Engineering, Procurement and Construction
EOR	Enhanced Oil Recovery
Facility	Taylorville Energy Center
FEED	Front End Engineering and Design
FEED Study	Front End Engineering and Design Study, conducted by Kiewit/Burns & McDonnell for the TEC

FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
FNTP	Full Notice to Proceed
ft.	Feet
ICCPSL	Illinois Clean Coal Portfolio Standard Law (Illinois Public Act 95-1027)
IEPA	Illinois Environmental Protection Agency
IGCC	Integrated Gasification Combined Cycle
KBMD	Joint venture consisting of the construction firm of Kiewit Energy Company and the engineering firm of Burns & McDonnell Engineering Company selected to conduct the FEED Study for the TEC
Kiewit	Kiewit Energy Company
kV	Kilovolt
kWh	Kilowatt-hour
Lurgi	Lurgi GmbH
Market Savings	Savings that are expected to be achieved by all electric customers in Illinois as a result of the beneficial effect on market prices of adding base load and dispatchable capacity to the Illinois market
Mgd	Million gallons per day
MISO	Midwest Independent Transmission System Operator
MMBtu	Million British thermal units
MMSCF/d	Million standard cubic feet per day
MT	Metric ton (2,205 lbs)
MW	Megawatt
MWh	Megawatt-hour
NOx	Nitrogen oxides

Owner's Engineer	WorleyParsons Group, Inc.
O&M	Operations and Maintenance
Pace	Pace Global Energy Services, LLC
Patrick Engineering	Patrick Engineering, Inc.
PEPL	Panhandle Eastern Pipe Line
Performance Model	References the two commercially available process models that were utilized to validate and predict TEC's performance – Aspen Plus® for the SNG Island and GateCycle™ for the Power Island
PJM	PJM Interconnection, LLC
Power Island	All equipment, materials and work required for the power production facilities
Project	Taylorville Energy Center
RAM	Reliability, Availability and Maintenance
REX	Rockies Express
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
Schlumberger	Schlumberger Carbon Services
SDD	Sanitary District of Decatur, Illinois
Siemens	Siemens Energy Inc., Energy Services Division
Site	713 acre site on which the TEC will be built
SNG	Substitute Natural Gas (methane)
SNG Island	All equipment, materials and work required for the SNG production facilities
SO_2	Sulfur dioxide
Sourcing Agreements	Agreements between the initial clean coal facility and Illinois Electric Utilities and ARES
Syngas	Synthesis gas (H_2 + CO)

take-off	Calculation of the material quantity and type required to build a designed structure or item
TEC	Taylorville Energy Center
Tenaska	Tenaska, Inc.
TIPS	Treasury Inflation Protected Securities
Tons	Unless otherwise indicated, short tons (2,000 lbs.)
WACC	Weighted Average Cost of Capital
Wood Mackenzie	Wood Mackenzie Ltd.
WorleyParsons	WorleyParsons Group, Inc.

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Exhibit 13.2.a	Schlumberger Carbon Services Summary Results for Carbon Storage Feasibility Study
Exhibit 13.2.b	Schlumberger Carbon Services Cost Report for the Taylorville Energy Center

FORWARD

The Illinois Clean Coal Portfolio Standard Law requires the owner of the initial clean coal facility to submit to the Illinois Commerce Commission, the Illinois Power Agency and the General Assembly a facility cost report, prepared by duly licensed engineering and construction firms, setting out the anticipated project costs, the method of financing, the operating and maintenance costs, an analysis of the ability of the facility to deliver power into the regional transmission organization markets, and the facility's expected capacity factor.

This document has been prepared in accordance with the requirements of the Illinois Clean Coal Portfolio Standard Law and comprises the facility cost report as required by that statute.

A critical part of the facility cost report for the "initial clean coal facility" is the requirement that the anticipated construction costs be determined based on a front end engineering and design (FEED) study. Conduct of a FEED study involves all engineering design and other activities necessary to translate an owner's needs into an engineered design to estimate the project costs.

There are only a handful of engineering and construction firms that have the requisite experience and resources to perform a FEED study for a complex facility such as the Taylorville Energy Center. Christian County Generation invited five qualified firms to make proposals to serve as the FEED study contractor. FEED study proposals were received from three firms.

Christian County Generation ultimately selected a joint venture consisting of the construction firm Kiewit Energy Company and the engineering firm Burns & McDonnell Engineering Company to perform the FEED study. In addition to their excellent general qualifications and outstanding international reputations, Kiewit and Burns & McDonnell had specific experience advantages over their two competitors. Kiewit had recently served as the contractor for the Dallman 4 unit in Springfield, Illinois, and both Kiewit and Burns & McDonnell had already been engaged in early FEED study work for the proposed Cash Creek gasification facility in western Kentucky.

Kiewit and Burns & McDonnell commenced the FEED study work in April 2009. The early portion of the study period included selection of technologies and equipment for the Taylorville Energy Center. Among the most important decisions were (i) gasifier technology; (ii) gas processing technology; (iii) combustion turbine selection; (iv) zero liquid discharge design; and (v) Power Island cooling technology selection. In order to provide the best overall performance and cost, Christian County Generation ultimately selected Siemens Energy, Inc. gasification technology, Lurgi gas processing technology, Siemens Energy, Inc. combustion turbines, a GE steam turbine and an air-cooled condenser (rather than a wet cooling approach).

In parallel with its selection of the FEED study contractor, Christian County Generation solicited proposals from leading engineering firms for owner's engineer services. Five firms submitted proposals and were interviewed to determine which firm had the best qualifications to act as owner's engineer for the Taylorville Energy Center project. In addition to preparing this Facility Cost Report, the owner's engineer's role is to provide technical guidance to Christian County Generation through the development, construction and commissioning periods, and to review key project deliverables. Christian County Generation ultimately selected WorleyParsons Group, Inc. for this role based on the breadth of its experience in the power sector and with process engineering and gasification technologies.

Respectfully submitted,

Christian County Generation, L.L.C.
By TENASKA TAYLORVILLE, LLC
Its Managing Member

1.0 Executive Summary

1.1 Overview

The Taylorville Energy Center (TEC, Facility or Project) will be the cleanest commercial-scale coal-fueled plant of its kind in the world, converting Illinois coal into pipeline quality substitute natural gas (SNG), and then efficiently burning the SNG to produce electricity. The TEC design is fundamentally different from existing coal generating plants and from most other proposed "clean coal" plants, in that the TEC will burn clean SNG rather than coal to generate electricity. In addition to exceptional conventional pollutant performance, the TEC will be a net reducer of carbon dioxide (CO_2) and other emissions as it displaces higher emitting Illinois facilities.

The Facility is based on an integrated gasification combined cycle (IGCC) process. It will use state-of-the-art emissions controls and carbon capture and storage technologies, along with a dry cooling system that will efficiently use treated wastewater and not discharge any process water. The Facility is being developed by Christian County Generation, L.L.C. (CCG) and will be located on a 713 acre site (Site) in Christian County, Illinois. An affiliate of Tenaska, Inc. (Tenaska) is the managing member of CCG.

The TEC will use SNG it converts from Illinois coal to fuel a conventional natural gas power block with two combustion turbine generators and one steam generator (2x1 Configuration). When operating in the 2x1 Configuration, the Facility will have a gross electrical generating capacity of 716 MW and net electrical generating capacity of 602 MW, equivalent to the consumption of approximately 600,000 Illinois homes. One of the benefits to ratepayers of the Project is that CCG will have the flexibility to idle one of the two combustion turbines (1x1 Configuration) and sell SNG into the natural gas market during certain electric off-peak periods when market conditions make such sales economically attractive, with the proceeds of such sales being credited to electric customers. When operating in 1x1 Configuration, the Facility will have a gross electrical generating capacity of 395 MW and net output of 285 MW, and will have an estimated 535 MMBtu per hour of pipeline quality SNG – the equivalent gas consumption of approximately 43,000 Illinois homes – available for sale into the domestic interstate pipeline system.

This Facility Cost Report is based on the assumption that construction of the TEC will commence in December 2010. In order to meet the December 2010 construction start date, among other things, the Illinois E.P.A. must complete its work in updating the TEC's air permit to conform to the requirements of the Illinois Clean Coal Portfolio Standard Law (ICCPSL). CCG also must close on its financing, which will require the U.S. Department of Energy (DOE) to complete its environmental review and credit documentation so the $2.579 billion DOE loan guarantee can be issued. Section 4 of this report addresses escalation in capital costs from the date of the estimate to the construction start date of December 2010. In addition, Section 4 discusses the effects of escalation and the potential impact on Project capital cost in the event construction does not begin by December 2010.

Based on a December 2010 construction start date, the TEC is scheduled to commence commercial operation in December 2014 following a 48-month construction period.

1.2 Project Benefits

The citizens of the State of Illinois will realize a number of significant direct and indirect benefits as a result of the construction and operation of the TEC. Those benefits include:

- **Construction Jobs** – At the peak of construction, approximately 2,470 workers will be employed on Site, with an estimated 9.6 million total man hours required over the four-year construction period;

- **Permanent Jobs** – During the Facility's 30+ year operating life, approximately 155 full-time employees (including CCG and contract employees) will work at the Site. In addition, coal required to fuel the TEC will result in the addition of approximately 175 mining jobs and 75 trucking jobs;

- **Additional Economic Activity** – Once the Project is in commercial operation, annual local expenditures, including Illinois coal purchases, are estimated to be approximately $126 million;

- **Ability to Cleanly Utilize High Sulfur Illinois Coal** – The TEC will use between 1.5 and 1.8 million tons of Illinois coal per year, proving that Illinois coal can be used in an environmentally responsible manner.

- **Numerous Offsetting Credits and Revenues to Reduce Rate Impact** – From a DOE Loan Guarantee, to environmental credits and lower market prices for electricity, the TEC will pass numerous benefits directly through to ratepayers to reduce the Project's rate impact.

1.3 Sourcing Agreements Under the ICCPSL

The ICCPSL, which became effective in June 2009, provides that the "initial clean coal facility" will enter into 30-year agreements (Sourcing Agreements) with each of the Illinois electric utilities subject to Section I-75 of the Illinois Power Agency Act (Commonwealth Edison and the three Ameren Illinois electric utilities) (Electric Utilities) and Alternative Retail Electric Suppliers (ARES). The TEC is the only project that qualifies as the "initial clean coal facility" under the terms of the ICCPSL.

Payments and any corresponding rate impact under the Sourcing Agreements will not begin until the second month after the Facility enters commercial operation. Commercial operation currently is scheduled for December 2014. Under the ICCPSL, pricing under the Sourcing Agreements is to be based on the cost of providing electricity, including level or deferred capital recovery and recovery of operating costs, and is subject to review by the Illinois Commerce Commission and the Federal Energy Regulatory Commission (FERC). All miscellaneous revenue, favorable financing cost impacts and tax credits earned by the TEC, such as revenue from the sale of substitute natural gas (SNG), will reduce dollar-for-dollar payments by the Electric Utilities and the ARES under the Sourcing Agreements.

The ICCPSL further provides that any proposed Sourcing Agreement with the "initial clean coal facility" shall not become effective without an approving enactment of the General Assembly following receipt of a Facility Cost Report.

1.4 Facility Cost Report Process

This Facility Cost Report includes (i) a summary of the FEED Study; (ii) results of a number of other studies that were undertaken to determine the projected capital and operating and maintenance (O&M) costs; and (iii) a method of financing the Facility. It also includes information with respect to operating performance, rate impact, capacity factor and environmental performance of the TEC. The cost of preparing this report (including the FEED Study described herein) has been funded in part with an $18 million grant provided by the Illinois Department of Commerce and Economic Opportunity (DCEO). This grant will be repaid when and if the TEC achieves financial closing.

Exhibit 1.4 contains additional information on the qualifications of the firms that contributed to this report.

In addition to providing the information necessary for this report, the engineering work undertaken in part with grant funds comprises approximately 10% of the total engineering necessary to construct the TEC. The FEED Study alone entailed more than 120,000 engineering hours by KBMD (the FEED Study contractor) with many tens of thousands of additional hours spent by technology providers, the Owner's Engineer and Tenaska's internal engineering staff in support of the FEED Study effort. The first step in the engineering, construction and procurement of the TEC has been taken. Now the General Assembly must decide whether the Project – and the jobs and economic benefits the Project creates – will continue.

The individual components of this Facility Cost Report, which are described in detail in later sections, include:

- **Core Plant FEED Study** - The FEED Study includes the design basis, scope of work and detailed estimate for engineering, procurement and construction (EPC) phases of the TEC;

- **Balance of Plant Analyses** - The balance of plant (BOP) analyses include the design basis, scope of work and estimate for engineering, procurement and construction of everything outside of the Core Plant;

- **Capital Cost Escalation Analysis** - This analysis, prepared by WorleyParsons Group, Inc. (WorleyParsons), evaluates the escalation of Project capital costs from January 2010 to the time when all material and labor costs become fixed;

- **Operations and Maintenance Cost Assessment** - This study, prepared by Siemens Energy Inc., Energy Services Division (Siemens), estimates fixed and variable costs associated with operation and maintenance of the Facility through the 30-year term of the Sourcing Agreements;

- **Delivered Fuel Study** - The delivered fuel study analyzes the potential sources and price of coal and the price of transportation from Illinois coal mines. The study was developed by Wood Mackenzie Ltd. (Wood Mackenzie), a recognized international energy consultant;

- **Analysis of Deliverability to Transmission Systems** - This analysis comprises a collection of studies and reports that summarize the system impact and potential upgrade costs to the regional transmission systems required to accept the electrical output of the TEC;

- **Method of Finance** – Describes Tenaska's proposed method of finance for the TEC;
- **Analysis of Capacity Factor** – Describes the capacity factor assumptions used in the FEED Study and this Facility Cost Report;
- **Rate Impact Analysis** - This analysis, developed by Pace Global Energy Services, LLC (Pace), describes the impact of the TEC on Illinois electricity rates under a reference case and under alternate cases;
- **Market Savings Analysis** – This analysis describes the savings (Market Savings) that are expected to be achieved by all electric customers in Illinois as a result of the beneficial effect on market prices of adding a facility such as the TEC. Pace conducted the market benefit analysis as part of its Rate Impact Analysis;
- **Secondary CO_2 Impact Analysis** – This study by Tenaska analyzes the effect of the dispatch of the TEC upon Illinois' electric system net CO_2 emissions, taking into account the reduction of emissions from Illinois generating sources that are displaced by energy produced at the TEC; and
- **CO2 Storage Cost and Feasibility Reports** – The primary and back-up CO_2 storage plans for the TEC are discussed in these studies.

1.5 Results Summary

This Facility Cost Report provides the results of each of the studies and analyses needed to meet the requirements of the ICCPSL. A brief summary of those results, which are discussed in detail in the body of the Facility Cost Report, is provided here.

1.5.1 *Rate Impact*

Other than municipal electric utilities or electric cooperatives, Illinois has not built a baseload plant – one that operates the great majority of the time – in more than 20 years. It is normal for such new plants to cause a rate impact when they enter "rate base." The effect of having the Electric Utilities buy power from the TEC on a "cost of service" basis and then pass through their costs in rates is to make the TEC the equivalent of a "rate base" plant.[1]

The revenue requirement used to calculate the rate impact is determined by adding together a capital recovery component, fixed operating costs, variable non-fuel O&M, fuel, tax adjustments, and an allowed return, then subtracting revenues and other credits.

Even without taking credit for the lower overall cost of power in the market that results from the TEC's increasing the market supply, the average projected rate impact over the 30-year Sourcing Agreement term is only 1.81% based on 2009 electric rates. This represents an average increase of approximately $1.82 on the average monthly bill for residential customers, or $0.06 per day beginning in 2015.

The rate impact calculation is expressed as a percentage of the average rates for eligible retail customers (basically, residential customers and small business customers) during the year ended May 2009, which was approximately $0.115 per kWh. The projected rate impact is somewhat overstated because it is being projected for periods that are many years in the future and there is no inflation adjustment to the $0.115 per kWh benchmark from 2009.

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[1] In the case of Duke Energy's Edwardsport IGCC project now under construction in Indiana, the Indiana Utility Regulatory Commission's order approving this project noted that the expected rate impact would be approximately 16%, citing testimony that this is in line with historical increases for Duke Energy Indiana from

1.5.2 *Capital Cost*

The ICCPSL requires the Facility Cost Report to estimate construction costs with and without escalation. The estimated construction costs without escalation (including the Core Plant and BOP, but excluding financing costs, taxes, insurance and start-up costs) in January 2010$ is $2.616 billion. This estimate includes $257 million of contingency. Total estimated escalation in materials and labor beyond January 2010 until the time that such costs become fixed is $184 million, which brings the estimated construction costs of the TEC with escalation to $2.801 billion. In addition, total capital costs will include an estimated $721 million in financing costs, insurance, start-up costs, process license fees and other owner's costs, as shown in Table 10.1.1.a. The estimated total "all-in" capital cost (including construction costs, escalation, financing costs, taxes, insurance, start-up costs, process license fees and other owner's costs) of the TEC is $3.522 billion.

1.5.3 *Revenues and Credits to Offset Rate Impact*

CCG has aggressively pursued numerous strategies to generate significant revenues and tax credits in order to minimize the TEC's rate impact. Unlike many other large electric generating projects, all of these benefits will pass directly through to Illinois ratepayers, rather than going to shareholders or investors. Revenues include:

- **SNG Revenues** – Over the first 10 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

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adding base load generation. *Duke Energy Indiana, Inc.*, Cause No. 43114-S1, Indiana Utility Regulatory Commission Order (Nov 20, 2007).

MT 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** – The ability to remove significant amounts of sulfur is one of the environmental benefits of the gasification process. Sales of sulfur also provide revenue to the Project. 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** – TEC's low emissions profile will qualify it for additional Clean Air Set-Aside and Early Adopter nitrogen oxides (NOx) allowances as set forth in the Illinois legislation implementing the Clean Air Interstate Rule. 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** – TEC will sell capacity into PJM's forward looking capacity market. 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 $21.9 million annually in 2010$.

In addition to direct revenues, CCG has pursued numerous Federal government incentives that will provide significant benefit to Illinois ratepayers. These include:

- **US Department of Energy (DOE) Loan Guarantee** – CCG has been selected by the DOE to enter into term sheet negotiations for a loan guarantee of up to $2.579 billion. The guarantee will result in interest savings of approximately $60 million per year, and a low projected total recoverable return on capital of 7.53%.

- **45Q Tax Credits** – Under the currently effective provisions of Section 45Q of the Internal Revenue Code, the TEC is eligible to receive carbon sequestration credits that are expected to result in approximately $22.3 million in nominal dollars per year in savings for ratepayers during the Project's first 10 years of operation.

- **Potential Cap and Trade Incentives** – If a Federal cap and trade bill should pass, bonus allowance incentives for the TEC could result in savings to Illinois electric customers of approximately $156 million in nominal dollars per year during the Project's first 10 years of operation.

Ratepayers in Illinois will receive other indirect benefits from the TEC as well:

- **PJM Market Savings** – By increasing electric supply in Illinois, all Illinois electric ratepayers will benefit from an estimated $1.2 billion in nominal dollars in savings during the TEC's first 10 years of operation as it reduces the market price of power.

- **Effective Hedge** – The TEC provides an effective hedge for Illinois electric customers against climate change regulation costs and rising natural gas costs.

1.5.4 Cost of Power

The levelized cost of power in 2010$ for the 30-year term of the Sourcing Agreements is projected to be approximately $0.15/kWh. In 2010$, the cost of power from the TEC is projected to average $0.148/kWh during the first 10 years of commercial operation from 2015 to 2024. The projected cost in nominal year dollars starts at $0.163/kWh in 2015 and is $0.191/kWh in 2024. These costs assume a 75% capacity factor for the Power Island. The projected cost per kWh would decrease if the TEC were dispatched at a higher capacity factor. However, the total rate impact would increase slightly. This is because if the TEC is dispatched at a higher capacity factor, the incremental electricity it produces would be sold in off-peak hours when the value of the electricity and the price it will command are lower. In those times, it is projected that the TEC could make more revenue and provide greater benefit to electric customers if it sells the SNG into the natural gas market instead of using it to generate electricity.

In order to provide a basis for comparing the cost of energy from the TEC to units that do not have flexibility of dispatch to operate at less than full output (like the TEC), the estimated cost per kWh should be calculated based on the assumption that the TEC is dispatched at full output 100% of the time the Facility is available (a 92% capacity factor). The estimated total cost per kWh based on the foregoing assumption is $0.133/kWh in 2010$ on average during the first ten years of commercial operation and ranges from $0.151/kWh in 2015 to $0.175/kWh in 2024 in nominal year dollars. If the Market Savings described in Section 1.4.10 were credited against the cost of power from the TEC, the projected levelized cost would be $0.119/kWh, while the net cost of power would be $0.112/kWh in 2010$ on average during the first 10 years of commercial operation and would range from $0.123/kWh in 2015 to $0.168/kWh in 2024 in nominal year dollars.

1.5.5 Summary of Method of Finance

CCG anticipates financing the TEC with a combination of $2.579 billion of 30-year, DOE-guaranteed debt from the Federal Financing Bank (FFB), together with an estimated $943 million in equity from Tenaska Taylorville, LLC, the managing partner of CCG. Tenaska Taylorville, LLC currently is wholly owned by affiliates of Tenaska.

In July 2009, CCG was selected to enter into term sheet negotiations with the DOE for a loan guarantee of up to $2.579 billion. Based on current market conditions and the anticipated guarantee terms, the DOE guarantee is expected to result in significant interest cost savings for Illinois ratepayers.

Assuming current market financing rates, the DOE loan guarantee would result in savings for electric customers of approximately $60 million each year over the 30-year term of the Sourcing Agreements, as the levelized capital recovery requirement is reduced by the interest cost savings due to the loan guarantee versus non-guaranteed financing. Over the 30-year period, the aggregate benefit of the DOE loan guarantee to TEC's electric customers is expected to be more than $1.8 billion.

The benefit of the DOE loan guarantee and the lower interest rates that it provides also is apparent in the TEC's projected total recoverable return on capital (combined debt and equity) of 7.53%, which is substantially less than Commonwealth Edison's current total return on capital (8.36% for its distribution assets and 9.45% for its transmission assets) or Ameren's current total return on capital (which ranges from 8.68% to 9.74% for its distribution assets and is 9.14% for its transmission assets).

The detailed discussion regarding the method of financing is provided in Section 8.

1.5.6 *Capacity Factor*

The TEC's annual electricity capacity factor is expected to be approximately 75%, as there are many periods during each year when market conditions will make it more economic for the TEC's electric customers to sell SNG produced by the TEC rather than to use the SNG to produce electricity. See Section 9 for a discussion of the capacity factor.

1.5.7 *Secondary Reduction in CO_2 Emissions*

The analysis shown in Section 12 demonstrates that the net effect of generation by the TEC is expected to be a reduction of approximately 1.9 million metric tons (MT) of CO_2 emissions per year, resulting in an estimated reduction in CO_2 emissions of 58.2 million MT over the 30-year term of the Sourcing Agreements. Also, it is notable that, because operating the TEC will result in old, coal-fired facilities, many in the Chicago area, being dispatched less often, not only CO_2, but SO_2, particulate (soot) and mercury emissions will be reduced by dispatching the Facility.

2.0 FEED Study, Including Capital Cost Estimate for Core Plant

The FEED Study sets out the estimated capital cost for the Core Plant. CCG selected a joint venture consisting of the construction firm of Kiewit Energy Company (Kiewit) and the engineering firm of Burns & McDonnell Engineering Company (Burns & McDonnell) (collectively, KBMD) to perform the FEED Study. The FEED Study and its associated work papers took KBMD more than 120,000 man-hours to complete and comprise many volumes of engineering specifications, drawings and reports providing the detail required to estimate all civil, structural, mechanical, electrical, control and safety system quantities used to develop the cost estimate. All of the work papers supporting the FEED Study have been made available to Boston Pacific Company (the consultant engaged by the ICC to assist in its review of this Facility Cost Report) and its engineering subcontractor, MPR Associates Inc. A FEED Study Summary, outlining KBMD's method and results, is included as Exhibit 2.0.

2.1 Project Overview

The Facility will process Illinois bituminous coal in two process islands to manufacture SNG and electrical power:

1. The SNG Island consists of:

- Two trains of gasifiers, which combine coal, steam and oxygen at high pressure and temperature to produce a synthetic gas (Syngas);
- A Syngas shift system, which catalytically adjusts the ratio of hydrogen and carbon monoxide in the Syngas to optimize the production of SNG in a methanation unit;
- One acid gas removal train, which remove contaminants (mainly sulfur and

CO_2) from the Syngas;

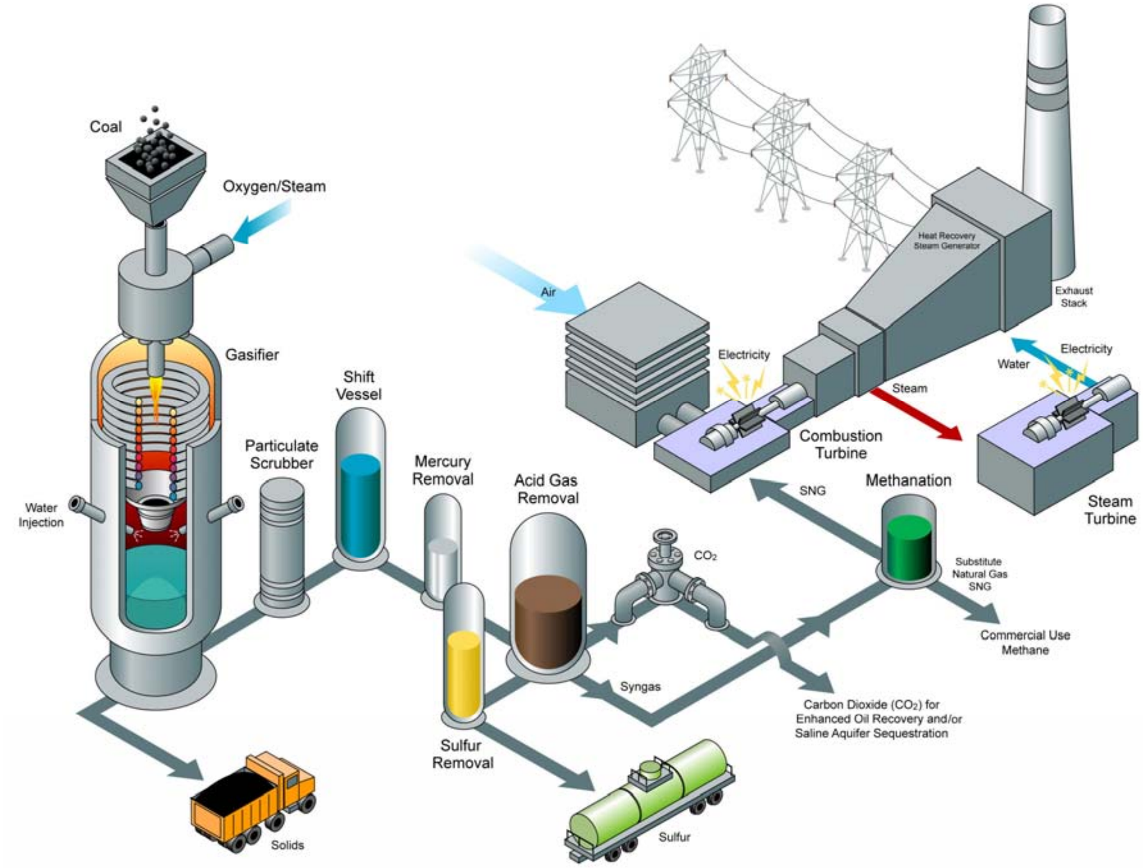
- A sulfur recovery system, which processes sulfur-laden streams into molten sulfur that can be sold as a by-product;
- A methane synthesis unit, which converts the Syngas to SNG (methane). Methane is the main constituent of natural gas; and
- A zero liquid discharge system utilized by both islands to process liquid waste streams, separating solids (for disposal) and the water for reutilization in the processes. There is no water discharge from the process islands.

2. The Power Island, which is a combined-cycle power plant that consists of:

- Two combustion turbine generators, which burn either SNG or natural gas to produce electric power;
- Two heat recovery steam generators, which recover waste heat from the combustion turbine generators;
- One steam turbine generator, which uses the waste heat to produce more electric power;
- One air cooled condenser to reject the heat from the process while reducing water consumption; and
- Electrical substation which receives the 345 kV and 138 kV interconnects.

Figure 2.1 shows a simplified diagram of the TEC's configuration.

FIGURE 2.1 – TEC CONFIGURATION



The Facility will emit significantly less CO_2 and regulated pollutants than other electric generating facilities that use coal or coal-derived fuel, while using proven technologies for coal gasification, gas processing and power generation. The Facility will produce SNG from coal to fuel the combined-cycle power plant. In addition, because the amount of SNG produced is projected to exceed the requirements of the Power Island under certain operating conditions, the Facility is designed to allow for the sale of surplus SNG into an existing interstate pipeline. The benefit of the revenue derived from such sales will inure to Illinois ratepayers via a reduction in payments required to be made by the Electric Utilities and ARES under the Sourcing Agreements.

The Facility is expected to capture approximately 1.9 million MT of CO_2 per year, which is more than 50% of the CO_2 that would otherwise be emitted at the Facility. The Project has executed a conditional offtake agreement with Denbury Onshore, L.L.C. (Denbury) for the Facility's captured CO_2, pursuant to which Denbury will purchase all CO_2 produced by the Facility and transport it via a Denbury pipeline for use in EOR efforts in the Gulf Coast region. CCG also is developing a geologic storage field near the TEC for injecting the captured CO_2 approximately 7,000 feet beneath the surface into the Mt. Simon saline formation (which underlies much of Illinois) so there will be a method of permanently storing CO_2 in the event that Denbury does not complete its pipeline or does not have capacity for the TEC's CO_2 volumes.

The Facility will be directly interconnected into the PJM Interconnection, LLC (PJM) regional transmission organization at Commonwealth Edison's Kincaid substation, approximately 14 miles from the Facility. Energy will be provided to Ameren and other customers located in the Midwest Independent System Operator (MISO) regional transmission organization through transmission service that the Facility will obtain from PJM into MISO.

The Project Description, Exhibit 2.1, provides more detail about the TEC. Attachment I to Exhibit 2.1 contains an illustration of the Facility's Site arrangement.

Natural gas will be used for start-up and as a Power Island back-up fuel. The Panhandle Eastern Pipe Line (PEPL) and the Rocky Mountain Express (REX) natural gas pipelines are located approximately nine miles north of the Facility. An interconnecting bi-directional pipeline between the Facility and PEPL will be constructed to transport natural gas and SNG to and from the Facility. This pipeline could also interconnect with REX in the future.

Illinois bituminous coal will be delivered to the Facility by truck. An approximate seven-day supply of coal will be stored on site in a covered active pile. The Facility layout will provide space for a future rail loop, rail car unloader, conveyors, coal stocking and reclaiming, and a 60-day capacity inactive coal storage pile, in the event that competitive conditions make it advantageous to deliver coal by rail.

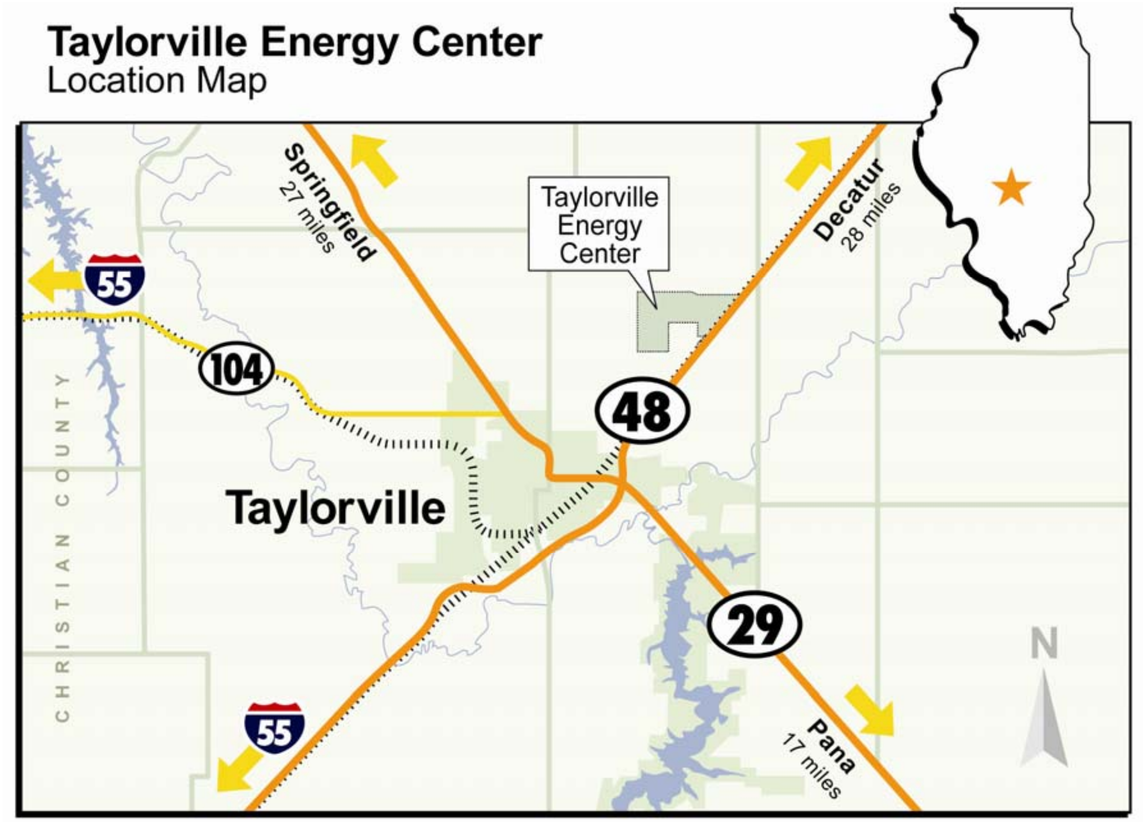
As discussed in Section 5.7, the TEC will procure oxygen and other gases from a third party and will not include the capital cost of the ASU in its rate base.

The Facility will control emissions of CO_2, mercury, sulfur compounds, oxides of nitrogen and particulates. More than 50% of the CO_2 that would otherwise be emitted from the overall Facility will be captured for EOR or injected into the Mt. Simon formation in Illinois, but in either case for ultimate geologic storage.

2.2 Facility Site

The Facility will be constructed on 713 contiguous acres in Christian County, Illinois. The Site is bounded by E1700N Road on the north, the Norfolk Southern Railroad on the east, farmland on the south, and N1400E Road on the west. Figure 2.2 is a map showing the location of the TEC.

FIGURE 2.2 – TEC LOCATION MAP



Approximately 410 acres of the Site were annexed by the City of Taylorville in 2000. The remainder of the Site is currently outside of the City of Taylorville city limits. Approximately 328 acres of the Site are zoned for industrial use (I-3). CCG anticipates that the remainder will be rezoned for industrial use. The majority of the Site is located in the Taylorville-Christian County Enterprise Zone. The Enterprise Zone is a partnership between city, county, and State government, businesses, labor and community groups to encourage economic growth.

2.3 FEED Study Results

2.3.1 Introduction

The detailed engineering documents produced as part of the FEED Study provide significant detail about the Facility. Examples of the documents produced by KBMD and the major equipment suppliers during the FEED Study include:

- Heat and Material Balances – Documents defining the composition, flow, temperature and pressure of the process streams;
- Process Flow Diagrams – Drawings depicting configuration of process equipment at a system level;
- Design Criteria – Documents defining the material and performance criteria applicable to the engineering disciplines, including structural, civil, piping, mechanical, electrical, control systems and plant design;
- Installation Specifications – Documents defining the scope of work and quantities of material included in scope of work packages;
- Equipment Datasheets – Documents specifying the process service conditions of equipment;
- Piping and Instrument Diagrams – Detailed drawings defining the overall design of the facility processes; and
- Engineering lists – Documents itemizing preliminary equipment, motor, piping and instruments required for the facilities.

Specific deliverables from the FEED Study are:

- Facility Arrangement Drawing – shows the Facility layout as prepared by KBMD and CCG. The Facility Arrangement Drawing can be found in the Basis of Estimate, which is included as Attachment I to Exhibit 2.0.
- Basis of Estimate – describes the cost estimating process and the estimate itself as prepared by KBMD, attached hereto as Attachment I to Exhibit 2.0;
- Project Performance Summary – summarizes the expected performance of

the Project. The Project Performance Summary was prepared by WorleyParsons based on deliverables provided by KBMD, Siemens and Air Liquide/Lurgi, and is further described in Section 2.3.3; and

- Project Execution Plan – describes CCG's plan to execute the Project. The Project Execution Plan was prepared by KBMD and CCG, and is attached hereto as Attachment II to Exhibit 2.0.

2.3.2 Capital Cost Estimate

KBMD and major equipment suppliers have estimated equipment and commodity quantities for the Facility based on design documents and outputs from an Intergraph SmartPlant 3D® model. These quantities have been used to provide a more precise method of estimating the cost of the Project. Entities performing off-Site studies have provided detailed cost estimates based on FEED level engineering for the remaining components of the Project.

KBMD used well-established in-house procedures to manage the estimating effort. Due to the size and complexity of the Facility, the estimate was divided into separate cost centers. The estimate does not include estimated costs for the BOP, which are addressed in Section 3, or financing costs, taxes, insurance, start-up costs, process license fees or other owner's costs, which are summarized on a total Facility basis in Section 10.1.1. Table 2.3.2.a shows the results of the KBMD estimating effort by cost center.

TABLE 2.3.2.a – KBMD CORE PLANT ESTIMATE BY COST CENTER

Cost Center	Capital Cost Estimate
Gasification	$386,376,385
Syngas Processing	392,725,450
Power Island	525,460,945
Water Treatment	187,159,747
Program Management	146,197,796
Other Core Plant*	590,455,593
JANUARY 2010$ SUBTOTAL	**$2,228,375,916**
Core Plant Escalation	179,236,347
TOTAL	**$2,407,612,263**

* includes roadways, lighting, administration buildings, warehousing, rail, coal handling and bulk storage systems and certain shared services which include medium voltage electrical distribution, waste collection, fire protection and interconnecting structural, piping and control systems

All of the estimates are detailed, bottom-up, quantity-based estimates. The KBMD team developed engineering deliverable documents and from these calculated the quantity of materials required for each system (take-offs). These quantities were then used as the basis to generate labor and material costs. Total budgeted owner's contingency for the Project, which is not shown in Table 2.3.2.a, is $257 million. Additional contractor contingency also is included in the fixed price components for the Power Island and water treatment facilities.

The direct and indirect costs are based on the construction execution plan developed by KBMD, which addresses the construction plan and schedules for the Facility.

All of the estimates developed by KBMD were compared against a second, independent in-house KBMD check estimate. Two estimating teams performed an independent material quantity take-off. The two estimating teams then met to compare calculated material quantities, resolve quantity differences and agree on the quantities to be used in the estimate. The teams then analyzed the direct and indirect work and met in an estimate review to compare production rates, man-hour factors and other elements making up the estimate.

Table 2.3.2.b is a sample of the high level quantity summary for certain materials. A more detailed Quantity Summary can be found in the Basis of Estimate, Attachment I to Exhibit 2.0, the FEED Study Summary.

TABLE 2.3.2.b – HIGH LEVEL QUANTITY SUMMARY

Description	Unit	SNG Island	Power Island and Water Treatment	Total
Pilings	EA	9,558	2,680	12,238
Concrete	Cubic Yards	100,185	29,378	129,563
Structural Steel	Tons	15,277	808	16,085
Piping	Linear Feet	522,744	131,080	653,824
Conduit	Linear Feet	892,007	418,064	1,310,071
Cable Tray	Linear Feet	72,076	17,891	89,967
Wire & Cable	Linear Feet	4,714,358	1,353,461	6,067,819

As described in the Basis of Estimate included as Attachment I to Exhibit 2.0, CCG intends the Project to 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 contract (for construction project management and installation of other Core Plant components). Under the incentive cost reimbursable contract, the contractor will share in savings if the final cost is below a target price and will bear a portion of the overrun cost if the final price is above the target price, in each case subject to an overall limit on shared amount. With this combined approach, CCG expects to take advantage of fixed price arrangements where the premium for shifting risk to the contractor is reasonable given the degree of risk shifted and to use an incentivized contract structure to make sure the contractor has a strong incentive to minimize costs where the cost of the premium payable for a full fixed price arrangement is not justified. As noted in the Basis of Estimate, KBMD has priced the Core Plant as if it were developing a lump sum (fixed price) proposal.

The KBMD estimate for the "overnight price" (i.e., subject to escalation) has a level of accuracy of +15% / -10%. The estimate summary can be found in the Basis of Estimate, which is Attachment I to Exhibit 2.0, the FEED Study Summary.

2.3.3 Project Performance Summary

The Facility performance is based upon parameters established during the FEED Study. During the conduct of the FEED Study, KBMD developed a design basis that defined the physical conditions required, environmental issues, the scope for the process configuration, the objectives for the design of the Facility and technical requirements. In support of the FEED Study, main technology providers supplied process data that was utilized by KBMD to establish the best configuration and performance of the Facility.

WorleyParsons reviewed the process data and performance estimates provided by equipment suppliers and KBMD using its internal data bases and separate modeling efforts that independently verified the performance of the Facility.

WorleyParsons utilized two commercially available process models to validate and predict TEC's performance – Aspen Plus® for the SNG Island and GateCycle™ for the Power Island (collectively, the Performance Model).

The Performance Model was based on the engineering deliverables provided by the technology providers and engineering groups. The SNG Island performance was validated against the engineering deliverables of KBMD, Siemens, and Air Liquide/Lurgi, and the Power Island performance was validated against the original equipment manufacturers' performance specifications and the well-understood design conditions of a natural gas-fired combined cycle power plant. The Performance Model also was used to determine performance of the Facility in various operating scenarios such as varying ambient temperature and varying feedstock qualities.

Results from both the Aspen Plus® and GateCycle™ for two cases are summarized as follows:

Case 1 – Two operating gasifiers at the TEC's expected gasifier output, two combustion turbine generators and one steam turbine generator at base load, resulting in gross (nameplate) electrical generating capacity of 716 MW and net electrical generating capacity of 602 MW. A net import of natural gas is required for this mode of operation. All available SNG is used for power production.

Case 2 – Two operating gasifiers at the TEC's expected gasifier output, one combustion turbine generator at base load, one combustion turbine generator in standby mode and one steam turbine generator at reduced load results in gross electrical generating capacity of 395 MW, net electrical generating capacity of 285 MW and 535 MMBtu/hr of SNG for sale.

2.3.4 EPC Project Execution Plan

The FEED Study included the development of a Project execution plan. Under this plan, the EPC contractor for the Core Plant will have overall responsibility for coordinating Project execution activities. The execution plan organizes the major islands with a project team for each island.

The KBMD Project Execution Plan is included as Attachment II in Exhibit 2.0.

As part of the FEED Study, KBMD developed a detailed 48-month schedule from

Full Notice to Proceed (FNTP) to commercial operation of the Facility. In accordance with normal practice, CCG anticipates issuing a FNTP for the Facility at financial closing. Accordingly, the FNTP is projected for December 2010, resulting in a commercial operation date of December 2014. In order to meet the December 2010 construction start date, among other things, the Illinois E.P.A. must complete its work in updating the TEC's air permit to conform to the requirements of the ICCPSL. CCG also must close on its financing, which will require the U.S. Department of Energy (DOE) to complete its environmental review and credit documentation so that the $2.579 billion DOE loan guarantee can be issued.

A high-level schedule for the TEC can be found in the Basis of Estimate, which is Attachment I to Exhibit 2.0, the FEED Study Summary. More detailed schedules are included in the work papers provided to Boston Pacific.

2.3.5 Logistics and Transportation

Due to the TEC's inland location, issues surrounding the transportation and handling of oversize equipment during the construction phase of the Project needed to be addressed early in the planning phase. In order to confirm the feasibility of transporting equipment and material, a preliminary logistics and transportation study was undertaken as part of the FEED Study. This work was performed on behalf of KBMD by BIGGE Crane and Rigging Co., a highly experienced heavy haul contractor. An "on the ground" survey was conducted for several alternate routes. The report concluded that transport of equipment and modules of the expected dimensions to the Site is feasible. The report developed combinations of barge, road and rail transport routes that could be used, pending approval of the Illinois Department of Transportation. The report also included recommendations for upgrade of local infrastructure required to support the transport plan. An estimate of the cost for these infrastructure upgrades has been included in the BOP cost estimate.

2.3.6 *Labor Survey*

CCG recognizes that access to a pool of qualified labor is critical for successful construction of the Facility. The TEC will require 2,470 workers at the peak of construction and approximately 9.6 million man hours to complete the Facility. KBMD has recent experience in construction of large energy facilities in downstate Illinois. They have drawn on this experience and contacts with local labor representatives to develop a regional labor survey for the Facility.

The survey assessed the Facility needs and potential impact of construction activities on the local labor market. It discussed the impact on local housing due to the influx of travelling workers required for a project of this magnitude, the availability of qualified trades-people, the impact on the local labor market and likely impact to skilled labor availability posed by potential competing projects. The survey concluded that any potential labor and infrastructure concerns can be overcome with advance planning and early preparation.

In 2006, CCG entered into a comprehensive Project Labor Agreement with the following labor groups:

- IUOE Local 965
- Laborers Local 477
- Mid-Central Illinois Regional Council of Carpenters
- Teamsters Local 279
- Asbestos Workers Local 1
- Boilermakers Local 363
- Painters Local 90
- Bricklayers Local 8
- Cement Masons Local 18
- Glaziers Local 1168
- IBEW Local 146

- Iron Workers Local 46
- Cement Plasterers Local 8
- Plumbers, Steamfitters & Refrigeration Fitters U.A. Local 137
- Roofers Local 112
- Sheet Metal Workers Local 218

KBMD engaged the City of Taylorville and local union labor representatives in its advanced planning efforts for the Facility. The labor unions are strong supporters of the TEC.

3.0 Study of Capital Cost for Balance of Plant Facilities

3.1 Introduction

In addition to the Core Plant, the TEC includes several critical elements described in the BOP scope. These include local infrastructure upgrades, interconnections to power, water and natural gas transmission systems and systems required to support CO_2 transmission for EOR.

CCG retained the services of several engineering companies in support of the preliminary design and cost estimation of these interconnect facilities. These companies include KBMD, WorleyParsons, Black & Veatch, and Patrick Engineering, Inc. (Patrick Engineering).

The estimated total projected cost of the BOP facilities is $149.6 million in 2010$. Estimated escalation is approximately $4.9 million, for a total estimated construction cost of $154.5 million. This does not include financing costs, taxes, insurance, start-up costs, process license fees and other owner's costs, which are summarized in Section 10.1.1.

3.2 Description of Balance of Plant Facility Components

3.2.1 Roadway and Infrastructure Improvements

Due to the increased volume of traffic expected during the construction phase of the Project by the transport of oversize equipment and an increase in vehicular traffic tied to the workers at the Site, upgrades of the existing infrastructure will be required. These upgrades/modifications include the following categories:

- Increase in width and turning radius of several sections of roadway;

- Temporary and permanent relocation of existing electrical distribution lines;
- Bridge improvements/replacements;
- Temporary upgrade to existing rail siding; and
- Upgrades of the existing barge landing area.

The estimated cost of the roadway and infrastructure improvements is approximately $18.6 million in 2010$.

3.2.2 Transmission Interconnection

The Facility will interconnect with the electric grid through a 345 kV transmission line that will be constructed from the Facility to Commonwealth Edison's Kincaid substation located west of the Facility. The proposed transmission line is approximately 14 miles long. The planned route for the transmission line will avoid densely populated areas and will parallel parcel boundaries and township borders to the extent possible to prevent bifurcation of private properties. The route will follow an existing transmission line route for one-fourth of its distance and will cross two bodies of water at locations already used by other lines, thus minimizing the need for additional right-of-way and environmental disturbance.

Patrick Engineering developed the preliminary route study, design and cost estimate for the interconnection between the TEC and Commonwealth Edison's existing Kincaid substation.

The estimated cost of the 345 kV transmission line from Commonwealth Edison's Kincaid substation to the TEC is approximately $24 million in 2010$.

The Patrick Engineering 345 kV Transmission Line Conceptual Design and Project Estimate is incorporated as Exhibit 3.2.2.

In addition to the cost of constructing the transmission line, it is estimated that the

Project will incur interconnection costs of $2.6 million and transmission upgrade costs of $36.4 million. These costs are discussed in Section 7.

3.2.3 Construction and Back-up Power

The Facility will obtain construction and back-up power from Shelby Electric Cooperative. Construction of an approximately 1.25 mile, 138 kV line from the existing NE Taylorville Substation to the Facility will be required. The line will remain in place during commercial operation to provide emergency backup power to the Facility.

Patrick Engineering developed the preliminary route study, design and cost estimate for the construction/back up power interconnect between the TEC and the existing Shelby Electric Cooperative NE Taylorville Substation.

The estimated cost of the 138 kV power connection to the TEC is approximately $1.9 million in 2010$.

The Patrick Engineering 138 kV Transmission Line Conceptual Design and Project Estimate is incorporated as Exhibit 3.2.3.

3.2.4 Natural Gas Pipeline

WorleyParsons was retained to provide preliminary routing review, design and cost estimate for the natural gas pipeline connecting the TEC to the PEPL pipeline system.

The interconnecting line will be capable of bi-directional flow, allowing for the transport of SNG from the Facility and the import of natural gas from the pipeline to the Facility. The interconnecting pipeline will be approximately nine miles long and 12 inches in diameter. The line will include provisions for smart pigging with permanent launchers and receivers, flow control valves and remote terminal unit at the PEPL yard. Metering will be provided by the pipeline system operators.

A system description, process flow diagram and preliminary layout sheets formed the basis of estimate and were used to develop material quantity estimates and construction plans.

The estimated cost of the new natural gas pipeline interconnection to the TEC is approximately $12.7 million in 2010$.

The WorleyParsons Taylorville Energy Center to REX/PEPL Pipeline Interconnects Report is attached as Exhibit 3.2.4.

3.2.5 Non-Potable Water Supply

CCG has entered into a Memorandum of Understanding with the Sanitary District of Decatur (SDD) to provide treated effluent from the SDD wastewater treatment facility to meet the non-potable water needs of the Facility.

The SDD wastewater treatment facility is a conventional, municipal wastewater treatment facility that treats wastewater from industrial, domestic, and commercial sources. To produce the quality of water required by the TEC, the SDD system will require modifications to segregate high chloride industrial flows from low chloride domestic flows so that they can be treated in separate treatment trains at the SDD treatment plant.

After treatment, the water will be pumped to the TEC from the SDD facility by a dedicated pump station and pipeline. The pipeline will be routed primarily along Illinois Route 48 from the Decatur area to the Site and will be approximately 26 miles long.

The estimated cost of the upgrades and new facilities at the SDD facility, including pumping stations and 26-mile, 16-inch diameter pipeline, the cost of which will be paid by CCG, is approximately $52 million in 2010$.

The Black & Veatch Water Supply System Final Conceptual Design Report for non-potable water facilities is incorporated in this report as Exhibit 3.2.5.

3.2.6 Potable Water

Patrick Engineering developed the preliminary route study, design and cost estimate for the TEC's potable water supply. Potable water will be obtained from the Taylorville municipal water system through an approximately 3-mile long, 8" diameter pipeline, which will be owned by the City of Taylorville.

The pump and pipeline system will be designed to transport 216,000 gallons per day of potable water to the TEC.

The estimated cost of the potable water system extension is approximately $1.4 million in 2010$.

Patrick Engineering's Concept Potable Water Line Cost Estimate for the TEC's potable water supply is included as Exhibit 3.2.6.

4.0 Capital Cost Escalation

The WorleyParsons escalation analysis evaluates the potential impact of price escalation on the Project capital costs from January 2010, the base date of the cost estimate, to the time when all material and labor costs become fixed, either on the assumed FNTP date of December 2010 or as they are incurred during construction of the Facility.

During the 1990s, power generation construction costs tracked the general inflation rate fairly closely. This was followed by a period of modest growth in the 2000 to 2003 period, but from 2004 until mid-2008, power plant construction costs increased at an extraordinary rate. This was followed by a significant correction through the first half of 2009. Metal costs, particularly steel, copper and aluminum products, have seen the greatest price swings.

Since 3Q 2009, commodity and equipment prices have rebounded and regained some of the ground lost during the preceding year.

As a result, traditional methods of estimating electric power plant cost escalation (prior to 2004) utilizing a fairly consistent historical trend will be skewed by the price volatility experienced during the past five to six years. While these factors and other market influences create additional uncertainty when predicting escalation, WorleyParsons considered several methods to establish the potential impact of escalation on the cost of the TEC, including:

1. A linear regression analysis of costs based on historical data provided in the Chemical Engineering Plant Cost Index. The analysis was made based on historical data beginning in 2003 through 2008 and the third quarter of 2009 (the last date data was available);

2. A review of the linear regression analysis prepared for the Power Island cost by Kiewit Power Inc.; and

3. Output from a confidential market survey of plant equipment, material and construction costs.

The Facility costs were grouped into seven categories – construction labor, supervision labor, equipment, permanent material, diesel fuels and lubricants, subcontract work and services, tools and supplies. An escalation rate was determined using the information from the three methods mentioned above and escalation rates were established for each year from 2010 through 2014. Escalation is applied to a grouping during each period in accordance with the projected escalation rate for such grouping except to the extent that, in accordance with the project schedule, a purchase commitment is scheduled to have already been made for such grouping as of such period. Once the commitment is made the price for that item or portion of becomes fixed and no further escalation is required.

The results of the escalation analysis for the Facility are presented in Table 4.0.

TABLE 4.0 – TEC ESCALATION ANALYSIS

	2010	2011	2012	2013	2014
Craft Labor	3.00%	3.50%	3.50%	4.00%	4.00%
Supervision	3.50%	4.00%	4.00%	4.50%	4.50%
Construction Equipment	3.00%	3.50%	3.50%	4.00%	4.00%
Diesel Fuels and Lubricants	10.00%	10.00%	10.00%	10.00%	10.00%
Supplies, Tools and Services	3.00%	3.50%	3.50%	4.00%	4.00%
Permanent Materials	5.00%	5.00%	5.00%	5.00%	5.00%
Subcontract work	5.00%	5.00%	5.00%	5.00%	5.00%

As shown in Table 2.3.2.a, the estimated escalation for the Core Plant based on this methodology is $179 million. Escalation for the BOP components was determined separately by WorleyParsons. Total escalation for the BOP is estimated to be $4.9 million which brings total projected escalation for the Facility to $184 million.

In order to make a preliminary assessment of the impact on Project capital cost resulting from a six month delay to start of construction beyond December 2010, WorleyParsons and KBMD performed an additional escalation analysis.

The analysis assumes that year-over-year rates of escalation for 2015 will continue at the same rate as 2014, and that the delay to the start of construction results in a day-for-day delay to the EPC schedule. The delay in effect pushes equipment and material procurement activities and construction equipment and labor costs six months into the future. Based on this approach to evaluating the impact of a six-month delay, the anticipated increase in Project capital cost is $60 million. This analysis does not attempt to quantify potential risk associated with the loss of continuity between the FEED and Project execution.

5.0 Operation and Maintenance Cost Assessment

5.1 Introduction

The O&M cost assessment for the TEC was prepared by Siemens in consultation with Tenaska. The combined Siemens and Tenaska team drew on decades of plant management experience and utilizes data from similar projects to develop initial O&M staffing plans and budgets for the TEC. The assessment estimates expected O&M costs on an annualized basis for the 30-year term of the Sourcing Agreements.

Operational costs are broken down into staffing, administrative and consumable material categories and are developed from historical data collected from the operation of similar facilities.

Maintenance costs also are estimated using a database of typical costs from similar facilities and represent material, tools and equipment, and labor costs required for maintenance of the TEC.

The cost assessment includes an allowance for pre-operational costs, which is representative of the costs incurred during the transition from construction to commissioning and initial commercial operation of the TEC.

The Siemens Operations and Maintenance Operating Cost Assessment Report is included as Exhibit 5.1.

5.2 Facility Staffing

The plant O&M model is derived from a database of existing facilities that have similar systems and equipment. A group of experienced plant management personnel performed an analysis of the historical data and developed an O&M

organization structure to meet the administrative, operation and maintenance needs of the TEC. The size and distribution of this workforce will accommodate specific design and plant layout factors at this preliminary stage of the Project.

The O&M organization will consist of approximately 120 permanent staff. These permanent employees will provide the core O&M, business and administrative functions required to manage the Facility. The core staff will be supplemented by contract personnel to support periodic maintenance functions and service activities at the Facility. The number of contract personnel will vary from time to time, depending on the scheduled maintenance needs at the TEC, but is expected to average approximately 35, for a total permanent employment of 155.

The O&M cost assessment includes an initial labor survey to verify availability of qualified labor and to determine wage and salary levels to be used in the cost assessment.

System One, an independent labor outsourcing company, conducted an independent wage and salary survey of the Southern Illinois area. The survey concludes that qualified labor is available to work at the salary levels used in the cost assessment.

5.3 Operating Consumables

Consumable plant materials consist of those materials, other than coal, natural gas and industrial gases, that are used to produce SNG and electricity. Examples of these materials include water treatment chemicals, flue gas catalysts or reagents, plant filter media, fuel for plant equipment, and chemical or oil spill absorbents.

Recent material estimate data was used by Siemens in the development of the annualized cost of this category in the O&M assessment.

5.4 Maintenance

5.4.1 Major Equipment

The maintenance philosophy and estimated cost was developed assuming a 12-year inspection and maintenance interval, which represents at least one complete cycle of outage repair and inspection to meet the original equipment manufacturers' recommendations.

5.4.2 Common Systems

Siemens applied an experience based maintenance cost to each component of the Power Island and applied the same breakdown structure to common facilities in the SNG Island. Examples of these common systems are the cooling water system and the power distribution system. This use of proven maintenance costs for similar equipment in these shared systems provides confidence in the resulting cost estimate.

5.4.3 Preventive Maintenance

This part of the cost assessment covers all plant maintenance including preventive, corrective, scheduled maintenance and contingency for all permanently installed plant equipment. Allowances are included for all parts, tools and materials associated with maintenance, inspection and repair of the major equipment for routine, scheduled and unscheduled maintenance.

5.5 Availability

Siemens conducted a reliability, availability and maintenance (RAM) analysis to determine the expected SNG Island availability. Siemens' prior experience shows that a "shakedown" period is required once operation commences to debug and improve plant performance. Siemens estimates that the SNG Island's availability will be 55-65% for the first year of operation and 75-85% for the second year of operation. Based on the RAM analysis, Siemens predicts that the SNG Island will experience average availability of 85% over the 10 years after the initial two-year "shakedown" period. The Siemens Operations and Maintenance Reliability Availability Maintenance Analysis is included as Exhibit 5.5.

The expected availability of the Power Island is 92%, based on well-established performance and maintenance characteristics of natural gas combined-cycle power plants.

5.6 Results of O&M Cost Assessment

The results of the Siemens cost assessment are shown in Table 5.6.

TABLE 5.6 –SUMMARY OF ESTIMATED AVERAGE ANNUAL O&M COST (2010$)*

Administrative, Operations, Maintenance Staff and Coal Yard Contract Labor	$14,448,908
Consumables	8,640,245
Maintenance	28,550,690
Administrative & Facility Support	752,100
Plant Materials	443,440
Plant Management	1,373,790
345 kV Switch Yard	116,510
Slag & Sludge Disposal	860,000
Utilities	638,200
Insurance	9,950,000
Capital Improvement Allowance	1,500,000
Total	**$67,273,883**

*Does not include coal, natural gas or industrial gases

5.7 Air Separation Unit

CCG anticipates that it will procure oxygen and other industrial gases necessary for operation of the Facility from a third party, thereby avoiding the up-front capital cost of the ASU. The third party will construct, own and operate the ASU on a portion of the Site adjacent to the SNG Island for the 30-year term of the Sourcing Agreements. In November, 2009, CCG issued a detailed, TEC-specific request for proposals from four internationally recognized industrial gas suppliers for the supply of guaranteed quantities of oxygen and other industrial gases at specified conditions and having other qualitative guarantees, requesting detailed proposals setting out the technical and commercial terms on which each party would be prepared to supply the TEC's needs.

CCG has not selected a specific ASU supplier at this time. However, CCG has analyzed the responses from the four parties and for purposes of this Facility Cost Report, and has provided representative costs to Pace for use in the Rate Impact Analysis. In addition, estimated revenue from the sale of liquids (argon, oxygen and nitrogen) has been taken into account in the costs provided to Pace.

Although not forming part of the Facility to be owned by CCG, as part of the proposal, the potential ASU owner and operator was to assume that the ASU would be transferred to the Illinois Power Agency as part of the Facility at the end of the 30-year term of the Sourcing Agreements, in accordance with the ICCPSL, if the Illinois Power Agency elects to take ownership of the Facility.

CCG currently is evaluating whether it would be in the best interest of the Project to acquire water treatment services under a similar structure.

5.8 Escalation

The escalation rate for O&M is the same as the inflation rate used by Pace in the Rate Impact Analysis. Pace developed its market projections in real terms and converted prices to nominal values using the market rate implied by the yield on Treasury bonds and similar maturity Treasury Inflation Protected Securities (TIPS). The yield quoted on treasury bonds is equal to the real yield plus inflation, while the yield quoted for TIPS is the real yield. Subtracting the yield of TIPS from the yield of Treasury bonds arrives at the market's forward implied inflation rate. Beyond the time period of available data (through 2017), Pace used a general inflation rate of 2.0% per year.

6.0 Delivered Fuel Cost Estimate

Wood Mackenzie was retained by CCG to produce a 30-year forecast of the delivered price of coal, inclusive of the Illinois Fuel Use Tax, for the TEC. The forecast was developed using Wood Mackenzie's proprietary modeling software after careful identification of, and adjustment for, the quality characteristics of individual Illinois coals and the mode or modes of coal transportation from coal source to the TEC.

Pursuant to requirements in the ICCPSL, the TEC is required to consume coal with a high volatile bituminous rank and greater than 1.7 pounds of sulfur per MMBtu content. CCG intends that all such coal will be sourced from Illinois. Depending on the energy content of the coal selected for use, the TEC will use between 1.5 and 1.8 million tons of coal per year.

Although it is expected that the addition of environmental equipment to existing coal plants and the installation of gasification technologies will have the effect of increasing demand for Illinois coal, the abundant, accessible and easily mineable Illinois coal supply is being aggressively expanded by several coal producers to meet this anticipated increase in demand. As a consequence, no shortage of Illinois coal is expected over the forecast period from 2015 through 2045. With no looming supply shortage, there should be little upward pressure on coal price beyond that normally associated with the cost of mining.

The analysis contained in the study considered the variability in the cost of mining and the quality of coal across Illinois owing to differences in geology and geography. Coal sources near the TEC have transportation cost advantages but suffer from disadvantages relative to quality and mining cost. Generally, the quality advantage enjoyed by mines located farther from the TEC in south and southwest Illinois is outweighed by the transportation advantage of mines located near the TEC.

While it was possible to determine the expected least cost source of coal to the TEC from all the sources available to the Project over the study period, reason and prudence dictated that the forecasted delivered price be based on an average delivered price of a group of coal sources within each of the six mining regions in the State of Illinois. The forecasted delivered price at the TEC is therefore defined as the lowest average delivered price at the TEC from among the six subdivisions that represent geographical mining areas of the State of Illinois.

When taking into account energy content, sulfur content and transportation cost, the least cost coal is derived from Subdivision 3 (West-Central Illinois). Subdivision 3 is the mining region located geographically closest to TEC, where truck-delivered transportation costs from mine to the TEC will be lower than transportation costs from other regions.

The forecasted delivered price at the TEC, including the 6.25% Illinois Fuel Use Tax, for the first 10 years of operation, is shown in Table 6.0:

TABLE 6.0 – DELIVERED PRICE FORECAST OF COAL TO TEC (2010$)

Year	Delivered Price, $/MMBtu
2015	2.21
2016	2.24
2017	2.24
2018	2.17
2019	2.15
2020	2.17
2021	2.18
2022	2.20
2023	2.16
2024	2.16

The forecast data developed by the Wood Mackenzie study for the full 30-year period of the Sourcing Agreements has been used in the rate impact analysis prepared by Pace. The Wood Mackenzie study, The Delivered Price of Coal to the Taylorville Energy Center, is included as Exhibit 6.0 to this report.

7.0 Analysis of Deliverability into Transmission System

The ICCPSL requires that the Facility Cost Report include "an analysis of the initial clean coal facility's ability to deliver power and energy into the applicable regional transmission organization markets."

The TEC will deliver energy to Electric Utilities and ARES located in both the PJM and MISO regional transmission organization markets.

Delivery into PJM will be through a direct interconnection from the TEC to Commonwealth Edison's Kincaid 345 kV substation (the point of interconnection), approximately 14 miles from the TEC site. Delivery of energy into PJM through this interconnection in an amount up to 726 MW at summer conditions was the subject of a PJM Interconnection System Impact Study dated December 2009, which is included as Exhibit 7.0.a. The purpose of this study was to determine the estimated interconnection costs and to determine whether transmission upgrades would be required in order for the TEC to deliver up to 726 MW into PJM at the point of interconnection. The system impact study determined that an estimated $2.6 million in interconnection costs and a $27.1 to $45.7 million range for transmission upgrades will be required. The $36.4 million midpoint of the transmission upgrade cost range and the $2.6 million in interconnection costs are taken into account as capital costs in the Balance of Plant Cost Study that is summarized in Section 3. The transmission upgrade costs will be further studied and a more precise estimate will be determined by PJM through a "Facilities Cost Study" that will be undertaken during 2010.

Delivery into MISO will be through firm transmission service from PJM to MISO. On December 17, 2009, CCG filed a 30-year firm transmission service request for 225 MW of transmission service from PJM into MISO. As described in the Winston & Strawn memorandum attached as Exhibit 7.0.b, PJM is required under its open access transmission tariff on file with the FERC to provide this service, with charges for reserved transmission capacity, any necessary transmission upgrade costs, congestion costs and applicable ancillary services.

Tenaska Vice President of Transmission Scott M. Helyer, P.E., in his December 4, 2009 Memorandum, attached as part of Exhibit 7.0.c, estimates the transmission upgrade costs, congestion costs and charges for ancillary services under the PJM to MISO transmission service agreement. All such estimated "Delivery Related Charges" to MISO customers are included in the assumed costs used in the Rate Impact Analysis set forth in Section 10. PJM will conduct a Transmission Service Request System Impact Study during 2010 to determine its own estimate of any transmission upgrade costs necessary to provide the transmission service requested by CCG.

8.0 Method of Financing

The revenue stream to be provided by the ICCPSL-mandated 30-year Sourcing Agreements, which incorporates the cost of service tariff and the associated formula rate for cost of service recovery, is critical to the method of financing described below. The ICCPSL requires such Sourcing Agreements to be entered into by the Electric Utilities and ARES to provide the TEC with a reliable, long-term revenue stream in order to be financeable.

CCG will finance the TEC with a combination of debt and equity. Up to $2.579 billion of debt will be guaranteed by the DOE and likely will be provided by the FFB. The balance of the necessary funds for construction of the Facility will be equity provided by Tenaska Taylorville, LLC or other investors and up to $50 million of cash grants from the Illinois Coal Revival Grant Fund.

Based on current projections, the TEC will be capitalized with approximately $943 million of project equity, net of cash grants addressed above. Affiliates of Tenaska intend to contribute a significant portion of the TEC's total equity requirement. However, Tenaska also anticipates soliciting third-party investors to take minority ownership positions in CCG. The Project sources and uses are shown in Table 8.0.

TABLE 8.0 – PROJECT SOURCES AND USES OF CASH

Sources	**Amount** (Nominal $000s)	**Uses**	**Amount** (Nominal $000s)
DOE Guaranteed Debt	$2,579,000	Capital Expenditures*	$2,562,000
Equity Contribution/Illinois Coal Revival Grant Fund	943,000	Financing, Start-Up and Owner's Costs	703,000
		Capital Contingency	257,000
Total	**$3,522,000**	**Total**	**$3,522,000**

*includes Core Plant, BOP and Escalation

In July 2009, CCG was selected in a competitive process to enter into negotiations with the DOE for a loan guarantee under the *Federal Loan Guarantees for Coal-Based Power Generation and Industrial Gasification Facilities that Incorporate Carbon Capture and Sequestration or the Beneficial Uses of Carbon and for Advanced Coal Gasification Facilities* program. CCG anticipates having the guaranteed debt issued by the FFB. The FFB is a U.S. Government lending institution and a unit of the U.S. Department of Treasury under the supervision of the Secretary of the Treasury. The FFB was created, in part, to provide financing at lower rates than can be obtained in private lending markets.

The DOE selected the TEC based upon a number of factors, including the revenue certainty to be provided by the Sourcing Agreements. CCG must still proceed successfully through document negotiations with the DOE in order to receive the guarantee, which will be predicated upon approval of Sourcing Agreements by the Illinois General Assembly, among other things. Assuming that CCG successfully completes this process and obtains final approval for the DOE loan guarantee, CCG will be able to obtain debt financing for the TEC at an estimated 25 basis points above the rate on U.S. Treasury debt securities with a final maturity of 30 years and an average life of approximately 17 years. Accordingly, the estimated interest cost of the 30-year DOE loan guarantee debt is based on an interpolated 17-year Treasury yield curve, currently 4.026% plus the estimated 25 basis point credit spread totaling 4.276%. This debt cost, as well as the estimated fees for participating in the DOE Loan Guarantee Program, is reflected in the weighted average cost of capital (WACC) that is used in the cost of service formula rate for determining return on capital and described in greater detail in Section 10.

The DOE's regulations may permit co-lending on a parity basis with the DOE-guaranteed debt. Accordingly, CCG's financing plan could include, in addition to a FFB loan, debt financing to be provided by Illinois tax exempt solid waste disposal/wastewater treatment bonds, moral obligation bonds, commercial lenders, or a combination of some or all of these. The Illinois Finance Authority 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 bond financing to CCG for the purpose of attracting clean coal generating capacity to the State of Illinois. CCG intends to explore with the DOE how such debt could be included in the financing structure under mutually acceptable terms and conditions.

The financing plan includes a cost overrun facility of $500 million. This cost overrun facility will be funded with a combination of debt and equity and will be utilized if cost overruns exceed the existing capital cost contingency of $257 million assumed in the Project sources and uses shown in Table 8.0. Together with the contingency, the cost overrun facility will provide greater assurance of completion and the commencement of energy sales under the Sourcing Agreements.

9.0 Analysis of the TEC's Expected Capacity Factor

The TEC is expected to be dispatched in one of two modes of operation. When energy prices are relatively high – that is, during peak periods (7 a.m. to 11 p.m., Monday to Friday) year around and during off peak periods from June 15 to September 15 – the Power Island will be dispatched in 2x1 Configuration, resulting in gross output of 716 MW and net output of 602 MW. During off-peak periods from September 16 to June 14, the Facility may operate in 1x1 Configuration, with gross output of 395 MW and net output of 285 MW. When the Facility operates in the 1x1 Configuration, an estimated 535 MMBtu per hour of pipeline quality SNG – the equivalent gas consumption of approximately 43,000 Illinois homes – is expected to be sold into the domestic interstate pipeline system. The decision whether to run in 2x1 Configuration during off peak hours from September 16 to June 14 will be made based on whether more value can be realized by selling SNG or electricity and will be subject to any necessary approvals from TEC's wholesale electric customers. Additional value realized from the sale of SNG will inure to the benefit of Illinois ratepayers via a reduction in payments required to be made by the Electric Utilities and ARES under the Sourcing Agreements.

Based on the expected modes of operation described above, the TEC is projected to have a capacity factor varying between 73 and 76% and averaging 75% over the term of the 30-year Sourcing Agreements.

10.0 Rate Impact Analysis

Under the ICCPSL, the Electric Utilities and ARES are not required to execute Sourcing Agreements with the initial clean coal facility unless and until the General Assembly has enacted legislation approving:

> *"(A) the projected price, stated in cents per kilowatt hour, to be charged for electricity generated by the initial clean coal facility, (B) the projected impact on residential and small business customers' bills over the life of the sourcing agreements, and (C) the maximum allowable return on equity for the project."*

CCG retained Pace to prepare an analysis of the projected price of electricity and projected rate impact for the TEC. Pace's Rate Impact Analysis is set forth in Exhibit 10.0.

10.1 Cost Assumptions

A projection of the price of electricity based on the TEC's cost of service tariff requires assumptions on the capital cost, authorized capital structure, method of financing (with assumed interest rates), projected dispatch of the Facility, performance of the TEC, and assumed operating costs, including cost of coal and other operating expenses. All of the inputs are supported by studies that are summarized elsewhere in this Facility Cost Report, including the Core Plant FEED Study, Balance of Plant Analysis, Capital Cost Escalation Analysis, Operation and Maintenance Cost Assessment, and Delivered Fuel Study. The capital recovery used by Pace assumes an authorized return on equity of 11.5%, as permitted by the ICCPSL if approved by the Illinois General Assembly and the Illinois Commerce Commission. Other general and specific economic assumptions including projections of natural gas prices, carbon prices, capacity market forecasts and general inflation rates are explained in the Pace Rate Impact Analysis.

10.1.1 *Capital Cost Recovery*

The TEC will recover its capital cost (including construction costs, financing costs based on an assumed 55% debt, 45% equity capital structure, taxes, insurance and other owner's costs) through the Sourcing Agreements that incorporate a tariff structure using a FERC-approved formula rate. The formula rate for capital recovery consists of three components: depreciation, return on capital and income tax allowance. The depreciation component of the formula rate allows the TEC to recover the actual capital cost of the Project utilizing 30-year straight line depreciation. The total capital cost of the Project will comprise the rate base on which the return on capital will be applied. The return on capital component of the formula rate is determined by multiplying the rate base minus accumulated depreciation by the WACC described below. The recovery of income tax liability for the TEC is also incorporated into the formula rate as the income tax allowance component. The resultant capital recovery charge as determined by the formula rate will be converted to a payment for each of the 30 years of the Sourcing Agreements.

Table 10.1.1.a shows the capital cost components for the TEC and the source of the cost estimate for each of the components of the Facility.

The estimated capital costs provided for the Core Plant, the Balance of Plant and Escalation are described in Sections 2, 3 and 4 of this report.

Other cost component information was derived from the following sources, as indicated on Table 10.1.1.a:

- Estimated workers compensation insurance costs were provided by KBMD.
- Estimated pre-operation costs were provided by Siemens in its Operating and Maintenance Operating Cost Assessment attached as Exhibit 5.1.
- Process license fee amounts were provided by Siemens and Air Liquide.

- Land and mineral rights and development costs were provided by CCG based in part upon costs already incurred and in part upon costs projected to be incurred prior to commencement of construction.

- Estimated owner's project management costs were provided by CCG.

- Contingency was estimated by CCG in consultation with the Owner's Engineer.

- The estimated sales taxes were provided by CCG.

- The estimated financing costs and allowance for funds used during construction were estimated by CCG based on rate of expenditure estimates provided by KBMD and the expected terms of the DOE loan guarantee.

- The estimated cost of builders risk insurance was provided by CCG and is based on quotes obtained by leading international insurance brokers.

TABLE 10.1.1.a – TEC CAPITAL COST COMPONENTS AND SOURCES

	($000)	Source
Core Plant	$2,407,612	KBMD
Balance of Plant	154,300	KBMD, WorleyParsons, Black & Veatch, Patrick,
Owner's Contingency	257,000	CCG
Total Construction Costs	$2,800,912	
Process Licenses and Fees	21,418	Siemens, Air Liquide
Catalysts	26,625	KBMD
Worker's Compensation Insurance	28,104	AON
Land and Mineral Rights	14,146	CCG
Development Costs	106,272	CCG
Owner's Project Management	55,000	CCG
Financing Costs	353,192	DOE, CCG
Builder's Risk Insurance	19,500	AON, FM Global
Pre-Operation Cost	28,981	Siemens
Spare Parts	24,189	Siemens
Coal Inventory	2,447	CCG
Sales Tax	22,864	CCG
Financing, Start-Up and Owner's Costs	$720,738	
Total Capital Cost	**$3,521,650**	

The Capital Cost Summary above is based on actual costs that are expected to be incurred and capitalized. Under FERC accounting rules and ratemaking principles, in the case of certain types of costs, the rate base for the TEC will be determined by an allowance for various items instead of actual costs. Actual costs incurred for spare parts and coal inventory are excluded from rate base but an allowance for funds used during construction is included. The revenue requirement provided to Pace for its Rate Impact Analysis included the adjustments required in accordance with FERC accounting rules and ratemaking principles. These adjustments will be subject to review by the ICC and the FERC.

The ICCPSL requires the Sourcing Agreements for the initial clean coal facility to use a formula contractual price "determined using a cost of service methodology employing either a level or deferred capital recovery component." In order to smooth the projected rate impact during the "shakedown" period, comprising the first two years of commercial operation, CCG will provide in its proposed formula rate that $31 million of capital recovery be deferred from early years to later years. The $31 million is recovered in future years on a levelized basis along with a carrying cost equal to TEC's WACC. The amounts deferred for specific years are as follows: year 1, $28 million; and year 2, $3 million. Pace has taken these deferrals into account in its Rate Impact Analysis.

The ICCPSL provides that a qualifying IGCC facility such as the TEC must offer service to its customers under contracts that include a formula rate in which the cost of service is to be calculated based on a capital structure consisting of 55% debt and 45% equity. The statute further allows the return on equity component of the capital structure to be a rate up to 11.5%. Within this statutory capital structure, the interest cost of the debt component of the capital structure will be calculated as the weighted average of the individual interest rates of the components that comprise the actual total debt used to finance the TEC. The resulting WACC is used to calculate the regulated rate of return in the formula rate used for the cost of service tariff for the TEC. Table 10.1.1.b sets forth the assumptions used in determining the

WACC for calculating the return on capital in the cost of service formula rate:

TABLE 10.1.1.b – TEC WEIGHTED AVERAGE COST OF CAPITAL

	Ratio	Cost	Weighted Cost
Debt	55.00%	4.276*%	2.352%
Equity	45.00%	11.50%	5.175%
Total	**100%**		**7.527%**

* Estimate based on Treasury Rates on February 15, 2010

10.1.2 Industrial Gas Purchases

CCG has assumed that it will procure oxygen and other industrial gases from a third party as discussed in Section 5.7.

10.1.3 Operation and Maintenance

The average, annual non-fuel O&M costs, which are based on inputs from the Siemens O&M Study, are projected to be approximately $67.3 million per year as described in Section 5.6. The O&M costs also include amounts for delivery-related charges for electric transmission service to MISO of $4.5 million per year, and $2.6 million per year in Owner general and administrative cost for O&M supervision.

Included in the $67.3 million per year O&M costs provided by Siemens are power-related variable O&M costs that are modeled separately in the Pace Rate Impact Analysis at $2.83/MWh (2010$).

10.1.4 Fuel

The price of delivered fuel in 2015 is projected to be $2.21/MMBtu in 2010$ based upon the Wood Mackenzie fuel study report attached as Exhibit 6.0. The delivered fuel price is projected to escalate an average of 2.38% per year over the course of the 30-year Sourcing Agreements in nominal dollars.

10.1.5 Natural Gas Revenues

As discussed in Section 9, there will be times when the Facility will sell SNG into the domestic interstate pipeline system. Natural gas revenues are projected using Pace's gas price forecast multiplied by the projected amount of SNG sold into the interstate pipeline.

On average, over the first 10 years of operation, revenues from SNG sales are projected to be $15.2 million annually in 2010$. These revenues will inure to the benefit of Illinois ratepayers via a reduction in payments required to be made by the Electric Utilities and ARES under the Sourcing Agreements.

10.1.6 Enhanced Oil Recovery Revenues

It is expected 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. As discussed in Section 13, the 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 $8.9 million annually in 2010$. These revenues will inure to the benefit of Illinois ratepayers via a reduction in payments required to be made by the Electric Utilities and ARES under the Sourcing Agreements.

10.1.7 Sulfur Revenues

Molten sulfur is one of the byproducts that is produced during the gasification process. CCG intends to sell the molten sulfur to regional sulfuric acid producers. Based on a study by Nexant, Inc., which is attached as Exhibit 10.1.7, on average, over the first 10 years of operation, net revenues from sulfur sales are projected to be $3.6 million annually in 2010$. These revenues will inure to the benefit of Illinois ratepayers via a reduction in payments required to be made by the Electric Utilities and ARES under the Sourcing Agreements.

10.1.8 NOx Allowance Revenues

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 be approximately $18.1 million annually in 2010$. These revenues will inure to the benefit of Illinois ratepayers via a reduction in payments required to be made by the Electric Utilities and ARES under the Sourcing Agreements.

TABLE 10.1.8 – SURPLUS NOx ALLOWANCE ANALYSIS

Year	Surplus Seasonal NO_x Allowances (tons)	Surplus Annual NO_x Allowances (Tons)	Seasonal NO_x Allowance Price (Nominal $/ton)	Annual NO_x Allowance Price (Nominal $/ton)	Total Surplus NO_x Allowance Revenue (Nominal $)	Total Surplus NO_x Allowance Revenue (2010 $)
2015	942.0	2,355.3	75.98	4,092.45	9,710,661	8,976,460
2016	1,657.0	4,142.9	80.93	4,341.19	18,119,232	16,428,333
2017	1,657.0	4,142.9	87.27	4,697.30	19,605,032	17,425,410
2018	1,657.0	4,142.9	93.88	5,083.87	21,217,521	18,478,943
2019	1,657.0	4,142.9	95.76	5,299.72	22,114,868	18,882,812
2020	1,657.0	4,142.9	102.68	5,525.92	23,063,485	19,306,656
2021	1,657.0	4,142.9	111.12	5,761.61	24,053,899	19,740,923
2022	1,657.0	4,142.9	119.86	6,007.12	25,085,500	20,183,875
2023	1,657.0	4,142.9	130.23	6,262.80	26,161,955	20,637,250
2024	1,657.0	4,142.9	140.96	6,529.02	27,282,665	21,099,309
				Average	**21,641,482**	**18,115,997**

10.1.9 Capacity Revenues

TEC will sell capacity into PJM's forward looking capacity market. 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 capacity sales are projected to be $21.9 million annually in 2010$.

10.2 Facility Performance

Pace's assumptions regarding the TEC's performance are taken from estimated performance as determined in the FEED Study, which is summarized in Section 2.3.3, and from the Siemens RAM analysis, which is summarized in Section 5.5.

10.3 Pace Methodology

The ICCPSL contemplates that the rate impact on the average eligible retail customer is to be based on the average eligible retail customer rate for the year ending May 31, 2009. Pace's Rate Impact Analysis is based on the weighted average rate for this period for Ameren Illinois and Commonwealth Edison, which, according to the Illinois Power Agency, was $114.92/MWh.

The cost of procuring electricity from the market is equal to the wholesale price of energy and capacity. The Pace Rate Impact Analysis sets forth projections of the capacity price and on-peak and off-peak wholesale energy pricing in the market encompassing Commonwealth Edison's service territory and Ameren Illinois' service territory.

In order to project the TEC rate impact on the average eligible retail customer, Pace compared the projected TEC price of electricity to the projected alternative cost of procuring such electricity from the market. The aggregate cost excess was spread over the projected eligible retail customer and ARES load to determine a dollar per

MWh effect. This dollar per MWh effect was then compared to the average eligible retail customer rates for year ended May 31, 2009 of $114.92/MWh.

10.3.1 Reference Case Assumptions:

Pace conducted its rate impact analysis based on a "Reference Case" which included its assumptions on key economic drivers and government policies that will affect the power sector generally and the TEC's rate impact in particular. These assumptions are as follows:

- Moderate recession in North America, with economic recovery in 2010;
- Widespread adoption of carbon control measures;
- Federal Renewable Portfolio Standard (RPS) of 17% by 2020;
- Moderate deployment of energy efficiency and demand side measures, partly in response to federal RPS;
- Rapid development of zero-emission resources, especially renewables in response to economic signals regarding the price of carbon and renewable energy credits;
- North America remains self-sufficient with natural gas supply; and
- A CO_2 sequestration tax credit of $10/MT as currently provided under Section 45Q of the Internal Revenue Code, subject to an inflation adjustment factor which is determined annually pursuant to Internal Revenue Code Section 45Q(d)(7). Pace is assuming that the inflation adjustment factor will be the same as its inflation projection. Internal Revenue Code Section 45Q currently provides for this credit to apply to the first 75 million MT sequestered nationally.

10.3.2 Alternate Cases

In addition, Pace also developed alternate cases to test the TEC rate impact under different scenarios. Three such alternative cases were studied:

1. **Coal/Gas**, in which a strong economic recovery and lower than expected efficacy of renewable and efficiency programs result in a stronger demand for gas and higher natural gas pricing than in the Reference Case;

2. **Environmental Policy**, in which a stronger climate change policy results in higher carbon pricing, a $70/MT bonus allowance for carbon storage, no new pulverized coal plant construction, and a higher rate of retirement of units in the existing coal fleet; and

3. **RPS/DSM**, in which more stringent environmental policies promoting renewable energy and efficiency result in lower demand for natural gas and lower natural gas pricing.

More complete descriptions of these cases can be found in Exhibit 10.0, the Pace Rate Impact Analysis.

10.4 Key Findings

The Pace Rate Impact Analysis made the following key findings:

- *Effective Hedging Due to Flexibility of Operations*: Pace found that the TEC provides an effective hedge for Illinois ratepayers against rising natural gas prices and carbon compliance costs, even resulting in a net benefit under very high natural gas price conditions. This is because the TEC can optimize between power generation and natural gas sales as a result of the conversion of coal to SNG;

- *Impact of Natural Gas Price:* The price of natural gas has a significant effect on the rate impact of the TEC. Holding all other market drivers and assumptions constant, a $1/MMBtu increase in the price of natural gas results in approximately a 0.1% decrease (for example, from 2.015% to 1.915%) in rate impact in 2015;

- *Impact of Proposed CO_2 Bonus Allowances:* The TEC's impact is highly sensitive to CO_2 bonus provisions offered in current legislative proposals. Adding a $70/MT bonus allowance for sequestered CO_2 would decrease the rate impact by 0.7% in 2015, leaving all other Reference Case assumptions constant. Both the House version (Section 786 of the Clean Air Act as amended by Section 115 of the proposed American Clean Energy and Security Act (Waxman-Markey)) and the Senate version (Section 780 of the Clean Air Act as amended by Section 111 of the proposed Clean Energy Jobs and American Power Act (Kerry-Boxer)) of the proposed climate legislation incorporate substantial bonus allowance incentives for early electric projects that capture and sequester CO_2. The amounts vary between $50 and $90 per MT ($96 per MT in the case of Kerry-Boxer) depending on the level of capture, with a minimum 50% capture requirement. Section 780(h)(1)(C)(I)(cc) of the October 23, 2009 "Chairman's Mark" of Kerry-Boxer includes as a milestone that would entitle a project to receive bonus allowances "an authorization by a State legislature to allow recovery, from the retail customers of electric utilities that are required to purchase all of the electricity from the project pursuant to State law, of the costs of the project, on the conditions that the project has been approved by the legislature and, under State law, retail electric providers are required collectively to purchase all of the net electric output from the project." This Kerry-Boxer subsection is intended to describe the ICCPSL, including the approving enactment that will be sought from the General Assembly, so that the TEC will qualify for the bonus allowances. The Reference Case assumes no bonus allowances, but does assume tax credits for CO_2 capture and sequestration currently in effect under Internal Revenue Code Section 45Q. The amount of the credit, which benefits customers by offsetting the tax component of the TEC's revenue requirement, is $20 per MT of CO_2 that is stored geologically and $10 per MT for CO_2 that is stored as part of an EOR process.

- *Impact of Energy Demand:* Higher energy demand is projected to increase power market prices, but also allow the cost impact of the TEC to be spread across more MWh. Holding all other market drivers and assumptions constant, a 1% increase in energy demand in 2015 decreases the rate impact just over 0.02% for the Reference Case;

- *Impact of Capacity Market Price*: Capacity prices in PJM have exhibited volatility and represent a significant revenue opportunity for the TEC. Holding all other market drivers and assumptions constant, changing the Reference Case capacity price from $0/kW-yr to $28/kW-yr results in approximately 0.05% decrease in the rate impact;

- *Impact of Coal Price*: The TEC will use coal from Illinois. A 10% decrease in the cost of coal below the Reference Case assumption, holding all other Reference Case assumptions constant, causes the rate impact to decrease by 0.04%; and

- *Impact of Plant Optimization between Power and Gas Sales:* The ability to optimize Project operations between energy sales and natural gas sales provides the Project flexibility and lowers overall cost impacts. Depending on the case, the ability to optimize such operations lowers the rate impact by 0.2 to 0.3%.

10.5 Projected Rate Impact

The percent rate impact projected by Pace for the average eligible retail customer, expressed as the percentage of such average customer's May 31, 2009 electric rate

($114.92/MWh) is shown in Table 10.5.a for the Reference Case and each of the alternate cases. For illustrative purposes, Table 10.5.a also shows the monthly rate impact for the average residential customer (the percent rate impact is assumed to be the same for residential and small business customers as it is for average eligible retail customers).

TABLE 10.5.a – PROJECTED RATE IMPACT

Year	Reference Case (% Impact)	Projected Impact on Average Residential Customer for Reference Case $/month	Envir. Policy Case (% Impact)	Gas/Coal Case (% Impact)	RPS/DSM Case (% Impact)
2015	2.17%	2.20	1.34%	2.51%	2.33%
2016	2.17%	2.20	1.12%	2.41%	2.41%
2017	2.17%	2.21	0.99%	2.32%	2.48%
2018	2.09%	2.12	0.82%	2.14%	2.43%
2019	2.09%	2.13	0.80%	2.11%	2.47%
2020	2.04%	2.07	0.77%	2.04%	2.49%
2021	1.96%	1.99	0.67%	1.95%	2.45%
2022	1.91%	1.93	0.60%	1.84%	2.45%
2023	1.93%	1.95	0.61%	1.85%	2.55%
2024	1.85%	1.88	0.54%	1.73%	2.50%
2025	1.98%	2.01	1.71%	1.75%	2.45%
2026	1.96%	1.98	1.72%	1.72%	2.45%
2027	1.88%	1.90	1.68%	1.60%	2.54%
2028	1.81%	1.83	1.62%	1.52%	2.52%
2029	1.83%	1.84	1.61%	1.44%	2.53%
2030	1.71%	1.72	1.40%	1.24%	2.46%
2031	1.76%	1.77	1.31%	1.22%	2.61%
2032	1.83%	1.85	1.35%	1.26%	2.73%
2033	1.72%	1.73	1.20%	1.16%	2.61%
2034	1.72%	1.73	1.21%	1.19%	2.65%
2035	1.68%	1.69	1.15%	1.16%	2.65%
2036	1.65%	1.66	1.08%	1.11%	2.65%
2037	1.59%	1.59	0.95%	1.04%	2.58%
2038	1.66%	1.67	0.96%	1.09%	2.70%
2039	1.58%	1.59	0.83%	1.03%	2.65%
2040	1.50%	1.51	0.68%	0.92%	2.58%
2041	1.57%	1.57	0.69%	0.98%	2.68%
2042	1.44%	1.44	0.50%	0.88%	2.58%
2043	1.42%	1.42	0.39%	0.84%	2.58%
2044	1.50%	1.50	0.39%	0.90%	2.67%

The Pace rate impact calculations do not take into account the Market Savings that are projected to be achieved by all electric customers in Illinois as a result of the beneficial effect on market prices of the TEC adding base load and dispatchable capacity to the Illinois market. The methodology of determining Market Savings and the projected amount of the Market Savings are described in Section 11.

Table 10.5.b shows the adjusted projected rate impact if the estimated Market Savings were subtracted from the projected rate impact shown in Table 10.5.a.

TABLE 10.5.b – ESTIMATED RATE IMPACT ADJUSTED TO REFLECT MARKET SAVINGS

Year	Reference Case Rate Impact with Market Savings (%)	Projected Annual Impact on Average Residential Customer Bills with Market Savings (2010$) ($/Month)
2015	1.30%	1.31
2016	0.92%	0.93
2017	0.52%	0.53
2018	0.42%	0.43
2019	1.42%	1.44
2020	1.84%	1.87
2021	1.45%	1.47
2022	1.63%	1.65
2023	1.63%	1.65
2024	1.65%	1.67
2025	1.61%	1.63
2026	1.94%	1.96
2027	1.64%	1.66
2028	1.39%	1.40
2029	1.81%	1.82
2030	1.70%	1.72

10.6 Projected Price of Electricity

Table 10.6 shows Pace's projection of the price of electricity from the TEC in each of the 30 years of the Sourcing Agreements for the Reference Case and each of the other three alternate cases. Prices are given in constant January 2010$.

TABLE 10.6 – PACE TEC ELECTRICITY PRICE PROJECTIONS (2010$/kWh)

Year	Reference Case (2010$)	Reference Case with Market Savings Included (2010$)	Coal/Gas (2010$)	Environmental Case (2010$)	RPS/DSM Case (2010$)
2015	**0.150**	**0.118**	**0.141**	**0.127**	**0.151**
2016	**0.152**	**0.106**	**0.142**	**0.123**	**0.150**
2017	**0.150**	**0.091**	**0.144**	**0.125**	**0.153**
2018	**0.143**	**0.086**	**0.142**	**0.122**	**0.147**
2019	**0.144**	**0.121**	**0.142**	**0.122**	**0.142**
2020	**0.148**	**0.141**	**0.143**	**0.120**	**0.146**
2021	**0.147**	**0.130**	**0.142**	**0.116**	**0.140**
2022	**0.145**	**0.136**	**0.143**	**0.113**	**0.139**
2023	**0.149**	**0.139**	**0.145**	**0.115**	**0.145**
2024	**0.148**	**0.141**	**0.144**	**0.115**	**0.138**
2025	**0.152**	**0.140**	**0.150**	**0.148**	**0.136**
2026	**0.154**	**0.153**	**0.152**	**0.148**	**0.136**
2027	**0.152**	**0.145**	**0.151**	**0.147**	**0.137**
2028	**0.153**	**0.141**	**0.152**	**0.148**	**0.137**
2029	**0.156**	**0.155**	**0.155**	**0.151**	**0.137**
2030	**0.155**	**0.155**	**0.155**	**0.153**	**0.138**
2031	**0.156**	**0.156**	**0.156**	**0.154**	**0.137**
2032	**0.158**	**0.158**	**0.158**	**0.157**	**0.140**
2033	**0.156**	**0.156**	**0.157**	**0.156**	**0.136**
2034	**0.156**	**0.156**	**0.159**	**0.158**	**0.137**
2035	**0.156**	**0.156**	**0.160**	**0.159**	**0.136**
2036	**0.156**	**0.156**	**0.160**	**0.160**	**0.135**
2037	**0.155**	**0.155**	**0.159**	**0.159**	**0.134**
2038	**0.158**	**0.158**	**0.162**	**0.162**	**0.136**
2039	**0.157**	**0.157**	**0.162**	**0.162**	**0.134**
2040	**0.156**	**0.156**	**0.161**	**0.162**	**0.133**
2041	**0.158**	**0.158**	**0.164**	**0.165**	**0.135**
2042	**0.156**	**0.156**	**0.164**	**0.164**	**0.132**
2043	**0.157**	**0.157**	**0.165**	**0.165**	**0.132**
2044	**0.160**	**0.160**	**0.168**	**0.168**	**0.134**

10.7 Projected Price of Electricity at Base Load

In order to provide a basis for comparing the cost of energy from the TEC to units that do not have flexibility of dispatch (like the TEC) but must be dispatched at full output when they are operating, Pace provided an alternate cost of power calculation based on the assumption that the TEC is dispatched at full output 100% of the time that the Facility is available. The projected total cost per kWh based on this assumed 92%[2] electric capacity factor is shown in Table 10.7, although as noted above during some off-peak periods the Facility will be dispatched economically at a lower rate to increase SNG sales in order to improve the economics for electric customers, as SNG sales will be credited against the revenue requirement. The cost per kWh at a 92% capacity factor for the Power Island after netting out Market Savings described in Section 11 also is shown in the table:

[2] Forced outages and maintenance outages are expected to comprise approximately 8%, so that the expected availability of the TEC to generate electricity is 92% following the first two years of operation.

TABLE 10.7 – PACE ELECTRICITY PRICE PROJECTION AT 92% DISPATCH (2010$/kWh)

Year	Reference Case (2010$)	With Market Savings Included (2010$)
2015	0.140	0.113
2016	0.136	0.099
2017	0.134	0.086
2018	0.129	0.081
2019	0.130	0.111
2020	0.132	0.127
2021	0.132	0.118
2022	0.131	0.123
2023	0.135	0.127
2024	0.135	0.130
2025	0.138	0.129
2026	0.141	0.140
2027	0.140	0.135
2028	0.142	0.132
2029	0.145	0.144
2030	0.145	0.145
2031	0.146	0.146
2032	0.148	0.148
2033	0.146	0.146
2034	0.147	0.147
2035	0.147	0.147
2036	0.147	0.147
2037	0.147	0.147
2038	0.149	0.149
2039	0.149	0.149
2040	0.148	0.148
2041	0.151	0.151
2042	0.150	0.150
2043	0.150	0.150
2044	0.153	0.153

11.0 Market Savings Analysis

The rate impact projections immediately above do not take into account the Market Savings of the TEC adding base load and dispatchable capacity to the Illinois market.

Pace projected the impact of the TEC on Illinois ratepayers using projected changes in market energy and capacity prices that result with the TEC operating in northern Illinois in the PJM market. Using consistent market assessments developed in the analysis of the overall rate impact of the project, this analysis was completed through the following steps:

- The annual savings realized from a decrease in energy prices in Illinois was calculated;
- The annual savings realized from a decrease in capacity prices in Northern Illinois was calculated; and
- The resulting total savings in thousands of dollars and $/MWh for ratepayers in Illinois was calculated.

In order to create a baseline, Reference Case market-clearing price projections for energy and capacity for the Northern Illinois and Gateway (Southern Illinois) power regions were developed *without* the TEC operating in the market. In addition, Pace performed a Reference Case analysis of market prices with the addition of the TEC in the Northern Illinois power region and projected new energy and capacity prices took into account the impact of the TEC.

Capacity price projections in Northern Illinois are based on PJM's Reliability Pricing Model (RPM), a forward-looking market for capacity. Pace's projections include representations of the key drivers in the market construct, including the cost of new entry, the regional reserve margin and projected energy and ancillary services revenues for new market participants.

The addition of the TEC to Northern Illinois is projected to result in a decrease in average annual energy market prices of about $0.25/MWh over the period from 2015 to 2030. This is due to the projection that the TEC will generally displace less efficient natural gas and coal-fired generating capacity during many hours of the year, lowering the marginal cost of electricity. While this is expected, the difference between the costs of the TEC and alternative capacity that would otherwise be expected to enter the market does not result in persistently significant energy cost savings. The addition of the 602 MW plant, however, also affects the supply/demand balance within the region, temporarily lowering projected capacity prices in the PJM capacity market. This results in a capacity price forecast that is slightly lower when compared with the Reference Case for a short period of time.

Pace multiplied the change in average annual energy prices (in $/MWh) due to the inclusion of the TEC by its long-term projection of total annual energy demand (in MWh) in Illinois in order to calculate the annual savings realized from the decrease in energy prices.

Pace multiplied the change in the annual capacity price (in $/kW) in Northern Illinois due to the inclusion of the TEC by the annual total capacity projected to be procured in the RPM auction for Illinois (in kW) in order to calculate the annual savings realized from the decrease in capacity prices.

These two savings (energy and capacity) were added together and divided by the total forecasted energy demand in Illinois in order to arrive at a $/MWh estimate of the benefits. Table 11.0.a presents this estimate of total savings to the Illinois ratepayers. The largest savings occur between 2015 and 2018 when the capacity payment in PJM-Northern Illinois is projected to be lower due to the addition of the TEC. During this time, savings average about $1.30/MWh in 2010$. The average savings across all ratepayers from 2015 to 2030, however, is less consistent and only estimated to be around $0.53/MWh in 2010$. Beyond 2030, Pace does not project a significant market cost impact.

TABLE 11.0.a – TOTAL PROJECTED MARKET SAVINGS TO ILLINOIS RATEPAYERS

Year	Energy Savings ($000) 2010$	Capacity Savings in PJM ($000) 2010$	Total Savings to Illinois Ratepayers ($000) 2010$	Total Savings to Illinois Ratepayers ($/MWh) 2010$	Total Savings to Illinois Ratepayers (nominal $/MWh)
2015	47,847	79,279	127,126	0.93	1.01
2016	32,341	146,398	178,739	1.30	1.44
2017	80,294	152,356	232,650	1.69	1.90
2018	65,275	164,856	230,130	1.67	1.92
2019	21,147	69,991	91,139	0.66	0.77
2020	26,214	0	26,214	0.19	0.23
2021	66,375	0	66,375	0.48	0.58
2022	35,509	0	35,509	0.26	0.32
2023	37,587	0	37,587	0.27	0.34
2024	24,959	0	24,959	0.18	0.23
2025	45,351	0	45,351	0.32	0.43
2026	3,170	0	3,170	0.02	0.03
2027	27,759	0	27,759	0.20	0.27
2028	48,917	0	48,917	0.35	0.49
2029	2,040	0	2,040	0.01	0.02
2030	398	0	398	0	0

SOURCE: Pace

Pace has combined the total projected savings with the TEC's cost impact to estimate a net impact of the Project for the Reference Case. The adjusted percent rate impact, customer monthly cost impact and cost of power at a 92% electric capacity factor are summarized in Table 11.0.b. These impacts are displayed for the Reference Case only.

TABLE 11.0.b – PROJECTED RATE IMPACT INCLUSIVE OF MARKET SAVINGS

Year	Percent Rate Impact with Market Savings	Monthly Impact for Average Residential Customer With Market Savings ($ Nominal)	Cost of Power at 92% with Market Savings (2010$/kWh)
2015	1.30%	1.31	0.113
2016	0.92%	0.93	0.099
2017	0.52%	0.53	0.086
2018	0.42%	0.43	0.081
2019	1.42%	1.44	0.111
2020	1.84%	1.87	0.127
2021	1.45%	1.47	0.118
2022	1.63%	1.65	0.123
2023	1.63%	1.65	0.127
2024	1.65%	1.67	0.130
2025	1.61%	1.63	0.129
2026	1.94%	1.96	0.140
2027	1.64%	1.66	0.135
2028	1.39%	1.40	0.132
2029	1.81%	1.82	0.144
2030	1.70%	1.72	0.145

SOURCE: Pace

12.0 Secondary CO_2 Emissions Analysis

The TEC will be designed to capture approximately 1.9 million MT of CO_2 per year. The captured CO_2 will be delivered into a CO_2 pipeline for transport to the Gulf Coast States for EOR or for injection into nearby geologic storage. The emissions of CO_2 and other pollutants from the Power Island will be the same as the emissions from a similarly sized, highly efficient natural gas power plant with the most up to date emission control devices.

Under any set of electric load (demand) conditions, energy dispatched from the TEC will "displace" an equal amount of energy that would have been dispatched at another facility to meet the electric load had the Facility not been generating. Based on available data bases and commonly used techniques in the electric industry, Tenaska determined in general which facilities will be "displaced" by energy from the TEC. The displaced facilities are all facilities that emit higher levels of CO_2 than those emitted by the TEC. Through an hour-by-hour analysis of this displacement effect during projected operations in a sample year (2017), Tenaska determined that the net effect of generation by the TEC is projected to be a net reduction of CO_2 emissions by more than 1.9 million MT in 2017. Similar results could be expected for other years. Also, it is notable that many of the displaced facilities are coal plants in the Chicago area, and that not only CO_2, but SO_2, particulate (soot) and mercury also are displaced (avoided) by dispatching the Facility.

Tenaska has prepared a report entitled "CO_2 Secondary Impact Analysis" to present the results of its study on which plants will be "displaced" and what the net effect of the TEC's operation will be on CO_2 emissions. The Tenaska CO_2 Secondary Impact Analysis is included as Exhibit 12.0.

13.0 CO_2 Storage

CCG plans to deliver CO_2 for EOR, assuming that Denbury completes its pipeline to the Facility. CCG has developed a backup geologic storage strategy that it will implement if the Denbury pipeline is not completed in a timely manner.

13.1 Enhanced Oil Recovery

CCG's primary storage strategy is to sell its captured CO_2 for use in EOR efforts and ultimate storage. EOR involves injecting CO_2 into a depleted oil field deep underground. The injection increases the reservoir pressure, and the CO_2 becomes dissolved in the crude oil, reducing the oil's viscosity. The higher pressure and lower viscosity enables remaining oil to move more freely through the formation. Much of the injected CO_2 flows to the surface with the oil and is captured, separated and re-injected. At the end of the EOR period, the CO_2 can be stored in the depleted oil field.

CCG has executed a CO_2 off-take agreement with Denbury, the major supplier of CO_2 in the Gulf Coast region. CCG's contract with Denbury, dated March 20, 2009, contemplates CCG selling the CO_2 at the Project fence to Denbury, at which point Denbury will take title to the CO_2 and pay CCG a variable price per MT for the CO_2, depending on an index price for crude oil. Denbury will be responsible for all costs associated with the CO_2 pipeline.

The off-take agreement with Denbury provides several important benefits to the TEC. First, the revenue from the CO_2 sales will partially offset the costs associated with capturing and compressing the CO_2. Second, Denbury will take title to the CO_2 at the Project fence, eliminating the need for CCG to construct a pipeline or off-Site permanent storage facilities. Third, Denbury will be responsible for operation of the CO_2 pipeline, a role for which it is well qualified. These significant benefits led the TEC to adopt EOR via a contract with Denbury as its primary storage strategy.

13.2 Geologic Storage

CCG is also developing local geologic storage as an alternative, secondary CO_2 strategy to EOR. CCG engaged Schlumberger to conduct a CO_2 storage-site characterization study for the Mt. Simon formation that underlies, and is adjacent to, the TEC. The Cambrian age Mt. Simon formation is a saline reservoir that underlies most of the Illinois Basin at depths from close to the surface to over 16,000 ft. It is overlain by shales of the Cambrian age Eau Claire Formation and is underlain by Precambrian granites. Mt. Simon gas storage fields indicate that the Eau Claire is an effective seal for gas containment. In addition, the nearly 50-year long history of successful natural gas storage in the Mt. Simon indicates the reliability of the cap rock and the injection capability of this saline reservoir, as well as providing reliable information on how to design wells, conduct monitoring and operations, and demonstrate site integrity.

Schlumberger's Summary Results for Carbon Storage Feasibility Study, attached as Exhibit 13.2.a, contains an evaluation of (i) the site's capacity to store the expected volume of CO_2 from the TEC; (ii) containment of the storage reservoir; and (iii) infrastructure requirements for storage (e.g. number and dimensions of injection wells and operational strategies). As part of this study, Schlumberger conducted an initial 21-mile 2-D seismic survey of the area, performed a comprehensive review of the properties in the Mt. Simon formation surrounding the TEC Site, developed a predictive reservoir model for a CO_2 storage field in the Mt. Simon formation, made determinations of storage targets and recommended a proposed well design.

Results from Schlumberger's modeling and technical assessments indicate that the target site in the Mt. Simon sandstone offers sufficient porosity (open space between the sand grains in the rock) and permeability (the degree to which the pore spaces are connected, determining how easily fluid will move through the rocks) that will allow for a high capacity injection field to be developed using a minimal number of wells. The Mt. Simon formation in the Site area is at a depth of approximately 5,615 feet and has a thickness of 1,100-1,500 feet. This places the base of the storage reservoir as deep as 6,900 feet below ground level and 5,000 feet below the active regional, municipal and commercial drinking water supplies. Because of favorable geologic characteristics, the expected size of the storage field would be no greater than approximately 14 square miles (5.6 miles by 2.5 miles) following 30 years of injection of the TEC's expected CO_2 volumes. The current model shows that the full capacity of the forecasted TEC field CO_2 injection can be managed with two or three injection wells, spaced approximately two miles apart. The target site also is confined by more than 200 feet of low permeability shale (the aforementioned Eau Claire formation). The depth of the storage reservoir and the presence of sealing caprock provide a secure storage reservoir target capable of accommodating all of the CO_2 produced by the TEC over the 30-year study period.

Schlumberger also performed a Cost Report for the Taylorville Energy Center, included as Exhibit 13.2.b, for the development of geologic CO_2 storage for the TEC. Schlumberger found that based on its evaluation and understanding of Project requirements—including pending regulations— 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.

The Schlumberger cost report assumes a total of six wells: two CO_2 injection wells completed in the Mt. Simon sandstone, the storage reservoir; two deep monitoring wells completed in the St. Peter sandstone, a deep zone of low-salinity water; and two shallow groundwater monitoring wells completed in the glacial outwash, the primary source of potable groundwater in the area. The costs also include estimates for insurance, land and access fees, monitoring, pipeline, work over, engineering, operations, and maintenance, contingency (due to such factors as fluctuations in commodities prices and changing regulations), plugging and abandonment, and decommissioning contingency. Schlumberger estimates that the total cost to construct the geologic storage for the TEC is $44.0 million. The cost to operate, monitor and decommission the geologic storage field is $44.1 million. If a third well is needed an additional $24.5million in contingency costs would be required over the life of the facility. All costs are expressed in January 2010$.

Of these costs, $44.0 million would be incurred prior to the commencement of commercial operations of the TEC. If insufficient progress is made by Denbury in developing and building its Midwest CO_2 pipeline, or if Denbury should terminate its contract with CCG for any reason including a determination that it will not have sufficient capacity on its pipeline to handle the TEC's volumes, CCG will proceed with its backup plan to construct its own storage field under and just north of the TEC Site. As noted in Section 8, CCG intends to provide for a contingency of $257 million and a cost overrun facility of $500 million as part of its financing plan. One or both of these sources could be accessed to pay for the construction of the storage field if it should be needed.

On December 15, 2009, CCG submitted a Class I Non-Hazardous Underground Injection Control Area Permit Application to the IEPA for up to four CO_2 injection wells. The design, installation, and operation of the proposed TEC injection wells will meet or exceed all IEPA regulations, and continuous, periodic on-site and off-site monitoring will ensure protection of Underground Sources of Drinking Water, compliance with all applicable environmental rules and assurance of community health and safety. Once the IEPA processes CCG's application, the first injection well can be drilled in order to collect and recover additional subsurface geologic, reservoir, and formation data regarding injection and confining intervals at the TEC site. This data will enable greater resolution and refining of the geologic, reservoir and operational models in support of any anticipated permit updates.

CCG's strategy of pursuing the sale of its CO_2 for EOR through its contract with Denbury while also developing its own nearby storage field and seeking an injection permit for geologic storage in the Mt. Simon formation, is a well developed and reasonable approach for ensuring that the TEC will be able permanently to store the CO_2 that is captured at the Facility.

The Pace Rate Impact Analysis, attached as Exhibit 10.0 and described in Section 10, is based upon CCG's plan to deliver CO_2 to Denbury for use in an EOR application. Under this approach, CCG would, under Section 45Q of the Internal Revenue Code, receive a tax credit of $10/MT of CO_2 stored and would receive a payment from Denbury for the CO_2. The amount of the payment varies with the price of crude oil, and in the Pace rate impact analysis is calculated in accordance with Pace's oil price forecast. In order to deliver CO_2 to Denbury, CCG will incur the cost of compressing the CO_2 to 2,100 pounds per square inch, which will require approximately 25 MW of electricity. Denbury will provide the CO_2 pipeline at the fence boundary, so CCG will not incur the cost of building a CO_2 pipeline.

As noted above, CCG is pursuing the development of its own storage field as a backup to its plan to deliver its CO_2 to Denbury, as Denbury is not obligated to build a CO_2 pipeline to the TEC unless it can secure other CO_2 contracts that would justify the construction of the pipeline. The incremental costs that CCG would incur if it must implement this backup strategy for CO_2 storage include the capital and operating costs of construction and operating the storage field, as described above. In addition, CCG would no longer receive revenue from CO_2 sales. Offsetting these costs would be an increase in the applicable tax credit from $10 to $20/MT under Internal Revenue Code Section 45Q and a reduction in CO_2 compression requirements to 1,900 pounds per square inch after approximately the first five years of injection. The net annual effect of these changes would be an decrease in projected costs of approximately $6 million per year for the first 10 years and an increase of $14 million per year on average for 30 years. In the first 10 years, the average rate impact would be -0.39%. Over the 30-year period, the average rate impact would be 0.86%.

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%.