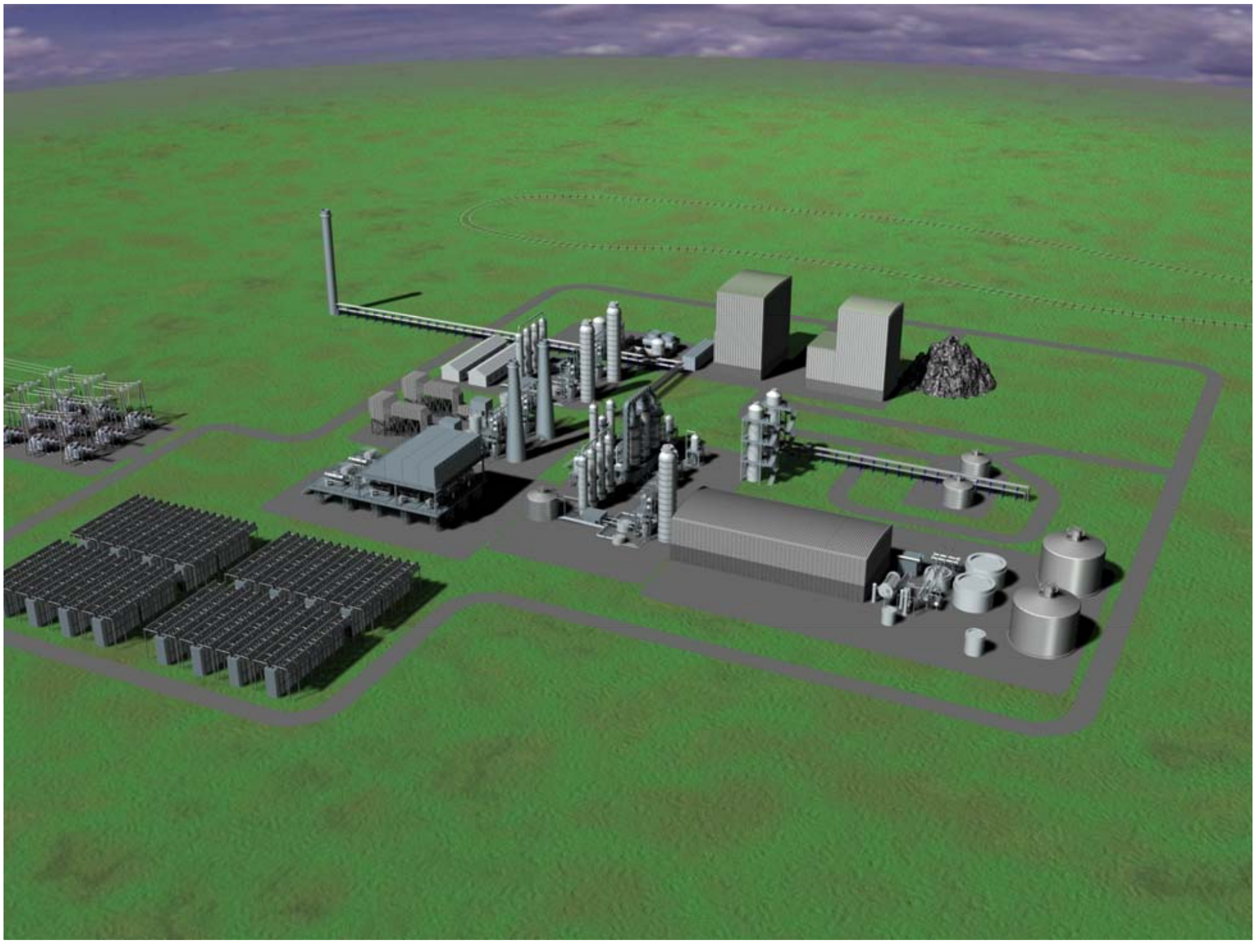
REVIEW OF THE TAYLORVILLE ENERGY CENTER'S FACILITY COST REPORT

PRESENTED TO
THE ILLINOIS COMMERCE COMMISSION



BY
BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

Boston Pacific Company, Inc.
Craig R. Roach, Ph.D.
croach@bostonpacific.com
1100 New York Avenue, NW, Suite 490 East
Washington, DC 20005
(202) 296-5520

MPR Associates, Inc.
Jim Bubb, P.E.
jbubb@mpr.com
320 King Street, Suite 400
Alexandria, VA 22314
(703) 519-0200

June 8, 2010

TABLE OF CONTENTS

ABOUT BOSTON PACIFIC COMPANY, INC.

Boston Pacific is a consulting and investment services firm, located in Washington, D.C., specializing in the electricity and natural gas industries. For 23 years we have provided information and insight to our clients who span the full range of stakeholders: state regulatory commissions, regional transmission organizations, energy consumers, competitive power producers, electric utilities, gas pipeline companies, and electric transmission companies. We are nationally recognized experts on the electricity business as documented by our service as expert witnesses throughout North America. Boston Pacific also is an industry leader in monitoring major power procurements for State Commissions across the country. And for six years we have advised the Board of Directors of the Southwest Power Pool RTO on its full range of issues.

As to the specific issues addressed herein, Boston Pacific has substantial experience with and expertise in Integrated Gasification Combined Cycle (IGCC) projects. Most recently, we served as an independent advisor to the Mississippi Public Service Commission on the proposed Kemper County IGCC Project; the Mississippi Commission just set the ground rules for moving forward with Kemper. We are also currently serving as market or financial advisors to the Department of Energy's Loan Guarantee Program on a range of technologies including gasification projects. Additionally, we have previously evaluated an IGCC project in the Northwest for the Oregon Public Utility Commission.

For more information on Boston Pacific please visit us at www.bostonpacific.com

ABOUT MPR ASSOCIATES, INC.

MPR Associates is an employee-owned engineering services firm founded in 1964 and has provided engineering services relating to the design and operation of electric generating stations since its inception. MPR has a staff of over 200 persons located at our headquarters office in Alexandria, Virginia and other offices in Houston, TX, East Lyme, CT and Albany, NY.

MPR clients include the world's leading energy companies and financial institutions as well as various U.S. government agencies. MPR has a long history supporting the development, construction and operation of large power projects and has also supported the evaluation and development of gasification technologies and projects. We have an extensive background in commercial due diligence for project, project portfolio and corporate acquisitions. MPR has performed technical and commercial reviews for literally hundreds of energy and process facilities for commercial and government clients and have advised clients on purchase or financing of assets valued at well over $30 billion.

More information about MPR Associates can be found at our website: www.mpr.com

EXECUTIVE SUMMARY

REVIEW OF THE TAYLORVILLE ENERGY CENTER'S FACILITY COST REPORT

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

Boston Pacific Company, Inc.
Craig R. Roach, Ph.D.
croach@bostonpacific.com
1100 New York Avenue, NW, Suite 490 East
Washington, DC 20005
(202) 296-5520

MPR Associates, Inc.
Jim Bubb, P.E.
jbubb@mpr.com
320 King Street, Suite 400
Alexandria, VA 22314
(703) 519-0200

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. ("Boston Pacific") and MPR Associates, Inc. ("MPR") make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

I. INTRODUCTION AND BACKGROUND

The purpose of this report is to assist the Illinois Commerce Commission in fulfilling the requirement under the Illinois Clean Coal Law to provide to the Legislature a review of the Taylorville Energy Center's Facility Cost Report.[1]

Taylorville is a proposed electric power plant which would first convert Illinois coal into the equivalent of natural gas; this is called either substitute or synthetic natural gas and its acronym is SNG. Taylorville would then use this SNG to produce electricity with a modern, efficient power plant using a technology called combined cycle generation. The term used for the overall technology is Integrated Gasification Combined Cycle and the acronym is IGCC. Since Taylorville will sometimes sell the SNG as natural gas rather than using it to produce electric power, its sponsor, Tenaska, Inc.,[2] refers to it as a Hybrid IGCC.[3] Note, too, that Taylorville will purchase a substantial amount of pipeline natural gas to supplement its SNG when it wants to produce maximum electricity output.

The most important part of the Taylorville proposal, however, is its plan to capture and store in the ground the power plant emission said to be the primary cause of global climate change. That is, it proposes to capture and store carbon dioxide emissions; the technical term for this is carbon capture and sequestration. We say this is the most important part because a stated purpose of the Clean Coal Law is to "demonstrate the viability of coal and coal-derived fuels in a carbon constrained economy."[4]

Beyond this Executive Summary, our report includes seven individual Task Reports as well as Work Papers which go into considerable detail on engineering, economic, financial, and policy issues with the Taylorville proposal. Our intent in this Executive Summary, however, is to summarize our work through our answers to the following six straightforward questions.

1. Can the Taylorville facility be built within the schedule and budget presented in the Facility Cost Report?
2. Will the Taylorville facility perform as planned?
3. How much will Illinois Consumers be charged for electricity from Taylorville?
4. What are the risks with Taylorville and who bears them?
5. How does Taylorville's price for electricity compare to that from other new power plants?
6. Will Taylorville's proposal comply with the Illinois Clean Coal Law?

---

[1] Public Act 095-1027, also referred to as the Clean Coal Portfolio Standard Law, hereafter the "Clean Coal Law" or simply the "Law." Law at Section 1-75(d)(4)(ii). The Law in large part consists of modifications to the Illinois Power Agency Act ("IPA Act") 20 ILCS 3855/1-1 et seq, and all citations to sections of the Law are to the IPA Act unless otherwise indicated.
[2] Boston Pacific Company, Inc. and MPR Associates, Inc. met in person on many occasions with Tenaska and its consultants, and we communicated routinely by email and phone. We very much appreciate Tenaska's cooperation. Tenaska was given the opportunity to review this report for factual accuracy prior to it being finalized.
[3] In "conventional IGCC", the syngas is not upgraded to be a substitute for natural gas as it is in Hybrid IGCC; this upgrading step significantly increases the cost of the facility.
[4] Law at Section 1-5(8).

Before we answer these six questions it is useful to provide some background on two topics. The first is to summarize the key requirements of the Illinois Clean Coal Law. The second is to summarize the key features of the Taylorville proposal.

A. Key Substantive Requirements of the Illinois Clean Coal Law

Taylorville is the "initial clean coal facility" cited in the Clean Coal Law. With that, the Law requires all Illinois retail electricity suppliers to buy a share of the power generated by Taylorville. The Illinois electric utilities subject to Section 1-75 of the Law (i.e., Commonwealth Edison and the three Ameren utilities) as well as the Alternative Retail Electric Suppliers or ARES who also serve electricity consumers in the State must buy a proportionate share of Taylorville's generation; for example, if Commonwealth Edison serves 30% of all the electricity need in Illinois, it must buy 30% of the energy output from Taylorville. This must-purchase requirement is an essential cornerstone for Taylorville's development.

The electric utilities and ARES will buy power from Taylorville under a contract called the Sourcing Agreement. The Sourcing Agreement (and the related Sourcing Tariff) must be approved by the Illinois Commission; that approval process can be a crucial opportunity for the Commission to assure that Taylorville is offering the best deal possible under the circumstances.

At the outset, it is important and appropriate to note that the Law fully anticipates that the price of power from Taylorville will be higher than the otherwise available market price of power. Given this, the Law sets up a method for determining which Illinois electricity consumers pay the above-market premium. Working through the mechanics of the Law, the bottom line is that, if Taylorville's above-market premium is $2.32 per megawatt-hour (MWh) or less when spread over every MWh of electricity consumed in Illinois, then all Illinois electricity consumers pay the same amount of the premium. That is, both the utilities and ARES will pay whatever the market price is for power in each of the 30 years of the Sourcing Agreement and, then, on top of that they will pay up to the $2.32 per MWh on every MWh they provide to consumers. For example, assume total electricity use in Illinois in coming years will be about 142.4 million MWh each year. If the above-market premium from Taylorville just hit the limit of $2.32 per MWh that would mean electricity consumers in Illinois *collectively* would pay an annual premium of approximately $330 million a year to Taylorville (this is $2.32 per MWh multiplied by 142.4 million MWh).[5]

Importantly, if the above-market premium is greater than $2.32 per MWh, then the Illinois consumers served by ARES pay more of the premium than the customers of the electric utilities. However, the point is that under the Law, Taylorville is paid the full above-market premium one way or another. Of course, we should say that if Taylorville's price for power is below market prices, there would be no above-market premium.

Taylorville must meet several other important requirements of the Law as summarized in the following list:

[5] It is worth a quick note on how the Law dictates the above-market premium. Under the option Taylorville will take, the Law states that the above-market premium cannot be more than 2.015% of the total price paid for electricity by retail customers in 2009. For ComEd, the 2.015% of the 2009 price is $2.38 per MWh; for the Ameren utilities it works out to be $2.17 per MWh. The weighted average of the two is $2.32 per MWh.

a. Capture and store at least 50% of the potential carbon dioxide emissions.
b. Use primarily coal as its feedstock.
c. Provide the prescribed content in the Facility Cost Report.
d. Use qualified vendors and consultants.
e. Offset its cost by crediting to consumers the revenue earned on byproduct sales (such as the sales of SNG) and passing through any benefits of Federal and State tax and financing incentives.
f. Demonstrate the viability of coal-derived fuels in a carbon constrained economy.

The Law also requires actions by the Illinois Commission. The two most important are these. First, the Commission must review the Facility Cost Report and advise the Legislature on its findings – again, the purpose of this report is to assist in that effort. Second, if the Legislature approves Taylorville after reviewing the Facility Cost Report and the Commission's review of that Report, the Commission must assess whether the Sourcing Agreement is "prudent and reasonable."

B. Key features of the Taylorville proposal

As explained above, Taylorville will begin by gasifying Illinois Coal to produce substitute natural gas or SNG. The facility is divided into two distinct sub-facilities: the SNG Block and the Power Block. The SNG Block is designed with two Siemens Fuel Gasifiers. Oxygen for the gasification process is provided from an Air Separation Unit. The raw syngas exiting the gasifier is then processed through Air Liquide's shift reactor, acid gas removal unit, sulfur recovery unit, and methanation unit to produce SNG and steam. Capture of carbon dioxide from the coal also occurs in the SNG Block.

The Power Block includes two combustion turbines, two heat recovery steam generators, and one steam turbine. The combustion turbines are natural gas burning Siemens "F Class" heavy-duty turbines. The exhaust energy from the combustion turbines is directed to two heat recovery steam generators that provide steam to the Power Block steam cycle. Steam from the gasification process is also directed to the heat recovery steam generators. The steam is then sent to a General Electric steam turbine.

Taylorville forecasts that, after a two-year ramp up period, its gasification facility will be available 85% of the time. In each hour of full operation, the gasification process will consume 4,433 million Btu per hour of Illinois coal – that is about 188 tons every hour. Taylorville will produce a maximum of 2,592 million Btu per hour of SNG. As explained later, these coal input and SNG output figures reflect Tenaska's view that the facility will perform 10% better than what equipment manufacturers are willing to guarantee. If only the guaranteed performance occurs, the facility will consume 4,030 million Btu per hour of coal and generate 2,351 million Btu per hour of SNG.

Taylorville will operate in three different modes. In Mode 1 it will generate 602 MWh of power each hour on average when market prices warrant. In Mode 1 it uses all the SNG it produces to generate power – there are no SNG sales in Mode 1. Indeed, to produce the 602 MWh in an hour it will require substantial purchases of pipeline natural gas – about 1,522 MMBtu per hour in addition to the 4,433 million Btu per hour of Illinois coal.

In Mode 2, Taylorville will use just one of its two combustion turbines and, therefore, will generate only 285 MW of power on average; also, because it cuts back electricity generation, Taylorville will sell 535 MMBtu per hour of SNG. In Mode 3, Taylorville uses pipeline natural gas solely to produce electricity – Mode 3 occurs when the gasifiers are not available, but operation with pipeline natural gas is warranted by market prices – 4,113 MMBtu per hour of pipeline natural gas will be consumed in Mode 3.

Importantly, we have reviewed the facility design proposed by Tenaska and have concluded that the design is one that can be feasibly constructed and operated over the facility lifetime. We judge that the useable life of this facility is at least 30 years and potentially longer with proper maintenance.

II. CAN THE TAYLORVILLE FACILITY BE BUILT WITHIN THE SCHEDULE AND BUDGET PRESENTED IN THE FACILITY COST REPORT?

To evaluate whether Taylorville can be built within the schedule and budget presented in the Facility Cost Report, we reviewed the following areas:

- Construction schedule
- Capital cost estimate
- Operations and maintenance cost estimate
- Fuel supply estimate

A. Construction Schedule

We have concluded that the construction schedule prepared by Tenaska is reasonably well developed for the stage of the project and is generally achievable. However, several key activities are not explicitly addressed in the schedule (e.g. permits, interconnections, and carbon dioxide sequestration infrastructure), and several areas of the schedule are not sufficiently developed to provide a high level of confidence in the overall project duration. Accordingly, we believe that the current schedule contingency of 5 weeks is insufficient. We recommend at least 10% schedule contingency. For the 47 month schedule, this would result in an additional 20 weeks for a total project duration of 52 months from Final Notice to Proceed.

B. Capital Cost Estimate

We have reviewed the capital cost estimate and believe the $3.5 billion estimate is a reasonable baseline estimate for the facility. However, while the Facility Cost Report claims this estimate to be accurate within a range of +15%/-10%, we believe this range is too narrow. Based on our analysis (based primarily upon ASTM cost estimating standards), the accuracy of the capital cost estimate is closer to +20%/-15% for a total project cost in the range of $3.0 to $4.2 billion. A breakdown of the capital cost is provided in the following table.

Table One
Taylorville Facility Cost Report Capital Cost Summary ($000)

Core Plant	
Program Management	$ 146,198
Other Core Plant	$ 590,456
Gasification	$ 386,376
Syngas	$ 392,725
Power Block	$ 525,461
Water Treatment	$ 187,160
Core Plant Subtotal	**$ 2,228,376**
Balance of Plant	$ 149,400
Escalation	$ 184,136
Contingency	$ 257,000
Owners Costs	$ 349,546
Financing	$ 353,192
Total Capital Cost	**$ 3,521,650**

As part of the design effort, the development team has recently made some significant design changes to reduce the cost of the facility that we believe are important to understand. An earlier design of the facility[6] included four gasifiers, and all of the input energy to the Power Block was coal-based rather than natural gas. The core cost estimate for such a facility developed during the Front End Engineering and Design (FEED) effort in January of 2010 was roughly $4 billion; $1.3 billion greater than the figure estimated in May 2009 ($2.7 billion). Consequently, the design team began a rigorous and determined effort to reduce costs by many methods; most notably by cutting the number of gasifiers in half, reducing equipment redundancy, and redesigning the plant layout. A key consequence of this scope change is that the plant design now has 33% less coal capacity.

These large changes in scope and cost have occurred over a relatively short timeframe. Further, it would not be unexpected for additional design changes to occur as the remainder of the facility design is completed (engineering is only 10% complete). These observations underscore our assessment that Tenaska's claimed uncertainty range is overly-optimistic.

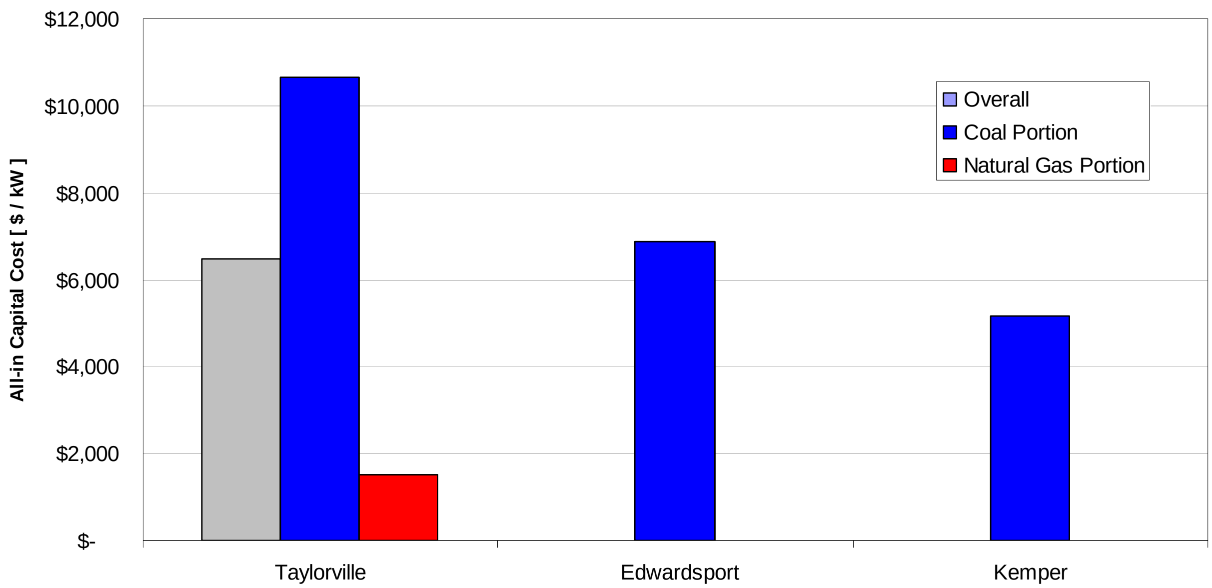
We have also compared the capital cost of the proposed facility to other notable gasification facilities that are currently under development as shown in Figure One. These facilities are Edwardsport and Kemper, both of which are based on a "conventional" Integrated Gasification Combined Cycle design (further discussion of the conventional design is provided in Section III.E). The comparison of facility costs includes several adjustments to account for

[6] The earlier design is presented in a report authored by R.W. Beck in May 2009.

important differences between the designs, notably the differences in carbon capture capability, and the significant amount of natural gas capacity that is included in Taylorville. Extended discussion of these adjustments is provided in the Task 3 Report.

As seen in Figure One, the cost of the coal portion of the Taylorville facility is significantly higher than the other facilities' cost. Some of this difference may be related to the "hybrid" design as compared to the "conventional" design. Additional discussion on this topic is provided in Section III.E.

Figure One
Comparison of Taylorville Capital Cost to Other Gasification Facilities



1 Cost of the Edwardsport facility has been increased by 20% and the output has been decreased by 20% to compensate for the lack of carbon sequestration. These estimates are based on information in a Department of Energy Report, DOE/NETL-2007/1281.

2 Output of the Kemper project is reduced by 60 MW, which is the natural gas fired duct burning capacity of the facility. The capital cost used here does not reflect direct Federal incentives that would lower the costs. See Phase Two Direct Testimony of Thomas O. Anderson On Behalf of Mississippi Power Company Before the Mississippi Public Service Commission, Docket No. 2009-UA-0014 at Exhibit TOA-1, page 6.

C. Operations and Maintenance Cost Estimate

Our review concludes that the Operations and Maintenance cost is likely to be under-estimated in the Facility Cost Report. Our review has identified several areas of the estimate that appear to be understated, including: capital improvement project budgets, staffing, inspection intervals, catalyst life, and technical field assistants. We consider that a more appropriate annual Operations and Maintenance budget is $105 million (in 2010 dollars, excluding escalation), which is $37.7 million more than the estimate used in the Facility Cost Report.

D. Fuel Supply Estimate

Based on our review of the fuel supply estimate included in the Facility Cost Report, we have concluded that the likelihood of achieving the predicted fuel supply costs for the facility is not well demonstrated due to: (a) the inherent uncertainties in future economic predictions and (b) the lack of any signed long term contracts.

The facility financial projections should consider sensitivity cases for a range of potential coal prices. The estimate identifies coal prices from various regions in Illinois and concludes the lowest cost coal is sourced from one particular region. We believe it would be reasonable to consider a possible high-side scenario based on coal supply from the next lowest price Illinois coal region. This price is on average $0.60/MMBtu higher.

The fuel supply estimate shows that the most economic sources of coal will be based on truck transportation. Using trucks to provide coal deliveries and to remove slag from the facility will require a high volume of truck traffic. Tenaska has estimated the maximum daily truck traffic will be 238 trucks for coal deliveries and 42 trucks for slag removal. Deliveries will be made six days per week during daylight hours only. In other words, approximately 23 trucks per hour will be required, or one 25-ton truck every 2.5 minutes.

III. WILL THE TAYLORVILLE FACILITY PERFORM AS PLANNED?

To evaluate whether Taylorville will perform at the levels presented in the Facility Cost Report, we reviewed the following areas:

- Facility performance
- Reliability and availability
- Environmental performance
- Power deliverability
- Hybrid vs. Conventional Integrated Gasification Combined Cycle

A. Facility Performance

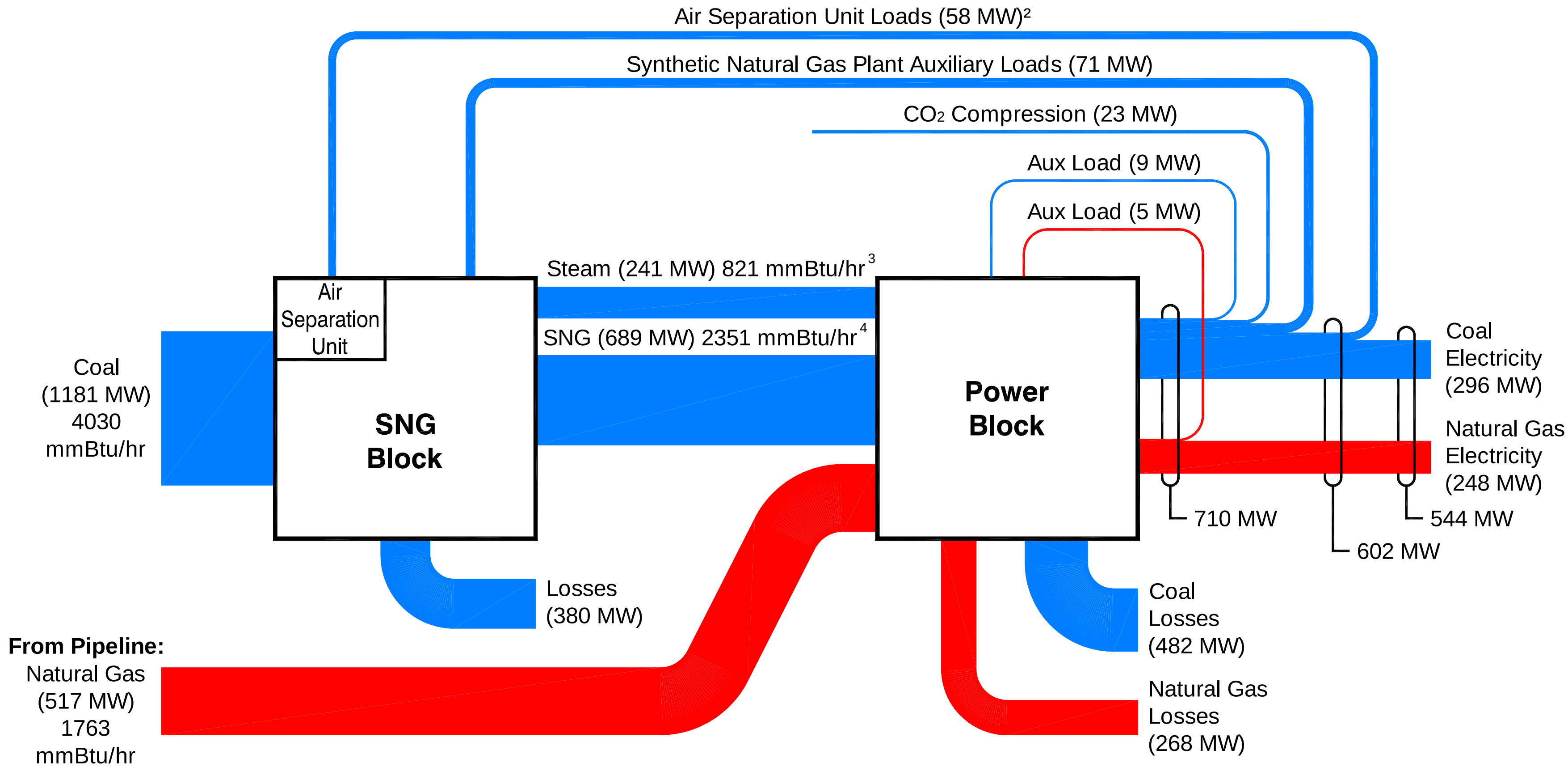
The Facility Cost Report is based upon a facility throughput that significantly exceeds vendor's guarantees. We believe the vendor's guaranteed performance provides a more reasonable basis for evaluating the performance of the facility, and the numbers presented below are based on this guarantee point. We believe that these guaranteed performance numbers are achievable.

Guaranteed Performance. The throughput and electrical and SNG output described in the Facility Cost Report assume that the performance of many of the key systems will be 10% better than their vendors are willing to guarantee. Considering that the Siemens gasifier does not have commercial experience, we do not believe it is reasonable to assume that the facility will exceed its guarantees by this margin. We recommend that the estimated facility performance be based on the vendor's guarantee point.

Air Separation Unit Auxiliary Loads. The 58 MW of power required by the Air Separation Unit is not included in Tenaska's auxiliary load estimate. This is because the Air Separation Unit is currently envisioned to be structured as a third-party "over-the-fence" contract, where the power required to operate the Air Separation Unit would be handled commercially outside of the Taylorville project. This would allow the project to sell an additional 58 MW of power at the higher above-market electric rate, while the third party would purchase power at the lower prevailing rate of the electric grid. While it is unclear to MPR and Boston Pacific if this arrangement would be allowed in the structure of the draft Sourcing Agreements, this parasitic load is required to operate the facility, and this power will not be new power to existing Illinois ratepayers.

Facility Output. At full load, at guaranteed performance the facility is expected to consume 4,030 MMBtu/hr of coal producing, 2,351 MMBtu/hr of Synthetic Natural Gas that is fed into the Power Block along with 1,763 MMBtu/hr of purchased pipeline natural gas. The net power produced from the Power Block is 544 MW (net of Air Separation Unit). These figures are illustrated in Figure Two.

Figure Two[1]
Taylorville Energy Balance – Mode 1 (2x1)



1. All data (except Air Separation Unit power consumption) is based on the Taylorville Energy Center Heat and Material Balance with production rates aligned to the Siemens syngas yield guarantee for the nominal ambient conditions (53°F). (Reference 4) We refer to this in the text as Guaranteed Performance.

2. Air Separation Unit power consumption data provided in memorandum "TEC Facility Cost Report ASU Basis" dated March 15, 2010. (Reference 18)

3. Steam is calculated as the difference between energy of the process steam, shift gas cooler streams and the feedwater streams.

4. Produced Synthetic Natural Gas to Power Block.

The Law requires Taylorville to use coal as its primary fuel. As seen at the left side of Figure Two, a significant portion of the electrical capacity of the facility is derived from pipeline natural gas input rather than coal. Coal represents 70% of the *fuel input* by the Taylorville facility when running at full load.[7] However, as seen on the right side of Figure Two, due to the fact that a large portion of the energy in the coal is consumed in the process of converting the coal to Synthetic Natural Gas (SNG) and sequestering the carbon dioxide (CO_2), only 54% of the *electrical output capacity* of the facility is from coal.[8] We should note that Taylorville will not run at full capacity (in Mode 1) all of the time. When running at half capacity (in Mode 2) all the fuel input is coal. So if we reflect actual operations, our economic models suggest between 62% to 71% of the *energy delivered* by the facility would be coal based.

The Law requires the facility to have a nameplate capacity of at least 500 MW. The 544 MW capacity of this facility exceeds this requirement, therefore the facility can be said to comply with the letter of the Law. However, as seen in Figure Two, the coal capacity of the facility (296 MW) is considerably less than 500 MW.

Ability to Produce SNG for Sale to Pipeline. Tenaska has stated that a key advantage of the hybrid-type gasification design (vs. a "conventional" Integrated Gasification Combined Cycle design) is the possibility for SNG sales during times when the markets are favorable to the economics of gas production rather than electricity generation. However, when Taylorville is operating in Mode 2 in which it sells SNG, a relatively small portion of the gas output (13%) is actually available for sale. The remainder of the SNG production is directed to the Power Block, which operates at half load.

Efficiency. While the performance of the individual process plants for the SNG Block and the Power Block are similar to other gasification facilities, the overall plant efficiency is less than that of a clean coal facility based on a "conventional" Integrated Gasification Combined Cycle design. A key difference between these two designs is the methanation reactors in the hybrid design which diverts some of the energy from the gas stream to steam energy. The Power Block converts the steam energy to electricity at a lower efficiency than the energy in the SNG stream. The differences between conventional and hybrid Integrated Gasification Combined Cycle are discussed further later in this section.

B. Reliability and Availability

We believe Tenaska's estimate of facility availability over the long-term is reasonable and achievable. However, we believe that Tenaska's availability prediction for the initial years of operation is overly optimistic. We have reviewed previous gasification facility operating experience and concluded that a "shakedown period" (when facility's availability would be lower than the long term value) lasting four years is appropriate, rather than Tenaska's prediction of two years.

[7] See the left side of Figure Two, coal input is 4,030 MMBtu/hr while pipeline natural gas input is 1,763 MMBtu/hr.
[8] See at the right side of the graph that coal electricity output is 296 MW out of the 544 MW total.

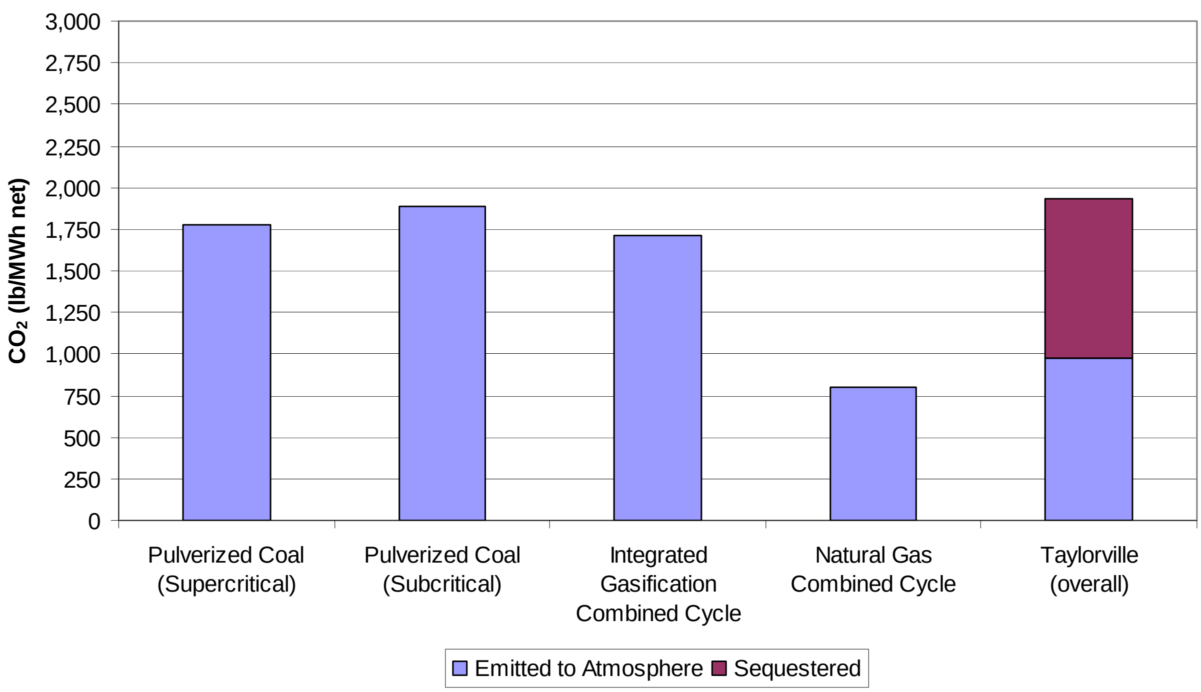
C. Environmental Performance

Based on our review, we believe the predicted environmental performance of the facility is achievable and is consistent with the requirements of the Law.

Air Emissions. Regarding air emissions (other than CO_2), the Taylorville facility performance is comparable to a traditional natural gas combined cycle facility (as required by the Law) and the emissions are much lower than a traditional pulverized coal plant.

CO_2 emissions. Taylorville is designed to capture approximately 49.4% of the CO_2 that the facility would have otherwise emitted when operating at full load, and 62% when operating at part load. Therefore, on an annual basis it is reasonable to expect Taylorville to exceed the 50% capture requirement of the Law. As shown in Figure Three, the CO_2 emitted per MWh is 45% less than that which would be emitted by a pulverized coal plant without CO_2 capture, and is 23% greater than that produced by a conventional natural gas fired combined cycle facility.

Figure Three
CO_2 Emissions[1,2,3]



1. Data for other facilities obtained from DOE/NETL and does not include carbon capture.
2. Taylorville emissions based on Mode 1 operation at 100% output data from material balance
3. Figures do not include carbon emissions associated with fuel transportation

Sequestration Options. Tenaska is pursuing two options to permanently sequester the captured CO_2 (as required by the Law). The first approach envisions selling the CO_2 to Denbury Resources for use in Enhanced Oil Recovery. This option requires that a pipeline be built from Taylorville to the Gulf Coast Region of the US. In order to justify the construction cost for a pipeline, at least one additional CO_2 source within the region will need to be identified. Therefore, there is considerable uncertainty about the feasibility of this option.

A second approach is to sequester the CO_2 in the Mount Simon saline aquifer which is below/adjacent to the Taylorville facility. A detailed study of this option was performed by Schlumberger Carbon Services, which concludes that the Mt. Simon formation is capable of sequestering all of the CO_2 from the Taylorville facility for the next 30 years.

However, the regulatory and liability issues associated with the long term impact of sequestration and the potential for an accidental release of the CO_2 should be well understood before implementing either of these options.

Water Consumption. The Taylorville facility performs very well compared to other facilities, largely due to its dry cooling system and zero-liquid discharge design. Another benefit of the zero-liquid discharge design is that there is no process wastewater leaving the facility.

D. Power Deliverability

Based on our review of the interconnection studies, electrical one-line diagram, and switchyard layout for the facility, we have concluded that the power from the facility can likely be delivered to the grid with various upgrades to the transmission and distribution system.

The interconnection study provides preliminary results, and final results are not expected to be provided until August of 2010. Consequently, conclusions about the deliverability of the power and necessary upgrades should be considered preliminary. The interconnection studies detail several upgrades to the transmission and distribution system that are required to allow the project to deliver its energy to the grid. The cost of these upgrades has been included in the capital cost estimate for the project.

E. Hybrid vs. Conventional Integrated Gasification Combined Cycle

The Taylorville facility is based on a “hybrid” Integrated Gasification Combined Cycle design approach that converts the syngas produced by the gasifiers (a mixture of mostly carbon monoxide and hydrogen) into methane (the equivalent of pipeline natural gas). An alternative approach that has been used by many other similar facilities is a “conventional” Integrated Gasification Combined Cycle design. This approach does not include a methanation step and burns the syngas from the gasifier directly in the Power Block. We believe the conventional Integrated Gasification Combined Cycle approach offers an opportunity to significantly lower the cost and increase the efficiency of the facility. For example, when compared to the Edwardsport facility, which is based on the conventional Integrated Gasification Combined Cycle, we estimate that a capital cost savings of roughly $3,700/kW on the coal portion might be achieved (see Figure One). A comparison to another conventional design being developed, the Kemper project, suggests similar potential savings. Furthermore, the efficiency of the conventional design would be expected to be better than the hybrid design. We see no obvious reason why a clean coal facility based on the conventional design would not meet the requirements of the Law[9].

To be clear, we have not developed an independent cost or performance estimate for a conventional design; and we have not concluded that a conventional design is definitively less expensive with better performance. However, the metrics above suggests the potential cost savings and performance increase could be significant.

At the time this report was being finalized, Tenaska stated that they have performed a scoping evaluation of the conventional approach. We have not reviewed this evaluation, since it was not possible to complete it in the available timeframe and a detailed review of this plant design was not in the scope of our assessment.

In summary, the Commission may find it constructive to consider the conventional Integrated Gasification Combined Cycle approach as a meaningful way to significantly reduce costs and increase the performance of the facility.

---

[9] The emissions control technology for a conventional design may need to be different than that used for a hybrid design in order to meet the Law's requirement that the facility emissions be less than a natural gas fired plant for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury.

IV. HOW MUCH WILL ILLINOIS CONSUMERS BE CHARGED FOR ELECTRICITY FROM TAYLORVILLE?

We developed a computer model to forecast the cost and performance of Taylorville. Our approach was to start with an effort to replicate, to the extent possible, the same forecast provided by Tenaska and its consultants, PACE Global Energy Services, LLC (the "Base Case"). As further described in this section, we were able to come quite close to replicating Tenaska's base case. Later, in Section V, we consider plausible changes in a variety of the Base Case's uncertain assumptions which, in turn, affect the forecasted cost and performance of Taylorville, and, thereby, reveal the risks of the Taylorville facility.

A. Capital Revenue Requirement

Capital Revenue Requirement is the amount Taylorville will charge each year to cover the cost of building and financing its facility. The starting point for the capital revenue requirement is the final cost of building the power plant called "Rate Base". Rate Base includes the costs of all labor and material needed to build the facility plus (a) the cost of financing construction – called allowance for funds used during construction, (b) anticipated increases in costs during construction – this is termed escalation, and (c) an expectation of money needed to cover unexpected costs – this is termed contingency. With all of this included, we estimate the final investment in Taylorville under Base Case assumptions will be about $3.7 billion; this is $6,228 per kW of capacity if we use the 602 MW of output. Tenaska's estimate of the final investment in Taylorville is almost identical to ours.[10]

With respect to the method and cost of financing Taylorville, the Clean Coal Law deems much of that for the purposes of calculating the rates Taylorville can charge consumers. The Law deems that 55% of the total cost will be financed with debt, 45% will be financed with equity, and allows Tenaska to earn no more than an 11.5% return on equity. Based on the fact that Taylorville will secure its debt finance through a U.S. Department of Energy Loan Guarantee, we assumed a 20-year term for debt and a 4.28% interest rate on that debt which is based on recent interest rates on U.S. Treasury bonds.

With these assumptions, we estimate that Taylorville will ask Illinois consumers to pay on average a levelized annual capital revenue requirement of $359.3 million per year. Tenaska's estimate is very close to ours at $358 million per year.[11]

---

[10] Apparently, this differs from Tenaska's $3.5 billion capital cost estimate cited above due to a difference in reflecting the cost of financing construction. See Tenaska Financial Model, "TEC FCR2 Financial Model MPR March 11-10.xls", Tab "14-AFUDC", and see Tenaska Responses to Data Requests on April 19, 2010.

[11] See Tenaska Financial Model, "TEC FCR2 Financial Model MPR March 11-10.xls", Tab "7-Levelized Capital Recovery".

B. Total Net Revenue Requirement

Total Net Revenue Requirement is the amount Taylorville will charge Illinois consumers for all costs – not only for the capital investment, but also for all the operating costs of the facility. The operating cost components of Total Net Revenue Requirements include the following:

a) Annual cost of coal
b) Variable and fixed operation and maintenance
c) Transmission service
d) Air Separation Unit purchases
e) Total cost for carbon dioxide emitted
f) Sulfur dioxide allowance purchases
g) Pipeline natural gas purchases

As noted, the Clean Coal Law requires Taylorville to offset its costs by crediting any revenue it receives from sales of byproducts as well as any tax and financing incentives it receives. These credits include the following:

a) Sales of SNG
b) Sales of captured carbon dioxide
c) Grossed up tax benefit of captured carbon dioxide
d) Nitrogen oxide allowance sales
e) Sales of sulfur

Given the above revenue requirement components and any revenues or clean coal credits, the Illinois consumers will be required to pay on average, a levelized net revenue requirement of $763 million per year. Put in other terms, this means Taylorville's price for electricity on average will be $213 per MWh (21.3 cents per kilowatt-hour (kWh)). Tenaska's estimate of total net revenue requirement is quite close to this at $795 million per year ($201 per MWh or 20.1 cents per kWh).[12]

This total net revenue requirement leads us to the issue of premium. That is, do the expected Taylorville prices exceed forecasted market prices and, if so, how much of a premium will Illinois consumers be asked to pay? The answer is that Taylorville's price will exceed market price throughout the 30-year contract. Our estimate of the average annual levelized premium is $286 million each year (or 60% above levelized market revenues). Tenaska's estimate of the levelized premium is just a bit higher at $309 million per year (or 65% above levelized market revenues).[13]

---

[12] Levelized values from "TEC FCR2 Financial Model MPR March 11-10.xls", Tab "8-Cost of Service". While our estimate of the levelized total net revenue requirement is higher than Tenaska's estimate, our estimate of the levelized total net revenue requirement per MWh is lower than Tenaska's estimate due to different assumptions in MWhs generated. Tenaska assumes a higher amount of MWhs generated.
[13] Levelized values from Pace's "Rate Impact Analysis for Taylorville Energy Center", February 21, 2010, Exhibit 5.

Related to the premium is the limit on rate impact to electric utilities in the Clean Coal Law. Recall that the total premium, when spread out over all the electricity sold in the State, cannot exceed $2.32 per MWh without having to shift a disproportionate share of the premium to competitive suppliers called ARES. In our Base Case, this rate impact limit is exceeded in just one year, that year is 2032, and the excess is quite small – the rate impact is $2.33 instead of $2.32 per MWh.

We also were asked to assess the bill impact of the premium. To do so, we took a typical bill for a ComEd residential customer and calculated the bill impact if the allowed $2.38 per MWh rate impact was incurred today. The effect would be to increase that typical bill by just 1.8%.

So we are left with two perspectives on the premium. Taken in total, $286 million every year is a substantial amount of money for Illinois consumers to pay collectively. However, since Taylorville will produce such a small share of the State's electricity need – we estimate that it will provide about 2.53% of the State's needs – when the $286 million annual premium is spread over all customers and all MWh used, it adds a relatively small amount per customer.

V. WHAT ARE THE RISKS WITH TAYLORVILLE AND WHO BEARS THEM?

A. Natural Gas Price and Carbon Regulation Risk

The Base Case forecast reflects only one possible scenario for the future, but there is considerable uncertainty over future market and regulatory events. Among the most uncertain and most important factors is the price for natural gas. The forecast of natural gas prices drives the forecast of market prices and, thereby, influences considerably the above-market premium Taylorville may charge consumers. That forecast also has a substantial effect on the cost of power from Taylorville – recall that Taylorville uses substantial amounts of pipeline natural gas to supplement the gasified coal it uses.

Another highly uncertain factor is the nature and extent of global climate change policy. For our purposes here, the most important effect of global climate change policy is its effect on natural gas prices; those prices can be pushed up significantly if, in response to that policy, a substantial number of suppliers switch to natural gas from coal and other fuels. On the other hand, global climate change policy can depress the price for natural gas if suppliers rush to nuclear and renewable fuels. We also reflect the direct consequences of global climate change policy on Taylorville's cost through a range of assumptions about the expected price for a permit (an allowance) to emit a ton of carbon dioxide; every power plant that emits carbon dioxide, including Taylorville, may have to pay this allowance price or another form of emission penalty.

Our approach to addressing this uncertainty is to assess results under a mix of future scenarios. Here we define three different natural gas price forecasts and three different forecasts of the price for carbon dioxide permits. We then present results under the nine possible futures defined with these range of assumptions.

Table Two displays the results in terms of (a) the price Taylorville would charge per MWh (this is the Levelized Total Net Revenue Requirement), (b) the average (levelized) Total Premium, and (c) the number of years the premium per MWh exceeds the rate impact level in the Clean Coal Law. Recall that our Base Case results, shown in the fifth row of Table Two, include a levelized price of $213 per MWh, a total premium of $286 million per year, and the rate impact limit is exceeded in only one year.

Table Two
Sensitivity Analysis on Natural Gas and CO_2 Allowance Scenarios

Scenario		Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit
Natural Gas	CO2			2015-2044
BPC Low	$10 CO2	**$186.02**	**$332,601**	**21**
BPC Low	Pace Reference	**$203.83**	**$396,429**	**30**
BPC Low	$30 CO2	**$200.55**	**$384,680**	**30**
Pace Reference	$10 CO2	**$194.93**	**$222,131**	**0**
Pace Reference	Pace Reference	**$212.73**	**$285,959**	**1**
Pace Reference	$30 CO2	**$209.45**	**$274,210**	**1**
BPC High	$10 CO2	**$201.92**	**$134,059**	**0**
BPC High	Pace Reference	**$219.72**	**$197,887**	**0**
BPC High	$30 CO2	**$216.44**	**$186,139**	**0**

Note: The $30 CO_2 scenario has a price per permit which starts out higher than the Pace Reference scenario, but then falls below in later years.

As also can be seen in Table Two, the total premium increases as natural gas prices fall – this makes sense because market prices for electricity will fall as natural gas prices fall. Of the nine scenarios shown in Table Two, the highest total annual premium is $396 million occurring with the BPC Low Natural Gas price forecast. Related to this total premium, we see that the rate impact limit would be exceeded in all 30 years. The lowest total annual premium is $134 million per year occurring when we use the BPC High Natural Gas price forecasts; the rate impact limit is never exceeded in this view of the future.

The uncertainty over the forecast of natural gas prices reflects uncertainty over the cost of finding and developing new sources of this fuel. Recent technological breakthroughs in exploring for and producing what is called “shale gas” have led many to predict lower-end natural gas prices; and recent futures prices would support the low-end natural gas price forecast. If shale gas has its potential impact, the low-end forecast is more likely. Not too long ago, however, the general view was that new natural gas would come in the form of imported liquefied natural gas or LNG. With LNG it was thought that America’s natural gas price would be dictated by world demand for natural gas and oil. And, as a consequence, natural gas prices would follow swings in the price of oil. The high-end natural price forecast used here accommodates those who believe prices will rise dramatically once again. The point to take away, however, is that under all these different natural gas price forecasts the price for power from Taylorville is above market prices.

As already noted, global climate change policy is another cause of uncertainty in the forecast of natural gas prices. In this sense, then, varying the price of natural gas is one way we show the effect of global climate change policy on Taylorville. Another direct effect of global climate change policy on the cost of power from Taylorville comes in the form of a possible payment for a permit (an “allowance”) for carbon dioxide emissions. Looking at the Pace

Reference natural gas price forecast, we see the range of premium driven by changes in the assumed price for carbon dioxide permits is from a low of $222 million to a high of $286 million per year.

B. Capital Cost Overrun and Escalation Risk

With any new power plant, especially one with newer technology like Taylorville, there is a substantial risk that capital costs are underestimated. One cause for this would be changes in engineering design as the facility engineering gets to more detailed stages; note that only 10% of the engineering is completed so far for Taylorville. We judge the range of this engineering design uncertainty for the Taylorville capital costs estimate to be from plus 20% to minus 15%, although any cost decrease would be unexpected. Beyond engineering, the capital cost can be increased by escalation in the cost of material and labor. There is some escalation embedded in Tenaska's capital cost estimates. Our Base Case assumes Taylorville's costs rise, over and above this embedded escalation, at Pace's general inflation rate of 2%, but capital cost escalation for power plants recently has been much higher and could be once again in the near future.

Table Three shows the effect of capital cost overruns and more rapid cost escalation. For example, a 20% capital cost overrun would increase the average annual premium to a rounded $358 million per year (this is a 25% increase in the annual premium as compared to our Base Case). Because of this, the rate impact limit would be exceeded in 26 of the 30 years of life for Taylorville. If escalation was 5% per year during the construction phase, the average annual premium would increase to a rounded $320 million and the rate impact limit would be exceeded in 11 years.

Table Three
Sensitivity Analysis on Capital Costs and Escalation

Scenario	Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit
			2015-2044
Base Case	**$212.73**	**$285,959**	**1**
10% Capital Cost Overrun	**$222.72**	**$321,773**	**13**
20% Capital Cost Overrun	**$232.71**	**$357,587**	**26**
3% Construction Escalation	**$215.82**	**$297,023**	**2**
5% Construction Escalation	**$222.22**	**$319,971**	**11**

C. Operating Performance and Cost Risk

Assumptions about operating performance and operating risk also are uncertain. Table Four displays the effect of changes in a variety of assumptions. For example, earlier we said we thought the annual operation and maintenance costs were too low. If we increased these costs accordingly, the average annual premium increases to $334 million and the rate impact limit is exceeded in 22 years.

Table Four
Sensitivity Analysis on Operating Costs and Performance

Scenario	Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit 2015-2044
Base Case	**$212.73**	**$285,959**	**1**
Slow Ramp Up in SNG Plant	**$219.71**	**$294,568**	**2**
Reduction in SNG Plant Performance to Guaranteed Levels	**$217.39**	**$302,659**	**5**
Increased O&M Costs	**$226.23**	**$334,344**	**22**
Higher Coal Transport Cost	**$219.84**	**$303,241**	**6**
Mt. Simon CO2 Storage	**$213.22**	**$287,715**	**7**

D. Combination of Risks

Taylorville's costs could be increased by a combination of risks. Table Five provides some examples. Looking at the second row, we assess the combination of a 20% capital cost overrun, an increase to a 5% escalation rate, and a reduction of gasifier output to the levels equipment manufacturers are willing to guarantee. With this combination of events, as compared to our Base Case the average annual premium increases by 45% to $415 million per year and the rate impact limit is exceeded in all 30 years of Taylorville's operating life.

Table Five
Sensitivity Analysis on Combination of Risks

Scenario	Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit 2015-2044
Base Case	**$212.73**	**$285,959**	**1**
Combination - 10% Capital Cost Overrun, 3% Construction Escalation, Reduction to Guaranteed Levels	**$230.77**	**$350,645**	**26**
Combination - 20% Capital Cost Overrun, 5% Construction Escalation, Reduction to Guaranteed Levels	**$248.75**	**$415,103**	**30**
Combination - Slow Ramp Up and Reduction to Guaranteed Levels	**$224.21**	**$310,273**	**8**
Combination - 10% Capital Cost Overrun, 3% Construction Escalation, Slow Ramp Up, Reduction to Guaranteed Levels	**$237.95**	**$358,258**	**26**

E. Implications of Risk

All energy investments today are made in the face of substantial risks, and Taylorville is no exception; our sensitivity analyses are meant to reveal the nature and extent of the risks. The extent to which those who purchase power from Taylorville – both the utilities and ARES (and ultimately their Illinois retail customers) – bear these risks will depend in large part on the terms and conditions of the Sourcing Agreements. Under the Clean Coal Law, the Sourcing Agreements are subject to Commission review within 90 days of any authorizing legislation enacted by the General Assembly. Based on a draft Sourcing Agreement circulated in the Fall of 2009, Taylorville proposed that significant risks be borne entirely by Illinois electricity consumers, unless, presumably, a cost increase is found to be imprudent.[14] We believe that, instead, those risks must be managed to protect Illinois electricity consumers. A key principle of risk management is to assign a risk to someone who can do something about it, and that means assigning cost and performance risks to Tenaska and through them, to engineering and equipment suppliers.

Tables Three, Four, and Five are meant to illustrate the nature and extent of the risk in terms of the effect on (a) the price of power from Taylorville, (b) the above-market premium

[14] Tenaska has stated that this draft is being revised; however, since the revised draft is not complete and has not been circulated by Tenaska, we have provided our thoughts on the Fall 2009 draft Sourcing Tariff.

paid by Illinois consumers, and (c) the number of years in which the rate impact limit is exceeded. There are two ways to address these risks. One is to conduct the kind of *after-the-fact* prudence reviews seen when nuclear power plants were suffering cost overruns and poor performance in the 1980s. In our view, neither consumers nor suppliers were well-served with the results of that era of after-the-fact prudence determination. In our view, a much better way for both Taylorville, and the utilities and ARES who will buy the power, is to set *before-the-fact* prudence standards through pay-for-performance features in the Sourcing Tariffs.

VI. HOW DOES TAYLORVILLE'S PRICE FOR ELECTRICITY COMPARE TO THAT FROM OTHER NEW POWER PLANTS?

We also were asked to compare the price of power from Taylorville to that from other new power plants. Again, we thought it was best to make the comparison in full recognition of the major uncertainties facing decision makers so we made the comparison under all nine scenarios as described above. In addition, since there is uncertainty with the capital cost for any new power plant, we looked at a range of capital costs for each technology.

Table Six presents the price comparison over nine scenarios for the High Capital cost assumption. As can be seen in the table, Taylorville is more expensive in all cases than the three competing base load technologies – nuclear, coal, and natural gas-fired combined cycle. It also is more expensive than wind but wind cannot match the reliability of Taylorville or the other base load technologies. Taylorville is less expensive than the simple cycle and solar PV technologies. These results hold for the Low Capital Cost assumptions, too.

Table Six
Taylorville Cost Compared to Other Technologies (Levelized $/MWh)

High Capital Cost Assumptions

			CO2 Allowance Price Scenarios		
			Pace CO2	*$30 CO2*	*$10 CO2*
Natural Gas Price Scenarios	*BPC High*	Nuclear	$128.03	$128.03	$128.03
		Coal	$153.03	$145.27	$112.82
		CCCT	$191.63	$188.26	$174.19
		SCCT	$394.72	$390.36	$372.12
		Solar PV	$511.05	$511.05	$511.05
		Wind	$121.97	$121.97	$121.97
		Taylorville IGCC	$219.72	$216.44	$201.92
	Pace Reference	Nuclear	$128.03	$128.03	$128.03
		Coal	$153.03	$145.27	$112.82
		CCCT	$160.78	$157.41	$143.34
		SCCT	$354.74	$350.38	$332.15
		Solar PV	$511.05	$511.05	$511.05
		Wind	$121.97	$121.97	$121.97
		Taylorville IGCC	$212.73	$209.45	$194.93
	BPC Low	Nuclear	$128.03	$128.03	$128.03
		Coal	$153.03	$145.27	$112.82
		CCCT	$121.72	$118.35	$104.28
		SCCT	$304.13	$299.77	$281.54
		Solar PV	$511.05	$511.05	$511.05
		Wind	$121.97	$121.97	$121.97
		Taylorville IGCC	$203.83	$200.55	$186.02

Tenaska did a similar comparison and came to similar conclusions.[15] The one big difference is that Tenaska did not always find Taylorville to be more expensive than a natural gas-fired combined cycle. The difference appears to be that Pace assumed a much lower capacity factor for combined cycle than for Taylorville. We do not see justification for such a difference.

[15] Pace, "Rate Impact Analysis for Taylorville Energy Center", February 21, 2010, Exhibit 23.

VII. WILL TAYLORVILLE'S PROPOSAL COMPLY WITH THE ILLINOIS CLEAN COAL LAW?

We listed earlier some of the primary substantive requirements of the Clean Coal Law. Here, we give our judgment on whether the Taylorville proposal will comply with those requirements.

A. Prudent and Reasonable?

At the top of the list we put the requirement that the Sourcing Agreements be found by the Commission to be "prudent and reasonable." Again, under the Law, the Commission will make its assessment through its 90-Day Hearing. Risk assignment is always a central issue in any power purchase agreement and so we expect it to be a central issue with the Sourcing Agreements. As we already noted, we think that setting before-the-fact prudence standards through pay-for-performance features is a better approach for both Illinois consumers and Taylorville than after-the-fact prudence review. Among other things, pay-for-performance features can be used to hold Taylorville to its own cost estimates. We now understand that Tenaska is open to reasonable pay-for-performance standards. The Legislature can direct the Commission to work out the detailed provisions in its proceeding.

A recent Order by the Mississippi Public Service Commission offers a good example of a Commission requiring such risk protection. Mississippi Power Company's proposal for a conventional IGCC was, at first, rejected by the Mississippi Commission unless and until the Company agreed to be held to their cost and performance estimates going forward.[16] The Mississippi Commission has since come to an agreement with the Company on basic risk assignment through pay-for-performance features that will be put in place.

B. Rate Impact Limit Met?

In our Base Case, the rate impact limit was met in all but one year. However, in many of our sensitivity runs the rate impact limit was exceeded in many years and, for some cases, all 30 years. In our analysis, exceeding the rate impact limit means that the premium paid by electric utilities is capped, but the premium for ARES will not be capped. This leads to higher costs for competitive suppliers (the ARES) than the regulated utilities. To mitigate such discrimination, Taylorville could be held to its base case estimates of cost and performance in some fashion as recommended above for a determination of prudence and reasonableness.

---

[16] Mississippi Public Service Commission, Order, Docket No. 2009-UA-14, April 29, 2010.
Note: Boston Pacific served as an advisor to the Mississippi Public Service Commission under this proceeding.

C. At least a 50% reduction in carbon dioxide emissions?

The Law requires Taylorville to reduce carbon dioxide emissions by 50% below what they otherwise would be. At full capacity (Mode 1 operation), as designed, Taylorville might barely miss the requirement to capture 50% or more of the carbon dioxide that would otherwise be emitted. However, Taylorville will not operate in Mode 1 year-round. It will also run in Mode 2 in which a greater share of the carbon dioxide emissions are captured and sequestered. Given this, we would expect Taylorville to meet the 50% reduction requirement on an annual basis.

However, while we expect Taylorville to meet this important 50% capture requirement, Taylorville's plan for carbon dioxide *storage* is not definitive. Given the importance of permanent storage to successful compliance with the Law, the Legislature should direct the Commission to review the costs, risks, and benefits of the two storage options being considered. One of our primary concerns would be that an option is chosen in which Illinois consumers are liable for the risk of failed, long-term storage.

D. A nameplate capacity of 500 MW or more?

The Law requires that the initial clean coal facility have a nameplate rating of 500 MW or more.[17] As discussed above, the net 544 MW capacity of this facility exceeds this requirement, therefore the facility can be said to comply with the letter of the Law. However, the coal-based capacity of the facility (296 MW) is considerably less than 500 MW. If the Legislature intended the nameplate capacity to relate to the coal capacity as we have measured it, Taylorville would be deficient in this respect.

E. Uses primarily coal?

The Law requires Taylorville to use coal as its primary "feedstock". The Law is not explicit on what the term "primarily" means or how it should be measured. As stated earlier, if measured as Btu fuel input at the front of the process, coal use would be 70% of *fuel input* at maximum capacity; the other 30% is natural gas. However, if the use of feed stock is measured with regard to the corresponding net output of the facility (i.e. *net electrical output)*, coal is used for 54% of the total. The Legislature will have to interpret and judge this provision of the Law.

F. Initial Clean Coal Facility provides 5% of Illinois power?

The Law states a preference that the initial clean coal facility supply 5% or more of the total Illinois electricity need.[18] Taylorville will not satisfy this preference; as noted, we estimate it will provide only 2.53% of the state need.

---

[17] Law at Section 1-75(d)(3).
[18] Law at Section 1-75(d)(1).

G. Pass through revenue and financing benefits?

The Tenaska analysis does show the pass through of most of the revenue from byproduct sales and most of the tax and other government incentives. The one concern we have is that, to determine the price it charges for electricity, Tenaska used the deemed capital structure and financing cost from the Law, not its actual financing structure. Specifically, if the Department of Energy Loan Guarantee allowed debt to finance more than 55% of the Taylorville facility, since debt is cheaper than equity, the price of power from Taylorville could be lower with the higher debt share. The Legislature could direct the Commission to address whether the full benefit of the Department of Energy incentive is being passed through to Illinois ratepayers if its intent was to pass through such benefits to ratepayers.

H. Content of facility cost report?

We believe all the required content was in the Taylorville Facility Cost Report.

I. Qualified vendors and consultants?

We believe Tenaska has pulled together a qualified team. Our one reservation is that Tenaska itself has no experience operating a Hybrid IGCC and may have to draw heavily on outside resources to get up to speed.

J. Demonstrates viability of coal-derived fuels in a carbon constrained economy?

As noted above, a primary goal for the Clean Coal Law is to demonstrate the viability of coal-derived fuels in a carbon constrained economy. We look at viability from both an engineering and a financial point of view. Notwithstanding some of our concerns about the levels of performance the facility may achieve, it seems likely that Taylorville could demonstrate the engineering viability of this technology by successfully building and operating its Hybrid IGCC. One additional concern we have is that there is no requirement for Taylorville to publicize and share the technical insights developed in the project. It is likely that any lessons learned or intellectual property established through Taylorville's operation will be controlled by the equipment manufacturers and other vendors. Of course those equipment manufactures and vendors should be eager to license the technology and, in this way, further use of the core technologies could be promoted. Still, since this goal is central to the Law, the Legislature and the Commission may want to require some public dissemination of what was learned.

Taylorville does not appear capable of demonstrating the financial viability of the Hybrid IGCC technology. This is because its power price is rarely lower than market prices under any scenario – this is evidenced by the fact that, on a levelized basis over the life of the facility, a premium is required to cover above-market costs in all years. In other words, even if Taylorville is an engineering success, it may fail financially in the sense that it shows that Hybrid IGCC is too expensive to make it on its own under any reasonable market and regulatory conditions. However, to be fair, a clear goal is to lower the cost of IGCC with what is learned through projects like Taylorville. And it is a fact that other technologies such as solar with above-market costs are being pursued and given substantial incentives.

TASK 1 REPORT

A BACKGROUND REVIEW OF IGCC AND CARBON CAPTURE AND SEQUESTRATION PROJECTS TO DATE

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. (“Boston Pacific”) and MPR Associates, Inc. (“MPR”) make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients’ or third parties’ reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

EXECUTIVE SUMMARY

A. Background and Introduction

The Taylorville Energy Center ("Taylorville") is a proposed electric power plant which would first convert Illinois coal into the equivalent of natural gas; this is called synthetic natural gas. It then would use that gasified coal to produce electric power in a modern natural-gas fired power plant using a technology called combined cycle generation. Note also that after the first step – gasifying the coal – Taylorville plans to sell some of the natural gas equivalent to others as fuel rather than use it to produce electric power on site. The technical term for the overall technology proposed by Taylorville is a "Hybrid" Integrated Gasification Combined Cycle, or IGCC, Facility.

The most important part of the Taylorville proposal, however, is its plan to capture and store in the ground the power plant emissions said to be the primary cause of global climate change; that is, it proposes to capture and store carbon dioxide emissions. The technical term for this is carbon capture and sequestration.

The purpose of this Task 1 Report is to give an indication (an early warning) of the challenges the Taylorville project may face based on the experience with other IGCC and coal gasification projects. To this end, we conducted four Case Studies which make up Sections I through IV of this Task 1 Report. Each Case Study serves to provide a review of a specific IGCC project, gasification project, or technology in order to highlight (a) the technologies used, (b) the challenges encountered, and (c) the lessons learned.

The first of these Case Studies is for the Kemper County IGCC facility which proposes to sell electric power in Mississippi. We chose to study Kemper because, like Taylorville, it intends to use a relatively new gasification technology and because it includes carbon capture and sequestration.[1] Also, since it is a contemporary of Taylorville, it faces all the same challenges and opportunities, and demonstrates how another developer addresses these.

The second of these four Case Studies is for the Great Plains coal gasification facility in North Dakota which has been selling synthetic natural gas (not electric power) since it started operation in 1984. Notably, it is the only large-scale coal gasification facility in the U.S. which includes a carbon capture and sequestration process.

The third Case Study is for the Polk IGCC facility in Florida which has sold electric power since it started operations in 1996. It does not include carbon capture and sequestration, but has a long public record of operation as an electric power plant.

---

[1] The discussion of the Kemper County IGCC facility relies heavily on several Direct Testimonies filed with the Mississippi Public Service Commission on January 16, 2009 in Docket No. 2009-UA-14. Since that time, however, additional rounds of Testimony have been filed, and the Mississippi Commission released an Order on April 29, 2010. This Task 1 Report has not been updated to reflect any changes to the Kemper County IGCC project that may have arisen as a result of subsequent filings.

The fourth Case Study focuses on the gasifier technology which Taylorville proposes to use – a gasifier from the Siemens Corporation. This Case Study reports on the limited operating experience to date with the Siemens gasifier and on what makes that gasifier different from other vendor's technologies.

The purpose of this Executive Summary is to draw out the major commercial and technical challenges uncovered in our four Case Studies that could be especially important when assessing the Taylorville proposal. Additional details are provided in each of the four Case Studies. In terms of what could go wrong, we discuss, below, two kinds of potential problems: technical and commercial. By technical problems we mean that the facility could fail to operate as designed. That is, the facility may simply break down and not work at all or it may not work as reliably as the owners want; it also could mean that the facility does not meet performance standards such as the amount of coal needed for gasification or the amount of air pollution emitted. By commercial problems we mean that a facility could fail to secure the money needed to build the plant in the first place. Or, if it does get built, the facility could fail to make money for its owners or to save money for its customers. That is, it can be so expensive to build and operate the facility that the cost of the electric power and/or synthetic natural gas could not be competitive with traditional sources under reasonable projections of market conditions. Table One provides an overview of the technical and commercial challenges discussed below and the lessons learned.

Table One
Technical and Commercial Challenges

Technical Challenges: Lessons Learned	**Commercial Challenges: Lessons Learned**
1. Conduct Engineering Tests	1. Anticipate the Consequences of Costs Being Higher Than Market Prices
2. Address Technology Integration Challenges	2. Secure Essential Government Support for Financing
3. Realistically Project Plant Availability	3. Mitigate the Risks of High Capital Costs and Cost Overruns
4. Budget for Repairs During Start-Up	4. Sell Byproducts to Earn Extra Revenue
5. Accurately Calculate the Impact of On-Site Power Use	
6. Plan Extensive Monitoring of Stored (Sequestered) Carbon Emissions	

B. Technical Challenges: Lessons Learned

An IGCC facility is a complex collection of separate process steps or components. There are four primary process steps involved in producing clean coal power: (a) gasifying the coal, (b) cleaning up the raw synthetic natural gas to separate pollutants, (c) producing electric power, and then (d) sequestering carbon dioxide. Technical breakdowns or low availability can occur because any one of the many components fails to work as planned, or because the separate components fail to work together.

To give examples of potential problems and, to a very limited extent, indicate what Taylorville might do to mitigate them, here are six lessons learned about technical problems from the Case Studies.

1. Conduct engineering tests

Great Plains used a gasifier technology developed by Lurgi, which had extensive operating experience in South Africa at the time Great Plains was being developed. There was little operating experience on the North Dakota lignite that Great Plains intended to use; therefore they hired South African Coal Oil and Gas Company to test actual samples of the project's coal. South African Coal Oil and Gas Company provided Great Plains with performance data on the feedstock and on the resulting gasification products. Great Plains also hired experts from Lurgi and South African Coal Oil and Gas Company to conduct design reviews and for commissioning support.

Kemper is planning to utilize the Transport Integrated Gasification system which has never been used on a commercial basis. Kemper sought to mitigate this risk through testing at the U.S. Department of Energy's Power Systems Development Facility in Wilsonville, Alabama. Kemper states that this testing has led to some process improvements. For example, tests concluded that a more efficient drying process was needed for the coal (Mississippi lignite) before gasification.

Taylorville will use the Siemens gasifier which has very limited commercial operating experience, although several units have been shipped recently to the U.S. and China. Based on lessons learned, Taylorville should report on any testing it does with the Siemens technology including specific tests using Illinois coal. Also, it should report on how that testing influences its design choices. In addition, Taylorville should investigate and report on operating experience when the recently-shipped Siemens gasifiers are commissioned and begin operation.

2. Address technology integration challenges

In the first item listed under technical challenges, we noted the importance of testing. However, this will mostly involve testing of the individual components of the gasification facility, notably the gasifier. Prior to construction of the facility, there is no practical way to test the entire process including integration of the process facilities. The risk is aggravated by the fact that multiple contractors will design and build individual components. Further, while performance guarantees for individual components may be provided by individual contractors, individual contractors will likely be unwilling to provide total system performance guarantees. The method for providing a system performance guarantee should be investigated.

Taylorville should state how it intends to manage the technology integration challenges and who bears these risks.

3. Realistically project plant availability

Taylorville, as with any proposed IGCC facility, should include realistic availability projections throughout the facility life consistent with previous experience of similar facilities. Kemper assumed that availability of its facility will start low and get better over the years. That is, availability was assumed to ramp up from 59% to 89% over the first 8 years of operation. In addition, Kemper assumed the equivalent forced outage rate will decline from 37% in 2014 to 5.2% in 2021.

Taylorville also should consider design choices that could improve availability. Examples of this include:

- Use of a backup fuel: This has proven effective in the Polk design to improve power generation availability. While the gasifier's availability was only about 70% from 1998-2001, the power block (using either syngas or distillate oil) was available about 90% of the time.
- Use of redundant/spare equipment and systems: Great Plains, for example, uses multiple process lines and multiple gasifiers; this allows maintenance on one process line while other lines are kept in production.
- Including storage or reserves of key feedstocks or process inputs: For example, Polk's two run tanks, which supply the gasifier with coal slurry, are large enough to operate the gasifier at full capacity for 8 hours. In addition, Great Plains' air separation unit was designed with an eight hour backup storage of liquid oxygen. Design features such as these can allow a facility to continue to operate using reserves or storage while certain processes undergo minor maintenance.

4. Budget for repairs during start-up

Kemper included $47 million in its capital cost budget for improvements during the first four years of operation. With respect to the need for an ongoing capital budget over its operating life, Great Plains has invested another $400 million to achieve environmental compliance, improve efficiency, and develop byproducts. Taylorville should assess the need for an appropriate capital budget for repairs and modification to the plant equipment in the initial years to address technical problems that may arise.

5. Accurately calculate the impact of on-site power use

One of the well-known challenges of IGCC facilities is that a substantial share of the electric power they generate is actually consumed by the facility itself; this is termed parasitic load. For example, Polk has a gross capacity rating of 315 megawatts (MW), but parasitic load is 65 MW which is 21% of the gross rating. The useful or net capacity that is supplied to the electric grid therefore is 250 MW. Most of this parasitic load results from powering the air compressors used in the air separation plant. Great Plains uses 116 MW of parasitic load, including 36 MW needed to compress the carbon dioxide. High parasitic load significantly increases the cost to the ratepayer for the power actually sold to them.

Taylorville should demonstrate that it has an accurate estimate of parasitic load; in addition, Taylorville should carefully reflect the parasitic load when calculating performance metrics such as heat rate, carbon capture effectiveness, and cost comparisons to conventional power generation technologies. The key in this regard is to not confuse gross and net electric power output. Taylorville should take special care to estimate the added parasitic load of carbon capture and sequestration, which is expected to be a large source of parasitic load.

6. Plan extensive monitoring of stored (sequestered) carbon emissions

The sequestration of carbon dioxide in enhanced oil recovery applications is a technique by which carbon dioxide is injected into existing oil fields, increasing the oil production from the fields, and storing the injected carbon dioxide underground. Enhanced oil recovery sequestration has been demonstrated on a commercial scale, including several notable applications in the U.S. gulf coast region. The Great Plains facility is another important example as it is the only coal gasification facility in the U.S. with carbon capture and sequestration capability; this facility only started sequestering carbon dioxide in October 2000. The carbon dioxide captured at Great Plains is compressed and sent over a 205-mile pipeline to Canada, where it is used for enhanced oil recovery. The major risk with carbon sequestration is that the carbon dioxide does not remain sequestered over time; that is, it escapes from underground. Great Plains has a number of leak detectors on the entire length of pipeline, and the owners of the oil field, PanCanadian, monitors the field for carbon dioxide leakage.

Carbon sequestration is the ultimate bottom line for Taylorville, and a significant justification for investment in this project. If carbon sequestration does not work, Taylorville could lose its designation as a "clean coal facility" under Illinois Law, and all the important benefits that come with it. Therefore, sequestration should be a major focus of design. Also, Taylorville should offer substantial evidence that its plan for sequestration will offer permanent storage. Who is liable if Taylorville's carbon dioxide escapes also should be well understood.

C. Commercial Challenges: Lessons Learned

Taylorville may also face commercial challenges. We provide four lessons learned about commercial challenges from the Case Studies below.

1. Anticipate the consequences of costs being higher than market prices

The Great Plains facility was motivated by fears of a natural gas shortage in the 1970s. Because of those fears, the Federal Government provided it with a $1.5 billion loan guarantee. The Federal Energy Regulatory Commission authorized above-market prices for the natural gas equivalent being produced, and several pipelines signed contracts to buy it. Still, soon after Great Plains was built, the buyers abandoned the project and Great Plains went into bankruptcy. The bankruptcy was caused by the fact that Great Plains' cost of producing synthetic gas was much higher than market prices for natural gas.

Given this lesson learned at Great Plains, Taylorville should provide extensive analysis of how its price for power and for synthetic natural gas compare to market prices over a wide range of market and regulatory conditions. Those conditions should include, but not be limited to, an array of forecasts for natural gas prices, carbon emission allowance prices, and construction costs for a range of power generation facilities.

2. Secure essential government support for financing

Kemper, Great Plains, and Polk all received or are seeking substantial financial support from Federal and State Governments. From the Federal level, that support often comes in the form of loans or loan guarantees and tax incentives. From the State, the most important support comes in the form of approval to sell to consumers at specified rates.

For example, Kemper is currently pursuing three federal incentive programs and one State incentive program. The Federal programs include: (a) tax savings though an investment tax credit, (b) funding through the Department of Energy's Clean Coal Power Initiative program, and (c) financing support through the Department of Energy loan guarantee program. Kemper estimates this funding will result in $262 million in capital cost reductions and $897 million in operating and maintenance cost reductions. Kemper is also pursuing permission from the Mississippi Public Service Commission for an alternative method of cost recovery. The method, known as Construction Work in Progress, would allow utilities to include the financing costs they incur during construction to be recovered through the rates *before* the plant is finished.

Another example of the importance of Federal financing support is that Great Plains received Government support through three programs: (a) the Department of Energy provided Great Plains with a $1.5 billion loan guarantee, (b) the synthetic natural gas purchase agreements allowed Great Plains to pass on the higher costs of synthetic natural gas to their pipeline customers, and (c) the Federal Energy Regulatory Commission allowed the price of synthetic natural gas to have a base of $6.75 per 1,000 cubic feet with future adjustments and cost gaps – a price that we presume was well above market price for competing natural gas at the time.

Polk also sought and received Government financing support. Polk received $123 million in Government funding through the Department of Energy's Clean Coal Technology Program (roughly 40% of the initial cost estimate for the facility).

It is our understanding that Taylorville is pursuing a loan guarantee from the Department of Energy. At least four central questions must be addressed by Taylorville. Is the Department of Energy loan guarantee essential to assure financing and, if so, what are the chances it will be granted? What terms and conditions for power sales and fuel sales will be required by the Department of Energy (or other lenders) and equity investors? Will the benefit of a Department of Energy loan guarantee and other Federal support be passed through to Illinois ratepayers? Is the loan guarantee the only Federal support Taylorville should and actually has sought?

3. Mitigate the risks of high capital costs and cost overruns

The capital costs incurred to build IGCC plants are very high. For example, the Kemper Project's capital cost estimate is $2.2 billion which is $3,798 per kilowatt (kW) (This capital cost estimate is net of incentives and has since been updated. The updated capital cost figures are used in the Executive Summary and the Task 3 Report). At that level, the facility would cost more than three times what it would cost to build a conventional natural gas-fired combined cycle power plant.

High capital costs set the stage for substantial cost overruns especially when dealing with technologies like gasification. For example, the Polk Project experienced significant cost overruns. Its original capital cost estimate was about $303.3 million, while the final actual capital cost was about $606.9 million which is a 100% cost overrun.

Taylorville should take actions to mitigate this risk of cost overruns. Taylorville should include cost control methods to protect ratepayers from cost increases without limitations. Taylorville should include appropriate schedule contingencies as needed to troubleshoot problems that might occur during startup. Taylorville should also include cost escalations in their estimates. For example, Kemper is including in their budgets $167 million in cost escalation and $132 million in contingencies, these totals are equivalent to 7.6% and 6.0% of the total budget, respectively.

Taylorville can also make strategic decisions to mitigate the risk of cost overruns. For example, Great Plains purchased their gasifiers from two different vendors.

In the end, the best mitigation might be to make Taylorville responsible for some or all of the risk through pay-for-performance contract features. With the risk for cost overruns put back on Taylorville, and taken off the shoulders of the Illinois ratepayers, Taylorville would then shift some or all of that risk back onto its suppliers; this is the traditional allocation of risk under the hundreds of pay-for-performance contracts signed for power sales over the past thirty years in the electricity business.

4. Sell byproducts to earn extra revenue

The sale of byproducts produced during the gasification and cleaning processes can achieve diversified sources of revenue. For example, Kemper estimates that it will make over $40 million per year in revenue from its sales of sulfuric acid, ammonia, and carbon dioxide. Polk sells sulfuric acid to the local fertilizer industry and slag to the cement industry. Great Plains sells carbon dioxide, ammonium sulfate, anhydrous ammonia, phenol, cresylic acid, naptha, krypton & xenon, and liquid nitrogen. Taylorville should supply an analysis of potential marketable byproducts, and provide a full, credible projection of byproduct sales. Further, Taylorville should explain how they intend to pass the benefits of any byproduct revenue back to the ratepayers of Illinois.

I. KEMPER COUNTY IGCC PROJECT

A. Overview

Mississippi Power Company, a Southern Company subsidiary, is planning a new Integrated Gasification Combined Cycle (IGCC) power plant in Kemper County, Mississippi.[2] This project was first proposed for Orlando, Florida, but was later moved to Kemper County due to uncertainties about the future use of coal generation in Florida. The power plant is projected to begin construction in 2010, and to commence operations by late November 2013.

The Kemper County IGCC power plant (Kemper IGCC Project) is being designed with a net summer capacity rating of 582 MW. Of this total, 494 MW will be lignite-fueled baseload capacity, while the remaining 88 MW will be natural gas-fired supplemental capacity (This is called "duct firing". The duct firing and lignite-fueled baseload capacity have since been updated; the lignite-fueled capacity is now 522 MW and the duct firing capacity is 60 MW. These updated capacity numbers are used in the Executive Summary and the Task 3 Report). Mississippi Power Company states that this supplemental capacity will be dispatched separately and will most likely only be used during peak periods. The heat rate for the baseload portion of the power plant (494 MW) is estimated to be 11,224 British thermal units (Btu)/kilowatt-hour (kWh), while the heat rate for the duct firing capacity (88 MW) is 9,055 Btu/kWh.

Mississippi Power Company's capital cost estimate for the Kemper IGCC Project is $2,210.6 million[3] (This capital cost estimate is net of incentives and has since been updated. The updated capital cost figures are used in the Executive Summary and the Task 3 Report). With a capacity of 582 MW (or 582,000 kW), this is equivalent to $3,798/kW. Included in this estimate is equipment for the capture and sequestration of roughly 50% of the plant's carbon dioxide (CO_2). Mississippi Power Company estimates that the carbon capture systems for the power plant will cost $261.1 million or 12% of the total. Mississippi Power Company plans to sell the captured CO_2 to a third party for sequestration through enhanced oil recovery.

[2] This Section of the Report relies heavily on the following Direct Testimonies filed with the Mississippi Public Service Commission on January 16, 2009: (a) Direct Testimony of Kimberly D. Flowers On Behalf of Mississippi Power Company Before the Mississippi Public Service Commission, Docket No. 2009-UA-14, ("Flowers"), (b) Exhibit KDF-2 to Flowers Testimony entitled *Mississippi Power Company Kemper County IGCC Project Description*, Docket No. 2009-UA-14, ("Flowers Exhibit KDF-2"), (c) Direct Testimony of Frances Turnage On Behalf of Mississippi Power Company Before the Mississippi Public Service Commission, Docket No. 2009-UA-14, ("Turnage"), and (d) Direct Testimony of F. Sherrell Brazzell On Behalf of Mississippi Power Company Before the Mississippi Public Service Commission, Docket No. 2009-UA-14, ("Brazzell"). We provide specific citations for the direct quotes included herein. Since that time, however, additional rounds of Testimony have been filed, and the Mississippi Commission released an Order on April 29, 2010. This Task 1 Report has not been updated to reflect any changes to the Kemper County IGCC project that may have arisen as a result of subsequent filings.

[3] The capital cost estimate only includes "direct project costs" so it does not include capitalized financing costs.

B. Technology Description

The Kemper IGCC Project can be broken down into two major components: (a) the gasification island and (b) the combined-cycle unit. Each of these components can then further be broken down into sub components or processes. The gasification island includes (a) lignite preparation and feeding processes, (b) gasification of the lignite into a synthetic gas (syngas), and (c) cleaning of the syngas. The combined-cycle component includes (a) combustion of the syngas in the combustion turbines, (b) heat recovery in the heat recovery steam generators, and (c) additional power generation from the steam turbine and generator. In addition, sequestration is said to be achieved by delivering the captured CO_2 to enhanced oil recovery facilities.

1. Gasification Island

The gasification island is made up of many processes that must be integrated to convert lignite into clean syngas that can be reliably used for the production of electricity in combustion turbines. Below is a brief, simplified explanation of each of these processes.

a. Lignite preparation and feeding

The Kemper IGCC Project will use lignite as its primary fuel. Lignite is a low rank coal, which means it has a lower heating value and higher moisture content than higher rank coals such as bituminous, sub-bituminous, and anthracite. Mississippi Power Company is planning to mine the lignite from the Damascus Reserve located in North Lauderdale and Southwestern Kemper Counties; this mine is also adjacent to the Kemper IGCC Project site. The lignite will be transported from the mine to the Project site by off-road trucks. There the lignite is crushed and dried and then pulverized before it can be used in the gasifier. Lastly, the prepared lignite must be fed into the gasifier.

b. Gasification of the lignite into syngas

Southern Company, along with KBR, designed and developed a new, circulating fluidized bed gasification technology in partnership with the U.S. Department of Energy at the Power Systems Development Facility near Wilsonville, AL. This new technology is called Transport Integrated Gasification (TRIG or Transport Gasifiers). The Kemper IGCC Project will utilize two air-blown Transport Gasifiers, which will mix the feedstock (in this case lignite) with compressed air and heat to facilitate a chemical reaction that produces syngas and ash. The syngas leaves the gasifier for cleaning, and the ash is removed for storage. Mississippi Power Company estimates that the gasifiers will result in a 97% carbon conversion.

c. Cleaning the syngas for combustion

Once the syngas leaves the gasifiers it must be cleaned before combustion. First, particulates are removed from the syngas using "high temperature, high pressure" particulate filters.[4] Particulates are small particles in the syngas that would result in damage to the combustion turbines if they were not removed. Next, other chemical processes are required to

[4] *See* Flowers Exhibit KDF-2 at Appendix A at page 5.

remove various chemicals and pollutants, including CO_2 and some pollutants regulated under the Clean Air Act.

The CO_2 capture process proposed for the Kemper IGCC Project will capture approximately 50% of the plant's CO_2. This is done by removing the CO_2 from the syngas using solvents, and then stripping the CO_2 from the solvent. Mississippi Power Company states that only about half of the 50% of CO_2 being captured is already in the syngas ready for removal. That is, there is some CO_2 inherent in the raw syngas. The remaining CO_2 needed for removal must be converted from carbon monoxide (CO) to CO_2 by using a water-gas shift reactor. This process combines steam and CO to produce CO_2 and H_2 ($CO + H_2O \rightarrow CO_2 + H_2$). This CO_2 produced from the water-gas shift is also captured from the syngas. Once captured, Mississippi Power Company plans to compress the CO_2 and deliver it to a third party for sequestration through enhanced oil recovery.

Sulfur is also removed from the syngas, which helps prevent the emission of sulfur dioxide (SO_2). This is done by removing hydrogen sulfide (H_2S). Some of the H_2S is inherent in the syngas, but additional H_2S is formed through hydrolysis. Hydrolysis converts carbonyl sulfide (COS) in the syngas to H_2S ($COS + H_2O \rightarrow H_2S + CO_2$).

Mississippi Power Company will also remove Ammonia (NH_3), which can be used to prevent nitrogen oxides (NOx) emissions, and Mercury from the syngas. The Mercury is removed using an activated carbon bed. What is left is a clean, higher H_2-concentrated syngas fuel.

2. Combined-Cycle Unit

The combined-cycle block of the Kemper IGCC Project is similar to a standard combined-cycle plant. It will consist of two gas turbines with associated generators, two heat recovery steam generators, and one steam turbine and generator. The cleaned syngas will power the two combustion gas turbines and the heat from the gas turbines is used by the heat recovery steam generators to create steam for the steam turbine. For the duct firing, the power plant will include burners in the heat recovery steam generators, which allows for supplemental power to be produced using natural gas.

C. Technical Challenges: Lessons Learned

The purpose of this section and the next section is <u>not</u> to identify all of the risks that the Kemper IGCC Project faces; rather it serves to highlight a few of the risks that Mississippi Power Company has identified and to provide a few of the ways Mississippi Power Company plans to mitigate these risks. We also do not make any representations as to whether Mississippi Power Company's actions are sufficient to successfully mitigate the Project risks. This section provides a list of the technical lessons learned from the Kemper IGCC Project experience, while the next section discusses commercial lessons learned.

1. Commercial Availability of Technologies and Process Integration

As discussed above, an IGCC power plant incorporates a large number of processes in hopes of producing electricity (and in some cases other byproducts) reliably, cost effectively, and efficiently. Given the complexity of these processes there are technological risks associated both with (a) each individual component of the Project functioning according to specification and (b) all of the components working together seamlessly according to its design.

Many of the components or processes are commercially available, and have been used in similar applications for years, especially with regard to the combined cycle block. However, Mississippi Power Company states that there are three systems <u>without</u> widespread commercial application: (a) the TRIG gasifier, (b) the coal feed, and (c) the ash removal systems. (Some would add a fourth system to this list – carbon capture and sequestration.) In addition, there is no current, full-scale IGCC plant that integrates all of the Kemper IGCC Project systems.

One way in which Mississippi Power Company has sought to mitigate the technological risks associated with the Project is through extensive testing at the Power Systems Development Facility near Wilsonville, AL. This testing facility, which was created in 1996 to support the Department of Energy's effort to develop "cost-competitive and environmentally acceptable" coal-based power generation, is a semi-commercial research and development facility.[5] The Department of Energy has stated that, "The Wilsonville PSDF [Power Systems Development Facility] gives U.S. industry the world's most cost-effective flexible test center for testing tomorrow's coal-based power-generating equipment. Capable of operating at pilot to near-demonstration scales, the facility is large enough to give industry real-life data, yet small enough to be cost-effective and adaptable to a variety of industry needs."[6] According to Southern, through over ten years of tests conducted at the Power Systems Development Facility, Southern Company has had the opportunity to test many of these systems at near demonstration level size, and therefore gain valuable operating experience that has resulted in technology and process improvements.

Examples asserted by Southern include the following: in a 543-hour test run of the lignite handling and feeding mechanisms in 2007, it was determined that a more efficient drying process was needed for the coal given the high moisture content of Mississippi lignite. After these tests, a "fluidized bed coal dryer" was designed and installed at the Power Systems Development Facility.[7] In 2008, a 742-hour integrated test of all of the syngas production processes was completed. Mississippi Power Company stated that, "The study showed extremely reliable operation of all phases of the gasifier – drying the lignite, feeding the lignite into the gasifier, producing syngas in the gasifier, and ash removal…The test demonstrated that the IGCC TRIG technology can effectively and reliably gasify Mississippi lignite."[8]

Mississippi Power Company gives several reasons why they have chosen to use the TRIG gasification technology rather than one that has already been used in a commercial application.

---

[5] *See* Flowers Exhibit KDF-2 at Section 7.3.
[6] Ibid.
[7] *See* Flowers at page 41.
[8] Ibid., at pages 41-42.

After studying other gasification technologies such as the Shell gasification process, the General Electric process, ConocoPhillips, and Sasol-Lurgi, Mississippi Power Company chose TRIG for the following reasons:

- TRIG uses an air-blown (rather than an oxygen-blown) approach, which requires a lower operating temperature. According to Mississippi Power Company, this is important because at the lower operating temperature the ash does not melt, which helps preserve the machinery and results in lower maintenance and replacement costs. For example, Mississippi Power Company states that other gasification processes require replacement of the main gasifier refractory every few years, while TRIG requires replacement only every 10 to 15 years.
- Southern believes air-blown gasification is favored for power generation. Mississippi Power Company states that other, oxygen-blown gasification technologies were designed primarily for fuels other than lignite.
- Southern asserts TRIG is able to use lower rank coal effectively.
- Because TRIG is air-blown, Southern states it does not require air-separation units like oxygen-blown gasifiers. This also reduces capital costs and maintenance costs.

Despite the perceived advantages of TRIG and the tests completed at the Power Systems Development Facility, Mississippi Power Company has included additional risk mitigation strategies for the first few years of Project operation. First, in Mississippi Power Company's economic models they have assumed a lower availability factor and a higher forced outage rate in the early years of Project operation. They have assumed that the availability of the unit ramps up from 59% to 89% over the first 8 years of operation. Conversely, Mississippi Power Company has assumed that the equivalent forced outage rate of the Plant will decrease from 37% in 2014 down to 5.2% in 2021. Second, Mississippi Power Company has included an additional $47 million in its capital cost budget to account for design improvement and process improvement during the first four years of operation. Third, Mississippi Power Company states it will test the power plant for at least six months before commercial operation.

2. Technology Risk Assessment Study

Mississippi Power Company has also performed two risk assessment studies, one was performed by an external consulting company and the second was performed by an internal group. The external study was performed by the consulting firm ScottMadden, and is discussed briefly in the next section (commercial lessons learned). The internal risk study analyzed the TRIG technology and related processes. This study also looked at commercial availability and integration of systems. Mississippi Power Company states that this study concluded the following: "The Research and Power Engineering group's review concluded that the commercial availability of the vast majority of the processes in the Plant and the successful tests conducted at the PSDF [Power Systems Development Facility] resulted in a design that constituted manageable risk."[9]

[9] *See* Flowers Exhibit KDF-2 at Section 7.5.

D. Commercial Challenges: Lessons Learned

This section provides a list of some of the commercial lessons learned from the Kemper IGCC Project experience.

1. Assumed Government Financial Support

Mississippi Power Company is actively pursuing local, state, and federal incentives programs which make the Kemper IGCC Project more economical through operations, maintenance, and capital cost savings. The Kemper IGCC power plant is pursuing three federal incentive programs: (a) Investment Tax Credits, (b) the Department of Energy Clean Coal Power Initiative and (c) Department of Energy loan guarantees. In order to receive money from these federal programs, the Department of Energy must first complete a National Environmental Policy Act review process, and give the plant a positive record of decision. Mississippi Power Company estimates that the benefits from these federal programs and other state and local programs could result in benefits that exceed $262 million in capital cost reductions[10] and $897 million of reductions in operations and maintenance.

In addition, a State law known as the Mississippi Baseload Act provides the Mississippi Public Service Commission the authority to allow utilities to utilize an alternative method of cost recovery during the building and construction of qualifying baseload facilities if it is believed to be in the best interest of customers. The purpose of the legislation is to "promote and foster" electric generation expansion.[11] This alternative method of cost recovery known as "Construction Work in Progress" would allow utilities to include the financing costs they incur during construction to be recovered through the rate base before the plant is finished. Traditionally, these costs are only included in the rate base once/if the project is completed.

2. Cost Controls

Several parts of the Kemper IGCC Project proposal could serve to limit the impact of capital cost and operating cost increases. First, in order to mitigate the impact of potential capital cost escalations and other potential problems during the planning and construction of the Kemper IGCC Project, Mississippi Power Company included in its capital budget $167 million in cost escalation and $132 million in contingencies. These totals are equivalent to 7.6% and 6.0% of the total budget, respectively.

Second, Mississippi Power Company states that they are in the process of negotiating a contract with Liberty Fuels Company, LLC, a subsidiary of the North American Coal Corporation, to secure a reliable, low-cost source of fuel (lignite) for the useful life of the Plant. Mississippi Power Company notes a few advantages with the contract structure they are likely to sign with Liberty. They assert the price of the coal in the contract will be driven by the cost of

[10] These capital costs savings have been accounted for in Mississippi Power Company's capital cost estimate of $2,210.6 million.
[11] *See* Turnage at page 29.

mining the coal rather than a volatile market price such as that for natural gas and higher rank coal.

> "MPC [Mississippi Power Company] and NAC [North American Coal Corporation] have been negotiating a contract that will supply our customers with a reliable, stable low cost fuel supply that is insulated from the influence of the fuel supply and transportation markets for the useful life of the Plant…With respect to pricing, the LSA [Lignite Supply Agreement] is structured with a cents per mmBtu [million British thermal units] price comprised of fixed and variable components. Therefore, the price will not adjust as a result of volumetric risk associated with mining and delivering the lignite but will adjust, or escalate, to reflect price risks relative to the resources used in mining and delivering the lignite. In addition, the base price will be adjusted from time-to-time based upon cost relationships at the time of adjustment."[12]

Mississippi Power Company also states the lignite contract would require the supplier to supply sufficient coal for 40 years of Plant operation, thus guaranteeing fuel supply for the useful life of the plant. Furthermore, Mississippi Power Company hired Marston & Marston, Inc., an outside consulting company, to review the North American Coal Corporation's data on the quantity and quality of lignite for the proposed site. Marston's report concluded that both the quality and quantity were sufficient for the annual requirements for the life of the plant. Finally, the contract would provide Mississippi Power Company with the option of terminating the contract after 15 years if Mississippi Power Company determines a different fuel or fuel source would be more economical.

Third, Mississippi Power Company states that natural gas will serve as a backup fuel for the plant. This would presumably provide a hedge against full reliance on lignite and could also increase Plant availability.

3. Sale of Byproducts

Mississippi Power Company plans to sell three byproducts from the syngas cleanup process: (a) sulfuric acid, (b) ammonia, and (c) CO_2. Mississippi Power Company estimates that the gasification cleaning process will result in approximately 110,000 tons/year of sulfuric acid, between 12,000 and 15,000 tons/year of ammonia, and 2,200,000 tons/year of CO_2. Mississippi Power Company estimates the sale of these three byproducts would result in over $40 million of revenue per year. In addition to selling these three products, Mississippi Power Company is also studying the possibility of selling the waste ash from the gasification process. With regards to CO_2, Mississippi Power Company states that they are currently in discussions with a company for a long-term CO_2 offtake agreement. The CO_2 would be used for enhanced oil recovery to increase oil production in diminished oil fields. Mississippi Power Company states that the plant is in a region with multiple enhanced oil recovery opportunities. Further, a study that Mississippi Power Company cites states that U.S. enhanced oil recovery sequestration capacity is approximately 98 gigatons of CO_2, enough capacity to sequester the current CO_2 emissions from the United States' power generation facilities for 36 years.

[12] *See* Flowers at page 58.

4. Commercial Risk Assessment Study

As mentioned, Mississippi Power Company performed two risk assessment studies, an internal and an external study. The external study was performed by the consulting firm ScottMadden. This study provided an assessment of completion risk, operations risk, and corporate risk. It provided some risk mitigation recommendations such as, "ramped availability, early procurement of major equipment, inclusion of an adequate contingency budget, the use of incentives to minimize capital risk, use of performance guarantees from equipment vendors, and anticipated construction and operational challenges during the Project's first years."[13]

[13] *See* Flowers Exhibit KDF-2 at Section 7.1.

II. GREAT PLAINS COAL GASIFICATION FACILITY

A. Overview

In the early 1970s, natural gas supplies were expected to become scarce in the near future (at the time, the U.S. Department of Interior forecasted that a natural gas shortage would occur in the United States by 1985[14]).[15] Consequently, American Natural Gas Company, a large interstate natural gas pipeline company, began looking for alternative sources of natural gas. They identified coal gasification as the most promising alternative to traditional natural gas production. This led to an evaluation of available coal supplies and eventual selection of North Dakota lignite as best suited for the United States' first commercial synthetic natural gas facility. In 1971 American Natural Gas Company signed an agreement with North American Coal Company for the rights to nearly four billion tons of North Dakota Lignite.

Around the same time, the U.S. federal government enacted the Non-Nuclear Energy Research and Development Act of 1974, which supported projects that would help the United States achieve energy security. What followed was the establishment of Synthetic Fuels Corporation and from that came a $1.5 billion guaranteed loan from the Department of Energy in November 1980 to build Great Plains. A consortium of subsidiaries of five natural gas pipeline companies formed Great Plains Associates and also contributed equity to the project. The project moved ahead with the construction, startup and successful commissioning was completed by July 1984.

Although the project successfully produced synthetic natural gas; declining natural gas prices forced the project into bankruptcy in August 1985. The Great Plains plant kept operating while Department of Energy went through a process to sell the plant. In 1988 the Department of Energy awarded the sale of Great Plains to the local rural electric cooperative, Basin Electric. Dakota Gasification, a subsidiary of Basin Electric, assumed ownership of Great Plains and continues today as owner and operator of Great Plains. Over the course of its operation, the project has achieved a 93% capacity factor producing on average 145 million standard cubic feet per day of synthetic natural gas from 18,000 tons a day of lignite.

In addition to the synthetic natural gas sales, Dakota Gasification made many plant modifications to purify and upgrade some of the byproducts of the gasification process (ammonia, phenol, sulfur, carbon dioxide). Most notably in October 2000, a 205 mile underground pipeline was commissioned that sends carbon dioxide to Canada to be used in enhanced oil recovery. The carbon dioxide production is nominally 8,000 metric tons per day or 152 million standard cubic feet per day.[16] Great Plains has a number of leak detectors on the entire length of underground pipeline, and the owner of the oil field, PanCanadian, monitors the field for carbon dioxide leakage.

[14] The New Synfuels Energy Pioneers, ISBN 0-9676795-9-1 at page 5.
[15] This Section of the Report relies heavily on personal knowledge of the Great Plains project by a member of the review team, Virg Sabin. Mr. Sabin was extensively involved in the development, construction, and operation of the Great Plains facility.
[16] *See* www.dakotagas.com.

Dakota Gasification Company has paid the Department of Energy $388.8 million towards the original $1.5 billion loan as part of a revenue sharing agreement.[17] In addition, Dakota Gas has invested over $400 million in other capital improvements over this time frame.

B. Technology Description

The Great Plains facility incorporates a large number of processes to produce synthetic natural gas and other byproducts. The major processes are described below.

1. Air Separation Unit

A two-train Air Separation Unit processes atmospheric air into liquid oxygen and liquid nitrogen. The oxygen is used in the gasifiers and the nitrogen is used as inerting gas throughout the plant. A liquid oxygen storage tank is included to avoid minor oxygen plant trips and also used to help with rapid cool down of the cold boxes on restarts.

2. Lignite Preparation and Handling

Lignite is locally mined and crushed in adjacent facilities operated by North American Coal. The crushed lignite is delivered by trucks and conveyors where it is further sized and sampled. After the secondary crushing, the lignite is stockpiled in a large 125,000 ton storage building. This allows for five day-a-week mining operations and seven day-a-week gasification operations. The live storage building is a full enclosure to keep the lignite dry during inclement weather.

3. Gasification

The synthetic gas path starts when crushed lignite is introduced to the top of a Lurgi-designed fixed-bed gasifier through a system of conveyors, bunkers, and feed chambers. Steam and oxygen enter the gasifier through the ash grate on the bottom of the gasifier and ash is withdrawn from the gasifier through an ash chamber. The raw gas produced is a mixture of hydrogen, carbon monoxide, carbon dioxide, methane, tar, oil, naphtha, phenol, ash, dusty sour water, and other gaseous compounds, such as hydrogen sulfide, and ammonia.

The raw gas stream exiting from the gasifier is then scrubbed with water and cooled to about 600 °F. The condensed liquids contain traces of oils and tars, phenols, ammonia, and other impurities, such as lignite dust. This contaminated water stream, called sour water, goes to the liquid path for processing. The raw gas stream is a combination of primarily carbon monoxide and hydrogen. After cooling, the raw gas moves to the next process step – shift conversion.

[17] Ibid.

4. Shift Conversion

The primary objective of shift conversion is to adjust the hydrogen and carbon monoxide molar ratio in the raw gas to 3:1 for later methanation. With Lurgi gasifiers, the hydrogen carbon monoxide molar ratio in raw gas is such that only one-third of the total gas flow is required to pass through shift conversion. The remaining two-thirds of the raw gas pass directly to gas cooling. The shift conversion reaction produces the necessary hydrogen for subsequent methanation by the reaction of carbon monoxide and steam producing carbon dioxide and hydrogen. The catalyst used in this action is a cobalt molybdenum type. At Great Plains, the shift conversion is accomplished in two parallel trains of catalytic reactors.

5. Gas Cooling

The shifted and unshifted raw gas streams are then combined and cooled to about 80 °F in two parallel gas cooling trains. This resulting cooled gas stream is called mixed synthetic gas.

6. Acid Gas Removal

The mixed synthetic gas is primarily carbon monoxide and hydrogen, but also contains acid gases (primarily hydrogen sulfide) and small amounts of hydrocarbons. Removal of the acid gases is accomplished by contacting the mixed synthetic gas stream with chilled methanol (-60 °F), using a gas cleanup technology called Rectisol. The chilled methanol absorbs the acid gases from the mixed synthetic gas stream. The acid gases are then directed to the sulfur and carbon dioxide processing units, while the cleaned syngas feed is sent to methanation. The Rectisol unit is divided into two parallel operating trains. The plant design also includes a number of methanol regeneration towers and methanol cleanup systems to remove hydrocarbons.

Initially Great Plains had a Stretford sulfur processing unit that received the Rectisol acid gases and converted the hydrogen sulfide stream to elemental sulfur. This process was never perfected and currently this hydrogen sulfide stream is now washed with anhydrous ammonia and Great Plains produces saleable ammonium sulfate fertilizer.

A small slip stream of synthesis gas from Rectisol is used to make 18 tons per day of methanol in a small catalytic processing unit. This uses a copper catalyst converting carbon monoxide and hydrogen to methanol. This methanol is used for makeup for the Rectisol process.

7. Methanation

Following the removal of acid gases, the synthesis gas is methanated to form synthetic natural gas (primarily methane) over a nickel-based catalyst in high pressure, high temperature reactors in two parallel trains. The catalytic reactors form methane and water from carbon monoxide, carbon dioxide, and hydrogen. This is a highly exothermic reaction and the heat of reaction is absorbed by generating high pressure steam.

8. Product Gas and Compression

Following methanation, the synthetic natural gas is compressed to pipeline specification. This is accomplished in two parallel trains with two stage compressors. The synthetic natural gas is then cooled and then dried to a low water content using triethylene glycol driers and continuously sampled and sent to interstate pipeline.

C. Technical Challenges: Lessons Learned

This section provides a list of some of the technical lessons learned from the Great Plains Project experience.

1. Lignite Test Runs

Design metrics were enhanced/validated by shipping 12,000 tons of North Dakota lignite in July of 1974 to South African Coal Oil and Gas Company, which was hired as a consultant to the project. South African Coal Oil and Gas Company had been making liquid fuels and chemicals through its gasification facilities in Sasolburg, South Africa since the 1950s. This $1.5 million test proved that North Dakota lignite could be gasified and provided detailed analytical data for the feedstock and gasification products.

2. Outside Technical Experts

Great Plains hired experts from Lurgi and South African Coal Oil and Gas Company for design reviews and commissioning support. This significantly contributed to completion of commissioning on time and on budget.

3. Multi-Train Design

All major processing areas are designed with two trains. One train has predominantly steam drivers on large rotating equipment while the other train has electric drivers. This design has three benefits. First, a large amount of high pressure steam generated by gasifiers, shift and methanation is consumed in the steam train. Second, this approach allows for repairs and maintenance on the down train as the other train supports production and avoids some total plant outages. Third, this approach has optimized energy efficiency and cost to build and operate.

4. Multi-Gasifier Design

The high number of gasifiers (14) allows the gasification area to continue to produce at high rates while gasification maintenance is performed on certain gasification units.

5. Flare Design

When the whole plant experiences emergency flaring, the sound and heat flux is significant at ground level. The location of the flare needs sufficient isolation.

6. Oxygen Backup

The air separation unit was designed with an eight-hour backup storage of liquid oxygen. This has averted many plant outages or plant rate turn downs. This reserve of liquid oxygen is also used for "cold shotting" the cold boxes for more rapid restarts.

7. Methanation Catalyst Life

Methanation catalyst life was improved by optimizing removal of sulfur in synthetic gas from Rectisol. Also, guard reactors in methanation to protect main reactors from sulfur poisoning are a must.

8. Winterization Methods

Great Plains had state-of-the-art winterization methods, due to the extreme temperatures in North Dakota. Most process equipment is not in buildings/shelters, so steam and electric tracing needed and was designed with a robust fault detection system.

9. Sulfur Plant Design Modifications

Sulfur emissions were finally contained with third design modification. Stretford and Sulfinol did not succeed. Great Plains is now using ammonia scrubber technology making ammonium sulfate byproduct and meeting air emissions standards.

10. Process Bottlenecks

The throughput bottleneck in the original design of the facility was the product compressor capacity. As Great Plains optimized their production processes and was able to achieve the maximum output from other components, this bottleneck limited the overall capability of the facility. Consequently, new larger product compressors were installed after the first few years of operation.

D. Commercial Challenges: Lessons Learned

This section provides a list of some of the commercial lessons learned from the Great Plains Project experience.

1. Government Support

The construction of Great Plains would not have been possible without three key government actions.

- The U.S. Department of Energy provided a loan guarantee of $1.5 billion.

- The synthetic natural gas purchase agreements allowed Great Plains to pass on costs of synthetic natural gas to their pipeline customers.
- The Federal Energy Regulatory Commission allowed the price of synthetic natural gas from the project to a base of $6.75 per 1,000 cubic feet with future adjustments and cost gaps.

2. Bankruptcy

By technical measures, the Great Plains project has been a resounding success. The project was commissioned on time and under budget, has reliably produced pipeline specification synthetic natural gas for over 20 years, and sequesters carbon dioxide. Unfortunately however, declining natural gas prices forced the project into bankruptcy in August 1985, shortly after commissioning. The five initial investors lost their equity. The Department of Energy assumed control of the facility and eventually found a new owner and operator of the facility: the local rural electric cooperative, Basin Electric. To date, the project has paid the Department of Energy $388.8 million towards the original $1.5 billion loan as part of a revenue sharing agreement.

3. High Capital Costs

Synthetic natural gas projects are capital intensive. The initial constructed cost of Great Plains was $2.1 billion (roughly $4.4 billion in 2009 dollars[18]). Since then, another $400 million has been invested to achieve environmental compliance, improve efficiency, and byproduct development.

4. Cost Sharing with Basin Electric

Great Plains looked to local power suppliers to share the cost of a new lignite mine, a new fresh water pipeline, rail facilities, and raw water storage. The parallel needs by Basin Electric to build a new 900 megawatt power plant adjacent to Great Plains helped to minimize these costs to both parties.

5. Long Lead Procurement

Gasifiers are expensive equipment with long procurement lead times. Great Plains purchased this equipment from two suppliers – seven from Japan and seven from the United States. This helped insure the delivery and construction schedule.

6. Diversification of Products

Carbon dioxide recovery and sales and upgrading of byproducts have had positive impact on revenues.

[18] Inflated by Consumer Price Index.

7. Volatility of Natural Gas Market

Market volatility of natural gas pricing has been challenging for Great Plains. A depression in natural gas prices led to its eventual bankruptcy. The later design modifications to include additional salable products (e.g. carbon dioxide and sulfur) have mitigated this risk somewhat, but it remains a large risk to the project. Inasmuch as new designs include revenue streams for additional products, this risk can be partially mitigated.

III. POLK POWER STATION IGCC PROJECT

A. Overview

The Tampa Electric Company (Tampa Electric) planned, constructed, and now operates the Polk Power Station Integrated Gasification Combined-Cycle Project (Polk Project).[19] Tampa Electric received roughly $123 million in funding for the Project through the Department of Energy's Clean Coal Technology Program. The purpose of the Department of Energy's program was to accelerate the commercialization of advanced, environmentally responsible coal technologies through the use of demonstration projects. The Polk Project was selected in January 1990 as one of the projects in Round 3 of the Clean Coal Technology Program. Tampa Electric began detailed design work on the Project in April 1993. Site work began a little over a year later in August 1994, and commercial operation commenced on September 30, 1996.

The Polk Project has a net capacity of 250 MW. This is net of 65 MW of parasitic loads drawn from the 315 MW gross capacity. The heat rate for the facility is 9,650 Btu/kWh.

The actual capital cost (excluding interest during construction) for the Polk Project was about $606,916,000, which is equivalent to $2,428/kW using the net capacity rating. The Polk Project does not include any carbon capture and sequestration systems.

B. Technology Description

The Polk Project can be broken down into three major components: (a) the air separation plant, (b) the gasification plant, and (c) the combined-cycle unit. Each of these three components can then further be broken down into sub-components or processes. The air separation plant consists of many components including the air separation unit and air compressors. The gasification plant includes (a) coal receiving and storage, (b) slurry preparation and feeding processes, (c) gasification of the coal into a synthetic gas (syngas) and heat recovery, and (d) cleaning of the syngas. The combined-cycle component includes (a) combustion of the syngas in the combustion turbine, (b) heat recovery in the heat recovery steam generator, and (c) additional power generation from the steam turbine and generator.

1. Air Separation Plant

The air separation plant at the Polk Project consists of an air separation unit and air compressors. Polk purchased their air compressors from Mannesmann DEMAG, and the air separation unit from Air Products and Chemicals, Inc. The air separation plant serves to separate

[19] This Section of the Report relies heavily on the following sources: (a) *Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project*, Final Technical Report, August 2002, ("Final Technical Report"), (b) *Clean Coal Technology, Tampa Electric Integrated Gasification Combined-Cycle Project, A DOE Assessment*, August 2004, ("DOE Assessment"), (c) *Tampa Electric Integrated Gasification Combined-Cycle Project, Project Fact Sheets 2003*, ("Fact Sheet"), and (d) PowerPoint Presentation, *Polk Power Station IGCC Operation – Lessons Learned, DOE Clean Coal Roundtable*, July 29, 2004, ("Lessons Learned"). We provide specific citations for the direct quotes included herein.

air into its major components. To do this, first, air is compressed in the main air compressor. Next, water vapor and any carbon dioxide are removed from the air, and then it is fed into the air separation unit where the air is cryogenically separated into two main streams, oxygen and nitrogen. The majority of the oxygen is used in the gasification process, while a small portion is used in the production of sulfuric acid. The nitrogen stream is predominately used in the combustion turbine to help reduce nitrogen oxides emissions.

The air separation plant results in roughly 55 MW of parasitic load. Of this, 34 MW is required by the main air compressor, 14 MW is required by compressors to compress the nitrogen stream before it is used in the combustion turbine, and 6.5 MW is required to compress the oxygen stream for use in the gasifier.

2. Gasification Plant

The Polk Project gasification plant is made up of many processes that must be integrated to convert coal or other fuels into clean syngas. The Polk Project used several vendors for its gasification plant. The Project used the General Electric gasification technology and process design (at the time of selection, however, the technology was developed and owned by Texaco). The engineering and construction management of all of the systems was provided by Bechtel, and Monsanto Enviro-Chem Systems provided the Sulfuric Acid Plant. Below is a brief explanation of each of these processes.

a. Coal receiving and storage

Most of the coal (and petroleum coke blends) used by the Polk Project are first delivered to Tampa Electric's Big Bend Station coal yard by barge. From there the coal is transported on trailers and unloaded at the Polk site. Conveyors bring the coal from the unloading point to one of two 5,000 ton storage silos. Each of these silos has a conveyor that can then deliver the coal to the grinding structure.

b. Slurry preparation and feeding processes

From the storage silos the coal is delivered to two independent grinding trains. Together these two trains can process 2,880 tons per day of coal. The ground coal is then fed, along with water, into a rod mill where it is further crushed into a coal slurry. The slurry moves from the rod mill to a discharge tank where it is pumped to two large, agitated run tanks. The slurry is stored in the run tanks until needed by the gasifier. Together the two run tanks can store a sufficient amount of coal slurry to operate the gasifier for 8 hours at full capacity. Lastly, a feeder pump is used to pump the slurry from the run tanks to the gasifier. These pumps can provide slurry to the gasifier at a rate of roughly 500 gallons per minute at 500 pound(s) per square inch gauge.

c. Gasification and heat recovery

The Polk Project uses a General Electric oxygen-blown, entrained-flow gasification process. The facility design uses a single gasifier without a spare train. The gasifier uses about

2,500 tons per day of coal (or coal blends). The operating temperature of the gasifier is between 2,300 °F and 2,700 °F. The gasification system also possesses a full heat recovery system. The gasifier mixes the feedstock (in this case coal slurry) from the agitated, coal slurry storage tank with oxygen from the air separation unit to facilitate a chemical reaction that produces syngas, slag, and flyash. After gasification, the raw syngas, slag, and flyash exit the gasifier and enter a radiant syngas cooler. The radiant syngas cooler accomplishes two important things. First, it cools the raw syngas, and second, it uses the heat to produce steam which is then used by the steam turbine to produce electricity. The raw syngas and about 60% of the flyash then leave the radiant syngas cooler for cleaning, while the slag and the remaining 40% of the flyash are removed. The slag is then sold to the market, and the flyash that is removed is recycled to the slurry preparation area.

d. Flyash and Chloride Removal

The raw syngas is predominately made up of hydrogen (H_2), carbon monoxide (CO), water vapor, and carbon dioxide (CO_2). The raw syngas also contains hydrogen sulfide (H_2S), carbonyl sulfide, and smaller amounts of other elements and compounds. The first step of the cleaning process removes chlorides and the remaining amounts of flyash (about 60%) that were not removed in the radiant syngas cooler using scrubbers.

e. Carbonyl Sulfide Hydrolysis

Next, the syngas undergoes a process called carbonyl sulfide hydrolysis. This process converts the carbonyl sulfide contained in the syngas to H_2S ($COS + H_2O \rightarrow H_2S + CO_2$). The H_2S created by this reaction is then removed in the acid gas removal process discussed below.

f. Acid Gas Removal

The purpose of this step is to remove sulfur from the syngas to reduce the emission of SO_2 when the syngas is combusted. The acid gas removal system is designed to remove H_2S from the syngas. This includes the H_2S that is already inherent in the syngas, and the H_2S created in the carbonyl sulfide hydrolysis process described above. The acid gas removal system removes H_2S by having the syngas stream flow in one direction and having a solvent called methyl diethanol amine flow in the opposite direction. As these two streams flow passed each other, the methyl diethanol amine reacts with the H_2S, and removes it from the syngas. Then the H_2S is stripped from the methyl diethanol amine using a methyl diethanol amine stripper. The H_2S is then sent to the sulfuric acid plant, and the syngas is piped to the power block where it passes through final filters that remove any remaining small particles and contaminants before it is combusted.

g. Sulfuric Acid Plant

The Polk Project contains a sulfuric acid plant to convert the H_2S removed from the syngas into sulfuric acid (H_2SO_4). This conversion takes several steps. First, the H_2S is burned in a decomposition furnace to produce SO_2. Next, the SO_2 is cooled which produces a "weak acid" stream which consists of only about 2%-3.5% H_2SO_4.[20] Then, the SO_2 is converted to SO_3 by adding O_2 from the air separation unit. Finally, the SO_3 reacts with water in absorbing towers to produce H_2SO_4. The sulfuric acid plant produces about 200 tons per day of sulfuric acid. This sulfuric acid is sold to the local fertilizer industry.

3. Combined-Cycle Unit

The Polk Project combined-cycle unit consists of one General Electric 7FA combustion turbine that has a capacity rating of 192 MW, one heat recovery steam generator, and one steam turbine that has a capacity rating of 123 MW. The full combined-cycle has a gross power rating of 315 MW. However, internal loads account for 65 MW, of which 55 MW is needed for the air separation plant and 10 MW is consumed by other auxiliaries. Taking account of this parasitic load results in a net capacity rating of 250 MW.

The cleaned syngas will power the combustion gas turbine, and a nitrogen stream from the air separation unit is used to both reduce NOx emissions and for power augmentation. The combustion turbine will also use low sulfur No. 2 distillate oil for startup and as a backup fuel. The steam turbine will use steam from the gasifier and the heat recovery steam generator to produce additional power.

C. Technical Challenges: Lessons Learned

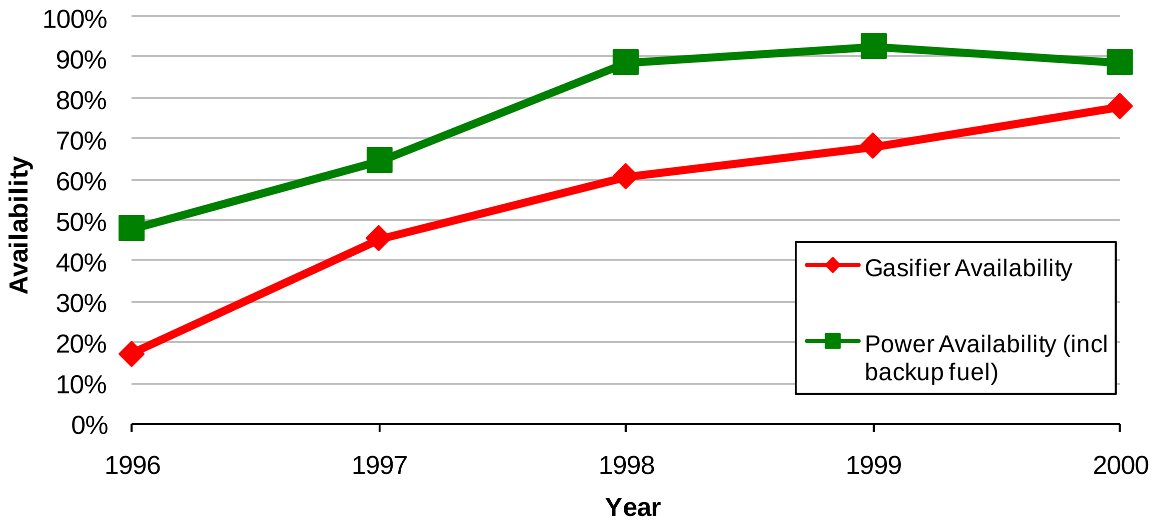
This section provides a list of some of the technical lessons learned from the Polk Project experience.

1. Low Availability

The availability of the facility was considerably reduced during the initial years of operation as various technical challenges were encountered (many are discussed further below). The first five years of availability is provided in the figure below. The availability of the combined cycle power was better than the gasification island availability due to the use of a backup fuel.

[20] *See* Final Technical Report at page 1-59.

Figure One
Polk Project Availability During First Five Years[21]



2. Backup Fuel

The Polk Project uses low sulfur No. 2 distillate oil for startup and as a backup fuel. This has helped availability of the power block. While the gasifier's availability was only about 70% from 1998-2001, the power block (using either syngas or distillate oil) was available about 90% of the time over the same time period.

3. Low Carbon Conversion

The carbon conversion rate from the coal slurry to syngas was much lower than expected at the Polk Project. The amount of unconverted carbon from the General Electric gasifier was actually twice what it was expected to be. Tampa Electric's estimates for carbon conversion rates were based on smaller General Electric gasifiers, because there were no operating General Electric gasifiers as large as the one planned for Polk. The expected conversion rates were between 97.5%-98%, while actual rates were closer to 90%-95%. The lower carbon conversion caused several problems. First, this caused much larger amounts of flyash than expected, which caused the flyash handling systems and water separation areas of the plant to be overloaded. Second, the lower conversion rate also negatively impacted the heat rate of the facility. Third, the lower conversion rate also contributed to the slag being unmarketable. To solve these problems, the main adjustment Polk made was to add systems to the plant to separate the flyash from the slag and recycle it back to the slurry preparation area to be used in the gasifier. By separating the flyash from the slag, the slag could also be sold to the market. They also increased the capabilities of some of their systems to accommodate higher flyash amounts. The costs for these modifications and others were well over $10 million.

[21] *See* Final Technical Report, Figure 2-1.

4. Heat Exchanger Plugging

The Polk Project facility design originally contained raw/clean syngas heat exchangers to recover additional heat from the syngas downstream from the Radiant Syngas Cooler. However, flyash deposits caused corrosion and subsequent cracking of heat exchanger tubes, which caused reliability problems for the combustion turbines as raw syngas leaked into the clean syngas used by the combustion turbine. Because the cost to modify and repair these exchangers was too high, the heat exchangers were removed. Removal of these heat exchangers resulted in increasing the heat rate of the facility by a small amount.

5. Convective Syngas Cooler Plugging

The convective syngas coolers also experienced plugging much like the exchangers described above. However, modifications were feasible that have largely resolved this issue.

6. Carbonyl Sulfide Levels

The General Electric gasifier produced twice as much carbonyl sulfide as Tampa Electric had expected. Higher carbonyl sulfide content in the syngas caused two problems: (a) piping failures and (b) SO_2 emissions levels that were higher than their permit allowed. To solve these problems, Tampa Electric installed a carbonyl sulfide hydrolysis unit. This unit converted carbonyl sulfide to H_2S so that it could be removed by the acid gas removal system. Tampa Electric also stated that it performed testing before choosing a catalyst for the carbonyl sulfide hydrolysis unit.

7. Technology Integration

Tampa Electric used several different vendors to acquire the equipment for the Polk Project. For example, Tampa Electric used General Electric for the gasifier and the combined-cycle, Air Products and Chemicals, Inc. for the air separation unit, and Monsanto Enviro-Chem Systems, Inc. for the sulfuric acid plant. Tampa Electric has stated that integrating technologies from different vendors was difficult. Furthermore, while performance guarantees could be attained for individual sections of the plant, a performance guarantee for the entire plant was not possible.

8. Fuel Flexibility

By the middle of 2004, the Polk Project had used over 20 different types of coal or coal blends, of which at least one contained biomass. This flexibility can provide the facility with options if one type of coal increases in price or becomes unavailable. For example, Tampa Electric states that during the first five years of operation mine closures resulted in the unavailability of two types of coal. However, each type of coal or coal blend can have different effects on such things as gasifier refractory liner and carbon conversion rate.

9. Process Bottleneck (Air Separation Unit)

As described previously, Tampa Electric made modifications to the Project to recycle flyash back to the gasifier to counter the low carbon conversion rate. Doing this, however, lowered the quality of the coal slurry, which results in the gasifier needing additional oxygen from the air separation plant. However, the air separation unit cannot provide enough oxygen given the increased demands caused by the low carbon conversion. Tampa Electric stated, "In the future, Polk has firm plans to increase the air flow to the air separation plant. This will provide enough additional oxygen so the plant can make at or very near 100% net rated capacity year around."[22]

D. Commercial Challenges: Lessons Learned

This section provides a list of the commercial lessons learned from the Polk Project experience.

1. Department of Energy Clean Coal Technology Program

The construction of the Polk Project was facilitated by funding from the national government. The U.S. Department of Energy selected the Polk Project in Round 3 of its Clean Coal Technology Program. The purpose of the Department of Energy's program was to accelerate the commercialization of advanced, environmentally responsible coal technologies through the use of demonstration projects. The Department of Energy provided roughly $123 million in funding.

2. Capital Costs Overruns

The actual capital cost of the facility was about $607 million. However, the initial capital cost estimate was about $303.3 million, with the Department of Energy agreeing to provide roughly 40% of the total as part of a cooperative agreement signed through the Clean Coal Technology Program. Tampa Electric was required to pay for the additional cost overruns, which ended up being roughly another $300 million.

3. Project Siting

Tampa Electric allowed the community to be involved with the planning of the Project. An independent task force made up of community representatives was formed to select the site for the Polk Project. The task force selected an abandoned phosphate mine in Polk Country, FL. In addition, Tampa Electric agreed to site reclamation.

4. Marketing Byproducts

Tampa Electric sells two byproducts to the market: (a) sulfuric acid and (b) slag. Tampa Electric is able to produce roughly 200 tons per day of sulfuric acid for sale in the local fertilizer

[22] *See* Final Technical Report at page 1-43.

industry. Tampa Electric sells the slag to the cement industry. Selling these byproducts can have positive impacts on revenues.

5. Training

Tampa Electric used an operating training simulator for staff training before commercial operation commenced.

IV. SIEMENS GASIFICATION EXPERIENCE

A. Overview

The Siemens gasifier has a long development history starting in the late 1970's.[23] Over that time, various companies have owned and developed the technology including DBI, Noell, Babcock Borsig Power, and Future Energy. In 2006, Future Energy was acquired by Siemens, which provided Siemens with intellectual property related to the gasifier design and a test center located in Freiberg, Germany. Freiberg also serves as the office for Siemens' gasification engineering group.

In general, the Siemens gasifier design has less operating experience than other major gasification vendors (e.g. Shell, General Electric, ConocoPhillips, Lurgi). A 200 megawatt thermal (MWt) gasifier design has been in operation since 1984 in the Schwarze Pumpe facility in Germany, but it is unclear how similar that gasifier is to the design proposed for the Taylorville project. This is a topic that should be explored with the Tenaska team.

The original design of the Taylorville project was based on General Electric gasification technology. The Tenaska team switched to the Siemens technology in mid-2009.

B. Technology Description

The gasifier design proposed for the Taylorville project is the SFG-500, which provides 500 MWt of syngas output. This gasifier is a dry feed, entrained flow gasifier.[24] A cross section of the SFG-500 gasifier is provided in Figure Two.

A unique feature of this gasifier design is the cooling screen used for the walls of the gasifier. As shown in Figure Two, the cooling screen is a membrane tube wall that circulates high pressure water to insulate the walls of the reactor for the hot gasification reactions. Other vendor's gasifier designs often use a refractory-lined wall to contain the gasification reactions. One consequence of the cooling screen approach is that the coal ash content must be greater than 2% in order to develop an insulating slag layer. A key advantage of the cooling screen design is that, if operated correctly, it can provide longer durations between outages than a refractory-lined design, which requires frequent replacement of the refractory material. This design also

---

[23] This Section of the Report relies heavily on the following presentations made by Siemens at several Gasification Technology Conferences. Specifically, (a) Morehead, Harry, "Siemens Gasification and IGCC Update", Presentation at the 2006 Gasification Technologies Conference., (b) Morehead, Harry, "Siemens Gasification and IGCC Update", Presentation at the PowerGen International Conference, December 3, 2008, (c) Klemmer, Klaus-Dieter, "The Siemens Gasification Process and its Application in the Chinese Market", Presentation at the 2006 Gasification Technologies Conference., and (d) Schmid, Christiane, "Siemens Fuel Gasification: Update for Power and Industrial Applications", Presentation at the 2007 Gasification Technology Conference. We provide specific citations for the direct quotes included herein.

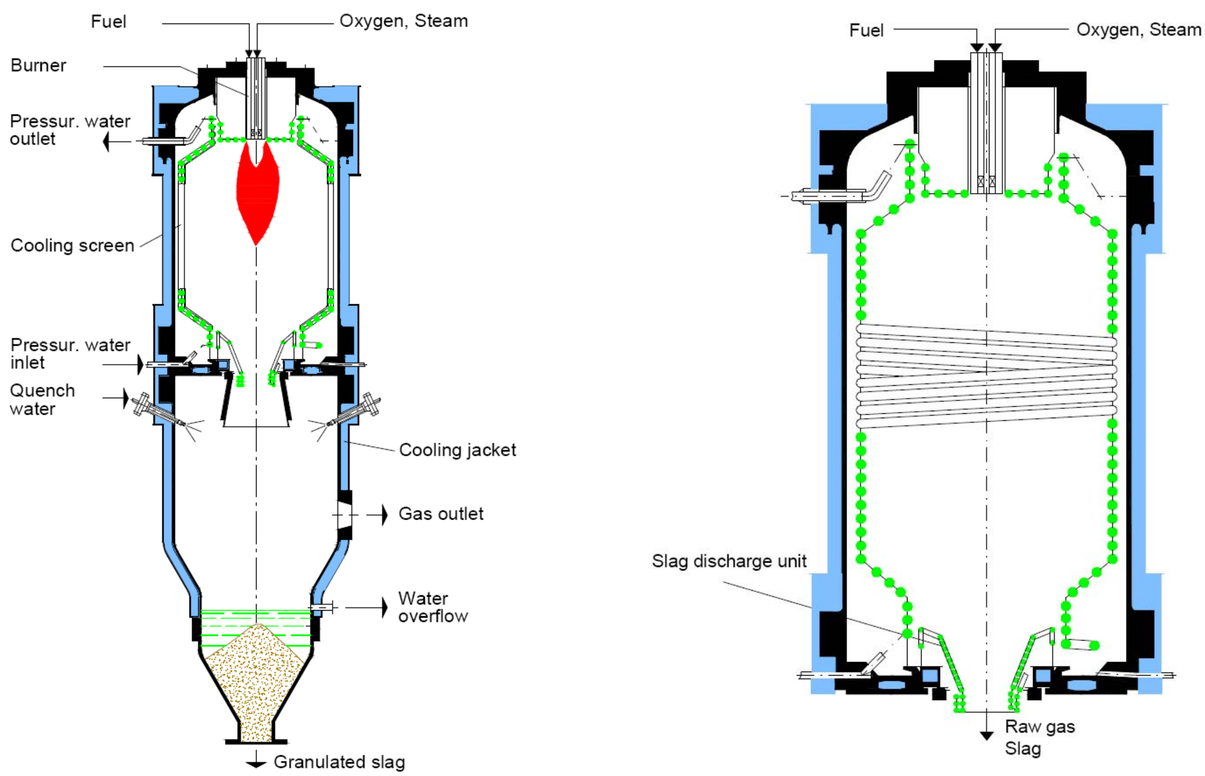
[24] Most modern large-scale gasifier designs are entrained flow; however the Great Plains facility (discussed in Section II) is a fixed-bed design. One notable consequence of the entrained vs. fixed-bed approach is that the entrained flow gasifiers operate at higher pressures and temperatures and generate less tars and liquids.

reportedly allows for faster startup times of the unit (approximately 1-hour) relative to refractory-based systems.

The gasifier is a dry feed system, and a schematic of the lock-hopper feeding scheme is provided in Figure Three. Dry feed systems may be more challenging to operate than liquid slurry-fed designs. A dry feed system also requires a feedstock drying step (and a source of drying heat) that is not required in a slurry-fed design. Either nitrogen or carbon dioxide can be used as the carrier gas.

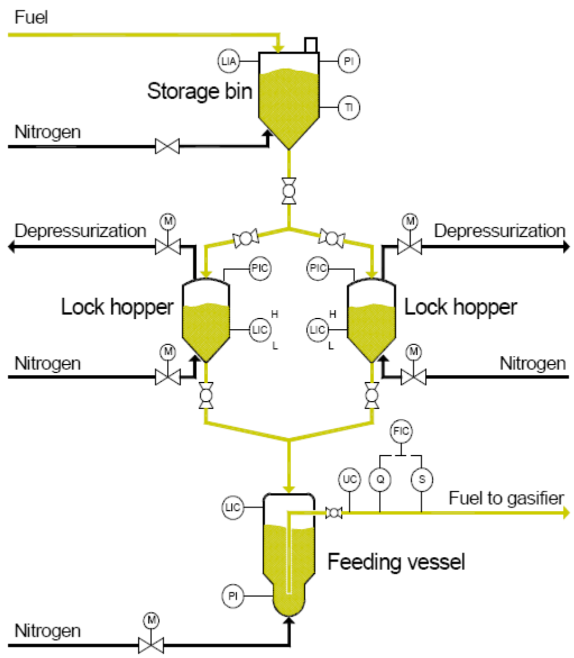
The Siemens design uses oxygen as an oxidant (rather than atmospheric air), which requires an air separation unit. The design and operation of an air separation unit is fairly commonplace in the industry.

Figure Two
Cross Section of Siemens SFG-500 Gasifier[25]



[25] *See* Klemmer, Klaus Dieter.

Figure Three
Schematic of Dry Feed System[26]



C. Operating Experience

A list of the projects using or planning to use Siemens gasification technology is provided in Table Two. Six SFG-500 gasifiers had been manufactured and shipped (two to Secure Energy and four to China). Three additional gasification vessels were being manufactured and are destined for various projects in China. To date, no operational experience with the SFG-500 gasifier has occurred. Operation on smaller scale pilot gasification projects has occurred at the Frieburg, Vresova, and Schwarze Pumpe sites.

In addition to the gasification experience listed in Table Two, Siemens has considerable experience designing and operating combustion turbines that use low heat content syngas. This experience is not particularly relevant to the Taylorville Energy Center, since the combustion turbines in this project will be conventionally designed to operate on synthetic natural gas. Operation of the combustion turbines at Taylorville is not expected to involve any significant technology risk.

[26] Ibid.

Table Two
Summary of Siemens Gasification Projects[27]

Project	Location	Capacity	Feed	Products	Comments
NCPP Project, Shenhua Ningixa Coal Industry Group	China	5 x 500 MWt	Bituminous coal	Poly-propylene	Commissioning expected 2009
JinCheng Project, Shanxi Lanhua Coal Chemical Co	China	2 x 500 MWt	Anthracite coal	Ammonia, Urea	Commissioning expected 2010
Secure Energy	Decatur, Illinois	2 x 500 MWt	Coal	Synthetic natural gas	Gasifiers delivered in late 2008
Vresova	Czechoslovakia	175 MWt	Tar oils, liquid residuals	Syngas for IGCC	Refractory lined gasifier. Operational since 2008. Not dry feed.
Freiberg Test Facility	Germany	2 – 3 MWt and 3 – 5 MWt	Hard coal, lignite, slurries	various	Both dry and slurry fed designs. Much smaller scale than commercial-scale gasifiers. Operational since the late 1970s. Both refractory and cooling screen designs.
Schwarze Pumpe	Germany	200 MWt	Lignite, natural gas, tar oils, waste	Methanol and power	Operational from 1984 - 2007. Unclear how similar this gasifier design is to SFG-500

[27] *See* Morehead, Harry (2006); Morehead, Harry (2008); Schmid, Christiane.

D. Conclusions: Lessons Learned

Based on this review of the Siemens gasification technology, the following conclusions are provided:

1. Contingencies

Given the lack of significant operating experience, the Taylorville project should include appropriate contingencies to account for a learning curve during the initial operation of the plant. These contingencies should include startup schedule contingency, reduced availability in the first several years of operation, and capital contingency for equipment modifications. These expected challenges may be partially mitigated if and when the planned projects listed in Table Two are commissioned (presumably before the Taylorville project is commissioned). However, if these projects are not commissioned as planned, the Taylorville project may bear more of the learning curve burden. Even if the other projects are commissioned as planned, it is expected that the Taylorville project will experience a significant learning curve.

2. Planned Projects

Tenaska should provide details on the characteristics of the planned projects in China and at Secure Energy. It should be understood how similar these characteristics are to the Taylorville project, and how applicable their experience will be to the Taylorville project.

3. Operating Experience

Tenaska should provide details on the characteristics of the operating experience at the Freiberg, Vresova, and Schwarze Pumpe sites, and how applicable is that experience to the proposed SFG-500 design.

4. Startup Time

The project team should investigate the startup time of the gasifier relative to the General Electric gasification design that the project originally envisioned using. This could be important in the startup emissions estimated in the air permit.

TASK 2 REPORT

AN ASSESSMENT OF TAYLORVILLE'S COMPLIANCE WITH THE ILLINOIS CLEAN COAL PORTFOLIO STANDARD LAW

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. ("Boston Pacific") and MPR Associates, Inc. ("MPR") make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

EXECUTIVE SUMMARY

A. Background and Introduction

The purpose of this report is to assess Taylorville's compliance with the Illinois Clean Coal Portfolio Standard Law (the "Law"[1]). The Law requires that the Commission's ultimate role in the implementation of the Law is to judge whether the contract through which Taylorville will sell power to Illinois utilities and alternative retail electric suppliers is "prudent and reasonable."[2] This contract is specified in what is termed the Sourcing Tariff.

Tenaska provided a draft of the Sourcing Tariff in the Fall of 2009. Tenaska has stated that this draft is being revised; however, since the revised draft is not complete and has not been circulated by Tenaska, we have provided our thoughts, herein, on the Fall 2009 draft Sourcing Tariff.

The Law also requires Taylorville to meet other important, specific goals. The most important of these is the requirements for Taylorville to capture and sequester at least 50% of the carbon dioxide (CO_2) emissions that would otherwise be generated. Judging compliance with these requirements also is an important role for the Commission and, again, many of these requirements are stated explicitly in the draft Sourcing Tariff and we also comment on these provisions.

In addition, the Law requires that Taylorville produce a Facility Cost Report and, to that end, a substantial number of documents underlying that Report; the documents establish a record for the General Assembly to make its ultimate decision. The Commission will provide a report to the General Assembly on its review of Facility Cost Report , with the assistance of its consultants (Boston Pacific and MPR), and that review will be based on the same documents. For that reason, we provide a checklist on the documents we expect to receive and have identified those we have received to date.

Further, the Law requires that Taylorville use qualified vendors and consultants to develop its project and all the required documents. We vet the qualifications of these vendors and consultants herein.

Finally, the Law sets a broad context for review when it states the requirement for electric service. Specifically, the Law states the following regarding the provision of electric service in Illinois:

> The health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.[3]

[1] Public Act 095-1027, also referred to as the Clean Coal Portfolio Standard Law, hereafter the "Clean Coal Law" or simply the "Law." The Law in large part consists of modifications to the Illinois Power Agency Act ("IPA Act") 20 ILCS 3855/1-1 et seq, and all citations to sections of the Law are to the IPA Act unless otherwise indicated.
[2] Law at Section 1-75(d)(4)(iv).
[3] Law at Section 1-5(1).

B. The Sourcing Tariff's Compliance With the Law

Our overall conclusion is that while the Sourcing Tariff is compliant with the Law in many regards, changes would have to be made to the Sourcing Tariff before the Commission could find it to (a) be "prudent and reasonable" and (b) provide electric service that is "adequate, reliable, affordable, efficient, and environmentally sustainable." Specifically, pay-for-performance provisions would have to be added to protect Illinois ratepayers against price, reliability, and environmental risks.

Our understanding is that Taylorville, while not opposed to such provisions, would argue that they "are not appropriate for a cost of service agreement." In earlier discussions, Tenaska has said that such provisions were originally considered and eventually rejected as part of the legislative process. As we see it, the deal embedded in the Sourcing Tariff is neither: (a) a traditional cost of service deal with regulatory protections for ratepayers, nor (b) a standard, fixed price, pay-for-performance deal with contractual protection for ratepayers. For that reason, we think it is entirely reasonable for the Commission to suggest provisions to provide ratepayer protections going forward, especially since the Law does not preclude the use of these types of provisions. A brief discussion of our top seven ratepayer concerns follows:

1. No Reliability Requirement

As we read the Sourcing Tariff, Taylorville would be paid in full no matter how well or how poorly it performs. Provisions such as Section 3.02 (b) seem to excuse Taylorville for failing to deliver power to Illinois ratepayers. Under traditional cost of service rates, the Commission (or the Federal Energy Regulatory Commission) would be in a position to penalize Taylorville for poor performance; we are concerned that language in the Sourcing Tariff would preclude this.

We have related concerns about excusing poor performance through the definition of *Force Majeure* in the Sourcing Tariff. In addition, we are concerned with the fact that, while the Illinois electricity consumer pays the full cost of the Taylorville facility, they are not entitled to the full benefits of the facility on all days of the year; this relates to the fact that Illinois would not be entitled to the capacity of the power plant.

Moreover, the Sourcing Tariff does not have any of the pay-for-performance provisions that are standard in power sales agreements today. We suggest that such provisions are necessary here to protect Illinois ratepayers against poor reliability at Taylorville. At an absolute minimum, if these standards are not imposed, it must be made clear that the Sourcing Tariff does not constrain the Commission's review of prudence with respect to poor performance.

2. No Substitute Natural Gas Usage Requirement

The overarching purpose of the Law is to promote clean coal technologies that are capable of limiting carbon emissions. However, despite these clear goals of the Law, the Sourcing Tariff does not provide any performance requirements for producing substitute natural gas or for the usage of substitute natural gas rather than conventional natural gas in the combined-cycle plant. That is, even if the substitute natural gas facility is often down for extended periods of time, Taylorville can continue to sell power to the utilities using natural gas, presumably at much higher rates than a standard natural gas-fired combined-cycle power plant. While having the capability of using a backup fuel as abundant as natural gas is good for the reliability of the power block, the Sourcing Tariff should include some performance requirements for the production of substitute natural gas to ensure that Illinois ratepayers are getting the benefits that should come with paying for electricity from a clean coal facility.

In addition, Tenaska has stated that Taylorville would contribute to affordability and assist in providing electric service at the lowest cost over time by reducing consumers' market exposure to volatile natural gas prices.[4] If this is indeed one of the benefits, performance requirements are necessary to provide the correct incentives for Tenaska to ensure that natural gas is not used for a large portion of the time.

3. Curtailed Commission Review

As we read it, the Commission has limited opportunity to rule on the justness, reasonableness, and prudence of the Sourcing Tariff for Taylorville. Under the Law, the Commission must rule on the Sourcing Tariff within 90 days after the General Assembly rules on it.[5]

The Law also provides that the Commission may rule on the justness, reasonableness, and prudence of the inputs to the formula rate at least once every three years going forward. The Sourcing Tariff currently does not have a provision that allows such a review; however, Tenaska has stated they will provide a reference to this requirement of the Law in the Sourcing Tariff.[6] Given that Illinois ratepayers are bearing the full cost and risk of Taylorville, it is important that such a provision be added so that there is no doubt of the Commission's ability to rule on prudence going forward.

4. No Effective Cost Limit

The Law appears to have a limit on how much of its costs Taylorville can pass through to Illinois consumers. On a more detailed reading it becomes clear that there is no effective cost limit. The key to understating this is to see that the cost limit applies to Illinois electric utilities, but not to alternative retail electric suppliers. Taylorville believes that the Law allows it to sell to the alternative suppliers what it cannot sell to the electric utilities when the cost limit applies.

Even though the cost limit is not effective, it is important to review the cost limit for electric utilities to allow it to reveal how much of an above-market premium might be paid to Taylorville. That is, how much over market prices might Taylorville be paid. We make explicit estimates of this premium in our Task 7 Report. It is not for us to say whether and how much of a premium is reasonable, but we do believe the premium should be transparently revealed. In this context we note also that, when measuring the possible premium, another fair comparison is

---

[4] Tenaska Response to Boston Pacific Information Request, Information Requests to Tenaska Concerning Compliance with the Illinois Power Agency Act's Clean Coal Portfolio Standard (Submitted on 9-11-09) (9.18.09) ("Tenaska Response to Boston Pacific Information Request") at page 1. (Attached as Appendix A to this document.)
[5] Law at Section 1-75(d)(4)(iv).
[6] Tenaska Response to Illinois Commerce Commission Staff Information Request on the Sourcing Tariff (9.25.09) ("Tenaska Response to Staff Information Request") at page 4. (Attached as Appendix B to this document.)

to compare Taylorville's cost to the cost of other new power plants that control or pay for carbon emissions. The Law requires such a comparison and Boston Pacific and MPR conducted this comparison in our Task 6 Report.

5. Illinois Ratepayers Have Unlimited Liability for CO_2 Offsets

Tenaska is required to achieve carbon capture and sequestration for 50% of the CO_2 emissions that would otherwise be emitted by Taylorville. If the 50% is not achieved (or previously sequestered CO_2 escapes), Tenaska must buy CO_2 offsets to compensate. However, Tenaska's liability for offsets is limited to $15 million per year.[7] We have no concern with the limit for Tenaska. Our concern is that there is no limit for Illinois ratepayers. This means that, if there is Federal regulation of CO_2 in place, Illinois ratepayers would have to bear the risk for offset prices over and above the $15 million paid by Tenaska.[8] A better approach is to allow the Sourcing Tariff to be terminated if the Commission finds that it is not prudent to continue to allow Tenaska to run Taylorville if it fails to achieve the 50% reduction in CO_2 emissions.

6. Use of a Deemed Rather Than Actual Cost of Capital

The Law allows Tenaska to use a "deemed" as opposed to an "actual" cost of capital in the calculation of the rates it can charge Illinois ratepayers. Specifically, Tenaska can deem that it used 55% debt and 45% equity to finance Taylorville. The Law also states that the return on that deemed equity will not be higher than 11.5%.[9]

A problem occurs because the Law also requires that Tenaska pass through the benefit of any support from the Federal Government. We understand that Tenaska has applied for a loan guarantee from the U.S. Department of Energy. If it gets that loan guarantee, its actual cost of capital may be quite different from that deemed in the Law. For example, debt might be used for 80% of the financing – not the deemed 55%. All of this means that, because of Federal support, the actual cost of capital has the potential to be lower than that deemed in the Law.

The problem arises from an internal inconsistency in the Law. Our remedy goes back, once again, to pay-for-performance features. High debt – 80% or more of the capital structure – is not unusual in pay-for-performance contracts and the result is that the actual return on equity can be 20% or more. Higher equity returns might be more appropriate if they are earned by taking risks off of the shoulders of Illinois ratepayers. Therefore, use of the deemed capital structure gives even more support for the use of pay-for-performance features.

7. Illinois Must Take on Debt and CO_2 Risk if Ownership of Taylorville is Transferred to the Illinois Power Agency

The Law gives the Illinois Power Agency the right to assume ownership of Taylorville at the end of its 30-year power sales agreements. The Law states that the assumption is to be done

[7] Christian County Generation, L.L.C. Sourcing Tariff (Draft 9/11/09) ("Sourcing Tariff") at Section 5.01.
[8] The Law and the Sourcing Tariff do allow the Attorney General rights to step in to enforce the 50% requirement, and the Illinois Commerce Commission is permitted to reduce the allowable rate of return on equity if Taylorville *willfully* fails to comply with the capture and sequestration requirements. It is unclear how much leeway the term *willfully* provides Tenaska.
[9] Law at Section 1-75(d)(3)(A)(i).

"without monetary consideration."[10] The Sourcing Tariff, however, implies that the Agency would have to both (a) take on the burden of remaining debt and (b) bear the risk of sequestered CO_2.[11] It is not clear that either provision complies with the Law.

C. Providing the Documents Required by the Law

The Law requires that Tenaska provide a Facility Cost Report.[12] Further, the Law dictates that certain documents are required as part of the Facility Cost Report, and also requires that certain line items be included for the cost quotes required in the Facility Cost Report. As indicated by the document checklist provided herein, we believe Tenaska has provided all the required information.

D. Vetting the Qualifications of Taylorville's Vendors and Consultants

The Law requires that Taylorville use qualified vendors and consultants to develop its project and all the required documents.[13] To that end, we asked for and received qualification packages for Tenaska's consultants, and reviewed these packages to determine whether the consultants were qualified to perform the tasks required for the production of the Facility Cost Report. Our conclusion is that Tenaska's vendors/consultants are all qualified to provide support for the development of the Facility Cost Report for the Taylorville Energy Center.

[10] Law at Section 1-75(d)(3)(D)(iv).
[11] Sourcing Tariff at Section 13.01.
[12] Law at Section 1-75(d)(4)(i).
[13] Law at Section 1-75(d)(4)(A).

I. OVERVIEW OF THE ILLINOIS CLEAN COAL PORTFOLIO STANDARD LAW

As stated in the Executive Summary, the purpose of this report is to assess Taylorville's compliance with the Illinois Clean Coal Portfolio Standard Law (the "Law"[14]). However, before doing this, we must first understand what the Law requires. Therefore, this Section of the task report discusses the major requirements laid out in the Law. This provides the backdrop against which the Taylorville Integrated Gasification Combined Cycle (IGCC) facility, assumed to be the "initial clean coal facility" will be judged.

The Law states its broad purpose as follows:

> "The State should encourage the use of advanced clean coal technologies that capture and sequester carbon dioxide emissions to advance environmental protection goals and to demonstrate the viability of coal and coal-derived fuels in a carbon-constrained economy."[15]

The development and operation of Taylorville is designed to serve this broad purpose. The technology that they are planning to use – "Hybrid" Integrated Gasification Combined Cycle or IGCC – is an advanced clean coal technology. Its prospects could be enhanced substantially with the successful commercialization of an IGCC facility that also includes carbon capture and sequestration, which is what Taylorville intends; thereby paving the way for more IGCC plants in the future.

The Law also sets broad standards for electric service. Specifically, the Law states:

> "The health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[16]

This provides another broad standard that the Taylorville facility must meet. Thus while one goal is to advance the clean coal technology it also should be done in a fashion to serve these other goals.

Beyond this broad purpose, the Law sets a significant number and a wide variety of narrower requirements for Taylorville as the "initial clean coal facility." Compliance with these specific requirements must also be judged.

At the outset, it is important to see that these requirements in the Law both enable and govern the development and operation of Taylorville. We say it "enables" because the Law requires Illinois electric utilities and alternative retail electric suppliers to buy power from the initial clean coal facility (that is, from Taylorville). We say it "governs" because the Law sets up

[14] Public Act 095-1027, also referred to as the Clean Coal Portfolio Standard Law, hereafter the "Law."
[15] Law at Section 1-5(8).
[16] Law at Section 1-5(1).

processes for setting the price and non-price terms and conditions for the required utility purchases. Notably, although the price is said to be a traditional cost of service rate, there are caps in place to protect the Illinois ratepayers from large rate increases. However, as explained below, these protections are only for utility customers and are not in place for ratepayers who rely on alternative retail electric suppliers for their electricity.

The Law also sets limits for regulated air pollution emissions and a requirement for the capture and sequestration of carbon dioxide emissions. And it sets requirements for the substantive information which must be included in the Taylorville Facility Cost Report which must be submitted to the General Assembly, the Commission, and the Illinois Power Agency before the contracts for utility purchases can be approved. The major provisions of the Law are discussed below.

A. Meet the Law's Definition of a Clean Coal Facility

Taylorville must meet the definition of a "clean coal facility" which is defined in the Law as an electric generating facility which (a) primarily uses coal as a feedstock[17] and (b) captures and sequesters carbon emissions at levels dictated by the year in which the facility is scheduled to be on line: if Taylorville is scheduled to come on line before 2016, its must capture and sequester 50% of carbon emissions; if it is scheduled for 2016 or 2017, it must capture and sequester 70%. These percentage reductions are said to be measured from the level of emissions that "the facility would otherwise emit". The Law also defines "sequester" as permanent storage of CO_2 by injection into (a) a saline aquifer, (b) a depleted gas reservoir, or (c) an oil reservoir (this includes use for enhanced oil recovery).[18]

In addition, other emissions *from the power block* of a clean coal facility will be limited to those that would be emitted by a natural gas-fired combined cycle power plant of the same size and at the same location as Taylorville. The emissions covered in this standard are sulfur dioxide, nitrogen oxides, carbon monoxide, particulates, and mercury.[19]

B. Assure the price to be paid for electricity from Taylorville does not exceed limits

Section 1-75 (d) of the Law requires Illinois electric utilities and alternative retail electric suppliers to enter into contracts, or "sourcing agreements", to buy power from the initial clean coal facility. The Law states they must buy at least 5% of their electric supply from a clean coal facility (subject to limitations) by the year 2015 and every year thereafter. The Law states a more aggressive "goal" of having 25% of supply met by clean coal by the year 2025.[20]

[17] A clean coal facility also must use coal which has a "high volatile bituminous rank" and sulfur content greater than 1.7 pounds of sulfur per million British thermal units (Btu). Law at Section 1-10.
[18] Law at Section 1-10.
[19] Law at Section 1-10.
[20] Law at Section 1-75(d)(1).

More importantly, the Law puts limits on how much money can be paid by utility customers in any one year for electricity from the initial clean coal facility.[21] The cost limit does not apply for customers of alternative retail electric suppliers.[22] The limit on what can be paid to clean coal facilities by utility customers is expressed in terms of a limit on how much of an increase in the average price for power can be caused by purchases from the clean coal facility. For the year 2014 and thereafter, the limit is the greater of two alternatives. The first alternative is that the increase can be no more than "2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009." The second alternative is to allow a 2% increase, to be measured in 0.5% increments against prices in 2009, 2010, 2011, and 2012. In its Sourcing Tariff, Tenaska chose to use the first version, so we describe the mechanics of that version later herein.[23]

C. The Sourcing Agreements must include a cost of service approach to pricing

The Law specifies that electric utilities must sign Sourcing Agreements with the initial clean coal facility and that the generating capacity for that facility must have a nameplate capacity of at least 500 megawatts (MW). The General Assembly must approve the Sourcing Agreements.[24] The Law also specifies the concept for power prices in the Sourcing Agreements. The Law calls for a "formula contractual price" which is based on a "cost of service methodology."[25] The capital cost portion of the cost of service rate – typically called the capital revenue requirement – is further dictated by the Law in three ways.

First, instead of having the capital revenue requirement be front loaded – start high and then decline over time as the facility is depreciated – the price must be either "level" or "deferred."[26] Again, these terms are open to interpretation. By level we understand that an equal annual payment – an "annuity" – would be calculated; the annuity would have the same cost over time (the same present value) as the front loaded capital revenue requirements. The term "deferred" could mean a lot of things. One view is that it means that something called a real annuity would be calculated. That is, an initial price would be set for the first year and then that price would increase with inflation each year thereafter. Again, the real annuity would have the same cost over time (the same present value) as the front loaded capital revenue requirement. We understand Tenaska intends to use the levelized approach, it says that deferrals may be used if the cost limit discussed above is binding.

Second, the assumed mix of equity and debt investment – the capital structure of the deal – is locked in so that 45% of the total capital cost is assumed to be paid by equity investors and the other 55% is assumed to be paid by debt investors.[27]

---

[21] Law at Section 1-75(d)(2)(A) through (E).
[22] Law at Section 16-115(d)(5)(iii).
[23] Law at Section 1-75(d)(2)(E).
[24] Law at Section 1-75(d)(3).
[25] Law at Section 1-75(d)(3)(A).
[26] Law at Section 1-75(d)(3)(A)(i).
[27] Ibid.

Third, the return on equity must be approved by the Federal Energy Regulatory Commission. However, it must not exceed the lower of 11.5% or a return approved by the General Assembly.[28]

D. The Sourcing Agreement must include many other non-price terms and conditions

The Law sets at least seven other requirements for non-price terms and conditions in the Sourcing Agreement. First, the net revenue for sales of other products from the clean coal facility must be used to reduce the price of power; that is, net revenue must be credited against the cost of service. This includes net revenue from the sale of emission allowances, substitute natural gas, firm transmission rights, byproducts, and energy and capacity sold outside the bounds of the Sourcing Agreement. The Law also requires "net revenues" from grants and other government support be credited against the cost of service.[29]

Second, there are requirements for the power purchase provisions of the Sourcing Agreements. Each utility must agree to (a) pay the Contract Price and (b) take a share of the power equal to its share of Statewide retail electricity sales as long as its cost cap is not exceeded. Two other related requirements are worth mentioning. The first is that the power must be delivered to the Regional Transmission Organization to which the relevant utility belongs. The second is that the Sourcing Agreement will be considered a "pre-existing contract" in the context of the overall State Procurement Plan.[30]

Third, as an alternative to a power purchase contract, there may be a contract for differences.[31] That is, rather than pay the Contract Price, the utility may be asked to pay the difference between the Regional Transmission Organization Day-Ahead market price and the Contract Price. The initial clean coal facility gets to choose between the power purchase provisions and the contract for differences provisions.[32]

Fourth, the Sourcing Agreement cannot have a term greater than 30 years.[33]

Fifth, the Illinois Power Agency, if it chooses, may assume ownership of the clean coal facility if it requests to do so no later than three years from the end of the term of the contract, without monetary consideration.[34]

Sixth, if the clean coal facility fails to sequester at least 50% of the carbon emissions, or emissions escape from sequestration, the owner of the clean coal facility must buy offsets in Illinois to compensate. However, the amount of money spent on offsets in anyone year is capped at $15 million.[35]

---

[28] Ibid.
[29] Law at Section 1-75(d)(3)(A)(ii).
[30] Law at Section 1-75(d)(3)(B).
[31] Law at Section 1-75(d)(3)(C).
[32] Law at Section 1-75(d)(3)(D)(x).
[33] Law at Section 1-75(d)(3)(D)(i).
[34] Law at Section 1-75(d)(3)(D)(iv).
[35] Law at Section 1-75(d)(3)(D)(v).

Seventh, the Sourcing Agreement must include what is termed "customary lender requirements."[36]

E. The Sourcing Agreements must be approved by the General Assembly and reviewed by the Commission

The General Assembly must approve the Sourcing Agreements. To win that approval, the initial clean coal facility must submit to the General Assembly, the Commission, and the Illinois Power Agency, a Facility Cost Report which includes a Front-End Engineering Design Study, a facility cost report, method of financing, and an operating and maintenance cost quote.[37]

Within six months of the submission of the Facility Cost Report, the Commission must provide its review which must include a comparison of the cost of electricity from the initial clean coal facility to that from other generating facilities, an analysis of rate impacts on residential and small business customers, and an assessment of the likelihood that the clean coal facility will be on line by 2016.[38]

The General Assembly may then enact legislation approving the Sourcing Agreements including approval of the projected prices in cents per kilowatt-hour, the rate impact on residential and small business customers, and the maximum allowable return on equity.[39]

After the General Assembly acts, the Commission will have 90 days to resolve any disputes and to rule on the prudence and reasonableness of the Sourcing Agreements.[40]

F. The Facility Cost Report must meet several requirements for content

The Law lists several requirements for the Facility Cost Report. First, The Facility Cost Report must be prepared by duly licensed engineering and construction firms.[41]

Second, it must include capital and operations and maintenance cost estimates for the clean coal facility. Separate estimates must be provided for the core plant and for the balance of plant (including sequestration). The costs must be in nominal dollars and must include financing cost during construction, owners' costs such as taxes and insurance, and escalation.[42]

Third, the Front-End Engineering Design Study and other studies must provide sufficient detail.[43]

[36] Law at Section 1-75(d)(3)(D)(xiii).
[37] Law at Section 1-75(d)(4)(i).
[38] Law at Section 1-75(d)(4)(ii).
[39] Law at Section 1-75(d)(4)(iii).
[40] Law at Section 1-75(d)(4)(iv).
[41] Law at Section 1-75(d)(4)(A).
[42] Law at Section 1-75(d)(4)(A)(i) and (ii).
[43] Law at Section 1-75(d)(4)(B).

Fourth, the operations and maintenance costs will include the cost of delivered fuel as well as all other costs such as that for personnel.[44]

Fifth, the delivered fuel cost estimate must be done by a recognized third party expert.[45]

Sixth, the other cost estimates must also be provided by experts including licensed engineers, potential vendors, and others.[46]

Seventh, the study must include an assessment of the ability to deliver to the relevant Regional Transmission Organization and an estimate of the capacity factor for the facility.[47]

Eighth, note that the cost of the core plant studies will be reimbursed through Coal Development Bonds.

The Law also sets requirements for substitute natural gas facilities that have begun construction by July 1, 2010. It sets limits on the price that can be paid for substitute natural gas. The price cap is $7.95 per million British thermal units (MMBtu) (2008 dollars) escalated for inflation; but the price may never exceed $9.95 per MMBtu in the first ten years of a sales contract.[48] We understand Tenaska does not intend to use the substitute natural gas provisions of the Law.

[44] Law at Section 1-75(d)(4)(C).
[45] Law at Section 1-75(d)(4)(C)(a).
[46] Law at Section 1-75(d)(4)(C)(b).
[47] Law at Section 1-75(d)(4)(D)(i) and (ii).
[48] Law at Section 9-220(h).

II. REVIEW OF THE SOURCING TARIFF'S COMPLIANCE WITH THE LAW

The Sourcing Tariff, in effect, is the power sales agreement that the electric utilities and alternative retail electric suppliers would have to sign with Taylorville. Importantly, this agreement is the vehicle through which Tenaska will implement the Illinois Clean Coal Portfolio Standard Law (the "Law"). Given this, the purpose of this Section is to provide a review of whether the Sourcing Tariff circulated by Tenaska for the Taylorville clean coal facility is compliant with the Law.

Ultimately, the Law requires the Commission to rule whether the Sourcing Tariff is "prudent and reasonable."[49] In addition, the Law states the following regarding the provision of electric service in Illinois:

> The health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.[50]

Our overall conclusion is that while the Sourcing Tariff is compliant with the Law in many regards, changes would have to be made to the Sourcing Tariff before the Commission could find the Sourcing Tariff to (a) be "prudent and reasonable" and (b) provide electric service that is "adequate, reliable, affordable, efficient, and environmentally sustainable." Specifically, pay-for-performance provisions would have to be added to protect Illinois ratepayers against price, reliability, and environmental risks.

Our understanding is that Tenaska, while not opposed to such provisions, would argue that they "are not appropriate for a cost of service agreement." In earlier discussions, Tenaska has said that such provisions were originally considered and eventually rejected as part of the legislative process. As we see it, the deal embedded in the Sourcing Tariff is neither: (a) a traditional cost of service deal with regulatory protections for ratepayers, nor (b) a standard, fixed price, pay-for-performance deal with contractual protection for ratepayers. For that reason, we think it is entirely reasonable for the Commission to suggest provisions to provide ratepayer protections going forward, especially since the Law does not preclude the use of these types of provisions. To that end, the remainder of this Section discusses seven ratepayer concerns we have with the Sourcing Tariff.

A. No Reliability Requirement

According to Tenaska, Taylorville will, "contribute to (a) adequacy and (b) reliability of electric service by increasing both the baseload supply and the dispatchable supply of electric energy in Illinois with a generating facility that is expected to achieve availability of over 90%."[51] However, as we read the Sourcing Tariff, Tenaska would be paid in full no matter how

[49] Law at Section 1-75(d)(4)(iv).
[50] Law at Section 1-5(1).
[51] Tenaska Response to Boston Pacific Information Request at page 1.

well or how poorly Taylorville performed. For background, note that the "price" paid for the power from Taylorville is simply the full, annual revenue requirement divided by whatever number of MWh are delivered to the buyers.[52] To see our point about the lack of any reliability requirement, start with Section 3.02 (b) which states:

> Seller's obligation to produce, deliver and sell Delivered Energy under this Sourcing Tariff shall be on a "unit contingent" basis. Accordingly, Seller shall not be responsible or liable for any failure to produce, deliver or sell any Delivered Energy to the extent such failure is the result of (i) any Scheduled Outage, (ii) any Unscheduled Outage, (iii) any Force Majeure Event affecting any Party, (iv) any failure of Buyer to perform any of its obligations under this Sourcing Tariff, (v) any other act or omission of Buyer, or (vi) any other act or event in respect of which the terms of this Sourcing Tariff excuse Seller's performance.

Contrast this with some of the standard provisions of pay-for-performance power sales agreements. First, the supplier would have to agree to an availability standard – it would have to be available to generate electricity say 90% of the time. If it did not achieve the 90% availability, its payments would be reduced according to a schedule. Moreover, if its availability fell below a certain level (say 50%) the supplier would have defaulted on the contract. Second, scheduled maintenance would be limited to a specific number of days or even to a specific time of the year. Third, unscheduled maintenance (or forced outages) would be limited to a specified number also.

Even if we take this out of the pay-for-performance context, under traditional prudence review the Commission would be in a position to penalize Tenaska for poor performance. We are concerned that provisions such as 3.02 (b) in the draft Sourcing Tariff would preclude such regulatory review.

In this same sense we are concerned with the definition of *Force Majeure* in the Sourcing Tariff. It is fine that events truly beyond the control of the supplier be excused – events like earthquakes and other Acts of God. But Tenaska excuses events that should be under their control. Most notably, Tenaska is excused under the Force Majeure definition if its equipment or fuel suppliers are late on deliveries.[53] So, for example, if Tenaska promised a 2014 on-line date, but misses that date because some piece of equipment is not delivered on time due to an alleged "shortage", Tenaska cannot be penalized. Being on time is a risk Tenaska has some ability to control and Tenaska should, in turn, shift that risk to its suppliers so the proper incentives are created.

Further, we are concerned because Tenaska is excused if it fails to live up to promises made to PJM through day-ahead schedules for power delivery and the like. Again, under the draft Sourcing Tariff, the Illinois ratepayer would pay any penalties assessed by PJM or the Midwest Independent Transmission System Operator in the form of charges such as imbalance energy charges.[54]

[52] Sourcing Tariff at Attachment A, page 2. See definition of *Buyer's Contract Price*.
[53] Sourcing Tariff at pages 3 and 4. See definition of *Force Majeure.*
[54] Sourcing Tariff at Section 3.02(d).

Finally, we are concerned with the assertion that, although the Illinois ratepayers are at risk for the total cost of Taylorville, they are not getting the capacity benefit.[55] To put it in blunt terms, is Tenaska saying that, on the hottest day of the year, it can use Taylorville to fulfill a bilateral capacity contract, thus leaving the Illinois ratepayers to find and pay for energy elsewhere? It is unclear whether this is at all consistent with the Law.

Our preferred remedy is that Taylorville be required to meet pay-for-performance standards including, but not limited to (a) an availability guarantee with price penalties, (b) a minimum availability triggering default, and (c) a limit on scheduled maintenance. At an absolute minimum, if the standards are not imposed, it must be made clear that the Sourcing Tariff does not constrain the Commission's review of prudence related to performance.

B. No Substitute Natural Gas Usage Requirements

The overarching purpose of the Law is to promote clean coal technologies that are capable of limiting carbon emissions. Specifically, the Law states, "The State should encourage the use of advanced clean coal technologies that capture and sequester carbon dioxide emissions to advance environmental protection goals and to demonstrate the viability of coal and coal-derived fuels in a carbon-constrained economy."[56] The Law also defines a "Clean Coal Facility" as an electric generating plant that uses "primarily" coal as a feedstock.[57] However, despite these clear goals of the Law, the Sourcing Tariff does not provide any performance requirements for producing substitute natural gas or for the usage of substitute natural gas rather than conventional natural gas in the combined-cycle plant. That is, even if the substitute natural gas facility is often down for extended periods of time, Taylorville can continue to sell power to the utilities using natural gas, presumably at much higher rates than a standard natural gas-fired combined-cycle power plant. While having the capability of using a backup fuel as abundant as natural gas is good for the reliability of the power block, the Sourcing Tariff should include some performance requirements for the production of substitute natural gas to ensure that Illinois ratepayers are getting the benefits that should come with paying for electricity from a clean coal facility.

In addition, Tenaska has stated that Taylorville would contribute to affordability and assist in providing electric service at the lowest cost over time by reducing consumers' market exposure to volatile natural gas prices.[58] If this is indeed one of the benefits, performance requirements are necessary to provide the correct incentives for Tenaska. If Taylorville is selling a large portion of its power under the Sourcing Tariff using its backup fuel of natural gas then ratepayers are simply paying for very expensive natural-gas fired generation that would not only expose them to the volatility of natural gas but, also much higher capital and operating costs compared with a standard combined-cycle generating plant.

[55] Sourcing Tariff at Section 3.02(f) and page 3. See definition of *Delivered Energy*.
[56] Law at Section 1-5(8).
[57] Law at Section 1-10.
[58] Tenaska Response to Boston Pacific Information Request at page 1.

C. Curtailed Commission Review

As we read the Sourcing Tariff, the Commission has limited opportunity to rule on the justness, reasonableness, and prudence of the Sourcing Tariff for Taylorville. Under the Law, the Commission must rule on the Sourcing Tariff within 90 days after the General Assembly rules on it.[59] Since this would be about five years before Taylorville's on-line date, the review would be based on estimated cost and performance. And it seems that this review is limited in its scope by the Sourcing Tariff – limited to inputs to the cost of service Template.

The Law also provides that the Commission may rule on the justness, reasonableness, and prudence of the inputs to the formula rate at least once every three years going forward. The Sourcing Tariff currently does not have a provision that allows such a review. Tenaska has stated that they believe that this is a requirement handed down by the General Assembly to the Commission and, therefore, it does not belong in the Sourcing Tariff. However, Tenaska has stated they will provide a reference to this requirement of the Law in the Sourcing Tariff.[60] It is important– with Illinois ratepayers bearing the full cost and risk of Taylorville – that an explicit provision be added to the Sourcing Tariff so that there is no doubt of the Commission's ability to rule on prudence going forward.

D. No Effective Cost Limit

At first glance, the Law appears to include a cost limit on how much of its costs (its "revenue requirement") Tenaska can pass through to Illinois ratepayers each year. This would provide some limits on the price ratepayers would pay, and if the cap was reasonable, would provide some assurance that the price of the power purchased from Taylorville would be "affordable." However, in the final analysis, we see no effective cost limit in the Sourcing Tariff.

To see this, understand that the cost limit specified in the Law applies only to electric utilities – not to alternative retail electric suppliers. Further, when the cost limit is applied to the electric utilities, rather than cut the price per MWh paid by those electric utilities, it cuts the number of MWh they are required to buy. Finally, as the initial clean coal facility under the Law, Tenaska can sell to the alternative retail electric suppliers the MWh that it cannot sell to the electric utilities when the cost limit applies.[61] In this sense, then, the cost limit in the Law really does not limit the costs Tenaska can pass through to Illinois electricity consumers when consumers are defined as the customers of both the electric utilities and the alternative retail electric suppliers.

It is not completely clear, but it appears that Tenaska does have the option to defer excess costs to later years for its electric utility customers rather than make the alternative retail electric

[59] Law at Section 1-75(d)(4)(iv).
[60] Tenaska Response to Staff Information Request at page 4.
[61] Law at Section 16-115(d)(5)(iv)(1).

suppliers pay. However, this appears to be a matter of choice for Tenaska, and, as Tenaska states, would be subject to annual and aggregate deferral limits.[62]

While the apparent cost limit is not really a limit, it is worth discussing it because it reveals the extent of the potential premium Illinois ratepayers may be asked to pay to Tenaska for this initial clean coal facility.

Under the draft Sourcing Agreement, here are the steps we understand Tenaska has to take to implement the cost limit for electric utilities.[63] In simple terms, the first step for Tenaska each year is to project for the upcoming year what costs it wants to pass through – this is called the Projected Annual Revenue Requirement. It then compares this revenue requirement to what it would have earned by selling into the day-ahead energy market in PJM or the Midwest Independent Transmission System Operator in the preceding year. If the Projected Annual Revenue Requirement exceeds the market revenue, Tenaska can cover the excess in two ways. It can pay for the excess by crediting against it the revenue it made by selling things like by-products. And, much more importantly, it can get what is best seen as a premium allowed under the Law. With the option Tenaska seems to have chosen, the premium works like a tax on every other MWh sold in Illinois. Specifically, Tenaska gets to pass through to Illinois ratepayers an amount equal to $2.38 for every MWh sold by Commonwealth Edison in the preceding year. The $2.38 per MWh is calculated according to the Law – it is 2.015% of the total retail price – not just the price for energy, but the *total delivered price* – paid by Commonwealth Edison ratepayers in 2009. Tenaska shows this 2009 full, delivered price to be $118.09 per MWh and 2.015% of that is about $2.38 per MWh.[64] The comparable calculation for Ameren yields $2.17 per MWh. The weighted average is $2.32/MWh assuming sales for Commonwealth Edison are 40 million MWh and those for Ameren are 16 million MWh.

It is not for us to say that the premium is good or bad, but we would suggest that the premium be explicitly stated rather than being implied by the cost limit language. Moreover, we would suggest that a real cost limit be imposed in the form of pay-for-performance pricing. This would help serve the goals of the Law to provide electric service that is "affordable."

E. Illinois Ratepayers Have Unlimited Liability for CO_2 Offsets

The Law states that a "Clean Coal Facility" is a facility that "captures and sequesters…at least 50% of the total carbon emissions that the facility would otherwise emit."[65] If the 50% is not achieved (or previously sequestered CO_2 escapes), Tenaska must buy CO_2 offsets to compensate. However, Tenaska's liability for offsets is limited to $15 million per year.[66] We have no problem with the limit for Tenaska. Our concern is that there is no limit for Illinois ratepayers. We are concerned that Illinois ratepayers must keep purchasing power from Tenaska no matter how poorly its carbon capture and sequestration system works. This means that, if there is Federal regulation of CO_2 in place, Illinois ratepayers would have to bear the risk for

[62] Tenaska Response to Staff Information Request at page 1.
[63] For Example, see Sourcing Tariff at Attachment A, Schedule CEL-2.
[64] Sourcing Tariff at Attachment A, Schedule CEL-1.
[65] Law at Section 1-10.
[66] Sourcing Tariff at Section 5.01.

offset prices over and above the $15 million paid by Tenaska. The Law and the Sourcing Tariff do allow the Attorney General rights to step in to enforce the 50% requirement, and the Illinois Commerce Commission is permitted to reduce the allowable return on equity if Taylorville *willfully* fails to comply with capture and sequestration requirements. It is unclear how much leeway the term *willfully* provides Tenaska.

A better approach is to allow the Sourcing Tariff to be terminated if the Commission finds that it is not prudent to continue to allow Tenaska to run Taylorville if it fails to achieve the 50% reduction in CO_2 emissions. After all, limiting CO_2 emissions through clean coal technology is the entire purpose of the Taylorville effort, and surely there must be an incentive to serve that purpose.

We will discuss the 50% reduction in the Task 4 Report. We do note, however, that the carbon capture requirement in the Sourcing Tariff is slightly different from that in the Law. As mentioned above, the Law states that Tenaska must capture and sequester 50% of the carbon emissions that would otherwise be emitted from Taylorville. The Sourcing Tariff includes this same language but has added a clause stating that this is the case "assuming SNG [substitute natural gas] production in the gasification/methanation island is equal to methane consumption in the Power Block ("Carbon Capture")."[67] The purpose of this additional phrase is not clear to us, and raises at least two potential concerns.

First, this additional provision would allow carbon emissions released during times that the facility was being powered by natural gas (rather than substitute natural gas) to be excluded from the calculation of the 50% carbon reductions. Limits on the operation of the facility on the "backup" natural gas would seem appropriate to address this concern.

A second concern is that it would remove the requirement of capturing and sequestering carbon emissions for the portion of substitute natural gas above and beyond what is used in the power block; that is, for the production of substitute natural gas that is sold to the market. Consider a scenario where the power facility portion of the Clean Coal Facility was not operating, the synthetic natural gas portion of the facility was fully operational delivering its full capacity to natural gas customers, and electricity is imported from the transmission grid. Since no substitute natural gas is being sent to the Clean Coal Facility's power block, the requirement for carbon capture would be lifted.

The Law also contains requirements that limit the emission of other pollutants. Specifically, the Law states, "The power block of the clean coal facility shall not exceed allowable emission rates for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury for a natural gas-fired combined-cycle facility the same size as and in the same location as the clean coal facility at the time the clean coal facility obtains an approved air permit."[68] Although we do not see a specific provision in the Sourcing Tariff, we assume that Tenaska would point to its required air permit for compliance. We discuss this in our Task 4 Report.

[67] Ibid.
[68] Law at Section 1-10.

F. Use of a Deemed Rather Than an Actual Cost of Capital

The Law allows Tenaska to use a "deemed" as opposed to an "actual" cost of capital in the calculation of the rates it can charge Illinois ratepayers. [This is one more reason Taylorville would not be paid true cost of service rates.] Specifically, Tenaska can deem that it used 55% debt and 45% equity to finance Taylorville. The Law also states that the return on that deemed equity will not be higher than 11.5%.[69]

A problem occurs because the Law also requires that Tenaska pass through the benefit of any support from the Federal Government. We understand that Tenaska has applied for a loan guarantee from the U.S. Department of Energy. If it gets that loan guarantee, its actual cost of capital may be quite different from that deemed in the Law. For example, debt might be used for up to 80% of the financing – not the deemed 55%. Further, the cost of that debt may be very low and the term of the debt might be very long. All of this means that, because of Federal support, the actual cost of capital has the potential to be lower than that deemed in the Law.

The problem arises from an internal inconsistency in the Law. Our remedy goes back, once again, to pay-for-performance features. High debt – 80% or more of the capital structure – is not unusual in pay-for-performance contracts and the result is that the actual return on equity can be 20% or more. Higher equity returns might be more appropriate if they are earned by taking risks off of the shoulders of Illinois ratepayers. Therefore, use of the deemed capital structure gives even more support for the use of the pay-for-performance features we have discussed in this Section.

G. Illinois Must Take on Debt and CO_2 Risk if Ownership of Taylorville is Transferred to the Illinois Power Agency

The Law gives the Illinois Power Agency the right to assume ownership of Taylorville at the end of its 30-year power sales agreements. The Law states that the assumption is to be done "without monetary consideration."[70] The Sourcing Tariff, however, implies that the Agency would have to both (a) take on the burden of remaining debt and (b) bear the risk of sequestered CO_2.[71] It is not clear that either provision complies with the Law.

H. Summary Compliance Checklist

Since the requirements of the Law are so wide ranging (and dispersed in the Law itself), we thought it would be helpful to list the major requirements in the Law, and to check Taylorville's compliance. The table below is a summary compliance checklist that highlights the important requirements of the Law.

Some caveats are necessary. Note in particular that a separate checklist on the many documents required by the Law is provided in Section III. Note also that, while including the

[69] Law at Section 1-75(d)(3)(A)(i).
[70] Law at Section 1-75(d)(3)(D)(iv).
[71] Sourcing Tariff at Section 13.01.

requirements in the Sourcing Tariff is necessary for compliance, it is not sufficient for compliance. For example, engineering documents would be needed to show compliance with the requirement that carbon emissions are reduced by 50%.

Table One

COMPLIANCE CHECKLIST FOR MAJOR REQUIREMENTS OF THE LAW	YES	NO	STILL AT ISSUE
A. Broad Requirements			
1. Encourage use of advanced clean coal technologies			√
2. Provide adequate, reliable, affordable, efficient, and environmentally sustainable electric service			√
B. Meet Definition of Clean Coal Facility			
1. Illinois coal as primary feedstock			√
2. Capture and sequester 50% of carbon emissions	√		
3. Sequester in acceptable, permanent storage	√		
4. Power block emissions same as gas-fired combined cycle	√		
5. 500-MW nameplate capacity			√
C. Assure Price Does Not Exceed Limits			
1. Electric utilities and alternative retail electric suppliers must sign sourcing agreement	√		
2. Cost limit imposed for electric utilities	√		
3. No cost limit for alternative retail electric suppliers	√		
4. Right to choose power purchase agreement or contract for differences	√		
D. Cost of Service Approach			
1. Levelized or deferred capital revenue requirement	√		
2. Deemed capital structure of 45% equity and 55% debt	√		
3. Equity return no higher than 11.5%	√		
E. Non-Price Terms and Conditions			
1. Net revenue credited	√		
2. Federal and State support credited			√
3. Electric utilities pay contract price	√		
4. Power delivered to regional transmission organization	√		
5. Sourcing Agreements be "pre-existing"	√		
6. Term not greater than 30 years	√		
7. Ownership transferred to Illinois Power Agency without monetary consideration			√
8. Buy offsets to compensate if 50% carbon capture and sequestration not achieved or CO_2 escapes	√		
9. Cap offset costs at $15 million per year	√		
10. Include customary lender requirements			√
F. Approvals			
1. General Assembly			√
2. Illinois Commerce Commission Review of Prudence and reasonableness			
a) Initial review in 2010			√
b) Ongoing review at least every three years			√

III. PROVIDING THE DOCUMENTS REQUIRED BY THE LAW

The Law requires that Tenaska provide a Facility Cost Report.[72] Further, the Law dictates that certain documents are required as part of the Facility Cost Report, and also requires that certain line items be included for the cost quotes required in the Facility Cost Report. A complete checklist of documents required by the Law is shown in Table Two below. All documents have been checked-off on this checklist because the information has been made available.

[72] Law at Section 1-75(d)(4)(i).

Table Two

TENASKA FACILITY COST REPORT COMPLIANCE CHECKLIST

	Document Received or Requirement Satisfied
√	Facility Cost Report from Kiewit/Burns & McDonnell
√	Includes a capital cost estimate for the core plant (4)(A)(i)
√	Based on one or more Front-End Engineering Design Studies for gasification island and related facilities (4)(A)(i)
	“Core plant” includes the following components (4)(A)(i):
√	Civil Systems
√	Structural Systems
√	Mechanical Systems
√	Electrical Systems
√	Control Systems
√	Safety Systems
√	Includes a capital cost estimate for the balance of the plant (4)(A)(ii)
	“Balance of the plant” includes the following components (4)(A)(ii):
√	Costs associated with sequestration of CO_2
√	Transmission infrastructure
√	Construction or backfeed power supply
√	Pipelines to transport substitute natural gas or CO_2
√	Potable water supply
√	Natural gas supply
√	Water supply
√	Water discharge
√	Landfill
√	Access Roads
√	Coal Delivery
√	All other interconnects and interfaces required to operate the facility
√	Construction costs expressed in nominal dollars as of the date of the quote’s preparation (4)(A)
	Construction costs include the following components (4)(A):
√	Capitalized financing costs during construction
√	Taxes, insurance, and other owners’ costs
√	Assumed escalation in materials and labor
√	Front-End Engineering Design Study for the Gasification Island from Kiewit/Burns & McDonnell
	Includes the following components (4)(B):
√	Sufficient design work to permit quantification of major categories of materials
√	Sufficient design work to permit quantification of necessary commodities
√	Sufficient design work to permit quantification of necessary labor hours
√	Quotes from vendors of major equipment
√	Cost Study for the Balance of Plant from WorleyParsons
	Includes the following components (4)(B):
√	Sufficient design work to permit quantification of major categories of materials
√	Sufficient design work to permit quantification of necessary commodities
√	Sufficient design work to permit quantification of necessary labor hours
√	Quotes from vendors of major equipment
√	Receive the Method of Financing (4)(i)

TENASKA FACILITY COST REPORT COMPLIANCE CHECKLIST

<u>Document Received or Requirement Satisfied</u>

√	Delivered Fuel Cost Estimate from Wood Mackenzie
	Includes the following components:
√	Taxes
√	Insurance
√	Other owners' costs
√	Assumed escalation in materials and labor
√	Expressed in nominal dollars as of the date that the quote is prepared
√	Balance of Operating and Maintenance Cost Quote from Siemens Power Generation, Inc.
	Includes costs from
√	Personnel
√	Maintenance Contracts
√	Chemicals
√	Catalysts
√	Consumables
√	Spares
√	Other fixed and variable operations and maintenance costs
	Includes
√	Taxes
√	Insurance
√	Other owners' costs
√	Assumed escalation in materials and labor
√	Expressed in nominal dollars as of the date that the quote is prepared
√	Analysis of Facility's Ability to Deliver Power and Energy into Applicable Regional Transmission Organization Markets from the Midwest Independent Transmission System Operator or PJM
√	Analysis of Facility's Expected Capacity Factor from Pace Global Energy

IV. VETTING THE QUALIFICATIONS OF TAYLORVILLE'S VENDORS AND CONSULTANTS

The Law requires that Taylorville use qualified vendors and consultants to develop its project and all the required documents.[73] The vendors/consultants that are responsible for portions of the Taylorville facility design and Facility Cost Report are presented in Table Three. MPR vetted the vendors/consultants' qualifications by reviewing the qualification packages provided by Tenaska. MPR received qualification packages for Kiewit and Burns & McDonnell, Pace Global Energy Services, Wood Mackenzie, and WorleyParsons. The qualification packages included corporate experience for each vendor/consultant that detailed specific experiences as it applies to the Taylorville Energy Center project. The packages from Kiewit and Burns & McDonnell and WorleyParsons included numerous resumes that showed the breadth and depth of personnel experience at these companies. Where qualification packages were not provided, MPR evaluated company information available from their websites. MPR assessed each vendors/consultants' qualifications based on the extent of relevant corporate experience and the applicable experience and credentials of personnel.

All of the vendors/consultants are reputable, industry-recognized firms with significant experience providing the services needed for the Facility Cost Report. For example, a key consultant is Burns & McDonnell who is preparing the Front-End Engineering Design Study documents, which represent a large portion of the Facility Cost Report. Burns & McDonnell has been in business for over 100 years, has annual revenues over $850 million, and over 3,000 employees. Burns & McDonnell plans, designs, permits, constructs, and manages facilities all over the world. Their project experience includes Front-End Engineering Design Study work for a similar gasification facility, Cash Creek Generating Station, and pre-Front-End Engineering Design Study work for a gasification facility in Pennsylvania. Their statement of qualifications package includes resumes for fifteen personnel including engineers, cost estimators, and procurement specialists. These persons have an average experience of 25-years, and nine of the proposed staff are licensed professional engineers.

Another key vendor, WorleyParsons, is serving as the Owner's Engineer for the project. WorleyParsons has responsibility to integrate the work provided by several consultants into the overall Facility Cost Report. WorleyParsons has more than 100 years of experience and has over 20,000 employees. Their qualification package included more than 50 examples of Owner's Engineering projects.

The responsibilities of the remainder of the vendors/consultants and specific relevant experience is presented in Table Three. One of the vendors, Siemens, is providing an estimate that is somewhat outside of their core experience. Siemens is a large company that is deeply involved in the power industry, including providing operations and maintenance services under contract to plant owners worldwide. Their experience operating gasifiers includes two facilities in Europe; Schwarze Pumpe and Freiberg, Germany. They are also the vendor for the critical gasification island components as well as the combustion turbine and associated auxiliaries. From these perspectives they should be considered qualified to perform their assigned scope of work in providing an operations and maintenance cost estimate. However, we note that their

[73] Law at Section 1-75(d)(4)(A).

experience with operations and maintenance of Integrated Gasification Combined Cycle and SNG facilities is limited. Further there is limited actual operating experience worldwide with the Siemens gasifier and in operating SNG facilities in general. Therefore, while we consider Siemens to be qualified in this area, we also believe that there is considerable uncertainty in their operations and maintenance cost estimate.

Table Three
Qualification of Vendors and Consultants for Tenaska

Vendor/Consultant	**Responsibility**	**Relevant Experience**	**Comments**
Kiewit/Burns & McDonnell	- Front-End Engineering Design Study preparation - Engineering, Procurement, and Construction*	- Significant engineering, procurement and construction experience, including at Cash Creek Generation (a gasification project) - Pre-Front-End Engineering Design Study work for gasification facility in Pennsylvania - Conceptual Engineering for Synthetic Natural Gas facility - Engineering for expansion of Coffeyville gasification facility	- Front-End Engineering Design Study includes Plant Design Report
Pace Global Energy Services	- Analysis of Facility's Expected Capacity Factor	- Market assessment experience across wide-spread clientele in the fuels, energy, and power sectors	- Capacity Factor Analysis includes: Busbar Cost of Power Study, Rate Impact Analysis
Schlumberger Carbon Services	- Assessment of Site for Geological Sequestration in Mount Simon Formation	- Global experience in all phases of carbon sequestration	
Siemens Power Generation, Inc.	- Balance of Operating and Maintenance Cost Quote - Equipment Supplier*	- National and international experience developing, constructing, and providing operations and maintenance services to.power plants - Limited experience operating and maintaining gasification facilities	- Cost Quote includes: Process Design Package, Basic Engineering Design Package

Vendor/Consultant	Responsibility	Relevant Experience	Comments
Tenaska Operations Inc.	- Operations and Maintenance of the Constructed Facility*	- Tenaska Operations Inc. has extensive experience operating combined cycle facilities but not gasification facilities	- Tenaska Operations Inc. lacks experience in operations of gasification facilities. Tenaska plans to recruit talent from other facilities, contract additional help when necessary, and rely heavily on vendor's Technical Field Assistants during the initial years of operations.
Wood Mackenzie	- Fuel Cost Estimate	- Consulting and research experience in coal, power, and gas both nationally and internationally	- Fuel Cost Estimate is part of the Operations and Maintenance Cost Quote
WorleyParsons	- Owner's Engineer	- Over 50 projects serving as Owner's Engineer - Long history of Engineering/ Procurement/ Construction work in gasification/power industry, both nationally and internationally	- Owner's Engineer role includes: ▪ Facility Cost Report Assembly ▪ Cost Study for Balance of Plant

* Activities that are not required for development of the Facility Cost Report (required by the Law), but are required to successfully construct and operate the project.

APPENDIX A: TENASKA'S RESPONSE TO BOSTON PACIFIC'S INFORMATION REQUEST ON THE LAW

INFORMATION REQUESTS TO TENASKA CONCERNING COMPLIANCE WITH THE ILLINOIS POWER AGENCY ACT'S CLEAN COAL PORTFOLIO STANDARD (SUBMITTED ON 9-11-09)

Part One: Questions on how Tenaska intends to contribute to the goals of the Act

The Illinois Power Agency Act ("the Act") lays out its findings and declarations in 20 ILCS 3855, Section 1-5, including the following:

> "(1) The health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.
> […]
> "(8) The State should encourage the use of advanced clean coal technologies that capture and sequester carbon dioxide emissions to advance environmental protection goals and to demonstrate the viability of coal and coal-derived fuels in a carbon-constrained economy."

1. Please demonstrate, using specific evidence, how Taylorville intends to contribute to each of the Act's goals of providing electric service that is:
    a. Adequate
    b. Reliable
    c. Affordable
    d. Efficient
    e. Environmentally sustainable
    f. All provided at the lowest cost over time, taking into account any benefits of price stability

    The Taylorville Energy Center ("TEC") will contribute to (a) adequacy and (b) reliability of electric service by increasing both the baseload supply and the dispatchable supply of electric energy in Illinois with a generating facility that is expected to achieve availability of over 90%. The project will contribute to (c) affordability and to (f) providing electric service at the lowest cost over time by (i) reducing consumers' market exposure to volatile natural gas prices and high carbon allowance prices, (ii) mitigating market prices for both energy and capacity by adding generating supply to the market [Note - Pace will provide a study estimating the extent of these market benefits to electric consumers], and (iii) deferring capital recovery to the extent necessary (within some limits to be imposed by TEC's lenders) to avoid having a rate impact on utility customers greater than the "cost effective limit" as defined in the Illinois Clean Coal Portfolio Standard Law ("ICCPSL"). The TEC will contribute to (d) efficiency and (e) environmental sustainability of electric service by using coal from sources in Illinois to produce energy in an efficient modern combined cycle generating facility in a way that is substantially as clean as natural gas generation.

2. Please demonstrate, using specific evidence, how the Taylorville project:
    a. Uses advanced clean coal technology that captures and sequesters carbon dioxide
    b. Advances environmental protection goals
    c. Demonstrates the viability of coal and coal-derived fuels in a carbon constrained economy.

    As will be shown in detail in the FEED study and Facility Cost Report, the TEC will employ technology that will convert coal to methane in processes that separate out for capture and sequestration at least 50% of the CO2 that would otherwise be emitted. Some or all of the methane will then be used to generate electricity in an efficient gas-fired combined cycle power block which will meet or exceed applicable Clean Air Act standards for natural gas fired generation.. The captured CO2 will be sequestered either in an enhanced oil recovery application or geologically. These steps will demonstrate that Illinois coal can be used as a plentiful fuel for electric power in a way that emits far less carbon than other types of coal-fired power generation. We will also provide an analysis showing that the net effect of the TEC will be a decrease in net CO2 emissions as a result of energy from the TEC displacing energy that would have been generated by higher emitting sources.

Part Two: Questions on how Taylorville intends to meet the Act's qualifications as a Clean Coal Facility

According to paragraph (3) of the Act's Clean Coal Portfolio Standard (20 ILCS 3855, Section 1-75, sub-section (d)), in order to qualify as the initial clean coal facility, Taylorville must "meet the definition of clean coal facility in Section 1-10 of this Act when commercial operation commences." [sic] That definition states:

> ""Clean coal facility" means an electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon emissions at the following levels: at least 50% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation before 2016, at least 70% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation during 2016 or 2017, and at least 90% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation after 2017. The power block of the clean coal facility shall not exceed allowable emission rates for sulfur dioxide, nitrogen oxides, carbon monoxide, particulates and mercury for a natural gas-fired combined-cycle facility the same size as and in the same location as the clean coal facility at the time the clean coal facility obtains an approved air permit. All coal used by a clean coal facility shall have high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content, unless the clean coal facility does not use gasification technology and was operating as a conventional coal-fired electric generating facility on the effective date of this amendatory Act of the 95th General Assembly."

Furthermore, the Act defines "sequester" as follows.

> ""Sequester" means permanent storage of carbon dioxide by injecting it into a saline aquifer, a depleted gas reservoir, or an oil reservoir, directly or through an enhanced oil recovery process that may involve intermediate storage in a salt dome."

3. Please demonstrate, using specific evidence, that Taylorville will use as its primary fuel coal which has
    a. High volatile bituminous rank
    b. Greater than 1.7 pounds of sulfur per million Btu

The Delivered Fuel Price Study that will be provided as part of the Facility Cost Report will demonstrate that Illinois coal has the characteristics described in the statute (ie high-volatile bituminous coal containing > 1.7 lb S/MMBtu). The Illinois Basin coal seams extend into Indiana and Western Kentucky. However, it would not be economic to transport coal from Indiana or Western Kentucky given the TEC sits in the middle of the Illinois coal fields. Furthermore, the requirement that TEC obtain fuel on a prudent basis would be inconsistent with incurring transportation costs to import coal from out of state. The FEED study will confirm that the TEC is designed to use coal with the characteristics indicated in the statute.

4. Please provide the following information:
    a. On what date is construction of the Taylorville project expected to commence?
    b. On what date is commercial operation scheduled to be achieved?
    c. What are the "carbon emissions that the facility would otherwise emit" (per MWh and in total tons per year)? Please describe the concept in words and show any and all calculations.

a. Our best case financial closing date and commencement of construction date is December 31, 2010. (There may be preliminary site activities that could constitute "commencement of construction" before financial closing. However, a full notice to proceed for construction will not be given before financial closing.) This date depends upon various factors, including timely action by FERC, the IEPA, the Illinois General Assembly and the Commission.
b. The expected construction period is forty-eight months after a full notice to proceed, with December 31, 2014 being the expected commencement of commercial operation date (based on a December 31, 2010 commencement of construction).
c. [INFORMATION ON THE TEC CARBON BALANCE IS BEING UPDATED AND WILL BE PROVIDED SOON]

5. Please demonstrate, using specific evidence, that the carbon dioxide captured from the plant will be stored permanently in either a saline aquifer, a depleted gas reservoir, or an oil reservoir (including use in enhanced oil recovery).

We have provided a copy of the executed agreement between Christian County Generation, L.L.C. ("CCG") and Denbury Resources for the sale of TEC's captured CO2 for sequestration in an enhanced oil recovery application. Denbury's obligation to build the contemplated CO2 pipeline is contingent upon the satisfaction of conditions that are outside of CCG's control. Accordingly, CCG is proceeding with the development of its own sequestration field near the TEC site. We have provided or will provide contracts under which Schlumberger is performing site characterization and reservoir modeling for this sequestration field and under which the Illinois Department of Commerce and Economic Opportunity has agreed to use its quick take, eminent domain authority to acquire pore space and easement rights if necessary to support the development of the sequestration field. CCG is also exploring other options for transporting CO2 by rail to enhanced oil recovery sites, if necessary, to support its commitment to capture and sequester at least 50% of the CO2 that would otherwise be emitted.

6. Please provide, using specific evidence, Tenaska's estimate of the rate of pollutant emission from a natural gas combined-cycle facility in the same location as the Taylorville plant, in pounds per million BTU of fuel consumed, for the following pollutants
    a. Sulfur dioxide
    b. Nitrogen oxides
    c. Carbon monoxide
    d. Particulate matter
    e. Mercury

   This will be provided as part of the best available control technology ("BACT") analysis that will be included in the air permit modification request that CCG expects to file in December or January.

7. Please demonstrate, using specific evidence, that emissions from the Taylorville plant will be no greater than those provided for each pollutant listed in question 6 above.

   This will be demonstrated as part of the BACT analysis that will be included in the air permit modification request that CCG expects to file in December or January.

Part Three: Questions on how Tenaska interprets some of the chief provisions in the Law

For each of the following issues, please (i) provide Tenaska's interpretation of the Act, and (ii) justify those interpretations with references to specific language in the Act. Except where otherwise noted, all citations to the Law herein refer to the Clean Coal Portfolio Standard (20 ILCS 3855, Section 1-75, sub-section (d), hereafter "sub-section (d)").

8. The limits, if any, on the initial clean coal facility's cost recovery through sourcing agreements with utilities, as described in paragraph (2) of subsection (d).

    We do not believe that paragraph (2) of subsection (d) imposes a limit on cost recovery, but rather that this paragraph imposes a limit on the amount of energy that the utilities are required to buy. Paragraph (2) of subsection (d) is made applicable to the utility Sourcing Agreements with the Initial Clean Coal Facility by the proviso contained in the last sentence of subparagraph (3)(B)(iii), which states "provided that the amount purchased by the utility in any year will be limited by paragraph (2) of this subsection (d)" and by subparagraph (3)(D)(vi), which requires that the utility sourcing agreements "include limits on, and accordingly provide for modification of, the amount the utility is required to source under the sourcing agreement consistent with paragraph (2) of this subsection (d)." It is the number of units purchased rather than the price per unit that is impacted, so there is no effect on cost recovery.

    This interpretation is supported by the different formulations of the amounts that must be purchased by the electric utilities, on the one hand, and the ARES, on the other hand. Under subparagraph (3)(B)(iii) of subsection (d), the amount to be purchased by an electric utility (subject to the aforementioned proviso) is "an amount of energy equal to all clean coal energy made available from the initial clean coal facility during such hour times a fraction, the numerator of which is such utility's retail market sales of electricity (expressed in kilowatthours sold) in the State during the prior calendar month and the denominator of which is the total retail market sales of electricity (expressed in kilowatt hours sold) in the State by utilities during such prior month and the sales of electricity (expressed in kilowatt hours sold) in the State by alternative retail electric suppliers during such prior month that are subject to the requirements of this subsection (d) and paragraph (5) of subsection (d) of Section 16-115 of the Public Utilities Act." There is a different requirement describing the amount to be purchased by the ARES in Section 16-115(d)(5)(iv)(1) of the Public Utilities Act: "an amount of electricity equal to all clean coal energy made available from the initial clean coal facility during such hour, *which the utilities are not required to procure under the terms of subsection (d) of Section 1-75 of the Illinois Power Agency Act* multiplied by a fraction, the numerator of which is the alternative retail electric supplier's retail market sales of electricity (expressed in kilowatt-hours sold) in the State during the prior calendar month and the denominator of which is the total sales of electricity (expressed in kilowatthours sold) in the State by alternative retail electric suppliers during such prior month that are subject to the requirements of this paragraph (5) of subsection (d) of this Section and subsection (d) of Section 1-75 of the Illinois Power Agency Act plus the total sales of electricity (expressed in kilowatthours sold) by utilities outside of their service areas during such prior month, pursuant to subsection (c) of Section 16-116 of this Act." The italicized words were added by Amendment No 5 to SB 1987 to make it clear that if the amounts purchased by utilities are reduced by application of paragraph (2) of subsection (d), these amounts would then be available for purchase by the ARES as part of their allocable shares, thereby reinforcing the interpretation that it is not the unit price, but rather the number of units, that is reduced in order for the utilities to stay within the cost effective limit.

The drafts of the Sourcing Agreements attached to the draft Sourcing Tariff include provisions consistent with this interpretation of the statute.

9. The limits, if any, on the initial clean coal facility's cost recovery through sourcing agreements with alternative retail electric suppliers, as described in 220 ILCS 5, Section 16-115, subsection (d), paragraph (5).

    None, other than limits imposed on just and reasonable rates under the Federal Power Act and the requirements for prior review of formula rate inputs as provided by subparagraph (3)(D)(vii) of subsection (d). We view the subparagraph (3)(D)(vii) as applicable to ARES sourcing agreements.

10. The limits, if any, on the amount of electricity which alternative retail electric suppliers are required to purchase from the initial clean coal facility, as described in 220 ILCS 5, Section 16-115, subsection (d), paragraph (5).

    Required purchases by the ARES from the Initial Clean Coal Facility are not subject to the "cost effective limit" constraint. In fact, as mentioned in the answer to question 8, the legislation specifically requires any amounts not purchased by the utilities to be purchased by the ARES. Purchases by the ARES from other clean coal projects in order to meet the ARES' 5% clean coal portfolio standard requirement are subject to the constraint that the price cannot be above benchmarks set by the Commission each year. (Section 16-115(d)(5)(iii) of the Public Utilities Act.)

11. The nature of the carbon dioxide sequestration requirement and offset purchase requirement described in subsection (d) paragraph (3) sub-paragraph (D) (v).

Subsection (d) paragraph (3) sub-paragraph (D)(v) describes contractual provisions that must be included in the sourcing agreement. Section 5.01 of the draft Sourcing Tariff includes these provisions. However, in connection with its application for the extension of its air permit, CCG has filed an undertaking with the IEPA committing to comply with these provisions.

12. The implications of the pro forma 55/45 Debt/Equity ratio (described in subsection (d) paragraph (3) sub-paragraph (A) (i)) for the plant's cost-of-service rates in the sourcing agreements.

    The 55/45 Debt/Equity ratio contemplates a "deemed" or "hypothetical" capital structure, so that the return on equity would be paid on 45 percent of the capital structure and the cost of debt would be paid on 55% of the capital structure.

13. The effect, if any, on the plant's cost of service rates if the actual Debt/Equity ratio differs from 55/45. For instance, say the debt share is 80% under a United States Department of Energy loan guarantee.

    The actual capital structure will not affect the plant's cost of service rates.

14. The nature of the credit against the plant's revenue requirement of all miscellaneous net revenue from the plant described in subsection (d) paragraph (3) sub-paragraph (A) (ii). In particular, please describe the nature of the credit for sales of synthetic natural gas and carbon dioxide and for government support such as a U.S. DOE loan guarantee.

    All miscellaneous net revenue such as proceeds of SNG and CO2 sales will be credited to the facility's revenue requirement in the formula rate. Tax benefits such as investment tax credits will also flow through the formula rate to reduce the revenue requirement. The proceeds of government grants will be used to pay project costs or to reimburse previous payments of project costs, thereby lowering the capital costs recovered through the formula rate. Although a guarantee does not result in net revenue and therefore is not covered by subsection (d) paragraph (3) sub-paragraph (A)(ii), consumers will benefit significantly from government guarantees in the form of the reduced borrowing cost on the 55% debt portion of the authorized capital structure.

15. The meaning of the phrase "the total carbon emissions that the facility would otherwise emit" in the carbon capture and sequestration portion of the definition of a clean coal facility in Section 1-10 of the Act.

The phrase refers to the total amount of carbon that the TEC would emit (including at the SNG island and at the power block) if CCG were venting rather than capturing and sequestering the CO2 separated in the gasification/methanation process.

16. Is the 500 MW nameplate capacity referred to in the description of the initial clean coal facility in subsection (d) paragraph (3) net of all station service requirements for the Taylorville plant? In other words, is it a gross or net capacity?

    Nameplate capacity is a gross concept. It is the nominal capacity assigned to a generating unit by an equipment manufacturer and does not take account of auxiliary loads.

17. What are the implications for the utilities in the event that the net output of the initial clean coal facility is not high enough to serve 5% of the load of the utilities' eligible retail customers, as required in subsection (d) paragraph (1)? If the 5% requirement is not met by Taylorville, will Illinois consumers have to pay both the cost of service rates to Taylorville and, in addition, pay for clean coal generation by others?

    Subsection (d), paragraph (1)(C), provides that a utility is deemed to have complied with the clean coal portfolio standard if it enters into a sourcing agreement with the initial clean coal facility. CCG was not involved in the drafting or negotiation of this language, but our interpretation is that a utility that has signed a sourcing agreement with CCG is not subject to any further obligations under ICCPSL.

18. The method by which the cost of service rates will incorporate the levelization or deferral of capital recovery described in subsection (d) paragraph (3) sub-paragraph (A) (i).

    The levelization and deferral methodology is set out in the draft of the Sourcing Tariff, including Schedule CEL to Exhibit A and Exhibit C.

19. The respective costs and benefits to Tenaska of electing in different situations that the utilities' sourcing agreements be governed by their power purchase provisions or contract for differences provisions, as such right is reserved to Tenaska in subsection (d) paragraph (3) sub-paragraph (D) (x).

    CCG expects that the Sourcing Agreements will be much easier to administer for both CCG and the Buyers if CCG operates under the contract for differences provisions, and this is what CCG currently intends to do. CCG does not see any material benefit beyond this administrative convenience, nor does CCG see a material cost. The only circumstance that we could see in which we would elect to sell physical energy to the

Buyers would be if something unexpected has happened to cause the contract for differences provisions not to mirror the economics of physical sales.

20. The meaning of subsection (d) paragraph (3) sub-paragraph (D) (iv), which states that the Act permits the Illinois Power Agency

> "to assume ownership of the initial clean coal facility, without monetary consideration and otherwise on reasonable terms acceptable to the Agency, if the Agency so requests no less than 3 years prior to the end of the stated contract term".

> This is a free option for the IPA to elect to take title to the TEC at the end of the 30 year service term, and is reflected in Section 13.01 of the draft Sourcing Tariff. It is entirely within the control of the IPA.

21. With regard to question 20 above, please specifically address
    a. The meaning of the phrase "without monetary consideration"
    b. The permissible timing of such an assumption of ownership by the Agency
    c. What kind of situations would make such an assumption beneficial to the ratepayers of Illinois but not to Tenaska
    d. What kind of situations would make such an assumption beneficial to Tenaska but not to the ratepayers of Illinois
    e. What kind of situations would make such an assumption mutually beneficial to the ratepayers of Illinois and to Tenaska
    f. What kind of situations would make such an assumption mutually detrimental to Tenaska and to the ratepayers of Illinois

a. The IPA would not pay CCG any money for the TEC.
b. The notice of election must be given by the 27th anniversary of the commercial operation date. If the IPA gives notice of its election, title would be transferred upon the 30th anniversary of the commercial operation date.
c. The assumption would benefit the ratepayers but not CCG if the TEC has positive value (taking into account any decommissioning reserve that would be transferred with the TEC) at the end of the 30 year sourcing agreement term.
d. The assumption would benefit CCG but not the ratepayers if the TEC has negative value (taking into account any decommissioning reserve that would be transferred with the TEC) at the end of the 30 year sourcing agreement term.
e. The assumption could be mutually beneficial if the TEC is worth more to the IPA than it is to TEC, which could be the case due to tax or regulatory considerations.
f. None that we can think of.

22. The meaning of the term "customary lender requirements" in subsection (d) paragraph (3) sub-paragraph (D) (xiii).

This covers provisions such as Section 14.08(c) of the draft Sourcing Tariff that we have provided and also refers to the general requirement that the Sourcing Agreement provisions support the predictability of revenue and mitigation of risks that are needed by lenders in order to provide financing. Please note that this draft has not been reviewed by our lenders' counsel, and that there may be additional customary provisions that are required.

23. The reason for the omission of other common power purchase agreement conditions from the sourcing agreements, such as a reliability guarantee, a heat rate guarantee, milestones, credit requirements, fixed-formula prices, etc.

There are many provisions that would be appropriate for a fixed price agreement that are not appropriate for a cost of service agreement. The cost of service concept is fundamental, with the model for financing the TEC being the same as the model on which most of the coal based generation in the United States was financed. A regulatory body (in this case the Illinois General Assembly) approves the plant based on estimates of capital and operating costs and the plant owner builds the plant and recovers a revenue requirement based on its cost of service, including an approved return on equity, subject to prudency oversight by a regulatory body. The ICCPSL does not contain the types of penalties and incentives that are typical for fixed price IPP contracts because such provisions are not appropriate in this context. Earlier versions of the legislation proposed by CCG contained some of the concepts that are referred to in the question, but these did not survive the legislative process.

24. The implications of the Legislature's pre-approval (referred to in subsection (d) paragraph (4) item (iii)) on the Commission review of the form of the sourcing agreements and the agreements' prudence and reasonableness (referred to in subsection (d) paragraph (4) item (iv).

We believe that the legislative approval addresses (and should be viewed as dispositive as to) the prudency of entering into the agreement based on the estimated capital cost, operating cost and performance, as well as the return on equity and the deemed capital structure. The legislature looks to the Commission to address and resolve other issues in the proposed form of sourcing tariff such as the prudency of costs incurred to build and operate the facility as approved by the legislature. In other words, we do not believe that ICCPSL contemplates that the Commission will review the prudency of building the plant envisioned by the Facility Cost Report that forms the basis for the legislative approval.

25. The applicability to the Taylorville plant of the requirements for gas utility contracts with a substitute natural gas facility, described in 220 ILCS 5, section 9-220, sub-section (h).

CCG does not intend to seek gas sales agreements pursuant to this provision, and in any case does not believe that it would be eligible to do so, given the required July 1, 2010 commencement of construction date. The NEPA EIS process required by the DOE Loan Guarantee program will not permit commencement of construction by this date.

26. Any other provisions of the Law that Tenaska believes carry important implications for the ratepayers of Illinois.

Paragraph 3(D)(ix) of subsection (d) provides that the utilities and the ARES have no liabilities under the sourcing agreements until the TEC is in commercial operation. CCG is not seeking construction work in progress (CWIP) payments or recovery of costs if the project is abandoned. Illinois ratepayers will not be impacted by the TEC until early 2015, when for the first time their bills will include amounts attributable to the TEC sourcing agreements. Many ratepayers will benefit directly or indirectly during the period prior to commercial operation from the economic activity associated with the development and construction of the project.

Note: CCG is cooperating with Boston Pacific in an effort to facilitate Boston Pacific's analysis of the TEC project and the ICCPSL on behalf of the Commission. In order to be as helpful as possible, CCG and its representatives are engaging in an open exchange of information and ideas with Boston Pacific. As part of this process, CCG has attempted to answer these information requests in a complete and open manner. However, these answers are necessarily based on the information currently available to us and our current expectations, and we do not consider the answers to be commitments beyond what is required by the ICCPSL and other applicable laws and the terms of contracts to be signed by CCG.

APPENDIX B: TENASKA'S RESPONSE TO STAFF'S INFORMATION REQUEST ON THE SOURCING TARIFF

(1) The Clean Coal Portfolio Standard Law ("Law") states that the formula rate shall "be determined using a cost of service methodology employing ***either*** a ***level*** or ***deferred capital recovery component***…."

- How are you interpreting these terms?

  WE INTERPRET THIS LANGUAGE AS PERMITTING BUT NOT REQUIRING A DEFERRED CAPITAL RECOVERY COMPONENT. WHAT IS PRECLUDED IS ACCELERATED CAPITAL RECOVERY. WE INTEND TO USE DEFERRALS WHEN NEEDED (IF AT ALL) TO AVOID EXCEEDING THE "COST EFFECTIVE LIMIT" APPLICABLE TO THE UTILITIES' ELIGIBLE RETAIL CUSTOMERS. THE AMOUNT SUBJECT TO DEFERRAL WILL BE LIMITED EACH YEAR AND IN THE AGGREGATE (SEE SCHEDULE CEL-2 TO FORM OF UTILITY SOURCING AGREEMENT). FOR EXAMPLE, IF A DEFERRAL IS NEEDED IN YEARS 1 THROUGH 3 TO STAY BELOW THIS RATE IMPACT LEVEL, THEN THIS DEFERRAL WOULD BE TRIGGERRED ONLY FOR THE NECESSARY PERIOD AND ONLY TO THE EXTENT NECESSARY TO AVOID EXCEEDING THE COST EFFECTIVE LIMIT (SUBJECT TO THE ANNUAL AND AGGREGATE DEFERRAL LIMITS). THEREAFTER THE RECOVERY OF CAPITAL (INCLUDING BOTH NORMAL CAPITAL RECOVERY AND RECOVERY ON DEFERRED AMOUNTS) WOULD BE ON A LEVELIZED BASIS.

- Do you agree that the language of the Law permits ***either*** of those two methods, but not both at the same time?

  NO, WE DO NOT THINK THE INTENT IS TO REQUIRE THAT CAPITAL RECOVERY BE EITHER LEVEL OR DEFERRED (ONE OR THE OTHER) IN ALL CIRCUMSTANCES OVER THE ENTIRE TERM. IF CAPITAL RECOVERY IS DEFERRED FOR A PERIOD FOR THE REASON DESCRIBED ABOVE, THE METHOD OF RECOVERY AFTER THE DEFERRAL HAS ENDED WOULD BE LEVEL. HOWEVER, AS STATED ABOVE, THERE WOULD NEVER BE ACCELERATED CAPITAL RECOVERY.

- Can you point us very specifically to places in your draft sourcing tariff and/or its attachments where you have incorporated either a "level capital recovery component" or a "deferred capital recovery component"?

  LEVELIZED CAPITAL RECOVERY CHARGES (FOR BOTH INITIAL CAPITAL COSTS AND ADDITIONS) ARE SET FORTH IN LINE 15 OF EACH OF WORKSHEETS A, B-1 AND B-2 OF THE FORMULA RATE TEMPLATE (ATTACHMENT C TO THE SOURCING TARIFF). AS DISCUSSED ABOVE, CAPITAL DEFERRAL IS PROVIDED FOR IN SCHEDULE CEL-2 OF ATTACHMENT A (THE FORM OF UTILITY SOURCING AGREEMENT) AND IN THE CORRESPONDING LINES OF WORKSHEET CEL-2, AS WELL AS IN LINE 4 OF WORKSHEET C OF THE FORMULA RATE TEMPLATE (ATTACHMENT C TO THE SOURCING TARIFF).

From the formulas on Line 15 (“Levelized Capital Recovery Charge”) of your capital cost recovery sheet of your Excel workbook, it appears that you are employing levelized capital recovery. Are you assuming that a “level capital recovery component” is the same thing as levelized capital recovery?

YES, WE INTERPRET LEVEL THE SAME AS LEVELIZED.

- I see that your sourcing agreement’s Schedule CEL-2 talks about a “Determination of Capital Recovery Deferral Amount.” Is this amount, in your view, related to the “deferred capital recovery component” mentioned in the Law? If not, where, specifically in the Law, do you believe you have the authority to recover Capital Recovery Deferral Amounts?

THE LAW AUTHORIZES LEVEL OR DEFERRED RECOVERY OF CAPITAL. AS DESCRIBED ABOVE, CHRISTIAN COUNTY GENERATION (“CCG”) IS ELECTING TO DEFER A PORTION OF ITS CAPITAL RECOVERY (SUBJECT TO LIMITS) TO THE EXTENT NECESSARY TO AVOID EXCEEDING THE COST EFFECTIVE LIMIT. WE BELIEVE THIS DEFERRAL IS EXPRESSLY ALLOWED BY THE STATUTE, AND THAT THE PLAIN MEANING OF “DEFERRED” IS “POSTPONED” RATHER THAN “FORFEITED”. SO CCG WOULD BE ENTITLED TO RECOVER THE DEFERRED CAPITAL AMOUNTS ON A LEVEL BASIS WHEN IT IS ABLE TO DO SO WITHOUT EXCEEDING THE COST EFFECTIVE LIMIT.

(2) There are two versions of the spreadsheet showing CEL-1, CEL-2, and CEL-3.

The first has

Provisions Applicable to Electric Utility Sales to Eligible Retail Customers

The second has

Provisions Applicable to Retail Sales Other than Sales to Eligible Retail Customers

- Why is the second version included, since there is no mention of CEL-1, CEL-2, or CEL-3 in the Form of Sourcing Agreement for ARE

ON REFLECTION WE DON’T BELIEVE THAT IT IS NECESSARY TO REFER TO THE ARES IN THIS WORKSHEET AND WILL TAKE THOSE REFERENCES OUT OF THE NEXT DRAFT. THE CALCULATION OF THE ARES’ SHARES OF ENERGY CAN BE MADE ACCORDING TO THE TERMS OF THE DRAFT ARES SOURCING AGREEMENT WITHOUT REFERENCE TO THE CEL WORKSHEET.

(3) On pages 3-4 of the Protocols, the draft states:

d. Review by ICC. Prior to the effectiveness of the Sourcing Tariff, the ICC and the Illinois General Assembly will have approved Seller's deemed capital structure and return on equity (the "Capital Structure Inputs"). Notwithstanding anything in these Protocols to the contrary:

(i) The Template shall be subject to ICC review as provided under the CCPSL[5];

(ii) If an amount in respect of an input (other than a Capital Structure Input) is deemed unjust or unreasonable and not recoverable under the Formula Rate by the ICC based on standards of prudency as applied under Illinois ratemaking principles, Seller will, after such determination becomes final and not subject to any rehearing requests or appeals and subject to any required approval by the Commission under its Federal Power Act authority, implement such determination in the next True-Up Adjustment for which Seller, as of such time, shall not have already provided the Annual Update; and

(iii) Seller does not waive its right to contest any factual determination by the ICC.

- Under item (iii), is it your intent to limit the venue for contesting any factual determination by the ICC to the ICC (e.g., request for rehearing) or might you also go to the FERC to contest a factual determination by the ICC? Please explain.

NO, THIS IS NOT OUR INTENT. OUR UNDERSTANDING OF THE ICCPSL AND ITS RELATIONSHIP TO THE FEDERAL POWER ACT IS THAT ALTHOUGH THE FERC HAS EXCLUSIVE JURISDICTION OVER THE SOURCING TARIFF, CCG WILL AGREE BY CONTRACT TO ABIDE BY THE DECISIONS OF THE ICC ON FORMULA RATE INPUTS. THE ICCPSL REQUIRES SUCH AN AGREEMENT FROM CCG IN ORDER FOR UTILITIES AND ARES TO BE REQURIED TO SIGN THE SOURCING AGREEMENT (WHICH IS PURELY A MATTER OF STATE LAW – FEDERAL LAW DOES NOT REQUIRE THE UTILTIES OR ARES TO SIGN.) WE BELIEVE THAT CCG'S RIGHT TO CONTEST A DETERMINATION OF THE ICC ON RATE INPUTS SHOULD BE THROUGH STATE COURTS. IT IS NOT CLEAR TO US THAT THIS IS PROVIDED FOR IN THE ICCPSL AS IT NOW EXISTS, SO WE MAY WANT TO SUGGEST AN AMENDMENT TO CLARIFY THAT ILLINOIS COURTS HAVE JURISDICTION OVER THIS KIND OF CASE TO THE SAME EXTENT THAT THEY WOULD HAVE JURISDICTION OVER APPEALS BY RETAIL UTILITIES FROM ICC ORDERS

(4) On pages 7-9 of the Protocols, the draft makes fairly clear that Tenaska's annual updates and challenges to those updates will be FERC jurisdictional. The ICC could be an interested party at the FERC, but not the decision maker.

- Please verify if this understanding of the Protocols is correct. If not, please explain.

  OUR UNDERSTANDING IS THAT UNDER THE FEDERAL POWER ACT, THE FERC HAS EXLUSIVE JURISDICTION. HOWEVER, AS DESCRIBED ABOVE, CCG WILL BE AGREEING BY CONTRACT TO ABIDE BY THE DECISION OF THE ICC ON INPUTS TO THE FORMULA RATE.

- If so, please explain how, in your view, this would be consistent with the IPA Act's Section 1-75(d)(3)(D)(vii), which requires:

  > Commission review: (1) to determine the justness, reasonableness, and prudence of the inputs to the formula referenced in subparagraphs (A)(i) through (A)(iii) of paragraph (3) of this subsection (d), ***prior to an adjustment in those inputs*** including, without limitation, the capital structure and return on equity, fuel costs, and other operations and maintenance costs and (2) to approve the costs to be passed through to customers under the sourcing agreement by which the utility satisfies its statutory obligations. ***Commission review shall occur no less than every 3 years,*** regardless of whether any adjustments have been proposed, and shall be completed within 9 months.

- Where in the sourcing tariff, form of sourcing agreements, or Protocols do you provide for ICC review, no less than every three years, to determine justness, reasonableness, and prudence of the inputs to the formula prior to an adjustment in those inputs?

  WE DO NOT CURRENTLY PROVIDE FOR THE REQUIREMENT THAT THE ICC REVIEW OCCUR NO LESS OFTEN THAN ONCE EVERY THREE YEARS. OUR INTERPRETATION IS THAT THIS IS A REQUIREMENT THAT THE GENERAL ASSEMBLY IS IMPOSING ON THE ICC AND THAT OUR SOURCING TARIFF DOES NOT HAVE THE AUTHORITY TO DO THIS. BUT WE CAN REFER TO THE STATUTORY REQUIREMENT FOR A REVIEW NO LESS OFTEN THAN ONCE EVERY THREE YEARS.

- Assume that such a review were to take place three years after start-up, and the ICC finds that some of the inputs to the formula (perhaps including the capital structure and return on equity, fuel costs, or other operations and maintenance costs) were not just, reasonable, or prudent, and the ICC orders Tenaska to reduce its rates. Please describe how this type of process is anticipated in the sourcing tariff, sourcing agreements, and Protocols. Please describe what steps, if any, Tenaska or others would need to take in order to ensure that such a process would remain subject to ICC rather than FERC jurisdiction.

WE THINK THAT THE CAPITAL STRUCTURE IS FIXED BY THE ICCPSL AND IS NOT SUBJECT TO CHANGE AFTER THE ASSUMED APPROVING ENACTMENT BY THE GENERAL ASSEMBLY. THE RETURN ON EQUITY IS SUBJECT TO THE APPROVAL OF THE GENERAL ASSEMBLY IN ITS APPROVING ENACTMENT, AND WE ALSO INTEND TO SEEK ICC APPROVAL OF THE RETURN ON EQUITY FOR THE ENTIRE TERM OF THE SOURCING AGREEMENTS. THE REASON IS THAT THE INVESTORS AND LENDERS IN THIS SINGLE ASSET PROJECT WILL NEED TO KNOW THE TERMS OF THEIR INVESTMENT FOR THE CAPITAL RECOVERY PERIOD, AND NOT BE SUBJECT TO HAVING THOSE TERMS CHANGED AFTER THE INVESTMENT IS MADE. THIS WILL BE FURTHER EXPLAINED IN THE TESTIMONY THAT WE WILL INCLUDE WITH OUR FERC FILING. WE RECOGNIZE THAT A CHANGE IN THE ICCPSL MAY BE NECESSARY IN ORDER TO CLARIFY THAT THE APPROVAL OF THE RETURN ON EQUITY IS FOR THE LIFE OF THE SOURCING AGREEMENTS.

THE PRUDENCY OF CAPITAL COST, FUEL AND OTHER O&M INPUTS WOULD BE DETERMINED BY THE ICC IN ACCORDANCE WITH ITS OWN PROCEDURES, ALTHOUGH INTERESTED PARTIES ARE ALSO FREE TO CONTEST COSTS BEFORE THE FERC AS WELL. BECAUSE FERC HAS EXCLUSIVE JURISDICTION OVER THE CONTRACT, WE WILL HAVE TO FILE THE COSTS (WITH ANY REDUCTION MANDATED BY THE ICC) WITH THE FERC IN ORDER TO IMPLEMENT THE ICC DETERMINATION.

OUR THINKING ON HOW BEST TO ACCOMODATE THE ICC'S REVIEW PROCESS (WHICH WILL TAKE PLACE AT LEAST ONCE EVERY THREE YEARS) IS THAT ALTHOUGH WE WOULD EXPECT THAT THE ICC WOULD PARTICIPATE IN THE STAKEHOLDER RESOLUTION PROCESS CONTEMPLATED BY THE PROTOCOLS IN THE SAME WAY THAT THE ICC NOW PARTICIPATES IN THE SIMILAR PROCESS FOR COMED'S TRANSMISSION TARIFF, THE ICC WOULD ALSO REVIEW FORMULA RATE INPUTS IN ITS OWN PROCEEDING. WE WOULD SPECIFICALLY PROVIDE IN THE SOURCING TARIFF THAT IF THE ICC DISAPPROVES AN INPUT THEN AFTER EXHAUSTING WHATEVER CONTEST PROCEDURES ARE AVAILABLE UNDER ILLINOIS LAW, CCG WOULD IMPLEMENT THE ICC DECISION WITH RETROACTIVE EFFECT IN ITS NEXT ANNUAL UPDATE FILED PURSUANT TO THE TARIFF.

(5) With respect to the formula rate template workbook file that you provided to us, would you please provide a version that, instead of zeros, has your current estimates of the various inputs? (We understand that these would be very preliminary and in no way binding, but we would give it confidential status in any event).

WE ARE WORKING ON POPULATING THE TEMPLATE WITH AN EXAMPLE, AND HOPE TO BE ABLE TO FORWARD THIS WITHIN A FEW DAYS.

APPENDIX C: QUALIFICATION PACKETS FOR TENASKA CONSULTANTS

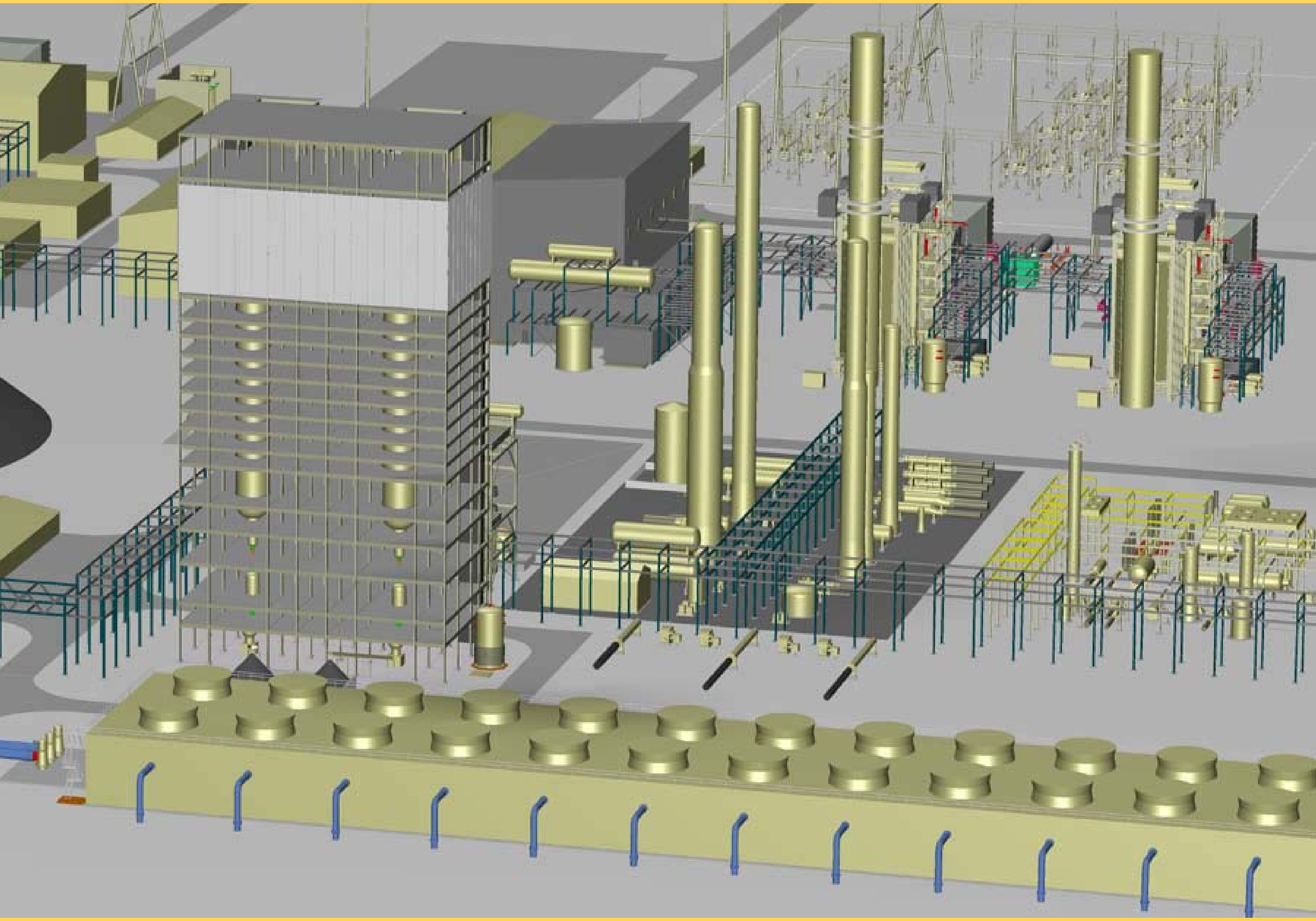
QUALIFICATIONS PACKET: KIEWIT/BURNS & MCDONNELL

Proposal to Provide Engineering and Construction Services for Taylorville Energy Center

Submitted to: Tenaska on behalf of Christian County Generation, LLC

Submitted by: Kiewit/Burns & McDonnell

November 21, 2008



1.0 Introduction

November 21, 2008

Mr. Steven J. Brewer
Tenaksa
1044 N. 115th Street, Suite 400
Omaha, Nebraska 68154
Phone: 402 691 9500

Re: Christian County Generation - Taylorville Energy Center Project
Evaluation Report

Dear Steve,

Kiewit and Burns & McDonnell are pleased to provide this Evaluation Report for the Christian County Generation –Taylorville Energy Center Project. Building on our past service for both Tenaska as well as the Taylorville Project, Kiewit and Burns & McDonnell are pleased to have this opportunity to serve as a potential partner for the design and construction of this clean-coal SNG and power facility.

The attached report has been prepared in response to your July 25, 2008 Request for Evaluation Report. We understand this report will be used by Tenaska to evaluate potential EPC partners for the preparation of the Facility Cost Report and Plant Design Report. These reports are to be completed by January 2010 for submission to the Illinois Power Agency and Illinois Commerce Commission to obtain final legislative approval and funding for the project, currently expected in 2010, as well as serve as the foundation for our EPC Contract for the implementation of the project.

Although the current Taylorville facility configuration represents an arrangement which is unique and uncommon in the current North American energy industry, both Kiewit and Burns & McDonnell have significant past project experience in the front-end design and construction planning, estimating and development of Gasification projects. Our team also has extensive detailed design and construction experience with the majority of the individual systems and equipment that will comprise this facility. A brief summary of our team's collective experience is attached within this document.

Our team's most recent project experience includes the Cash Creek Generating Station. We have been contracted by Cash Creek Generation, LLC to perform, and are currently executing the Pre-Finance Engineering Phase of this project, which is currently scheduled to be completed in July, 2009. If our team is selected as the successful bidder for this project, we request that Christian County Generation consult with Cash Creek Generation regarding the sharing of intellectual property between the two projects in order to fully leverage our team's unique experience.

Burns & McDonnell Gasification Technologies

Kiewit

We are ready to work with Tenaska to implement this project with a dedicated team of power generation and gasification engineering, project management and construction professionals that have the skills and resources to make this project a success. We look forwarding to meeting with you to discuss this exciting, and groundbreaking clean-coal project.

Sincerely Yours,

Daniel H. Lumma
Vice President
Kiewit Energy Company

James Jurczak
Director of IGCC Technology
Burns & McDonnell Engineering Company

cc: Brad Kaufman
Ray Kowalik

KIEWIT ENERGY COMPANY
7906 N. Sam Houston Pkwy. West, Suite 300
(281) 517-8900 (281) 517-8909 fax

2.0 Organization

Project Organization

Plant Design Report – Key Contacts

Jeff Reid

Manager Business Development – Gasification
Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114
Direct: 816.822.3536
Cell: 816.769.2774
Email: jreid@burnsmcd.com

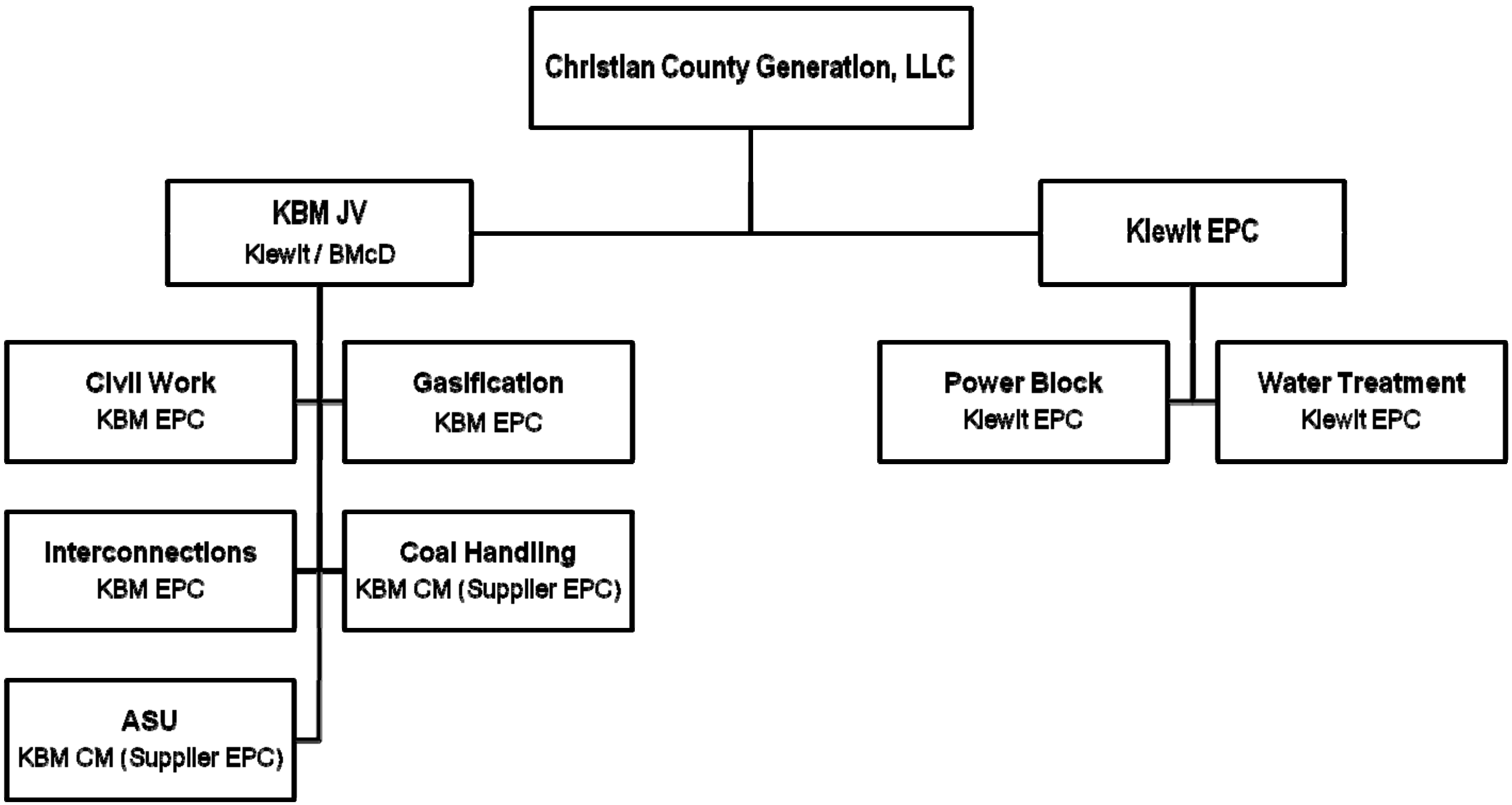
James A. Jurczak, P.E.

Director - Gasification / IGCC Projects
Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114
Direct: 816.822.3899
Cell: 816.813.1499
Email: jjurcza@burnsmcd.com

Dan Lumma

Vice President - Gasification
Kiewit Energy Company
7906 North Sam Houston Parkway West, Suite 300
Houston, TX 77064
Direct: 281.517.8916
Cell: 832.657.5118
Email: dan.lumma@kiewit.com

Taylorville Energy Center
EPC Organization Plan



Kiewit

TENASKA
MDL HOLDINGS

Burns & McDonnell
SINCE 1898

Team Organization

Christian County Generation LLC
Taylorville Energy Center Gasification Facility
Burns & McDonnell Project Team Organization Chart

Officer-In-Charge
Doug Riedel, P.E.

- **Project Director** – Jim Jurczak, P.E., 816-822-3899
  - **Project Manager** – Darrell Leis, P.E., 816-822-3819
    - **Project Assistant** – Marla Moore
    - **Engineering Manager** – Tom Dean, P.E.
      - **Project Mechanical Engineer** – Ron Vering
        - **Project Mech Equip Engineer** – TBD
        - **Coal Handling Engineer** – Bill Ward
      - **Project Piping Lead** – Dave Peniston
      - **Project Process Engineer** – Tom Anderson, P.E.
        - **Process Engineer** – Janel Junkersfeld
          - **Water Treatment Specialist** – Don Schilling
      - **Project Electrical Engineer** – TBD
      - **Project Civil Engineer** – Randy Sedlacek
      - **Project Structural Engineer** – Mike McMahon
        - **Geotechnical Engineer** – TBD
      - **Project I/C Engineer** – Jerry Thomas
    - **Commercial Manager** – TBD
      - **Kiewit Team** – Greg Blackard
      - **Project Controls** – Larry Lucas
      - **Construction Manager** – TBD
      - **Procurement Manager** – John Rise
      - **Estimating** – Gary Mouton

Burns & McDonnell
Gasification Technologies

James A. Jurczak, P.E.

Director, IGCC / Gasification Projects

Burns & McDonnell
SINCE 1898

Expertise

- Integrated Gasification Combined Cycle
- Power Plant Equipment and Systems

Education

- B.S. in Mechanical Engineering, Kansas State University, 1989

Registration

- Professional Engineer – Kansas
- Professional Engineer – Iowa

Total Years of Experience

19

Years with Burns & McDonnell

17

Start Date

February 1991

Mr. Jurczak is a project director specializing in Gasification Technologies and Integrated Gasification Combined Cycle (IGCC) technology, and is currently in charge of Burns & McDonnell's IGCC gasification business. He has been responsible for the preparation of feasibility studies, technology assessments and detailed Front End Engineering Design (FEED) for gasification and IGCC projects. The FEED and feasibility studies have required that Mr. Jurczak work closely with several major gasification system providers in determining plant BOP requirements, piping, instrumentation, electrical and civil/structural plant requirements. In addition, Mr. Jurczak is an experienced project manager having worked on several combined cycle and coal fired power projects.

Cash Creek Project, Cash Creek Energy Center

Henderson, Kentucky

Mr. Jurczak is currently the project manager for Cash Creek Gasification Project. Burns & McDonnell is working on the development of the Substitute Natural Gas (SNG) and electric power facility. Burns & McDonnell is currently performing the FEED for the facility. The project ownership is the same group as is developing the Taylorville Energy Center. The ownership expects to receive State of Kentucky tax incentives to enhance the project feasibility.

Future Fuels, LLC

Kentucky

Mr. Jurczak is currently the project director for the Future Fuels coal to gasoline project in Kentucky. The project will gasify local coal to generate marketable grade gasoline. Burns & McDonnell is currently performing a conceptual feasibility study for the project.

HES Gasification Facility, Homeland Energy Solutions

New Hampton, Iowa

Mr. Jurczak is currently the project director for the HES Gasification Project. Burns & McDonnell is providing the engineering, procurement, and construction management for the project. The project is a coal gasification plant providing clean syngas as a fuel for an ethanol plant. The project will deliver a nominal 500mmBtu/hr of syngas from the two EPIC gasifiers. The project is currently in the initial design stages.

Taylorville Energy Center Project, ERORA Group

Louisville, Kentucky

Mr. Jurczak is currently the project manager for the Taylorville Energy Center IGCC project development. Burns & McDonnell is providing the Front-End Engineering Design (FEED) for the project including the project cost estimating. The project is a nominal 600MW integrated gasification combined cycle power plant utilizing the GE gasification technology. The project will also produce a commercial chemical feedstock. Mr. Jurczak is responsible for the overall project management to support the FEED project development. His responsibilities include overall program management, overall coordination and supervision of the design engineering, development of specifications, and conceptual systems design. Mr. Jurczak and Burns & McDonnell previously provided pre-feasibility planning studies and reports used by the client in securing project financing and State of Illinois tax incentives.

IGCC Feasibility Study, EPRI / CPS Energy

Mr. Jurczak was the project manager for the technical feasibility study of a 600 MW IGCC facility utilizing Wyoming USA sub-bituminous coal as feedstock. The project is based on the Shell gasification technology.

Coffeyville Fertilizer Plant Project, Coffeyville Resources Nitrogen Fertilizers, LLC
Coffeyville, Kansas

Mr. Jurczak was the project manager for the capacity upgrades to the gasification systems at Coffeyville Resources Nitrogen Fertilizer's petroleum coke gasification facility. Burns & McDonnell provided all detailed design engineering for the project. The project utilizes petroleum coke from the adjacent refinery. The gasifiers covert the petroleum coke to syngas, which is then used to make fertilizer. Mr. Jurczak was responsible for the overall engineering effort to support the project development including coordination of all engineering activities for the project.

IGCC Feasibility Study Project, CLECO Corporation
Alexandria, Louisiana

Mr. Jurczak was the project manager for Cleco Corporation's IGCC Feasibility Study. The project required the development of a IGCC pre-feasibility study as required to develop a cost estimate for comparing the financial feasibility of the project to a conventional PC coal-fired project. Mr. Jurczak was responsible for the coordinating all activities of the study, including technical assistance, cost estimating, and conceptual systems and process design.

Zeeland Combined Cycle Plant Project, Mirant (former SEI)
Zeeland, Michigan

Mr. Jurczak was the engineering manager for the Zeeland Combined Cycle Power Project. The project was a nominal 570MW combined cycle consisting of two GE 7FA gas turbines, Vogt triple pressure level HRSGs, and a GE D11 steam turbine. Burns & McDonnell was the EPC Contractor. Mr. Jurczak was responsible for supervising and directing all engineering activities for the project. Mr. Jurczak was the primary contact between construction, subcontractors, and engineering, as well as the primary technical contact for the Owner.

Osborne Cogeneration Project, Transfield Technologies
Adelaide, Australia

Mr. Jurczak was a systems design engineer on the 180MW Osborne Cogeneration Power Plant project in Adelaide, Australia. The project included a GE Frame 9EA combustion turbine with a 60 MW steam turbine. Mr. Jurczak's duties included system design, pipe routing, and layout. During the detailed design phase of the project, Mr. Jurczak coordinated a portion of the project design in the offices of the project construction contractor in Australia.

Jack County Generation Facility Project, Brazos Electric Power Cooperative
Waco, Texas

Mr. Jurczak was the project manager for Owner's Engineer services for the Jack County Generation Facility. The project is a nominal 620MW combined cycle plant, and consists of two GE 7FA gas turbines, EPTI triple pressure level HRSGs, and a GE D11 steam turbine. His responsibilities included the development of the overall project schedule, development of specifications and drawings for all contracts, assisting with Owner / Contractor negotiations, coordinating all engineering activities, and insuring Contractor compliance with the terms of the Contract.

Hamakua Cogeneration Plant Project, Hamakua Power Partners, LLP
Hawaii

Mr. Jurczak was project mechanical engineer for the Hamakua Cogeneration Project. The project was a 60MW cogeneration facility that consisted of two GE LM2500 gas turbines, and an MHI steam turbine. Mr. Jurczak was responsible for all of the mechanical engineering activities for the project, including preparation of specifications and drawings, schedule, monitoring on-site mechanical construction activities.

Massengale Station Repower Project, West Texas Municipal Power Agency
Lubbock, Texas

Mr. Jurczak was project engineer for a single 1-on-1 Combined Cycle retrofit project using a single GE LM 6000 combustion turbine for West Texas Municipal Power Agency. He was responsible for the overall technical activities of the project, supervising the staff and directing the activities of the design team. Mr. Jurczak was the primary contact for the Owner and the project construction contractors.

Darrell M. Leis, P.E.

Senior Project Manager

Burns & McDonnell
SINCE 1898

Education

- B. S. in Mechanical Engineering, Wichita State University, 1975

Organizations

- American Society of Mechanical Engineers
- American Nuclear Society

Registration

- Professional Engineer – Missouri
- Professional Engineer – Texas
- Professional Engineer – Canada
- Professional Engineer – Minnesota

Total Years of Experience

32

Years of Gas Turbine Experience

22

Mr. Leis has 32 years of experience in the Power business in project engineering and project management. As a Project Manager, he has been responsible for full risk projects with contract values ranging from $60 million to $475 million US. In the last decade, the majority of the projects have been offshore lump sum EPC turnkey power stations. Projects ranged in size from 70 MW to 1200 MW. These power stations were in Australia, Thailand, Philippines, United Kingdom, Pakistan, Mexico and Canada. Domestic projects have included coal-fired, nuclear and gas-fired stations. His skills and experience best-fit oil or gas fueled combined cycle / cogeneration plants.

Mr. Leis joined Burns & McDonnell in the Energy Group in Jun 03 as an EPC Project Manager. He is at Principal Level in the firm.

Burns & McDonnell Experience:

Project Manager

2007-Present

Erora Group – Cash Creek Generation 770 MW IGCC 2x1 7FB syngas project. Program Manager for $1.5 billion coal gasification project. FEED Contract role.

Project Director

2005-2007

Power Holding Company of Nigeria- 4 x 9E 500 MW EPC simple cycle gas turbine project. Green site in Rivers State, Nigeria. $160 million.
Phase 2- 2 x 2on1 9E Combined Cycle 1050 MW. $550 million .

Project Manager

2004

Olmsted County Waste to Energy 200 tpd Unit 3 Design Build Project. FEED Engineering FEL1 and 2 completed. $90 million project.

Project Manager

2003

Cinergy Celanese 120 MW Cogeneration MACT Compliance project in West Va. Two new retrofit CFBs steaming existing steam turbine. FEED Engineering

Proposal Manager

2003

Plymouth Energy 330 MW 1 x 1 F class combined cycle on green site. $140 million turnkey contract proposal.

Parsons Experience:

Parsons Energy and Chemical, Program Director

Houston, Texas, 2001-2003

Responsible for managing the Power projects executed in the Houston Operations of the Parsons E&C group. P&L responsibility for EPC, EPCM, Ep and E type services. Projects recently supported the Petrochemical industry clients in a cogeneration format.
Project Director - ExxonMobil Baytown Cogen Feed; PPL University Park 480mw simple cycle peaking plant, PetroCanada Cogen Feed, etc.

Black & Veatch Experience: 1975-2001

Project Director
NOVA Chemicals Ltd. 400 MW Joffrey Combined Cycle Cogeneration Feeding 500 K pph HP/VHP process steam to multiple ethylene process plants. One block of two-on-one F Class combined cycle with extraction steam turbine on NOVA's green site. Responsible for the prime EPC $200 M contract. Joint venture with BVS Power (Spantec) and UMA-B&V Ltd for construction and engineering.
Joffrey, Alberta, Canada – ATCO Power, EPCOR, Nova Chemicals.

Project Manager
Salt River Project, Santan Expansion – Responsible for engineering, procurement and CM services for this 825 MW plant with 2 on 1 and 1 on 1 blocks of GE 7F units on the Santan site near Phoenix, Arizona.

Project Manager
Siemens Power Generation, Multan, Pakistan. Rousch Power Limited's Rousch Power Plant, a 412 MW heavy oil fired combined cycle unit. Turnkey plant on greenfield site. Rousch is one block of two-on-one 125 MW Siemens V84.3A combustion turbines heating HRSGs steaming a 175 MW Siemens steam turbine. Responsible for the balance-of-plant turnkey contract including all facets of the $61 M engineering, procurement, and construction contract.

Project Proposal Manager
Central and SouthWest, 330 MW Cogeneration Plant, Sweeney Refinery Phillips Petroleum feeding 1.8 million lb/h steam to the chemical plant. Responsible for the project proposal and FEED work.
ENERTEK, 100 MW Cogeneration Plant, Tampico, Mexico feeding 800,000 lb/h steam to alpha group petrochemical plants. Responsible for the project proposal.
British Gas, 450 MW Combined Cycle Plant in Batangas, Philippines. Project delayed. Responsible for the project proposal.
Exxon, 100 MW Cogeneration Plant, Baytown, Texas Olefins Plant extension, a 100 MW combustion turbine feeding one HRSG steaming a process steam header. Responsible for the project proposal and FEED work.

Project Manager
Medway Power Ltd., Isle of Grain, United Kingdom for AES Power. Medway Generating Station, a 660 MW gas fired combined cycle plant on developer's new site. One block of two-on-one 230 MW combustion turbines feeding HRSGs steaming a 250 MW steam turbine. Responsible for project staff, budget, schedule, procurement, construction, client liaison, and all facets of turnkey $475 million EPC contract.

Enron, Lawford Power Ltd., United Kingdom, a 380 MW combined cycle plant. Engineering FEED work and turnkey cost estimate.

Engineering Manager
Westinghouse Electric, three 150 MW one-on-one cogeneration sites processing steam to existing hosts. Ridgefield, Clark, and Bayonne sites in New Jersey. Responsible for all engineering disciplines, including design, procurement, construction drawings, and startup documents. Coordinated project schedules and budgets.

Project Manager
INDECK, United Kingdom, a 1,200 MW combined cycle plant. Turnkey engineering services for Neptune Power.

Proposal Engineering Manager
Manila Electric Railroad and Light Company, Bataan Station, Philippines, a 330 MW heavy oil fired combined cycle plant on new ocean site. Each block consists of three 80 MW gas turbines feeding three heat recovery boilers conveying steam to a 100 MW steam turbine. Responsible for all engineering disciplines, including design, procurement, construction, and site management. Coordinated project schedules and budgets to provide deliverables to the client.

Project Mechanical Engineer
Electrical Generating Authority of Thailand, Rayong Station, a 1,200 MW gas fired combined cycle plant on new site. Four blocks of 300 MW each consisting of two 100 MW gas turbines with two heat recovery steam boilers furnishing steam to a 100 MW steam turbine. Responsible for all mechanical design, procurement, and construction contracts.

Directed staff of 15 engineers and technicians through project schedule and budgets to produce engineering services deliverable to client.

Project Mechanical Engineer
Exxon-Baton Rouge Refinery Cogeneration – One 7EA/HRSG set 70 MW turnkey design and construct – Baton Rouge, Louisiana.
Cogeneration. Three units simple cycle gas turbines coupled to heat recovery boilers 110 MW turnkey design and construction responsibility. Responsible for management, administration, construction, and commissioning of the GT/HRSG contracts.

Project Mechanical Systems Engineer
Northern Territory of Australia Electricity Commission -Channel Island Power Station, 210 MW gas fired multiple gas turbines with combined cycle heat recovery steam boilers turbine generator set. Responsible for all mechanical site design. Developed, evaluated, negotiated, and awarded the mechanical construction, emergency generator set, and electrical construction contracts.
Lead Mechanical Engineer - Directed staff through construction and commissioning.
Systems Manager - Developed and implemented systems turnover packages.
Mechanical Systems Engineer - Responsible for startup of all the mechanical systems on the project. Developed and completed performance tests for the open and combined cycle gas turbines, boilers, and turbine generator.

Mechanical Engineer
Assigned to Northern States Power Company's Sherburne County Station Unit 3, an 860 MW coal fired generating unit. Responsible for design of the AQCS, solids handling, dust control, fuel oil, lime handling, condenser extraction, and demineralizer systems. Responsible for procurement and administration of vacuum, oil, vertical turbine, submersible and vertical cantilever slurry solids pumps; field erected and shop fabricated tanks; AQCS, solids handling and conditioning equipment; lime handling; dust control; and landfill and coal yard facilities construction. Directed associate engineers in tasks related to these responsibilities.

Resident Engineer

Assigned to Rawhide Project Construction Management. Responsible for coordination, startup, and administration of the air quality control dry scrubber, fabric filters, ash handling, fire protection, and testing services contractors. Performed surveillance and quality control inspections for the mechanical construction contract. Developed work authorizations, modification proposals, and contract change orders. Negotiated final dollar settlements to construction contracts.

Platte River Power Authority, Rawhide Energy Center

Assigned to Platte River Power Authority, Rawhide Energy Center, a 250 MW coal fueled power plant. Responsible for 42 systems and 16 equipment and construction contracts including developing system design and associated procurement and for coordinating and administering contracts through bidding, review, evaluation, contract, post-contract equipment, and conformance review. Directed mechanical engineers in design, calculations, computerized lists, P&IDs, etc., as well as various engineering tasks related to above responsibilities.

US Army Corps of Engineers Middle East Cities Project

US Army Corps of Engineers Middle East Cities Project - Responsible for design, procurement, and construction contracts including turnkey power plants, central city heating and cooling facilities, hospitals, schools, shopping centers, and urban housing camps.

Black Fox 120 MW Nuclear Power Plant

Black Fox 120 MW Nuclear Power Plant - Responsible for preparing design and P&IDs for nuclear boiler system, including main steam and feedwater, leak detection systems, fuel pool cooling and cleanup system, main steam isolation valve leakage control system, fuel pool filter demineralizer system, etc. Responsible for input to the preliminary safety analysis report for the above listed systems.

625 MW LaCygne 1 Plant Air Quality Control Scrubber System, KCPL

KCPL 625 MW LaCygne 1 Coal Plant Air Quality Control Scrubber System - Responsible for preparing the design for the addition of an eighth module to the scrubber system; preparing piping and instrument diagrams, construction bid specifications, valve lists, and accessory equipment lists; and reviewing shop drawings.

Thomas M. Dean, P.E.

Engineering Manager

Expertise
- Project Management
- Engineering Management
- Electrical Construction Documents
- Lightening Protection
- Hazardous Areas

Education
- B.S. Electrical Engineering, University of Missouri-Columbia, 1990
- B.S. Computer Engineering – Minor in Mathematics, University of Missouri-Columbia, 1990

Organizations
- IEEE
- NSPE
- PMI

Registration
- Professional Engineer
  -Virginia
  - Pennsylvania
  - Kentucky

Total Years of Experience
18

Years With Burns & McDonnell
18

Start Date
1990

Coal Gasification, Coal to Natural Gas Facility, Cash Creek Generation
Henderson, Kentucky

Mr. Dean has been the engineering manager for a 3 plus 1 coal to natural gas plant using GE 900 cubic foot quench gasifiers. The project front end planning effort involved obtaining purchase pricing for all major equipment, construction planning and scheduling, and complete facility site plan layout in 3D modeling software (Smart Plant 3D from Intergraph). The facility includes a 2 on 1 combined cycle power plant based on GE 7FA combustion turbines, and 100% CO2 sequestration. Preliminary engineering design including creation of P&ID's and support for environmental permitting was included. Other details include an on site cryogenic air separation unit, a water treatment system including zero liquid discharge system, and coal handling with barge unloading.

Electrical Department manager, Process & Industrial Division
Kansas City World Headquarters

As the Electrical Department Manager for the Process & Industrial Division of Burns & McDonnell, Mr. Dean was in charge of all Electrical, Instrument and Controls Engineers as well as all Electrical Drafters, Detailers and Designers. Budgets, schedules and resource loading of all technical jobs in the division were included in Mr. Dean's responsibilities. Mr. Dean worked in petroleum refining, energy production, petrochemical, chemical, pharmaceutical and food processing.

FEP-2 Study, Ethanol Plant
Georgia

Mr. Dean was the lead engineer for the study of a corn to ethanol plant utilizing only biomass (wood) as a fuel source for steam and electricity. The facility included saleable products of ethanol, corn oil, and dry distillers' grain. Facility layout, cost estimate, and electrical, structural, mechanical, civil design basis were created.

FEP-1 Study for MSAT2, Marathon Petroleum Company
Multiple Locations

Mr. Dean supervised this MSAT2 Preliminary Study as the Manager of the Electrical Department. For this assignment he visited their Canton, Garyville, and Detroit refineries to investigate for the project. This project involved investigating the available electrical interconnects and existing DCS at each refinery to determine the need for new satellite control buildings as well as developing solutions for new operator stations in the existing control rooms.

Diesel Hydrotreater ISBL, Marathon Petroleum Company
Canton, OH

As the Electrical Department Manager, Mr. Dean supervised the electrical engineering effort for this ISBL project in the Canton refinery. His team established the ISBL scope and material takeoffs for the project. They also reviewed various vendor documents with the client and prepared an electrical drawing package for construction of the ULSD Hydrotreater.

Hydrogen Plant, ConocoPhillips
Borger, TX

Outside Battery Limits work for the addition of a new hydrogen plant and makeup compressor. Electrical and instrument work included loops done in Intools software and new 15kV switchgear.

Simple Cycle Combustion Turbines, Aquila
Piatt County, IL
Greenfield project consisting of six GE 7EA gas fired combustion turbines. Project electrical scope included all electrical procurement for transformers, switchgear, motor control centers, UPS. Electrical construction package of duct bank, grounding, lighting, one-line drawings, panelboards, wiring and circuit schedule was produced. GE Fanuc PLC control system.

600MW Coal Plant, Kansas City Power & Light
Kansas City, MO
Detailed design of large steam turbine and generator including new control room, ABB/Bailey computer system, new 4160 volt and 6900 volt switchgear, new MCCs, Construction package of one-line drawings, cable tray layout, plans and circuit schedule was produced.

Chlorine Spill Abatement Enclosure, Bayer
Kansas City, MO
A new control room with Delta V computer system was installed with a new, enclosed rail car unloading facility designed to unload two 90 ton chlorine rail tanker cars. The building was ventilated through a chlorine scrubber designed to treat any volume of chlorine spill within the building.

Emissions Thermal Oxidizers, Parke-Davis
Holland, MI
Three thermal oxidizers with scrubbers on the outlet and process boilers to use the heat from thermal destruction of volatile organic compounds emitted by the pharmaceutical plant. Foxboro IA computer system with Allen Bradley PLC burner management system. Electrical system included 750kVA emergency backup diesel generator, 300hp variable frequency drives and high speed transfer switch to backup power source.

Synthetic Rubber, Goodyear Tire & Rubber
Beaumont, TX
Multiple projects to install process instrumentation, pumps and mixers as part of the process of manufacturing synthetic rubber. Also, new double ended electrical substations added.

2 X 400MW Coal Power Plant, Old Dominion
Clover, VA
Three years as on-site engineering supervision for Owner. In charge of instrumentation in the scrubber, fabric baghouse filters, cooling towers, water treatment system, river intake system and coal handling system.

Baghouse Addition at Coal Plant, TriState Energy
Craig, CO
Demolition of existing precipitator for fly ash removal from gas stream. Addition of a new baghouse. Project also included new chimney annulus fans, new ID fans and new bypass ductwork between the chimney, scrubber and baghouse of a 450MW coal fired power plant. Honeywell computer control system was installed.

Black Start Diesel Generator, Hoosier Energy
Worthington, IN
A new 750MVA diesel generator was added to allow the black start up of four GE

LM6000 combustion turbines. Delta V control system allowed for paralleling of the unit with the running utility to exercise the diesel generator.

Burner Management System, Union Electric
Meramec, MO
New burner management system and replacement of benchboard controls with Westinghouse WDPFII computer controls.

Ronald D. Vering, P.E.

Project Mechanical Engineer

Burns & McDonnell
SINCE 1898

Expertise

- Power Plant Mechanical Design
- Fluid Hydraulics and Pump Application
- Intake/Pump Structure Hydraulics
- Piping
- Cooling Towers
- Condensers
- Shop Fabricated Boilers
- Fire Protection
- Facility Retrofit and Piping System Retrofit
- Power Plant Wastewater Collection and Treatment
- Cathodic Protection

Education

- B.S. in Civil Engineering, Kansas State University, 1978

Registration

- Professional Engineer – Kansas
- Professional Engineer – Texas

Mr. Vering has over 25 years of power plant design experience. This experience includes performing studies to determine project feasibility and scope; developing plans and schedules for implementing the project scope; developing system design philosophy addressing the type of equipment and materials, capacity, redundancy and control schemes; performing detailed mechanical system design; preparing equipment procurement and construction contract commercial terms and technical specifications; administering contracts including bidder qualification, bid evaluation; addressing commercial and technical terms with suppliers and contractors, and reviewing compliance submittals; and construction support including expediting, on site observation, and overseeing performance testing. Additionally, his responsibilities have included project schedule and budget monitoring and reporting.

Mr. Vering's new coal power plant design project experience includes:

- Kansas City Power & Light Iatan Generating Station, Unit 2, 850 MW
- Deseret G&T Cooperative's Bonanza Power Plant, Unit 1, 400 MW.
- Board of Municipal Utilities of Sikeston, Missouri Sikeston Power Station, Unit 235 MW.
- City of Gainesville, Florida's Deerhaven Generating Station, Unit 1, 235 MW.
- A.E. Staley's Decatur, Illinois, Cogeneration Plant, 60 MW.
- Schuylkill Energy Resources, St. Nicholas Cogeneration Plant, 100 MW.

Mr. Vering's gas/oil power plant design project experience includes:

- Alliant Energy, Emery Power Station, a 560 MW 2 x 1 combined cycle power plant including heated (to 360 deg F) fuel gas system design.
- Arkansas Electric Power Cooperative Corporation, Fitzhugh Power Plant, repowering a 75 MW steam turbine utilizing a 100 MW combustion turbine and heat recovery steam generator.
- Mirant/CLECO, Perryville, Louisiana Power Plant, he assisted in mechanical design for a 500MW 2 x 1 combined cycle power plant.

Mr. Vering's design-build project experience includes:

- City of Springfield, Illinois, 225 MW coal plant at the Dallman Station, conceptual design for a coal plant addition to an existing site.
- General Electric's/Babcock & Wilcox's bid proposal to Saudi Consolidated Company in the Western Region, Shoaiba 5 by 350 MW steam power plant, conceptual design of balance of plant mechanical systems and balance of plant costs estimates.
- General Electric's bid proposal to the Electricity Generating Authority of Thailand, Ratchaburi 2 by 700 MW power plant, conceptual design of balance of plant equipment and cost estimates.
- Babcock & Wilcox's bid proposal to the Electricity Generating Authority of Thailand, Krabi 1 by 350 MW power plant, boiler island cost estimates.
- Old Dominion Electric Cooperative, Clover Leaf 2 by 400 MW power plant, Mr. Vering was responsible, as owner's engineer in reviewing EPC contractor's submittals.
- City of San Antonio Texas, design-build proposal evaluation for a 400 MW power plant.

Mr. Vering's over 25 years of experience at Burns & McDonnell is summarized below:

Kansas City Power & Light
Weston, Missouri, 2006-2008
Mechanical design for a 850 MW coal fired supercritical power plant at the Iatan Generation Station (Unit 2) including new common systems serving Unit 1.

City of Springfield, Illinois
Springfield, Illinois, 2005
Mechanical design for a scrubber blowdown treatment system including clarifier and brine concentrator serving existing Unit 31, 32 and 33 and new Unit 4.

City of Springfield, Illinois
Springfield, Illinois, 2004
Develop site and building general arrangements and preliminary system piping and instrument diagrams for a 225 MW pulverized coal power plant addition to the existing Dallman plant site.

University of Virginia
2004
Technical design review and permitting support for a retrofit project at a five boiler 440,000 lb/hr. utility plant, including three stoker fired boilers with dry scrubbers and baghouses and two packaged gas/oil fired boilers.

Alliant Energy
2002-2003
Mechanical design for a 560MW combined cycle power plant (240 MW steam turbine with two 160 MW combustion turbines and heat recovery steam generators) at the Emery Power Station.

City of Springfield, Illinois
2002
Prepared a cathodic protection testing scope of service and reviewed test data and upgrade recommendations for the 3 unit Dallman Power Station and three combustion turbine sites.

Sempra Energy
2002
Review of the design, hydraulic analysis and permitting for a submerged screen intake and once through cooling water system on the lower Mississippi River meeting new 316B regulations, for the proposed two unit 1200 MW Bonne Carre Power Station.

Arkansas Electric Power Cooperative Corporation
2001
Mechanical design for repowering a 75 MW steam turbine with 100 MW combustion turbine and heat recovery steam generator at the Fitzhugh Generating Station.

MidAmerican Energy
2000-2001
Mechanical design for replacing a once through cooling water intake, pump and piping system on the three unit (135 MW, 300 MW and 515 MW) Neal North Power Station.

Mirant and CLECO

2000-2001

Assisted in mechanical design for a 500MW 2 x 1 combined cycle power plant at a site in Louisiana (Perryville).

Dave Peniston

Project Piping Lead

Expertise
- Piping
- Equip. layout

Total Years of Experience
43

Years With Burns & McDonnell
35

Start Date
1971

Mr. Peniston has performed detailing for several recent piping projects. He provided detailing for piping, screw conveyor and equipment layout for a sugar packing tower and a truck and rail car loading station for Corn Products Corporation's dextrose processing plant. Other projects included equipment and piping layout for a water treatment plant at Iowa State University, and a cogeneration facility at Vulcan Chemical's Geismar, Louisiana chemical processing plant.

Mr. Peniston, as a lead design detailer, supervises drafters in preparation of piping layout isometrics. He was the lead design detailer for two major power projects located in Mississippi and Missouri, which included piping layout and preparation of scale models of the plants from design drawings.

Prior to joining Burns & McDonnell in 1971, Mr. Peniston worked for a Kansas City petrochemical company for 8 years as a design detailer. His work consisted of layout and detailing of pressure vessels, absorbers for drying various gases and liquids as well as detailing cooling towers.

Iatan, Kansas City Power and Light
Weston, Missouri, 2008
Lead Designer

Fremont Energy Center
Ohio, 2002
Lead Designer

Tom Anderson, P.E.

Project Process Engineer

Burns & McDonnell SINCE 1898

Expertise

- Gasification Processes
- CO_2 Capture Processes
- Sulfur Recovery Processes
- Process Design and Simulation
- Technology Assessment Studies
- Feasibility Studies

Education

- M.S. in Chemical Engineering, Kansas University, 1987
- B.S. in Chemical Engineering, Kansas University, 1979

Organizations

- American Institute of Chemical Engineers

Registration

- Professional Engineer - Kansas

Years Experience

27

Years With Other Firms

0

Start Date

1981

Mr. Anderson is a chemical process engineer specializing in process system design. Mr. Anderson spent 24 years in Burns & McDonnell's Process and Industrial Division working in the chemical and refining industries before transferring to the Energy Division to assist in developing the company's Integrated Gasification Combined Cycle (IGCC) business. Mr. Anderson is part of Burns & McDonnell's Greenhouse Gas Program where his responsibilities include assessment of carbon dioxide capture technologies. While in the Process and Industrial Division, he served as the company's technical representative to both Fractionation Research Institute and Heat Transfer Research Institute. Mr. Anderson has extensive experience in distillation and other separations processes and in sulfur recovery operations, including Claus plant design, tail gas treating, amine absorption and sour water stripping.

Cash Creek Gasification Facility Coal-to-Methane Facility with Combined-Cycle Power Generation ERORA

2006-Present

Mr. Anderson is the lead process engineer on the development of this world-class coal-to-methane facility with combined cycle power generation. The facility utilizes General Electric quench gasifiers, sour gas shift, and proprietary solvent acid gas removal and methanation processes. The facility includes a 2x1 combined cycle power plant, carbon capture and compression, and a zero-liquid discharge treatment system for process wastewater streams. Burns & McDonnell is responsible for the overall engineering design effort to support the project including coordination of vendor technology packages for air separation, gasification, acid gas removal, methanation and wastewater treatment. Burns & McDonnell is also responsible for design of the gas shift and cooling process areas and all balance-of-plant (OSBL) facilities.

Coal-to-Methane Technical Evaluation and FEL1 Estimate, Southeast USA

2008

Mr. Anderson led the technical evaluation of a proprietary coal-to-methane process. The proposed process utilized fluid-bed, air-blown gasifiers operating on petroleum coke to produce pipeline-quality methane.

Syngas Process Feasibility Study and FEL1 Estimate, Ethanol Plant, Midwestern USA

2007-2008

Mr. Anderson was the lead process engineer for the technical feasibility study and FEL1-level cost estimate for a syngas production unit at a Midwest ethanol plant. The proposed process utilizes air-blown gasifiers operating on Powder River Basin coal to produce syngas for use as fuel in the ethanol plant.

IGCC Feasibility Study, Old Government, Australia

2007

Mr. Anderson was the lead process engineer for the technical feasibility study of a nominal 2x1 500MW IGCC facility utilizing bituminous coal as feedstock. The project is based on the Shell gasification technology. The study includes the evaluation of costs and technical issues associated with CO_2 "capture ready" and CO_2 capture. The study evaluated the costs and technical issues for adding CO_2 capture at a later date or for constructing the initial project with CO_2 capture.

Cash Creek Energy Center Synthetic Natural Gas (SNG) Facility Conceptual Engineering, ERORA

2006-2007

Mr. Anderson was the lead process engineer for development of a process to convert gasifier syngas to SNG. He was responsible for process simulation, preparation of the process flow diagrams, heat and mass balances, and technical performance specifications.

Taylorville 600 MW IGCC Project, Christian County Generation, LLC

2006

Mr. Anderson served as process design engineer for the Taylorville Energy Center IGCC project development. Burns & McDonnell assisted The ERORA Group by providing the Front-End Engineering Design (FEED) for the project. The project is a nominal 600MW integrated gasification combined cycle power plant utilizing GE gasification technology. The project will include chemical co-production. Mr. Anderson was responsible for developing the conceptual design package for a synthetic natural gas (SNG) facility using gasifier syngas as feed. Mr. Anderson was also responsible for specification of sulfur product loading, chemical railcar unloading and storage and plant flare systems.

IGCC Feasibility Study, Electric Power Research Institute/City Public Service (San Antonio, TX)

2006

Mr. Anderson recently served as process design engineer for a benchmark study evaluating the feasibility of IGCC facilities operating on Wyoming USA sub-bituminous coal and petroleum coke feeds. The study was based on Shell gasification technology. Mr. Anderson was responsible for evaluation of various acid gas recovery technologies and for design of sulfur recovery and tail gas treating facilities.

Sinclair Oil Corporation

2004-2006

Mr. Anderson served as Lead Process Engineer for the specification and EPC installation of a new 25 LTPD Claus sulfur recovery unit, incinerator and caustic tail gas scrubber in parallel with an existing 20 LTPD SRU and scrubber. Mr. Anderson was also responsible for design of a new above-ground sulfur storage tank, modernization of burner controls and safety systems for the existing SRU and incinerator, and coordination of the new SRU subcontractor's design with refinery Clean Fuels Program modifications. Mr. Anderson was also responsible for capacity improvements to the refinery sour water stripper, including the use of high-capacity trays and welded plate and frame exchangers for heat recovery.

Sinclair Oil Corporation

2004-2005

Mr. Anderson served as Process Design Engineer for the retrofit of a diesel/naphtha hydrodesulfurization unit to produce ultra-low sulfur diesel fuel for the refinery's Clean Fuels Program. Mr. Anderson was responsible for the design of a new high-pressure amine scrubber, conversion of a reboiled diesel product stripper to steam stripping, and for design of diesel drying equipment.

Suncor

2004

Mr. Anderson served as Lead Process Engineer for the FEL2 engineering design of a

Sour Water Stripper column for the Denver refinery's Clean Fuels program. The new Stripper was integrated with an existing stripper column to provide increased sour water stripping capacity needed to meet Clean Fuels Program requirements.

Suncor

2003-2004

Mr. Anderson was Lead Process Engineer for the revamp of Suncor's #2 HDS from diesel to naphtha/kerosene service for the ULSD project at the Denver Refinery. Mr. Anderson was responsible for incorporating technical data from Suncor's selected catalyst technology vendor into heat & material balances for the unit; and for equipment and control modifications required to implement the revamp.

Mr. Anderson was also responsible for FEL2 engineering design for the revamp of Suncor's #3 HDS from gas oil to diesel service.

The Goodyear Tire & Rubber Company

2001-2002

Mr. Anderson served as Lead Process Engineer for the design of a hydroquinone production facility revamp. The modifications were made to improve plant safety by replacing the previous benzene-based process with a process using a safer solvent. The project required innovative design changes, including the use of new separations technology, and close cooperation between Burns & McDonnell and Goodyear engineers and operations staff.

Tesoro Petroleum

2001

Mr. Anderson served as lead process design engineer and consultant for a mandated evaluation of Sulfur Recovery Unit facilities that included a 15 LTPD Claus sulfur recovery unit, incinerator, amine regenerator and sour water stripper. Burns & McDonnell reviewed the design of all equipment and performed testing to establish baseline SRU performance. Recommended improvements resulted in increased sulfur recovery efficiency.

ORL

2000

Mr. Anderson served as Lead Process Engineer for the design of new Sulfur Recovery and Tail Gas Treating facilities installed at ORL's refinery in Haifa, Israel. The project included two 85 LTPD, 3-stage Claus SRUs designed for future oxygen enrichment, an MDEA Tail Gas Treater, and associated hot oil and incineration equipment.

Randell L. Sedlacek, P.E.

Project Civil Engineer

Burns & McDonnell SINCE 1898

Expertise

- Site Layout
- Roads and Railroads
- Site Grading and Drainage

Education

- B.S. in Civil Engineering, Kansas State University, 1970

Organizations

- American Railway Engineering and Maintenance-of-Way Association
- American Society of Civil Engineers
- Kansas Society of Professional Engineers
- National Society of Professional Engineers
- Society of American Military Engineers

Registration

- Professional Engineer – Kansas
- Professional Engineer – Florida
- Professional Engineer – Iowa
- Professional Engineer – Minnesota
- Professional Engineer – Mississippi
- Professional Engineer – Texas
- Professional Engineer – Wisconsin

Total Years of Experience

34

Years With Burns & McDonnell

34

Years with other Firms

0

Start Date

Mr. Sedlacek is a civil engineer for power projects. He oversees the administration of civil work contracts, staffing requirements, work assignments, and design criteria establishment. Mr. Sedlacek also monitors the civil work during the construction phase of projects.

He has prepared numerous preliminary site layouts for site selection studies for coal-fired generating facilities and gas turbine, both simple and combined cycle, generating facilities.

Laramie River Station, Basin Electric Power

Wheatland, Wyoming

Mr. Sedlacek was project civil engineer for Unit 3 of the Basin Electric Power Project's Laramie River Station. He also served as the civil design engineer on Units 1 and 2. He was responsible for the design of all power plant roads and railroads, plant drainage, raw water storage reservoir, ash ponds, landfill, emergency holding pond, and final grading and landscaping.

Unit 4 Project, Southern Illinois Power Cooperative

Marion, Illinois

Mr. Sedlacek was also civil engineer for Southern Illinois Power Cooperative's 173-MW Unit 4 at Marion, Illinois. He was in charge of the final site grading and paving contract, which involved grading and drainage design, new road alignments, repair and surfacing of existing roads and surfacing new parking lots.

Alabama Electric Cooperative

McIntosh, Alabama

As project civil engineer for the 100 MW compressed air energy storage project for Alabama Electric Cooperative, Mr. Sedlacek was responsible for the site layout, preparation of the turnkey civil specifications, and review of the design engineer’s plans and specifications.

Clover Project, Old Dominion Electric Cooperative

Clover, Virginia

For the two-unit Clover Project for Old Dominion Electric Cooperative, Mr. Sedlacek was the project civil engineer for the preliminary site layout and preparation of turnkey specifications. Working as Owner’s project civil engineer he reviewed the turnkey consortium’s design and assisted the Owner in the plant permitting.

Thomas Hill Energy Center, Associated Electric Cooperative

Clifton, Missouri

Mr. Sedlacek was the project civil engineer for the addition of a loop track and associated plant modifications for unit train coal unloading at Associated Electric’s Thomas Hill Energy Center.

Red Hills Generating Facility, Tractebel Power

North Central Mississippi

For the Red Hills Generating Facility for Tractebel Power, Inc., Mr. Sedlacek was the project civil engineer for the preliminary site layout and the preparation of turnkey specifications. Working as Owner’s project civil engineer he reviewed the turnkey contractor’s design and assisted the Owner in the plant permitting.

City Utilities of Springfield, Missouri, Sempra, and Otter Tail Power

1974

Mr. Sedlacek prepared preliminary site plans and cost estimates for studies to add additional generating capacity at Southwest Station for City Utilities of Springfield, Missouri, at Twin Oaks Power Plant for Sempra, and at Big Stone for Otter Tail. At Southwest Station the scope included expansion of the existing rail facilities to allow 150-car unit train coal delivery.

J.K. Spruce Unit 2 Project, CPS Energy
San Antonio, Texas

For CPS Energy's 750 MW J.K. Spruce Unit 2 Project, Mr. Sedlacek is the Owner's project civil engineer. He prepared the preliminary site plan, cost estimate, and civil scope for the EPC specification and evaluated the EPC bids. He is currently reviewing contractor drawings and submittals for the construction of the new unit.

IGCC Project, The ERORA Group
Taylorville, Illinois

Mr. Sedlacek prepared preliminary site plans for a new mine-mouth plant being developed by The Erora Group. The site was laid out for either a 400 MW pulverized coal unit or a 644 MW IGCC unit.

Dallman Station, City Water, Light and Power
Springfield, Illinois

Mr. Sedlacek was the Owner's project civil engineer for City Water, Light, & Power of Springfield, Illinois new 200 MW unit addition at their Lakeside facility. He prepared preliminary site plans for the new unit and the civil scope for the EPC specification.

Study for Construction of Pulverized Coal Unit, Old Dominoin Electric Cooperative

For Old Dominion Electric Cooperative's study for construction of a new pulverized coal unit, Mr. Sedlacek prepared preliminary site plans and cost estimates. The study scope included the rebuild of approximately 8 miles of track and 4 miles of new track for coal delivery.

Granite Fox Power Plant, Sempra Energy
Northwest, Nevada

Mr. Sedlacek is Owner's project civil engineer for Sempra Energy's two 750 MW unit Granite Fox Power Plant in northwest Nevada. He has prepared preliminary site plans and cost estimates and provided engineering support for the plant permitting.

Hugo Unit 2, Western Farmers Electric Cooperative
Hugo, Oklahoma

Mr. Sedlacek is the Owner's project civil engineer for the addition a new 750 MW unit at Western Farmers Hugo Plant. He has prepared preliminary site plans and the civil scope for the EPC specification.

Council Bluffs Unit 4, MidAmerican Energy
Council Bluffs, Iowa

Mr. Sedlacek was the Owner's project civil engineer for review of the EPC proposals for MidAmerican Energy Company's CB Unit 4. He also worked as the Owner's project civil engineer for the construction of Unit 4.

Cargill Plant, Cargill, Inc.
Blair, Nebraska

For the Cargill plant in Blair, Nebraska, Mr. Sedlacek was the project civil engineer for studies to add a circulating fluidized bed boiler unit for process steam and rail coal unloading facilities. The studies included plant layout, preliminary horizontal and vertical alignments for ladder track yard, and cost estimates.

Nelson Dewey Generating Station, Alliant Energy

Cassville, Wisconsin

At Alliant Energy's Nelson Dewey Generating Station where coal is delivered by barge, Mr. Sedlacek is the project civil engineer for preliminary engineering and permitting for the addition of a new circulating fluidized bed unit that includes the addition of a ladder track-siding arrangement for the delivery of coal by unit train.

Iatan Generating Station Unit 2, Kansas City Power & Light

Weston, Missouri

Mr. Sedlacek is the project civil engineer for the new 790MW Unit 2 addition at Kansas City Power & Light's Iatan Generating Station. The project includes the addition of SCR, bag house, and scrubber for Unit 1 and the permitting and construction of a new coal combustion waste product landfill.

Oak Grove Steam Electric Plant, Luminant

Franklin, Texas

Mr. Sedlacek was the Owner's project civil engineer for the preparation of the EPC request for proposal for construction restart and completion of Luminant's Oak Grove Steam Electric Plant. He is currently

Boswell Generating Station, Minnesota Power

Cohasset, Minnesota

At Minnesota Power's four coal fired unit Boswell Generating Station, Mr. Sedlacek is the project civil engineer for the addition of SCR, bag house, and scrubber for Unit 3. To make space for the new facilities a sheet pile wall was installed in Blackwater Lake and the lake area behind the sheet pile was filled in.

Michael J. McMahon, P.E.

Project Structural Engineer

Expertise

- Structural Design of Industrial Facilities
- Construction Contract Management

Education

- B.S. in Civil Engineering, University of Kansas, 1980.
- M.S. in Civil Engineering, University of Kansas, 1989.

Organizations

- American Society of Civil Engineers

Registration

- Professional Engineer – Arizona, Georgia, Iowa, Kansas, Missouri, Nebraska, Oklahoma, Virginia

Total Years of Experience

27

Years With Burns & McDonnell

16

Start Date

1990

Mr. McMahon has 25+ years experience in the construction and design field. In addition to his design experience he has considerable experience in the areas of permitting, field inspection, testing, and quality control.

As lead Civil Structural (C/S) Engineer, he is responsible for all civil and structural work which includes development of design criteria, estimates, technical specifications, design, detailing, and development of required construction packages.
Representative projects include the following:

Arizona Public Service

Joseph City, Arizona

Lead Structural Engineer for air quality upgrade projects on Units 3 and 4 of the APS Cholla Generation Facility. Both projects included new ID fans, flue gas desulfurization equipment, and new fabric filter modules. Mr. McMahon was responsible for procurement packages and structural design of all ductwork, duct supports, pipe racks, pre-engineered buildings, and foundations.

Great River Energy

Cambridge, Minnesota

Lead Structural Engineer for the new generation facility consisting of a single Siemens Westinghouse V84.3A gas turbine. Mr. McMahon was responsible for design of all foundations and procurement specifications for buildings on the project.

Southern Company

Zeeland, Michigan

Lead Structural Engineer for the new generation facility consisting of two GE 7FA simple cycle units and a two on one GE 7FA with GE D11 Steam Turbine combined cycle plant. Mr. McMahon was responsible for design of all foundations, pipe racks and buildings on the project. Major foundations required for the project included a steam turbine generator and four gas turbine generators. The project included a pipe rack consisting of over 200 tons of structural steel, equipment access platforms, and a steam turbine building with a bridge crane.

Ameren

Pinckneyville, Illinois

Lead Structural l Engineer for Phase 1 of the new generation facility consisting of four GE LM6000 simple cycle units. Mr. McMahon was responsible for the design of site grading, storm sewers, and a two-mile water supply line.

Dayton Power and Light Company

Miamisburg, Ohio

Lead Structural Engineer for a new cooling tower installation on the plant discharge system. Mr. McMahon was responsible for design of sheet piling, the cooling tower foundation, and pipe supports.

NutraSweet Kelco Company

San Diego, California

Lead C/S engineer for the plant upgrade project. Mr. McMahon was responsible for structural design of pipe supports, equipment platforms, cooling tower foundations, and fire safety upgrades of structures. Major structures included a five-story platform designed to meet seismic zone 4 requirements.

PQ Corporation
Kansas City, Kansas

Mr. McMahon was the lead C/S engineer, for the Molecular Sieve project and construction permit coordinator for the PP4 and Molecular Sieve projects. He was in charge of site work design, including the storm-water management. His structural design responsibilities included pre-engineered building specifications, modifications of existing structures, equipment supports, guyed stack design, access platforms, lateral load analysis, and a vibration study. Mr. McMahon coordinated all building finish bid documents including painting, locker rooms, control rooms, and offices. All design was accomplished under a fast-track schedule.

Danisco Ingredients
St. Joseph, Missouri

Mr. McMahon was the Project Engineer and lead C/S Engineer for the design/build new plant construction and equipment relocation. His responsibilities included coordination of the multi-discipline design effort, construction permits, and C/S design. The project consisted of site development, relocation of process equipment to a new concrete frame process tower, and new precast concrete office and warehouse.

Ralston Purina
Atlanta and Davenport plants

Served as lead C/S Engineer for plant upgrades. Work included structural steel, masonry, foundations, and analysis of existing concrete frame structures. The retrofit projects included new process structures, a frozen ingredients warehouse, electrical utility rooms, conveyor supports, and roof modifications.

Allco Chemical Corporation
Galena, Kansas

Served as lead C/S Engineer on the new production line addition. Scope included basic design, cost estimate, and detailed design. The plant expansion consisted of a new process tower within an existing structure, pipe racks, and foundations for process vessels.

Crosfield Catalysts
Chicago, Illinois

Mr. McMahon served as lead C/S Engineer from basic design through construction. The design included access platforms, pipe racks, and process towers constructed within an existing facility. In addition, Mr. McMahon coordinated construction permit activities.

Aqualon
Hopewell, Virginia

Mike was the lead Civil/Structural Engineer for Aqualon Company's new CMC dry product handling building in Hopewell, Virginia. The new, 7-story steel frame structure was designed with Good Manufacturing Practices (GMP) as an important criterion. Mr. McMahon was responsible for the building features as well as the foundations, utilities, structural frame, and explosion venting.

Prior to joining Burns & McDonnell, he was a Project Engineer with Raytheon Service Company. He designed fire safety improvements for the various air traffic control towers. He was the Project Engineer for 28 underground storage tank removal and site assessment projects at remote facilities operated by the Federal Aviation Administration. During his two years with Raytheon Service Co., Mr. McMahon was responsible for cost estimates and budget control during the design and construction phases.

At Kansas City Testing Laboratory, he was Project Manager for the new General Motors plant in Kansas City, KS. During his seven years at KCTL, Mr. McMahon was responsible for construction quality control on a wide range of projects and developed construction quality control programs.

Jerry Thomas, P.E.

Project I/C Engineer

Expertise
- Controls design
- Power generation instrumentation
- Petroleum refining

Education
- M.S. Electrical Engineering, University of Kansas, 2001
- B.S. Chemical Engineering, University of Missouri-Columbia, 1996

Registration
- Professional Engineer - Missouri

Total Years of Experience
8

Years With Burns & McDonnell
6

Start Date
2002

Mr. Thomas is an Instrument & Controls Engineer for Burns & McDonnell's Process and Industrial Division, and has over 6 years experience in the areas of petroleum refining and power generation instrumentation and controls design. Mr. Thomas has broad knowledge of instrumentation and control systems related to refinery and power generation facilities. His experience extends from conceptual design and specification through field construction and startup support.

Low-NOx Boiler, Frontier Refining
Cheyenne, WY

Mr. Thomas served as the Lead I&C Engineer responsible for all phases of instrumentation and control system design on the EPC boiler project.

Hydrotreater Revamp, Sunoco
Philadelphia, PA

Mr. Thomas served as the I&C Engineer responsible for the design and coordination of the control system and machine monitoring hardware and configuration.

Low-NOx Boilers, Texas Petrochemicals
Houston, TX

Burns & McDonnell was contracted to design and construct two new boilers with low-NOx burners to improve efficiency and emissions. Mr. Thomas served as Lead I&C Design Engineer on the project, and remained on the job from conceptual design through construction and startup.

Low Sulfur Gasoline, ConocoPhillips
Lake Charles, LA

Mr. Thomas served as an I&C Engineer for a new 40,000+ BPSD Szorb unit project offsite facilities. Mr. Thomas was responsible for the design and coordination of the controls relocation for an existing HDS unit and related equipment. Responsible for DCS equipment specifications and relocation procedures, Mr. Thomas worked with plant operations in order to assess project requirements and develop construction documents. In addition, Mr. Thomas coordinated subcontractors and plant personnel to perform the work with units online.

Distillate Hydrotreater Revamp, NCRA
McPherson, KS

Mr. Thomas provided complete marshalling and DCS design for installed instrumentation at NCRA's McPherson plant. He was responsible for the site DCS survey to enable utilization of existing control equipment.

Amine & Sour Water Stripper, NCRA
McPherson, KS

Mr. Thomas provided complete marshalling and DCS design for installed instrumentation. His work involved design and specification of new marshalling panels and control equipment racks.

Plant Environmental Upgrades, Tristate G&T
Craig, CO

Mr. Thomas provided I&C design and site startup support for a power plant environmental upgrade project. Mr. Thomas provided I&C design for equipment, including a new baghouse and a retrofitted wet flue gas desulfurization unit. His responsibilities included developing construction specifications for instrumentation and control systems. This work also included modifications to the existing plant DCS equipment. His field support involved construction supervision and startup coordination essential in successfully meeting an aggressive schedule.

Combined-Cycle Power Plant, Alliant Energy

Clear Lake, IA

Mr. Thomas served as an I&C engineer for a new combined-cycle power plant. Mr. Thomas performed control system and instrumentation design and engineering for the 575 MW unit. His responsibilities included development and administration of contract documents associated with the plant continuous emissions monitoring system. Work also involved I/O and functional logic development in coordination with the control system subcontractor.

William J. Ward, Jr., P.E.

Coal Handling Engineer

Expertise

- Coal Handling
- Limestone Handling
- Gypsum and Sludge Handling
- Dust Control

Education

- B.S. in Mechanical Engineering, Purdue University, 1975

Organizations

- American Society of Mechanical Engineers
- P.R.B Coal Users Group

Registration

- Professional Engineer - Kansas

Total Years of Experience

32

Years With Burns & McDonnell

32

Start Date

June 1975

Mr. Ward is responsible for the evaluation, design and specification of fuel, reagent and sludge handling systems and has worked on such projects for the following electric utilities: Alabama Electric Cooperative; Southern Illinois Power Cooperative; Arizona Electric Power Cooperative; Basin Electric Power Cooperative; Associated Electric Cooperative; Western Farmers Electric Cooperative; city of Sikeston, Missouri; city of Springfield, Illinois; city of Gainesville, Florida; Plains Electric G&T Cooperative (now Tri-Sate); Deseret G&T Cooperative; the Department of the Navy, Puget Sound Naval Shipyard, Old Dominion Electric Cooperative, and CPS Energy (San Antonio, TX).

As one of Burns & McDonnell's material handling engineers, Mr. Ward is responsible for the design of material handling systems for assigned utility projects. The design work includes sizing and routing of conveyors, determining the best type conveyor and preparation of equipment specifications and construction contracts. This responsibility continues with compliance submittal review and material handling system contract administration.

Experience:

Calaveras Lake Plant, CPS Energy of San Antonio, TX

San Antonio, TX, 2006 – Present

Beginning five-year program for major coal yard improvements for the Calaveras Lake plant site. Work includes train positioner replacement, washdown systems, stacker-reclaimer renovation, conveyor upgrades and addition of a rotary plow reclaim system. Construction is in progress.

Erora IGCC

Cash Creek, KY, 2007

Development services for new IGCC project. Project is starting the preliminary engineering phase.

Schahfer Station, Northern Indiana Public Service Company

Wheatfield, IN, 2006 – 2007

Prepared specifications for chute replacement project at Schahfer Station for the U14/15 Sample House.

Jeffrey Energy Center, Westar

St. Marys, KS, Present

Contract engineer to refurbish old limestone conveyors and add new limestone and gypsum handling conveyors. Construction is nearing completion.

Rodemacher Plant, Cleco Power LLC

Alexandria, LA, Present

Owner's engineer for new 500 MW coal-fired CFB boiler unit at their Rodemacher Plant site. Work includes a new barge unloading system, tubular (belt) conveyor and coal, limestone and coke handling facilities. Construction is under way.

Clinton Cogeneration, ADM

Clinton, IA, 2004 – 2006

Prepared concept design and technical specification packages for coal and limestone handling systems for ADM's new coal-fired cogeneration facility. All B&McD prepared contracts have been awarded and are nearing completion of construction.

750 MW Coal-Fired Plant, Western Farmers Electric Cooperative
Ft. Towson, OK, 2004 –2006

Owner's Engineer for new 750 MW coal-fired unit. EPC bids were taken. Project is currently on hold.

250 MW Coal-Fired Plant, City Water Light & Power
Springfield, IL, 2004 – Present

Owner's Engineer for new 250 MW coal-fired unit. Completed conceptual design of coal, limestone and gypsum handling systems expansion. Prepared specifications for new unit bid documents. Construction is in progress.

Schahfer Station, Northern Indiana Public Service Company
Wheatfield, IN, 2005 – 2006

Prepared specifications for chute replacement project at Schahfer Station.

750 MW Coal-Fired Plant, CPS Energy of San Antonio, TX
San Antonio, TX, 2003 – Present

Owner's engineer for new 750 MW coal-fired unit. Construction is in progress.

Mechanical Conveying System Project, Rocky Mountain Steel Mills
Pueblo, CO, 2003

Prepared evaluation of alternative mechanical conveying systems for steelmaking additives.

Calaveras Lake Power Plant, City Public Service of San Antonio, TX
San Antonio, TX, 2002 – 2004

Prepared study for coal pile wet suppression (irrigation) system. This was followed by preparation of specifications for equipment purchase contract. System was put into service in 2004.

Coal Handling Studies, PacifiCorp
Salt Lake City, UT, 2001 – 2003

Prepared coal handling dust control studies for their Naughton, Wyodak and Dave Johnston plants. This was followed by preparation of specifications for coal handling/dust control upgrade projects at the Dave Johnston and Wyodak plants.

2 – 250 MW Coal-Fired Plant, Reliant Energy
Seward, PA, 2001 – 2004

Owner's engineer support services for new 2 X 250 MW CFB boiler power plant burning waste fuel. Support includes review of EPC contractor prepared specifications and review of conveyor contractor drawings for the fuel, ash, and limestone handling systems. Additional work includes a "Critical Equipment Evaluation Program" and "Failure Recovery Program" for the Seward Material handling system.

Lakeside & Dallman Generating Station, City Water Light and Power
Springfield, IL, 1999

Prepared limestone handling contracts for CWLP's Lakeside and Dallman Generating Station. The work at Dallman was part of the Units 31 and 32 scrubber retrofit project.

Mill Creek Station, Louisville Gas & Electric
Louisville, KY, 1997 – 1999

Material handling engineer for FGD gypsum handling and barge loadout system for LG&E's Mill Creek Station forced oxidation conversion project.

Red Hills Power Plant, Choctaw Generation Inc.
Ackerman, MS, 1997 – 2002
Material handling engineer for lignite and limestone handling systems for the Red Hills Power Plant.

FGD Retrofit Project, Taiwan Power Company
Taiwan, 1996 – 1999
Material handling engineer for limestone and gypsum handling systems for FGD retrofit.

Palatka Station, Seminole Electric Cooperative, Inc.
Palatka, FL, 1996
Prepared specification for replacement wet dust collectors at Palatka.

2 x 424 MW Coal-Fired Plant, Old Dominion Electric Cooperative
Clover, VA, 1988 – 1996
Material handling contract engineer for the 2 x 424-MW unit project in Virginia. Prepared material handling specifications for the turnkey contract. Evaluated the material handling sections of the turnkey contract proposals. Assisted owner review of the material handling subcontract specifications and review compliance submittals.

Laramie River Station, Basin Electric Power Cooperative
Wheatland, WY, 1975 – 1982
Contract engineer for the coal, limestone and sludge handling systems for the 3 x 570-MW Laramie River Station. Coal handling system included rotary car dumper, three 17,000-ton concrete coal storage silos, scraper loadout system and crusher house. All conveyors are mounted in 13-foot-diameter tubular galleries. The sludge handling system uses overland conveyors to deliver fixed sludge to the landfill area.

Dallman Station Unit 33, Springfield Illinois City Water, Light & Power
Springfield, IL, 1978 – 1981
Contract engineer for the limestone and sludge handling system for a scrubber retrofit at the Dallman Station Unit 33. System included truck unloading hopper and a radial stacker for sludge.

235 MW Coal-Fired Plant, Alabama Electric Cooperative
Le Roy, AL, 1975 – 1979
Contract engineer for the coal and limestone handling systems at this add-on 235-MW unit. Coal handling system included a track hopper, crusher house, overhead tripper stockout system, rotary plow reclaimer and a sample system.

233 MW Coal-Fired Plant, Plains Electric G&T Cooperative
Prewit, NM, 1979
Contract engineer for the coal, limestone and sludge handling systems for a 233-MW unit. System includes a rotary car dumper, large conical stockpile and coal crushers.

Bonanza Unit 1, Deseret G&T Cooperative
Vernal, UT, 1979
Material handling engineer during the conceptual design and material handling contract award for the 400-MW Bonanza Unit 1. System includes large track hopper for rapid

discharge cars, a 17,000-ton coal storage silo and crusher house.

236 MW Coal-Fired Plant, Gainesville Regional Utilities
Gainesville, FL, 1977
Contract engineer for the coal handling system for a 236-MW unit. Coal handling system included a large rail hopper for rapid discharge cars, twin conical pile stockout and reclaim structure and crusher house.

235 MW Coal-Fired Plant, Sikeston Board of Municipal Utilities
Sikeston, MO, 1977
Material handling engineer for the coal and limestone handling systems for this 235-MW plant. Coal handling system includes a track hopper, twin stockout conveyors and a crusher house.

Thomas Hill Unit 3, Associated Electric Cooperative
Thomas Hill, MO, 1976
Contract engineer for the coal handling system for the 670-MW Thomas Hill Unit 3. Coal handling system has a raw/washed coal blending system, twin conical stockpiles and a crusher house. Also provided engineering assistance for the limestone and sludge handling systems. The sludge handling system features a large rail-mounted traveling stacker.

Janel K. Junkersfeld, P.E.

Process Engineer

Burns & McDonnell SINCE 1898

Expertise
- Power Plant Systems Design

Education
- Bachelor of Science, Chemical Engineering, Kansas State University

Organizations
- American Society of Mechanical Engineers

Registration
- E.I.T. - Kansas

Total Years of Experience
10

Years With Burns & McDonnell
2

Start Date
March 26, 2007

Miss Junkersfeld has served as a development engineer for the technical development of gas-fired cogeneration, simple-cycle and combined-cycle, and IGCC projects for Burns & McDonnell's Energy Division. Her duties include conceptual design, budget and definitive cost estimates, performance, technical feasibility, and economic analysis of these projects.

Miss Junkersfeld has served as mechanical system engineer on a number of power projects where she was responsible for detailed design, plant layout, equipment specification and installation, piping specifications and piping design, and mechanical systems design. Miss Junkersfeld also had experience in contract management on numerous mechanical contracts of over $1 million. Her responsibilities included drafting technical specifications, analyzing bids, contract negotiation, critically reviewing shop drawings, and overseeing progress of fabrication, delivery and installation. Contracts administered included water treatment & chemical feed systems, and boiler feed pumps, among others.

Gas Turbine Technology Assessment, South Texas Energy Cooperative
Texas

Development engineer for evaluation of the frame gas turbine vs. aeroderivative gas turbine for simple cycle and combined cycle application. Analyses included capital cost, LTSA cost, performances and estimated emissions; all of which will be used as inputs for further site specific development effort.

Cash Creek Project, Cash Creek Energy Center
Kentucky

Miss Junkersfeld is a process engineer working on the Cash Creek Generation Plant establishing system descriptions, interface diagrams, and EPC specifications. Burns & McDonnell is working on the pre-finance engineering development of the 550 MW coal gasification to SNG project.

Confidential Gasification Projects, Confidential Clients
Various - Confidential

Lead engineer for conceptual design development of several gasification projects. Projects include various proprietary gasification and chemical production technologies. Front end planning development studies include site layout, capital cost and operations & maintenance cost estimates, preliminary performance and emissions, and report preparation; all of which are incorporated into a bound report presented to the client.

Don Schilling, P.E.
Water Treatment Specialist

Expertise
- Water Treatment
- Waste Water Treatment
- Chemical Conditioning
- Water Quality Control
- Material Selection

Education
- B.S. Chemical Engineering, Rockhurst University, 1972

Registration
- Professional Engineer - Missouri

Total Years of Experience
32

Years With Burns & McDonnell
7

Start Date
2000

Mr. Schilling is a Senior Associate Chemical Engineer with more than thirty years of experience in water and wastewater treatment. His areas of expertise include the design, specification, and procurement of Chemical Treatment Systems for Industrial Facilities and Power Plant Water Treatment and Wastewater Treatment Systems. He has specialized experience in material selection, corrosion control, desalination systems, water treatment systems, ion exchange processes, and water chemical conditioning. Mr. Schilling has participated in the design of numerous power projects and provided design in an Owner Engineer capacity.

Iatan Station, Kansas City Power & Light
Weston, Missouri

Responsible for the design and procurement of water and wastewater treatment systems for a new 850 MW coal fueled steam generating unit. The new unit design incorporates an FGD blowdown treatment system with reuse of cooling tower blowdown to achieve zero liquid discharge.

J. K. Spruce Station, City Public Service
San Antonio, Texas

Prepared conceptual studies to determine additional water treatment system requirements for a new 750 MW coal fueled steam generating unit. Prepared EPC specifications for the procurement of the water treatment equipment.

Council Bluffs Energy Center, MidAmerican Energy Company
Iowa

Responsible for the review of EPC Contractor submittals for water treatment systems for the 790 MW coal-fired plant utilizing one supercritical steam generator burning Powder River Basin (PRB) coal.

Hugo Unit 2, Western Farmer's Electric Cooperative
Fort Towson, Oklahoma

Currently providing the conceptual design for the development of a 750 MW supercritical coal fired unit. The design includes a zero discharge concept for the new unit.

Prairie State Generating Station, Peabody Energy
Lively Grove, Illinois

Responsible for the review of EPC Contractor submittals for the water treatment systems for two 750 MW coal fueled units. Major water treatment equipment includes raw water clarifier/softener, reverse osmosis treatment with mixed bed demineralizer, and deep bed full flow condensate polishing.

Sugar Creek Combined Cycle, Mirant Sugar Creek, LLC
Terre Haute, Indiana

As a Project Process Engineer, he designed and procured water treatment consisting of multimedia filters, reverse osmosis followed by electrode ionization, cycle and circulating water chemical feed, and the sample and analysis system.

Choctaw Gas Power Plant, Tractebel
Ackerman, Mississippi

He was assigned as a Project Process Engineer. He reviewed design of water treatment, wastewater treatment, and chemical conditioning systems as the Owner's Engineer for the combined cycle gas power plant. The design included wastewater treatment facilities to allow zero discharge operation.

Zeeland Power Station, Mirant Corporation
Zeeland, Michigan
As a Project Process Engineer, he designed and procured water treatment equipment for the combined cycle conversion, including 2-pass reverse osmosis system, sampling and analysis system, cycle chemical feed, and circulating water chemical feed.

Chehalis Generation Facility, Chehalis Power Generating Limited Partnership
Lewis County, Washington
He was assigned as a Project Process Engineer. He provided engineering review of the design of water treatment and water conditioning systems as the Owner's Engineer for the combined cycle generating plant.

Perryville Combined Cycle Plant, Perryville Power Company, L.L.C.
Perryville, Louisiana
As a Project Process Engineer, he designed and procured water treatment system consisting of greensand filters, reverse osmosis treatment followed by electrode ionization, sampling and analysis system, circulating water chemical feed, and cycle chemical feed systems for the Combined Cycle Project.

Bosque County Unit 4, Southern Energy, Inc.
Laguna Park, Texas
As a Project Process Engineer, he designed and procured water treatment equipment consisting of reverse osmosis treatment of Brazos River water, sampling and analysis system, circulating water chemical feed, and cycle chemical feed for the Combined Cycle Conversion Project.

Mr. Schilling provided design of water and wastewater treatment facilities for the following coal-fired units as the EPC contractor. His work included design, procurement, startup, and commissioning.

- JAWA Power, Paiton Power Project; Paiton, Indonesia: The EPC scope included seawater desalination, cycle makeup treatment, condensate polishers, electrochlorination, chemical feed, sampling systems, and wastewater treatment for heavy metals removal for two 650 MW coal-fired units. Mr. Schilling also provided on-site startup and commissioning assistance for all water treatment systems.

- Taiwan Power Company – Taichung Power Station; Taichung, Taiwan: The EPC scope included treatment of the wastewater generated by the flue gas desulfurization systems for eight coal fueled steam generated power plants. On-site assistance was needed to optimize the operation of the treatment process to achieve necessary discharge limits.

Mr. Schilling also had performed studies for several clients to review and develop water management programs or investigate problems associated with corrosion or plant operations. Following is an example of a study performed for a multi-unit facility:

- China Light & Power Company – Castle Peak Power Station; Hong Kong: Prepared a wastewater management study for a 4,500 MW generating facility. The station consisted of eight coal-fueled units and multiple gas/oil fueled combustion turbines. The study evaluated the existing water and wastewater management practices and determined modifications necessary to achieve compliance with new environmental regulations. Following this study, Mr. Schilling managed the engineering effort to implement the recommendations of the study.

Larry K. Lucas

Project Controls Engineer

Burns & McDonnell SINCE 1898

Expertise

- Project Controls Management
- Project Planning
- Commercial Management

Education

- B.S. Construction Management University of Nebraska-Lincoln, 1973

Organizations

- American Association of Cost Engineers

Years of Experience

34

Mr. Lucas has served as the commercial manager, project controls manager, and as project planner on a variety of power plant projects. He has directed project controls teams in planning and cost control for large coal-fired plants to simple cycle combustion turbines.

As commercial manager, Mr. Lucas has provided project controls services for combined cycle projects ranging from 115 MW to 560 MW and located in all parts of the USA and overseas. Mr. Lucas has served as project controls manager for numerous large coal and gas fired power plants located in Minnesota, Colorado, Arizona, Kansas, Oklahoma, and North Dakota. Retrofit projects and extensive field assignments complete Mr. Lucas experience in the industry.

Mr. Lucas was also project controls manager for combined cycle plants for City Public Service of San Antonio, Alabama Electric, Tenaska, Florida Power Corp., and Enron. These projects all involved managing the project controls functions between contractors, vendors, and design.

As a project controls manager, projects for Cooperative Power Association at Coal Creek in North Dakota and for Platte River Power Authority in Colorado have occurred through his career. Mr. Lucas provided project controls manager duties for Circulating Fluidized Bed projects in Hawaii and Florida for AES.

Other coal projects are large stations for Kansas Power and Light, Public Service Co. of Oklahoma, and Salt River Project ranging from 250 MW to 700 MW.

Other project experience:

Progress Energy

2007 – Present

He is the Project Commercial Manager for project controls for an AQCS upgrade for 2 x 750 MW pulverized coal power plant in Florida.

Kansas City Power & Light

2005 – 2007

He was the Project Controls Manager for initial project controls planning for a new 850 MW pulverized coal 2nd unit power plant and a AQC upgrade for unit 1 at the Iatan Plant site.

Prairie States

2005 – Present

He is the Project Controls Manager for 2x700MW pulverized coal power station, an Owner's Engineer project.

Alliant Energy

Mason City, Iowa, 2002 – 2005

He was the Commercial Manager for a 500 MW combined cycle project. The project included the project control coordination of multiple contracts for the construction and detail design. .

Florida Power and Light

Rhode Island, 2000 – 2001

He was the Commercial Manager for installation of 500 MW combined cycle.

Reliant Power
Illinois, 2000
He was the Project Controls Manager on a fastrack 8 unit 320 MW simple cycle project.

City Public Service Company
Texas, 1998 – 1999
He was the Commercial Manager for 500 MW combined cycle project.

Hanfeng Boiler Steel Project, Hebei Hanfeng Power Company
China, 1997 – 2000
He was the commercial manager for the project located in central China. Duties included planning, cost control, and contracts administration involved with the design, procurement, and logistics for steel supply to a new 800 MW coal plant.

Florida Power Corp
Rhode Island, 1997 – 1999
He was the Project Controls Manager for design & procurement of 500 MW combined cycle plant in central Florida.

Alabama Electric
Alabama, 1999 – 2001
He was the Project Controls Manager for 500 MW combined cycle project located in southern Alabama

ENRON Power
Puerto Rico, 1997 – 1999
He was the Project Controls Manager for a 560 MW combined cycle project.

Kwinana Combined Cycle Project, Mission Energy
Perth, Australia, 1994 – 1997
He was assigned as commercial manager for 120Mw Combined Cycle project. He was responsible for field office management, project controls, purchasing and invoice approvals of all vendors and contractors on the project

Tenaska
Washington, 1994 – 1995
He was the Project Controls Manager for a 250 MW combined cycle project.

Tenaska
Washington, 1992 – 1994
He was the Project Controls Manager for a 260 MW combined cycle project.

Omaha Public Power District
Nebraska, 1992 – 1993
He was the Project Controls Manager on a 140 MW simple cycle project.

Boston Edison
Massachusetts, 1990 – 1992
He was the Project Controls Manager for a balanced draft project.

AES
Florida and Hawaii, 1990 – 1992
He was the Project Controls Manager for 250 MW CFB projects.

Omaha Public Power District
Nebraska, 1989 – 1990
He was the Project Controls Manager for balanced draft/precipitator project. Also consulted OPPD on Project Controls procedures for their home office.

AT&T
Arizona, Nevada, California, and Colorado, 1988 – 1989
He was the Project Planner for the Western Lightguide Fiber Optics Projects.

Salt River Project
Arizona, 1987 – 1988
He was the Field Project Planner on site at a 450 MW coal plant.

Northern States Power
Minnesota, 1983 – 1987
He was the Field Project Controls Manager for the 800 MW Sherco Unit 3.

Platte River Power Authority
Colorado, 1980 – 1983
He was the Field Project Controls Manager for a 250 MW coal plant.

Cooperative Power Authority
North Dakota, 1977 – 1980
He was the Field Planner for the 2 unit 1000 MW Coal Creek Station.

Kansas Power and Light
Kansas, 1975 – 1977
He was the Project Planner and Cost Engineer for the 2 unit 1400 MW Jeffery Energy Center project.

Public Service Company of Oklahoma
Oklahoma, 1974 – 1976
He was the Project Planner for a 400 MW gas fired plant.

City Public Service Company
Texas, 1973 – 1975
He was the Project Planner for the 2 units 500 MW JT Deely plant and railcar maintenance facility.

John A. Rise

Procurement Manager

Burns & McDonnell SINCE 1898

Education

- B.S. Mathematics, Nebraska Wesleyan University, 1989

Total Years of Experience

10

Years With Burns & McDonnell

8

Start Date

August 2000

Mr. Rise is a Project Procurement Manager for Burns & McDonnell Engineering Company, Inc. He is responsible for developing, implementing and managing project procurement plans in support of specific project requirements. Mr. Rise develops project procurement plans, establishes appropriate procurement strategies, sources and qualifies prospective suppliers and subcontractors, and manages the bid solicitation, receipt, evaluation, negotiation and award processes for purchase orders and subcontract agreements. He also performs purchase order and subcontract administration activities including tracking and expediting supplier deliverables, analysis and preparation of changes orders, review and tracking of supplier insurance certificates and performance bonds and other forms of security, and verification of supplier invoices to ensure compliance with contractual requirements.

Mr. Rise's most recent experience while at Burns & McDonnell includes:

- Project Procurement Manager on Seminole Electric Cooperative, Inc.'s Seminal Generating Station, Unit 3 Project, an 800 MW coal plant located in Palatka, Florida.
- Project Procurement Manager on Seminole Electric Cooperative, Inc.'s Seminal Generating Station, Units 1 and 2 Pollution Controls Upgrade Project. This project consists of adding SCR's, and upgrading the FGD's and ID fans on two 715 MW coal units located in Palatka, Florida.
- Project Procurement Manager on the Alaoji Power Project, a 1000 MW 4-on-2 combined cycle plant located in Nigeria, Africa.
- Project Procurement Manager on Alliant Energy Generation, Inc.'s Sheboygan Falls Energy Facility, a 350 MW simple cycle plant located in Sheboygan Falls, Wisconsin.
- Project Procurement Manager on Interstate Power and Light Company's Power Iowa Energy Center, a 550 MW 2-on-1 combined cycle plant located in Clear Lake, Iowa.
- Project Procurement Manager on South Texas Electric Cooperative's Sam Rayburn Combined Cycle Plant Addition, a 170 MW 3-on-1 combined cycle plant added to the existing plant located in Nursery, Texas.
- Purchaser on the Mirant Bosque County Combined Cycle Project, a one-on-one combined cycle project adding an additional 244 MW to the existing plant located in Laguna Park, Texas.

Prior to joining Burns & McDonnell Mr. Rise worked as a buyer on a multitude of domestic and international coal and combined cycle power projects located in China, Pakistan, Bahrain, Turkey, Mexico, and various part of the united States. Mr. Rise prepared Request For Quotation documents, participated in pre-qualifying suppliers, analyzed commercial proposals, negotiated, recommended award, prepared purchase orders and contracts, expedited commercial submittals, and tracked documents from initial design through contract execution. Mr. Rise was responsible for coordinating bid lists between projects and coordinating the purchase of similar equipment between projects to increase leveraging opportunities between projects. Noteworthy projects include:

- Nantong, located in China
- Bin Qasim, located in Pakistan
- Al Hidd, located in Bahrain
- Marmara, located in Turkey
- Merida, located in Mexico
- CPS San Antonio, located in San Antonio, Texas
- Empire District State Line Project, located in Joplin, Missouri

Gary Mouton

Cost Estimator

Burns & McDonnell SINCE 1898

Education

- Terrebonne High School, 1974

Training

- Supervisory Skills Training, 1987
- Frontline Leadership Training, 1992
- Supervisory Conference, 1993
- Primavera Construction and Planning Conference, 1995, Superintendent's School, 2001
- Project Engineers School, 2005

Total Years of Experience

33

Years With Burns & McDonnell

1

Start Date

March 2007

Mr. Mouton serves Burns & McDonnell as a Mechanical Estimator with 22 years experience. He is responsible for developing project estimates from the conceptual stage through final design. His duties include quantity take-offs, pricing of construction materials, labor and indirects. He has provided estimating assistance on design build projects and engineering estimates. A summary of Mr. Mouton's previous experience is provided below:

Prairie State Energy Center 1500 MW Coal Fired Power Plant, Peabody Coal

Illinois, 5/07 – present

Mr. Mouton serves as Mechanical Cost Estimator and is responsible for verifying contractors lump sum EPC estimate and construction sequence and reviewing change orders.

800 Ton Chilled Water Plant and 100 MW Combined Cycle Heat & Power Expansion, TECO

Houston, TX, 3/07 – present

Mr. Mouton serves as Mechanical Cost Estimator and is responsible for coordination of all discipline estimators and creation of total EPC estimate. Duties also include constructability input and acting as sub-contracting coordinator.

Cedar Bayou 200 MW Combined Cycle Cogeneration Plant, Chevron Phillips

Baytown, TX, 8/07 – present

Mr. Mouton serves as Mechanical Cost Estimator and is responsible for coordination of all discipline estimators and creation of total EPC estimate.

Catoctin 500 MW Combined Cycle Power Plant, Sempra Energy

Fredrick, MD, 10/07 – 11/07

Mr. Mouton served as Mechanical Cost Estimator and was responsible for verifying contractors lump sum EPC estimate and construction sequence.

Teche Energy Center 500 MW Combined Cycle Power Plant, CLECO

Franklin, LA, 9/07

Mr. Mouton served as Mechanical Cost Estimator and was responsible for constructability input.

33 MW Co-gen, Sasol

Lake Charles, LA, 9/07 – 11/07

Mr. Mouton served as Mechanical Cost Estimator and was responsible for coordination of all discipline estimators and creation of total EPC estimate.

PREVIOUS EXPERIENCE

Kiewit Industrial Co.

Lenexa, KS, 3/06 – 3/07

Mr. Mouton served as Sr. Lead Estimator. His responsibilities included: Ownership, management and production of EPC and Construction Only Estimates, from cradle to grave, including but not limited to, coordinating/directing discipline leads and engineering partners through deliverables list with dates and estimate schedules assuring a sound estimate foundation and within the confines of the proposal schedule. Additionally, it includes selecting the proper projects for past cost comparables, reviewing each discipline estimate, setting a game plan and methodology (including review of bid tabs) for pricing permanent materials and subcontracts, develop a full set of indirects, clarifications and exceptions, project schedule and assist in the proposal effort. Estimates performed included gas fired; simple and combined cycle; coal; wind; preliminary IGCC (integrated gas combined cycle); air quality control systems; LNG (liquidified natural gas) terminals; SAG-D and upgrader refinery in Northern Alberta oil sands; nuclear; Y-12 weapons manufacturing.

Kiewit Industrial Co.
Egan, MN, 5/05 – 2/06
Mr. Mouton served as Assistant Project Engineer and was responsible for managing approximately twelve multi-disciplined field engineers on a construction only ultra-low sulfur diesel unit expansion at an existing refinery. Additionally responsible for the assembly, negotiation and execution of all change orders.

Kiewit Industrial Co.
Lenexa, KS, 3/05 – 5/05
Mr. Mouton served as Piping Lead and was responsible for piping and structural steel constructability and engineering liaison on the design of a gas-fired combined cycle power plant. This was a temporary assignment.

Kiewit Industrial Co.
Lenexa, KS, 3/02 – 2/05
Mr. Mouton served as Lead Piping Estimator/Estimate Lead and was responsible for material take-off activities for as many as 16 estimators on multiple projects, permanent material and subcontract, RFQ's, evaluations and preparing bid tabs with recommendations, applying unit rates and rolling up into a discipline estimate. Additionally from 2003 – 2005, performed as estimate lead with same duties.

Kiewit Industrial Co.
Baton Rouge, LA, 10/00 – 2/02
Mr. Mouton served as Piping General Superintendent and was responsible for the procurement, subcontracts, hiring, scheduling, planning, erection and testing of all piping systems for a 500 MW natural gas fired combined cycle power plant. Employee contingent was 5 superintendents with field engineers and 100+ pipefitters.

Aker Gulf Marine (Aker/Kiewit J.V.)
Ingleside, TX, 6/85 – 9/00
Mr. Mouton performed in numerous positions over this period that included pipefitter, general foreman, MTO/Estimator, field engineer, senior piping field engineer/coordinator, project engineer and managing an offsite pipe spool and pipe support facility with 75 employees.

Numerous Companies
Houma, LA, 11/74 – 5/85
Mr. Mouton worked for three construction companies developing skills as a pipefitter and as a pipefitter foreman.

Dan Lumma, P.E.

Education			
Degree	**Specialty**	**Institution**	**Year**
B.S. Electrical Engineering		University of Missouri, Rolla	1990
Professional Engineer	Kansas (#13545)		

Kiewit Education	
School	**Year**
Executive Leadership Development Program (ELDP)	2007
Senior Engineering Seminar	2005
Management Seminar	2002

Kiewit Experience

Project Name	Title*	From	To	Description of Responsibilities**
Kiewit Energy Company	Vice President, Gasification	6/07	Present	Responsible for identifying bidding and sponsoring Gasification projects
Kiewit Energy Canada, Co.	EPC Project Manager	11/04	5/07	Canadian Natural Resources, LTD. (CNRL)"Horizon Oil Sands Project" Gas Treating and Sulphur Recovery Facility Responsible for management of engineering, procurement, construction, pre-commissioning of a $350 M (Canadian), 800 ton per day sulphur recovery and gas treating facility.
Kiewit Offshore services, Ltd.	EPC Project Manager	1/03	10/04	Responsible for identifying and bidding domestic and international offshore EPC projects.
Kiewit Power Engineering	Vice President	10/02	12/03	Responsible for business development and operations for Industrial Division.
Kiewit Power Engineering	Manager of Projects	12/01	9/03	Responsibilities included sponsoring from bid to completion all engineering and design scope for multiple major power plant design projects. Projects included the following: Kiewit Industrial Co. – MidAmerican Energy Company – "Greater Des Moines Energy Center", Pleasant Hill, Iowa – Project Sponsor - Nominal 540 MW Combined Cycle power project. The Industrial Company – Public Service Co. of New Mexico – "Afton Power Project", Las Cruces, New Mexico – Project Sponsor - Nominal 140 MW Simple Cycle facility.

Kiewit Power Engineering	Engineering Project Manager	8/97	11/01	Responsibilities included engineering and design project management for major power plants. Projects included the following: Kiewit Industrial Co. – Constellation Energy – “High Desert Power Project”, Victorville, California – Design Project Manager - 750 MW Combined Cycle project. *Named “2003 Power Plant of the Year” by Platts Power Magazine*. Kiewit Industrial Co. – Calpine – “Los Medanos” Project, Pittsburg, California – Design Project Manager - 500 MW Combined Cycle power project.
Kiewit Power Engineering	Project Engineer	1/95	7/97	Responsibilities included engineering management for major power plants, and other industrial projects. Projects included the following: National Power Development, Inc. a subsidiary of Marubeni Corporation – KMR Power, “Termovalle” Project, Cali, Colombia - Engineering Manager - 200 MW combined cycle power plant. General Motors Corporation – Fairfax Assembly Plant, Kansas City, KS - Project Engineer – Bodyshop-wide safety upgrade retrofit including over 130 automated robotic work cells.
Kiewit Power Engineering	Engineer	5/90	12/94	Responsibilities included design, field engineering, operations training and construction and start-up support. Projects included: Browning-Ferris Gas Services, Inc. - Pine Bend Landfill Power Project - Startup Engineer - 15 MW Pine Bend landfill gas turbine power project, near Minneapolis, MN. Jamaica Public Service – GT 10 Simple Cycle Power Project – Resident Engineer – 35 MW Simple Cycle power project located in Kingston, Jamaica. Clarion Power Constructors, J.V. – “Piney Creek Project” - Project Controls Engineer and Resident Controls Engineer - 30 MW waste coal power plant located in Clarion, Pennsylvania.

Brad Wolf – Electrical Superintendent

Career Summary

Worked for Kiewit Energy for 3.5 years and have held a number of positions from Superintendent to ConstructSim administrator. Worked on a number of estimates and projects within the Kiewit organization with Kiewit Energy as well as with other districts. Currently running work in electrical department at the field at the Mt. Vernon Ethanol Project.

Education

Degree	Specialty	Institution	Year
Bachelor Science of Electrical and Computer Engineering (BSECE)	Microprocessor design and high voltage distribution	The Ohio State University	2005

Kiewit Education

School	Year
Kiewit Scheduling Course	2008
KIC Project Engineer School	2007
Supervisory Conference	2007
ConstructSim Admin Training	2006
Field Engineer School	2006

Professional Registrations

Registration	Reg. #	State	Expiration

Associations

Association	Assoc. #	Position Held
Institute for Electrical and Electronics Engineers (IEEE)	80030872	--

Kiewit Experience

Project Name	Title*	From	To	Description of Responsibilities**
Mt. Vernon Ethanol	Electrical Supt.	6/08	Pres	Ran crews, schedule, & materials for installation of electrical.
Mt. Vernon Ethanol	Electrical Field Engineer	8/07	6/08	Assisted a superintendent with his duties, cost control, schedule, material ordering, and planning with supervision.
Houston Office	Lead Estimator	1/07	8/07	Lead electrical estimator and lead estimator.
Houston Office	Estimator	4/06	1/07	Electrical estimator
Pine Bend	Field Engineer – ConstructSim Administrator	9/05	4/06	Field engineer in charge of ConstructSim. Planning and creating piping work packs for field use.
Houston Office	Estimator	7/05	9/05	Electrical estimator

* If you held multiple titles on one project, enter each title separately
** Describe responsibilities and skills of the person – this is not for project descriptions

Other Experience

Project Name	Title	From	To	Description of Responsibilities

TYSON BUNDY, Construction Manager

Education

Degree	Specialty	Institution	Year
Bachelor of Science	Mechanical Engineering	Iowa State University, Ames, Iowa	1996

Kiewit Education

School	Year
Peter Kiewit Son's Supervisory Conference Peter Kiewit Son's Surveying Course Peter Kiewit Son's Scheduling Course Peter Kiewit Son's Superintendent's School	1998 1999 1999 2003

Kiewit Experience

Project Name	Title*	From	To	Description of Responsibilities**
Mt Vernon Ethanol, a 108MGY ethanol production facility in Mt. Vernon, IN	Construction Manager	1/07	Present	Overall responsibility for all construction activities. Managed a team of 40 superintendents and field engineers in safety, quality of work, planning and scheduling of craft (340,000 Direct MHR) and subs, construction equipment, and cost control.
Illinois River Energy, a 50MMGY ethanol production facility in Rochelle, IL	General Mechanical Superintendent	2/06	12/06	Overall responsibility for all piping, rotating equipment, non-rotating equipment, boiler, dryer package, and scaffolding. Managed a team of superintendents and field engineers in safety, quality of work, planning and scheduling of craft and construction equipment, and cost control.
Pine Bend Phase II, a greenfield Hydrocracker process plant at the Flint Hills refinery near Rosemont, MN	General Equipment Superintendent	4/05	1/06	Overall responsibility for all concrete, structural steel, rotating equipment, non-rotating equipment, scaffolding, fireproofing, painting, insulation, and refractory work. Managed a team of superintendents and field engineers in safety, quality of work, planning and scheduling of craft and construction equipment, and cost control. Heavy involvement with owner and construction management company.
Compass Port FEED, a 50,000 cu. meter off-shore LNG storage facility. ARUP Engineering, Houston, TX	Lead Mechanical / Electrical Estimator	9/04	3/05	Designed and estimated all utilities for new graving dock development. Prepared estimate for all mechanical and electrical work on the concrete gravity caisson.
Kiewit Industrial Co.'s Home Office in Lenexa, KS	Lead Estimator	6/04	9/04	Responsible for leading an estimate team in preparing all aspects of estimates for various coal and combined cycle power projects. Responsibilities include coordination of all discipline leads, supporting needs of business development team, production of indirect item estimates, risk analysis, and estimate closeout.

Kiewit Industrial Co.'s Home Office in Lenexa, KS	Lead Piping Estimator	9/03	6/04	Responsible for leading a piping estimate team in preparing all aspects of piping estimates for various coal and combined cycle power projects. Responsibilities include supervising direct takeoff, material, and subcontract solicitations. Determining production factors, and planning and scheduling how to build the work.
Fluvanna Generating Station, an 890 MW combined cycle power plant in Scottsville, VA.	Piping Superintendent	2/02	9/03	Responsible for direct supervision of pipefitter crews. Area of work includes underground piping, and all water treatment and non-power block piping. Also responsible for all crafts and subcontractors in the water treatment building. Responsible for safety, productivity, planning and scheduling, and quality of work for said crews. Also responsible for system turnover to startup group.
Lindsay Hill Generation Station, an 860 MW combined cycle power plant in Billingsley, AL	Piping Superintendent	6/01	2/02	Responsible for direct supervision of pipefitter crews. Area of work included combustion turbine piping, balance of plant power block piping, as well as punchlists for all piping in plant. Responsible for safety, productivity, planning and scheduling, and quality of work for said crews. Also responsible for system turnover to startup group, as well as startup support.
Lindsey Hill Generation Station, an 860 MW combined cycle power plant in Billingsley, AL	Lead Piping Field Engineer	9/00	6/01	Area of work included all balance of plant piping, water treatment piping, combustion turbine piping, and steam turbine piping and non-rotating equipment. Responsibilities include interpretation of all design drawings for craft, requisitioning of site purchase materials, tools, and consumables, quantity tracking, productivity and cost tracking, cost projections, owner billing, scheduling of craft, resolution of field problems and engineering errors, managing other field engineers and clerical help within the piping department. Also responsible for administration of several material contracts and EPO's.
Frontier Generation Station, an 830 MW combined cycle power plant in Shiro, TX	Lead Piping Field Engineer	1/99	9/00	Area of work includes all balance of plant piping and non-rotating equipment. Responsibilities include interpretation of all design drawings for craft, requisitioning of site purchase materials, tools, and consumables, quantity tracking, productivity and cost tracking (including giving staff training sessions), scheduling of craft, resolution of field problems and engineering errors, managing other field engineers and clerical help within the piping department, and assisting startup group to meet needs associated with bringing plant on-line. Also responsible for administration of several material contracts and EPO's.

Morris Cogeneration Project, a 118 MW and 1,080,000 lb steam cogeneration plant within the Millennium Chemical plant in Morris, IL	HRSG Field Engineer	6/98 -	12/98	Area of work included Heat Recovery Steam Generator (structural and piping), duct burners, off-gas compressors and all associated piping. Responsibilities included interpretation of design drawings for craft, field routing of small bore piping, requisitioning of site purchase materials, tools, and consumables, quantity tracking, productivity and cost tracking, coordination of chemical clean subcontractor, and resolution of field problems and engineering errors. Also responsible for administration of insulation subcontract, redesign of heat trace system, and assisting with electrical quantity tracking system.
Kiewit Industrial Co.'s Home Office in Omaha, NE	Engineer-Estimator	9/97	5/98	Responsible for estimating numerous projects, including cogeneration, water treatment, chemical, and process work. Performed quantity takeoffs, solicitation, evaluation, and incorporation of vendor and manufacturer materials and subcontract pricing, prepared recaps, pricing sheets, bid forms and other proposal documents for in-house review and bid submittal. Additionally, acted as network administrator for a 50-user computer network. Responsibilities included hardware and software upgrades for workstations, purchasing and replacements of parts and workstations, trafficking of incoming and outgoing e-mail, troubleshooting of various software and network problems, worked with vendor to prepare proposal and installation of new network server and operating system.
Northeast Corridor Rail Electrification Project, a joint venture between Mass Electric Co and Balfour Beatty to convert the 172 mile rail line between Boston, MA and New Haven, CT from diesel to electric cantenary train service	Field Engineer	1/97	8/97	Worked with foundation subcontractor J.F. White to install over 14,000 precast foundations. Responsibilities included survey verification and coordination of utility locates prior to entering work area. Worked with drilling rigs to ensure drilling tolerances were met and provided engineering solutions to site problems. Worked with grouting rigs to ensure final placement of foundations were within allowable tolerances. Worked with distribution rigs on material layout and distribution. Responsible for reporting of all quantities of completed work. Worked with shift superintendent to coordinate work with crews and Amtrak representatives.
Kiewit Industrial Co.'s Home Office in Omaha, NE	Engineer-Estimator	6/96	12/96	Responsible for estimating numerous projects, including cogeneration and chemical process work. Performed quantity takeoffs, solicitation, evaluation and incorporation of vendor and manufacturer material and subcontract pricing, prepared recaps, pricing sheets, bid forms and other proposal documents for in-house review and bid submittal.

* If you held multiple titles on one project, enter each title separately
** Describe responsibilities and skills of the person – this is not for project descriptions

Other Experience

Project Name	Title	From	To	Description of Responsibilities

ACI Mechanical	Mechanical Engineer	5/95	5/96	Project management and engineering responsibilities for estimating work, material takeoffs, HVAC and plumbing design and layout, CAD drafting, and dealing directly with jobsite personnel, material vendors and subcontractors.

Roger E. Errington, Jr.

Education

Degree	Specialty	Institution	Year
Bachelor of Science	Civil Engineering	University of California, Berkeley CA	1976
Master of Science	Construction Management	University of California, Berkeley CA	1980
Master of Science	Real Estate Development	Massachusetts Institute of Technology	1995

Kiewit Experience

Project Name	Title*	From	To	Description of Responsibilities**
Kiewit Energy Ltd. Houston, Texas	District Estimating Manager	1/05	Present	Responsible for managing all company estimates in the U.S. and Canada on a wide variety of construction projects in the energy - oil and gas sector.
Kiewit Engineering Co. Omaha, NE	Senior Engineer-Estimator & Estimate Sponsor	1/99	1/05	Lead Estimator for the successfully bid Woodrow Wilson Bridge Foundation contract, Afton Simple-Cycle Power Plant and the Palomar Combined-Cycle Power Plant. Estimate Sponsor for major industrial, structural and transit projects.

Other Experience

Project Name	Title	From	To	Description of Responsibilities
SeaStar Properties Ltd. Rayong, Thailand	Executive Director	1/96	12/98	Executive Director for a joint venture developing and managing planned communities for multi-national companies, such as Shell and Caltex, operating in Thailand.
Various Singapore/Thailand	Management Consultant	1/95	12/95	Worked on the development and successful presentation of a major construction arbitration case in Singapore. Consultant for a publicly–listed Thai property developer.
Thai Leighton Bangkok, Thailand	Construction Manager	1/93	12/94	Construction Manager for large port construction project. Revised the construction methodology, resulting in significant time and cost savings. Introduced QA/QC program that reduced material problems that were impacting the job.
IPCO International Singapore	Project Development – Various positions	6/82	12/92	Strong track record in major project development work around the world over an 11–year period resulting in increasingly responsible positions, including Business Development Manager, Technical Services Manager and Project Manager
Torno America California	Chief Engineer	1/89	1/90	Chief Engineer, Marine Works, on the Lake Roosevelt Lake Tap and Tunnel Project for the Bureau of Reclamation in Arizona. Helped develop drilling system used for the first time for this type of construction. ENR named the job one of the top ten construction projects in the U.S. in 1990.

Peggy M. McCullough

Education

Degree	Specialty	Institution	Year
Bachelor of Business Administration in Management		Sam Houston State University, Huntsville, TX	2007
Associate of Applied Science in Real Estate		North Central Texas College, Gainesville, TX	1975
ISO 9000 (ASQC Certified) Service Process Management (ASCQ Certified)			

Kiewit Experience

Project	Title	From	To	Description of Responsibilities**
Mt. Vernon Ethanol Plant	Procurement Manager/ Contract Admin	1/08	Present	Responsible for Site Procurement, Contract administration and maintenance, manage warehouse operations and personnel, and Buyers for ST&S.
Location	**Title**	**From**	**To**	**Description of Responsibilities****
Lenexa, KS	Contract Admin	10/07	12/07	Assisted with Mt. Vernon & Aurora West Contracts
Monroe, LA	Purchasing Agent	7/07	9/07	Expedited steam jacketed pipe spools
Houston District Office	Purchasing Agent	5/07	12/07	Performed vendor interviews, cost analysis, commodities market analysis, project cost estimating, presentation preparation, and P3 schedule review.

Other Experience

Project Name	Title	From	To	Description of Responsibilities
Primary Care		8/95	6/04	Primary Care Person for my husband during his bout with lung cancer. In order to stay current with my computer skills, I created reports in Microsoft Access. This skill allowed me to develop accurate records of his daily statistics for the many physicians he saw on a regular basis
Beazer Homes Texas, Inc.	Purchasing Manager	12/94	7/95	Organized and set up the initial purchasing department, Set up and managed all aspects of the computerized purchasing system, take-offs, customer upgrade pricing, vendor pricing, MSDS maintenance, and Director of Safety and OSHA compliance.
Life Forms Homes, Inc	Purchasing Manager	6/92	12/94	Set up standards and price files, customization pricing, options development, change order process and the command post manager of the Johnson Management System. Initiated MSDS maintenance and OSHA compliances as well as directed safety standards.

David Weekley Homes	Purchasing Coordinator	7/91	5/92	Actively establishing material and labor budgets for custom classic division. Material purchases for the Houston Division, product research, supervisor of Expedition Department, and assisted with OSHA compliance.
Royce Homes, Inc.	Purchasing Agent	6/89	7/91	Obtaining material bids, material purchases, and estimating for the Houston, Dallas, and build on Your Lot Division.
Stanford Homes	Construction Manager	5/86	5/89	Managing all aspects of construction on multiple projects
Landmark Homes	Lead Superintendent and Purchasing Agent	3/83	5/86	Setting up the purchasing department as a startup company. Promoted to the field to assist in establishing a production schedule using the ten stages.
Marrs Real Estate	Agent	8/73	10/92	Full time agent 8/73-3/80, Part time agent 3/80-10/92

Volunteer Experience

Project Name	**Title**	**From**	**To**	**Description of Responsibilities**
Aztec Cove Property Owners Association Trinity, Texas		9/02	-	Secretary/Treasurer performing duties of dues collection, statement distribution, bank reconciliation, lien filing, sewer plant operations coordinator, and reporting to state and federal agencies.
McCarCo Auto Sales		8/95	8/98	Set up and maintained all aspects of office procedures for stepson’s auto dealership

Brandon Valverde – Piping Field Engineer

Career Summary

Education

Degree	Specialty	Institution	Year
B.S. Mechanical Engineering		New Mexico State University	2006

School	Year
New Mexico State University	2006

Professional Registrations

Registration	Reg. #	State	Expiration
American Welding Society	08090142	National	09/01/2011

Associations

Association	Assoc. #	Position Held
American Welding Society	08090142	CAWI

Kiewit Experience

Project Name	Title*	From	To	Description of Responsibilities**
Houston District Office	Estimator	01/07	09/07	Pipe & instrumentation estimates, lead estimator for Mt. Vernon Ethanol Project expansion, labor wage rate analysis
Mt. Vernon Ethanol Project	Field Engineer	09/07	Present	ConstructSim administrator, weld database administrator, Certified Associate Welding Inspector, quantity claiming/ tracking, material procurement, 4 week and 90 day scheduling, communicate with and support fire sprinkler subcontractor, misc. field engineer duties

* If you held multiple titles on one project, enter each title separately
** Describe responsibilities and skills of the person – this is not for project descriptions

Other Experience

Project Name	Title	From	To	Description of Responsibilities

Qualifications

Table of Contents

Company Overview

Firm Profile

Founded in 1898, Burns & McDonnell Engineering Company, Inc. is an internationally recognized architectural/engineering and construction firm with our headquarters in Kansas City, Missouri. The firm maintains branch offices throughout the United States and serves international clients through its wholly-owned subsidiary, Burns & McDonnell International, Inc. With annual revenues that exceed $850 million, Burns & McDonnell plans, design, permits, constructs, and manages facilities all over the world with one mission in mind – to make our clients successful.

Safety

Burns & McDonnell is focused on safety for our employee-owners and the Clients and Partners that we work next to every day. We have consistently beat the Construction Industry Institute safety statistic averages, putting B&M in the upper 10% of the industry on safety … and we recognize that still is not good enough. Our words are backed with action and results.

Metric	2006	2007	2008
Experience Modifier Ratio	0.59	0.57	0.57
Recordable Cases / Rate	3 ea / 0.17	4 ea / 0.14	0 ea / 0
Restricted Work Activity Cases / Rate	0 ea / 0	0 ea / 0	0 ea / 0
Lost Workday Cases / Rate	0 ea / 0	0ea / 0	0 ea / 0
Fatalities / Rate	0 ea / 0	0 ea / 0	0 ea / 0
Recordable Incident Rate	0.17	0.14	0.00
Total Workhours	3,559,983	5,342,508	5,863,618

Firm Ownership

Since 1986, Burns & McDonnell has been a 100% employee-owned firm, whose operations are directed by an officer group practicing a participative management philosophy. This combination produces an active interest and involvement on the part of each employee-owner in the performance of our firm. These same employee-owners form the Burns & McDonnell teams that serve our clients.

Operating Global Practices

Our more than 3,000 employee-owners include professional engineers, architects, construction managers, geologists, planners, estimators, economists, computer, and environmental scientists, representing virtually all design disciplines. Burns & McDonnell is comprised of ten functional groups that offer professional services: Energy, Process & Industrial, Environmental Services, Environmental Studies & Permitting, Transmission & Distribution, Aviation & Facilities, Infrastructure, Business & Technology Services, Healthcare & Research Facilities, and Construction Design-Build Services. Our services and expertise directly related to Gasification projects reside in our Energy Group and Process and Industrial Groups. In addition to our World Headquarters in

Kansas City, MO, Burns & McDonnell has a number of regional offices, including nearly 120 employee-owners in Houston, TX (including process engineering capabilities).

Energy

Our Energy group serves electric utility, commercial, institutional, industrial, and government clients, conducting various power-related economic, cost, and design studies. This global practice provides facility design services for steam and electric generation including assisting clients in the start-up and performance testing of new and reconditioned plants, in performing plant performance and operations assessments, in providing facility operations and maintenance (O&M) services, and in training clients' O&M personnel. This group has several specialists available to our clients to address critical issues and aspects of electric system and power plant planning, design, operations, and upgrades.

Process & Industrial

The Process & Industrial Group serves manufacturers that convert the physical or chemical form of a raw or intermediate material into more valuable products. Included are consumer food products, chemicals, petrochemicals, petroleum refinery products, pharmaceuticals, intermediates, and biofuels.

Our engineers (chemical, equipment, piping, electrical, instrument, controls, and civil/structural/architectural), designers and managers provide complete engineering and construction services. The Process & Industrial Group's fundamental expertise in process design is the basis for each successful engineering and construction project. Because we understand the science behind the engineering and the management behind the construction, our designs meet your expectations for efficiency, safety, and cost effectiveness.

Environmental Services

Since the first environmental laws were passed more than 30 years ago, Burns & McDonnell has helped clients achieve cost-effective compliance. Our experts provide risk assessment, soil and groundwater testing, and remediation; and design facilities and systems to handle solid and hazardous waste.

Environmental Studies & Permitting

Environmental studies and permitting are a critical first stage for many projects. Focused studies, comprehensive knowledge of environmental guidelines and longtime relationships with regulatory agencies are the keys to steering your project through the permitting process. Burns & McDonnell's Environmental Studies & Permitting group understands the complex regulatory requirements that affect your projects. A multidisciplinary staff of environmental scientists, engineers, and planners collaborates to find practical and cost-efficient solutions for your project's present and future permitting needs

Transmission & Distribution

Transmission & Distribution (T&D) services include T&D system studies and analyses, transmission engineering, distribution engineering, substation engineering, and relay and control engineering for both industrial and large utility clients.

Aviation & Facilities

The Aviation & Facilities group specializes in serving government, commercial, retail, educational, health care, institutional, military, and industrial clients, other than in power projects. Their services include the design of airport and aviation facilities, central utility plants, hospitals and laboratories, academic and other institutional facilities, public and commercial office buildings, and industrial manufacturing, administrative and warehouse facilities. This global practice is especially noted, both domestically and internationally, for its more than 60-year history of providing specialty services for airport and aviation projects.

Infrastructure

Our Infrastructure group is involved in the design of water and wastewater projects. This global practice provides engineering services from early water supply to final wastewater facilities studies and design projects. Burns &

McDonnell can help clients complete treatment process evaluations, compliance audits, waste minimization/reuse, flow monitoring, sludge management, toxicity reduction evaluations, feasibility studies, and water/wastewater system design.

Business & Technology Services

Business & Technology Services provides comprehensive financial and management services. Organizations rely on the group's expertise in forecasts, resource evaluations, rate studies, operations analysis and system planning studies. Burns & McDonnell can also help organizations prepare for future industry changes through competitiveness evaluations, strategic planning, and decision analyses.

Healthcare & Research Facilities

Burns & McDonnell's Healthcare & Research Facilities Global Practice offers integrated full service architecture and engineering for three types of facilities – healthcare (hospitals, clinics and surgery centers), research (laboratories, biopharmaceutical, biomedical and pharmaceutical manufacturing facilities) and design for aging (long term care, Alzheimer, assisted living).

Services include: Master Planning and Programming, Architecture, Interior Design and Space Planning, Mechanical, Electrical, Structural and Civil Engineering, Landscape Architecture, Laboratory Planning and Design, Program Management, Security (physical, structural, operational and cyber), Communications and tele-medicine, Environmental, and Construction.

Construction Design-Build Services

Construction Design-Build Services provides the construction management resources for Burns & McDonnell construction projects including on-site representatives for our construction jobsites.

Construction safety, scheduling, progress tracking, and cost control services are provided. Construction Services perform design-build and turnkey projects through a multiple subcontract approach. Ongoing relationships with specialty firms across the country and around the world extend our capability to address special problems and to provide local liaison where needed or desired.

Burns & McDonnell Services

Safe, on-time, and on-budget projects are the expected results when an owner hires Burns & McDonnell. We combine technical expertise in process design with effective project management to achieve predictable project results. Safety, cost, schedule, and quality are managed with proven procedures and experienced leadership. Our philosophy is to operate as an extension of the client's staff. We seek to provide our clients a single source responsibility for their projects. We provide services which may begin with front-end engineering design packages or consulting services through detailed engineering, procurement and construction (EPC) services. Startup services, process hazard analysis (PHA) reviews, value management process (VMP) execution, financial and economic consulting, consent decree, site vulnerability assessment, security planning, and design services are also available.

After our involvement is defined on a project, we have an established framework for execution of a project of which the key components are planning, organization, execution and control. Finally, we seek to provide "No Surprises" in execution of projects.

Front-End Project Planning (FEP)

Front End Project Planning (FEP) is an important part of determining the economic viability of a project. A majority of our projects begin as FEP projects. The project definition is developed through the three step FEP process.

The FEP 1 or Feasibility phase of the Front End Project Planning process typically consists of a series of studies that aid the owner in determining if they have a viable project. Those studies are important tools that allow owners to gain management and project team alignment on the business objectives and project assumptions to be used. This is accomplished by generating block flow diagrams and project parameters that allow the project team to develop an order of magnitude cost estimate.

The FEP 2 or Conceptual phase of the Front End Project Planning process has a typical set of deliverables. This phase of the project typically takes the most promising options from FEP 1 and further develops them.

During the execution of FEP 2, the project team will be able to validate the project assumptions that have been made in FEP 1 and develop key project documents. The key project documents that will be developed include, but are not limited to process flow diagrams, individual discipline design bases, a project schedule, and a budgetary cost estimate. During this phase, it is important for the project team to continue to review the business objectives and the economic viability of the project.

During the FEP 3 or Detailed Scope phase of the Front End Project Planning process, it is important for the project team to freeze the project scope, schedule, and execution plan. The project team will establish the specific equipment, piping, electrical, instrumentation, civil, and structural requirements for the project. This will include key documents such as piping and instrumentation diagrams, equipment datasheets, equipment arrangements, and preliminary design quantities. The project team will assemble a complete resource loaded project schedule that discusses detail engineering, equipment procurement, and construction scheduling. The project team will, once again, consider the economic viability of the project as they revalidate the project assumptions and ensure that the project is set-up to successfully meet the business objectives. The project team will establish the execution plan for detailed engineering, procurement and construction and the documents required to release the project team to begin detailed design. In addition, a definitive cost estimate will be prepared.

The fact that Burns & McDonnell later executes many of these projects as EPC projects has helped us refine our approach to design development and definitive estimating.

Design Engineering

Burns & McDonnell offers experience in providing the required integration of layout, equipment selection, detail design and construction for quality processing facilities in many industries. We work very closely with our clients to meet the requirements and restraints of designing expansion, retrofit projects, new battery limits and grass roots facilities.

Our strong background in a wide variety of power generation applications, combined with our strong process industry background gives us a broad knowledge to meet our clients' needs. We are skilled in the considerations of quality, constructability, value engineering, maintenance, safety, operations, and aesthetics. Our staff understands the intricacies inherent with layout of piping, electrical and structural project features, and as such, our initial layouts typically require minimal modification into detailed design. Burns & McDonnell was one of the Beta testers in the 1980s for Integraph's version of 3-D modeling … we still fully believe in this concept and are leading the industry as we have recently rolled out SmartPlant on our latest large power generation projects … allowing our clients to "see" the plant take shape during the design phase of the project and allowing the engineering staff significant intelligence and interaction within the plant model.

Our design efforts often culminate with a complete construction contract package, including design drawings and specifications. We offer the flexibility and the resources to utilize client specifications or to develop all construction documents required for a specific project. We also have experience in providing, prior to design completion, bid packages sufficient for accurate bidding by construction contractors on fast track projects. We have provided our clients with on-site shutdown assistance for retrofit projects, start-up assistance for new systems and long-term on-site design/construction coordination engineers.

Site Vulnerability Assessment, Security Planning and Design

In early 2007, the Unites States Department of Homeland Security issued new rules for security in Chemical Facilities. Burns & McDonnell is a company that brings many years of experience in chemical facilities together with experts who have up-to-date knowledge on government security regulations and the methods that industries have been using to meet the regulations. Burns & McDonnell engineers and security experts can provide expertise in site vulnerability assessments, critical asset protection, site security planning, cyber security and physical security that meet the guidelines of the new government chemical facility anti-terrorism standards.

Procurement

Burns & McDonnell's purchasing staff has worked on a wide variety of projects in the power generation, chemical, food processing, grain-processing, refining, and petrochemical industries. Equipment purchased on these projects include process equipment ranging from reactors, fractionation towers, vessels, pumps, compressors, exchangers to crystallizers, dryers, furnaces, electrical hardware, gas and steam turbines, power generation equipment, control systems, and instrumentation.
Our purchasing procedures are specifically designed to effectively obtain pricing and place orders for engineered equipment on capital expansion projects. For the Taylorville Project, we will form a procurement organization based on "best athlete" approach within the Burns & McDonnell and Kiewit organizations.

Estimating

Our in-house staff has the experience and capabilities to develop several different levels of estimates. Burns & McDonnell utilizes commercially available software along with extensive in-house cost databases, which are used for cost estimates.

We work with subcontractors where detailed labor and productivity estimates are required.

Our estimating experience includes:

- Conceptual estimates (factored or scale-up).
- Definitive cost prior to construction document issue.

- Construction check estimates.
- Contractor change order review.

Scheduling

We have in-house schedulers who are responsible for working with the project team to develop schedules of increasing details as required by the project. We use computer based project scheduling software, primarily Primavera. Our scheduling capabilities include:

- Major project milestone schedules.
- Resource Loaded Detailed Schedules
- Critical path definition
- Bar chart reports
- Labor and resource reporting and allocation

Construction / Design-Build

Burns & McDonnell has a centralized construction group that provides construction services to all the Burns & McDonnell engineering global practices. This centralized group allows for a uniform approach to our construction and construction management. For this particular project, our internal Construction/Design/Build organization will provide only support as required for our construction partner, Kiewit.

Technical Capabilities

The Energy Practice and the Process & Industrial Global Practice has been providing our clients with design solutions for more than 100 years. Burns & McDonnell has built a reputation by providing outstanding engineering design and predictable project results in the electric utility and refining industry. The benefits of our experience are highlighted in the following items.

Strong Process Capabilities

Many of our assignments deal with unusual, unique processes and challenges. Our process staff is skilled in applying engineering and unit operations principles to solve problems.

We have considerable experience in the following areas:

- Hydrotreating
- Hydrocracking
- Crude/vacuum distillation
- Isomerization
- Reforming
- Gas Processing / Treating
- Coking
- Sulfur Recovery
- Amine Systems
- Sour Water Stripping
- Gasification
- Tailgas Treating
- Flare Systems
- Flare Gas Recovery
- Steam Generation
- Electrical Distribution
- Water Treatment
- Nitrogen Oxide Reduction
- DCS Control Systems
- Utilities

We understand the importance of proper equipment design and selection to meet the design process conditions.

Strong Power Generation Capabilities

We have served the utility industry with new generation and retrofit

We have considerable experience in the following areas:

- Project Development
- New Generation – Coal Fired
- New Generation – Gas Fired
- Gasification/IGCC
- Cycle Optimization
- Wet/dry scrubbers
- Mercury/Particulate removal
- Selective Catalytic Reduction
- Water Treatment
- Combustion Improvements
- Controls Systems
- Electrical Systems
- CO_2 Mitigation
- Permitting
- Electrical Distribution
- Water Treatment
- Nitrogen Oxide Reduction
- Project Management
- Scheduling

We understand the importance of proper equipment design and selection to meet the design process conditions.

Detailed Design Capabilities

Burns & McDonnell is a full-service multi-discipline Engineering, Procurement and Construction (EPC) firm, which executes all facets of plant design. Our discipline capabilities include:

- Process Design
- Equipment Specifications
- Plant Layout
- Piping Design
- Civil/Structural/Architectural Design
- HVAC Design
- Mechanical Systems Design
- Plumbing Design
- Fire Protection and Fire Proofing Design Basis

- Electrical Design
- Controls/Instruments System Design
- Project Coordination
- Project Execution Planning

Our detailed design capabilities are further enhanced by our use of various tools and software packages which (amongst others) include:

- SmartPlant
- PDS 3-D design software
- Laser Scanning for Revamp Projects
- Microstation
- AutoCAD
- SmartPlant P&ID
- InTools
- PIP Standards and Specifications
- CF Design (Computational Fluid Dynamic Modeling Software)
- Autodesk Inventor

In-Plant Experience

Our engineers travel to the jobsite. Having spent a significant amount of time in various processing facilities, our engineers can efficiently gathered equipment data and develop as-built drawings as the first step in debottlenecking projects for many plants. Interviewing plant operations and maintenance personnel and studying plant operating data allow us to more effectively complete the projects we undertake.

Team Concept

We prefer to work as an extension of your staff—to work with your staff toward a common goal. Burns & McDonnell engineers get personally involved with and take pride in every project we do. Your goals and objectives are our goals and objectives because we work together as a team. The team concept is an integral part of the Burns & McDonnell project approach.

Leveraging Past Work

For this project, Burns & McDonnell has some distinct advantages … we've already been working on your project. B&M completed the original Front End Planning document for Taylorville Energy Center. In addition, we have discussed our recent work with Cash Creek Generation, LLC and how, with agreements in place, we could utilize the work that we have completed for that project to advantage all parties involved in Cash Creek and Taylorville. To the extent that Burns & McDonnell can help facilitate discussions between Tenaska, Green Rock, and Cash Creek Generation, LLC we would volunteer our services to that end.

In addition to the above two projects, B&M has outlined below past gasification and related projects that have formed the backbone of our gasification experience and thus our qualifications to proceed with this project.

Gasification Technologies Council

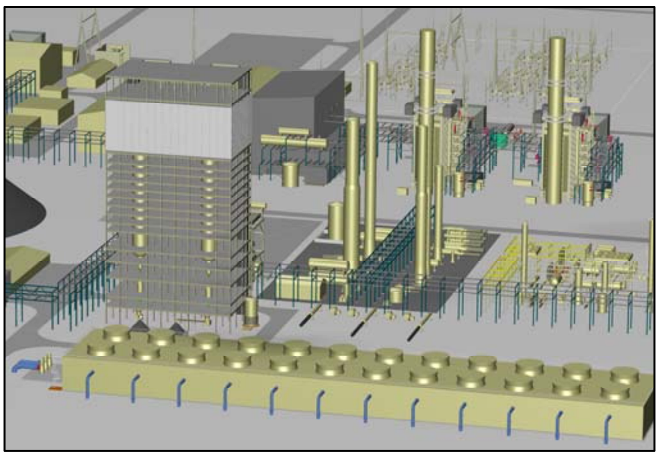
Burns & McDonnell is a very active member in a number of organizations supporting the process and power generation industries, including the Gasification Technologies Council.

Gasification Experience

Over the last several years, Burns & McDonnell has been a leader in the United States in the development, design, and technical evaluations for gasification and IGCC facilities. During this period, interest in IGCC technology has increased dramatically. Burns & McDonnell has remained on the forefront of IGCC development and design, as demonstrated by our IGCC and gasification experience described below.

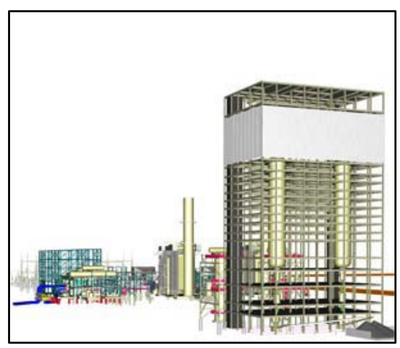
Cash Creek Energy Center, Coal to SNG Facility, The ERORA Group and Cash Creek Generation, LLC; Current and Ongoing

Burns & McDonnell has been selected as the Project Engineer for the development and implementation of a Coal to Substitute Natural Gas (SNG) facility located in the State of Kentucky. Burns & McDonnell is currently responsible for the overall engineering effort to support the project development including the Front End Planning (FEP) Level 3 (or FEED) study. Burns & McDonnell has also subcontracted the construction related portions of the study to Kiewit. Kiewit will be performing the construction for the project. Burns & McDonnell's scope includes the preparation of all engineering deliverables to support an EPC level project estimate to be utilized by the Client to obtain all permits, and financing. Burns & McDonnell is also assisting the Client in the acquisition and execution of the project technology license agreements. Burns & McDonnell will serve as the Project Engineer throughout the implementation of the project up to commercial operation.



Taylorville Energy Center, Tenaska/The ERORA Group, Current and Ongoing

In 2005/2006, Burns & McDonnell served as the Project Engineer on The ERORA Group's nominal 600 MW IGCC / chemicals co-production facility located in southern Illinois. Burns & McDonnell was responsible for the overall engineering effort to support the project development and FEED design. The facility is based on the GE gasification technology. Burns & McDonnell responsibilities have included technical assistance, cost estimating, and systems design, including the preparation of Piping & Instrument Diagrams, one-line diagrams, overall plant layout drawings, process flow diagrams, and technical and commercial specifications. The FEED package was completed in late 2006. Since completion of the FEED package, Burns & McDonnell has provided technical and consulting support to The ERORA Group and Tenaska (current managing partner) reviewing path forward for the project.



Confidential Client, 150 MW IGCC, Current and Ongoing

Burns & McDonnell is currently performing Front End Planning (FEP) Level 2 study (Pre-FEED) for a nominal 150MW IGCC facility to be located in the State of Pennsylvania. The project is a mine mouth facility, and will utilize an air-blown fixed bed gasification process, including all gas cleanup technologies, and a 1x1 syngas fired combined cycle. Burns & McDonnell's responsibilities include the development of Process Flow Diagrams, Heat and Material Balances, site permitting data, site plan, and capital and operations and maintenance cost estimates. For this project, Burns & McDonnell is reviewing a confidential alternative gasification technology for project feasibility.

Confidential Client, Coal to Gasoline, Current and Ongoing

Burns & McDonnell is currently finalizing an FEP Level 1 study for a nominal 10,000barrel per day Coal-to-Gasoline facility. The project is a mine mouth facility located in the State of Kentucky. The project will utilize local coal to create methanol, which is then converted to an ultra-low sulfur gasoline product. Burns & McDonnell has performed the conceptual engineering including, site plan, process design, and cost estimating.

Homeland Energy Solutions, Current and Ongoing

Homeland Energy Solutions plans to construct a 100 million gallon per year ethanol plant in New Hampton, Iowa, USA. Burns and McDonnell is currently performing an FEP-2 level feasibility study for utilizing the EPIC coal gasification technology to provide the fuel for the ethanol process. Burns and McDonnell has performed a FEP Level 2 feasibility study for facility utilizing coal gasification technology to provide the fuel for the ethanol process. Burns & McDonnell is currently negotiating with HES to perform the engineering, procurement, and construction of the facility. Construction is expected to begin upon financial closure of the facility, anticipated by 3Q 2010.

Process Energy Solutions, 2006

BMcD conducted a FEL1+ Study for PES to evaluate the cost to restart the El Dorado Gasifier and modify the unit to produce hydrogen for use in the refinery. The existing configuration was to power a co-generation unit with the syngas. The new configuration included the following modifications:

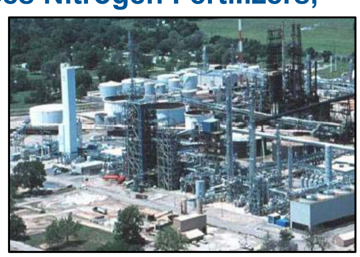
- Addition of a new Air Compressor to replace the original Air Separation Unit (ASU) feed from the co-generation unit combustion turbine.
- Addition of a new ASU to supply additional oxygen for sale to the refinery.
- Modifications to the coke grinding system to improve operation
- Addition of a new sour Shift Unit
- Addition of a new Acid Gas Removal Unit (AGRU)
- Restart of an existing PSA unit

BMcD performed the process design for the sour Shift Unit. We evaluated several AGRU technologies including Selexol, MDEA, Shell Paques, and others. The effort included the evaluation of process and utility requirements for each system. Tie-in reviews, equipment layouts and rack studies were done to provide a +/- 35% estimate.

Synthetic Natural Gas (SNG) Facility Conceptual Engineering, Confidential Client, 2006

Burns & McDonnell provided conceptual engineering services for a Coal-to-SNG facility. Burns & McDonnell was responsible for development of the SNG process and process simulation. Burns & McDonnell was also responsible for preparation of the process flow diagrams, heat and mass balances, preliminary one-line diagrams, utility summaries, and technical performance specifications.

Gasifier Expansion, Coffeyville Gasification Plant, Coffeyville Resources Nitrogen Fertilizers, LLC, Current and Ongoing



The Coffeyville Coke Gasification to Ammonia Plant gasifies 1,100 tons per day (TPD) of petroleum coke. The gasifier produces 75 million cubic feet of hydrogen, which is then converted to 1,100 TPD of ammonia. Burns & McDonnell is currently designing an expansion of the gasification process to increase production capacity at the plant, which is located in Coffeyville, Kansas. Construction has been completed. Burns & McDonnell continues to consult for Coffeyville on various plant improvement projects.

IGCC Feasibility Study, 600MW IGCC, EPRI / CPS Energy, 2006

Burns & McDonnell is currently performing a technical feasibility study of a 600MW IGCC facility utilizing Powder River Basin coal as a feedstock. The project is based on the Shell gasification technology. Burns & McDonnell is responsible for the conceptual engineering, process modeling, cost estimating, and report preparation.

IGCC and Solid Fuel-Fired Siting Study, Wisconsin Public Service and Wisconsin Power & Light, 2005

Burns & McDonnell provided development services to perform a siting assessment to identify feasible sites for installation of a base load generation facility. Potential sites were identified that could support a solid fuel-fired PC unit or an IGCC facility. Development services included site selection, fuel delivery analysis, environmental assessment, preliminary water supply analysis, and transmission load flow analysis and interconnection assistance.

550 MW IGCC Assessment, Minnesota Power, 2004-2005

Burns & McDonnell was retained by Minnesota Power to provide a conceptual design and screening level cost estimate for a 2x1 550 MW GE 7FA IGCC plant to be located in Minnesota. In addition to a capital cost estimate, Burns & McDonnell prepared a site plan, electric one-line diagram, water mass balance, and emissions estimates for the facility.

On-Time Reliability Upgrades, H2 and CO Production Facility, Singapore Syngas, 2001

Singapore Syngas' H2 and CO production facility utilizes Visbreaker Tar as a feedstock with a GE 600TPD gasifier to produce chemicals. Burns & McDonnell provided mechanical and process design engineering services to the chemical production facility to improve overall on-time reliability.

IGCC Project Development, Confidential Client, Ongoing

Burns & McDonnell is completing IGCC project development activities for a confidential client that is developing two alternative IGCC facilities. Development services include site assessments, conceptual engineering, initial feasibility studies, capital and performance estimates, transmission interconnection analyses, and environmental reviews.

Technology Assessments

Burns & McDonnell has completed technology assessments for gasification facilities for over twenty other clients.

Refining Project Summaries

ConocoPhillips, Low Sulfur Gasoline
Ponca City, OK

Burns & McDonnell was contracted by ConocoPhillips to provide engineering, procurement, and construction (EPC) services for the OSBL part of the Clean Fuels project at the Ponca City Refinery. The OSBL side of the project consisted of an Isom unit, utility upgrades, all process piping tie-ins to the existing refinery, pipe rack modifications, process unit revamps, electrical, controls and instrumentation that will occur outside the main process unit. In addition, Burns & McDonnell was also contracted to construct the ISBL for this project. The ISBL portion of the project consisted of a 45,000 BPSD Axens' Prime G+ technology and a 20MM SCFD Hydrogen Plant.

Burns & McDonnell was responsible for the FEP-3 and definitive cost estimate of the OSBL for AFE approval. Burns & McDonnell worked with operations personnel to collect field data for pipe routing and pipe rack modifications. Burns & McDonnell personnel were assigned to the field for this effort. The data collected was used to put better define the offsites work and to develop a definitive cost estimate for the OSBL work. Burns & McDonnell completed the construction for both the OSBL and ISBL portions of the project using a multiple subcontract approach. Burns & McDonnell developed defined bid packages.

ConocoPhillips, OSBL Low Sulfur Gasoline
Lake Charles, LA

Burns & McDonnell was contracted to provide FEP engineering and EPC services for the OSBL and ISBL portion of the LSG project at ConocoPhillips' Lake Charles Refinery. Burns & McDonnell's refinery experienced project team was sent to the site to help develop Front-End Loading definition for the offsites and tie-in locations to the existing refinery. The project consisted of interconnecting piping, a new storage sphere, new piperacks, tie-ins and a new air compressor. A definitive cost estimate was provided at the end of FEP-3 for use in the AFE approval process and as the basis for the EPC contract.

Burns & McDonnell was also contracted to construct the ISBL portion of the project. The ISBL consisted of ConocoPhillips' SZorb technology and is the largest SZorb unit in the refining industry. All construction was completed utilizing a multiple subcontract approach.

ConocoPhillips, Ultra Low Sulfur Diesel
Ponca City, OK

Burns & McDonnell was awarded the FEP engineering and EPC services for the OSBL portion of the ULSD project at ConocoPhillips' Ponca City refinery. Burns & McDonnell placed process engineers on-site to help develop the OSBL portion of the

project. The OSBL included two hydrotreater revamps (33,000 BPD Diesel Hydrotreater and a 15,000 BPD Kerosene Hydrotreater), modifications to the tank farm, interconnecting piping and upgrades to utility systems. At the end of the FEP phase of the project, Burns & McDonnell completed a definitive cost estimate for use in the AFE approval process. The construction of the hydrotreater revamps are being completed during planned turnarounds. Burns & McDonnell is responsible for planning and execution of the capital project portion of the turnaround.

Burns & McDonnell was also contracted to construct the ISBL portion of the project. The ISBL consisted of a new diesel hydrotreater and related equipment. All construction will be utilizing a multiple lump-sum subcontract approach.

ConocoPhillips, Coker/VDU Project

Borger, TX

Burns & McDonnell was contracted to provide FEP and EPC services for the Balance of Plant portion of the Coker/Vacuum Distillation Unit project at the Borger Refinery. The installation of a new coker/VDU at the refinery requires extensive reconfiguration of the refinery for the new coker.

Burns & McDonnell was contracted to provide process engineering services related to development of the reconfiguration process designs during front-end project planning. This reconfiguration will include revamps of an atmospheric resid desulfurization (ARDS) unit, gas plants on two FCC units, interconnecting piping, extensive electrical infrastructure work, installation of a Hydrogen plant, site preparation work, installation of new make-up compressors, HF alkylation revamp and other work. Burns & McDonnell process engineers were onsite for over six months during the FEP stage of this project.

Cost estimates and scope documents were developed for the AFE approval process and were the basis for the EPC contract. Burns & McDonnell completed the Balance of Plant project with an excellent safety record. The project started-up on-time and within budget. A multiple lump-sum subcontract approach will be utilized for the construction of the project.

Sinclair Oil, Sulfur Block

Tulsa, OK

Burns & McDonnell was hired to provide FEP and EPC services for the installation of a new SRU, TGTU, and revamps of related units including the Sour Water Stripper unit, Amine Regenerator Unit, and a FCC Gas Absorber at the Tulsa Refinery. The work included FEP activities such as definition development, analysis of sulfur technologies, and estimate development. The SRU will be modularized and installed at the site. Burns & McDonnell process engineers helped develop the specification for the technology providers' and the modular bids.

ConocoPhillips, ULSD

Borger, TX

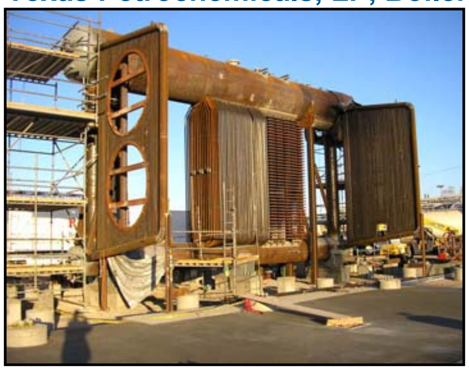
Burns & McDonnell has been contracted to provide FEP engineering services for the OSBL portion of the ULSD project at ConocoPhillips' Borger Refinery. We have provided a project team on-site to provide definition and scope of work services. The offsites include interconnecting piping, water treatment, tank farm upgrades, and utility modifications. Cost estimates and scope documents will be prepared as deliverables for this project.

Suncor, Sour Water Stripper

Denver, CO

Burns & McDonnell provided engineering services for the ULSD project at the Denver refinery for Suncor. As part of this project, Burns & McDonnell process engineers studied and reviewed the existing sour water stripper. This evaluation included review of existing equipment and gas flows and composition. Burns & McDonnell has completed the FEP3 portion of the project.

Texas Petrochemicals, LP, Boiler Replacement



Burns & McDonnell was retained by Texas Petrochemicals (TPC) to perform FEP-3 and EPC services for a Powerhouse NO_x Reduction project. The project was required to meet 2004 Houston area emission limits. The scope included the preliminary engineering and development of a definitive cost estimate for the demolition of an existing boiler and the installation of two new package boilers (250,000 pph each, 750 psig/SH), new feedwater equipment, a Continuous Emission Monitoring systems (CEMs), provisions for the addition of a future SCR, as well as an extensive upgrade of the existing Honeywell DCS. The boilers are to utilize the latest Ultra Low NO_x technology firing a varying refinery fuel gas stream resulting in emission rates of less than 0.02 lb NO_x/MMBtu. The boilers will be controlled from a Honeywell HPM system, including a Fail Safe Controller (FSC) burner management system.

Flint Hills Resources, Boiler Replacement

Corpus Christi, TX

Burns & McDonnell was retained by Texas Petrochemicals (TPC) to perform FEP-3 for a Powerhouse NO_x Reduction project. The project was required to meet 2004 Houston area emission limits. The scope included the preliminary engineering and development of a definitive cost estimate for the demolition of an existing boiler and the installation of two new package boilers (250,000 pph each, 750 psig/SH), new feedwater equipment, a Continuous Emission Monitoring systems (CEMs), provisions for the addition of a future SCR, as well as an extensive upgrade of the existing Honeywell DCS. The boilers utilize the latest Ultra Low NO_x technology firing a varying refinery fuel gas stream resulting in emission rates of less than 0.02 lb NO_x/MMBtu. The boilers will be controlled from a Honeywell HPM system, including a Fail Safe Controller (FSC) burner management system.

Sunoco, Hydrocracker Conversion

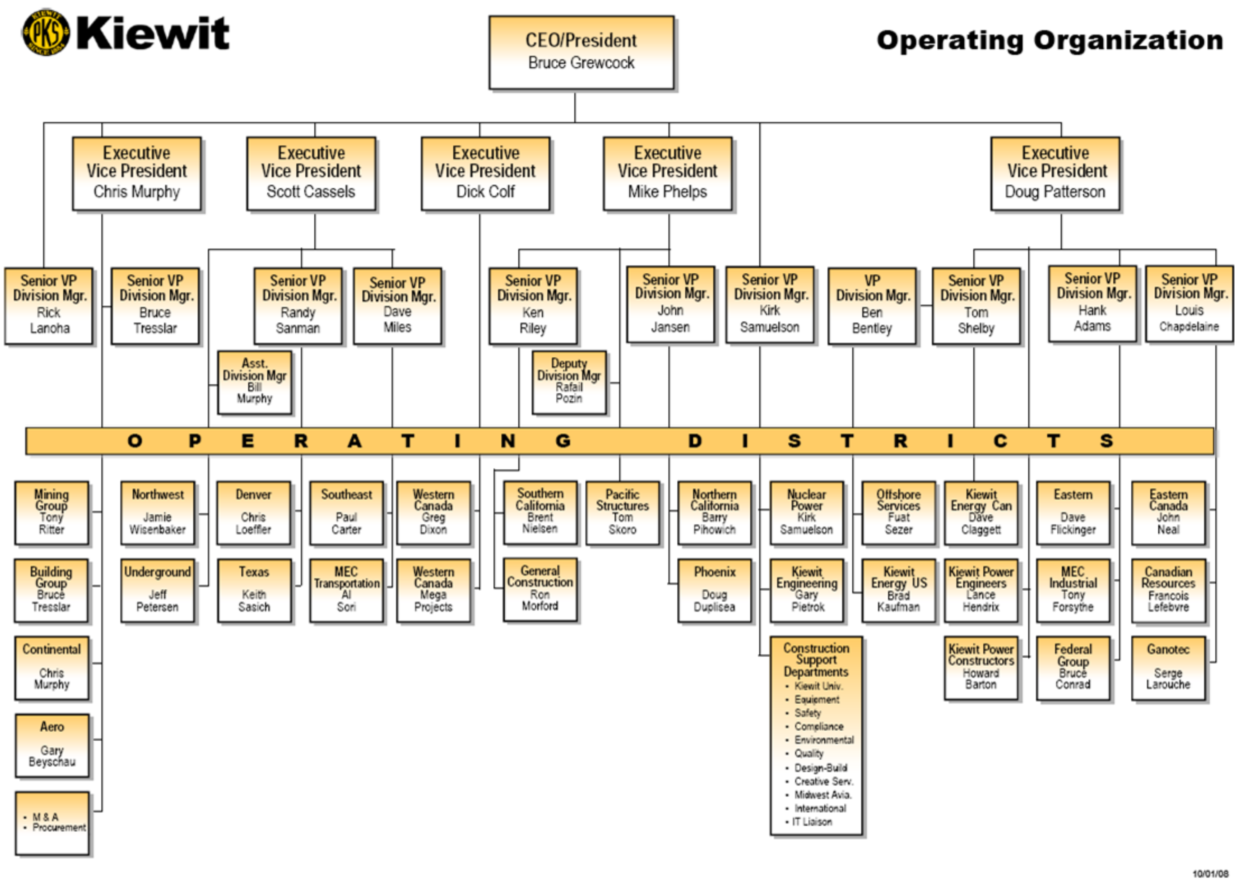
Philadelphia, PA

Sunoco contracted Burns & McDonnell to provide front-end project planning, field inspection, procurement, and construction management services for a hydrocracker conversion project. Burns & McDonnell process engineers analyzed and developed the flow sheets for the conversion of the hydrocracker to an Ultra Low Sulfur Diesel unit. Burns & McDonnell field personnel hired and managed subcontractors to inspect the hydrocracker unit equipment to determine its viability in a new service. After inspection and process design, Burns & McDonnell providing FEP cost estimates to allow Sunoco to perform economic evaluations for the project. Burns & McDonnell helped procure long lead equipment and materials to support the overall schedule. Burns & McDonnell will provided detail engineering and construction services to complete the project.

Table of Contents

Company Overview

Clients have been counting on Kiewit since 1884 and we've always delivered. While other contractors have come and gone, we've evolved into one of the largest and most respected construction organizations in North America. With no long-term debt, our strong balance sheet offers clients the assurance their projects will get done.



Kiewit Corporate Information

- More than $6.2 billion 2007 revenue
  - 92% construction
  - 8% mining
- Over $12 billion in backlog
- 6,500 staff employees August, 2008
- 38 million direct construction man-hours performed in 2007
- Over 1,000,000 engineering man-hours managed on EPC projects in 2007
- Largest, most modern equipment fleet in North America
- Employee-owned, Kiewit has on the most highly motivated staffs in the industry
- Headquarters in Omaha, Nebraska; 77 district and area offices throughout the US and Canada, including Illinois.

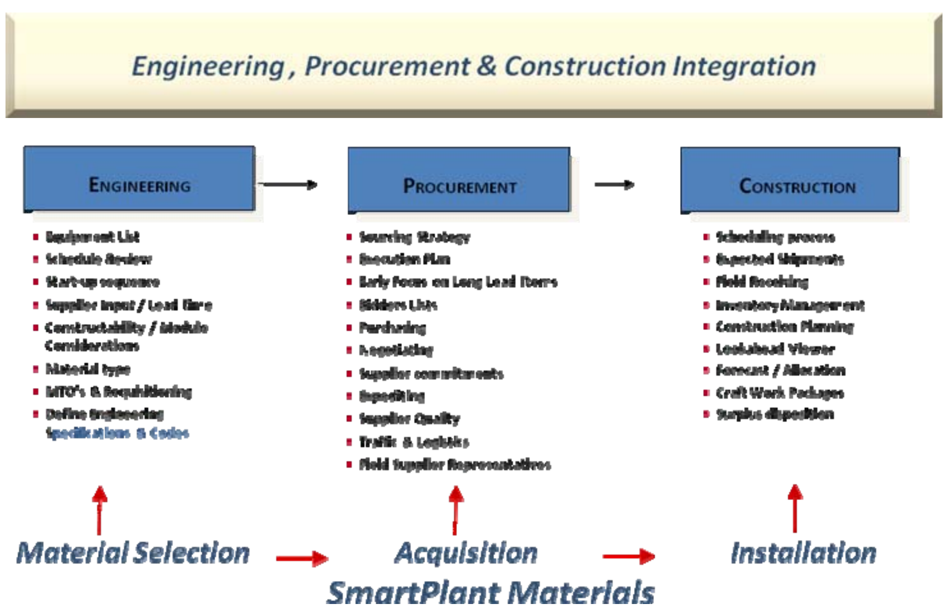
Kiewit Safety Statistics

Kiewit has a robust safety program with proactive participation by all levels of management, staff, and craft to identify potential issues and avoid accidents. The company's mantra is that all accidents are preventable and everyone goes home safe every night. The following statistics reflect the company's devotion to the safe planning and execution of work.

Metric	2006	2007	2008
Experience Modifier Ratio	0.57	0.57	0.57
Recordable Cases / Rate	7 ea / 0.91	14 ea / 1.06	3 ea / 0.99
Restricted Work Activity Cases / Rate	6 ea / 0.78	6 ea / 0.45	0 ea / 0
Lost Workday Cases / Rate	2 ea / 0.26	2 ea / 0.15	0 ea / 0
Fatalities / Rate	0 ea / 0	0 ea / 0	0 ea / 0
Recordable Incident Rate	0.91	1.06	0.99
Total Workhours	1,541,007	2,548,548	604,578

Supply Chain Management

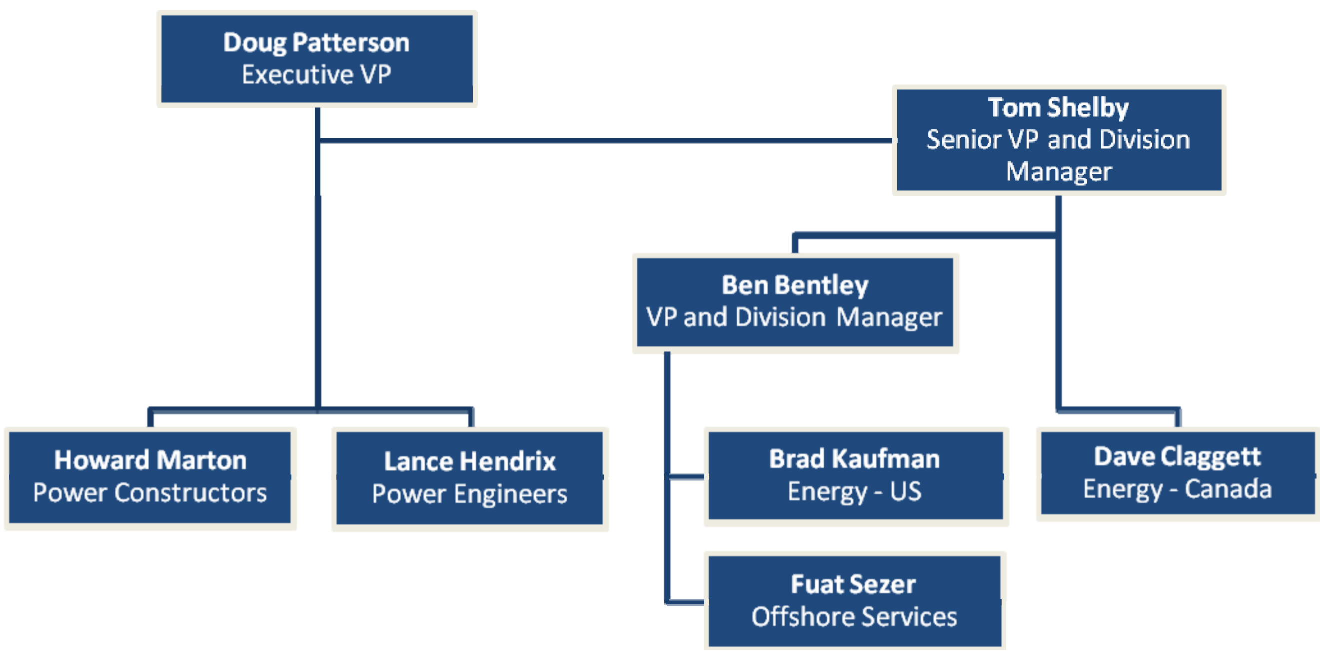
Kiewit has a highly experience group of supply chain management professionals skilled at international and North American sourcing and procurement. They manage all engineered equipment and bulk materials acquisition from the point they are identified as requirements until they are issued to the construction supervisors.



Kiewit

Energy Group Capabilities

Kiewit Energy Group, Inc., a Kiewit Corporation subsidiary, is comprised of Kiewit Energy, Kiewit Power Constructors, Kiewit Offshore Services, and Kiewit Power Engineers. With a "right the first time" quality objective, Kiewit Energy Group, Inc. has become an industry leader in EPC and has gained extensive experience in the oil, gas, industrial and power industries. Our office and facility locations span the United States and Canada, making us well-equipped to handle jobs of any size at nearly any North American location. Our world-class fabrication facility in Ingleside, Texas includes a 400-acre yard with 2,800 linear feet of continuous pile-founded bulkhead. Our water depth of 45 feet and a 77-foot hole allows for successful offloading of large floating structures. We are proud owners of a significant fleet of heavy lift cranes and equipment, including the heavy lift device, which is unmatched in lifting capability.



Energy

Kiewit Energy is located in Houston, Texas to serve the process industries. With boots on the ground in Illinois and throughout North America, Kiewit is focused on building quality projects safely, on time and on budget; no matter how challenging or unique the project, no matter how large or small. Kiewit has three decades of EPC and design-build project experience in capital projects markets including oil sands, refining, bio-fuels, industrial gases, oil & gas processing, gasification, and LNG. Kiewit has a proven track record of success with an execution model based on:

- An integrated, EPC team co-located at the engineer's offices
- Direct perform construction
- Risk sharing commercial model

Horizon Sulfur Recover Project

Location: Ft. McMurray, Alberta, Canada
Contractor: KAPEC (a Kiewit-APEC partnership)
Engineering/Construction Manager: KAPEC (a Kiewit-APEC partnership)
Client: Canadian Natural Resources, Ltd.
Contract Approach: EPC Fixed Price
Approximate Contract Value: $ 500 million
Date of Award: December 2004
Contract Completion Date: 2008
Project Description: 800 TPD gas treating and sulfur plant sour water stripper, amine, sulfur recovery and degassing, SCOT tail gas, incinerator, stack and common utilities. This project requires the fabrication of 117 modules: 43 piperack modules, 15 electrical modules, and 59 equipment and skid modules.

Pine Bend Refinery Phase II

Location: Eagan, Minnesota
Contractor: Kiewit Energy District
Engineering/Construction Manager: Jacobs Engineering
Client: Flint Hills Resources, Inc.
Contract Approach: Construct Only
Approximate Contract Value: $57 million
Date of Award: March 2005
Contract Completion Date: April 2006
Project Description: Major mechanical work for new diesel hydrocracker unit that included setting and installation of 128 pieces of equipment, 86,000 linear feet of pipe, and 900 tons of structural steel. At peak, the project employed approximately 500 personnel.

Mount Vernon Ethanol

Location: Mount Vernon, Indiana
Contractor: Kiewit
Client: Aventine Renewable Energy, Inc.
Contract Approach: EPC Fixed Price
Approximate Contract Value: $230 million
Date of Award: September 2007
Contract Completion Date: Under Construction
Project Description: Engineering, procurement, and construction of a 113-million-gallon-per-year denatured fuel grade ethanol facility utilizing Delta-T proprietary process technology.

Christina Lake SAGD Phase II

Location: Christina Lake, Alberta, Canada
Owner: MEG Energy Corp.
Contract Value: $600,000,000
Contract Approach: EPC Reimbursable
Completion Date: Under Construction
Project Description: Design and construction of a 22,000 BPD oil sands extraction facility. Second phase of a multi-phase project.

Pekin Ethanol

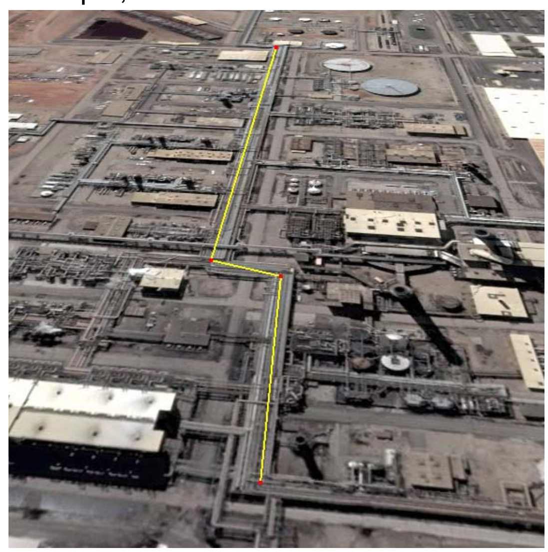
Location: Pekin, Illinois
Engineer/Construction Manager/Contractor: Fagen Inc.
Client: Confidential
Contract Approach: Reimbursable/Lump Sum
Approximate Contract Value: Confidential
Completion Date: December 2006
Project Description: Construction and equipment procurement of a 50 million gallon per year ethanol distillation facility utilizing proprietary process technology

Rochelle Ethanol

Location: Rochelle, Illinois
Engineer/Construction Manager/Contractor: Fagen Inc.
Client: Confidential
Contract Approach: Reimbursable/Lump Sum
Approximate Contract Value: Confidential
Completion Date: December 2006
Project Description: Construction and equipment procurement of a 50 million gallon per year ethanol distillation facility utilizing proprietary process technology

Gasification Experience

- Cash Creek Generation – A coal to substitute natural gas plant co-located with a 2 on 1 combined cycle power plant in Henderson County, Kentucky. Privately financed project developed by the ERORA Group, a subsidiary of Green Rock Energy. Pre-NTP scope of work involves planning, constructability reviews, logistics survey, pre-project labor negotiations, procurement planning, detailed construction schedule and detailed estimate. Planned Kiewit scope of work and responsibilities for the detail engineering, procurement and construction phase of the program includes Kiewit providing program management, engineering, procurement, and construction services.
- Rentech REMC Feedstock Conversion Project—Project Development, Licensor Selection, FEED and Estimate, Constructability, Power Island and Coal Handling planning, development of Project Execution Plan. This project entailed the Conversion of Ammonia Facility to Coal Gasification in East Dubuque, Illinois.
- Great Plains Coal Gasification Project (now Dakota Gasification Company)
  Beulah, ND; Kiewit constructed the main pipe rack; approximately 2,000 feet long (see image)
- Jim Bridger Integrated Gasification Combined Cycle (IGCC) Project, a PacifiCorp "Mouth of Mine" coal gasification project development in Wyoming----Conceptual Planning, Constructability and Feasibility Estimate. The work included determination of costs for remote jobsite and high altitude coal gasification facility.
- Kiewit serves on the Gasification Technology Council board and has been a member of GTC since 2006.



Gasification Technologies Council

Module Fabrication

Ingleside, Texas

- FEED support
- Constructability studies
- Fabrication services
    - Process, oil & gas, and gasification industry modules
    - Offshore platforms and jackets
    - Hook-up and commissioning
    - Subsea templates, piles, and assemblies
    - Drill rig and maintenance
    - Bridge and marine facility components
- Kiewit wholly owns the fabrication facility in Ingleside, TX
- Over 400 acres of property, 350 acres developed
- Versatility in services offered (plant modules, offshore platforms, bridgework
- Heavy Lifting Device with 13,000 ton lifting capability
- Large-capacity plate-bending (rolling) machine
- Heavy lift crane fleet
- Modular trailers at 1,400 tons
- Strong manufacturing and heavy lift engineering expertise
- Heavy haul and barge transport logistics specialists

Modules

Bullwinkle

Independence Hub

Marco Polo

Thunder Horse

XBR

Power

Kiewit Power Constructors Co. specializes in large integrated industrial, mechanical and electrical projects. Our experience began in 1951 with the award of several U.S. Army Corps of Engineers contracts to construct facilities in the harsh climate of Northern Greenland. From our early exposure to mechanical and electrical work, we expanded to build major power and mechanical process facilities. We have built nuclear and fossil fueled, simple and combined-cycle gas turbine, waste-to-energy and geothermal power projects; natural gas compressor stations; oil and process facilities; nuclear fuel process facilities; water and waste water treatment plants; and many other power and heavy industrial facilities throughout the United States, Canada and the Philippines.

Power Experience – Total Installed Capacity

3,300 MW Coal Projects
12,000 MW Gas Projects
2,300 MW AQCS Projects

Award-winning Power Projects

High Desert Power Project – *POWER* Magazine Plant of the Year

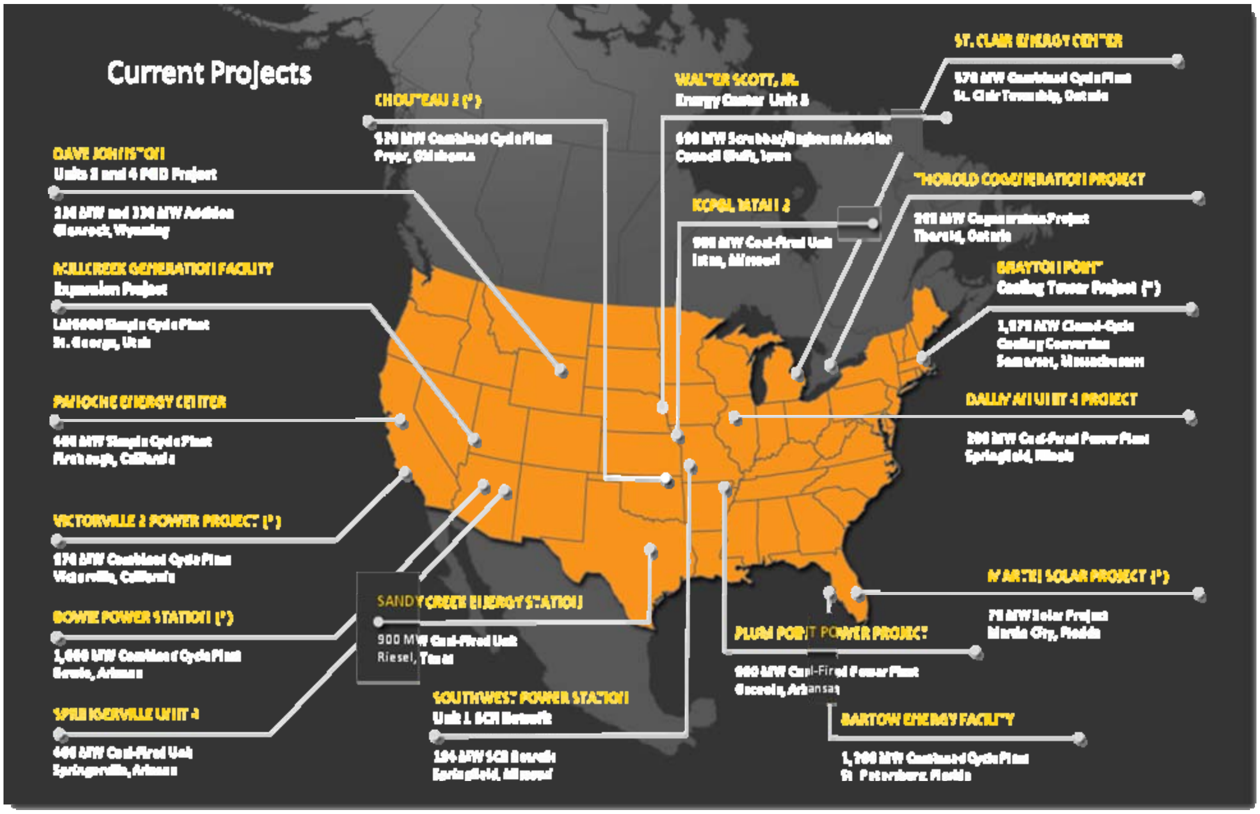
Palomar Energy Project – *Combined Cycle Journal* Pacesetter Plant Award *Environmental Protection* Magazine Facility of the Year Honorable Mention Adobe Success Story

LADWP Haynes Repowering Project – Los Angeles Council of Engineers & Scientists Project Achievement Award

Tenaska Virginia Power Project – DBIA-MAC 2005 Best Project Industrial/Process Sector Over $25 Million, *POWER* Magazine Top Plants

Los Medanos Energy Center – *POWER* Magazine Top Plants

Magnolia Power Project – *POWER* Magazine Plant of the Year



Full scope of services

- Conceptual space studies
- Detailed scope and cost estimating
- Detailed design
- Procurement
- Construction
- Startup / commissioning
- All market segments
  - Gas-fired, coal-fired, air quality control systems, nuclear, renewables, transmission/substations

With extensive resources that include talented people, in-depth market knowledge, state-of-the-art equipment and unparalleled experience, Kiewit Power Constructors is uniquely qualified to handle any size project.

Engineering Capabilities

Our team works closely with energy industry clients to provide them with complete engineering services unique to each project's specifications. These award-winning services range in magnitude from small scale owner's engineer studies to full scope EPC joint venture project developments and projects. As a wholly owned subsidiary of the Kiewit Corporation, Kiewit Power Engineers Co. can handle any project, regardless of size, with the same personal touch on which our company was founded years ago. We remain committed to quality and excellence as we continue to satisfy the energy needs of clients throughout the U.S. and Canada.

Looking ahead, the future of the energy market is constantly changing. The unstable price of natural gas and the focus on global warming are moving the market toward new technologies. Our commitment to innovation means we're staying on top of those technologies, continuing to be big enough to work on a variety of projects but small enough to give our clients and their projects the attention they deserve.

- Excellent “production design engineering” capabilities
- Integration with Kiewit
  - Constructability
  - Focus on project execution (schedule and cost performance)
- Excellent power resume
- Engineering for “minimal project Total Installed Cost (TIC)”
- Quality program
  - Lessons learned database
  - Quality incident rate/quality incident cost tracking
- Estimating
- Schedule certainty achieved through rigorous to detail
- Track record of successes working collaboratively with customers to achieve price certainty.

Project Schedule Development

- Key milestones and logic from Planning Sessions used to develop initial detailed Level 3 Project Schedule
- Project schedule resource loaded using production rates included in the estimate
- Schedule levelized to eliminate manpower peaks without affecting critical path activities
- Area superintendents use Project Schedule to develop their 90-day schedules for crew and equipment planning
- 90-day schedules used to develop a more detailed 3-week look ahead
- 3-week look ahead feeds the Plan of the Day
- Everything is tied back to the master Project Schedule

Schedule Certainty

This table illustrates Kiewit's track record completing power projects on schedule.

Project	EPC Scope	Guaranteed COD	Actual COD	Days early (late)	% complete
CWLP	200 MW PC	May, 2010	Dec., 2009*	150	58%
NC2	660 MW PC	May, 2009	Jan.,2009*	90	80%
Plum Point	660 MW PC	April, 2010	Jan.,2010*	90	20%
Louisa	700 MW AQCS	Dec., 2007	Dec., 2007*	0	95%
CB3	700 MW AQCS	April, 2009	Feb., 2009*	60	16%
Lindsay Hill	840 MW CC	June, 2002	June, 2002	0	100%
Fredrickson	248 MW CC	Aug., 2002	Aug.,2002	0	100%
Palomar	500 MW CC	April, 2006	March, 2006	30	100%
Greater Des Moines	540 MW CC	March, 2005	Dec., 2004	74	100%
Fluvanna	890 MW CC	July, 2004	April, 2004	68	100%
Valley	500 MW CC	March, 2004	March, 2004	15	100%
High Desert	840 MW CC	July, 2003	April, 2003	70	100%

*** Expected Completion Dates**

Cost Control

- Kiewit is and has been historically a “hard money” contractor, so we are razor-focused in managing costs within budget which is critical for the customer’s and our success
- Success in controlling cost starts with a solid, quantity-based estimate, using real past costs and verified with an independent second estimate
- Knowing their daily costs is a condition of employment for our foreman and superintendents

Price Certainty

The following table illustrates Kiewit’s track record of completing power projects on budget.

Project	EPC Scope	Bid amount	Change Orders	% of Change Order	Final Price	% complete
CWLP	200 MW PC	$436MM	$26.6MM	6.1%	$463MM*	58%
NC2	660 MW PC	$604MM	$10.7MM	1.8%	$615MM*	80%
Plum Point	660 MW PC	$875MM	$7.6MM	0.9%	$883MM*	20%
Louisa	700 MW AQCS	$136MM	$2.1MM	1.5%	$138MM*	95%
CB3	700 MW AQCS	$180MM	$1.7MM	0.9%	$182MM*	16%
Lindsay Hill	840 MW CC	$150MM	$3.1MM	2.1%	$153.1MM	100%
Fredrickson	248 MW CC	$46MM	$4.1MM	8.9%	$50.1MM	100%
Palomar	500 MW CC	$186MM	$10.1MM	5.4%	$196.1MM	100%
Greater Des Moines	540 MW CC	$164MM	$2.3MM	1.4%	$166.3MM	100%
Fluvanna	890 MW CC	$165MM	$3.9MM	2.4%	$168.9MM	100%
Valley	500 MW CC	$208MM	$13.2MM	6.3%	$222MM	100%
High Desert	840 MW CC	$255MM	$13.5MM	5.3%	$268.5MM	100%

***Estimated**

Joint Work

Over the last five (5) years, Burns & McDonnell and Kiewit have worked together on projects in over ten (10) cases. This working relationship has been fostered in many different relationship arrangements:

- Kiewit EPC Contractor, B&M Owner's Engineer
- Kiewit Subcontractor role on EPC Team, B&M Owner's Engineer
- B&M Engineer, Kiewit General Contractor
- Kiewit Subcontractor to B&M
- B&M Subcontractor to Kiewit
- Joint Venture Relationship on EPC Projects

These projects have been focused on power generation, air quality control, and gasification business units. Most notably, Burns & McDonnell is currently heavy into the Pre-Finance Engineering package development as the Project Engineer for the development and implementation of a Coal to Substitute Natural Gas (SNG) facility located in the State of Kentucky. This project is owned by Cash Creek Generation, LLC Burns & McDonnell is currently responsible for the overall engineering effort to support the project development including the Front End Planning (FEP) Level 3 (or FEED) study. Burns & McDonnell has also subcontracted the construction related portions of the study to Kiewit. Kiewit has been supporting B&M on the constructability of the facility, and will be rolling heavy into the cost estimate rollup for the project in the upcoming months. Burns & McDonnell's scope includes the preparation of all engineering deliverables to support an EPC level project estimate to be utilized by the Client to obtain all permits, and financing. Burns & McDonnell is also assisting the Client in the acquisition and execution of the project technology license agreements. It is anticipated that the Client will move forward with the project in 3Q 2009 with Burns & McDonnell and Kiewit as Joint Venture partners to complete the Engineering, Procurement, and Construction of the facility.

In addition to Cash Creek, Burns & McDonnell is the Engineer and Kiewit is the General Contractor for the 900 MW Iatan II and AQCS upgrade for Iatan I; both entities contracted directly to Kansas City Power & Light. Kiewit and Burns & McDonnell have a Joint Venture agreement in place, jointly marketing EPC air quality control projects, of which MidAmerican Energy's Louisa scrubber/baghouse project is complete, and MidAmerican Energy's Walter Scott Energy Center Unit 3 scrubber/baghouse project is under construction. In addition, Burns & McDonnell has been Owner's Engineer on a number of Kiewit EPC projects, including a combined cycle project for Sempra Generation and various coal-fired generation projects.

3.0 Plant Performance

QUALIFICATIONS PACKET: PACE GLOBAL ENERGY SERVICES, LLC

REPRESENTATIVE POWER MARKET EXPERIENCE

Prepared for:

Tenaska, Inc.

September 17, 2009

INTRODUCTION

Since its founding almost 30 years ago, Pace Global Energy Services, LLC (“Pace”) has specialized in energy sector strategy and transactional support. Based in Fairfax, VA, Pace employs approximately 200 full-time professional energy consultants, including professional staff located in our platform offices in New York, Houston, Columbia, Sacramento, San Diego, London, and Moscow who provide local insight and a broadened perspective on the challenges and opportunities facing our clients. Pace clientele consist broadly of energy sector companies, financial institutions, other passive investors in the sector, energy intensive industries, regulatory bodies and other government institutions charged with energy sector oversight.

We offer strategic, market, tactical implementation, and transactional support across the fuels, electric power, energy management, finance, and risk management sectors. As an independent source of energy expertise, Pace serves as an objective outsourcing partner, executing transactions on behalf of our clients and protecting their energy interests.

In addition to the power market experience specifically referenced in this document, Pace has supported or is supporting power financing transactions valued at over $5 billion. Pace isn’t able to disclose the descriptions of these transactions due to the confidentiality restrictions.

POWER MARKET ADVISORY QUALIFICATIONS

SMELTER ASSESSMENT

Pace preformed a nodal market analysis of the ERCOT power market to assist client to understand the impacts to the Rockdale smelter of the ERCOT market moving from a zonal to a nodal market. Pace evaluated the implication of these developments on the value of client's power position at Rockdale and on the economic implication to smelting operation at Rockdale.

SOLAR ASSESSMENT

Pace prepared an independent power market assessment of the PJM East power market covering the period from 2009 through 2028. Pace developed reference case assumptions about future market pricing that did not include the impacts of environmental compliance costs. This was done to value the energy and capacity from a solar facility which has no compliance costs associated with its generation.

POWER MARKET ASSESSMENT - NY AND CA

Pace developed NYISO and CAISO power market assessment report. The Report provided an analysis of the main market drivers and risk factors in the California and New York power markets as well as the results of market dispatch simulations for the market. Pace provided projections of the likely range of Short Run Avoided Cost and Market Index Formula energy prices applicable to qualifying facilities in California consistent with these long-term fundamental forecasts.

CUSTOM FORECASTING SERVICE

Pace supported the client's budgeting and planning processes through customized forecasts of specific coal commodities, emission rates for 500 eastern coal plants, delivered coal prices by U.S. census region, reagent prices, and emission allowance prices in addition to Pace's quarterly Outlook service. Pace presented the forecasts and supporting assumptions to the client's staff through several on-site presentations. The forecasts took into consideration the client's views on future, environmental regulatory conditions and other concerns. Pace conducted an analysis of the Alexander-Lieberman multi-pollutant legislation that included carbon caps and stricter regulation of SO_2, NO_x, and mercury on the price of power and coal.

RISK INTEGRATED RESOURCE PLAN FOR MUNICIPAL UTILITY

Pace supported a municipal electric utility in the development of a long term Risk-Integrated Resource Plan and facilitated a stakeholder process to solicit public opinion and achieve consensus around a preferred resource planning strategy. Pace performed a complete risk analysis for fourteen distinct portfolio options, evaluating the choices through a wide range of uncertainties, including statistically derived distributions for fuel prices, power market prices, electricity demand, and capital costs; uncertainties around regulatory regimes for CO_2 compliance and emissions accounting; uncertainty around the availability of certain renewable technologies; uncertainty around the price at which divested coal power could be sold; and analysis of the reliability of the utility's system.

COLORADO FINANCING SUPPORT

Pace provided a power market assessment for a gas-fired combined cycle power plant in Colorado. Pace's power market assessment was suitable for financing support for an existing power plant and the content of the report was referenced in a Confidential Information Memorandum.

MULTI-REGION POWER MARKET ASSESSMENT

Pace performed a power market assessment for an energy asset developer across three power markets: ERCOT, California ISO, and NYISO. As part of the assessment, Pace provided key market driver inputs and produced long term plant operational projections and pricing estimates for wholesale market values and regulated tariff rates.

PJM POWER MARKET ASSESSMENT AND DISPATCH ANALYSIS

Pace provided a market assessment and plant dispatch analysis for a waste coal developer in the western PJM market area. As part of the analysis, Pace documented key market drivers, including fuel price projections, carbon compliance cost expectations, transmission constraints, and expansion expectations. Pace developed long term energy and capacity price forecasts, as well as projected operating margins for the coal facility.

FRCC POWER MARKET ASSESSMENT

Pace was engaged by the client to advise them in developing a binding bid for the potential acquisition of a gas-fired generator in Florida. Pace provided an independent review of power market conditions and expected power prices for a 25-year horizon.

REGIONAL POWER PLANT DEVELOPMENT REVIEW

Pace reviewed the status of existing and proposed natural gas power plants in a six state region in order to support a natural gas provider. Pace prepared a review of plant capacities operating characteristics and regional locations.

SIX-REGION NORTH AMERICAN POWER MARKET ANALYSIS

Pace provided a market overview and analysis of North American power markets, including specific assessments in six geographically diverse regions. As part of the analysis, Pace provided historical data on market conditions, including historical pricing, reserve margins, demand growth, and supply mix, as well as projections for market pricing and generating technology performance.

NEW YORK AND PJM POWER MARKET AND TRANSMISSION PROJECT ANALYSIS

Pace provided an updated power market and financial analysis for a transmission developer assessing the NYISO Zone J and PJM East market areas. Pace developed and documented key market driver assumptions for both regions, including fuel price projections, expansion unit costs, demand projections, and expectations for carbon compliance costs. Based on long term market price projections, Pace performed a discounted cash flow analysis to provide a fair market valuation of the project. Pace supported the inclusion of its analysis and market price projections into a Confidential Information Memorandum for project equity offering.

ISO NEW ENGLAND MAINE POWER MARKET ASSESSMENT

Pace provided a power market assessment of the ISONE Maine market region to support a power generation owner. As part of the assessment, Pace delivered documentation of key market drivers and risk factors and provided 20-year projections for market energy and capacity prices.

ERCOT POWER MARKET ASSESSMENT

Pace provided a summary of key ERCOT market drivers for an independent power producer looking to refinance a natural gas-fired combined cycle asset. Key drivers included load growth expectations, capacity expansion costs, transmission expansion, fuel prices, and environmental compliance costs.

MULTI-REGION POWER MARKET ASSESSMENT

Pace provided a power market assessment for a hydro asset developer across six North American power regions in order to evaluate comparative market attractiveness. As part of this assessment, Pace developed analysis on market drivers including fuel prices, load growth, capacity expansion, and environmental compliance costs. Pace provided long term energy and capacity market projections for each of the six regions.

NEW YORK AND PJM POWER MARKET AND TRANSMISSION ASSESSMENT

Pace provided power market and financial analysis and advisory support for a transmission developer assessing the NYISO Zone J and PJM East market areas. Pace developed and documented key market driver assumptions for both regions, including fuel price projections, expansion unit costs, demand projections, and expectations for carbon compliance costs. Long term power market price projections were provided for both regions. Based on the market price projections, Pace performed a discounted cash flow analysis to provide a fair market valuation of the project. Pace also conducted an analysis of the probability of an emergency curtailment event in the PJM ISO in order to assess risks to the project.

PJM CAPACITY MARKET ANALYSIS

Pace provided a long run capacity market forecast for the PJM East area within the Reliability Pricing Model structure. In addition to capacity price projections, Pace developed a report documenting market structure, market rules, key market drivers, and assumptions on the cost of new entry and reserve margin expectations.

CALIFORNIA MUNICIPAL ELECTRIC COMPANY SALES AND LOAD FORECAST

For a municipality, Pace developed long-term electric energy sales and peak demand forecasts in support of integrated resource planning analyses. Forecasts were based on econometric forecasting model developed by Pace and customized for the clients service area, as well as in-depth review of major construction and economic expansion projects in the municipality.

MID-WEST IGCC MARKET ASSESSMENT

Pace has assisted the developer of a high-profile IGCC project since its inception by providing market assessments for power, coal, and gas sectors, including estimates of project revenue and impacts of the project on retail power prices and consumer bills. These assessments have explored a wide range of potential states of the market, providing important insights to the effects of varying fuel costs, wholesale market conditions, and power plant specifications.

NATIONAL FUEL AND POWER MARKET ADVISORY SERVICES

Pace performed long term energy and capacity price projections for ten power regions throughout the United States, including markets in four NERC regions and four ISO territories. As part of its advisory support, Pace provided regional fuel market projections and national CO_2 compliance cost estimates.

CALIFORNIA POWER MARKET ASSESSMENT

Pace provided power market analysis and energy and capacity price projections for two market areas in the Western United States. These long term market projections included specific analyses of local ISO pricing tariffs, based on market indicators and expectations.

PJM POWER MARKET ASSESSMENT

Pace was hired to support the financing by providing an independent power market assessment report for a major power asset manager considering acquiring a hydroelectric facility located in the PJM market. . Pace provided energy and capacity market forecasts for two power regions - the PJM-West Hub and AEP. Downside sensitivity was performed to analyze the effect of low demand and low gas prices.

QUALIFICATIONS PACKET: WOOD MACKENZIE

Credentials Pack

Wood Mackenzie

Wood Mackenzie's reputation as one of the leading providers of high quality research to the Energy industry dates back to May 1973 when its very first North Sea Report was published. Its energy coverage now extends across 93 countries covering upstream oil and gas, oil refining and marketing, downstream gas and power generation.

With regional centres around the world, we cover all aspects of the global industry including Upstream, Downstream, LNG, Coal, Gas and Power as well as coal. We have partnered with more than 800 diverse clients around the world, in both public and private sectors, ranging from global super majors to regional service specialists.

Our competitive advantage comes from over 30 years of hands-on experience and teams of professionals drawn from a variety of backgrounds who bring with them a wealth of industry and client knowledge.

Wood Mackenzie has grown significantly in recent years and currently employs around 600 staff making it one of the largest energy research and consulting companies in the world. Whilst most staff are located at the head office in Edinburgh, Scotland, Wood Mackenzie also has offices in London, New York, Houston, Boston, Johannesburg, Moscow, Brisbane, Perth, Sydney, Tokyo, Singapore, Kuala Lumpur, Beijing and Dubai.

Wood Mackenzie has been a respected adviser to the energy industry for more than 30 years and has developed a reputation associated with quality and trust. We combine experience with knowledge of the industry to provide energy companies and financial institutions with analysis which is commercial, forward looking and value based.

Wood Mackenzie has been providing its unique range of consulting services and research products to the Energy, Metals, & Mining industries.

With our foundation in quality analysis, our detailed industry understanding and our wealth of experience, Wood Mackenzie is able to offer clients a unique skill combination that sets us apart from other solution providers.

Our market proposition is based on our ability to provide forward-looking commercial insight that enables our clients to make better business decisions.

Blending analysis with advice

Wood Mackenzie's research and consulting businesses are highly integrated and provide a full range of services to the world's leading energy companies ranging from content and analytics through to action orientated advice. By combining rigorous analysis with creative thinking we have helped the major stakeholders in the Energy business make better informed decisions.

Expert Analysis

Wood Mackenzie has more than 190 dedicated Energy professionals including a range of recognised industry leaders. The importance of maintaining quality is ingrained in the culture of the company and knowledge is valued throughout the business.

Sectors and Clients

Wood Mackenzie applies its integrated research and consulting services to the upstream oil & gas, LNG, gas & power, and downstream oil sectors. Our clients include all of the major Energy companies and leading financial services organisations.

Wood Mackenzie provides invaluable commercial analysis and strategic advice to the world's leading Energy companies. Wood Mackenzie has developed a unique and unrivalled formulation of knowledge, experience and understanding of a broad range of markets and companies. Firmly established as the market leader in its field, Wood Mackenzie's reputation has been built on the provision of high quality and innovative consultancy services and research products.

Clients throughout the world subscribe to Wood Mackenzie's research retainer services on an annual basis and can choose to have analysis delivered to their desktops via a number of media, including the Internet and CD-ROM. This 'Packaged Insight' enables our clients to reduce the risk associated with decision making and increases the productivity of key functions supporting operational and corporate decision making.

Wood Mackenzie's solutions have gained a worldwide reputation for being informed, perceptive, thorough, independent and confidential. Our commitment to quality and our detailed industry understanding makes us uniquely placed to help our clients meet the challenges which lie ahead with absolute confidence.

Wood Mackenzie's knowledge-based consulting expertise includes strategy development, market analysis, corporate and competitor analysis, public policy and regulation, valuations, benchmarking and project analysis.

The company is privileged to count amongst its clients virtually every major company in the global Energy industry, as well as Governments and Government agencies across the globe.

Woodmac Consulting

To compete effectively in a complex and dynamic industry, energy companies need strategies forged from deep knowledge, proven analytic capability and thought leadership.

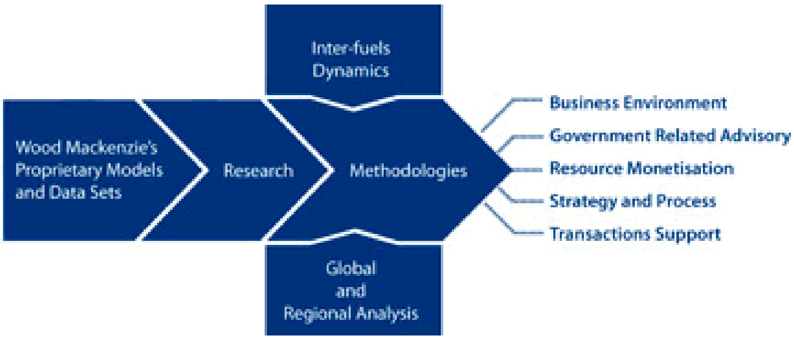
Over the past 30 years, Wood Mackenzie has helped more than 800 companies grow and become more profitable. We have more than 400 analysts around the world, including specialists in all aspects of the industry.

They draw on our extensive databases, a huge resource of authoritative analysis at asset, company, country and regional level.

Our proprietary data and unique analytical tools allow our consultants to provide local insight with a global perspective. In short, it's what's behind us that keep you in front.

Our clients rely on us to anticipate how the industry is changing and guide them to remain successful.

Whether you want to evaluate investment options, mitigate risk, build partnerships or maintain investor confidence, you can trust us to help you make better decisions.



To cover the Energy market in more detail, Wood Mackenzie has joined forces with Hill & Associates and Barlow Jonker, two internationally renowned coal consultancies.

Now, our global team of experts draws on all three companies' extensive research, proprietary data and analytical tools to provide informed advice to our clients. Whether you want to evaluate investment options, mitigate risk, build partnerships or maintain investor confidence, you can trust us to help you make better decisions.

Our wide ranging consulting expertise covers four key areas.

Business Environment

We provide insight and advise clients on:

- Trends, risks and opportunities in coal markets
- Developing their existing coal portfolio
- Competing successfully in the future

Resource Monetisation

Through detailed analysis we assist clients:

- Find and value coal reserves
- Understand the market and all the commercial aspects
- Consider the transportation options and other constraints
- Bring coal to market profitably

Strategy and Process

We help clients play to their strengths and make the right decisions when:

- Entering a new market
- Evaluating investment opportunities for existing coal interests
- Introducing coal into their portfolio
- Considering corporate scenarios

Transactions Support

Clients seek our advice throughout the transaction process, for:

- Independent and thorough fair market valuations
- Commercial and technical due-diligence
- Support at all stages of negotiation
- Data-room analysis
- Independent market reports for project financing

In an increasingly competitive coal market we have helped clients gain a sustainable advantage.

Woodmac's Coal Experts

Both organisations (Barlow Jonker and Hill and Associates) are founded on proprietary supply data and high quality independent analysis. The combined expertise enhances the support we provide to our clients' commercial decision making.

The most notable characteristic of our staff is that every consultant has had considerable experience working in the coal and/or utility industries.

The educational background of the consulting staff includes a wide variety of disciplines including: business administration, geology, mining engineering, industrial engineering, chemistry, and chemical engineering. Most of the consulting staff has advanced degrees.

Like most consulting firms, we occasionally utilize other consultants for their expertise in particular areas. For example, we recently received assistance from a financial expert in the evaluation of the creditworthiness of a coal supplier bidding on a long-term coal supply contract. We also draw upon outside resources for support in the detailed programming of some models; steam and coking coal market research in Latin America, Western Europe and Eastern Europe; coal supply data for Australia, South Africa, and Indonesia; and some work on the outlook for ocean freights.

We provide research and consulting services to hundreds of clients worldwide, including from the following countries and industry sectors:

5.1. Client Countries

Australia
Bangladesh
Botswana
Brazil
Canada
Chile
Colombia
Cyprus
France
Germany
Hong Kong
India
Indonesia
Ireland
Israel
Japan
Netherlands
New Zealand
Norway
Philippines
Russia
Singapore
South Africa
South Korea
Switzerland
Thailand
The People's Republic of China
The Republic of China
UAE
United Kingdom
United States
Vietnam

5.2. Client Sectors

Accounting Companies
Cement Companies
Coal Producers
Coal Traders
Financing Organisations
Government Bodies
Investment Banks
Port Operators
Power Companies
Rail Providers
Shipping Companies
Steel Companies

Summary

Wood Mackenzie (Woodmac) is a global energy company supplying research and consulting services to its customers. The integration of coal into the existing oil and gas services makes Woodmac a global energy advisor on the most important energy sectors.

The coal division is globally spread and offers research and consulting services. Woodmac's coal research products are used by many leading company's in their decision making processes. The utilisation of coal experts in the coal industry to conduct consulting services, make Woodmac the ideal company to evaluate potential investments and to advise on existing and potential projects.

QUALIFICATIONS PACKET: WORLEYPARSONS

Two Westbrook Corporate Center
Westchester, Illinois 60154
USA
Telephone: 708-449-4080
Facsimile: 708-449-4081
www.worleyparsons.com

January 22, 2009

Mr. Nicholas N. Borman
Vice President - Engineering & Construction
1044 N. 115 Street
Suite 400
Omaha, NE 68154-4446

Subject: Owner's Engineer Proposal
Taylorsville Energy Center

Dear Nic:

WorleyParsons is pleased to submit the enclosed proposal to provide Owner's Engineer services for the proposed Taylorsville Energy Center project. Our proposal is in response to our January 20th telephone conference. We are honored to be afforded this opportunity by Tenaska, Inc. (Tenaska) to bid on this very important project.

We are proposing to lead this effort from our Westchester, IL office with support on an as needed basis from both our Reading and Houston offices. We are proposing Bob Nespechal from our Chicago office to lead this effort as the Project Manager with support from Calvin Hartman. Bob has significant as a project developer and an Owner's Engineer that includes developing a project that utilized Illinois State Coal Development Board and DOE funding. Calvin has been involved with most of our recent gasification projects. Between them, they will be able to quickly and efficiently personally address any issue that arises or find the resource within WorleyParsons that can.

We greatly appreciate being considered for this very important assignment and look forward to the opportunity of continuing a successful working relationship with Tenaska. Until then, please do not hesitate to call me at (708) 449-4088 if you have any questions or require additional information.

Sincerely,
WorleyParsons

Scott Johnson, P.E.
Director - Business Development

1. Introduction

WorleyParsons has performed technical and economic evaluations for a wide range of advanced coal-based power generation technologies cases for numerous clients over the last several decades. Several such evaluations are in progress at the current time. WorleyParsons is pleased to offer to assist Tenaska in support of its application for a Federal Loan Guarantee under Solicitation Number DE-FOA-0000008.

The scope of work identified below is aimed at covering the role the Owner's Engineer in support of this endeavor. If deemed acceptable by Tenaska and the US Department of Energy, WorleyParsons is also fully capable and qualified to prepare the Independent Engineer Assessment as a part of the Owner's Engineer role.

WorleyParsons has significant and current experience relevant to this project from both a technical and commercial standpoint. We have working models of many of the commercially available gasifiers and are developing additional models on an ongoing basis. We have significant EPC experience both as an EPC provider and as an Owner's Engineer on the development of recent EPC proposals for IGCC and coal to SNG gasification projects. In addition our proposed Project Manager, Bob Nespechal, has extensive experience developing a coal based project in the State of Illinois following the same process with the DOE and the State of Illinois Coal Development Board. The intent to draw upon all the experience gained from this previous work to facilitate the work described herein.

2. Scope of Work

2.1 Independent Engineer Evaluation

WorleyParsons will comprehensively evaluate the Taylorville Energy Center project and prepare an independent engineering report for submittal to DOE. The report will evaluate the following aspects of the project.

- Siting and Permitting.
- Engineering and Design.
- Major contracts for supply of key systems and components, and the Engineering/Procurement/Construction (EPC) contract.
- Environmental Compliance.

- Testing and Commissioning plans.
- Operations and Maintenance Plans.

2.2 Owner's Engineer Support

The Owner's Engineering role will initially focus on assisting Tenaska in the following key areas:

- Evaluation of prospective EPC contractors and assistance in crafting the final EPC contract.
- Evaluation of the FEED study.
- Technical and commercial evaluation of competing vendor offerings for the gasifier and its ancillary scope of supply.
- Assistance in preparation of the Cost Report required by DOE.
- CO_2 sequestration study.
- Supervision and interface with the contractor responsible for conducting the FEED study and associated cost and economic evaluations.

2.3 Deliverables

The deliverables for this task will include the following:

- Independent Engineering Report
- CO_2 Sequestration Study Report
- Other reports and data as may be required

2.4 Additional Services

The above is just a sampling of the type of services that would be available from WorleyParsons as the Owner's Engineer. The full range of services that will be available to Tenaska is described in the attached Owner's Engineer brochure.

3. Project Team

The resume of our proposed Project Manager, Bob Nespechal, is attached. Bob is uniquely qualified for this role because of his background in project development and specific experience with the State of Illinois Coal Development Board and

DOE. Since Bob has limited gasification experience, we are also providing the resume of Calvin Hartman, another Chicago based senior Project Manager who has significant IGCC and gasification project experience. Calvin will be available to support Bob on any gasification issues and be an additional contact for Tenaska. We are also providing resumes of a number of key people that would be available to support the project as the need arises.

4. Schedule

We understand this assignment will begin in early February 2009 and quickly ramp up to require full time support of the Project Manager and equivalent half time technical support by the of the month. Beyond that, the Owner's Engineer work will be performed in concert with the project schedule as prepared by Tenaska. The start of work will be coincident with the Notice to Proceed (receipt of a signed Task Order). Work is expected to continue through the conduct of the FEED and into the project execution phase and beyond, in accordance with the requirements of Tenaska. We are prepared to support this project with the full compliment of Owner's Engineer staff required by Tenaska for the duration of the project.

5. Compensation

The work described above will be performed on a time and material basis in accordance with our Master Services Agreement. Updated rates for 2009 are attached.

Robert J. Nespechal, P.E.
Project Manager

Resume

SUMMARY

Over thirty-five years of experience in business and project development, corporate, and project management, and engineering of fossil and alternative fueled power plants in the public and private sectors of the marketplace. Experienced with engineer, engineer/procure and engineer/ procure/ construct (EPC) type projects including design, contract preparation and negotiation, procurement, environmental permitting, and financial proformas. WorleyParsons experience includes project management.

EXPERIENCE

2005 - Present

Project Manager – WorleyParsons, Westchester (Chicago), Illinois

Responsible for planning, organizing, directing, supervising, and controlling the execution of all business, technical, fiscal, resource, and administrative functions of an assigned program or project. Act as the Company representative with the client and select subcontractors during the program or project execution.

- Project manager for the retrofit and modification of 9 x 150,000 pph existing stoker coal fired boilers (located at 2 operating sites) to fire up to 30% TDF and 30% waste wood including new SO_2 and NOx removal systems, wood handling systems, CEMS and DCS systems.
- Project manager for the conceptual design to support of air permitting of an 80 MW waste wood bio-mass co-generation facility consisting of 2 x 375,000 pph bubbling fluidized bed boilers.
- Project manager for the site selection and conceptual plant design of a new pulverized coal fired, base loaded, super critical facility located in the southeast.
- Project manager for expert witness support on a new IGCC facility being planned in the upper Midwest.
- Project manager for the condition assessment of an existing LM6000 cogeneration power plant.
- Project manager for owner's engineer services involving the retrofit/replacement of the existing limestone handling and preparation system for a confidential project's 3 x 745,000 lb/hr CFB boilers.

2004

Independent Consultant/Engineer – Lisle, Illinois

Provided project development and project engineering expertise to Smith Consulting, LLC for Corn Belt Energy Generation Cooperative's nominal 90 MW pulverized coal-fired electrical generation plant in Elkhart, Illinois. Responsibilities included:

- Conceptual plant design and performance, development and management of environmental permitting, EPC proposal review and evaluation, EPC negotiations and contract development, O&M services development, O&M proposal review and evaluation, O&M negotiations and term sheet development, and project financial proformas review.

2003 **Business Development Manager – Innogy America, LLC, Chicago, Illinois**

Responsible for business development of an international United Kingdom company's U.S. subsidiary, involving the sale of their operations and maintenance technology, products, and services to the power generation market.

2000 - 2003 **Director, Project Development – EnviroPower, LLC, Lexington, Kentucky**

Responsible for project development, conceptual project design, and project performance of new raw/waste coal-fired electrical generation plants for the company, which is in the business to develop, finance, own, construct, and operate independent power generating facilities.

- Managed and/or assisted in managing the business planning, project development, and technical development of five nominal 525 MW circulating fluidized bed (CFB) raw/waste coal-fired power plants in Pennsylvania, Kentucky, Illinois, and Indiana.
- Responsibilities included conceptual plant design and performance, development and management of project budgets and schedules, management of internal and external manpower/consulting resources, financial proformas, site selection and acquisition, environmental permitting, contracts for fuel and limestone supply, water supply, wastewater discharge, ash disposal, EPC technical specifications development, EPC contractor technical reviews and negotiations, and O&M services development.

1999 - 2000 **Director, Projects – Unicom Power Holdings Inc., Chicago, Illinois**

Responsible for project development and management of new fossil-fueled electrical and cogeneration projects for the company, an unregulated affiliate of Exelon Corporation (formerly Unicom Corp.) that was established to develop, finance, own, and operate independent power generating facilities.

- Managed the development and permitting of two fast-track natural gas-fired simple cycle peaking facilities (2 x 60 MW for North Chicago, Illinois and 4 x 50 MW for Calumet City, Illinois) including start of construction at North Chicago.
- Responsibilities included conceptual plant design and performance, development and management of project budgets and schedules, management of internal and external manpower/consulting resources, financial proformas, site selection and acquisition, Phase I environmental studies, environmental permitting, procurement of gas turbines (LM 6000, GE Frame 6B and Westinghouse W25 IB 12), EPC technical specifications development, procurement and management of EPC contractor services, and preparation/presentation of proposals to customers for energy services.
- Formed a strategic venture with TXU Development to utilize their 2 x 750 MW pulverized coal-fired supercritical boilers and turbine equipment, including O&M services.

1997 - 1999 **Project Manager – Sargent & Lundy LLC, Chicago, Illinois**

Responsible for project management and development support for independent power producers' new coal and natural gas-fired electric generation facilities.

- Technically managed and provided project development support for a new 90 MW base-loaded, non-recourse debt/government grant financed, pulverized coal-fired electrical power generation facility in Elkhart, Illinois including conceptual design, boiler/flue gas cleaning equipment design review, environmental permitting, budgeting and scheduling, financial pro-formas and the agreements for power purchases, fuel supply, ash disposal, EPC services, and O&M services.

- Developed and negotiated a host site agreement with Pekin Energy (Pekin, Illinois) for siting new developmental flue gas cleaning technology

- Assisted in providing commercial and technical liaison with federal (DOE) and state (DCEO) government agencies for funding the development of new coal combustion and flue gas cleaning technologies.

1993 - 1997 **Independent Consultant/Engineer – Lisle, Illinois**

Provided professional services to clients in the areas of business and project development, project management, project engineering, contracts, and procurement.

- Provided project development and project engineering expertise to PCI Energy Inc. for the privatization and reconversion to coal-firing of an existing gas-fired 30 MW thermal cogeneration power facility (Tenneco Packaging's Filer City, Michigan plant) including asset assessment review, development of construction and operational cost estimates, financial analyses review, environmental permitting, mass and energy balances, and contractor selection/negotiation of the reconversion work.

- Provided project development and project engineering expertise to PCI Energy Inc. for the development of a new wood, coal and natural gas-fired 50 MW thermal cogeneration power facility (for Tenneco Packaging's Tomahawk, Wisconsin plant) including conceptual design, environmental permitting, budgeting, and the EPC agreement.

- Provided procurement services (equipment specification writing and purchasing) to Sargent & Lundy, LLC for material and capital equipment for coal-fired power plant projects in the Republic of China (Dandong, Dalian and Yangzhou projects) and the Republic of India (the RAIN project).

- Provided technical consulting expertise for proposal development and conceptual design to BG Checo, Canada for the rehabilitation and retrofit of a waste incineration project near Montreal, Quebec.

- Provided professional expertise to Harza Environmental and Intercontinent Engineers, Inc. for the rehabilitation of an existing waste-to-energy facility for the City of Chicago. Services included facility needs assessment review, development of capital and operational cost estimates, financial analyses review, process system conceptual design, waste composition analysis, environmental permit support, and development of project procurement documents relating to a full-service construction and operations contract.

- Provided technical expertise to PCI Energy, Inc. in developing an EPC agreement for a 50 MW simple cycle diesel fuel-fired project under development in the Philippines.

1979 - 1993 **President/Vice President/Engineering Manager – Volund USA Ltd., Oak Brook, Illinois**

Corporate Management:

- Responsible for the business development and growth of an international Danish company's U.S. subsidiary involving the sale of their alternative fuels combustion and process technology, products, and services.
- Had full profit and loss responsibility and as a member of the Board of Directors made monthly presentations on financial results and short-term and long-term business plans to the Board.
- Developed, negotiated, and closed four contracts for waste-to-energy projects for engineer, procure, and deliver or EPC.
- Formed strategic ventures with Japanese, French, Italian, and Danish companies to develop, build, own, and operate alternative fuels cogeneration projects in North America, Latin America, and Taiwan. Led joint marketing and project development activities.
- Formed partnerships with major domestic contractors to provide EPC services to the waste-to-energy market.

Engineering Management:

- Responsible for the overall engineer, procure, construct and start-up activities of the company including scheduling, budgeting, and resource development and training.
- Started, organized, and standardized the subsidiary's engineering, procurement, and construction capabilities.
- Maintained on-going technology transfer to the U.S. including conformance to codes, standards, and practices, and acted as technical liaison between the subsidiary and its clients, suppliers, and contractors.

Project Management:

- Responsible for overall project execution, budgeting, scheduling, resource loading, engineering, design, procurement, construction, and start-up activities.
- Project Director for the design, engineering, procurement, delivery, and start up of the process technology on the 5 MW Commerce City, North Carolina cogeneration waste-to-energy facility.
- Project Director for the design, engineering, procurement, delivery, construction, and start up of the combustion technology on the 7 MW New Hanover County, North Carolina electrical generating waste-to-energy facility.

- Project Manager for design, engineering, procurement, delivery, construction, and start-up of the process technology on a 22 MW McKay Bay, Florida electrical generating waste-to-energy facility.

- Project Manager for the design and engineering of the process technology on the 50 MW Broward County, Florida electrical generating waste-to-energy facility.

1971 - 1979 **Project Engineer – Sargent & Lundy Engineers, Chicago, Illinois**

Responsible for all mechanical phases of layout, studies, design, schedules, equipment specifications, and procurement evaluations for Wisconsin Power & Light's 400 MW Edgewater Unit 5 coal-fired power plant and Cincinnati Gas & Electric's 650 MW East Bend Unit 2 coal-fired power plant.

EDUCATION

MBA, Finance/Marketing, DePaul University

B.S., Engineering (Thermal-Mechanical), University of Illinois

REGISTRATIONS/AFFILIATIONS

Registered Professional Engineer - California, Illinois, Indiana, Michigan, Pennsylvania, and Wisconsin

Member, American Society of Mechanical Engineers

WorleyParsons
resources & energy

Calvin L. Hartman, P.E.
Senior Project Manager

Resume

SUMMARY

Over thirty years of experience in power plant and industrial plant engineering. Recent key experience includes Owner's engineering and technology evaluation for the FutureGen Integrated Gasification Combined Cycle (IGCC) project. Project manager for the feasibility/conceptual design for a 600 MW IGCC facility. Project manager of a nominal 400 MW coal-fired facility. Project manager for a 1000 MW combined cycle project, and project manager for two 200 MW cogeneration plants.

Experience includes proposal development, feasibility evaluation, contract preparation and negotiation including EPC and EPCM, major equipment procurement, engineering management and project implementation of medium to large power generation facilities. Also served as procurement manager for two new coal-fired units in China, performed as owner's engineer for a combined cycle gas turbine plant in Indonesia, and project manager for several waste-to-energy facilities.

EXPERIENCE

2005 - Present **Senior Project Manager – WorleyParsons, Reading, Pennsylvania**

Currently a Senior Project Manager in the Power Consulting Services sector of WorleyParsons. Various assignments include Owner's engineering, engineering and design, and asset analysis.

Confidential Client, Feasibility Study, 600 MW IGCC – Project manager for the feasibility study of a 600 MW IGCC facility. The scope includes development of a cost estimate, detailed performance, equipment arrangement drawing, process flow diagrams, one-line, evaluation of different degrees of CO_2 separation, and evaluation of wet, dry, and hybrid cooling systems.

FutureGen IGCC Project – Project manager for technology evaluation for the FutureGen Near Zero Emissions Project that will convert coal to gas, produce power and byproducts for sale, and sequester most of the CO_2 gases. The scope included evaluation of four major gasification technologies, which included modeling the configuration and performance of each technology, evaluating the performance differences using three different coal specifications, including the design CO_2 separation for sequestration or enhanced oil recovery (EOR).

NYPA Power Plant Project – Project manager for the site evaluation for an IGCC or advanced coal power generation facility. Evaluated and ranked over 100 potential sites for use as a future power plant site. The evaluation included consideration of future potential for CO_2 sequestration.

Ohio FutureGen Project – Project manager for evaluation and selection of various sites proposed for the location of a new 275 MW IGCC power plant using advanced technology including coal conversion to gas, CO_2 sequestration, and production of saleable byproducts. Detailed proposals were prepared using the selected sites from the evaluation. The evaluation included study of the infrastructure, site access, fuel delivery modes, transmission, water supply, site characteristics, electricity and byproducts market, labor market, transmission and utility "right of ways," environmental qualities, severe storm and earthquake risk, and geology characteristics. The geology evaluation included the CO_2 plume analysis and determination of the injection well configuration.

2000 - 2005 **Vice President in Fossil Power Technologies – Sargent & Lundy**

Basin Electric Dry Fork Mine Mouth Coal Fired Power Plant. The plant is a 385 MW coal fired plant combusting coal form an adjacent mine. Project manager for the conceptual design, feasibility and contract strategy. Managed the early design phase. The project included

Pinnacle West Energy, Redhawk Power Plant – Project manager for the combined cycle, 1000 MW facility. Duties included preparation of the EPC bid document and negotiation of final EPC contract. Managed the home office and field engineering and managed the procurement for all equipment, valves and piping. The Plant uses four GE7FA combustion turbines, two ABB steam turbines, four NEM heat recovery steam generators (HRSG) with reheat and duct firing, cooling tower, well water supply, and zero discharge system. Project scope included design and procurement of all engineered equipment. Construction performed by a joint venture partner.

1999 - 2000 **Senior Manager – Sargent & Lundy**

Calpine, Pine Bluff Energy Center – Project manager for the gas and oil, cogeneration, 200 MW facility. Managed the engineering, procurement and startup. Plant uses a GE 7FA combustion turbine, HRSG condensing steam turbine, cooling tower, and steam process export line to a paper mill. Project scope includes design and procurement of all material and equipment. Installation performed by joint venture partner. Participated in proposal development, contract negotiation, and project implementation.

1997 - 1998 Enron, East Java – Project manager on the gas turbine combined cycle, 500 MW, Indonesia facility. Provided project management and technical review oversight as owner's engineer. Main equipment includes three frame 9E gas turbines, HRSGs, triple-pressure condensing turbine generator, reverse osmosis desalination system, and a seawater in-take structure. Scope of services included review of the engineering design and principal project contracts and permits, project design requirement, and conceptual design of the project facilities; and monitoring the execution of the engineering, procurement, and construction.

1996 - 1997 **Procurement Manager – Sargent & Lundy**

Jiangsu Ligang Electric Power Company, Yangzhou Units 1 and 2, Coal 1200 MW – New unit balance-of-plant design. Equipment included electrical equipment such as main transformers, switchgear; bus ducts, station batteries, motor control centers, diesel generators, cable, wiring, and conduit; and mechanical equipment including condensate polishers, HVAC system, heat exchangers, pumps, piping, valves, and hoists. Responsibilities included preparation of technical and commercial specifications, prequalification of bidders, issuing requests for bids, evaluation and selection of successful supplier, contract award, contract administration, invoice approval, and payment.

1994 - 1995 **Independent Consulting – Sargent & Lundy**

Various projects – Provided services in process application, system evaluation, economic analyses, permitting assistance, project development, engineering and management of proposals and contracts. Services included preparation of a proposal for the design and supply of hazardous waste facility equipment to the 3M Company. Developed and led project team that included Volund Ecology, a technology supplier, and a major construction company in the U.S. to propose a design-build-construct retrofit of the incinerator plant for the Montgomery County, Ohio waste-to-energy project. Consulted to Volund Ecology on contract terms and conditions for construction, design, guarantees, and performance-related issues. Consulted to Intercontinent Engineers, Inc., on the Chicago waste-to-energy rehabilitation project and on the Illinois Institute of Technology's cogeneration facility. Consultant for Volund in marketing biomass technology and for Power Consultants, Inc., in various aspects for cogeneration projects.

1989 - 1993 **Vice President Projects – Volund USA, Ltd.**

Government of Guam; Mecklenburg County North Carolina; City of Harrisburg, Pennsylvania – Various projects. Responsibilities included marketing and project development for Volund technologies in North and South America. Also responsible for contract negotiations, project management, engineering resources, quality assurance, and technology transfer – 800 tons per day waste-to-energy facility.

1981 - 1989 **Project Manager – Volund USA, Ltd.**

Various Waste-to-Energy Projects including mass burn facilities in the 250 TPD range that cogenerated process steam and electrical power. Projects performed in cooperation with a major engineer and construction firm. Scope of work included design, purchasing, supply, and start-up of cranes, boilers, ash handling equipment, pollution control equipment, and controls.

1974 - 1980 **Mechanical Engineer – Sargent & Lundy**

NIPSCO Generating Stations Schafer Units 17 and 18; Bailey Units 7 and 8; and Michigan City Various Projects – Responsible for boiler and boiler auxiliaries, cooling water systems, forced draft, induced draft fan system, and miscellaneous systems.

Education

M.B.A., Engineering, Illinois Benedictine College, 1987

B.S., Engineering, Purdue University, 1974

Registrations/Affiliations

Professional Engineer – Arkansas, Illinois, Indiana, Ohio, and Pennsylvania

Member, American Society of Mechanical Engineers (ASME)

Member, Midwest Cogeneration Association

Past Session Co-chairman, ASME

Publications/Presentations

Co-author, “DCS Control in Waste-to-Energy,” ASME Conference, 1991.

Satish Gadde
Project Manager
WorleyParsons *Select* Group

Resume

SUMMARY

Over fourteen years of combined technical and project management experience in diverse engineering fields, including two years with WorleyParsons. Strong inter-personal and leadership skills with ability to communicate effectively to all organizational levels. A six sigma certified Black Belt with proficient problem solving, analytical, and statistical skills. Other experiences includes engineering design and development of dry low NOx gas turbine combustion systems and low BTU fuel combustion systems; laboratory and field full-scale engine testing experience of various prototype gas turbine systems; engineering process and design of gas turbine auxiliaries and control systems; start-up, and commissioning experience of various simple and combined cycle plants. Three years of experience as mechanical operations and maintenance engineering in marine machinery including diesel engines, gas, and steam turbines, and steam generators.

EXPERIENCE

2006 - Present

Project Manager – Power *Select* Group, WorleyParsons, Reading, Pennsylvania

Coordinate efforts, lead, manage, and support new combined cycle, integrated gasification combined cycle (IGCC), and other power generation technologies. Major assignments include:

2008

- Air Products, AK Steel Project – Project manager for front-end engineering design (FEED) of a 3 x 1 100 MW combined cycle project with GE 6B gas turbines configured to fire-blast furnace gas. The project involves other tasks to incorporate established guidelines required by Air Products per their internal standards.

- Korea Power KOPEC IGCC Project – Lead engineer for the execution of the IGCC task for engineering evaluation, and cost estimate using E-Gas and Shell gasification technologies.

- Sithe Global Energy, Arcelor Mittal Dofasco (Steel) Project – Project manager for FEED of a 1 x 1 500 MW gas turbine combined heat and power (CHP) project with Mitsubishi M501G power island and Mitsubishi blast furnace-fired boiler in a 2 x 1 steam turbine configuration.

- Pennsylvania Power & Light; Sequoia Project – Project manager in supporting role providing owner's engineers' services to the client for evaluating the GE, Siemens, and MHI Power Island bids for the combined cycle 2 x1 660 MW project.

- TransCanada Energy, Saddlebrook Power Station – Project manager for preliminary engineering of a 1 x 1 350 MW gas turbine combined cycle with Siemens SGT6-5000F4 and Alstom steam turbine.

- Southern California Edison – Project manager for several tasks including (a) the selection of the gasification technology for the project; (b) feasibility study for a 600 MW IGCC plant in Utah with near 90% CO_2 capture technology; and (c) technology evaluation between IGCC and ultra-supercritical clean coal with CO_2 capture for a 600 MW plant based on Utah-based Bituminous coals. Five gasification technology OEMs were involved in the project which include ConocoPhillips E-Gas, Siemens Fuel Gas Gasification, Shell, GE Radiant Quench, and Mitsubishi's enriched air blown gasifiers for the evaluation of the IGCC technology.

Resume

2007 **Project Manager – WorleyParsons, Reading, Pennsylvania**

- Stanwell ZeroGen, Australia – Provided gas turbine combustion engineering support and technical guidance for the pre-feasibility and front-end engineering design study of 80 MW IGCC plant in Australia with 90% CO_2 capture based on Shell gasifier operating with a GE gas turbine.

- SHED – Allied Syngas SNG Project, North Dakota – Provided technical guidance on the gas turbine application for the various options study including GE 6B, 6FA, and 7EA engines.

- PacifiCorp, Utah – Performed as a project manager and lead mechanical engineer for the feasibility study and proposal support of a 600 MW IGCC plant in Wyoming with CO_2 capture based on E-gas gasifier operating on Powder River Basin (PRB) coal and Siemens "F' class gas turbine.

- E.on – U.S., Kentucky – Performed as project manager and lead mechanical engineer for the feasibility study and proposal support of a 600 MW IGCC plant in Kentucky with CO_2 capture based on GE radiant quench gasifier operating on Eastern bituminous coal and GE "7FB' gas turbine.

- Energy East Management Corporation, New York – Rochester Gas & Electric – Provided guidance and support for design and construction of a combined cycle power plant at the Russell site in Rochester, New York.

- UCC Energy Pty, Ltd., Australia – Served as a lead mechanical engineer in completing the feasibility study of combusting ultra clean coal in a gas turbine combined cycle. The feasibility study included the conceptual design of the fuel system and gas turbine combustion system and also the performance, cost, emissions, and other comparisons of an UCC-fired combined cycle with a pulverized coal, IGCC, and a natural gas combined cycle power plant.

- DLS Power Holding, New Jersey – Served as a lead mechanical engineer for performance and cost development of one 750 MW net each supercritical and ultra-supercritical power plant and an IGCC Plant.

- O&G Industries, Connecticut – Provided technical guidance on the Kleen Energy 620 MW net combined cycle project based on Siemens SGT6-5000F3 gas turbines.

- Tennessee Valley Authority, Tennessee – Owner's engineering services for the 600 MW Lagoon Creek and 940 MW Gleason Combined Cycle project. The project was based on existing gray market 2 x 1 "F" class gas turbines at the Lagoon Creek site and conversion of existing three "F" class simple cycle peaker units at the Gleason site to combined cycle configuration.

- Rentech Natchez Coal-to-Liquid Project, Mississippi – Provided technical guidance on the gas turbine application for the various power plant options study (600-900 MW) to support the 25,000 BPD coal-to-liquid project. The power generation options (combined cycle and conventional Rankine cycle) utilized off and tail gas from the process.

- FuelCell Energy, Connecticut – Provided feasibility support for application of gas turbines in several sizes (5 MW – 130 MW) in a fuel cell energy plant operating on H_2 rich fuel in a gasification island with CO2 capture.

Resume

2006

- Electric Power Research Institute (EPRI) – Project manager for the development of pre-design specifications for the IGCC early deployment projects. Assisted the coal fleet IGCC members in their decision-making and application process for building IGCC plants. Assisted EPRI in developing the IGCC User Design Basis document.

- Salt River Project, Utah – Served as lead mechanical engineer for performance and cost development of one 800 MW net and 1900 MW net IGCC plant.

- Duke Energy Generation Services, Pennsylvania – Performed as lead mechanical engineer for the technology assessment study of syngas repowering of the existing 620 MW Fayette Energy facility consisting of 2 x 1 "7FA" gas-turbine-based combined cycle plant with GE Radiant Quench gasifiers and GE Quench gasifiers.

- Xcel Energy, Colorado – Performed as lead mechanical engineer for the feasibility study and proposal support of a 600 MW IGCC plant in Colorado with CO2 capture based on E-gas gasifier operating on PRB coal and Siemens "F" class gas turbine.

- U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL) – Project manager and lead mechanical engineering responsibility for completing feasibility study on the construction and use of a gasification system at the U.S. Department of Agriculture (USDA), Agricultural Research Service (ARS), and Beltville Agricultural Research Center (BARC) to create a research and development platform to study various biomass and industrial feedstocks.

- Energy East Management Corporation, New York – Served as project manager in supporting role and lead mechanical engineer for generation technology evaluation study for 300 MW-800 MW combined cycle, pulverized coal (PC), CFB, and IGCC plants at various Northeast sites. The IGCC plants are with E-gas gasifier, Siemens 501F gas turbines, and will be in 1 x 1 or 2 x 1 configuration (300-600 MW nominal rating).

- SouthWestern Power Group, Arizona – Performance support and technical guidance for the 600 MW IGCC plant using PRB coal, E-Gas gasifier, and Siemens 501F gas turbine at the Bowie site.

- FutureGen Industrial Alliance – Supported the conceptual study for a nominal 300 MW near zero emissions power plant with hydrogen-fired IGCC plant, CO2 capture, and sequestration.

2004 - 2006 **Engineering Program Manager/Principal Engineer – Siemens Power Generation, Orlando, Florida**

Duties included:

- Overall responsibility for IGCC gas turbine engineering development program.

- Responsibility for teams working on the thermal cycle, combustion, fuel system, auxiliaries, and gas turbine component designs on the IGCC application.

- Project planning and working with balance-of-plant engineers, engineer/procure/construct, and front-end engineering and design team leads in developing an optimized Reference IGCC Power Plant design.

- Providing complete operational specification for syngas, natural gas, and distillate operation in an IGCC plant.
- Evaluating the gas turbine performance, emissions risks, and work with marketing, sales, and negotiation groups in providing gas turbine quotes, guarantees, proposals, and firm price biddings.
- Leading and supporting the syngas combustor development and testing programs.
- Leading the design and development of gas turbine engine components to meet the operational, design, and cost requirements.
- Evaluating gas turbine operational feasibility with various fuels – high- and low-heating value fuels, distillate oil, LNG, etc.
- Implementing design changes, prioritizing drawing changes, interfacing with drafting, and signing off developmental and production drawings.
- Interfacing with manufacturing, service, and purchasing groups.
- Supporting various testing programs for new and re-designed engine hardware incorporated with advanced state-of-the-art features.

2002 - 2006 **Six Sigma Black Belt – Siemens Power Generation, Orlando, Florida**

Duties included:

- Leading and continuously supporting Black Belt and Green Belt projects.
- Gas Turbine Engineering Six Sigma Tool Master network representative.
- Completed five Black Belt projects and mentored fifteen Green Belts through certification.

1998 - 2004 **Senior Gas Turbine Combustion Applications Engineer – Siemens Power Generation, Orlando, Florida**

Duties included:

- Managed global gas turbine programs across Power Generation Division for Siemens Germany and Siemens USA gas turbine Econopac systems.
- Supported start-up, commissioning, and tuning of the gas turbine engines to meet the contractual guarantees in performance, emissions, and operability.
- Designed, analyzed, tested, validated, and implemented several gas turbine combustion system components.
- Led the frame engineering team to continuously improve the gas turbine operational flexibility (operations, emissions, performance, and parts' life durability).
- Led failure analysis and root cause investigations, providing recommendations to reduce non-conformance costs and mitigate risks.

- Interfaced with plant and Econopac engineering groups regarding development of auxiliary systems and control logic functionals for operational improvement of combined cycle plant.
- Led the service engineering team to continuously improve the gas turbine availability, reliability, and starting reliability through directly interfacing with customers.
- Supported several user's conference meetings related to combustion service topics.
- Managed technical data interface with combustor component suppliers. Followed product through manufacturing, testing, and field implementation.

1997 - 1998 Graduate Research Assistant, Mechanical Engineering – Michigan Technological University, Houghton, Michigan

Duties included:

- Teaching and coordinating experimental equipment installed in Michigan Technological University's automotive engineering lab.
- Teaching the working of combustion in various spark and compression-ignition engines available in energetics lab.
- An Exhaust Gas Re-circulation (EGR) Project devised and implemented on 1995 M11 Cummins engine for performance experimentation.

Research Projects:

- Design and modeling of diesel particulate traps working on steady state and transient cycles
- Development of computational fluid dynamics (CFD) code using TVD schemes and advanced turbulence models for incompressible flow simulations.
- Design of a vibration fixture used in the dynamic testing of rubber bushings with PRO/E and FEA with I-DEAS.
- Study of loading and regeneration characteristics of IBIDEN, NoTox SiC, and Corning Cordierite traps.
- Study of vapor phase species in an exhaust gas re-circulated diesel engine exhaust emissions.
- The influence of a catalyzed and an un-catalyzed IBIDEN SiC trap on heavy duty diesel exhaust emissions.

1996 - 1997 Junior (Marine) Engineer – Acomarit (UK) Ltd., Glasgow, United Kingdom

Complete management of the vessel's refrigeration and air-conditioning systems. Responsible for performing, working, and evaluating diesel generators and steam/gas turbines equipped on board. Installation, maintenance, and continuous monitoring of the working of main diesel engine (10500 bhp) and boilers. Supported and participated in various auxiliary equipment development and testing projects.

1994 - 1996 **Assistant (Marine) Engineer – Pacific International Lines, Singapore**

Responsible for working and troubleshooting diesel engine equipment (6660 bhp), auxiliary equipment, and boilers in the vessel. Management of various heavy duty machineries planted in the vessel. Hands-on experience in various high precision manufacturing processes. Supported and participated in various auxiliary equipment development and testing projects. Responsible for conducting various performance and total quality evaluations on all the machinery on board.

EDUCATION

M.S., Mechanical Engineering, Michigan Technological University, Houghton, Michigan, 1998

B.E., Mechanical Marine Engineering, Andhra University, College of Engineering, India, 1994

SPECIFIC TECHNICAL EXPERTISE/SPECIALIST COURSES

Six Sigma Black Belt Certified, 2003

Project Management

OSHA

Six Sigma DFSS Green Belt Training

Six Sigma DMAIC Black Belt Training

Weibull – Log Normal Analysis Training and Workshop

PUBLICATIONS/PRESENTATIONS

Published over 120 product design and development technical reports and engineering manuals internally in Siemens Power Generation and Westinghouse Electric Corporation.

“A Study of Filtration, Loading and Regeneration Characteristics of IBIDEN SiC Diesel Particulate Filter,” Report Submitted to Lubrizol Corporation, Ohio and ECS, Canada, August 1997.

“A Computational Model Describing the Performance of a Ceramic Diesel Particulate Trap in Steady State Operation and Over a Transient Cycle,” SAE Publication No. 1999-01-0465, International Congress and Exposition, Detroit, Michigan, March 1 - 4, 1999.

“Advanced F Class Gas Turbines Can Be a Reliable Choice for IGCC Applications,” Electric Power 2006, Atlanta, U.S., May 2 - 4, 2006.

“Introducing the SGCC 6-5000F 2 x 1 Reference Power Block for IGCC Application,” Electric Power 2006, Atlanta, U.S., May 2 - 4, 2006.

“Advancing F-Class Gas Turbines to Maximize IGCC Availability and Performance,” ASME Turbo Expo 2006, IGCC Panelist for Siemens Power Generation, Barcelona, Spain, May 8 - 11, 2006.

“Syngas Capable Combustion Systems Development for Advanced Gas Turbine,” ASME Turbo Expo 2006, Publication No. 2006-90970, Barcelona, Spain, May 8 - 11, 2006.

"CO_2 Capture: Impact on IGCC Plant Performance in a High Elevation Application Using Western Grade Sub-Bituminous," Gasification Technologies Conference, San Francisco, October 14 - 17, 2007.

"Cost Impacts of CO2 Capture using Western Grade Sub-bituminous in IGCC Plant", Electric Power 2008, Baltimore US., May 6- 8, 2008.

"Impact of Site Elevation on IGCC Plants with and without CO_2 Capture", Coal Gen 2008, Louisville, KY, Aug 13 – 15, 2008.

"Feedstock Impact on an IGCC Plant with CO_2 Capture", Gasification Technologies Conference, Washington DC, October 5 - 8, 2008.

PATENTS

"Humidity Compensation for Combustion control in Gas Turbine Engines," U.S. Patent – 6,708,496 B2, Siemens Westinghouse Power Corporation, March 2004

"Gas Turbine Pilot Burner Water Injection and Method of Operation," U.S. Patent – 6,715,295 B2, Siemens Westinghouse Power Corporation, April 2004

"New Main Gas Support Housing Nozzle designed to reduce part load CO emissions on Gas Turbine engines," U.S. Patent – 6,996,991, Siemens Power Generation, February 2006

"Outlet Temperature Corrected – New Control Loading Process for Gas Turbine engines", Siemens PG U.S. Patent – 7,269,953, September 2007

PENDING PATENTS

"Closed Loop Ignition Control Method for Gas Turbine Engines", Combustion Applications Group, Siemens Westinghouse Power Corporation

"Online Fuel Debris Monitoring using an IR Camera in Gas Turbines to detect filter/strainer cloggage", Siemens Power Generation

"Diesel Exhaust Particulate Concentration Measurement Procedure Using Pressure Measurements", ME-EM Department, Michigan Technological University

"Diesel Particulate Trap Performance Software - Steady state (version 8.1) and Transient (version 8.2)", ME-EM Dept., Michigan Technological University

AWARDS

Science Trailblazer Award by Science Spectrum Magazine's Minorities in Outstanding Research Science, 2006

Performance Award, Siemens PG, Gas Turbine Combustion System Component Design, 2005

Performance Award, Siemens PG, Gas Turbine Frame Engineering, 2004

Performance Award, Siemens PG, Site Startup and Commissioning Operations, 2003

Performance Award, Siemens PG, Gas Turbine Technical Field Support, 2002

Performance Award, Siemens PG, Gas Turbine Long Term Programs and Technical Service Management, 2002

Siemens Top+ Star Award (highest honor in entire Siemens) runner-up, in Innovation, "Combustor Bypass Elimination on W501F," 2002

Performance Award, Siemens PG, New Unit Projects, 2002

Performance Award, Siemens PG, Gas Turbine Service Programs, 2001

Performance Award, Siemens PG, Gas Turbine Engineering, Combustion Applications, 1999

National Merit Scholarship, Government of India, August 1990 – July 1994

Christopher A.A. Higman
Independent Consultant

Resume

SUMMARY

Over 35 years experience in the sale, design, development, execution, and management of capital investment projects in the water supply, power, and chemical process industries in a wide range of countries. Special emphasis is in the field of synthesis gas production and treatment in a broad variety of applications. Experience also includes covered process and mechanical design and sales of process plants, as well as project management, construction, and start-up management of such projects in different countries.

EXPERIENCE

2000 - Present **Independent Consultant**

Recent and current activities include reliability audit on an ammonia plant based on gasification of refinery residues, seminars for various clients on gasification and related topics (including Sasol, Eni, UOP,EUCI, Midrex).

EPRI CoalFleet Project, Member of Expert Group, developing user design specifications for integrated gasification combined cycle (IGCC).

1999 - 2000 **Director – Lurgi AG, Frankfurt am Main, Germany**

Responsible for business information management, quality assurance, health, safety, and environmental management.

1998 - 1999 **Managing Director**

Company is a 200-strong process engineering contractor working on an engineer/ procure/construction (EPC) basis in the Indian market and internationally as a high value engineering center. The range of plants handled covers oil, gas, petrochemical, fiber, metallurgy, and power. As Managing Director, responsible for implementing strategies for growth and improvement in operating efficiency as well as ensuring overall profitability.

1997 - 1998 **Vice President, Corporate Development**

Company acquired control of and responsibility for a number of overseas subsidiaries. As Vice President - Corporate Development, had the task of developing and implementing strategic planning for engineering offices in Kraków, Delhi, Beijing, Kuala Lumpur, Jakarta, and Johannesburg with the objective of integrating these offices with German offices in Frankfurt and Chemnitz into an international operating group. Also acted as project manager for a strategic acquisition in the U.S.

1994 - 1997 **Vice President, Gas Technology**

Responsibilities included the fields of steam reforming, methanol synthesis and associated technologies, partial oxidation and sulphur recovery, and gas treatment by physical and chemical absorption processes. Directly responsible for running a department of 50 process engineers. Other responsibilities included:

- Sales – Responsible for all proposal managers responsible for tender preparation in the field of gas technology.

- Process operations – Responsible for all process engineering in the field of gas technology, both during tendering and project execution was conducted in one of the three departments.
- Research and Development - Responsible for research and development (R&D) policy in the field of gas technology and for monitoring progress of such approved R&D projects carried out in the R&D division.

1993 - 1994 **Head of Department, Gas Production and Synthesis Technologies**

Responsibilities included fields of steam reforming, methanol synthesis, and associated technologies.

1987 - 1993 **Department Manager, Gas Production**

Responsible for sales, process design, and R&D policy in the fields of catalytic and non-catalytic partial oxidation and CO shift. Important projects executed by the department during this period included:

- SMDS Synfuels project for SHELL Malaysia,
- Mossgas Synfuels Project, South Africa,
- Three ammonia plants in China developed in cooperation with Toyo Engineering Corp., Japan.

Other activities included development of a new process for treating vanadium-rich soot from partial oxidation processes, and development of concepts for IGCC power production from refinery residues.

1985 - 1986 **Senior Process Engineer**

Responsible for various tenders and process development projects in the field of gas production. This period also included assignments as trouble-shooter on various projects including the start-up of a 2000 t/d methanol plant for VEB Leuna-Werke, East Germany.

1978 - 1984 **Proposal Manager/Project Manager**

Responsibilities included preparation of basic design package, award of subcontract to and then supervision of detail engineering by Portuguese engineering companies in Lisbon.

Construction/Start-up Manager

1978 **Deputy Star-up Manager**

A 1660 t/d ammonia plant based on partial oxidation for VEBA Chemie AG in Brunsbüttel.

1977 - 1978 **Project Manager**

Mitsubishi Chemical Industries, Japan. Prepared a basic design package for a 330 t/d methanol plant based on partial oxidation.

Resume

1975 - 1976 Process Engineer

Responsible for a 1660 t/d ammonia plant based on partial oxidation for VEBA Chemie Ag in Brunsbütte.

1974 - 1975 Project Engineer – IPI Contractors AG

Pertamina, Indonesia, 1500 t/d Ammonia Plant. Responsible for ammonia synthesis unit and interface integrity between synthesis design (Grande Paroisse, Paris) and syngas production (Lurgi, Frankfurt).

1969 - 1974 Project Engineer – Stewarts and Lloyds of SA Ltd. Dorman Long Ltd. Africa

Projects included:

- Uranium treatment plant, Western Deep Levels
- Power station projects for Eskom, including Arnot, Hendrina and Grootvlei power stations.

1966 - 1969 Mechanical Design Engineer – Rand Water Board, Johannesburg

Construction supervisor and start-up engineer for various projects including lime burning kilns with coal gasifier and lime slaking plant.

EDUCATION

B.A., Mathematics

M.A., Mechanical Engineering

M.S., Mechanical Engineering

REGISTRATIONS/AFFILIATIONS

M.I., Mechanical. (London)

F.I., Chemical (London)

AIChE

VDI

PUBLICATIONS

“Clean Power Generation from Heavy Residues.” IMechE., London, November 1990

"Partial Oxidation in the Refinery Hydrogen Management Scheme," AIChE, Houston, March 1993

“Perspectives and Experience with Partial Oxidation of Heavy Residues.” L'Association Française des Techniques du Pétrol, Paris, June 1994

"The Zero-Residue Refinery Using the Shell Gasification Process." Ullmanns Encyclopaedia of Industrial Chemistry, 5th Edition Vol B 8

"Methanol Production by Gasification of Heavy Residues," IChemE Gasification Conference, London, November 1995

"Gasification – an Indian Perspective," European Gasification Conference, Dresden, 1998

"New Developments in Soot Management," European Gasification Conference, Noordwijk, 2002

"The Reliability of IGCC Power Generation Units," Gasification Technologies Conference, San Francisco, 2005

"Gasification" (in collaboration with M van der Burgt) published by Gulf Professional Publications, September 2003

SPECIFIC TECHNICAL EXPERTISE/SPECIALIST COURSES

Languages: English; German (bilingual with qualification as geprüfter Übersetzer"); French; Portuguese; Afrikaans (read and speak)

WorleyParsons
resources & energy

Santosh K. Lanka
Associate Technical Specialist

Resume

SUMMARY

Power plant simulation experience includes experience in optimizing and modeling batch process operations of sodium azide and amino pyridines at a production plant. Posses project management skills including strategic planning and analysis, problem solving, team building, customer service, and decision-making abilities. Also, excellent written and verbal communication skills coupled with inter-personal skills. WorleyParsons experience includes gasification projects related to power and substitute natural gas (SNG) production.

EXPERIENCE

2007-Present **Associate Technical Specialist – WorleyParsons, Reading, Pennsylvania**

Project Feasibility Group – Responsible for gasification projects related to power production as well as SNG production. Also, work on projects to remove CO_2 from gas- and coal-fired power plants. Involved in additional technologies that include circulating fluidized bed (CFB) and fuel cells.

2007 **Simulation Engineer – Trax, LLC, Lynchburg, Virginia**

Jeffrey Power Plant – Prepared process model schematics from the customer process and instrumentation diagrams (P&ID) data using ProTRAX software. Worked on building a flue gas desulphurization model.

Sherco Power Plant – Prepared balance-of-plant, boiler, and electrical models. Developed power plant heat balance using MathCAD. Developed Mark II control logic to integrate with process models.

2003 - 2004 **Assistant Process Engineer – Alkali Metals Ltd., Hyderabad, India**

Supervised the process operations of a sodium azide and amino pyridines production plant. Assisted senior process engineer in trouble shooting of plant operations. Developed process flow diagrams (PFD) for the reaction and purification section of the plant. Optimized the reaction time of sodium azide from 24 hours to 18 hours through pilot plant experiments. Prepared daily and monthly performance reports along with material and energy balances for assessing the efficiency of plant operation.

2003 **Internship – Dr. Reddy's Laboratories, Hyderabad, India**

Designed Rotating Disc Contactor extraction column for the extraction of acetic acid-isopropyl ether-water system. Evaluated the number of theoretical stages in the extraction column using McCabe Thiele method with the available data.

EDUCATION

M.S., Chemical Engineering, Lamar University, Texas

Bachelor of Technology, Chemical Engineering, Jawaharlal Nehru Technological University, AP, India

SPECIFIC TECHNICAL EXPERTISE/SPECIALIST COURSES

Aspen Plus

PRO-II

HYSYS

ProTRAX

C

MS Office

WorleyParsons
resources & energy

Lora L. Pinkerton, P.E.
Estimating Department Manager

Resume

SUMMARY

Over twenty-six years of experience with WorleyParsons in cost estimating and engineering, planning, scheduling, and structural design engineering for nuclear, fossil, and industrial facilities. Domestic and international experience in estimating new and retrofit projects on a lump sum turn-key (LSTK); engineer, procure, construct (EPC); and program management or traditional engineer, procure, construction management (EPCM) basis for independent power producers (IPPs), utility, and government clients. Additional responsibilities include cost consulting, review and analysis of management programs and procedures, and risk analysis modeling.

EXPERIENCE

2004 - Present

Estimating Department Manager – WorleyParsons, Reading, Pennsylvania

Responsible for the administration and technical supervision of all estimating services performed in the Reading, Pennsylvania operations center. Specific responsibilities include: Performing estimate reviews, providing technical advice and guidance, developing and scheduling resources, monitoring budget compliance, and interfacing with project teams, clients, and executive management. In addition, continue to act as an Estimating Sponsor on larger or more complicated projects.

2000 – 2004

Chief Estimator and Project Estimating Group Leader – WorleyParsons, Reading, Pennsylvania

Responsible for oversight of both the definitive and conceptual project estimating groups, including estimate reviews, supervision of personnel, scheduling of resources, training, and mentoring. In addition, continue to fill the role of Lead Estimator or Estimating Sponsor, and provide on-going project support on a variety of projects.

Major projects include:

- Progress Energy Carolinas, North Carolina Clean Air Program, Roxboro Power Station (four-unit, 2400 MW) and Asheville Power Station (two-unit, 400 MW) FGD and SCR projects
- Santee Cooper, Cross Unit 3, 600 MW pulverized coal power plant (supercritical)
- Dominion Energy, Dominion Person Combined Cycle Facility, 1000 MW combined cycle power plant
- Oxychem/Sempra, Elk Hills Power Project, 500 MW combined cycle power plant re-estimate
- Mirant, San Severo Power Plant, Italy, 400 MW combined cycle power plant
- Allegheny Energy Supply, St. Joseph's County Generating Facility, 550 MW combined and simple cycle power plant
- Constellation Power, Endless Mountains Energy Facility, 750 MW combined cycle power plant
- Constellation Power, Gateway Power Plant, 800 MW combined cycle power plant
- Dynegy, Renaissance Power Project, 500 MW simple cycle power plant

- PG&E Generating, Harquahala Generation Project, 1060 MW combined cycle power plant
- Siemens Westinghouse, Big Sandy Energy Project, 500 MW combined cycle power plant
- Tennessee Valley Authority (TVA), Bellefonte Power Plant, Repowering Study

1998 - 1999 **Project Estimator – WorleyParsons, Reading, Pennsylvania**

Lead Estimator for a number of lump sum turnkey (LSTK) engineer, procure, construct (EPC) proposals for combined cycle and nuclear decommissioning projects as well as a variety of conceptual estimates and studies. Responsibilities included: Coordination of cost estimates and final price development; overall estimate accuracy; development of indirect costs and cash flows; oversight of discipline estimators; preparation of proposal schedules and expediting of team members for schedule compliance; interface/coordination with engineering, management, partners, owners, and other third parties; participation in technical, commercial and management reviews; and support of bid negotiations.

Major projects include:

- Electricidad de Caracas, El Sitio Power Project, Venezuela, 500 MW combined cycle power plant
- Electricidad de Caracas, Arrecifes Power Project, Venezuela, 525 MW combined cycle power plant
- Pluespetrol Energy S.A., San Miquel de Tucuman Power Station, Argentina, 370 MW combined cycle power plant
- CSW Energy Inc., Eastex Cogeneration Project, combined cycle power plant
- Maine Yankee Nuclear Generating Station Decommissioning
- Consumers Power Company, Big Rock Point, Major Component Decommissioning

1991 - 1997 **Project Cost Engineer – WorleyParsons, Reading, Pennsylvania**

International Energy Agency (IEA), Greenhouse Gas R&D Programme – Responsible for the development of capital and operating cost estimates, economic evaluations and sensitivity analyses for comparative studies of a variety of plant configurations associated with the production of electricity and/or chemical products. Traditional screening methods were utilized to determine a required cost of electricity or cost of product based on plant capital and operating costs combined with plant performance.

Major Projects include:

- Carbon Dioxide Capture in Oxygen-Blown Integrated Gasification Combined Cycle Power and Chemical Plants Fueled with Orimulsion
- Carbon Dioxide Capture in Molten Carbonate Fuel Cell Power Plants

U.S. DOE Office of Fossil Energy – Responsible for the development of capital and operating cost estimates, economic evaluations and sensitivity analyses for a study of clean coal technologies suitable for application in Brazil. Technologies evaluated included a 400 MW pulverized coal plant and both a 400 MW and a 200 MW circulating fluidized bed combustor plant. Results of this study were incorporated into the DOE technical presentation at the Brazilian Coal Policy Workshop.

Senior Cost Engineer – WorleyParsons, Reading, Pennsylvania

TVA, Bellefonte Completion Project, Fossil Repowering Study – Responsible for the development of capital and operating cost estimates, design and construction cash flows, and capital cost risk analysis for use by TVA in financial evaluations. Technology options evaluated included pulverized coal, integrated gasification combined cycle and natural gas combined cycle. Combined cycle options were evaluated both with and without chemical co-production.

Lead Cost Engineer – WorleyParsons, Reading, Pennsylvania

Northern Division Naval Facilities Command (NAVFAC) Projects – Responsible for the development of cost estimates for a variety of new construction, renovation, and relocation projects ranging in value from $350,000 to over $17 million. Major Projects include:

- Realignment/Consolidation of Carderock Division
- Renovation of Foundry
- Hazardous Waste Handling Facility
- Asbestos Removal Facility

Estimates are prepared at various stages throughout the project design, evolving from conceptual to fair price. Work is performed in close coordination with the design team to facilitate the selection of cost effective design alternatives and to ensure compliance with pre-established construction budgets.

U.S. Department of Energy (DOE) Projects – Responsible for the development of independent cost estimates (ICE) for various DOE projects. Projects include:

- Oak Ridge National Laboratory Environmental Restoration Program Projects
- New Production Reactors and Associated Support Facilities
- Upgrade of Canyon Exhaust Systems, Savannah River Site
- Monitored Retrievable Storage Project
- Plantwide Fire Protection Project, Savannah River Site

Estimates range in value from $100 million to over $5 billion. Estimates are based on conceptual design reports prepared by others and are used to validate the project baseline, technical, cost and schedule, prior to DOE funding approval.

Additional responsibilities include risk analysis modeling to establish or confirm project contingencies and their corresponding level of risk. Risk analysis is performed using commercially available software; REP-PC and @RISK.

Management Consultant – WorleyParsons, Reading, Pennsylvania

U.S. Department of Energy Programmatic Issues – Review and evaluate various DOE programs and procedures, engineering and total project costs, and organizational structures. Compare DOE data and methods to similar elements in the private sector. Make recommendations to DOE for improving methods, results, and cost performance. Assist/advise DOE in the development and implementation of select components of the Office of Waste Management Total Cost Management Program, such as Performance Indicators, Performance Measures, and Productivity Improvement.

Cost Consultant – WorleyParsons, Reading, Pennsylvania

U.S. Department of Energy Office of Fossil Energy – Served as a principal investigator and developed the cost analysis and market assessment for two reports identifying potential new and/or expanded markets for coal; "Assessment of National Benefits from Advanced Coal Preparation Technologies" and "Co-firing of Hospital/Industrial/Municipal Wastes Outreach."

Lead Cost Engineer – WorleyParsons, Reading, Pennsylvania

U.S. Department of Energy, Advanced Neutron Source (ANS) Project – ANS is a heavy water research reactor to be located in Oak Ridge, Tennessee. Responsibilities included the development of a detailed project cost estimate submitted to the DOE with the Conceptual Design Report. Additionally, prepared numerous cost effectiveness studies utilized in the selection of design alternatives.

Cost Consultant – WorleyParsons, Reading, Pennsylvania

TVA, Advanced Light Water Reactor (ALWR) Cost Evaluation Project – Participated in risk analysis of ALWRs proposed for commercial operation.

1988 - 1990 Project Manager – WorleyParsons, Reading, Pennsylvania

Metropolitan Edison Company, Facilities Management Department, Corporate Headquarters Site – Served as project manager for Metropolitan Edison's $20 million Corporate Headquarters expansion and renovation program consisting of exterior modifications, building additions and upgrades of the mechanical and electrical infrastructure of existing facilities utilizing state-of-the-art technology. Responsibilities included preparation of specifications for architectural/engineering and construction management services, technical bid evaluation, design scope development, budget, schedule, invoice approval, acting as liaison between owner and architect, and coordination of in-house project-related tasks including interior layouts, personnel moves and procurements.

Also served as project manager for a wide variety of smaller reconfiguration/renovation projects ranging in value from $50K to $1.2 million. Responsible for scope development, work order preparation, coordination of engineering and construction activities, preparation of specifications, reports and purchase orders, budget, schedule and invoice approval.

1986 - 1988 Cost and Schedule Engineer – WorleyParsons, Reading, Pennsylvania

Florida Power Corporation, Crystal River, Unit 3 – Coordinated and prepared study, conceptual and definitive cost estimates, and installation schedules for ongoing retrofit work packages. Additional responsibilities included economic evaluation of engineering studies including the impacts of capital, operations and maintenance and potential forced shutdown costs and estimate reconciliation.

1984 - 1986 Pennsylvania Power & Light Company, Susquehanna Steam Electric Station, New Emergency Diesel Generator – Estimated labor costs for over 350 multi-discipline supplemental work packages.

General Electric Erie Plant, Electric Utility Reliability Study – Prepared conceptual level cost estimates for a wide variety of upgrade projects. These estimates were utilized in preparing a ten-year plan for plant upgrades to assure continued safe and reliable operation.

Florida Power Corporation, Crystal River, Unit 3 – Developed detailed construction and functional testing schedules for the Refuel V Outage and ongoing maintenance efforts, integrating plant operations, engineering, procurement, procedures, training requirements, work package and maintenance interfaces, craft manpower requirements and cash flow projections.

1982 - 1984 **Planning and Scheduling Engineer – WorleyParsons, Reading, Pennsylvania**

Provided engineering scheduling for:

- Cleveland Electric Illuminating Company, Perry Nuclear Power Plant.
- General Public Utilities Corporation, Three Mile Island, Unit l.
- Allis Chalmers Corporation, KILnGAS Commercial Module.
- Virginia Electric & Power Company, various conceptual projects.

Consumers Power Company, Midland Nuclear Cogeneration construction site – Analyzed and reviewed heating, ventilating and air conditioning (HVAC) supports and evaluated field changes for design integrity.

1980 - 1982 **Structural Engineer – WorleyParsons, Reading, Pennsylvania**

Philadelphia Electric Company, Peach Bottom Atomic Power Station – Designed cover slabs and retaining walls for the onsite, low-level, radwaste storage facility.

Analyzed and reviewed cable tray and conduit supports for:

- Cleveland Electric Illuminating Company, Perry Nuclear Power Plant.
- South Carolina Electric & Gas Company, V.C. Summer Nuclear Generating Station.

EDUCATION

B.S., Civil Engineering, The Pennsylvania State University, 1979

REGISTRATIONS/AFFILIATIONS

Registered Professional Engineer – Pennsylvania, 1986

American Society of Civil Engineers

Reading Branch, ASCE Board of Directors, 1982-83

WorleyParsons
resources & energy

Jay S. White
Lead Process Engineering Specialist

Resume

SUMMARY

Over eighteen years of experience with WorleyParsons in process engineering, process design and technology selection, and process evaluation and analysis. Emphasis on process engineering associated with integrated gasification combined cycle (IGCC), fuel cell power cycles, flue gas desulfurization (FGD), chemical plant design and analysis (SNG, methanol, hydrogen, and ammonia), and industrial projects (pulp and paper, reclaimed fibre, cogeneration, CFB).

EXPERIENCE

2004
Present

Lead Process Engineering Specialist – WorleyParsons, Reading, Pennsylvania

Responsible for process design and engineering associated with FGD, IGCC, gaseous mercury removal, and flue gas treating. Significant projects include:

South Heart Energy Development JV – Synthetic Natural Gas (SNG) Project, South Heart, North Dakota – Lead engineer for pre-FEED on 100 MMSCFD SNG plnt based on seven British Gas-Lurgi gasifiers. Plant also produces 100 MMSCFD CO_2 for enhanced oil recovery (EOR) and high purity H2SO4. Responsible for all process design, equipment arrangement and plant layout, equipment specification and sizing, 3-D modeling, PFD development, catalyst and process technology selection, vendor interface, thermodynamic performance modeling, production estimates, and utility requirement estimate.

FuelCell Energy, Integrated Coal Gasification Solid Oxide Fuel Cell (SOFC) Power Plant – Consult and guide project team on performance modeling of plant configuration, PFD development, and estimation of plant utility requirements and gross power production.

Stanwell ZeroGen, Australia, Phase 1 – Lead engineer for process design, technology choice, and technical direction. Oversee process model development, equipment/catalyst/technology specifications, vendor interface, technology selection, PFD general arrangement development, analysis of alternative configurations, performance, and utility requirement estimate.

Conoco Phillips, Houston, Texas – Lead process engineer for 600 MWe IGCC pre-FEED; E-Gas gasifier, PRB feed, with CO2 capture. Plant to be located in Colorado. Work performed for Xcel Energy.

Rentech, Inc., Natchez Coal to Liquid Project – Responsible for process design, PFD development, specification development, and vendor selection for water gas shift, hydrolysis, mercury removal reactors, as well as sulfur-guard bed.

American Electric Power Services Corporation, Coal-to-Liquids Project – Responsible for developing PFD, material balances, plant layout, utility requirements, and equipment sizing for a coal-derived syngas to 5,300 bbl/day Fischer-Tropsch diesel plant. Responsible for all aspects of study including choice of reactor technology and catalyst, reactor characterization, hydrogen production, wax refining approach, plant cost development, and plant availability analysis.

FutureGen Industrial Alliance, Phase 1 – Project technical lead, responsible for all technical decisions, client presentations to Alliance Board, and overall technical direction of project. Oversaw development of flowsheet computer modeling, PFD development, material balances, utility requirement estimation, and major equipment sizing. Conceptual designs were for four IGCC plants based on four separate gasification technologies firing a single Frame 7 combustion turbine with provision for 90% carbon dioxide removal and conditioning for EOR.

American Electric Power Services Corporation, Muskingum River Unit 5 and Big Sandy Unit 2 Wet Flue Gas Desulfurization (WFGD) Projects – Responsible for developing general arrangements and plot plans for three WFGD technologies (open spray tower, dual-tray tower, and jet bubbling reactor). Responsible for developing material balances, equipment lists and preliminary sizing, and developing plant design criteria. One of three engineers that conducted original equipment manufacturer bid evaluation and process technology recommendation for both WFGD installations. Developed bid specifications for procurement process and selected equipment for purchase. Integral member of team that developed three-dimensional process-piping model. Project put on hold at 30 percent engineering .

2003 - 2004 **Air Quality Process Engineer – WorleyParsons, Reading, Pennsylvania**

Progress Energy Carolinas, Asheville Station and Roxboro Station, North Carolina – Responsible for process engineering and computer modeling of combustion, SCR, and FGD systems. Lead engineer on three-dimensional flow model study of ductwork and absorber. Generated specifications for ammonia supply to SCR and UV make-up water treatment system. Evaluated performance of steam coil air heaters to mitigate air pre-heater acid gas condensation. Performed analysis of waste water generated from absorber blow-down and the level of “new” noise added to the environment due to the addition of the new FGD system equipment. Units commissioned August and September of 2006, respectively.

American Electric Power Services Corporation, Mitchell Project, Moundsville, West Virginia – Responsible for material and energy balances, equipment sizing, evaluation of alternative flowsheet options, and analysis of wastewater impact on local environment. Performed detailed assessment of trace plant emissions, air pre-heater design, and impact of various coal sources to SCR and FGD systems. Unit commissioned February of 2007.

National Energy Technology Laboratory, Pittsburgh, Pennsylvania, Water Consumption Survey – Developed heat and material balances, performance summaries, and water balances for four IGCC plants (Conoco-Phillips E-Gas, GE-Texaco Radiant, GE-Texaco Radiant Quench, and GE-Texaco Radiant Convective), natural gas combined cycle, and supercritical and conventional pressure PC steam plants. Study purpose was to document water consumption for different types of advanced-term and conventional power plants.

Develop a proprietary code used to evaluate combustion, SCR, and wet FGD systems. Code models all chemistry, thermodynamics, and gas-side hydrodynamics as well as provide options for equipment sizing and trace element analysis of wastewater blow-down.

Basin Electric, Leland Olds Station Repowering Project, Stanton, North Dakota – Developed heat and material balance of Foster Wheeler’s air-blown partial gasification process to assess engineering and economic feasibility of repowering Basin Electric’s Leland Olds Station Unit 2 steam plant, which is currently powered on steam generated in a pulverized coal furnace.

2000 - 2003 **Process Engineer Consultant – WorleyParsons, Reading, Pennsylvania**

Responsible for providing guidance, generating heat and material balance diagrams, evaluating alternative cycle configurations, determining utility requirements, and estimating net plant efficiency for integrated gasification combined cycles (IGCC), natural gas combined cycles (NGCC), coal and natural gas-fired solid oxide fuel cell (SOFC) systems, and hybrid SOFC and gas turbine power cycles. Primary clients were Electric Power Research Institute (EPRI) and Department of Energy (DOE).

1994 - 2000 Senior Process Engineer – WorleyParsons, Reading, Pennsylvania

Responsible for task and team management, process conceptualization, flowsheet development, detailed and preliminary design, mathematical modeling, computer simulation, analytical computations, and equipment specifications. Significant projects included:

1999 – 2000 EPRI, San Palo, California – Lead engineer on project to determine break-even feasibility point for coal-fired IGCC to become completive with natural gas-fired combined cycles. Report results included flow diagrams, utility requirements, sensitivities to alternative approaches, and economic evaluations for each approach. Excellent client relationship resulted in several follow-on contracts for additional services.

1999 Ponderosa Paper Project, Wallulla Washington – Key member of engineering and on-site team for debottlenecking a secondary fiber plant. Developed and utilized thermodynamic model of plant which generated results mitigating $50,000/day liquid-damage payments.

1996 - 1998 U.S. Department of Energy (USDOE), Morgantown, West Virginia – Responsible for task management, engineering, and dynamic (non-steady-state) computer modeling of commercial sized APFBC and PFBC power plants. Model developed to ascertain the feasibility of various process control schemes. Model included thermodynamics, chemistry, hydrodynamics, PID, and three element controllers, as well as various logic routines. Proved feasibility of plant control design and approach.

1995 Industrial Partner, Mexico – Team member for feasibility study of gasification of petroleum coke to synthetic gas/fuel plant (Fischer-Tropsch). Positive relationship with process developer has resulted in repeat business evaluating process feasibility with crude oil refineries wishing to utilize both vacuum residuum and/or petroleum coke as process feedstock.

1990 - 1994 Junior Engineer – WorleyParsons, Reading, Pennsylvania

Engineering position responsible for process and systems engineering, and the computer modeling of conventional power systems, such as NGCC and pulverized coal (PC) steam plants, industrial processes, such as VOC scrubbing and steam stripping, as well as advanced technology power generating systems such as IGCC, APFBC, MCFC, SOFC, and MHD. Significant projects included:

Samsung Engineering Co., Ltd. (SECL) – Trained two SECL engineers for three months in IGCC technology.

1992 - 1994 Korea/IGCC Project – Provided technical analyses, comparative assessments, and conceptual design of commercial-scale IGCC plants, including ASPEN simulation of two 400 MW commercial IGCC plants. Provided broad R&D supports including vendor evaluation, process selection, and on-site consultations to clients in Seoul, Korea for a 3-TPD-coal gasification pilot plant built in Korea.

1992 U.S. DOE – Part of a four-man team that completed a preliminary design of a 3000 TPD coal drying plant. Sized and specified all major pieces of equipment. Developed process flow diagram, elevation view of central equipment, and plot plan.

Resume

1991 U.S. DOE, Gaithersburg, Maryland – Designed equipment for a commercial hot potassium carbonate process for CO_2 removal. Integrated design into existing phosphoric acid fuel cell power plant scheme. Design used to determine performance and economics of hybrid PAFC plant.

1990 Procter & Gamble Company – Specified equipment for VOC scrubber system used in an industrial pulping process. Specification used to design and construct scrubber system.

1990 - 1994 Used ASPEN steady-state simulation code to model the following:

- Catalytic, moving-bed, fluidized-bed, and entrained-bed IGCC cycles
- Natural gas and solid fuel-fired phosphoric acid, molten carbonate, and solid oxide fuel cell combined cycles
- MHD power plant system, including plasma thermodynamics and seed (K2CO3) regeneration
- PFBC-II and AFBC-II combined cycles
- Duct injection of hydrated lime for flue-gas desulfuriztion
- Binary, multicomponent, and steam distillation
- Organic thermal cycles
- Conventional PC power plants, natural gas-fired combined cycles, and supercritical steam plant.

1989 - 1990 **Research Fellow – Polytechnic University**

Dynamics simulation and application of State Estimation Algorithms.

1988 **Teaching Assistant – Polytechnic University**

Undergraduate unit operations lab.

1987 - 1988 **Student – Polytechnic University**

Pursued B.S. degree in chemical engineering.

1986 **Engineering Assistant – Hydrocarbon Research, Inc.**

New Technology Department – Built bench-scale ebullated-bed reactor. Ran reactor to determine liquid velocities for optimal catalyst bed expansion. Also, performed bench study to establish operating conditions for rejuvenation of spent catalyst from CTSL Process.

1985 **Engineering Assistant – Hydrocarbon Research, Inc.**

Process Research Department – Generated daily operating summary for pilot-scale CTSL Process. Ran microautoclave reactor to study coking and anti-solvent precipitation present in H-Oil Process separation systems.

1984 **Engineering Assistant – Philadelphia Water Department**

Sludge Management Unit – Worked on improving plant sludge curing process. Also studied the effect of different curing agents on sludge curing efficiency.

EDUCATION

M.S., Chemical Engineering, Polytechnic University, Brooklyn, New York, 1990

B.S., Chemical Engineering, Drexel University, Philadelphia, Pennsylvania, 1988

PUBLICATIONS/PRESENTATIONS

The following are representative of more than 38 presentations and technical papers:

Co-author with J. Doyan, H. Ghezel-Ayah, J. Walzak, S.T. Junker, D. Patel, A. Adriani, P. Huang, D. Stauffer, V. Vaysman, B. Borglum, E. Tang, R. Petri, and C. Sishtla, “SECA Coal-based Multi-MW SOFC Power Plant Development,” Electrochemical Society Transactions – 2007 Fuel Cell Seminar & Exposition Volume 12, March 2008.

Co-author with Satish Gadde, Ron Herbanek, and Jayesh Shah, “CO_2 Capture: Impacts on IGCC Plant Performance in a High Elevation Application using Western Sub-bituminous Coal,” Gasification Technologies Conference, San Francisco, California, October 2007. Portions reprinted in “Gas Turbine World,” Volume 37, Number 6, November-December 2007.

“Evaluation of Innovative Fossil Fuel Cycles Incorporating CO_2 Removal,” 18th Annual Pittsburgh Coal Conference, New South Wales, Australia, December 2001.

“Logistic SOFC Design,” DOE/EPRI/GRI Joint Fuel Cell Technology Conference, Chicago, IL, August 1999.

“Comparative Performance and Economic Analysis of Clean Coal Technologies,” Electric Power 1999 Conference, March 1999.

“Innovative CO2 Separation and Sequestration Processes for Treating Multicomponent Gas Streams,” 23rd Coal Utilization And Fuel Systems Conference, Clearwater, Florida, March 1998.

“Economic Evaluation of Coal Gasification Technologies for Power Generation,” 1997 Gasification Technologies Conference, San Francisco, California, October 1997.

“Dynamic Modeling of Advanced Power Systems,” Advanced Coal-Fired Power Systems 1995, Morgantown, West Virginia, June 1995

“Theoretical Maximum Sulfur Removal for PFBC-II Power Plants,” Tenth Annual International Pittsburgh Coal Conference, 1993

“Korea IGCC Project: 2 TPD BSU,” IGCC Workshop: Technology Status and Future Prospects, Seoul, Korea, 1992

Co-author with J.H. Hirschenhofer, D.B. Stauffer, “An ASPEN/SP Fuel Cell Performance USER-Block,” 1992 Fuel Cell Seminar, Tucson, Arizona, 1992

“Carbon Dioxide Capture in Fuel Cell Power Systems,” 1992 Fuel Cell Seminar, Tucson, Arizona, 1992

WorleyParsons

resources & energy

Owner's Engineer

Capability and Experience

when experience counts

[redacted]

Table of Contents

Company Overview

WorleyParsons is one of the world's largest engineering and project delivery firms, servicing the global resource, energy, and infrastructure markets. With 20,400 personnel in 97 offices in 30 countries around the globe, WorleyParsons has the technical expertise, project delivery systems, and resource depth to provide a comprehensive range of solutions to clients. ***When capability counts***, WorleyParsons has the track record and expertise that customers trust.

WorleyParsons focuses on safe and successful project delivery in the following sectors:

- Power
- Hydrocarbons (upstream and downstream)
- Minerals and Metals
- Infrastructure

WorleyParsons provides ***engineering, procurement, construction management, program management, and consultancy services*** to clients in these sectors. Our solutions are customized to address regional, client, and magnitude requirements. We are listed on the Australian Stock Exchange (ABN 17 096 090 158).

WorleyParsons is one of a few global companies with the capability and track record to execute large capital projects from conception through operation. Our ability to continuously emphasize improving the customer's production and financial performance provides the cornerstone to this successful approach.

30 countries | 97 offices | 20,400 project services staff

Company Overview

WorleyParsons is characterized by:

- A resource base of approximately 20,400 personnel
- 97 offices in 30 countries
- Specialist skills in the rapidly growing power and hydrocarbons sectors
- Ability to handle complex large-scale resource projects in all markets
- Long history of success in project delivery – large and small
- Commitment to outstanding operational and corporate performance
- Focus on long-term contracts, integrated service contracts, and alliances
- Comprehensive geographic presence and capability across energy, resource, and complex process industries

Zero Harm
Leadership
No Incidents
Safe Behavior

Commitment to Health, Safety, and Environment

WorleyParsons provides services in sectors that require the highest commitment to health, safety, and environment (HSE) excellence. WorleyParsons targets ***Zero Harm***. Zero Harm is a culture inherent in all levels of the organization, driven through the implementation of systems, processes, and training programs. It is measured against aggressive yearly targets on Key Performance Indicators and audit results.

History

WorleyParsons was formed in 2004 as a result of the acquisition by Worley of Parsons E&C. This acquisition merged complementary sector, geographic, and project capabilities, enabling WorleyParsons to offer customers a full suite of services across all phases of project delivery.

Worley

Wholohan Grill and Partners, an Australian structural engineering consultancy, was formed in Sydney in 1971, with John Grill as the CEO. Worley was established in the USA in the 1960s and expanded to the Asia Pacific region in the 1970s. In 1975, Wholohan Grill and Partners purchased Worley Engineering (Australia) Pty Ltd, and the company changed its name to Worley.

From that point, Worley grew steadily both geographically and in terms of industry sectors serviced. Geographic coverage extended first into Southeast Asia, then to North America, and finally to the Middle East. When listed on the Australian Stock Exchange (ASX) in November 2002, Worley had operating offices in 14 countries. By July 2004, this had increased to 18 countries. A policy of diversification saw Worley grow from providing services in the Oil & Gas sector into Industrial & Infrastructure, Minerals Metals & Chemicals, and Power & Water.

Company Overview

Worley's business has been characterized by successful partnerships formed with both clients and other project services providers. In the Australian region, Worley is considered a leader in establishing and executing alliance-style contracts. These have been benchmarked as world class within the industries in which they operate. In November 2004, Worley commenced trading as WorleyParsons, in recognition of the successful heritage both firms delivered to the merged operation.

Parsons E&C

In 1944, Ralph M. Parsons founded what is now the Parsons Corporation in Los Angeles, California. Until 2002, Parsons E&C operated as a business unit of the Parsons Corporation providing engineering, procurement, construction, construction management, and program management services to clients in the energy sector. At the beginning of 2002, Parsons Corporation separated Parsons E&C from the other business units by transferring its ownership from Parsons Corporation directly to the Parsons Employee Stock Ownership Program (ESOP), thereby establishing Parsons E&C as an independent entity and a sister company to, rather than subsidiary of, Parsons Corporation. This divestiture was in recognition of the types of projects Parsons E&C executed for its energy sector clients, which were subject to different business conditions than those of the consulting and general services provided by the rest of Parsons Corporation. The divestiture of Parsons E&C from Parsons Corporation enabled Parsons E&C to consolidate a strong market position and to invest further in the development of resources and capabilities.

Parsons E&C is widely recognized for high-quality project services to the Power, Oil & Gas, Refining, Petrochemicals & Chemicals sectors globally, having designed, constructed, or managed the construction of more than 595 power generation units, 250 gas processing plants, and 600 chemical and petrochemical facilities units worldwide. The company built an enviable reputation for:

- Standardized design for multiple power plant programs
- Projects in remote locations with severe weather conditions
- Modular construction techniques
- Sulfur removal and handling technologies

Services

Cross Generating Station – South Carolina Public Service Authority (Santee Cooper) - 600 MW coal-fired units at the South Carolina site

Backed by more than 100 years of experience, WorleyParsons provides total solutions to clients' needs, supported by an array of state-of-the-art management, engineering, and construction services. We offer the following comprehensive services:

- Feasibility studies/optimization
- Technology development
- Process/licensor selection
- Front-end engineering
- Detail engineering
- Owner's engineer
- Construction
- Construction management
- Project management
- Plant rehabilitation
- Plant decommissioning
- HAZOP analysis
- Operator training
- Procurement
- Quality assurance
- Safety programs
- Source inspection
- Start-up and operations

WorleyParsons specializes in:

- **Capital Development Projects.** Increasingly throughout the resource, energy, and infrastructure sectors, customers are seeking contractors with the capability, systems, and resources to deliver "mega" projects. WorleyParsons has successfully executed a multitude of projects valued in excess of USD 1 billion and understands the critical components. This experience has led to a range of specialist capabilities, such as modularization solutions to manage remote and extreme weather challenges.

- **Sustaining Capital Projects and Operations Support Services.** WorleyParsons recognizes that the skills and capability to execute "mega" projects are not necessarily transferable to the ongoing sustaining capital projects that maintain and enhance the performance of a facility. Our reputation is built on the ability to safely and successfully execute projects without compromising current asset performance. This has led WorleyParsons to undertake long-term services contracts supporting operations in the power, hydrocarbons, and minerals sectors.

- **Consulting.** At the core of the WorleyParsons capability is a talented group of professionals whose technical skills, innovation, and understanding of latest technologies enable clients to make better decisions faster. WorleyParsons utilizes its extensive understanding of assets and markets to create value through a range of consulting roles.

Power

WorleyParsons designed and built America's first merchant power plant at Dighton, Massachusetts.

WorleyParsons has over 100 years of power industry experience, tracing its roots in Power to Chas. T. Main and Gilbert/Commonwealth. Drawing from this long history of combined experience, WorleyParsons has performed engineering, design, procurement, construction, and operations and maintenance services for hundreds of power, industrial, commercial, and government facilities. Providing full engineering services to all types of gas, coal, oil, and nuclear power plants and power delivery systems, WorleyParsons' heritage companies have been instrumental in supplying over 153,300 MW of generating capacity worldwide.

Specific power services include:

- Program management
- Feasibility studies and services
- Estimating and project controls
- Owner's engineer
- Repowering and retrofitting
- Civil/structural engineering
- Mechanical engineering
- Electrical engineering
- Instrumentation & control
- Project management
- Procurement
- Expediting
- Materials management
- Construction management
- Equipment testing and start-up
- Operations and maintenance
- Technology transfer/training

WorleyParsons takes a full-service approach to provide cost-effective engineering services. In supporting engineering and procurement, WorleyParsons possesses the versatility and flexibility to serve as the sole supplier, work as the subcontractor, or subcontract our services locally. WorleyParsons also promotes and has formalized alliances, joint ventures, partnerships, consortiums, and partnering agreements to respond more effectively to our clients' needs.

Company Overview

WorleyParsons' varying roles are illustrated in the following projects:

- **Belene Nuclear Power Plant** - WorleyParsons is serving as Owner's Engineer to Natsionalna Elektricheska Kompania for the 2 x 1000 MWe nuclear power plant in Bulgaria.

WorleyParsons' full engineering services brought the 540 MW Cross Station Unit 1, one of the few utility baseload plants built in the U.S. during the 1990s, on line six months ahead of schedule.

- **Cross Station Units 3 & 4** – WorleyParsons is providing engineering, procurement, construction management, and start-up for Santee Cooper's 2 x 600 MW coal-fired facility.

- **Flue Gas Desulfurization (FGD) Program** – WorleyParsons is the A/E in an alliance with Progress Energy, the OEM, and the constructor for Progress Energy Carolinas' project to install FGD systems on 11 of the company's coal-fired plants.

- **Tractebel 10-PAC** – WorleyParsons, in a joint venture with The Industrial Company - TIC, provided lump sum turnkey EPC services to Tractebel Power, Inc. for construction of three merchant power plants at different locations in North America. The plants are based on a 2-on-1 combined cycle configuration using Siemens Westinghouse 501G combustion turbine generators.

- **Delaware City Refinery Repowering –** WorleyParsons provided lump sum turnkey EPC services to Premcor (formerly Motiva, a joint venture between subsidiaries of Texaco and Saudi Aramco) for an integrated gasification combined cycle (IGCC) 235 MW repowering project.

- **Santee Cooper Pee Dee Unit 1 –** WorleyParsons has been assigned by South Carolina Public Service Authority (Santee Cooper) with the detail design, procurement, and construction management of a 600 MW supercritical pulverized coal unit.

Termocentro power plant conversion project in Colombia

- **Termocentro Combined Cycle Plant Conversion** – WorleyParsons, in a joint venture with Inelectra, provided the EPC lead in converting a 200 MW gas/oil-fired simple cycle plant in Port Olaya, Colombia, to a combined cycle plant by adding to the existing two 501D gas turbine generators.

- **Selective Catalytic Reduction (SCR) Projects** – WorleyParsons provided engineering, procurement, and construction management for SCR systems for Allegheny Energy's 3 x 640 MW coal-fired Harrison Station and their 2 x 625 MW Pleasants Station.

- **Te-To Zagreb Repowering Project** – WorleyParsons provided full lump sum turnkey EPC services for an existing district heating plant with 2 x 70 MW gas turbines and a 60 MW steam turbine for Hrvatska Elektroprivreda, the Croatian national utility.

Company Overview

- **Virgil C. Summer Nuclear Power Plant** – WorleyParsons served as A/E of Record for this 900 MW nuclear power plant and has been providing engineering and design services that include 10CFR50.59 safety analyses, on-site support for major modifications, and licensing support.

Automation

WorleyParsons designed and built the Te-To combined cycle cogeneration plant.

Information Management System

WorleyParsons has designed our automation strategy to work for our clients, reducing construction schedules through integrated network applications. We have pioneered the reference plant design process, which maximizes the reuse of design by using a dynamic collection of data that supports varied predefined configurations resulting in:

- Reduced plant construction and operation costs
- Shortened schedules
- Mitigated risks
- More efficient systems leading to similar facility "footprints"

To provide such innovative solutions, WorleyParsons uses specific automation tools such as the ENCOMPASS® System. Unlike other 3D design CAD systems, the ENCOMPASS® System is an integrated, PC-based information management system using commercially available software.

Fully utilizing networked computer technologies, the ENCOMPASS® System minimizes engineering rework by improving the integration of various work processes from the earliest feasibility studies through plant execution and plant operations. We are actively using this system to integrate project schedule data with the 3D plant model to produce a time-phased, "4D" graphic representation of the construction sequence.

Additionally, WorleyParsons also supports the efforts of the U.S. Government in developing new generation technologies and assisting other countries in developing power generation facilities and energy use programs.

As we continue to meet the needs of our clients, we continue to develop and refine our services to meet the engineering industry demands of the future.

WorleyParsons
resources & energy

Qualifications | Owner's Engineer Experience

As Owner's Engineer, WorleyParsons focuses on integrating our team with our client's team, promoting a seamless flow of communication and progress. Our goal is to assist our clients in reaching their financial, operating, and technical goals.

We apply our experience to critical areas of the work scope and concentrate on those aspects that have high potential for impact on the project. Some key examples include:

- Licenses and permit support
- Site layout
- NOx and SO_2 control
- Wastewater and water processing
- Fuel handling
- Ash disposal
- Noise abatement
- Cycle performance and overall systems design
- Component design spot checks
- Construction issues
- Operating philosophy and controls approach
- Test practices and procedures
- Schedule compliance

Ennis Power Station
Ennis, Texas

We keep our client fully informed through each phase of the construction process of a project by:

- Assessing the overall engineering and technical feasibility of the project to establish if the proposed plant systems and specified equipment will function as anticipated.
- Reviewing and validating the estimated construction cost.
- Analyzing the proposed construction schedule to determine whether the project will be in service within its projected time frame.
- Ensuring that the project complies with all essential permits and regulations, including those addressing environmental issues.
- Reviewing the proposed operating budget over the projected life of the plant, focusing on prospective operating expenses, projected operating revenues, and a reasonable assurance of defined debt service coverages.
- Reviewing proposed test procedures and other completion criteria to determine the suitability and reliability of installed systems and equipment.

WorleyParsons provides Owner's Engineer services throughout the construction and start-up phase to ensure that the project will fully meet our client's expectations.

The following pages include WorleyParsons' Owner's Engineer experience.

Qualifications — Owner's Engineer Experience

Project/Location	Client	Description	Services	Completion Date
Milam Power – Rockdale Rockdale, Milam County, Texas	Genova Power Solutions (Milam Power Partners, LLC)	500 MW Coal-fired (Phase 2)	Owner's Engineer	2007
Cherry Point Bellingham, Washington	Sempra Energy Resources	3-on-1 150 MW Cogeneration Combined Cycle	Due Diligence, Plant Optimization, Engineering Support, Development of EPC Contract, and Site Support	2007
Western Greenbrier Co-generation Clean Coal Power Initiative West Virginia	U.S. Department of Energy/Western Greenbrier Co-generation LLC	90 MW CFB Waste-coal-fired	Conceptual Design to Support Permitting and Licensing; Specifications for Major Engineered Equipment and Major Construction Contracts; Final Cost Estimate for Financing Arrangement.	2006
River Hill Power Plant Karthaus, Pennsylvania	River Hill Power Company, LLC	290 MW Waste Coal Fuel Power Plant	Engineering Services, Preparation of Various Specifications and Contracts for Major Equipment	2005
Leland Olds Repowering Evaluation Stanton, North Dakota	Basin Electric Power Cooperative	Two-Unit Lignite-fired Power Station Unit 1 – 220 MW Unit 2 – 440 MW	Technical and Business Analysis of Repowering Options (including the option of applying for funding from the DOE Clean Coal Program)	2004
Osprey Florida	Calpine	2-on-1 520 MW Combined Cycle	Engineering and Permitting Support	2004
Wawayanda New York	Calpine	2-on-1 520 MW Combined Cycle	Engineering and Permitting Support	2004
Termobahia, Phase I and II Salvador, State of Bahia, Brazil	Termobahia Ltda. (ABB Energy Ventures and Petrobras)/Main Engineers	196 MW Gas-fired Combined Cycle Cogeneration Plant with Export Steam for the Petrobraz Refinery	Owner's Engineer	2003
Abu Sultan Ismailia Power Plant	Egyptian Electricity Holding Company (formerly Egyptian Electricity Authority)	4 x 150 MW Turbine Generators	Owner's Engineer for Design Review and Construction Monitoring	2002
Osceola Florida	Reliant Energy	6 x 7FAs (changed to 3 x 7FAs) Simple Cycle	Engineering and Permitting Support	2002
Rock Springs Maryland	Reliant Energy	6 x 7FAs Simple Cycle	Engineering and Permitting Support	2002

WorleyParsons
resources & energy

Qualifications — Owner's Engineer Experience

Project/Location	Client	Description	Services	Completion Date
ABB Thermobahia Salvador, State of Bahia, Brazil	ABB Energy Ventures	190 MW Gas-fired Combined Cycle Cogeneration Plant with Export Steam for the Petrobraz Refinery	Review and Finalization of the Existing EPC Scope Document and Development of the Performance Testing Procedures	2002
Abu Qir, Units 1-4 Cairo, Egypt	Egyptian Electricity Holding Company (formerly Egyptian Electricity Authority)	4 x 150 MW Oil/Gas-fired	Condition Assessment of Plant Control Systems, Upgrade Scoping, Owner's Engineer, Construction Management, and Start-up	2002
Glenville Energy Park Glenville, New York	Glenville Energy Park	520 MW Gas-fired, Combined Cycle 2 GE 7FA Combustion Turbines 2 HRSGs, and 1 Steam Turbine	Permitting	2001
Constellation PJM Project Towanda (Endless Mountains), Pennsylvania	Constellation Power Development	750 MW 3-on-1 Combined Cycle SWPC "F" Technology-based	Permitting, Conceptual Design, Layouts, Arrangement Drawings, Water Balances, Process Flow Diagrams and One-lines, Emissions Analysis, Detailed Estimate, and Technical Specifications	2000
Cuiaba Gas Pipeline/Power Project Cuiaba, Brazil	Empresa Produtora de Energia (ENRON, GASMAT, GASBOL)	627 km, 18″ diameter Gas Pipeline/ 480 MW Combined Cycle	Owner's Engineer for Design Audit of Hydraulic Analyses, Detailed Design, Cathodic Protection, Material Specifications, and Construction Plans	2000
Ontelaunee Reading, Pennsylvania	Calpine	2-on-1 520 MW Combined Cycle	Engineering, Detail Design, and Permitting Support	2000
Richmond County Plant Hamlet, North Carolina	Carolina Power & Light	520 MW Combined Cycle 2 x 1 GE PG 7241FA	Permitting, Conceptual Design, Arrangement Drawings, Performance Data, Water Balances, Air Emissions, Support Data, Plant Design Criteria, Estimating Input, and 3D CAD Renderings	2000
Standard Combined Cycle Plant Program	Carolina Power & Light	10 x 2-on-1 Combined Cycles GE 7FA Combustion Turbines 20 HRSGs	Conceptual Design, Assistance with Purchase of Major Equipment (Note: Currently performing engineering on one of the ten plants)	2000

WorleyParsons
resources & energy

Qualifications | Owner’s Engineer Experience

Project/Location	Client	Description	Services	Completion Date
Hainan Hohbond Refinery Ltd. Hainan Peninsula, China	Hohbond Refinery Ltd.	70 MW 2-on-1 Combined Cycle GE LM 2500+	Conceptual Studies, Design, Arrangement Drawings, Heat Balances, Water Balances, P&IDs, Single-line Diagrams, Cost Estimates, and EPC Bid Specifications	1999
IPP Korea	Teagu Electric Corp.	LNG CCPP 2 x 460 MW	Owner’s Engineer	1988-Present
AES Ironwood Plant Lebanon, Pennsylvania	Siemens Westinghouse Power Corp.	700 MW 2-on-1 Combined Cycle SWPC 501G	Permitting, Conceptual Design, Arrangement Drawings, Water Balances, Cost Estimates, and 3D CAD Renderings	1998
Aswan Dam Egypt	Egyptian Electricity Authority	12 x 100 MW Hydro Electric	Condition Assessment of Plant Control Systems, Upgrade Scoping, Owner’s Engineer, Construction Management, and Start-up	1998
Red Oak Project Sayerville, New Jersey	AES Corporation	750 MW 3-on-1 Combined Cycle “F” Technology-based	Permitting, Conceptual Design, EPC Bidding Documenting, Arrangement Drawings, Water Balances, One-lines, and Technical Specifications	1998
Termobarranquilla Barranquilla, Colombia	TEBSA (a consortium of GPU International, ABB, and Distral)	274 MW Oil/Gas-fired Steam Electric Station	Condition Assessment and Owner’s Engineer	1998
Tiverton Project Tiverton, Rhode Island	Energy Management, Inc.	250 MW 1-on-1 Combined Cycle GE PG 7241FA	Permitting, Conceptual Design, Arrangement Drawings, Plant Performance Data, Water Balances, Air Emissions Support, and Data and Cost Estimates	1998
Midland Cogeneration Midland, Michigan	Midland Cogeneration Venture (MCV)	12 x 83 MW, 12 HRSGs	Independent Engineer for Various Tasks Related to Plant Conformance to the Operation Contract and for Annual Inspection to Verify MCV’s Conformance with Operation, Maintenance, and Facility Improvement Commitments	1997
Panda Brandywine Cogeneration Facility Brandywine, Maryland	Panda Energy Corporation	240 MW Combined Cycle	Engineering Support During Design, Construction, and Start-up; Transmission Design; and Utility Interface	1996

WorleyParsons
resources & energy

Qualifications — Owner's Engineer Experience

Project/Location	Client	Description	Services	Completion Date
Billerica Cogeneration Plant Billerica, Massachusetts	Concord Energy Corporation	100 MW Combined Cycle Cogeneration	Owner's Engineer for Preliminary Engineering, Licensing Support, and Preparation of Specifications for Critical Items and EPC Contract	1995
Dighton Power Project Dighton, Massachusetts	Energy Management, Inc.	170 MW 1-on-1 Combined Cycle ABB GT 11N2 Single Shaft	Permitting, Conceptual Design, Arrangement Drawings, Plant Performance Data, Water Balances, Air Emissions Support, and Cost Estimates	1995
Mahmoudia and Damanhour Plants Combined Cycle Conversion Mahmoudia City and Damanhour City El Behera Governorate, Egypt	Egyptian Electricity Authority	150 MW Gas-fired Combined Cycle, 12 HRSGs, SWPC 701D, Peaking Units (2)	Joint Venture with Electricity Supply Board International for Owner's Engineer for Conversion of Simple Cycle Combustion Turbine Plant to Combined Cycle	1995
Chester Cogeneration Facility Chester, Pennsylvania	CRSS Capital	The cogeneration facility includes a 650,000 lb/hr circulating fluidized bed (CFB) boiler designed by C-E/Lurgi that provides process and heating steam to a paper mill and supplies a 51 MW steam turbine-generator	Due Diligence Engineering and Economic Review	1995
Kathleen Cogeneration Facility Lakeland, Florida	Panda Energy Corporation	125 MW Combined Cycle	Owner's Engineer for Site Selection, Feasibility and Conceptual Design, and Preparation of Tender Documents for the Complete EPC Project	1994
Cairo South Cairo, Egypt	Egyptian Electricity Authority	109 MW Gas/Oil-fired	Field Investigations/Plant Assessments, Conceptual Design/Cost, Final Design/Construction Bid Document, Procurement, and Construction and Construction Management	1993
Grant Town Waste Coal Plant Grant Town, West Virginia	Monongahela Power Company for Allegheny Power Service Company	80 MW Waste Coal-fired Cogeneration Plant with Fluidized Bed Boilers	Third-party Engineering Review	1993
Commonwealth Atlantic Combustion Turbine Peaking Plant Chesapeake, Virginia	WESTPAC Banking Corp./Credit Lyonnaise	375 MW Gas/Oil-fired Combustion Turbine Peaking Plant	Independent Engineering Review	1992

WorleyParsons
resources & energy

Qualifications — Owner's Engineer Experience

Project/Location	Client	Description	Services	Completion Date
East Providence Cogeneration East Providence, Rhode Island	Caithness Resources, Inc.	80 MW Coal-fired CFB Cogeneration	Engineering Support, Preparation of RFP, Evaluation of Proposals, and Contract Administration	1991
Fort Drum Powerhouse New York	Aetna Life & Casualty	50,000 lb/hr Single Fluid Bed Boiler	Independent Engineering Review of Plant Systems and Equipment, O&M and Construction Costs and Schedule, Permit, and Licensing	1991
Selkirk Cogeneration Plant Selkirk, New York	J. M. C. Selkirk, Inc.	345 MW Combined Cycle Cogeneration	Preliminary Engineering, Licensing Support, and Bid Specification Preparation	1991-1993
Christina River Plant Wilmington, Delaware	Delmarva Power & Light Company	150 MW Combined Cycle	Owner's Engineer for the Conceptual Design and Detailed Cost Estimate	1990
Delano Delano, California	Bank of Boston	26 MW Biomass-fired Cogeneration	Due Diligence Engineer	1990
Filer City Cogeneration Plant Dearborn, Michigan	CMS Generation/Tondu Energy Systems	60 MW Cogeneration	Independent Engineer and Steam Host Design Engineer	1990
Hopewell Cogeneration Hopewell, Virginia	Citibank	357 MW Multi-unit, Combined Cycle Cogeneration	Independent Engineer for the Project Lending Institution	1990
Mendota Mendota, California	Bank of Boston	24 MW Biomass-fired Cogeneration	Due Diligence Engineer	1990
Talkha Egypt	Egyptian Electricity Authority	2 x 150 MW Combined Cycle, 8 HRSGs, 2 x 50 MW Steam Turbine	Owner's Engineer for Conversion of Simple Cycle Combustion Turbine Plant to Combined Cycle	1990
Woodland Cogeneration Plant Woodland, California	Bank of Boston	25 MW Biomass-fired CFB Plant	Due Diligence Engineer	1990
Hazelton Cogeneration Project Hazelton, Pennsylvania	Commercial Union Capital Corporation	80 MW Cogeneration Facility	Due Diligence Engineer for this Facility with CFB Steam Generator and All Supporting Auxiliary Systems	1987
Ramagundam Thermal Power Plant India	National Thermal Power Corp.	3 x 500 MW Coal-fired 2400 psig, 1000/1000°F	Design Consultancy and Review of Owner's Plant Design	1984

WorleyParsons
resources & energy

Qualifications | Owner's Engineer Experience

Project/Location	Client	Description	Services	Completion Date
Scott Paper Chester, Pennsylvania	CRSS Capital	80 MW CFB	Due Diligence Associated with Privatization of Power Plant	1983
CELCO Industries Narrows, Virginia	Jones Capital Corporation	Various	Owner's Engineer Services for Multiple Projects	
Fort Wayne Assembly Division Fort Wayne, Indiana	General Motors Truck and Bus	2 x 150,000 lb/hr CFBC	Detailed Engineering and Design, Owner's Engineer/Bank's Engineer, and Operations Assessment/Consulting	
Mongolian Energy Sector Mongolia	U.S. Agency for International Development (USAID)	5 Coal-fired Plants, 3 Coal Mines, a Transportation System, and District Heating Systems	Services Involved Site Visits and Evaluations to All Major Facilities Associated with the Mongolian Energy System	
Webster Site Rochester, New York	Xerox Corp	Site-wide Chilled Water, Steam, and Electric Power Study	Services Included Site Survey, Conceptual Design, Capital and Operating Cost Estimates for Multiple Options, and Economic and Financial Evaluations	

TASK 3 REPORT

ASSESSMENT OF REASONABLENESS OF CAPITAL COSTS AND OPERATION COSTS FOR THE PROPOSED TAYLORVILLE ENERGY CENTER

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. ("Boston Pacific") and MPR Associates, Inc. ("MPR") make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

EXECUTIVE SUMMARY

This task report presents the results from our assessment of the reasonableness of capital costs and operation costs for the proposed Taylorville Energy Center. It specifically addresses: the capital cost estimate, the operations and maintenance estimate, and the fuel estimate. Key conclusions from each of these topics are as follows.

A. Capital Cost Estimate

Tenaska has estimated the total capital cost of the facility to be $3.5B. A breakdown of this cost is provided in the following table.

Taylorville Facility Cost Report Capital Cost Summary ($000)

Core Plant	
Program Management	$ 146,198
Other Core Plant	$ 590,456
Gasification	$ 386,376
Syngas	$ 392,725
Power Block	$ 525,461
Water Treatment	$ 187,160
Core Plant Subtotal	**$ 2,228,376**
Balance of Plant	$ 149,400
Escalation	$ 184,136
Contingency	$ 257,000
Owners Costs	$ 349,546
Financing	$ 353,192
Total Capital Cost	**$ 3,521,650**

The Taylorville facility is based on a first-of-a-kind "hybrid" Integrated Gasification Combined Cycle approach, rather than a "conventional" Integrated Combined Cycle approach that has been used in other facilities. The hybrid design approach appears to be significantly more expensive than the conventional approach. In comparison to the cost of a conventional Integrated Gasification Combined Cycle facility currently being constructed, Edwardsport, at $6,857/kW (when correcting for carbon capture and sequestration), the $10,641/kW cost for the coal portion of the Taylorville facility is significantly more expensive (the development of this metric is described in more detail in Section I.E). A comparison to another conventional design being developed, the Kemper project, suggests similar potential savings. Further study should be made of the possibility of reducing capital cost by using a conventional Integrated Gasification Combined Cycle design approach.

Regarding scope, Tenaska has treated the Air Separation Unit as a separate facility, despite being located on the Taylorville Energy Center property. The capital costs of this facility will be carried by a third party, and these costs are recovered over the course of the contract with periodic payments. Therefore, costs for the Air Separation Unit have been excluded from the capital cost estimate in the Facility Cost Report. From a cost estimate perspective, this is a reasonable exclusion; the operating costs of the Air Separation Unit are appropriately accounted for in the operating and maintenance budgets.

The $3.5 billion capital cost reported in the Facility Cost Report is based on a two gasifier design. This design was significantly scaled back relative to the design originally proposed. A four gasifier design was the basis for the Taylorville design evaluated in the R.W. Beck report in May 2009 and the DOE loan-guarantee Part II response. One of the gasifiers was a spare, but the gasification island, downstream gas-cleanup and conversion equipment and Power Block were based on a three gasifier throughput. The preliminary cost estimate for the earlier design was $3.2B. The current plant design has a cost estimate which represents a 9% increase in cost despite a 33% reduction in clean-coal capacity when compared to the original design.

Based on our review of the estimate preparation process and participation in the open book reviews, we believe that KBMD used a methodical approach to develop the cost estimate that encouraged transparency and accuracy. Based on the state of the design, the recent changes in scope and significant fluctuations in cost, it would be reasonable to estimate that the accuracy of this estimate is +20/-15% for a total project cost in the range of $3.0 to $4.2 billion.

B. Operations and Maintenance Estimate

Our review of the Operations and Maintenance estimate identified several areas of the estimate which appeared to be overly-optimistic. We recommend using an annual budget of $105M, which is $37.7M more than the costs used in the Facility Cost Report. Detailed observations are provided in the body of this report.

Operation of a large gasification facility is outside of the experience base of Tenaska Operations. Tenaska plans to recruit talent from other facilities, contract additional help when necessary, and rely heavily on vendor’s Technical Field Assistants during the initial years of operations to account for their lack of experience. We view this as a key challenge that must be addressed for the project to be successful. The recruiting and outside labor budgets for staff must be robust, allowance for technical field assistants must be much more than typical, training programs must be rigorous and well funded, and a realistic projection of the facilities availability in the early years of operation must reflect the learning curve that will be required.

C. Fuel Estimate

The Fuel Estimate was prepared by Tenaska's consultant, Wood Mackenzie. Wood Mackenzie's analysis predicts that the cost of fuel for the facility will be relatively stable over the life of the project ranging from $2.14 to $2.47/ MMBtu. The analysis concludes that the most economic coals will be sourced from mines in Subdivision 3 (West-Central Illinois) and all of the coal will be trucked to the facility.

We have reviewed the fuel estimate for the facility and have the following comments.

The likelihood of achieving the predicted fuel supply costs for the facility is not well demonstrated due to: (a) the inherent uncertainties in future economic predictions, and (b) the lack of any signed long term contracts. The facility financial projections should consider sensitivity cases for a range of potential coal prices. It is recommended to consider a possible high-side scenario using coal supplies from the next lowest price coal subdivision. The fuel study shows that over the life of the project, this price is on average $0.60/MMBtu higher than the forecasted price shown in the study.

Tenaska has not signed any long term contracts for supply of coal. They have stated that their procurement strategy will be to issue a competitive solicitation for proposals and expects to purchase fuel for the facility with a combination of short and long term purchase agreements. The stability in coal prices forecasted by Wood Mackenzie depends on roughly quadrupling Illinois coal production by 2045, representing a significant expansion in the regional use of coal. Other predictors of coal use expect a 40% nation-wide *decline* during the same period (Reference 1). A decline of coal demand this significant will affect for both the supply and demand of Illinois coal (the supply would be reduced due to mines closing), and could cause significantly different results than the fuel study is predicting. The risks associated with the disparity of these coal use predictions and their effects on the coal market should be mitigated by contracting long term supply from the operating coal mines in Subdivision 3 (West-Central Illinois).

The study results depend heavily on coal mines using coal washing techniques to reduce the sulfur content of their coals prior to delivery to the Taylorville facility. This has several important consequences.

- Coal washing will increase the moisture content of the coal, which could degrade the performance of the facility.

- Several mines that the study identifies as available to supply coal to the Taylorville facility will need to develop washing capabilities. The process of coal washing introduces new requirements for permitting of the coal mine that will increase both the timeline and the costs of the delivered coal.

Using trucks to provide coal deliveries and to remove slag from the facility will require a high volume of truck traffic. Tenaska has estimated the maximum daily truck traffic will be 238 trucks for coal deliveries and 42 trucks for slag removal. Deliveries will be made six days per week during daylight hours only. In other words, approximately 23 trucks per hour will be required, or one 25-ton truck every 2.5 minutes.

I. CAPITAL COST ESTIMATE

The purpose of this analysis is to examine the capital cost estimate prepared for the Facility Cost Report. The capital cost estimate was evaluated on the basis of estimated scope, cost estimate preparation methodology, cost estimator qualifications, and estimate uncertainty. Based on this review, our key conclusions are as follows.

Tenaska has treated the Air Separation Unit as a separate facility, despite being located on the Taylorville Energy Center property. The capital costs of this facility will be carried by a third party and these costs are recovered over the course of the contract with periodic payments. Therefore, costs for the Air Separation Unit have been excluded from the capital cost estimate in the Facility Cost Report.

Similarly, the cost estimate does not include capital costs for carbon sequestration in the Mt. Simon formation or costs for constructing the Denbury pipeline. Tenaska assumes that the Denbury pipeline will be operational by the time the Taylorville facility is fully operational. As discussed further below, there is considerable uncertainty whether this pipeline will be constructed.

The $3.5 billion capital cost reported in the Facility Cost Report is based on a two gasifier design. A four gasifier design was the basis for the Taylorville design evaluated in the R.W. Beck report from May 2009 and the DOE loan-guarantee Part II response. One of the gasifiers was a spare, but the gasification island, downstream gas-cleanup and conversion equipment and Power Block were based on a three gasifier throughput. The preliminary cost estimate for the earlier design was $3.2B. Thus, the current design results in a 9% increase in cost despite a 33% reduction in clean-coal capacity. In comparison to the cost of the Edwardsport facility at $6,857/kW (when correcting for carbon capture and sequestration), the $10,641/kW[1] cost for the coal portion of the Taylorville facility is significantly more expensive.

Based on our review of the estimate preparation process and witnessing several open book reviews, we believe that KBMD had a methodical approach to developing the cost estimate that encouraged transparency and accuracy. Based on the state of the design, the recent changes in scope and significant fluctuations in cost, it would be reasonable to estimate that this accuracy of this estimate is +20/-15% for a total project cost in the range of $3.0 to $4.2 billion. This range is wider than Tenaska has used to characterize the accuracy of the cost estimate.

[1] The development of cost estimate for the coal portion of the facility is detailed in Section E.1.

A. Summary of Capital Costs

The core plant cost reported in the Facility Cost Report is $2.2B and the total capital cost including escalation and financing is $3.5 billion (Reference 2). Table 1 provides a summary of the cost estimate where all values are in 2010 dollars. Detailed breakdowns of the Core Plant costs and Owner's Costs are provided in Tables 2 and 3, respectively.

Table 1
Taylorville Facility Cost Report Capital Cost Summary ($000)

Core Plant[1]	
Program Management	$ 146,198
Other Core Plant[2]	$ 590,456
Gasification	$ 386,376
Syngas	$ 392,725
Power Block	$ 525,461
Water Treatment	$ 187,160
Core Plant Subtotal	**$ 2,228,376**
Balance of Plant[3]	$ 149,400
Escalation	$ 184,136
Contingency	$ 257,000
Owners Costs	$ 349,546
Financing	$ 353,192
Total Capital Cost	**$ 3,521,650**

1 Core Plant - Core plant includes all civil, structural, mechanical, electrical, control, and safety systems (Reference 3)
2 Other Core Plant - 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 (Reference 2)

3 Balance of Plant – costs associated with sequestration of carbon dioxide emissions and all interconnects and interfaces required to operate the facility, such as transmission of electricity, construction or backfeed power supply, pipelines to transport substitute natural gas or carbon dioxide, potable water supply, natural gas supply, water supply, water discharge, landfill, access roads, and coal delivery (Reference 3)

Table 2
Core Plant Capital Cost Estimate Detailed Summary ($000)

Silo	Equipment	Labor	Materials	Subcontracts	Owner Furnished Materials & Subcontracts	**Total**
Program Management	$17,753	$13,654	$9	$114,782	$0	**$146,198**
Other Core Plant	$112,171	$123,964	$80,136	$67,072	$207,113	**$590,456**
Gasification	$79,762	$88,389	$61,985	$41,802	$114,439	**$386,376**
Syngas	$63,306	$66,862	$53,719	$59,417	$149,421	**$392,725**
Power Block	$143,122	$84,761	$97,553	$24,025	$176,000	**$525,461**
Water Treatment	$61,944	$30,603	$67,853	$26,760	$0	**$187,160**
Total	**$478,057**	**$408,233**	**$361,255**	**$333,858**	**$646,973**	**$2,228,376**

Table 3
Taylorville Facility Cost Report Owner's Costs Detailed Summary ($000)

Process Licenses and Fees	$	21,418
Catalysts	$	26,625
Worker's Compensation Insurance	$	28,104
Land and Mineral Rights	$	14,146
Development Costs	$	106,272
Owner's Project Management	$	55,000
Builder's Risk Insurance	$	19,500
Pre-Operation Cost	$	28,981
Spare Parts	$	24,189
Coal Inventory	$	2,447
Sales Tax	$	22,864
Total Owners Costs	**$**	**349,546**

B. Capital Cost Estimate Scope

The purpose of this section is to clarify what has been included or excluded from the scope of the \$3.5B cost estimate in the Facility Cost Report.

1. Carbon Sequestration

According to the Law (Reference 3), the Core Plant costs should include all civil, structural, mechanical, electrical, control and safety systems; whereas the Balance of Plant costs should include sequestration of carbon dioxide emissions and interconnects and interfaces required to operate the facility, such as transmission of electricity, construction power supply, pipelines to transport substitute natural gas, potable water supply, natural gas supply, water supply, landfill, access roads and coal delivery.

The overall process of Carbon Sequestration can be analyzed by describing it in terms of capturing the carbon (i.e. separating the CO_2 from a process stream), pressurizing the CO_2 and piping it underground. In the case of the Taylorville facility, piping underground is either injection into the Mt. Simon formation or injection into the Denbury pipeline for enhanced oil recovery.

The Law requires Carbon Sequestration to be included in the Balance of Plant costs; however, the Facility Cost Report lists the carbon capture costs in the Syngas silo of the Core Plant. This was a reasonable approach because carbon capture is included as part of the Acid Gas Removal process which also removes sulfur and other impurities from the SNG. It would not have been practical to segregate the cost of carbon capture from the overall process step of Acid Gas Removal. We conclude that the costs for CO_2 compression (or CO_2 oxidation in case of venting), the carbon sequestration costs were correctly included in the Balance of Plant portion of the estimate.

The \$3.5B cost estimate does not include costs for carbon sequestration in the Mt. Simon formation or costs for constructing the Denbury pipeline. The facility cost report assumes that the Denbury pipeline will be operational by the time the Taylorville facility is fully operational. This assumption precludes the need for the development of the Mt. Simon formation which was estimated as a \$44M capital cost in the Schlumberger report (Reference 4). The costs for constructing the Denbury pipeline have also been excluded because the March 2009 Carbon Dioxide Offtake Agreement between Christian County Generation and Denbury Onshore refers to a CO_2 Pipeline Operator, a yet to be determined third party, that will provide "the construction and operation of a CO_2 pipeline" (Reference 5).

Given the uncertainty associated with the development of the Denbury pipeline, it is recommended to include the capital cost for development of the Mt. Simon formation and any additional operation and maintenance cost associated with operation of the Mt. Simon sequestration and insurance for the liability associated with sequestering carbon in a saline aquifer. This would increase the capital costs by \$44M.

2. Air Separation Unit

The following text has been extracted from page 43 of the Facility Cost Report. It has been provided here as a summary of Tenaska's approach to the capital cost of the 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."

In summary, the Air Separation Unit, although located on the Taylorville Energy Center property, will in effect be a completely separate facility. This approach is reasonable given the generic nature of an Air Separation Unit and the commonality of the proposed arrangement between Tenaska and the third party. Effectively, this arrangement lowers the capital costs by $191M and results in an increase in operating costs (Reference 6).

3. Gasifiers

The $3.5 billion capital cost reported in the Facility Cost Report is based on a two gasifier design. This means that of the 544 MW capacity of the facility (net of Air Separation Unit), about 54% of the capacity or 296 MW, will be from coal. The remainder of the capacity, approximately 248 MW, will be from natural gas (See Section V.A of Report 4 for detailed power output estimates). In other words, in the current design of the Taylorville facility, the Power Block is significantly oversized relative to the SNG block. The excess capacity is only used when a significant flow of natural gas is routed to the Power Block.

A four gasifier design was the basis for the Taylorville design evaluated in the R.W. Beck report in May 2009 and the DOE loan-guarantee Part II response. One of the gasifiers was a spare, but the gasification island, downstream gas-cleanup and conversion equipment and Power Block were based on a three gasifier throughput. The total capital cost estimate of the facility in the R.W. Beck report and the DOE Part II response was $3.2 billion and $3.1 billion, respectively. However, despite the reduction from four gasifiers to two, the current cost of the facility has increased to $3.5 billion. This is a 9% increase in cost despite a 33% reduction in clean-coal output.

The reduction in the number of gasifiers will also lower the facility availability. The Tenaska DOE Part II Response stated an estimated 92% availability for the SNG island (based on a 95% availability of the gasification island). The current Facility Cost Report estimates that the SNG block will have an availability of 85% based on a two gasifier design.

Lastly, four gasifiers would have also allowed for future uprates to the facility. This is not an easily quantified loss of value; however, the loss of the spare gasifier does lower the overall value of the facility.

4. Other Scope Reductions

Due to the significant increase in capital cost after completing the first draft of the cost estimate, KBMD and Tenaska undertook an extensive effort to reduce costs. There were two phases of this effort: Cost Reduction Effort Phases I and II. A summary of the changes that were made in each of these phases is provided below.

It is reasonable and typical for cost estimates to undergo reductions in scope to lower the overall cost. This effort on the part of Tenaska and KBMD reflects their commitment to lower the overall cost of the facility. The cost reductions described below reduced the core plant costs by approximately $1B (Reference 8).

Cost Reduction Effort Phase I (data obtained from Reference 9)

- Eliminated fourth (spare) gasifier train and associated coal and blackwater systems and redesigned the gasifier structure to remove un-needed structural steel.
- Removed area in revised plot plan that was allocated for fourth gasifier and blackwater systems.
- Optimized plant layout: Reduced main piperack; deleted fin fan farm and changed out process coolers for gasification service; reduced and relocated underground utilities; revised on-site electrical distribution; reduced site work/drainage/grading
- Modified pre-cast walls in gasifier to fire-rated gypsum board
- Deleted shift area high pressure boilers
- Eliminated steam turbine building
- Provided enclosures around pulverizers at coal milling building, deleted remaining enclosures
- Reduced number of reject silos to one (1)
- Coal receiving modifications: Eliminated rail unloading, provided for future rail loop; utilized bottom dump truck unloading. Deleted alternate coal storage and reclaim conveyor
- Removed sulfur landfill
- Deleted page party system (GAITRONICS), replaced with warning horn system
- Reduced site development and materials in laydown including rock, lime stabilization
- Deleted local start/stop stations
- Substituted VPI (Vacuum pressure impregnators) transformers in lieu of castcoil

Cost Reduction Effort Phase II (data obtained from Reference 9)

- Changed Gasification silo to 2 gasifiers and associated Coal Milling and Blackwater Treatment
- Changed Syngas silo to single train of Shift, Acid Gas Removal, Sulfur Recovery Unit, and Methanation
- Reduced capacity of Syngas silo from 105% of gasifier output to 100% of gasifier output
- Changed Balance of Plant silo to compress site and resize affected equipment
- Changed Water Treatment silo to reflect lower flowrate requirements
- Changed Power Block steam cycle (Heat Recovery Steam Generator, Steam Turbine Generator, Steam Condensate Cooler, and other Balance of Plant) to reflect reduced steam flows
- Changed to Owner Controlled Insurance Program (OCIP)

In addition to above specific scope related cost reduction methods, KBMD also reviewed the following cost categories and reduced costs associated with these items:

- Labor productivity
- Manhour Services Tools and Supplies (ST&S)
- Overheads
- Contingency
- Escalation

C. Cost Estimating Methodology

1. Core Plant

KBMD had the primary responsibility for the preparation of the Core Plant capital cost estimate, including escalation. The methodology employed by the KBMD is well documented in their Basis of Estimate (Attachment 1 of Exhibit 2.0 of the Facility Cost Report). In summary, KBMD divided the Core Plant into silos and cost categories. The silos were as follows:

- Program Management
- Other Core Plant
- Gasification
- Syngas
- Power Block
- Water Treatment

The estimate groups were as follows:

- Sitework
- Excavation

- Concrete
- Structural Steel
- Mechanical
- Piping
- Electrical and Instrumentation
- Start-up
- Engineering Equipment
- Pre-engineering Buildings
- Construction Equipment
- Indirects

Each silo had a lead estimating team for each estimate group, resulting in a matrix of responsibility that is shown in Figure 1. In addition to the primary estimating team, KBMD also used a secondary team (also shown in Figure 1) to perform independent quantity take-offs, compare production rates and compare man-hour factors.

At the conclusion of each estimate preparation, KBMD conducted open book reviews for each silo. MPR was invited to witness these reviews and observed two. Based on our review of the estimate preparation process and participation in the open book reviews, we believe that KBMD had a methodical approach that encouraged transparency and accuracy.

Detailed descriptions of the estimate approach are provided in the Basis of Estimate – Facility Cost Report Exhibit 2. For example, the craft wages and fringes used in the estimate were from the current union wage sheets for 11 different local unions

Figure 1
Tenaska Approach to 1st and 2nd Estimate Preparation
(figure extracted from Attachment 1 of Exhibit 2 to the Facility Cost Report)

TEC Estimate Group		No. 1 Program Mgmt Estimate		No. 2 BOP Estimate		No. 3 Gasification Estimate		No. 4 Syngas Estimate		No. 5 ASU Estimate		No. 6 Power Island Estimate		No. 7 Water Treatment Estimate	
		1st Estimate	2nd Estimate	1st Estimate	2nd Estimate	1st Estimate	2nd Estimate	1st Estimate	2nd Estimate	1st Estimate	2nd Estimate	1st Estimate	2nd Estimate	1st Estimate	2nd Estimate
	Lead	Kiewit Energy	Kiewit Power	Kiewit Energy	KECO	Kiewit Energy	TIC	Kiewit Energy	Kiewit Power	TIC	Kiewit Energy	Kiewit Power	KECO	Kiewit Power	KECO
D-1	Sitework	Eastern	Kiewit Power	Eastern	KECo	Eastern	Southeast	Eastern	Kiewit Power	Southeast	Eastern	Kiewit Power	KECo	Kiewit Power	KECo
D-2	Excavation	Eastern	Kiewit Power	Eastern	KECo	Eastern	Southeast	Eastern	Kiewit Power	Southeast	Eastern	Kiewit Power	KECo	Kiewit Power	KECo
D-3	Concrete	N/A	N/A	Eastern	KECo	Eastern	Southeast	Eastern	Kiewit Power	Southeast	Eastern	Kiewit Power	KECo	Kiewit Power	KECo
D-4	Structural Steel	N/A	N/A	Eastern	KECo	Eastern	Southeast	Eastern	Kiewit Power	Southeast	Eastern	Kiewit Power	KECo	Kiewit Power	KECo
D-5	Mechanical	N/A	N/A	NorCal	KECo	Kiewit Energy	TIC	Kiewit Energy	Kiewit Power	TIC	Kiewit Energy	Kiewit Power	KECo	Kiewit Power	KECo
D-6	Piping	N/A	N/A	NorCal	KECo	Kiewit Energy	TIC	Kiewit Energy	Kiewit Power	TIC	Kiewit Energy	Kiewit Power	KECo	Kiewit Power	KECo
D-7	E & I	N/A	N/A	MassElec	KECo	MassElec	TIC	MassElec	Kiewit Power	TIC	MassElec	Kiewit Power	KECo	Kiewit Power	KECo
D-8	Start-Up	N/A	N/A	Kiewit Energy	KECo	Kiewit Energy	TIC	Kiewit Energy	Kiewit Power	TIC	Kiewit Energy	Kiewit Power	KECo	Kiewit Power	KECo
D-9	Engineered Eqpt	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	ALPC	ALPC	Kiewit Power	Kiewit Power	Kiewit Power	Kiewit Power
D-10	Pre-Engr Buildings	N/A	N/A	Kiewit Energy	Kiewit Energy	Kiewit Energy	Kiewit Energy	Kiewit Energy	Kiewit Energy	Kiewit Energy	Kiewit Energy	Kiewit Power	Kiewit Power	Kiewit Power	Kiewit Power
D-11	Construction Eqpt	N/A	N/A	Kiewit Energy	KECo	Kiewit Energy	TIC	Kiewit Energy	Kiewit Power	TIC	Kiewit Energy	Kiewit Power	KECo	Kiewit Power	KECo
*I1-6	Indirects	Kiewit Energy	Kiewit Power	Kiewit Energy	KECo	Kiewit Energy	TIC	Kiewit Energy	Kiewit Power	TIC	Kiewit Energy	Kiewit Power	KECo	Kiewit Power	KECo

2. Tagged Equipment

The cost estimates for tagged equipment are based on a list of tagged equipment from the Piping and Instrumentation Diagrams (P&IDs) and single line diagrams. Budgetary quotes from prospective vendors were obtained and evaluated for each piece or lot of equipment. The price included in the estimate was a mix of lowest bidder, average price, or a particular vendor (typically a supplier that is well-known and respected). Requotes were obtained when the plant design was modified for a two gasifier design. Supporting costs for transportation, technical advisor support, warranties, insurance, and others were also assessed to provide a total cost. Proprietary equipment from Siemens and from Air Liquide[2] were provided as a lump sum cost for the lot. Instrumentation and actuated valves were estimated as a single lot for each silo.

3. Balance of Plant

WorleyParsons, the owner's engineer, subcontracted the conceptual design and cost estimating for the interconnections. A brief summary of the subcontractors and the methodology that they applied is discussed below.

Roadway/Infrastructure Improvements

Bigge Crane and Rigging Company was retained by KBMD to perform a transportation study for the delivery of major equipment to the site. This transportation study was performed as part of the Front-End Engineering and Design effort. The study assumed barge delivery of major equipment to a site on the Illinois River. The study evaluated the barge landing for ability to off-load equipment of the size anticipated for Taylorville, the transportation equipment required, highway routes for both standard height trucks and high truck loads (up to 24 ft clearance), and a review of improvements from the nearest rail siding to the facility. Railroad clearances from potential points of origination were not reviewed.

The highway routes were traveled to identify specific interferences, inadequate turn radii, and other potential improvement needs for the anticipated loads and hauling equipment. The details of the improvements required were then estimated.

Transmission Interconnections

Patrick Engineering was retained to develop a conceptual routing and design of the 345 kV transmission line and interconnect and the 138 kV construction power and back-up service interconnection. The design is based on routing developed with input from Tenaska. Local utility standards were applied to the design. Costs for various surveys such as geotechnical and aerial surveys were determined from budgetary quotes obtained from qualified contractors. Direct costs were obtained from vendor quotes. Engineering services costs were also provided. Total costs for this conceptual routing are anticipated to be within 30% of the estimate.

---

[2] Tenaska intends to procure the syngas silo equipment from Air Liquide.

Gas Pipeline Interconnections

WorleyParsons Tulsa, OK office developed a conceptual design and cost estimate for the nine mile natural gas pipeline for interconnections to the Panhandle Eastern Pipe Line and Rockies Express pipeline. The design assumes bidirectional flow and no compression or valve stations. Taylorville is currently only going to interconnect to Panhandle Eastern Pipe Line with the capability to interconnect to Rockies Express at a later time. The cost estimate included direct costs based on the conceptual routing and vendor quotes. Indirect, engineering and construction management, freight, and right of way costs were also estimated. Twenty percent (20%) contingency was applied. Tenaska provided the costs for interconnection.

Process Water Interconnections/Improvements

Black & Veatch developed a conceptual design and cost estimate for supplying non-potable water from the Sanitary District of Decatur to Taylorville based on water quality and quantity demands of Taylorville and a conceptual routing of the pipeline. Improvements to the Sanitary District of Decatur facilities that are necessary plus pipeline design were identified and estimated. The costs for each portion of work were estimated with 30% contingency. Engineering services were estimated separately.

Potable Water Interconnections

Patrick Engineering developed a conceptual routing and design. Costs were estimated from material take-offs of this design using 2009 Means Heavy Construction Cost Data. Adjustments for local conditions and recent experience were applied. 15% contingency was applied to this estimate.

4. Contingency

Tenaska prepared a Taylorville Contingency Matrix (Reference 10) to document the contingency included in the estimate. The matrix is divided into three main parts: Cost Reimbursable Contracts, Fixed Price Contracts and Owner's Costs. For the Cost Reimbursable Contracts, separate line items were shown for each of the major categories of expenses (e.g., equipment, labor, materials, subs) where each line item contained the estimate total cost and a percent contingency. For the Fixed Price Contracts part of the matrix, separate line items were shown for each major contract along with the estimate total cost and percent contingency. For the Owner's Cost part of the matrix, separate line items were shown for each major component of Owner's Costs.

All of the $257M included in contingency in the Facility Cost Report is attributable to specific line items on the Taylorville Contingency Matrix. This contingency value represents about 9% of the capital costs.

As part of a separate and independent effort, KBMD prepared Risk Analysis and Mitigation Plans for the Other Core Plant, Syngas and Gasification silos. Each item in the Risk Analysis and Mitigation Plan had a risk description, possible impact, mitigation, likelihood and resolution. The contingency values in the Risk Analysis and Mitigation Plans were approximately 6% of the capital costs and are thereby bounded by the 9% of contingency included in the Facility Cost Report.

The owner's contingency estimate is for the contingency the project should have available upon full notice to proceed. The owner's contingency of $257M does not take into account the uncertainty in the capital cost estimate prepared for the Facility Cost Report and is far less than the upper limit of uncertainty in the capital cost estimate. Tenaska estimates that the cost of the facility may increase by approximately 15% or approximately $525M. The estimate uncertainty will reduce significantly as the design is completed and cost estimates by vendors and subcontractors are finalized. We conclude that the $257M of contingency included in the capital cost estimate is reasonable. Our analysis of the estimate uncertainty is provided in Section F of this report.

5. Owner's Costs (including escalation)

Insurance costs were developed from budgetary quotes from Aon and FM Global. The budgetary quotes are based on assumptions for covered losses, payroll, builder's risk, and delays in construction and start-up. Process and license fees for the major components from Siemens and Air Liquide were obtained from quotes from the respective vendors. Other lesser licensing fees were estimated as part of development costs. Other development costs and project management costs were determined by Tenaska from actuals to date and monthly estimates through the remaining development and construction of the facility. Siemen's estimated pre-operational and spare parts costs based on an assessment of staffing schedule, start-up activities, and training requirements. Spare parts costs are rough values based on a facility of a similar size. Catalyst costs were estimated by KBMD based on the processes. The coal inventory costs were estimated by assuming a 10.5 day stockpile and delivered coal prices consistent with a Wood McKenzie coal price analysis.

D. Cost Estimator Experience and Qualifications

The majority of the costs in the Facility Cost Report have been prepared by Kiewit, Burns and McDonnell, Tenaska and WorleyParsons. We have reviewed the prior cost estimating experience of the companies and concluded that they have the appropriate experience and qualifications to perform this cost estimate. For completeness, we have included summaries of experience that were provided either as an exhibit in the Facility Cost Report or in the Christian County Generation, L.L.C. response Part II to the DOE.

1. Tenaska

Tenaska is the developer of the Taylorville project. The following description of Tenaska's experience and qualifications has been extracted from Exhibit 1.4 of the Facility Cost Report (Reference 2).

> "In its 23-year history, the company has developed approximately 9,000 megawatts (MW) of generation, representing more than $10.2 billion in aggregate financing and

capital investment. In addition to having ownership interests, Tenaska is a managing partner and provides operations services for about 6,700 MW of generation.

Tenaska's natural gas affiliate, Tenaska Marketing Ventures, and its power marketing affiliate, Tenaska Power Services Co., are considered to be among the largest marketers in the United States providing asset management products and services to the gas and power industries.

Tenaska BioFuels, LLC, uses its expertise to provide innovative solutions for helping customers market and move their bioproducts to consumers. Tenaska Exploration & Production (E&P) has acquired gas leases for drilling and production activities in the Marcellus Shale.

Tenaska also provides administrative and operations oversight services for nine generating stations, totaling more than 5,000 MW, owned by stand-alone private equity funds Tenaska Power Fund, L.P (TPF I) and TPF II, L.P. (TPF II). Tenaska Capital Management, LLC (TCM) is the manager of TPF I and TPF II, and on behalf of TPF I and TPF II, is responsible for the evaluation, acquisition, operation, optimization and divestiture of opportunities in the U.S. energy industry."

2. Kiewit

Kiewit was selected to perform the core plant cost estimate. The following description of Kiewit's experience and qualifications has been extracted from the Christian County Generation, L.L.C. response Part II to the DOE (Reference 11).

- "Participation with Burns & McDonnell in the design and construction of the Cash Creek project, a HIGCC project similar to TEC, located in Kentucky;
- Rentech REMC Feedstock Conversion Project—Project Development, Licensor Selection, FEED and Estimate, Constructability, Power Island and Coal Handling planning, development of Project Execution Plan. This project entailed the Conversion of Ammonia Facility to Coal Gasification in East Dubuque, Illinois;
- Jim Bridger Integrated Gasification Combined Cycle (IGCC) Project, a PacifiCorp "Mouth of Mine" coal gasification project development in Wyoming----Conceptual Planning, Constructability and Feasibility Estimate. The work included determination of costs for remote jobsite and high altitude coal gasification facility; and
- Kiewit serves on the Gasification Technology Council board and has been a member of GTC since 2006.

Tenaska has a significant amount of experience working with Kiewit. Kiewit and Kiewit subsidiaries have been the EPC contractor on six Tenaska gas-fired power projects totaling more than 3,000 MW."

3. Burns and McDonnell

Burns and McDonnell performed the engineering that was included in the Front End Engineering and Design effort. The following description of Burns & McDonnell's experience and qualifications has been extracted from the Christian County Generation, L.L.C. response Part II to the DOE (Reference 11).

- "Participation with Kiewit in the design and construction of the Cash Creek project, a HIGCC project similar to TEC, located in Kentucky;
- Front End Planning (FEP) Level 2 study for a nominal 150 MW IGCC facility to be located in the State of Pennsylvania;
- FEP Level 1 study for a nominal 10,000 bpd coal-to-gasoline facility in Kentucky;
- FEP Level 2 study for utilizing the EPIC coal gasification technology to provide fuel for an ethanol plant to be constructed in New Hampton, Iowa;
- FEP Level 1 study for Process Energy Solutions to evaluate the cost to restart the El Dorado Gasifier in Kansas and modify the unit to produce hydrogen;
- Design of an expansion of the gasification process at the Coffeyville Gasification Plant in Coffeyville, Kansas;
- Technical feasibility study of a 600 MW IGCC facility utilizing the Shell gasification technology and Powder River Basin coal; and
- Screening assessment for Minnesota Power to provide a conceptual design and screening level cost estimate for a 2x1 550 MW IGCC plant.

Burns & McDonnell has been involved with the TEC since 2005, when they were engaged to provide overall engineering support for the initial FEED work conducted when TEC was still contemplating a traditional IGCC design. Tenaska also retained Burns & McDonnell to provide engineering for the 534 MW Lakefield Junction project in Trimont, Minnesota."

4. WorleyParsons

WorleyParsons is the Owner's Engineer for Tenaska. In additional to performing traditional Owner's Engineer's tasks, WorleyParsons also assisted with the cost estimates for the owner's costs. The following description of WorleyParsons's experience and qualifications has been extracted from the Christian County Generation, L.L.C. response Part II to the DOE (Reference 11).

"Tenaska has engaged Worley as Owner's Engineer to assist Tenaska's internal engineering staff in overseeing the FEED study. Worley is a leading international engineering firm with strong capabilities both in the power and chemical process areas. Worley has provided services to the power industry for more than 100 years:

- **Coal.** Worley has designed hundreds of coal-fired electric generating stations using all types of coal. They are an industry leader in supercritical coal power plant technology;

- **Gas.** Worley's worldwide projects include more than 34,000 MW of simple and combined cycle installations for more than 120 gas turbine plants. Worley has designed in excess of 20,000 MW of installed gas turbine capacity during the last 10 years;
- **Nuclear.** Worley has successfully implemented 18 nuclear generating units, totaling more than 13,100 MW, around the world; and
- **Renewables.** Worley's renewable capabilities span the entire spectrum of renewable energy technology, including solar, wind, biomass, geothermal, ocean power and off-grid applications.

Worley's gasification background includes coal gasification and fluid bed boiler plant design and support services for the US Department of Energy (DOE), the Electric Power Research Institute (EPRI), the Institute of Gas Technology (IGT), and domestic and offshore private utilities and corporations. Worley has experience with all of the major gasification technologies, including GE, ConocoPhillips E-Gas, Shell, BGL, Lurgi, KBR and Siemens. Recent gasification experience includes:

- Technical support contract with DOE Fossil Energy for various emerging energy technologies, including gasification, since 1988;
- Technical support contract with DOE Federal Energy Technology Center (FETC)/Morgantown for various emerging energy technologies, including gasification and fluidized bed, since 1989;
- 2,200 ton-per-day fluid coke IGCC repowering EPC project;
- Dual gasification trains syngas production EPC project; and
- Numerous IGCC feasibility studies and front-end process design contracts."

E. Estimate Reasonableness

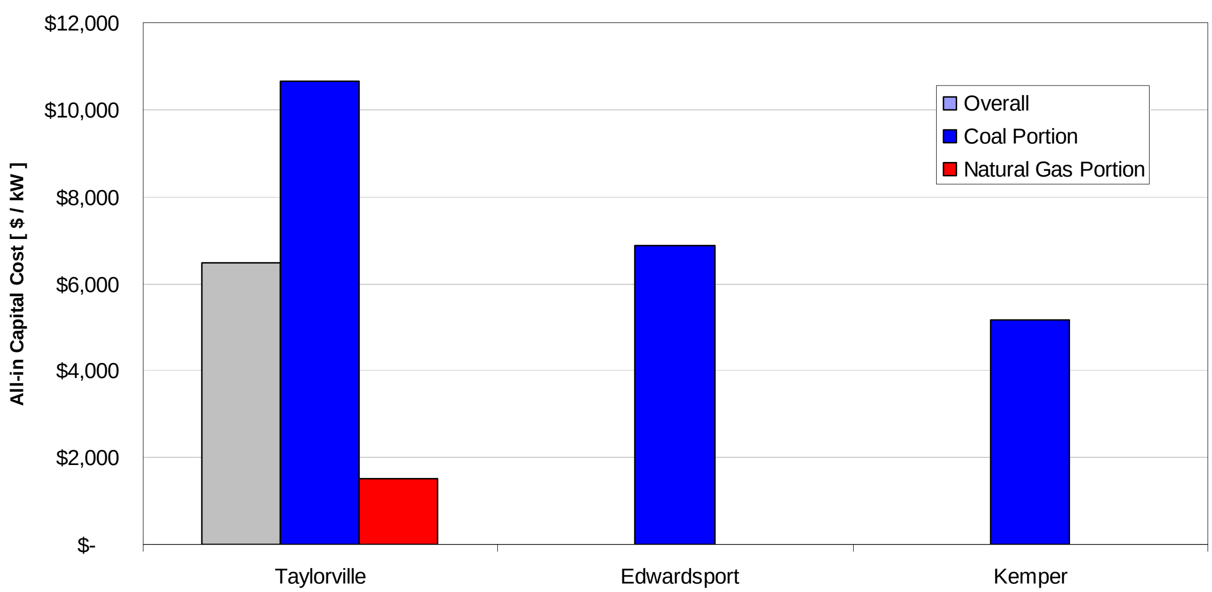
1. Overall Plant Cost

Taylorville is an expensive facility by any measure. A net output of 544 MW (net of Air Separation Unit) at a cost of $3.5B results in a cost per kilowatt of $6,474. This is a high number in comparison to other types of power facilities. However, the true cost of the clean-coal portion of this facility is masked by the fact that approximately 46% of the electrical capacity is actually from natural gas (see Section V.A of Report 4). The cost for the portion of the facility powered by natural gas can be estimated by assuming $1,500 per kilowatt for a natural gas combined cycle facility and multiplying this cost by the net output from natural gas (248 MW) which equates to $372M. The remainder of the costs for the facility ($3.15B) is then divided by the net output from coal (296 MW) which results in a cost of approximately $10,641 per kilowatt for the coal portion of the Taylorville facility.

Perhaps the best facility to compare to Taylorville is the Edwardsport Integrated Gasification Combined Cycle plant. Edwardsport is a 630 MW facility that gasifies coal and combusts syngas in a combined cycle plant for an all-in capital cost of $2.88B. There are two primary differences between the Edwardsport and Taylorville facilities: Edwardsport burns syngas instead of SNG, and Edwardsport does not sequester carbon. For the purposes of an equitable comparison to Taylorville, we have increased the cost of the Edwardsport facility by 20% and decreased its output by 20% to compensate for the additional capital and increased parasitic loads resulting from carbon capture and sequestration. These changes are based on the data provided in a DOE/NETL report (Reference 12). Burning syngas results in lower capital and operating costs, but precludes the ability to sell SNG. However, from the perspective of making electricity from clean-coal, burning syngas is equivalent, if not superior, to burning SNG. Therefore, the only compensation necessary to compare the two facilities is for the carbon sequestration. This results in a corrected Edwardsport cost of $6,857/kW or $3.5B for 504 MW of coal output. Another Integrated Combined Cycle facility currently under consideration, Kemper County, is also shown in Figure 2.

In comparison to the cost of the Edwardsport facility at $6,857/kW, the $10,641/kW cost for the coal portion of the Taylorville facility is significantly more expensive. A comparison to the Kemper facility also suggests similar potential savings. We recommend that further study should be made of the possibility of reducing capital cost by using a conventional Integrated Gasification Combined Cycle design approach.

Figure 2
Comparison of Taylorville Capital Cost to Other Gasification Facilities



1 Cost of the Edwardsport facility has been increased by 20% and the output has been decreased by 20% to compensate for the lack of carbon sequestration. These estimates are based on information in Reference 12.

2 Output of the Kemper project is reduced by 60 MW, which is the natural gas fired duct burning capacity of the facility. No correction has been made to the price of the facility, which is a conservative approach because this artificially increases the cost ($/MW) and yet Kemper is still significantly lower than Taylorville.

2. Interconnections/Development Costs

Based on a review of the scope of the work for the interconnections and the costs presented, the costs are considered reasonable for this stage of the design. Although the cost estimate for interconnections is considered reasonable, the transmission upgrade costs may potentially change by a substantial amount as the design proceeds. This is due to two concerns:

- The PJM Interconnection System Impact Study indicates that if there is a need to replace support structures at a substation, there will be an $18M increase in cost. The Facility Cost Report increased the capital cost for the interconnection by approximately $9M to account for this potential need. The contingency in the Facility Cost Report for this line item does not fully address the potential to realize the full replacement of the support structures. The cost is to be updated in 2010 in a PJM Facility Cost Study.
- The PJM Interconnection System Impact Study apportions the impact costs among the projects within the queue. If some of these projects do not proceed, then Tenaska's proportion could increase. The cost is to be updated in 2010 in a PJM Facility Cost Study.

F. Estimate Accuracy

Tenaska has stated the accuracy of the capital cost estimate is +15/-10%. For the purpose of this evaluation, the capital cost estimate will be examined based on the terminology and guidance found in ASTM E2516-06, "Standard Classification for Cost Estimate Classification System" (Reference 13) [3]. Table 4 describes the various cost classes used in the estimate where Class 1 is the most accurate and Class 5 is the least accurate. Tenaska's claim of +15%/-10% would be most consistent with a Class 2 estimate.

[3] ASTM International, originally known as the American Society for Testing and Materials (ASTM), was formed over a century ago, and is considered to be a trusted source of technical standards for materials, products, systems, and services.

Table 4
Estimate Classes

Estimate Class	Level of Project Definition (Expressed as % of complete definition)	Estimate Accuracy
5	0% to 2%	-20% to -50% +30% to +100%
4	1% to 15%	-15% to -30% +20% to +50%
3	10% to 40%	-10% to -20% +10% to +30%
2	30% to 70%	-5% to -15% +5% to 20%
1	50% to 100%	-3% to -10% +3% to +15%

1. Level of Project Definition

Section 6.2 of ASTM E2516-06 states that the primary characteristic that affects the accuracy of an estimate is the level of project definition. This roughly corresponds to the overall engineering design percent complete. According to the Facility Cost Report, the engineering work performed during the Front-End Engineering and Design study comprises approximately 10% of the total engineering necessary to construct the Taylorville facility. This level of project definition is consistent with an estimate that falls somewhere between a Class 3 or Class 4 estimate according to ASTM E2516-06.

2. End Usage of Estimate

The end usage of an estimate is described as a secondary characteristic of estimate accuracy in Section 6.3 of ASTM E2516-06. Tenaska intends to use fixed price contracts for several of the process areas in the plant, including the following: Power Block, Water Treatment, Coal Handling, Gasifier Technology/Equipment and Syngas Technology/Equipment. Due to the relative stability of design for these components, this contracting vehicle will reduce the financial risk to Tenaska and reduce the amount of contingency Tenaska needs to carry for these contracts. However, with the exception of the Gasifier Technology/Equipment contract, none of the other contracts have been signed. The End Usage of these individual component parts of the capital cost estimate is consistent with a Class 2 or Class 3 estimate according to ASTM E2516-06.

3. Methodology

The estimating methodology is described as a secondary characteristic of estimate accuracy in Section 6.4 of ASTM E2516-06. Estimating methods fall into one of two broad categories: stochastic and deterministic. Stochastic methods rely heavily on expert judgment and probability. Deterministic methods rely primarily on quantitative measures (e.g. takeoffs and productivity factors). As described in detail in Section C "Capital Cost Methodologies", the capital cost estimates in the Facility Cost Report are primarily deterministic in nature. This is consistent with the definition of an estimate in the Class 1 or Class 2 range according to ASTM E2516-06.

4. Preparation Effort

The preparation effort is described as a secondary characteristic of estimate accuracy in Section 6.6 of ASTM E2516-06. The level of effort required for the estimate does not include the resources used in designing the facility or managing the various EPC team members. The cost of preparing the Facility Cost Report (including the Front-End Engineering and Design Study described therein) was funded in part with an $18M grant provided by the Illinois Department of Commerce and Economic Opportunity (DCEO). We assume that the Preparation Effort of the capital cost estimate corresponded to an estimate in the Class 1 or Class 2 range according to ASTM E2516-06.

5. Other Considerations

There have been significant changes to the cost of the Taylorville facility over the past 12 months. The total capital cost of the facility in the R.W. Beck report and the DOE Part II response was $3.2B and $3.1B, respectively, which corresponded to a core plant cost of approximately $2.3B. In January 2010, when the first draft of the KBMD core plant estimate was completed, the core plant costs were $4B (Reference 8). Through a 33% reduction in capacity of the SNG block and a number of other cost reduction efforts, the capital cost estimate has been reduced by $1.4B. Tenaska has estimated that approximately $200M of the $1.4B reduction in costs was from the optimization of the plant layout. The progression of cost reductions since January reflects KBMD's rigorous and determined efforts to minimize the cost of the facility. However, it also demonstrates that due to the size and complexity of this plant, something as simple as a change in layout can change the cost by hundreds of millions of dollars.

It is typical for facility costs to continue to change after completing the Front-End Engineering and Design study. After all, the only "primary characteristic" of estimate accuracy in the ASTM standard is the level of project definition. This also means that the cost estimate provided in the Facility Cost Report is significantly more accurate than the cost report submitted 12 months ago. Over a period less than 12 months, the core plant costs rose by approximately 75%, and were only lowered to a 9% increase by reducing the scope of the coal throughput by 33%.

6. Conclusion

The methodology, assumed preparation effort and cost estimator qualifications are all consistent with a Class 1 or 2 estimate according to ASTM E2516-06. If these were the only factors involved, it would be reasonable to claim an estimate accuracy of +15/-10%. However, due to low level of project definition, lack of signed contracts for major equipment, and the gross increases in project cost and reductions in scope over the past 12 months, it would be overly optimistic to claim that this estimate is accurate to +15/-10%.

A presentation at the 2008 Gasification Technologies Council (Reference 14) suggested that estimates prepared at the Front-End Engineering and Design stage are typically ASTM Class II with 25-50% of the engineering complete and an expected accuracy of +15%/-10%. However, for this project, only 10% of the engineering is complete (per the Facility Cost Report) and there was a recent change that reduced the SNG throughput by 33%, therefore the stated accuracy of +15/-10% is optimistic. It would be reasonable to classify this project at the low end of the Class 2 or the middle of Class 3, which would give it an accuracy of +20/-15% for a total project cost in the range of $3.0 to $4.2 billion.

G. Summary of Capital Cost Estimate Review

1. Carbon Sequestration Costs Excluded ($44M)

The $3.5B cost estimate does not include costs for carbon sequestration in the Mt. Simon formation or costs for constructing the Denbury pipeline. The facility cost report assumes that the Denbury pipeline will be operational by the time the Taylorville facility is fully operational. This assumption precludes the need for the development of the Mt. Simon formation which was estimated as a $44M capital cost. Given the uncertainty associated with the development of the Denbury pipeline, it is recommended that the project budget include the capital cost for development of the Mt. Simon formation.

2. Air Separation Unit Costs Excluded ($191M)

In summary, the Air Separation Unit, although located on the Taylorville Energy Center property, will in effect be a completely separate facility. This approach is reasonable given the generic nature of an Air Separation Unit and the commonality of the proposed arrangement between Tenaska and the third party. Effectively, this arrangement lowers the capital costs by $191M and increases operating costs.

3. Substantial (33%) Reduction in Clean-coal Throughput

The $3.5 billion capital cost reported in the Facility Cost Report is based on a two gasifier design. A four gasifier design was the basis for the Taylorville design evaluated in the R.W. Beck report in 2009 and the DOE loan-guarantee Part II response. One of the gasifiers was a spare, but the gasification island, downstream gas-cleanup and conversion equipment and Power Block were based on a 3 gasifier throughput. The total capital cost of the facility in the R.W. Beck report and the DOE Part II response was $3.2 billion and $3.1 billion, respectively. However, despite the reduction from 4 gasifiers to 2, the current cost of the facility has increased to $3.5 billion. This is 9% increase in cost despite a 33% reduction in clean-coal output.

4. Methodology and Cost Estimator Qualifications

KBMD had the primary responsibility for the preparation of the Core Plant capital cost estimate, including escalation. The methodology employed by the KBMD is well documented in their Basis of Estimate (Attachment 1 of Exhibit 2.0 of the Facility Cost Report). In summary, KBMD divided the Core Plant into silos and cost categories. Each silo had a lead estimating team for each estimate group, resulting in a matrix of responsibility that is shown in Figure 1. In addition to the primary estimating team, KBMD also used a secondary team (also shown in Figure 1) to perform independent quantity take-offs, compare production rates and compare man-hour factors.

At the conclusion of each estimate preparation, KBMD conducted open book reviews for each silo. MPR was invited to these reviews and observed two. Based on a review of the documented estimate preparation process and participation in the open book reviews, we believe that KBMD had a methodical approach that encouraged transparency and accuracy.

5. Accuracy

The methodology, assumed preparation effort and cost estimator qualifications are all consistent with a Class 1 or 2 estimate. If these were the only factors involved, it would be reasonable to claim an estimate accuracy of +15/-10%. However, due to low level of project definition and, more significantly, the gross increases in project cost and reductions in scope over the past 12 months, it would be optimistic to claim that this estimate is accurate to +15/-10%. However, it would be reasonable to classify this project at the low end of the Class 2 range for the Process Industry, which would give it an accuracy of +20/-15% for a total project cost in the range of $3.0 to $4.2 billion.

II. OPERATIONS AND MAINTENANCE COST ESTIMATE

Tenaska Operations will operate and maintain the Taylorville Energy Center facility. Operation of the facility includes running the SNG Block and Power Block, sampling all necessary streams, maintaining equipment during operation, and providing necessary maintenance during outages. As part of the Front-End Engineering and Design Study, Siemens' prepared an Operations and Maintenance Cost Estimate for these items.

Our review concludes that the Operations and Maintenance estimate included in the Facility Cost Report is likely to be under-predicted. A more reasonable annual budget is $105M (in 2010 dollars, excluding escalation), which is $37.7M more than the estimate used in the Facility Cost Report.

Operation of a large gasification facility is outside of the experience base of Tenaska Operations. To account for this lack of experience, Tenaska plans to recruit talent from other facilities, contract additional help when necessary, and rely heavily on vendor's Technical Field Assistants during the initial years of operations. We view this as a key challenge that must be addressed for the project to be successful. The recruiting and outside labor budgets for staff must be robust, allowance for technical field assistants must be much more than typical, training programs must be rigorous and well funded, and a realistic projection of the facilities availability in the early years of operation must reflect the learning curve that will be required.

This section discusses five aspects of the operations and maintenance estimate: the background of the estimator, the scope and exclusions, the accuracy, methods of implementation, and any modifications or considerations. The following discussions provide details for each of these topics.

A. Operations and Maintenance Estimator Experience and Qualifications

The Operations and Maintenance Estimator for Taylorville is Siemens Energy Service. Siemens' operations and maintenance experience is discussed in Exhibit 1.4 of the Facility Cost Report (Reference 15), a presentation titled "Fuel Gasification Product/Service Development and New Technology Commercialization" (Reference 16), and a Siemens' presentation titled "Gasification: A Journey to Commercialization" (Reference 17). A summary of the experience Siemens' mentioned in these documents is listed below.

- Global Industrial Operations & Maintenance Experience in 23 locations, some local to TEC
- 39 Industrial Operations & Maintenance Support Contracts Worldwide
- Involvement in Feasibility and Front-End Engineering and Design Studies
- Possession of the "Reliability Availability Maintainability" tool
- Over 320,000 hours of gas turbine operation on syngas, 4,600,000 hours of 5000F gas turbine fleet operation and 160,000 hours of gasifier operation

While Siemens lists a considerable amount of operations and maintenance experience, most of this experience is at combined cycle power plants, not experience operating gasifiers. The majority of the gasifier operating experience is from two facilities (Schwarze Pumpe and Freiberg, Germany) which are very different than the Taylorville facility.

Siemens is a large company that is deeply involved in the power industry, including providing operations and maintenance services under contract to plant owners. They are also the vendor for the critical gasification island components as well as the combustion turbine and associated auxiliaries at Taylorville. From these perspectives they should be considered qualified to perform their assigned scope of work in providing an operations and maintenance cost estimate. However, we note that Siemens' experience with operation and maintenance of Integrated Gasification Combined Cycle and SNG facilities is limited. Further, there is limited actual operating experience worldwide with the Siemens gasifier and in operating SNG facilities in general. Therefore, while we consider Siemens to be qualified in this area, we also believe that there is considerable uncertainty in their operations and maintenance cost estimate.

B. Operations and Maintenance Estimate Scope

1. Inclusions

A comprehensive evaluation of the predicted costs to operate and maintain the Taylorville facility was presented in Exhibit 5.1 of the Facility Cost Report (Reference 18). Items that were included in the cost estimate include:

- permanent labor
- contract labor
- consumables
- maintenance parts and materials
- additional outside outage labor
- administrative systems/tools
- plant and management equipment
- tools
- switchyard
- waste disposal
- insurance
- capital improvement

Siemens' also evaluates pre-operational operating costs in the same report. The pre-operation phase is the period prior to commercial operation, but not including construction costs. This pre-operational operating cost estimate includes many of the same categories listed for the operational plant costs but it is scaled to fit the duties required for the pre-operational period. This is the period of transition between construction and commercial operation. The pre-operation estimate is included with the capital costs for the facility, not the annual operations and maintenance costs.

2. Exclusions

The Air Separation Unit operating and maintenance costs were not included in Siemens' cost estimate, but Pace included the necessary costs in the cash flow summary of the Rate Impact Analysis (Reference 19). Siemens states that their cost estimate does not include industrial gases (those that are provided from the air plant). Between Siemens and Pace, the costs of the Air Separation Unit have been incorporated appropriately.

The costs associated with fuel are not included in the Operations and Maintenance Cost Estimate. Wood Mackenzie performed a study for the price of coal, which is included as Exhibit 6.0 of the Facility Cost Report (Reference 20). The cost of fuel is discussed in Section III of this report.

The cost of sequestering the CO_2 is also not included in the Operations and Maintenance Estimate. Unlike the exclusion of fuel, we believe CO_2 sequestration should be included in the cost estimate. Tenaska has chosen to evaluate the plant with the assumption that the captured CO_2 will be sent to the Denbury pipeline. The Denbury arrangement will only occur if multiple other gasification plants also capture their CO_2 and direct it to the proposed pipeline. Since there is great uncertainty whether this will or will not occur, it is recommended to budget assuming that Taylorville will have to sequester the CO_2 in the Mount Simon saline aquifer. A study performed by Schlumberger Carbon Services (Reference 4), reports that operation and maintenance of the sequestration pipeline and equipment would cost approximately $640,000 per year. This sequestration cost should be included as part of the plant's annual operations and maintenance costs. Furthermore, the financial projections should consider the possibility of not receiving the additional revenue associated with CO_2 sales.

C. Accuracy of the Operations & Maintenance Estimate

Tenaska intends to have Tenaska employees operate and maintain the Taylorville Energy Center. Therefore, there is no firm operations and maintenance contract supplied with any control of cost certainty. The Siemens' estimate has a higher level of uncertainty than would be found if a contract had been used to operate the facility.

1. Overall Budget

Other gasification facilities we are familiar with have a operation and maintenance costs which is roughly 4% of the total installed capital cost. In addition, a DOE/NETL study (References 12), estimates a ratio of operations and maintenance cost to total capital cost of 4.2%. A value of 4% of Taylorville's total installed capital costs[4] would be $105M per year. However, Siemens operations and maintenance estimate is $67.3 million per year, which is only 2.6% of the capital costs.

[4] Total Installed Capital Cost is assumed to exclude owner's costs, escalation and financing. Total Installed Capital Costs for Taylorville is $2,634,776,000.

2. Specific Observations

Several individual areas of the operations and maintenance cost estimate are discussed below where we believe costs may be under-estimated. While the mathematical sum of these individual observations does not necessarily equal the difference between the 4% estimate discussed above and the Siemens' estimate, these observations suggest a pattern throughout the estimate that could explain the difference.

Capital Improvements.
The annual operations and maintenance budget includes $1,500,000 for capital improvement projects, which is 0.06% of the total capital costs. Although estimating budgets for capital improvement projects is particularly challenging, we would expect to see between 0.5% - 2% of the total capital cost for an annual capital improvement budget. One subtlety in this cost account is that some capital projects will pay for themselves with consequent performance improvements. These performance improvements have not been accounted for in the plant performance projections, and are therefore inappropriate to include in the capital projects budget. However, many capital improvement projects do not increase plant performance and will be required. Accordingly, using the low end estimate of 0.5% seems reasonable. This results in approximately $13,000,000 in annual capital improvement costs.

Staffing
Tenaska's proposed staff for TEC is presented in Figure 3. The proposed staffing seems to be in the correct range for a plant the size of Taylorville, although possibly under-staffed in a few specific areas. Specifically, three examples of light staffing are chemistry lab technicians, control operators, and dedicated rotating equipment personnel.

Tenaska has one chemist and two lab technicians to process their entire facility. Other gasification facilities we are familiar with have numerous lab staff on every shift. In Tenaska's response to our questions on this topic (Reference 9), they described that the operators will do the sampling on shifts when the lab technicians are not there, which is a reasonable approach. However, these samples still need to be processed by the lab technicians. There are large amounts of samples taken daily and the man power required to process all of these samples are a 24-hour effort, meaning there should be at least one lab technician per shift to be able to cover the samples from every shift.

The control room staffing also seems light compared to other facilities we are familiar with. The Siemens estimate includes the following control room staff:

Control Room Operators:	17	(approx. 4 per shift)
Shift Leaders	5	(4 per shift plus 1 relief)
Operations Coordinators:	2	(only 2 of 4 shifts)
Total	24	

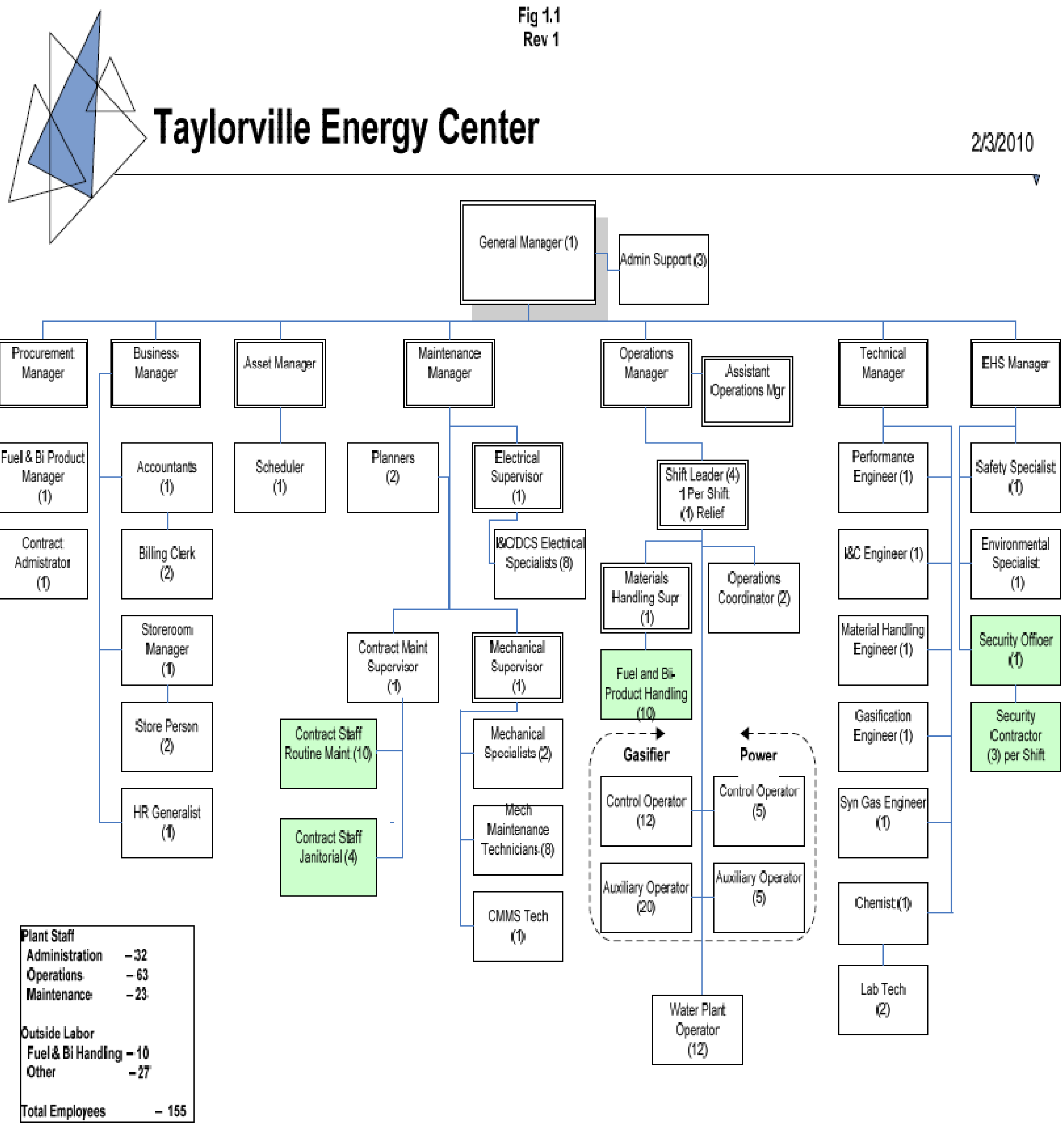
This represents four control room operators for the entire facility (excluding coal handling and water treatment). Other facilities we are familiar with use an operator for each different part of the process: gasification, shift, Rectisol, sulfur recovery, methanation, and power. Other facilities also have an Operations Coordinator on every shift, plus one relief position. Based on industry practice, and taking into account the advances in technology, we expect control room staffing as follows:

Control Room Operators:	24	(6 per shift)
Shift Leaders	5	(1 per shift plus 1 relief)
Operations Coordinators:	5	(1 per shift plus 1 relief)
Total	34	

In summary, we believe there should be an additional 10 people included in the control room staff.

Lastly, the organization chart does not designate dedicated staff assigned to rotating equipment. These personnel are vital to maintaining the plant at high availabilities. Other facilities we are familiar with have multiple personnel dedicated to maintaining rotating equipment, and at least two staff should be dedicated to this maintenance role.

Figure 3
Taylorville Organizational Structure (Reference 18)



Hot Gas Path Inspection
Exhibit 5.1 of the Outage Maintenance schedule states that 21 days have been dedicated to Combustion Turbine Hot Gas Path Inspections. In a document titled "Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability" (Reference 21), EPRI recommends 25 days for the Hot Gas Path Inspection. Individually, this number does not have a large effect on the overall operations and maintenance cost, but this is one of several places where detailed review suggests Siemens has used an optimistic approach to cost estimating.

Catalyst Life
The consumable cost for the methanation catalyst in Exhibit 5.1 of the Facility Cost Report indicates that the catalyst will be replaced every four years. The cost to fill the first bulk methanation reactor with Nickel catalyst is quoted costing $4,641,698 and then annualized to $1,160,424 (Reference 22). The replacement cost is divided over four years. An Air Liquide/Lurgi document titled "Catalysts & Chemical Data – Methanation" indicates that the guaranteed life of the Nickel catalyst will be two years, while the expected life of the catalyst is four years (Reference 23). This is another example of using an optimistic approach to estimating, i.e. using a four year catalyst replacement instead of either the guaranteed life or the average of the two.

Dust Suppression Polymer.
The EPA is becoming increasingly restrictive with coal dust suppression methods. In the original operations and maintenance estimate, polymer was designed to be the dust control method. As part of the cost reduction methods this has been removed, with a water wagon and coal pile maintenance vehicles still included. Although this may be fine for the time being, there is a trend in industry that plants are moving to improved dust control methods in anticipation of future EPA regulations. Improved dust control has been cut from scope to lower the budget. We advise that improved dust control methods might quickly return to the design if the EPA continues to increase dust control regulation.

Technical Field Assistants
Technical field assistants, provided by the equipment vendors, supply insight, troubleshooting, and training during commissioning and start-up. These are typically treated in a cost reimbursable manner. A portion of these costs are assumed to be included in service agreements that have not been formalized yet. The assumption that these assistants will be included in service agreements is another example of the optimistic approach Siemens' used in developing the costs estimates.

Carbon Capture and Sequestration.
As discussed in Section II.B.2, there has been no cost included for sequestration of CO_2 into Mt. Simon. This is a concern because it is uncertain if the Denbury pipeline will be developed. If the Denbury pipeline does not get developed, then there will be annual operating and maintenance costs associated with the pipeline and equipment required to sequester the CO_2 into Mt. Simon. This is an additional $640,000 in operations and maintenance costs that have not been included in the estimate.

The seven areas discussed above provide examples of the operations and maintenance cost estimate using optimistic methods for developing the operating cost of the plant. These observations support our recommendation that the operations and maintenance estimate is likely to be understated and a more reasonable value would be around 4% of the Total Installed Costs, or $105 million / year.

3. Operating Approach

Tenaska Operations will operate and maintain the Taylorville facility. Operation of a large gasification facility is outside of the experience base of Tenaska Operations. To account for this lack of experience, Tenaska plans to recruit talent from other facilities, contract additional help when necessary, and rely heavily of vendor's Technical Field Assistants during the initial years of operations (Reference 9). We view this as a key challenge that must be addressed for the project to be successful. The recruiting and outside labor budgets for staff must be robust, allowances for technical field assistants must be much more than typical, training programs must be rigorous and well funded, and a realistic projection of the facilities availability in the early years of operation must reflect the learning curve that will be required.

4. Escalation

The Siemens Operations and Maintenance estimate includes escalation (costs that reflect increasing maintenance as the equipment ages)[5]. In the year-by-year projection (Section 16 of the estimate) this escalation is shown as a 1.5% increase in cost in years 13 and 21. In the front section of the Operations and Maintenance estimate, Siemens states that their experience is that maintenance costs typically increase 1% per year after operating year 12. It is not clear to us why this judgment is not reflected in the estimate's year-by-year projection (Section 16). We agree that an escalation of about 1% per year in the later years is a reasonable estimate of cost increases.

5. Division of Fixed and Variable Costs

The Siemens' Cost Estimate provides an estimate for the division of fixed and variable costs. The Siemens cost estimate is roughly split evenly between fixed and variable costs while. A DOE/NETL study, which evaluates six different gasification designs with and without carbon sequestration, provides estimated fixed and variable costs that are also roughly split evenly between fixed and variable costs (Reference 12). Based on the DOE/NETL report findings, Siemens' estimate of fixed and variable costs is a reasonable division.

[5] In addition to this escalation, the Rate Impact Analysis provided by Pace adds 2% inflation to all operations and maintenance values (Reference 19).

III. FUEL ESTIMATE

We have reviewed the Fuel Study for the Taylorville Facility (Reference 20). Our observations and conclusions are provided below.

A. Summary of the Fuel Estimate

The Fuel Estimate was prepared by Tenaska's consultant, Wood Mackenzie, using their PRISM™ model. The analysis predicts that the cost of fuel for the facility will be relatively stable over the life of the project ranging from $2.14 to $2.47/MMBtu.

The analysis concludes that the most economic coals will be sourced from mines in Subdivision 3 (West-Central Illinois). Nearly all coal is delivered by truck to the facility[6]. Tenaska has not signed any long term contracts for supply of coal. They have stated that their procurement strategy will be to issue a competitive solicitation for proposals and expects to purchase fuel for the facility with a combination of short and long term purchase agreements.

B. Comments on the Fuel Estimate

1. The study identifies a relatively small number of mines capable of providing coal to the facility. Only three currently operational mines are identified. Another two currently operating mines will need to develop a coal washing process to be able to provide coal suitable to the gasification process. The study identifies the potential for another seven mines (currently in the planning stages) to provide coal to the facility in the future. Coal washing will be required at each of these planned mines to produce suitable quality coal for the gasification process.

   The availability of capital for investment in coal mine development is a significant risk. Considerable uncertainty related to future regulations for greenhouse gases and other air emissions exists that could drastically change the total market for Illinois coal and investor willingness to provide capital for coal projects. One recent study has predicted the closure of 27 GW of coal-fired plants by 2015 as a result of pending U. S. Environmental Protection Agency rule-making (Reference 1). Many of these facilities are responsible for the increased use and stability in the Illinois coal market.

   Given the relatively small number of mines that are identified, signing long term contracts in the near term for some or all of the facility's needs would reduce the considerable uncertainty in future fuel prices.

[6] In an effort to reduce capital costs, the facility design was recently changed to eliminate the capability to take rail deliveries of coal. Although the fuel study is based on a plant design that allows both rail and truck, the economic model predicts truck deliveries to be the lowest cost supply for nearly all of the facility's coal. If the study was updated to remove rail, the expected impact to the results would be small.

2. The study states that the use of coal blending from different mines is a potential approach for the project to manage coal procurements and mitigate coal quality concerns. Meaningful coal blending requires investment in additional coal stockpile area, expansion of the reclaim hoppers, feeders and conveyor systems, additional coal scales, and integration of an on-line coal analyzer into the fuel handling control system. The proposed facility design does not include these provisions for coal blending. Therefore, coal blending should not be advanced as a meaningful way to mitigate the coal quality uncertainties with the current design.

3. The study depends heavily on coal mines using coal washing techniques to improve the sulfur content of their coals prior to delivery to the Taylorville facility. As much as 80% of the coal delivered to the Taylorville facility will need to be improved through coal washing techniques. This has several important consequences

    i. Coal washing will increase the moisture content of the coal. The unwashed moisture content in the candidate coals identified by the study is between 8% – 16%. The performance estimate for the facility should consider the potential for higher levels of moisture and the consequent drying required. For example, increasing the moisture content from 10% to 20% would decrease the SNG output of the facility by roughly 90 MMBtu/hr (about 4% of the SNG output of the facility), due to the increased drying needs. While this decreases the efficiency of the overall facility, the electrical output of the facility would remain relatively unchanged, since the difference in SNG would be made up by increased use of pipeline natural gas. Coal washing could potentially reduce ash content and increase heat content, which might mitigate some of this moisture increase.

    ii. Several mines that the study identifies as available to supply coal to the Taylorville facility will need to develop washing capabilities. The process of coal washing, while technically feasible for the identified coals, introduces new requirements for permitting of the coal mine (e.g., water use, collection and treatment of the filtrate, and discharge of the treated water) that will increase both the timeline and the costs of the delivered coal. If the mine owners decide the upgrade is not justified (either for financial or regulatory reasons), the ability to source fuel will be challenged and could increase the uncertainty of the predictions made in this study.

    iii. The environmental aspects of coal washing are under increasing regulatory scrutiny. In particular, the use of "ash ponds" to contain the filtrate are subject to new U. S. EPA regulations beginning in 2010. Management under these regulations will increase the costs for washed coal for the facility. These regulatory changes were not addressed in the cost estimates provided by the study.

    The facility should consider the feasibility of using additional waste heat recovery to reduce the moisture in the washed coal delivered. Stack exhaust energy might be used as a source of heating to reduce the coal moisture. This process could eliminate the impact of higher coal moisture on the facility outputs.

Furthermore, the facility might consider the feasibility of recovering the water released in the coal drying process. This recovered water could reduce the water consumption requirements of the facility.

Any contracts for washed coal should include require a minimum storage period at the mine prior to delivery to reduce the adsorbed moisture from the washing processes. Hold periods of 3 to 5 days are effective to limit importing unwanted moisture to the facility. This will also reduce the costs for coal delivery by maximizing the useful weight transported in each truckload.

4. No sensitivity analyses were developed in the study. The results of the analysis are a function of numerous inputs and predictions each with uncertainty. It would be useful to provide a sensitivity analysis to understand the possible ranges of cost of electricity that the Taylorville facility might provide. One important variable we would expect the results to be sensitive to is the future greenhouse gas regulations. A similar study prepared for the project, the Rate Impact Study prepared by Pace, considered several sensitivity studies with different CO_2 price scenarios. A similar set of cases would be useful for the fuel study.

C. Conclusions

1. The likelihood of achieving the predicted fully supply costs for the facility is not well demonstrated due to: (a) the inherent uncertainties in future economic predictions, and (b) the lack of any signed long term contracts. The facility financial projections should consider sensitivity cases for a range of potential coal prices. It is recommended to consider a possible high-side scenario using coal supplies from the next lowest price subdivision. The fuel study shows that over the life of the project, this price is on average $0.60/MMBtu higher than the forecasted price shown in the study.

2. The stability in forecast coal pricing depends on roughly quadrupling Illinois coal production by 2045, representing a significant expansion in the regional use of coal[7]. Other predictors of coal use expect a 40 percent nation-wide decline in this same period. The risks associated with the disparity of these coal use predictions, should be mitigated by contracting long term supply from the operating coal mines in Subdivision 3 (West-Central Illinois). The study shows that these mines provide the least cost transportation alternatives, a conclusion unaffected by the coal use forecast. A long term supply contract will ensure adequate supply to support facility operation.

3. In evaluating any coal mine source outside Subdivision 3, the moisture in the as-delivered coal should be evaluated for its effect on both the facility operation and the

[7] See Exhibits 12 and 17 of Fuel Estimate.

cost of transportation. These costs may be mitigated by the addition of waste-heat, coal drying capability to the facility design.

4. Using trucks to provide coal deliveries will require a significant amount of traffic. Tenaska has estimated the maximum daily truck traffic will be 238 trucks for coal deliveries and 42 trucks for slag removal. Deliveries will be made six days per week during daylight hours only. In other words, approximately 23 trucks per hour will be required, or one 25-ton truck every 2.5 minutes.

IV. REFERENCES

1. "The Next Big Thing," Barclays Capital Power Market Study, February 2010.
2. Taylorville Energy Center, Facility Cost Report dated February 2010.
3. Illinois Public Act 095-1027.
4. Schlumberger Carbon Services "Cost Report for the Taylorville Energy Center", February 18, 2010 (Facility Cost Report Exhibit 13.2.b).
5. "Carbon Dioxide Offtake Agreement" between Christian County Generation LLC and Denbury Offshore, LLC dated March 20, 2009.
6. Tenaska, Inc. Memorandum "TEC Facility Cost Report ASU Basis" from Justin Vala to Steve Brewer, March 15, 2010.
7. Syngas Silo Sponsor Schedule, TEC Syngas - CRE II Changes, Revision 12, dated February 16, 2010.
8. Taylorville Energy Center, Current Estimate Summary, Revision 7, dated January 5, 2010.
9. Brewer, Steve, Tenaska. "Your E-mail dated 04/02/2010 requesting Additional Supporting Documentation for Taylorville Facility Cost Report", memorandum, addressed to Jim Bubb, MPR. April 9, 2010.
10. Taylorville Contingency Matrix, "Taylorville Capital Cost and Contingency Matrix CRE2-MPR.pdf".
11. Christian County Generation, L.L.C. Part II Response to Solicitation Number DEFOA0000008.
12. DOE/NETL-2007/1281 "Cost and Performance Baseline for Fossil Energy Plants", Revision 1, August 2007.
13. ASTM E2516-06 "Standard Classification for Cost Estimate Classification System."
14. L. Bonnell; J Hemmings; J. Leatherwood; J. Davis, SNC Lavalin Presentation entitled "ENGINEERING ESTIMATES FOR GASIFICATION PROJECTS" presented at 2008 Gasification Technologies Council.
15. "Siemens Fuel Gasification Technology" Siemens AG. 2008 (Facility Cost Report Exhibit 1.4).
16. Schulte, Bob. "Fuel Gasification Product/Service Development and New Technology Commercialization". Siemens Fossil Service. October 2009.
17. Zwirn, Randy. "Gasification: Journey to Commercialization". Siemens Power Generation. 2006 Gasification Technologies Conference. Washington, D.C. October 2006.
18. "Operations and Maintenance, Operating Cost Assessment Report, Taylorville Energy Center". Siemens Energy, Inc. Rev01. (Facility Cost Report Exhibit 5.1).
19. "Rate Impact Analysis for Taylorville Energy Center". Pace. February 2010. (Facility Cost Report Exhibit 10.0).
20. "The Delivered Price of Coal to the Taylorville Energy Center". Wood Mackenzie. October 2009. (Facility Cost Report Exhibit 6.0).
21. Phillips, J. "Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability". Volume 1. 1012226 Electric Power Research Institute. March 2007.
22. "TEC Catalyst and Adsorbent Summary" from file "TEC Catalyst Cost Basis for MPR 03-11-10.pdf".
23. "Catalysts & Chemicals Data, Methanation". Revision 01. Document No. 69814PR00045. Lurgi. January 2009.

TASK 4 REPORT

ASSESSMENT OF POTENTIAL FOR THE TAYLORVILLE ENERGY CENTER TO COME ON-LINE AS PLANNED AND WITHIN THE PROPOSED TIMEFRAME

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. ("Boston Pacific") and MPR Associates, Inc. ("MPR") make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

EXECUTIVE SUMMARY

This task report presents the results from our assessment of the potential for the Taylorville Energy Center to come on-line as planned and within the proposed timeframe. It specifically addresses: construction schedule, power deliverability, the plant's environmental impact, and plant performance. Key conclusions from each of these topics are as follows.

A. Facility Construction Schedule Assessment

The schedule provided by Tenaska has an overall duration of about 47 months from Final Notice to Proceed (December 15, 2010) to Commercial Operations Date (November 5, 2014). Based on our review of the schedule we have concluded:

- The schedule is reasonably well developed for the stage of the project.
- Several key activities are shown as milestones in the construction schedule, including:
    - CO_2 sequestration infrastructure construction (either the geologic sequestration approach or the Enhanced Oil Recovery approach),
    - Transmission line construction and upgrades to the transmission and delivery system,
    - Gas interconnection construction,
    - Water interconnection construction,
    - Air Separation Unit construction is described only at a summary level (Tenaska has stated they are currently negotiating with a vendor who would be willing to meet the construction duration shown in the schedule),

  We understand that these activities will be scheduled in more detail as the project is developed. The lack of detail in these areas adds to the risk that the actual construction duration could be longer than the duration described by the current schedule. One particular area that should be better developed is the schedule for the CO_2 sequestration infrastructure, since CO_2 sequestration is a key motivation for the development of the Taylorville project.
- The required permits are not shown in the schedule. This approach assumes that the required permits will not delay construction or startup activities.
- We identified several areas where further development of the schedule could potentially result in longer durations. Given these observations, the level of maturity of the schedule, and the overall duration of the schedule, we believe that the current schedule contingency of 5 weeks of total float is insufficient. MPR recommends at least 10% schedule contingency be shown in the schedule in the form of total float. For the 47 month schedule, this would result in about 20

weeks of total float and a total project duration of 52 months from Final Notice to Proceed.

- Assuming the external milestones to the schedule are met (e.g. permitting, approval of the project by the State legislature and issuance of Final Notice to Proceed), there is a high likelihood that the facility will commence commercial operations prior to 2016 as required by the Law.

B. Power Deliverability Assessment

MPR reviewed the interconnection studies, electrical one-line diagram, and switchyard layout for the facility. The interconnection study provides preliminary results, and final results are not expected to be provided until August of 2010. Consequently, conclusions about the deliverability of the power and necessary upgrades should be considered preliminary. The interconnection studies detail several upgrades to the transmission and distribution system that are required to allow the project to deliver its energy to the grid. The cost of these upgrades has been included in the capital cost estimate for the project. However, as noted above, the project schedule assumes the upgrades can be completed without affecting the project completion date.

Our review of the electrical one-line and switchyard arrangement concludes that the current arrangement for the Taylorville facility does not allow for easy maintenance of breakers while still providing the full availability of the facility. We would typically expect a ring-bus type design for this type of facility, which would improve the availability and reliability of the facility.

C. Environmental Impact

We have reviewed the environmental impact of the Taylorville facility and have the following conclusions.

Coal consumption. The Taylorville facility has a higher rate of coal consumption per MWh of energy produced as compared to a traditional pulverized coal facility. This is due to the power required to capture carbon and the energy losses related to converting coal to synthetic natural gas.

Water consumption. The Taylorville facility includes features that minimize water consumption such as a dry cooling system and a zero-liquid discharge system. Consequently, it performs very well compared to other facilities. Another benefit of the zero-liquid discharge design is that there is no process wastewater leaving the facility.

Air emissions (other than CO_2). Regarding air emissions, the Taylorville facility performance is comparable to a traditional natural gas combined cycle facility and the emissions are much lower than a traditional pulverized coal plant.

<u>CO_2 emissions</u>. Taylorville is designed to capture approximately 49.4% of CO_2 when operating at full capacity and more than 50% when at part load. As a result, on an annual basis it is reasonable to expect Taylorville to exceed the 50% capture requirement of the Law. While the overall CO_2 generation rate is higher than traditional facilities (for the same reasons as the high fuel consumption), the CO_2 emitted per MWh is less than 45% of that which would be emitted by a pulverized coal plant without CO_2 capture.

<u>CO_2 sequestration</u>. Tenaska is pursuing two options to sequester the CO_2 from the facility. Approach #1 envisions the use of the CO_2 in Enhanced Oil Recovery Applications and would require construction of a long-distance pipeline to the oil field in the Gulf of Mexico region of the US. This pipeline does not exist, and in order for it to be economically justified, several additional sources of CO_2 must be developed that would share the pipeline's capacity. Consequently, there is considerable uncertainty if this pipeline will be constructed. Approach #2 envisions geologic sequestration in the nearby Mt. Simon saline aquifer. Sequestration Approach #1, is preferred by Tenaska because it has lower capital costs, provides an additional source of revenue, and lowers the risks associated with permitting and long-term storage of carbon in a saline aquifer. However, given the uncertainty associated with this development approach, it would be reasonable to plan that, at least initially, the facility would rely on the Mt. Simon formation for CO_2 sequestration. This would result in an increase in Tenaska's cost estimate by $44M in capital costs, $0.6M per year in operations and maintenance costs, and a reduction in revenue by $8-9M per year.

D. Plant Performance

We have reviewed Tenaska's plant performance predictions and have the following observations. The performance estimates discussed below are based on the "Guaranteed Condition" and are net of the parasitic loads including the Air Separation Unit.

<u>Facility Output</u>. At full load, the facility is expected to consume 4,030 MMBtu/hr of coal producing, 2,351 MMBtu/hr of Synthetic Natural Gas that is fed into the Power Block along with 1,763 MMBtu/hr of purchased pipeline natural gas.

The net power produced from the Power Block is 544 MW (net of Air Separation Unit). These performance numbers are illustrated in Figure 1. This net output differs from Tenaska's estimate in two areas: (1) the use of guarantee performance, and (2) the accounting of parasitic loads from the Air Separation Unit. These differences are discussed in more detail below.

A significant portion of the electrical capacity of the facility is derived from pipeline natural gas input rather than coal. Coal represents 70% of the fuel consumed by the Taylorville facility when running at full load. However, due to the fact that a large portion of the energy in the coal is consumed in the process of converting the coal to Synthetic Natural Gas (SNG) and sequestering the CO_2, only 54% of the output capacity of the facility is from coal.

<u>Guaranteed Performance</u>. In their financial projections, Tenaska has assumed the performance of the major equipment in the SNG Block will exceed the vendor's guaranteed

performance, resulting in 4,433 MMBtu/hr of coal throughput and 2,592 MMBtu/hr of Synthetic Natural Gas Output. If the SNG Block performance was at the guaranteed conditions, the facility would import more pipeline natural gas to make-up the difference, so that the electrical output of the facility would not be significantly different. We recommend that the estimated facility performance be based on the vendor's guarantee point.

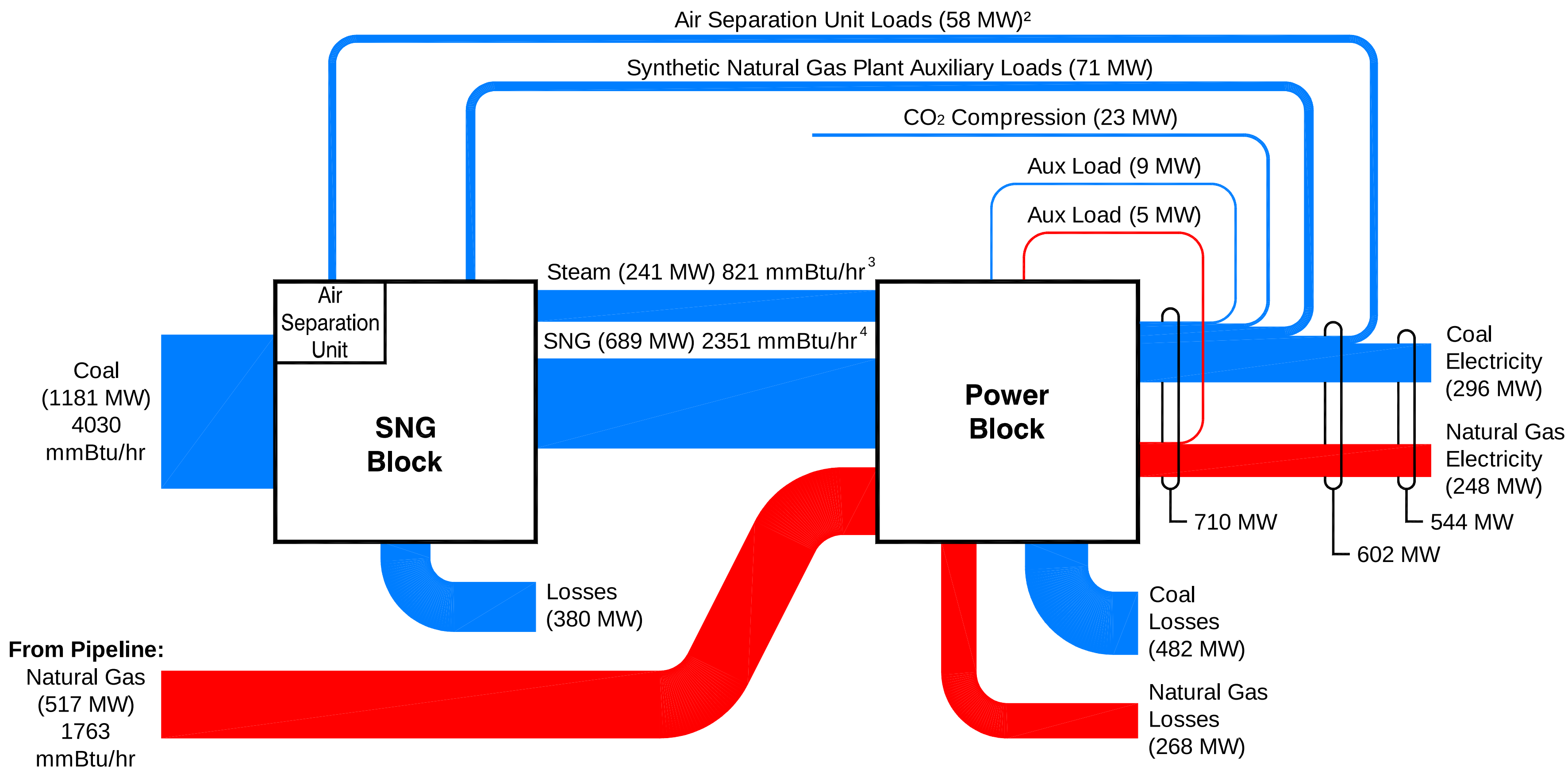
Air Separation Unit Auxiliary Loads. The 58 MW of power required by the Air Separation Unit is not included in Tenaska's auxiliary load estimate. This is because the Air Separation Unit is currently envisioned to be structured as a third-party "over-the-fence" contract, where the power required to operate the Air Separation Unit would be handled commercially outside of the Taylorville project. This would allow the project to sell an additional 58 MW of power at the higher subsidized electric rate, while the third party could purchase power at the lower prevailing rate of the electric grid. While it is unclear to MPR and Boston Pacific if this arrangement would be allowed in the structure of the proposed Sourcing Agreements, this parasitic load is required to operate the facility, and this power will not be available to existing Illinois ratepayers.

Ability to Produce SNG for Sale to Pipeline. Tenaska states that a key advantage of the hybrid-type gasification design (vs. a "traditional" Integrated Gasification Combined Cycle design) is the possibility for SNG sales during times when the markets are favorable to the economics of gas production rather than electricity generation. However, when Taylorville is operating in "SNG production mode", a relatively small portion of the gas output (13%) is actually available for sale. The remainder of the SNG production is directed to the Power Block, which operates at half load.

Efficiency. While the performance of the individual process plants for the SNG Block and the Power Block are similar to other gasification facilities, the overall plant efficiency is less than a clean coal facility based on a traditional Integrated Gasification Combined Cycle design. A key difference between these two designs is the methanation reactors in the hybrid design which diverts some of the energy from the gas stream to steam energy in the reactors. The Power Block converts the steam energy to electricity at a lower efficiency than the energy in the SNG stream.

Availability. We believe Tenaska's estimate of the facility availability over the long-term is reasonable and achievable. However, we believe that Tenaska's availability prediction for the initial years of operation is overly optimistic. We have reviewed previous gasification facility operating experience and concluded that a "shakedown period" (when facility's availability would be lower than the long term value) lasting four years is appropriate, rather than Tenaska's prediction of two years.

Figure 1 [1]
Taylorville Energy Balance – Mode 1 (2x1)



1. All data (except Air Separation Unit power consumption) is based on the Taylorville Energy Center Heat and Material Balance with production rates aligned to the Siemens syngas yield guarantee for the nominal ambient conditions (53°F). (Reference 4) We refer to this in the text as Guaranteed Performance.
2. Air Separation Unit power consumption data provided in memorandum "TEC Facility Cost Report ASU Basis" dated March 15, 2010. (Reference 18)
3. Steam is calculated as the difference between energy of the process steam, shift gas cooler streams and the feedwater streams.
4. Produced Synthetic Natural Gas to Power Block

I. OVER-ARCHING OPERATIONAL ISSUES AND RISKS

The original outline for this Task Report included a section for discussing the over-arching operational issues and risks that will need to be addressed for successful operation of the Taylorville facility. These operational risks are discussed in detail in the Task 1 Report. Rather than repeating these lessons learned here, the reader is directed to that Task Report. The insights developed in that report have informed our review of the facility and conclusions presented in this Task Report.

II. FACILITY CONSTRUCTION SCHEDULE ASSESSMENT

MPR reviewed the construction schedule provided by Tenaska. The schedule has an overall duration of about 47 months from Final Notice to Proceed (December 15, 2010) to Commercial Operations Date (November 5, 2014). The schedule includes resources loading for craft man-hours only. Several key activities are not shown in the construction schedule, including:

- CO_2 sequestration infrastructure construction (either the geologic sequestration approach or the Enhanced Oil Recovery approach),
- Transmission line construction and upgrades to the transmission and delivery system,
- Gas interconnection construction,
- Water interconnection construction,
- Air Separation Unit construction is described only at a summary level (Tenaska has stated they are currently negotiating with a vendor who would be willing to meet the construction duration shown in the schedule),
- The required permits are not detailed explicitly in the schedule (the assumption is that required permits will not delay construction or startup activities).

Some of these interconnection projects are represented only as a milestone in the core plant schedule. We understand that these activities will be scheduled in more detail as the project is developed. The lack of detail in these areas adds to the risk that the actual construction duration will be longer than the duration described by the current schedule. One particular area that should be better developed is the construction schedule for the CO_2 sequestration infrastructure, since CO_2 sequestration is a key motivation for the development of the Taylorville project.

Assuming the external milestones to the schedule are met (e.g. permitting, approval of the project by the State legislature and issuance of Final Notice to Proceed), we conclude there is a high likelihood that the facility will commence commercial operations prior to 2016 as required by the Law.

We have structured our detailed review of the schedule in four areas as follows:

1. Critical Path Analysis
2. Activity Relationships and Durations
3. Activity Sequence
4. Resource Loading

The following sections will evaluate each of these areas in order.

A. Critical Path Analysis

A project critical path is defined as a series of activities that will delay the overall project completion date if the activities on the path are not finished by their scheduled dates. A delay in the finish date of any one activity will affect the completion dates of all subsequent activities and milestones, including the project completion milestone. In general, delays in critical path activities will extend construction duration and increase associated support costs even if the resources required to complete the project (e.g., manhours) do not increase. The concept of "float" as discussed below is the numbers of days that a particular activity can be delayed until it becomes a part of the critical path.

The project schedule has two primary critical paths with similar total float.

- Acid Gas Removal and Sulfur Recovery Unit procurement, and
- Gasifer engineering and construction

These two parallel critical paths tie together at plant startup since gasifier startup requires the acid gas removal, sulfur recovery, and gasifier silos to be complete and ready for operation.

The path with the lowest amount of total float runs through activities associated with Acid Gas Removal and Sulfur Recovery Unit procurement, installation and commissioning. These activities lead to 1st gasifier startup and tuning. The acid gas removal and sulfur recovery unit path has 25 work days of float (5 weeks) upon delivery of the Lurgi proprietary equipment. Prior to Lurgi equipment delivery, the acid gas removal and sulfur recovery unit path has 56 days of total float.

The second critical path runs through activities associated with the gasifier work silo from early engineering (piping and instrumentation diagrams, process flow diagrams, and piping design) through foundation construction, structural steel procurement and installation, gasifier installation, piping and electrical installation, and ending with gasifier startup and commissioning. The gasifier path has 33 work days of total float (6.5 weeks) beginning at the limited notice to proceed date for the project in June 2010.

The gasifier and acid gas removal system equipment have the longest lead times of any equipment for the project and are also two of the most complex work silos in the project. The long lead time for the Lurgi supplied equipment puts that equipment on a critical path for completion. Earlier equipment delivery could increase float for this path from 5 to up to 11 weeks.

The gasifier path is critical from early engineering due to the importance of timely engineering information to support procurement of equipment and materials. These materials are needed to avoid delays to the long duration activities associated with installation of foundations, structural steel, and mechanical gasifier components.

Note that the Power Block and the bulk of the balance of plant systems are off the critical path by significant amounts. In fact, the Power Block completion shows 330 days or 66 weeks of total float. This is due to the fact that the Power Block construction is relatively independent of the gasification and Syngas production facility throughout construction and the construction duration for the power facility is more than one year shorter than for the gasification/syngas facility.

Engineering, procurement of gasifier components, gasifier structural steel, and Lurgi proprietary equipment procurement are early project activities with high risk of extending the overall completion date of the project should durations extend longer than currently planned.

Construction activities are based on a 5-day-a-week by 10-hour-a-day, single shift calendar while engineering activities are on a 5-day-a-week by 8-hour-a-day calendar. These work schedules and associated overtime are consistent with typical construction practices. These calendars allow management room to accelerate work during the course of execution by using more aggressive calendars including working weekend days or working night shifts on critical activities. However, there are higher costs associated with more aggressive work calendars due to overtime and work inefficiencies associated with multiple shifts.

Any delays in the date of Final Notice to Proceed will push the project end date day for day but should not affect the overall construction duration, nor significantly affect the construction costs. Many factors could affect the final notice to proceed date including delays in air permit approval, project financing, or legislative approval. Delays in the date of the Limited Notice to Proceed (June 2010) could potentially be compensated for with increased engineering resources.

The 5 weeks of indicated total schedule float is insufficient for a project of this duration. At this stage of development for a project of this magnitude, MPR recommends at least 10% schedule contingency in the form of total float. For the 47 month schedule, this would result in about 20 weeks of total float.

Some additional inherent float in the current schedule may become apparent with further refinement of the schedule activities, durations, and relationships. Tenaska has claimed that many of the activity durations and activity sequencing in the schedule are conservatively estimated and hence there is implicit float not shown explicitly in the schedule. However, the magnitude of this implicit float cannot be known until the more detailed schedule development work is complete.

In summary, the critical paths identified by the schedule are judged to be reasonable. However, for the purposes of project modeling, MPR recommends utilizing a total project duration of 52 months starting at the final notice to proceed date.

B. Activity Relationships and Durations

The overall duration for the project and its major activities appear reasonable based on other similar projects. However, the level of detail is low in some critical activities, such as delivery and mechanical installation of equipment, which may cause durations to increase once the detailed implementation plan is developed. The relationships between equipment delivery dates guaranteed by vendors should be closely coupled to the required foundation pour/cure dates and the start of mechanical installation for that particular piece of equipment.

Instrumentation related activities are not sufficiently addressed in the schedule for most work silos. Tenaska has indicated that instrumentation is currently being included in electrical schedule activities and that they have not yet broken instrumentation out into separate activities. Instrumentation is usually the last work group to finish before startup and commissioning of a unit can begin and is therefore very important to establishing a reasonable work silo construction duration.

Notwithstanding the above areas of concern, we conclude that the project schedule includes realistic activity durations and appropriate activity relationships for the level of detail that this schedule represents. However, the lack of detail in the areas noted above create schedule risks that durations will need to be extended after further planning and schedule development.

C. Sequence of Activities

The sequence of activities for the project was reviewed to determine if the sequence was reasonable, achievable, and proceeds in a logical fashion that is consistent with good industry practices. While the sequence of activities was found reasonable for most work silos there were several areas of weakness.

In most work silos, the schedule calls for delivery of all equipment to be completed before mechanical installation begins. This is a conservative but unrealistic approach. In reality, equipment deliveries will occur over a period of months and installation can begin as soon as the first piece of equipment is delivered and its foundation is sufficiently cured to accept the equipment.

The startup schedule for the gasifier, acid gas removal and sulfur recovery units appear well developed with a detailed activity network describing step by step startup and commissioning activities. However, the current schedule does not have a logical sequence of system startup for balance of plant systems which creates risk that startup durations may increase and delay project completion. Our expectation is that these activities would be outside of the critical path, but the schedule should be revised to confirm this expectation. Further, the tie between plant startup and the balance of plant support systems is not developed in sufficient detail. Specifically, all of the balance of plant systems are tied as required predecessors to the gasifier startup milestone without regard for a sequence of startup. A sequence of startup is required to ensure that safety systems and required utilities are in place before each system can be started. For example, the diesel driven firewater system must be operational before electrical systems are energized to provide fire protection to equipment and potable water must be available for safety showers and eye wash stations before chemicals are delivered to the site.

These relationships are important for establishing required turnover dates for systems so that they do not affect the overall project duration. For example, the completion of startup of the coal handling system is not tied to gasifier startup. This missing logical tie results in misleading total float for the coal handling system and misleading required late finish dates. The lack of a logical startup sequence increases schedule risk and causes inaccurate float calculations for these systems.

As noted above, mechanical installation activities are also poorly developed at this stage with overly simple relationships between equipment delivery and mechanical installation. The lack of detail introduces risk that the mechanical installation activity duration may increase after more detailed planning.

With the exception of the areas noted above, the sequence of activities is reasonable and executable. As discussed above, while there are some non-critical path activities whose logical sequence should be corrected, we did not observe any critical path construction activities that have abnormal sequencing.

D. Schedule Resource Loading

The Level 2 schedule includes man-hour resources for all construction activities with a few exceptions. Startup and commissioning activities are not yet resource loaded with craft labor support hours. Engineering activities are not planned for resource loading, which is reasonable and consistent with typical practices in the power industry.

All resources in the schedule associated with construction activities are craft labor man-hours. These man-hours are derived from the project cost estimate which contains quantities, unit rates, and man-hours. The man-hours are then incorporated into the schedule, thereby creating crew sizes and activity durations. The activity durations generally appear to be reasonable as stated above. The unit rates used in schedule resource loading are reasonable compared to other large power projects (e.g., man-hours per cubic yard of concrete or per linear feet of piping).

One area of concern is that mechanical installation activities appear to be under-resourced. For example, "Gasifier #1 and Components Installation" has an overall duration of 550 days and 1927 man-days allocated. This indicates that there is, on average, a 3.5 man crew assigned to this activity over the course of the over two year duration. This is not reasonable for the scope and duration of this activity and creates concern that cost estimates for mechanical installation labor may not be reasonable.

Several of the resource curves generated using the "late start" for activities show unreasonable results. This is due to a lack of complete relationship logic for some aspects of the plant to startup and commissioning. For example, the "Concrete Craft" late start resource curve extends into August 2014. This is well into the startup and commissioning period and beyond the timeframe when all concrete work on site should be complete.

These resource leveling issues are cause for concern that indicated float values may not be accurate or feasible because activity delays may create unreasonable numbers of workers to be required at the end of the project.

In summary, the resource loading curves in the project schedule do not appear to be sufficiently mature in their detail. A lack of adequate logic to support resource leveling creates risk that the indicated schedule float is unrealistic and activities must, in fact, finish earlier than indicated to prevent an unrealistic buildup of manpower at the end of the project.

III. POWER DELIVERABILITY ASSESSMENT

MPR reviewed the interconnection study and the electrical one-line diagrams for the proposed facility. Our comments on each are provided below.

A. Interconnection Studies

MPR reviewed the System Impact Study performed by PJM (Reference 1). Earlier in the project development Tenaska applied for a separate interconnection with Midwest Independent System Operator (MISO), however the MISO application has been abandoned, and only the interconnection to the PJM will be sought. The key conclusions from the PJM System Impact Study are:

- The System Impact Study includes a short circuit analyses, reliability and contingency assessments, stability assessments, and overload assessments. This study assesses potential impacts of the project on the PJM transmission system.
- The System Impact Study provides preliminary results and final results are not expected to be provided until August of 2010 when PJM completes a Facilities Study. Consequently, any conclusions about the deliverability of the power and necessary upgrades should be considered preliminary.
- The project will construct 10 miles of new transmission lines to interconnect into the Kincaid Substation. These costs are included in the Facility Cost Report's capital cost estimate and are roughly $24 million.
- The Kincaid Substation will require upgrades to accommodate the interconnection. A preliminary cost estimate for this upgrade is $2.6 million.
- The study identifies several impacts to the PJM transmission system. Preliminary costs to address these impacts total about $5 million, assuming other planned projects bear a portion of the costs. If these other projects are not developed, the full costs of the upgrade is $8.8 million.
- The study identified several potential impacts to the MISO system (the MISO system will have impacts even though the interconnection occurs in the PJM system). These impacts will be assessed in the Facilities Study Report. Preliminary costs to correct these deficiencies are between $28 and $47 million.
- The study also identifies several Local Energy Deliverability issues associated with overloads in transmission during conditions when certain transmission lines are taken out of service. This has the potential to limit the facility's deliverability. However, the study does not identify any upgrades that would be required to

eliminate this potential constraint. Tenaska is currently working with PJM to understand these issues and expects clarification by August when the Facility Study is completed.

- The specific interconnection approach for the Air Seperation Unit (which Tenaska's intends to structure as a separate entity) has not been developed. A wholly separate interconnection to the transmission grid may be constructed, or a "net metering" approach may be used.

B. Electrical Design

MPR reviewed the electrical one-line diagram and switchyard layout for the facility (Reference 2 and 3). The arrangement of the switchyard has some disadvantages that do not allow easy maintenance of breakers while still providing the full availability of the facility. A more robust arrangement would be a ring-bus arrangement. In discussions with Tenaska on this topic, they have stated that they do not believe the additional cost of a ring-bus arrangement is justified by the additional maintenance flexibility and consequent facility availability. They have stated this arrangement is typical for Tenaska's other operating facilities. MPR's opinion is that a ring bus design is more appropriate for this type of facility.

IV. ENVIRONMENTAL IMPACT

The purpose of this section is to evaluate the environmental impact of the Taylorville facility with respect to consumption and emission rates.

With regard to fuel consumption, the Taylorville facility has a higher rate of coal consumption per MWh of energy produced as compared to a traditional pulverized coal facility. This is due to the power required to capture carbon and the energy losses related to converting coal to synthetic natural gas.

With regard to water consumption, the Taylorville facility performs very well compared to other facilities, largely due to its dry cooling system and zero-liquid discharge design. Another benefit of the zero-liquid discharge design is that there is no process wastewater leaving the facility.

Regarding air emissions (other than CO_2), the Taylorville facility performance is comparable to a traditional natural gas combined cycle facility and the emissions are much lower than a traditional pulverized coal plant.

Regarding CO_2 emissions, Taylorville is designed to capture approximately 49% of the CO_2 that it would have otherwise emitted when operating at 100% capacity, and more than 50% when operating at part load. Therefore, on an annual basis it is reasonable to expect Taylorville to exceed the 50% capture requirement (see further discussion in Section IV.D below). While the overall CO_2 generation rate is higher than traditional facilities (for the same reasons as the high fuel consumption), the CO_2 emitted per MWh is less than 45% of that which would be emitted by a pulverized coal plant without CO_2 capture.

A. Coal and Natural Gas Consumption

The coal and natural gas consumption rates for the Taylorville facility are shown in Table 1. On an energy basis, coal represents 70% of the fuel consumed by the Taylorville facility. However, due to the fact that a large portion of the energy in the coal is utilized in the process of converting the coal SNG and carbon capture and sequestration, only 54% of the electricity produced by the facility is from coal at full electric output (see Section V.A for a detailed analysis of the facility energy balance).

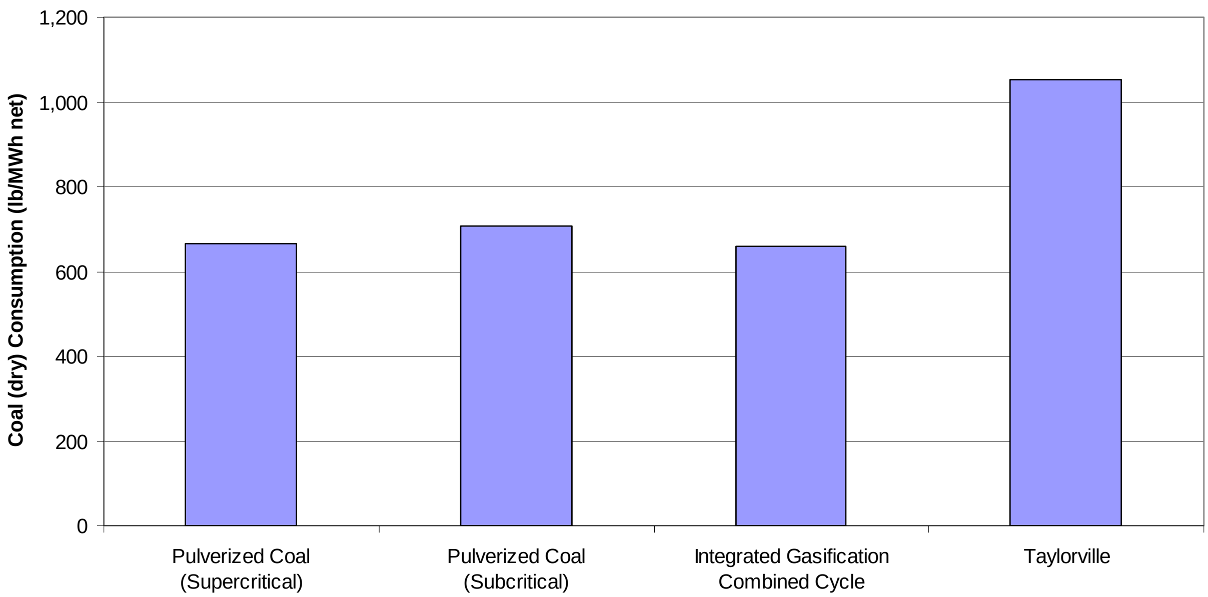
Table 1
Facility Fuel Consumption Rates

Rate	Coal	Natural Gas
MMBtu/hr (HHV)	4,030	1,763
lb/hr	341,583	-
tons/day	4,099	-
tons/year[2]	1,271,715	-

1. Data obtained from Guarantee Case material balance (Reference 4)
2. Assumed an 85% capacity factor for annual coal consumption

Figure 2 below shows the coal consumption rate of Taylorville in comparison to other facilities. Given the energy required to convert the coal to SNG and for carbon capture and sequestration, Taylorville's high coal consumption compared to traditional (non-carbon capture) coal fired power facilities is expected.

Figure 2
Coal Consumption



1. Data for Pulverized Coal and Integrated Gasification Combined Cycle facilities obtained from DOE/NETL (Reference 24).
2. Note that Taylorville coal consumption rate is based on the total amount of dry coal fed to the facility divided by 296 MW (which is the amount of net electricity produced by the coal fed to the facility as described in Section V.A).
3. Comparison facilities do not include carbon capture.

B. Water Consumption

Based on the Water Balance Diagrams in Attachment VII to Facility Cost Report Exhibit 2.1 (Reference 6), the estimated water consumption rate for Taylorville at full load is approximately 1,400 gpm, or 0.15 gal/kWhr. Figure 3 provides a comparison of the Taylorville water consumption rate to other types of generating facilities.

In comparison to other facilities, the water consumption for Taylorville is favorable. This is largely due to the dry cooling design selected by Tenaska. In a "dry cooling" system, the heat exchangers and condensers are air-cooled instead of water-cooled. This increases capital costs, but substantially reduces the water consumption rate of the facility. Also note that the water supply used by Taylorville is tertiary reclaim water from the city of Decatur (as opposed to freshwater) [Reference 7]. This approach virtually eliminates the withdrawal of water from freshwater sources (e.g. lakes, rivers or aquifers).

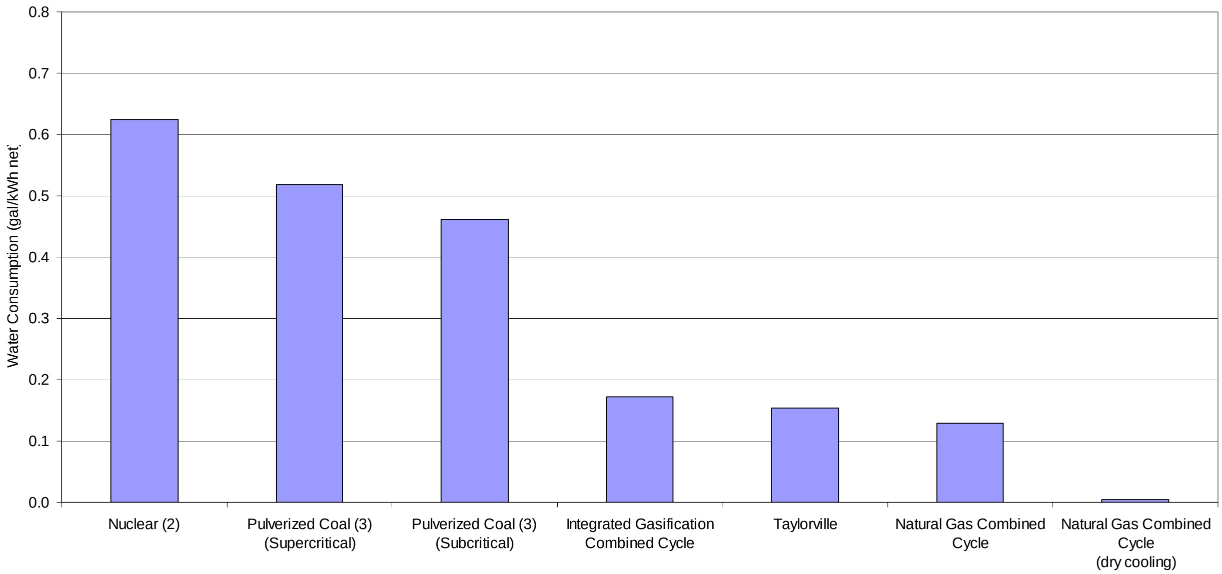
As shown in Figure 3, the water consumption rate for Taylorville is slightly higher than for Natural Gas Combined Cycle (with cooling towers). There are two factors inherent to the Taylorville design that increase its water consumption relative to other plant types:

1. A Natural Gas Combined Cycle plant does not have carbon capture, whereas Taylorville is a 50% carbon capture plant. Therefore, it is expected that the Taylorville water consumption rates on a per kilowatt-hour basis should be higher.

2. Compared to a Natural Gas Combined Cycle plant, the Taylorville facility has significantly higher process cooling demands. This is because the Taylorville facility is gasifying the coal and converting it to Synthetic Natural Gas (SNG) prior to burning it in the Combustion Turbine.

The Taylorville facility is also a Zero Liquid Discharge facility. This does not reduce the rate of water consumption, but it does significantly reduce the water withdrawal rate. Often water usage is evaluated both on a water withdrawal rate (i.e. the amount delivered to the plant) as well as the water consumption rate (i.e. the amount delivered to the plant less the amount returned to the supply source). Due to the Zero Liquid Discharge design, there is no stream of liquid discharge from the facility other than storm water discharge overflow.

Figure 3
Water Consumption[1]



1. Data for Taylorville obtained from Water Balance Diagrams in Attachment VII to Facility Cost Report Exhibit 2.1 (Reference 3). Data for other facilities obtained from DOE/NETL report (Reference 5).
2. All reference plant designs based on use of cooling towers (rather than once-through cooling) except for the Natural Gas Combined Cycle reference plant labeled "dry cooling".
3. Coal plant water consumption rates assume use of Wet Flue Gas Desulfurization

C. Air Emissions (not including CO_2)

The purpose of this section is to evaluate the air emissions from the Taylorville facility.

The largest emission source from the Taylorville facility is the exhaust of the combustion turbines. These emissions are comparable to a traditional combined cycle facility since the Taylorville design uses current emissions control technologies including Selective Catalytic Reduction and dry low NOx combustors. Good combustion controls will be used to control carbon monoxide, volatile organic material and particulate matter. The SO_2 is controlled by removing sulfur from the Synthetic Natural Gas prior to combustion as part of the gas clean-up step in the Synthetic Natural Gas plant.

For the purposes of comparison to an alternative Illinois coal-burning plant, the Prairie State Generating in Washington City, Illinois was selected. Prairie Island is a supercritical pulverized coal facility. It is currently under construction and has several climate control technologies, including low NOx burners, Selective Catalytic Reactor, Electrostatic Precipitator and Flue Gas Desulfurization. The final Prairie air permit issued on April 28, 2005 (Reference 8) has been used to obtain the values in Table 2.

The Taylorville data are from the updated air permit dated April 2, 2010 (Reference 9). As an additional point of comparison, Table 3 shows the emission limits of the Hunlock Natural Gas Combined Cycle Facility.

Table 2 compares the total annual air emissions, including startup and shutdown events. Taylorville is comparable to or outperforms the traditional coal facility for all pollutants except Mercury. Note however that the Taylorville plant still achieves a 90% mercury reduction.

The emissions from the Taylorville combustion turbines is superior to a Natural Gas Combined Cycle facility except for Carbon Monoxide (CO) emissions where it emits at 4.22 ppmvd as compared to the 4.0 ppmvd of the traditional combined cycle facility. Given the very small difference between these two values, the Taylorville performance with regard to Carbon Monoxide (CO) can be described as comparable to a traditional combined cycle facility.

Considering the positive performance of the Taylorville facility compared to a traditional coal plant and a natural gas combined cycle plant, we do not have any recommendations for improvement to the Taylorville design with regard to air emissions.

Table 2
Maximum Allowable Annual Emissions from Air Permit[1] (tons/yr)

	Taylorville	**Prairie – Adjusted[2]**	**Prairie**
CO	1,237	2,838	3,912
VOM	92	94	130
NOx	222	1,655	2,282
PM10	163	829	1,143
SO2	646	4,303	5,933
H2SO4	5	118	163
Hg	0.10	0.05	0.07
Pb	0.22	0.21	0.30

1. Annual emissions limits consider all facility emissions sources and include estimated startup/shutdown emissions.
2 ."Prairie - Adjusted" data has been scaled by the net output of the facilities (544/750) to provide a useful comparison to Taylorville.

Table 3
Comparison of Taylorville to Natural Gas Combined Cycle Facility

	Taylorville[1]	Hunlock
CO	4.22 ppmvd	4.0 ppmvd
VOM	1.04 ppmvd	1.20 ppmvd
NOx	2.0 ppmvd	2.5 ppmvd
PM[2]	0.0049 lb/MMBtu	0.0141 lb/MMBtu
SO2	0.00074 lb/MMBtu	0.0030 lb/MMBtu
H2SO4	0.00016 lb/MMBtu	0.0009 lb/MMBtu
Hg	0.0464 lb/hr	Note 3
Pb	0.0212 lb/hr	Note 3

1. Taylorville data are for combustion turbine emissions only
2. Taylorville PM is PM_{total} whereas Hunlock PM is just PM10 (this is a conservative comparison because the Taylorville PM_{total} is still lower than the Hunlock PM10).
3. Mercury and lead emissions data are not available for the Hunlock facility which is consistent with our experience that natural gas facilities generally do not have monitored or regulated mercury or lead emission limits. The mercury and lead emissions limits for Taylorville are likely higher than the expected emissions from the facility as discussed in Section IV.E.3 of this report.

D. CO_2 Emissions

Tenaska is developing two possible sequestration approaches for Taylorville. For the purposes of this report, these approaches have been labeled Sequestration Approach #1 (Denbury Pipeline) and Sequestration Approach #2 (Saline Aquifer). Sections 1 and 2 describe these approaches and Section 3 provides a comparison between the two.

1. Sequestration Approach #1 – Denbury Pipeline

Tenaska is pursuing an opportunity to sell CO_2 for Enhanced Oil Recovery (EOR). This option requires that a pipeline be built from Taylorville to the Gulf Coast Region of the US. Christian County Generation LLC has entered into a "Carbon Dioxide Offtake Agreement" with Denbury Onshore LLC (Reference 10). This agreement provides terms for the operating plan, CO_2 quality, price and other commercial terms. Selling CO_2 for Enhanced Oil Recovery (EOR) represents the lowest cost option for CO_2 sequestration; however, this approach is contingent upon the construction of a CO_2 pipeline. In order to justify the construction cost for a CO_2 pipeline, at least one additional CO_2 supply within the region will need to be identified. This necessity is addressed in Section 3.4 of the offtake agreement (Reference 10):

> "Owner and Offtake will cooperate in connection with the identification of and entering into an agreement with CO_2 Pipeline Operator for the construction and operation

of a CO_2 pipeline. It is anticipated by the parties that the CO_2 Pipeline Operator may require that an additional source of CO_2 (in addition to [Taylorville]) be identified which commits to provide CO_2 to the CO_2 Pipeline such additional volume of CO_2 as is reasonable necessary to make the construction and operation of the CO_2 Pipeline commercially viable."

2. Sequestration Approach #2 – Saline Aquifer

Recognizing that Sequestration Approach #1 requires the construction of a CO_2 pipeline by a third party, Tenaska is also pursuing an option to sequester the CO_2 in the Mount Simon saline aquifer which is below/adjacent to the Taylorville facility. A detailed study of this option was performed by Schlumberger Carbon Services and it includes seismic studies, potential injection points, plume modeling, monitoring plans and permitting (Reference 11). This study concludes that the Mt. Simon formation is capable of sequestering all of the carbon from the Taylorville facility for the next 30 years and that there will be satisfactory containment within the aquifer.

Schlumberger Carbon Services also created a Cost Report to evaluate the capital and operating costs associated with sequestering carbon in the Mt. Simon formation (Reference 12). The estimated capital costs are $44M. Total operations and maintenance costs are $19M over the life of the facility or approximately $640,000 per year. Note that these costs do not include compression of the CO_2; instead, the operations and maintenance costs only represent water sampling, well-head sampling and seismic/well work orders. The cost of CO_2 compression (namely, the additional parasitic load) applies to both sequestration approaches and is reflected in the net plant electrical output. In addition to the capital and operations and maintenance costs, the report also listed approximately $25M in decommissioning costs, which includes 10 years of post-sequestration monitoring.

3. Likely Approach to Sequestration

Sequestration Approach #1, the Denbury pipeline, is preferred by Tenaska because it has lower capital costs, provides an additional source of revenue and lowers the risks associated with permitting and long-term storage of carbon in a saline aquifer. However, given that construction of the Denbury pipeline requires additional CO_2 sources in the region, there is a significant amount of uncertainty to this approach.

Due to the uncertainty with the Denbury pipeline, Tenaska has simultaneously pursued sequestration in the Mt. Simon formation. However, all of the data in the Facility Cost Report are based on the Denbury pipeline. Given the uncertainty, it would be reasonable to plan that, at least initially, the facility would rely on the Mt. Simon formation. This would result in an increase of $44M in capital costs, $0.6M per year increase in operations and maintenance costs, and a reduction of $8-9M per year in revenue.

Tenaska provided the following in response to MPR/BP inquiry regarding whether Tenaska was planning to simply vent CO_2 during initial operations (Reference 13):

> "We are not intending to vent CO_2 during the initial operations. For purposes of its economic analysis, we suggested to Beck [the Independent Engineering] that it assume that the Denbury pipeline would not be completed (and therefore we would have a disposal cost instead of revenue from Denbury) until two or three years after our commercial operation date. This is purely conservatism on our part, because we recognize that unless the federal bonus allowance incentives (i.e., Section 780 of the Kerry Boxer bill) are legislated we would not be able to pay Denbury enough to build the pipeline until it is assured of having at least one other major CO_2 producer operating in the Midwest. Our plan during any such period is not to vent, however. Our plan is to inject in the Mount Simon formation, and we have a development schedule for the sequestration field that supports this plan."

If neither of the sequestration options described above were ready when the facility begins commercial operation, then Taylorville would be unable to sequester 50% of the CO_2 that would otherwise be emitted. According to "the Law", Tenaska would then be required to purchase up to $15,000,000 per year in CO_2 off-set credits.

4. CO_2 Emission Rates

The overall CO_2 generation rate for Taylorville is 1,930 lb/MWh or 3.9 million tons/year (at 85% Capacity Factor). A summary of the overall CO_2 generation, emissions and sequestration is provided in Table 4. As shown in Table 4, during "Mode 1" operation (full plant output), 49.4% of the CO_2 that would otherwise be emitted is captured and sequestered. While this is below the 50% requirement stipulated by the Law, it is reasonable to expect that the facility will meet the requirement over the course of the year. As shown in the Task 7 report, the facility is predicted to run some portion of the year in Mode 1 and some portion in Mode 2. During Mode 2 operation (half load), the carbon capture percentage increases to approximately 62%. Therefore, over the course of the entire year, the facility is likely to exceed 50% carbon capture even though during the primary operating mode at 100% of rated capacity the facility will only capture approximately 49.4% of the carbon.

Decreased efficiency in the Synthetic Natural Gas block would result in a decrease in the rate of carbon capture. For example, if the coal contains a higher than planned amount of water, this would result in a lower carbon capture percentage (see Section V.A.3 for a discussion of coal drying).

Table 4
CO_2 Emission and Sequestration Rates[1]

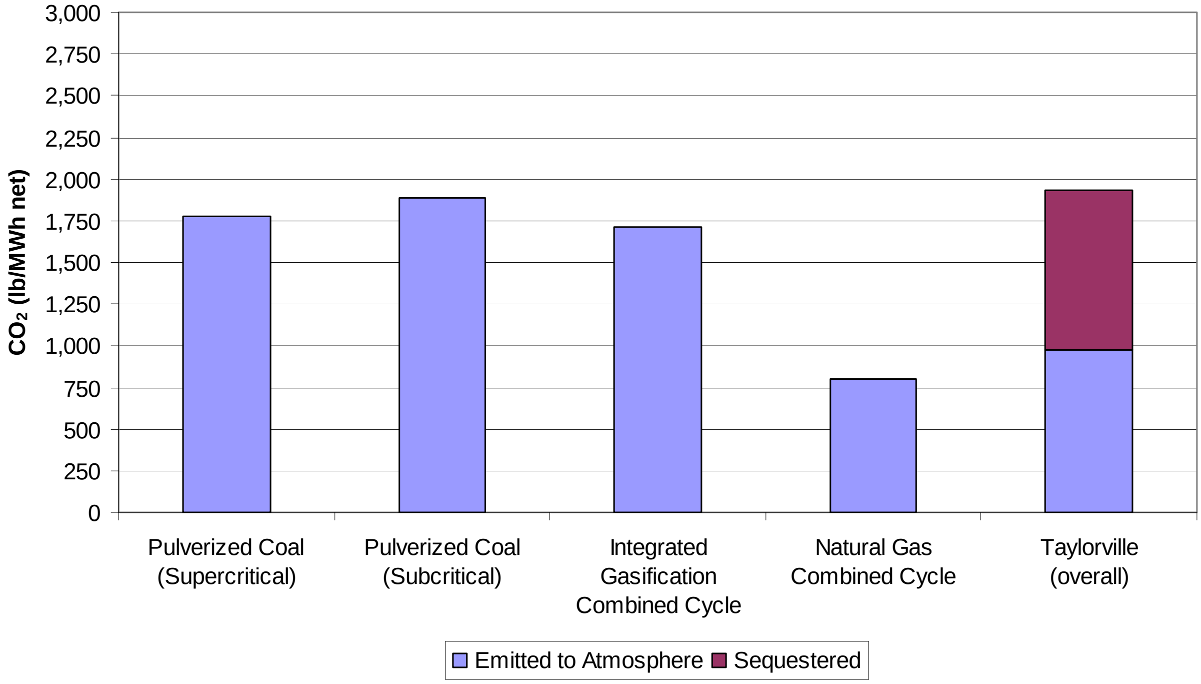
839,199	lb/hr CO_2 equiv from Coal feed
210,931	lb/hr CO_2 equiv from Natural Gas feed
518,723	lb/hr CO_2 sequestered
531,407	lb/hr CO_2 emitted
49.4%	Percent Capture

1 Based on Mode 1 operation at guarantee case. Data obtained from material balance (Reference 4)

2 Calculated using carbon content specification in Siemens contract (Reference 14).

Figure 4 below provides a comparison of the CO_2 emissions of Taylorville to other types of generation. The blue columns in this graph show the CO_2 emissions to the atmosphere; the red columns show the CO_2 that is sequestered. Taylorville has been designed for approximately 50% CO_2 capture. At this level, Taylorville emits approximately 23% more CO_2 than a Natural Gas Combined Cycle facility and approximately 45% less than the CO_2 that would be generated from a more traditional coal fired power plant without carbon capture and sequestration (on a per MWh basis).

Figure 4
CO_2 Emissions[1,2]



1. Data for other facilities obtained from DOE/NETL (Reference 5) and does not include carbon capture.
2. Taylorville emissions based on Mode 1 operation at 100% output data from material balance (Reference 4)

E. Solid-waste (including potentially salable waste streams)

1. Solid-waste (Slag and Sludge)

The slag generation rate for Taylorville is approximately 18,000 lbs/hr or 68,000 tons/year. Although it is possible that the slag produced by Taylorville could be salable, Tenaska's operations and maintenance estimate does not show the slag as a source of revenue. If not sold, slag will be deposited in an on-site landfill.

The sludge generation rate for Taylorville is approximately 15,000 lbs/hr or 57,000 tons/year. Unlike the slag, there is no expectation that sludge is salable. Sludge will be deposited in an on-site landfill.

2. Sulfur

The sulfur generation rate for Taylorville is approximately 8,000 lbs/hr or 30,000 tons/year. Tenaska intends to sell the sulfur and presently shows it as a $2.6M revenue stream in 2010 dollars for the first year of operation.

3. Mercury

Mercury is controlled in the process by removing it during the synthetic natural gas production and clean-up so that very little mercury is present during combustion. Due to the relatively low concentrations of mercury in the coal, mercury is not contained as a separate line in the material balance for the Taylorville facility. Therefore, there is limited documentation regarding the flow of mercury into and out of the Taylorville facility. Upon request, Tenaska provided the following description of mercury in the system.

> "With respect to Mercury (Hg), the TEC design assumes that the plant could see 1.44 lb/d; this value was developed from an assumed maximum coal input of 7,200 sTpd and that this coal would contain 100 ppbw Hg. This concentration is consistent with internal coal analyses and with public domain studies for high-sulfur bituminous coals.
>
> Siemens Gasification has provided estimates documenting their expectations of how Hg will distribute in the TEC process. However, these estimates are based on limited data from different coals. They are shown in the Table below.

Product	Slag	Filter Cake Solids	Wastewater Blowdown to Treatment (ZLD)	Raw Unshifted Syngas
Distribution (% input)	**< 10%**	**>80%**	**<5%**	**<0.05%**

> Assuming these are correct, the approximate flow rates and concentrations are:

Product	Slag	Filter Cake Solids	Wastewater Blowdown to Treatment (ZLD)	Raw Unshifted Syngas
Stream Flow (lb/hr)	68,334	624,801	38,256	1,781,342
Hg Flow (lb/hr)	0.006	0.003	0.05097	0.00003
Hg Concentration (ppbw)	87.8	4.8	1332.34	0.02

> In the slag and Filter Cake Solids, the mercury is expected to exist as mercuric sulfide (HgS) which is a stable compound for long term storage. As mentioned in the response to questions 2 & 3, the slag and filter cake waste will be trucked to a properly-permitted on-site landfill.

However, there is significant uncertainty in this distribution. Eastman Chemical and the DOE point out this uncertainty in section 4.2 of the study document titled "The Cost of Mercury Removal in an IGCC Plant," issued September, 2002. Quote: "At the Polk County plant, approximately 40 percent of the mercury in the coal was unaccounted for..." Furthermore, the Eastman/DOE study's data is based on much higher mercury levels in the syngas than Siemens' distribution would indicate.

Thus, the TEC process has been designed (very conservatively) to assume that all of the Mercury distributes to the syngas. And the majority of the mercury will be removed from this stream across beds filled with activated carbon that is impregnated by sulfur. This technology has been used successfully in natural gas treating and syngas treatment at the Eastman Chemical Plant in Kingsport, TN. If this is the case, the mercury absorption rate increases to 0.06 lb/hr.

Lurgi has indicated that the syngas from the outlet of the activated carbon beds will contain less than 10 ppbv Hg. Thus, assuming all mercury distributes to the syngas, these beds will remove greater than 95% of the mercury from the stream. This sorbent will be changed out periodically due to pressure drop accumulation or contaminant saturation. The spent sorbent will be characterized for proper disposal. Like the other areas, the mercury species will be mercuric sulfide (HgS). It is likely that the material will be trucked to an off-site landfill (possibly a hazardous landfill if necessary) or reclaimer. Tenaska may also evaluate the option to process the spent adsorbent (which is carbon) through the gasifier with the coal.

Furthermore, any residual mercury in the syngas is likely to be removed (condensed) in the Rectisol Unit. Lurgi has published a paper that discusses this phenomena. Any condensed mercury is expected to accumulate in the gas cooling and pre-wash sections, which is experienced in the Sasol Rectisol units. The condensed mercury does not have an affect on the Rectisol process and can be collected and removed during periodic outages."

We have reviewed this description of mercury flow through the Taylorville facility and concluded it is reasonable. This description indicates that at least 90% mercury removal will be achieved and likely a much higher removal rate. The Panhandle Eastern Pipe Line tariff specifies that gas sold into the pipeline shall not contain any hazardous materials, so the removal of mercury will be critical.

Note that the flowrates provided above are based on a 3 gasifier design and should be reduced by approximately 33% to account for the change to a 2 gasifier design.

V. PLANT PERFORMANCE

The purpose of this section is to summarize the expected facility performance. The numbers presented in this section are based on the "Guaranteed Condition" and are net of the parasitic loads including the Air Separation Unit. A summary of the key conclusions is as follows.

At full load, the facility is expected to consume 4,030 MMBtu/hr of coal producing, 2,351 MMBtu/hr of Synthetic Natural Gas that is fed into the Power Block along with 1,763 MMBtu/hr of purchased pipeline natural gas. The net power produced from the Power Block is 544 MW (net of Air Separation Unit).

The 58 MW load required by the Air Separation Unit is not included in Tenaska's auxiliary load estimate, because the Air Separation Unit is currently envisioned to be structured as a third-party "over-the-fence" contract. While it is unclear to MPR and Boston Pacific if this arrangement would be allowed in the structure of the proposed Sourcing Agreements, it should be understood that the facility consistently requires 58 MW of power in order to operate, and this power will not be available to existing Illinois ratepayers.

Tenaska has assumed the performance of the SNG Block will exceed the vendor's guaranteed performance. We recommend that the estimated performance be based on the vendor's guarantee point.

While the performance of the individual process plants for the SNG Block and the Power Block are similar to other gasification facilities, the overall plant efficiency is less than a clean coal facility design based on a traditional Integrated Gasification Combined Cycle. A key difference between these two designs is the methanation reactors in the hybrid design which diverts some of the energy from the gas stream to steam energy in the reactors. The Power Block converts the steam energy to electricity at a lower efficiency than the energy in the SNG stream.

Lastly, Tenaska's predictions of facility availability appear to be overly optimistic, and a more realistic projection is described in Section V.B.

Detailed discussion of the plant performance is provided in the following sections.

A. Plant Output

The SNG Block is designed with two Siemens Fuel Gasifiers (SFG-500) sized to consume 4,030 MMBtu/hr of coal (Reference 15). Oxygen for the gasification process is provided from an Air Separation Unit. The raw syngas exiting the gasifier is then processed through Air Liquide's shift reactor, acid gas removal unit (Rectisol), sulfur recovery unit, and methanation unit to produce Synthetic Natural Gas and steam.

The Power Block is designed to produce approximately 710 MW of gross electrical output from two combustion turbines, two heat recovery steam generators, and one steam turbine. The combustion turbines are natural gas burning Siemens "F Class" heavy-duty, single-shaft turbines (SGT6-5000F, Reference 16). The exhaust energy from the combustion turbines is directed to two heat recovery steam generators that provide steam to the Power Block steam cycle. Steam from the gasification process is also directed to the heat recovery steam generators. The steam is then sent to a tandem compound, single reheat General Electric steam turbine (Reference 17).

WorleyParsons prepared material balances of the Taylorville facility as part of the Front-End Engineering and Design Study (Reference 4). These material balances detail the major streams entering and leaving the plant (including coal, natural gas, and electricity). The values, presented in Table 5, provide a summary of the most significant performance numbers from the Taylorville facility. Figures 5 and 6 provide a visual representation of how these streams relate.

Table 5
Plant Performance Summary [1,2]

Parameter	**Units**	**Mode 1** [3]	**Mode 2** [4]
Coal Feed	MMBtu/hr	4,030	4,030
Net Synthetic Natural Gas Produced	MMBtu/hr	2,351	2,351
Synthetic Natural Gas Sold	MMBtu/hr	0	294
Pipeline Natural Gas Feed to Power Block	MMBtu/hr	1,763	0
Gross Electrical Output	MW	710	388
Auxiliary Load [5]	MW	166	162
Net Electrical Output	MW	544	226
Fuel Feed Percent Coal	%	70	100
Percent Power from Coal	%	54	100

1. Illustrations of these values are presented in Figures 5 and 6.
2. All numbers presented in this summary are based on the nominal 100% (vendor guaranteed) case provided by WorleyParsons (Reference 4).
3. Mode 1 is when the Gas Block and Power Block are at full load. (discussed further in Section V.A.2).
4. Mode 2 is when the Gas Block is at full load and the Power Block is at reduced load, running one combustion turbine (discussed further in Section V.A.2).
5. Auxiliary Loads include power required from Air Separation Unit.

Figures 5 and 6 provide a useful means to compare Taylorville performance numbers between modes and with other facilities. The following observations can be drawn from these figures.

- When the entire plant is at full load (Mode 1, Figure 5), 70% of the fuel is from coal while 30% is pipeline natural gas.

However, after accounting for the parasitic loads required to operate the gasification and CO_2 compression facilities, the net electric output capacity at full load is only 54% from coal, while the other 46% is from the natural gas.

- When Taylorville is operating in at half load Mode 2 (Figure 6), the fuel input to the facility is entirely coal. Furthermore, in Mode 2 a relatively small portion of the gas output (13%) is available for sales.

  Tenaska has stated that a key advantage of the hybrid-type design is the flexibility in output represented by Mode 2. However, given the relatively small amount of the natural gas available for sale, there appears to be limited benefit in the sale of Synthetic Natural Gas in Mode 2.

- The efficiency of the SNG Block is approximately 71% for both Mode 1 and Mode 2 [1]. The Power Block efficiency is 48% for Mode 1 and 45% for Mode 2 [2]. The efficiencies of these individual plants are reasonable and on target with typical Synthetic Natural Gas plants and combined cycle plants.

- Individually, the SNG and Power Block have appropriate efficiencies, but when combined, the heat rate of Taylorville is significantly worse than a typical Integrated Gasification Combined Cycle design.

  The overall heat rate of the entire Taylorville facility approximately is 10,643 BTU/kWh (Reference 4). The Integrated Gasification Combined Cycle facilities with carbon capture as described in a DOE/NETL study have a heat rate of about 10,645 BTU/kWh (Reference 5). These heat rates are remarkably close. However, this comparison can be misleading because the Taylorville heat rate is improved by the pipeline natural gas that is being fed directly into the Power Block, which has minimal auxiliary load associated with it.

  A more appropriate comparison is to compare the coal portion of Taylorville against a standard Integrated Gasification Combined Cycle facility with carbon capture and sequestration. Taylorville's Mode 1 "coal heat rate" is approximately 13,625 BTU/kWh[3], as compared to a standard Integrated Gasification Combined Cycle facility heat rate of 10,645 BTU/kWh. A key difference between these two designs is the methanation reactors in the hybrid design which diverts some of the energy from the gas stream to steam energy in the reactors. The Power Block

---

[1] SNG Block efficiency is defined as the plant outputs (steam and Synthetic Natural Gas) divided by the inputs (coal, auxiliary electrical load and Air Separation Unit electrical load) multiplied by 100.

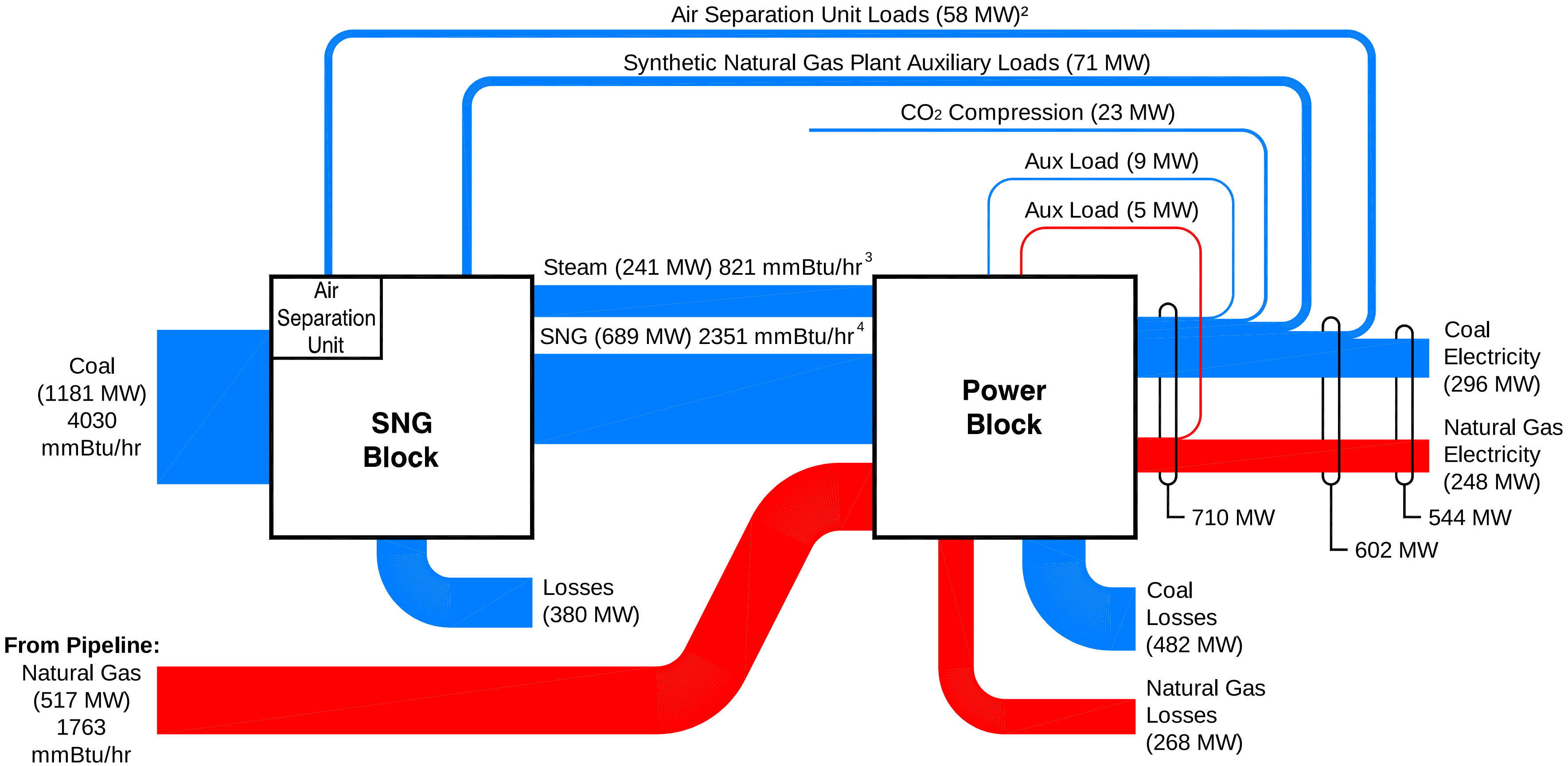
[2] Power Block efficiency is defined as the gross output, less auxiliary loads internal to the power block, divided by the inputs (Synthetic Natural Gas, steam and pipeline natural gas) multiplied by 100.

[3] Mode 1 coal heat rate is defined as the total as-received coal energy entering the SNG Block divided by the fraction of electricity produced from coal (See Figure 4 for the fraction of electricity of coal versus natural gas).

converts the steam energy to electricity at a lower efficiency than it converts the energy in the SNG stream to electricity.[4]

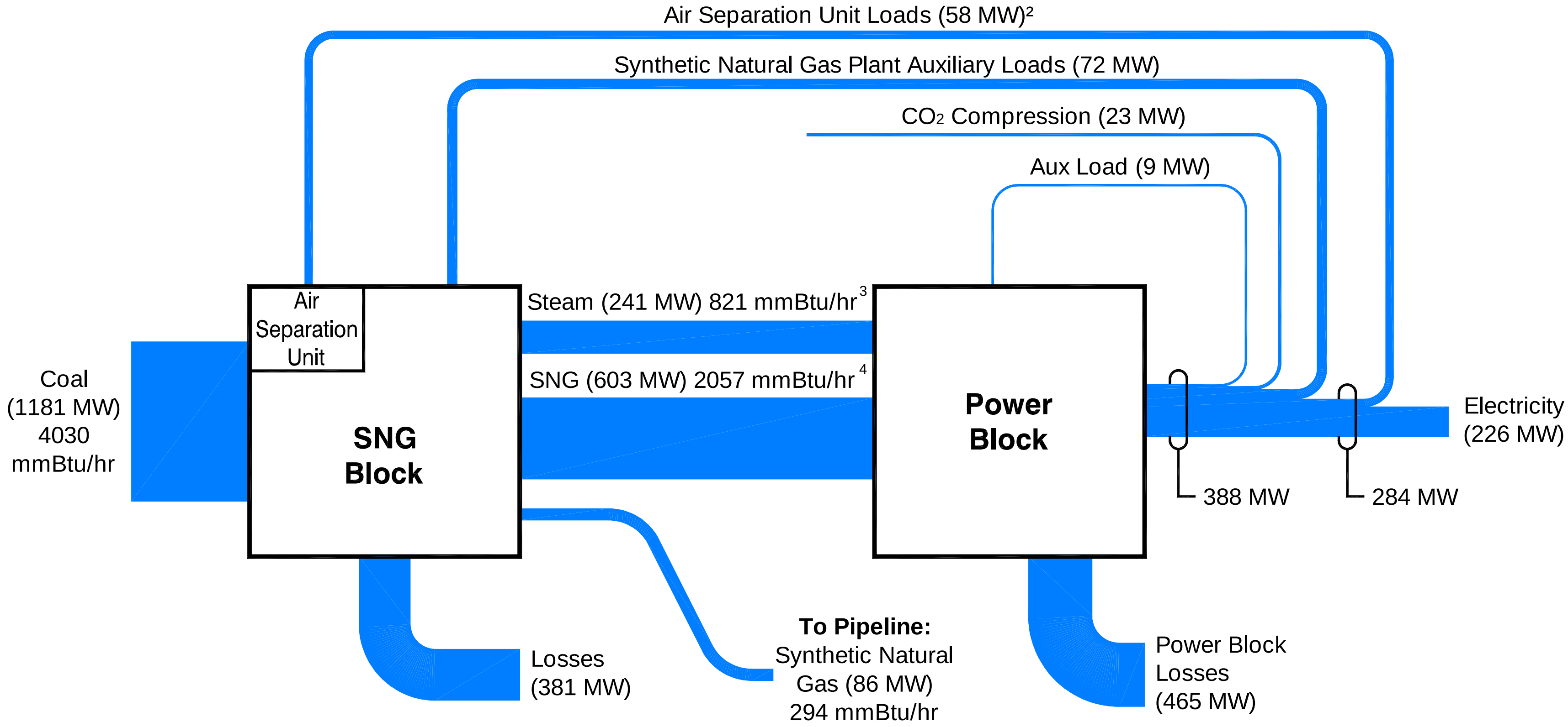
[4] While the methanation reactor is likely to be a large contributor to the difference in these heat rates, there may also be additional design differences between the facility presented in Reference 5 and the Taylorville facility. An accurate quantification of the potential heat rate improvements should be provided by the Tenaska team.

Figure 5 [1]
Taylorville Energy Balance – Mode 1 (2x1)



1. All data (except Air Separation Unit power consumption) is based on the Taylorville Energy Center Heat and Material Balance with production rates aligned to the Siemens syngas yield guarantee for the nominal ambient conditions (53°F). (Reference 4).
2. Air Separation Unit power consumption data provided in memorandum "TEC Facility Cost Report ASU Basis" dated March 15, 2010. (Reference 18).
3. Steam is calculated as the difference between energy of the process steam, shift gas cooler streams and the feedwater streams.
4. Produced Synthetic Natural Gas to Power Block

Figure 6 [1]
Taylorville Energy Balance – Mode 2 (1x1)



1. All data (except Air Separation Unit power consumption) is based on the Taylorville Energy Center Heat and Material Balance with production rates aligned to the Siemens syngas yield guarantee for the nominal ambient conditions (53°F). (Reference 4).
2. Air Separation Unit power consumption data provided in memorandum "TEC Facility Cost Report ASU Basis" dated March 15, 2010. (Reference 18).
3. Steam is calculated as the difference between energy of the process steam, shift gas cooler streams and the feedwater streams.
4. Produced Synthetic Natural Gas to Power Block

1. Guaranteed Performance

Equipment vendors typically provide guarantees on the performance of major equipment. Since commercial penalties are tied to the performance guarantees, vendors often include margin in guaranteed values, and it is not uncommon that the as-tested performance will exceed the guaranteed performance. The performance figures that Tenaska has chosen to use in the Facility Cost Report and Front-End Engineering and Design Study are based on their expectation that vendors of the major equipment in the SNG Block, Siemens and Lurgi, will exceed their performance guarantees by 10%. Table 6 summarizes the key performance metrics at both the guarantee point, and at 110% of guarantee.

Table 6
Comparison of Performance at Guarantee and 110% of Guarantee Conditions during Mode 1 Operation [1]

Performance Metric	Units	Guaranteed Performance	110% of Guaranteed
Coal Feed	MMBtu/hr	4,030	4,433
Net Synthetic Natural Gas Produced	MMBtu/hr	2,351	2,592
Pipeline Natural Gas Feed	MMBtu/hr	1,763	1,522
Gross Power Produced	MW	709.8	716.2
Auxiliary Loads	MW	107.9	114.0
Net Power Produced [2] (without Air Plant auxiliary load)	MW	601.9	602.2
Net Power Produced [2] (with Air Plant auxiliary load)	MW	544.3	544.6
Fuel Feed Percent Coal	%	70	74
Percent Power from Coal	%	54	61
Total Plant Heat Rate [3]	Btu/kWh	10,643	10,934

1. These cases are being compared when both the SNG and Power Block are running at full load.
2. Auxiliary loads are discussed further in Section V.A.3.
3. Total Plant Heat rate defined as energy in (coal and pipeline natural gas) divided by energy out (net power).

Considering that this is the first time Siemens has demonstrated this scale and type of gasifier, we do not believe it is reasonable to assume that the facility will exceed its guarantees by this margin. A more reasonable expectation is to evaluate Taylorville on the basis of the guaranteed performance values.

2. Definition of Operating Modes

There are three modes of operation that the Taylorville facility expects to operate in: producing excess electricity, producing excess Synthetic Natural Gas, or operating fully on pipeline natural gas. The decision of which mode to operate in is based on availability and the relative economics of the natural gas and electricity markets. The three modes are defined as follows:

> Mode 1 (2x1) – Two gasifiers operating at Taylorville's guaranteed gasifier output, two combustion turbine generators and one steam turbine generator at base load, resulting in gross electrical generating capacity of 710 MW and net electrical generating capacity of 544 MW (net of Air Separation Unit). A net import of natural gas is required for this mode of operation. All available Synthetic Natural Gas is used for power production.
>
> Mode 2 (1x1) – Two operating gasifiers at Taylorville's guaranteed 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 388 MW, net electrical generating capacity of 226 MW (net of Air Separation Unit) and 294 MMBtu/hr of Synthetic Natural Gas for sale.
>
> Mode 3 (Operation only on pipeline natural gas) – No operating gasifiers, two combustion turbine generators and one steam turbine generator operating at base load. All gas is imported from the natural gas pipeline for this mode of operation. No Synthetic Natural Gas is produced. No carbon dioxide is captured and sequestered.

Most of our evaluations for the facility are based on Mode 1, as the primary purpose of this facility is to produce clean coal electricity for Illinois, not to produce Synthetic Natural Gas for the pipeline or operate fully on pipeline natural gas.

As apparent in Figure 6, Mode 2 does not to generate enough Synthetic Natural Gas to provide a large benefit. Mode 2 is better understood as the mode of operation required to keep the gasifiers running at full load as much as possible. Gasifiers do not respond well to load changes, so it is important to keep them at a steady load.

It is expected that Synthetic Natural Gas will be produced whenever possible, either for power or for sale. With this reasoning, operation in Mode 3 should only occur when the SNG Block is in an outage but the Power Block is still available and dispatched to run.

One important aspect of these modes of operation is the carbon capture characteristics of each. As discussed in Section IV.D, in Mode 1 the facility captures 49.4% of the carbon that would have otherwise been emitted. In Mode 2, the facility captures 62%. If the facility is operated in Mode 3, it would capture none of its carbon. The effective carbon footprint of the facility over the course of a year is therefore a result of the amount of time the facility is dispatched in each of these modes. The 50% carbon capture requirement of the Law could have the effect of placing operational limitations on the facility.

3. Auxiliary Loads and Internal SNG Consumption

WorleyParson's "TEC Performance Aligned with Siemens Syngas Guarantee" (Reference 4) provides expected auxiliary loads for the entire plant. Table 7, below, summarizes the expected auxiliary loads.

Table 7
Expected Auxiliary Loads at Taylorville Energy Center [1]

Equipment	Mode 1 (MW)	Mode 2 (MW)
Power Block	14	9
CO_2 Compression	23	23
SNG Block	71	72
Subtotal	108	104
Air Separation Unit	58	58
Total Auxiliary Loads	166	162

1. All auxiliary loads are based on the 100% (guaranteed) case (Reference 4)

The 58 MW load required by the Air Separation Unit is not included in Tenaska's auxiliary load estimate (Reference 4). This is because the Air Separation Unit is currently envisioned to be structured as a third-party "over-the-fence" contract, where the power required to operate the Air Separation Unit would be handled commercially outside of the Taylorville project. This would allow the project to sell an additional 58 MW of power at the higher subsidized electric rate, while the third party would purchase power at the lower prevailing rate of the electric grid. While it is unclear to MPR and Boston Pacific if this arrangement would be allowed in the structure of the proposed Sourcing Agreements, this parasitic load is required to operate, and this power will not be available to existing Illinois ratepayers.

The SNG Block uses internal Synthetic Natural Gas to dry the incoming coal. This internal consumption may vary depending on the initial moisture content of the coal. The moisture content of the coal may vary for two significant reasons: (1) Taylorville has multiple potential sources of coal, and (2) the various sources of coal will require washing techniques to remove sulfur. The unwashed moisture content in the coal study appears to be between 8% – 16% (Reference 19). This shows that even before washing, there is a potential for higher levels of moisture. Once washing is included, the consequent drying required becomes significant. For example, increasing the moisture content from 10% to 20% would decrease the Synthetic Natural Gas output of the facility by roughly 90 MMBtu/hr, due to the increased drying needs. Note that the electrical output of the facility would remain relatively unchanged, since the difference in Synthetic Natural Gas would be made up by increased use of pipeline natural gas. However, the efficiency of the process decreases due to increased internal consumption and the fraction of carbon captured and sequestered is reduced because less Synthetic Natural Gas is being fed to the Power Block.

B. Plant Availability and Capacity Factor

Tenaska provides availability projections in Section 5.5 of the Facility Cost Report. Tenaska also uses capacity factor estimates in the financial model. It is useful to consider availability and capacity factor separately for the two portions of the Taylorville Energy Center: the SNG Block and the Power Block.

The output of each facility is a function of both the facility availability and capacity factor. Plant availability is a measure of the hours that the plant is capable of operating (all hours less facility outages). Capacity factor describes how much the facility is requested to operate, and includes effects due to the economic dispatch of the facility.

1. SNG Block

It is expected that the SNG Block will be operated at baseload all of the time (except for outages). Therefore, the annual production of the gasification plant (capacity factor) is best represented with availability.

Long-term Availability. In a report titled "Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability" (Reference 20), EPRI describes the expected availability of an Integrated Gasification Combined Cycle facility. The report suggests that a plant can expect a long term availability of approximately 85% for a single train gasification facility.

Tenaska is expecting the long-term availability of Taylorville to average 85%, which matches the EPRI expected availability. This is an acceptable availability considering the facility does not have a spare gasifier or any other redundancy for the major pieces of equipment.

In previous revisions of the design, Taylorville reported higher availability (92%) in the Tenaska DOE Part II Response (Reference 21). This higher availability was because the design included a spare gasifier and additional redundancy in other sections of the plant. By removing this additional equipment from the design, the availability of the facility is reduced.

Early Years Availability. In Exhibit 5.5 of the Facility Cost Report (Reference 22), Siemens' Reliability Availability Maintenance Analysis predicts that the Taylorville Energy Center will have availabilities within the ranges listed in Table 8. Table 8 also lists the availabilities used by Pace in the Rate Impact Analysis (Reference 23).

Table 8
Availabilities in the Taylorville Facility Cost Report

Year	Siemens' RAM Availability Range [1]	Pace Rate Impact Analysis Availability [2]
1	55% - 65%	65%
2	75% - 85%	80%
3+	85%	85%

1. Siemens' Reliability Availability Maintenance (RAM) Analysis (Reference 22)
2. Rate Impact Analysis performed by Pace (Reference 23)

The numbers used in the Rate Impact Analysis are an optimistic interpretation of Siemens' analysis. Furthermore, the Siemens' analysis itself is optimistic in that it matches the availability predicted for a second generation gasifier ramp up. However, the Taylorville design includes gasifiers that have never been operated commercially before. It is expected that similar gasifiers will be commissioned prior to Taylorville, providing some experience that Tenaska can learn from, however these gasifier will still be in their early years so it is not practical to assume that Taylorville will resemble a second generation ramp up. Taylorville will likely have a ramp up somewhere in between a first generation and second generation start up that increases at a slower rate than what was predicted in the Facility Cost Report, as shown in Table 9.

Table 9
Expected Availabilities at Taylorville Energy Center [1]

Year	EPRI Availability Range [a]	MPR's Expected Availability
1	0% - 40%	35%
2	15% - 60%	50%
3	27% - 62%	60%
4	40% - 78%	70%
5+	55% - 82%	85%

1. Based on Integrated Gasification Combined Cycle Availability History graph by EPRI (References 20)

2. Power Block Availability

Based on industry experience with combined cycle plants, a reasonable availability for the Power Block is 92%. Further, the electricity generation from the Power Block will be primarily driven by economic considerations, rather than equipment availability. The economic dispatch and capacity factor of the facility is discussed in detail in the Task 7 report. Since the Power

Block has natural gas as an alternative supply, its availability is largely unaffected by the availability of the SNG facility.

VI. REFERENCES

1. ”PJM Generator Interconnection Queu #Q68 Kincaid-Pana (Christian County) 345kV (746MW Capacity) System Impact Study Report”. Document No. 542613v5. December 2009.
2. Electrical One-Line Diagrams. Burns & McDonnell. EEE-00-001 through EEE-85-0001.
3. Switchyard General Layout. Burns & McDonnell. EES-00-003. Revision 0. September 2009.
4. Tenaska, Inc. Memorandum “TEC Material Balance” from Justin Vala to Steve Brewer, March 28, 2010 and April 20, 2010
5. DOE/NETL-2007/1281 “Cost and Performance Baseline for Fossil Energy Plants”, Revision 1, August 2007.
6. Burns & McDonnell “Water Balance Diagram, Power” Rev. A, 1/25/10 (Attachment VII to Facility Cost Report Exhibit 2.1).
7. Water Treatment Technical Specification, Revision 1, August 7, 2009.
8. Construction Permit – PSD Approval, NSPS-NESHAP Emission Units, Prairie State Generating Company, LLC, Application #01100065, issued April 28, 2005.
9. Updated Prevention of Significant Deterioration and State Construction Permit Application for the Taylorville Energy Center, Volume 1 of 2, dated April 2010.
10. “Carbon Dioxide Offtake Agreement” between Christian County Generation LLC and Denbury Offshore, LLC dated March 20, 2009.
11. Schlumberger Carbon Services “Summary Results for Carbon Storage Feasibility Study”, February 23, 2010 (Facility Cost Report Exhibit 13.2.a).
12. Schlumberger Carbon Services “Cost Report for the Taylorville Energy Center”, February 18, 2010 (Facility Cost Report Exhibit 13.2.b).
13. Brewer, Steve, Tenaska. “Response to Questions on Taylorville,” memorandum, addressed to Jim Bubb, MPR. October 31, 2009.
14. Contract between Tenaska Taylorville LLC and Siemens Energy, LLC for the SUppy of Equipment Related to the Coal to SNG Conversion Project for the Hybrid IGCC Plant Located Near Taylorville, Ilinois dated October 8, 2009.
15. Simon, Robert J., Siemens. “Tenaksa, Taylorville Project, Request for Siemens Gasifiers, Revised Payment Terms.”, e-mail, addressed to Brewer, Steven J., Tenaska. February 15, 2010.
16. Wolfe, Ben. Siemens Energy. “Taylorville Energy Center – Revised Firm Price Offer – Two (2) SGT6-5000F Gas Turbines”, letter, addressed to Mr. Andy Jones, Tenaksa. October 2, 2009.
17. “Project Description – Taylorville Energy Center”. Christian County Generation, L.L.C. February 22, 2010. (Facility Cost Report Exhibit 2.1)
18. Tenaska, Inc. Memorandum “TEC Facility Cost Report ASU Basis” from Justin Vala to Steve Brewer, March 12, 2010.
19. “Response to MPR Inc. questions and requests as detailed in the 12/4/2009 memorandum titled ‘Additional Questions and Request for Information on Taylorville – Fuel Study,” Wood Mackenzie, December 2009

20. Phillips, J. “Integrated Gasification Combined Cycle (IGCC) Design Considerations for High Availability”. Volume 1. 1012226 Electric Power Research Institute. March 2007.
21. “Part II Response to Solicitation Number DE-FOA-0000008” Christian Count Generation, L.L.C. Taylorville Energy Center.
22. “Operations and Maintenance Reliability Availability Maintenance Analysis (RAM) Taylorville Energy Center”. Siemens Energy, Inc. RevG. February 19, 2010. (Facility Cost Report Exhibit 5.5).
23. “Rate Impact Analysis for Taylorville Energy Center”. Pace. February 2010. (Facility Cost Report Exhibit 10.0).
24. DOE/NETL-2006/1235 “Estimating Freshwater Needs to Meet Future Thermoelectric Generation Requirements”, August 2006.

TASK 5 REPORT

AN ASSESSMENT OF THE ABILITY TO FINANCE THE TAYLORVILLE FACILITY

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. ("Boston Pacific") and MPR Associates, Inc. ("MPR") make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

I. EXECUTIVE SUMMARY

A. Background and Introduction

The purpose of this report is to assess Taylorville's ability to finance its proposed clean coal facility. Raising a sufficient amount of debt investment is always the threshold issue for project-financed energy facilities. This is especially true for Taylorville, both because it is using a technology that is not fully commercialized and because it has to raise debt in the middle of the continuing financial crisis.

It seems clear that government-provided financing is the only option for Taylorville. The U.S. Department of Energy (DOE) is running a loan guarantee program that is at its peak in terms of actually deciding which projects to finance. Taylorville is in advanced stages of discussion with DOE. In simple terms, DOE is looking to meet two threshold standards. First, as would any bank making a loan, it wants to see that the projects it finances are likely to pay back the loan. Second, it wants to see that all the risks of the projects are identified and assigned. These are the two threshold standards by which we will assess Taylorville's ability to obtain debt financing.

Taylorville's owners are in the best position to know whether the necessary equity investment can be raised. Still, we will make some calculations of the actual equity return likely to be achieved so we may add our judgment on whether equity investment is likely to be secured. Again, there are two similar threshold standards for equity investors. First, am I likely to get my equity investment back with an adequate rate of return? Second, have all the risks been identified and assigned?

B. Summary on Ability to Finance

As already noted, DOE, as would any bank, will make a loan to the Taylorville project if and only if DOE expects to get its money back with interest. The standard metric for judging this is called a Debt Service Coverage Ratio or DSCR. The DSCR equals the amount of operating cashflow the project will have available to pay debt service divided by the amount of debt service; debt service is the sum of the principal and interest due in a given time period.

Based on our experience with power plant project finance, we judge that the DSCR must fall in the range of 1.3x to 1.5x for DOE to justify debt investment. Our Base Case projection for the Taylorville project meets this standard. That is, the annual DSCR never falls below 1.5x. The average DSCR over all thirty years of project life is 1.98x which indicates sufficient funds to repay the loan over time. This Base Case result is an initial indication that Taylorville has the ability to secure debt investment.

With respect to equity investment, we made a quantitative assessment of the ability to attract equity investors. A standard metric here is to estimate the after-tax rate of return to project equity based on a cash flow projection – not based on the deemed 11.5% return on equity. Based on our experience with power project finance, we judge that a project level, after-tax return in the 13% to 18% range would be necessary – the higher the risk assigned to equity investors the higher the return must be. In our Base Case projection, the after tax equity return is 13.92% which is at the low end of this range. This is an initial indication that Taylorville has the ability to secure equity investment.

For both debt and equity investors a detailed assessment and assignment of risk is central to deciding whether to invest. As documented in our Task 2 Report, the risk assignment reflected in Taylorville's Sourcing Tariff and Agreement is unfavorable to Illinois electricity consumers. It fails to create any incentives for Taylorville to control costs and to ensure good performance and it places far too much risk on Illinois electricity consumers by assuming all cost overruns and all costs of poor performance will be passed through to them.

Two of the bigger and more obvious risks for Taylorville are the risk of capital cost overruns and the risk of poor operating performance. We ran several sensitivity analyses to explore these and other risks. In one sensitivity, we assumed that the project suffered a 20% capital cost overrun, that DOE did not step up to increase its loan to finance this cost overrun, and that the Illinois Commission did not allow the cost overrun to be passed though to Illinois ratepayers. In this sensitivity DOE would still find justification to make the loan – its minimum would be 1.44x and its average DSCR would be 1.90x. This means that, even if a performance standard was set to assign cost overrun risk to equity investors, DOE could still find the loan to be warranted.

The equity return in this sensitivity is reduced to 7.74% which is well below the range we stated was necessary to attract investors. However, it remains appropriate to assign this risk to equity investors since they are the ones responsible for making sure the Taylorville project comes on line on time and on budget. Furthermore, if the risk is assigned to equity investors, they will re-assign that risk through contracts and warranties to the engineering, procurement, and construction contractor and to equipment suppliers to the maximum extent possible. The fact that it is appropriate to assign this risk to equity investors, and that equity investors will re-assign it to contractors and suppliers, leads us to conclude that equity investment is still likely to be secured if Tenaska is confident in its capital cost estimate.

Another big risk is the risk of poor operating performance. Tenaska assumes the gasifiers ramp up to 85% by the third year of operation. We ran a sensitivity in which the project gasifiers ramped up more slowly and reached 85% in the fifth year of operation. We also assumed that the Commission, in response to the poor performance, disallowed 5% of the full Capital Revenue Requirement. In this sensitivity, the minimum DSCR falls slightly to 1.43x and the average falls to 1.88x. The equity return falls to only 12.43%.

We ran other sensitivities that reveal ways to improve both DOE's DSCRs and Tenaska's project return on equity. For example, in our Base Case, we assumed DOE's loan had a 20-year term. If that was extended to a 25-year term, the minimum DSCR increases to 1.68x and the average to 2.33x, Tenaska's return on equity increases to 15.7%.

In sum, we believe the Taylorville project can be project financed with both debt and equity; and we believe that it can be project financed even when substantial performance requirements are set that assign risks to equity investors. However, this does not mean there is an unlimited amount of equity investment for Taylorville. Indeed, as we understand it, it was a concern that equity might have reached its limit that, among other factors, led Tenaska to reduce total investment by reducing the number of gasifiers from four to two.

II. TAYLORVILLE'S TOTAL REVENUE REQUIREMENTS

In our Task 7 Report we described and provided a complete four-part model of Taylorville's total revenue requirements. To conduct the assessment of Taylorville's ability to finance its project we added a fifth part to the model. The most important use of this fifth part of the model is to address DOE's question – will Taylorville be likely to pay the loan back? To address this question we use a standard metric called Debt Service Coverage Ratio (DSCR). This metric measures whether the amount of operating cash flow available to pay the required debt service (principal and interest) on the loan is adequate. Specifically, this metric takes the net operating income for Taylorville (essentially the revenue collected less the operating costs paid) and divides it by the total debt service each year. For DOE it is our judgment that this ratio – the DSCR – should be in the range of 1.3x to 1.5x at its minimum value. The greater the expected risk of repayment of the loan, the higher the ratio will be required to be within this range.

For the purposes of sensitivity analyses, we also gave the model the ability to consider what happens if certain cost increases are not passed through due to performance standards or are disallowed in a prudence review. If, for example, there is an overrun on capital costs, and the overrun is not allowed to be passed through to ratepayers, the model will show the subsequent effects on Taylorville's ability to repay the loan. Embedded in this is an option in which DOE does not step up its loan obligation to help cover the cost overrun, and instead Taylorville takes out a subordinated loan from another source to cover the shortfall.

We also added to the model the ability to estimate the actual return on equity to Taylorville equity investors. Again, we use a standard metric called the internal rate of return (IRR). To calculate the IRR, we must forecast after-tax cash flow to the project. The calculation of State and Federal income taxes is the most complex part of this calculation. Rather than get into the intricacies of Taylorville's possible tax situation, we took the most straightforward approach. That is, we assumed the equity investors in Taylorville were able to take advantage of the tax reductions due to any federal tax losses or tax credits Taylorville experienced. If these equity investors are not able to use all of the tax incentives of Taylorville, the return on equity as measured by the IRR would be lower than estimated in the model.

As to the question of what level of return might be needed to attract equity investors, we would judge, based on our experience, that a range of 13% to 18% at the <u>project level</u> would be required. We note that the equity return at the project level often understates the true equity return. This is because equity investors are likely to use a mix of <u>corporate level</u> equity and debt to finance the "equity" investment at the project level. For example, assume the equity investors use a mix of 50% corporate equity and 50% corporate debt. Assume further that the required return on corporate equity is 18% and the required interest rate on corporate debt is 8%. Given these assumptions, the required return on project level equity would be 13% (which equals .5 times 18% plus .5 times 8%).

III. RISK ASSIGNMENT FOR TAYLORVILLE

Before they invest, debt and equity investors want to know that all the major risks have been identified and assigned. By risk we mean variation from what is expected or predicted. For example, assume there is an analytic consensus before the facility is completed that the final installed capital cost for Taylorville will be about $3.7 billion as estimated in our Base Case. These investors want to know what happens if the actual capital costs are higher or lower – who pays for the cost overrun or who gets the benefit if costs are lower than expected. Similarly, assume there is an analytic consensus on non-fuel operation and maintenance costs. The investors will want to know who pays if these costs are higher and who benefits if they are lower.

With respect to identifying risk, it is important that all aspects of the construction and operation of the facility be assessed for risks. With respect to assignment, we think there is a good guiding principle for this: risks should be assigned to someone who can do something about it. That is, with the goal of lowering risk, assign the risk to a party who is most able to minimize the risk through mitigation measures.

We look to the Sourcing Tariff and Sourcing Agreements as the documents in which the risk assignment is stated. We reviewed in the Task 2 Report the Sourcing Tariff and Agreements proposed by Taylorville. The details of our concerns are in that report, but suffice it to say that we found the Sourcing Tariff and Agreements (a) were not always in compliance with our interpretation of the Law, (b) gave no incentives for efficient construction and operation of the facility, and (c) assigned far too much risk to the buyers of the power who, ultimately, are Illinois consumers. In sum, we believe the risk assignment in the Draft Sourcing Tariff/Agreement is not acceptable.

Moreover, as we pointed out in our Task 2 Report, while Taylorville continually refers to its ratemaking as a cost of service approach, it is not. For example, a traditional cost of service approach would include after-the-fact prudence review, but Taylorville seems to envision a one-time preapproval of construction costs. Similarly, traditional cost of service rates would not have a "deemed" and forever-fixed cost of capital, but, rather, would have to go through repeated reviews of its actual cost of capital.

Given our concerns with the Sourcing Tariff and Agreements, we strongly recommend that Taylorville move toward a pay-for-performance approach. This approach is conducive to identifying and assigning risk to those who can best control it before the fact – which is exactly what we believe is in the best interest of all stakeholders.

Table One defines eight risks, lists to whom the risk would initially be assigned, and, importantly, to whom the risk could be re-assigned by Taylorville under typical pay-for-performance agreements. The re-assignment is crucial given the principle of assigning risk to someone who can do something about that risk.

Illinois electricity consumers are best protected by a risk assignment of the sort illustrated in Table One. We believe Taylorville's debt and equity investors are best protected with that sort of risk assignment, too. If Taylorville fails to explicitly identify, assign, and re-assign risks with a pay-for-performance approach illustrated in Table One, we think this invites substantial political risk to the facility, especially given the fact that in our Base Case the prices charged by Taylorville are substantially above market. By political risk we mean that Taylorville's cost recovery will be subject to any unfavorable change in the political view of the clean coal law. Put another way, it's not realistic to presume that all cost overruns and the cost of poor operations performance will be automatically passed through to Illinois consumers under cost of service theory.

TABLE ONE

ASSIGNMENT OF PROJECT RISKS UNDER TYPICAL PAY-FOR-PERFORMANCE AGREEMENT

Category	**Nature of Risk**	**Assign Risk To:**	**Re-assignment of Risk to:**	**Reassignment of Risk Through:**
Market Risk	Variations in need for and price of electricity	Buyer/Ultimate Consumer	----	----
Fuel Risk	Variations in cost and availability of coal supply and transport	Seller	Coal suppliers and transporters	Supply Agreements, Transport Agreements
Reliability Risk	Variations in operating performance	Seller	Equipment supplier	EPC Agreement
O&M Risk	Variations in cost of operating and maintenance (O&M)	Seller	O&M Contractor	O&M Agreement
Construction Cost Risk	Variations in timing and cost of construction	Seller	EPC Contractor	EPC Agreement
Financing Risk	Variations in structure and cost of actual financing	Seller	Banks, Equity Partners	Credit Agreements, Partnership Agreements
Carbon Regulation Risk	Variation in the extent and cost of carbon emissions control	Buyer/Seller negotiate and allow termination	CO_2 Purchaser	CO_2 Purchaser and Sequestration Agreement
Revenue Credit Risk	Variation in how much SNG is sold at what price and how much CO_2 is sold at what price	Buyer/Seller negotiate	SNG Purchaser, CO_2 Purchaser	SNG Purchase Agreement, CO_2 Purchase and Sequestration Agreement

IV. ABILITY TO FINANCE

A. Base Case Results

In this section we quantitatively assess the ability to finance the Taylorville facility. For debt, we have already stated that the most likely (if not the only) source will be the DOE loan guarantee program. Each DOE loan guarantee will be unique in the sense that the amount of debt and the required risk mitigation will be tailored to the reality of the project being financed. Taylorville has given no documentation on what they believe the loan agreement might require so for our analysis we must make judgments. For purposes of the report, we presume that this, in effect, will be a direct loan from the U.S. Government – the loan will come through the Federal Financing Bank and the DOE will guarantee the loan. As to the basic structure of the loan, we assume for our Base Case that (a) the actual loan will be an amount set by DOE – about $2.6 billion, b) repayment will be in equal annual principal payments over 20 years, and (c) the interest rate will equal 4.28% based on Treasury interest rates.

As already explained, Debt Service Coverage Ratio is the primary metric used to judge the ability of Taylorville to secure debt financing from DOE. Again, this DSCR divides the amount of operating cash flow available from the Taylorville facility to pay debt by the debt service payment in each year. We judge that the DSCR must be in the 1.3x to 1.5x range for DOE to make the loan.

With our Base Case we calculate that Taylorville is likely to achieve the required DSCR. Over the 20-year term of the loan the average forecasted DSCR is 1.98x. The DSCR never falls below 1.5x. Our conclusion is that, looking only at the Base Case results, DOE would find that Taylorville is a good candidate for a DOE loan guarantee. Given that the DOE threshold requirements are met, DOE would then assess risk through sensitivity analyses, just like any bank would. We turn to that in the next section. (We have included a copy of our Base Case Model run as part of the confidential work papers.)

As to the ability to find equity investors, again, we have no documentation from Taylorville on its expectations. We stated earlier herein that we thought an after-tax rate of return on project equity in the range of 13% to 18% might be required. In our Base Case, if we assume the full value of tax incentives is captured, we calculate that the after-tax return on equity is at the low end of this range – at 13.92%. Based on this, we would conclude that equity investors would see Taylorville as a good candidate for equity investment. They, too, would assess risks through sensitivity analyses.

B. Sensitivity Analyses

As stated above, since the threshold requirements for investment are met in the Base Case run, both the debt investor (which is DOE here) and equity investors would turn to an assessment of risk to judge whether to go forward with the investment. The goal of these sensitivity analyses is to identify and quantify risks so that risk mitigation measures can be put in place.

Table Two displays results for the Base Case and for a number of sensitivity cases. The key summary results include: (a) the minimum debt service coverage ratio (DSCR) in any year; (b) the average DSCR over all the years of the loan; (c) the number of years in which the DSCR falls below the 1.3x level; (d) the estimated project level return on equity; and (e) the number of years in which the rate impact limit in the Law is exceeded.

TABLE 2

Financing Results From The Base Case And Sensitivity Cases.

	Scenario	Minimum DSCR	Average DSCR	Number of Times DSCR Under 1.3x	Equity IRR	No. of Years Above Impact Limit
	Base Case	1.50x	1.98x	0	13.92%	1
1	Capital Cost Overrun (20%) DOE Loan Does Not Increase	1.80x	2.38x	0	11.21%	26
2	Capital Cost Overrun (20%) Use Subordinate Debt*	1.80x (1.06x)	2.38x (1.13x)	0 (10)	13.62%	26
3	Capital Cost Overrun (20%) Capital Revenue Disallowance (10%) DOE Loan Does Not Increase	1.62x	2.14x	0	9.51%	26
4	Capital Cost Overrun (20%) Capital Revenue Disallowance (20%) DOE Loan Does Not Increase	1.44x	1.90x	0	7.74%	26
5	SNG Plant Slow Ramp Up	1.50x	1.98x	0	13.53%	2
6	SNG Plant Slow Ramp Up Capital Revenue Disallowance (5%)	1.43x	1.88x	0	12.43%	2
7	Increased O&M Costs	1.50x	1.98x	0	13.92%	22
8	Increased O&M Costs O&M Disallowance (20%)	1.41x	1.82x	0	12.25%	22
9	25 Year DOE Loan	1.68x	2.33x	0	15.70%	1
10	30 Year DOE Loan	1.83x	2.65x	0	17.11%	1

* ( ) is the total for both the DOE loan and the Subordinate Debt, Average DSCR is calculated for term of sub-debt (10 years)

1. Capital Cost Overruns

The first four sensitivities assess the impact of capital cost overruns. In Sensitivity 1, there is a 20% capital cost overrun. However, it is assumed that the capital cost overrun is passed through in full to Illinois ratepayers, but that DOE does not step up to provide increased debt investment to cover any of the cost overrun. Because of these two assumptions, there is actually an increase from the Base Case in DSCRs because, with higher rates, there is more operating cash flow to cover debt payments. However, project level return on equity falls to 11.21%. Illinois ratepayers, however, do feel the impact; they pay a higher price for electricity from Taylorville as indicated by the fact that the Law's rate impact limit is exceeded in 26 years.

In Sensitivity 2, the same assumptions apply as in Sensitivity 1 except that Taylorville is assumed to arrange an additional ten-year private loan with an interest rate of 10%. The purpose of the private loan is to have the new lender, rather than the equity investors, finance the cost overrun. The private loan is assumed to be subordinate to the DOE loan – that is, DOE gets paid first. Importantly, it is assumed that the cost overrun continues to be passed through to Illinois ratepayers. Again, the DSCRs for the DOE loan actually improve as compared to the Base Case exactly as they did in Sensitivity 1. However, when we look at the two loans together, we see that the DSCR ratios are quite low; the minimum DSCR is 1.06x and the average over the ten-year subordinated loan term is 1.13x. The DSCR for both loans is below the 1.3x minimum in all ten years. This means it would be difficult to get a private loan with similar terms. The project level return on equity is lower than in the Base Case, but still substantial at 13.62%. For Illinois ratepayers the rate impact is exceeded in 26 years.

In Sensitivity 3, there is the same 20% capital cost overrun, but, importantly, the cost overrun is not passed through in full to the Illinois consumers – we assume there is a 10% capital cost disallowance. Again, DOE does not step up to provide debt finance for the cost overrun. The DSCRs for the DOE loan are still better than in the Base Case. This is an important outcome. It means that, even if a performance standard was set so the Taylorville equity investors, not Illinois consumers, bear the risk of capital cost overruns, DOE could still find the loan to be doable. The big change in Sensitivity 3 is that the project level return on equity falls to 9.51% which is well below the low end of the range we suggested was necessary to attract investment. Sensitivity 4 is the same as Sensitivity 3 except that the disallowance is increased to 20% of the Capital Revenue Requirement. Here the DSCRs fall slightly from the Base Case. The project return on equity falls substantially to 7.74%.

Despite the drop in equity return in these sensitivities it is however, appropriate that equity investors bear the risk of capital cost overruns since it is their responsibility to bring the project on line and on budget. Furthermore, if the risk is assigned to equity investors, Taylorville will re-assign that risk to the engineering, procurement, and construction contractor and to the equipment suppliers, those who are best able to mitigate such risks.

2. Poor Operating Performance

In the Base Case, the gasification island of the Taylorville facility is assumed to have a few years of ramp up in which plant availability is below the long-run expectation – gasifier availability is 65% in the first year, 80% in the second, and 85% in the third. Thereafter, the gasifiers are assumed to be available 85% of the time.

In Sensitivity 5 there is a much slower ramp up. That is, the gasifiers are assumed to be available 35% 50%, 60%, 70%, and 85% of the time in each of the first five years. Then, in all years thereafter, availability is 85%. However, since there are no disallowances assumed, the poor performance does not lower the capability of the project to make payments on the loan—that is, it does not lower the DSCR, the return on equity falls slightly to 13.53%.

In Sensitivity 6, the same slow ramp up as in Sensitivity 5 is assumed, but the difference is that, as a penalty for that slow ramp up, there are disallowances of 5% of the Capital Revenue Requirement recovery in all years. Because of that disallowance, the minimum DSCR falls to 1.43x and the average DSCR falls to 1.88x. The return on equity over the full life of the project falls only moderately to 12.43%.

3. Variation in O&M Costs

In Sensitivity 7, there is higher-than-expected non-fuel operating and maintenance costs throughout the life of the project. Again, if we assume no disallowances, there is no harm to DSCRs or return on equity. In contrast, in Sensitivity 8, 20% of operation and maintenance costs are disallowed. With this, the minimum DSCR falls to 1.41x and the DSCR on average is 1.82x. The return on equity falls to 12.25%.

4. Changes in the Terms of the DOE Loan

In the Base Case it was assumed that the DOE loan had a term of 20 years. Sensitivities 9 and 10 show the effects of changing the term of the DOE loan. In Sensitivity 9, increasing the term of the loan to 25 years increases the minimum DSCR to 1.68x and increases the average DSCR to 2.33x. With the longer term, the return on equity is increased to 15.70%. In Sensitivity 10, a 30-year term would increase the minimum DSCR to 1.83x and the average DSCR to 2.65x. The return on equity is increased to 17.11%. The debt term, as is often the case, is more important than interest rates in the loan negotiation between Taylorville and DOE. While it is not the case in the Sensitivities we tested here, if the DSCRs or return on equity fall below what is needed to attract investors, a longer term loan from DOE can help.[1]

---

[1] DOE would not be concerned about the decline in the DSCRs-discussed here. However, even if DSCRs declined further, rather than decide not to make the loan, we could expect the DOE to require risk mitigation to be put in place. First, DOE would require, as would any bank in a project financing, that a debt service reserve fund be put in place - this is a sum of money equal to a specified number of future debt service payments, often six months' worth. DOE would draw on the debt service reserve in any year in which added funds are needed to make the debt payment. Second, DOE may require additional mitigation measures to ensure risks from underperformance fall upon equity investors; for example a minimum performance guarantee from Tenaska (say, that the gasifiers will be available a minimum percent of the time) for Taylorville that provides for financial penalties for underperformance. Moreover, as explained above, the equity investors are likely to assure the risk of poor performance is assigned to the EPC contractor and to equipment suppliers. Third, DOE could re-structure debt payments if and when the DSCR falls below 1x. That is, DOE could defer re-payment of the debt to later years; with a high average DSCR, it would appear there would still be sufficient funds over time to repay the DOE loan.

TASK 6 REPORT

A COMPARISON OF TAYLORVILLE ELECTRICITY COSTS WITH THOSE OF OTHER GENERATION OPTIONS AND AN ASSESSMENT OF TAYLORVILLE'S EFFECT ON OTHER MARKET PARTICIPANTS

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. ("Boston Pacific") and MPR Associates, Inc. ("MPR") make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

EXECUTIVE SUMMARY

A. Introduction and Summary

For this Task Six Report we were asked to review the costs of Taylorville and compare them with other technologies. We did this via a levelized cost model. The model looks at the levelized annual revenue requirement of a facility over its expected life and divides this cost by the expected annual energy produced. The result is expressed as a dollar per MWh annuity.

We compared the levelized costs of Taylorville against several alternative generation options. To account for the uncertain nature of many key inputs we made these comparisons under a variety of assumptions about key risk drivers such as capital cost, natural gas prices and carbon dioxide emissions costs. We also checked our findings against those reported by PACE, Tenaska's consultant, in their levelized cost analysis.

Overall, we found that that Taylorville is more expensive than the three alternative base load generating technologies – nuclear, conventional coal, and natural gas combined cycle. For example, under our "Base Case" assumptions regarding natural gas prices and emissions costs, the annualized cost of Taylorville is $212.73/MWh while the costs for these three technologies range from around $100/MWh to about $150/MWh. Our conclusion that Taylorville is more expensive holds up under a range of assumptions regarding natural gas prices, emissions costs, and capital costs. These results are similar to those produced by PACE, except that PACE finds Taylorville to sometimes beat combined cycle generation.

I. COST COMPARISONS

A. Method

We conducted our review using a levelized cost model that we developed in house. The model looks at all the major costs of building and operating a facility over its lifespan. Costs considered include: capital cost, fuel cost, and fixed and variable operating and maintenance (O&M) cost. We also presume that there will be some price placed on carbon dioxide emissions.

For simplicity, we did not include some categories of costs. For example, because we are not stating a specific location for each alternative we did not add any costs for transmission integration and interconnection, or unit-specific fixed fuel charges (e.g. demand changes for natural gas). Also, we did not include costs for emissions other than for CO_2. Additionally, we did not include the benefit of any technology-specific incentive programs (such as the Production Tax Credit). Using our model we calculated costs over the lifespan of the facility and annuitized them to create an annual cost in nominal dollars. We divided this cost by estimated output to create a single dollar per MWh cost for each generating alternative.

We selected several alternate generating technologies for our cost comparison, including: nuclear, super-critical pulverized coal, natural gas combined cycle, natural gas combustion turbine, solar photovoltaic (solar PV), and wind. We chose these technologies because they are some of the chief resource options currently available from the market or being considered by resource planners. They were also analyzed in the PACE report.

Key cost and performance inputs for the model can be seen in Table One. These costs are all in nominal dollars and for a new facility. Capital costs were based on our experience as independent evaluators for unit-contingent and renewable Request for Proposals (RFPs), supplemented by a review of recent utility Integrated Resource Plans (IRPs) and other cost sources. To account for the uncertainty inherent in the capital costs for many technologies we utilized a "stylized"[1] range of capital costs. Operating and Maintenance costs were also based on our review of projects bid into RFPs as well as industry sources. Plant MW sizes were taken from our knowledge of projects currently being offered into the market and capacity factors were estimated based on our experience

[1] The term "stylized" means that these cost and performance assumptions are designed to reflect a range of estimates we have seen in our work rather than being a precise estimate.

Table One
Stylized Estimates of Cost and Performance
for Alternate Technologies for New Power Plants

		Nuclear		Coal		CCCT		SCCT		Solar PV		Wind	
	[units]	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Logistical Inputs													
Plant Life	*[years]*	30	30	30	30	30	30	30	30	20	20	25	25
Cost Inputs													
Capital Cost (in. AFUDC, Esc.)	*[$/kW]*	$6,000	$8,000	$3,500	$4,400	$1,100	$1,350	$1,100	$1,300	$5,000	$8,000	$2,000	$2,500
Fixed O&M	*[$/kW-yr]*	$100.00	$100.00	$40.00	$40.00	$20.00	$20.00	$24.00	$24.00	$35.00	$35.00	$40.00	$40.00
Variable O&M (includes Uranium)	*[$/MWh]*	$5.00	$5.00	$3.00	$3.00	$3.00	$5.00	$2.00	$3.00	$0.00	$0.00	$0.00	$0.00
Performance Inputs													
Net Output	*[MW]*	1,150	1,150	530	530	600	600	300	300	25	25	100	100
Coal Heat Rate	*[Btu/kWh]*	–	–	9,200	9,200	–	–	–	–	–	–	–	–
Natural Gas Heat Rate	*[Btu/kWh]*	–	–	–	–	7,100	7,100	9,200	9,200	–	–	–	–
2015 Capacity Factor	*[%]*	90%	90%	90%	90%	70%	70%	10%	10%	20%	20%	32%	28%
2016 Capacity Factor	*[%]*	90%	90%	90%	90%	70%	70%	10%	10%	20%	20%	32%	28%
2017+ Capacity Factor	*[%]*	90%	90%	90%	90%	70%	70%	10%	10%	20%	20%	32%	28%

An important aspect of evaluating different generating options is acknowledging key risks going forward. We do this above by examining a range of capital costs for new facility construction. In our experience, the two other key risks going forward are natural gas prices and the cost of carbon dioxide emissions. These are important because they have the power to change our order of preference for new technologies. For example, if natural gas pries are low and emissions costs are high, then natural gas-fired plants are more attractive, the opposite case makes coal-fired or nuclear facilities more economic.

To account for these uncertainties we considered three paths or "states" each for natural gas prices and emissions costs. These are the same as used in Task 7 for our analysis of Taylorville costs.

B. Results

The results using the "low case" capital costs are shown in Table Two. In all scenarios the Taylorville project is more expensive than nuclear, coal, combined cycle combustion turbine and wind projects. It is less expensive than solar PV and single cycle combustion turbine projects. This conclusion does not change under any combination of emission costs or natural gas prices. Changes in these variables affect the rank order of resources, for example, in lower gas price situations the combined cycled is cheaper than a coal facility, but the Taylorville project is continually more expensive that the four above-mentioned alternatives.

Table Two
Levelized Cost of Alternative Technologies, Low Case Capital Cost (Nominal $/MWh)

			CO2 Allowance Price Scenarios		
			Base Case	***$30 CO2***	***$10 CO2***
Natural Gas Price Scenarios	*High*	Nuclear	$101.45	$101.45	$101.45
		Coal	$141.08	$133.31	$100.86
		CCCT	$184.90	$181.53	$167.46
		SCCT	$370.09	$365.73	$347.50
		Solar PV	$328.12	$328.12	$328.12
		Wind	$88.80	$88.80	$88.80
		Taylorville IGCC	$219.72	$216.44	$201.92
	Base Case	Nuclear	$101.45	$101.45	$101.45
		Coal	$141.08	$133.31	$100.86
		CCCT	$154.05	$150.68	$136.61
		SCCT	$330.12	$325.75	$307.52
		Solar PV	$328.12	$328.12	$328.12
		Wind	$88.80	$88.80	$88.80
		Taylorville IGCC	$212.73	$209.45	$194.93
	Low	Nuclear	$101.45	$101.45	$101.45
		Coal	$141.08	$133.31	$100.86
		CCCT	$114.99	$111.62	$97.55
		SCCT	$279.51	$275.14	$256.91
		Solar PV	$328.12	$328.12	$328.12
		Wind	$88.80	$88.80	$88.80
		Taylorville IGCC	$203.83	$200.55	$186.02

We should note that this comparison of resources has some issues. First, the Taylorville facility gets the full benefits of unique revenue streams such as (a) DOE grants, (b) profits from sales of substitute natural gas, and (c) tax incentives for carbon capture. Other technologies are not assumed to have such benefits so, in some cases, this would make Taylorville look relatively less costly. Second, these technologies are not all perfect substitutes for each other. For example, you could not simply replace Taylorville with a single 100 MW wind-backed resource since that (a) might not fill the supply need and (b) would not provide a significant capacity benefit. This makes wind appear relatively less expensive.

When we move to the high capital cost case (seen in Table Three) we get the same conclusions. Again, the Taylorville facility is more expensive than nuclear, coal, wind and natural gas combined cycle plants and cheaper than solar PV and natural gas single cycle combustion turbines. Again, this is true under every combination of emissions cost and natural gas price. The bottom line from our analysis is that the Taylorville project is much more expensive than most competing alternate technologies, even accounting for key risks going forward.

Table Three
Levelized Cost of Alternative Technologies, High Case Capital Cost (Nominal $/MWh)

Natural Gas Price Scenarios			CO2 Allowance Price Scenarios		
			Base Case	*$30 CO2*	*$10 CO2*
	High	Nuclear	$128.03	$128.03	$128.03
		Coal	$153.03	$145.27	$112.82
		CCCT	$191.63	$188.26	$174.19
		SCCT	$394.72	$390.36	$372.12
		Solar PV	$511.05	$511.05	$511.05
		Wind	$121.97	$121.97	$121.97
		Taylorville IGCC	$219.72	$216.44	$201.92
	Base Case	Nuclear	$128.03	$128.03	$128.03
		Coal	$153.03	$145.27	$112.82
		CCCT	$160.78	$157.41	$143.34
		SCCT	$354.74	$350.38	$332.15
		Solar PV	$511.05	$511.05	$511.05
		Wind	$121.97	$121.97	$121.97
		Taylorville IGCC	$212.73	$209.45	$194.93
	Low	Nuclear	$128.03	$128.03	$128.03
		Coal	$153.03	$145.27	$112.82
		CCCT	$121.72	$118.35	$104.28
		SCCT	$304.13	$299.77	$281.54
		Solar PV	$511.05	$511.05	$511.05
		Wind	$121.97	$121.97	$121.97
		Taylorville IGCC	$203.83	$200.55	$186.02

C. PACE Study

For a check on our findings we reviewed a similar study performed by PACE and included as part of Tenaska's Rate Impact Study. Similar to our analysis, PACE looked at levelized dollar per MWh costs to operate various alternate technologies and compared them with Taylorville. Note that the results are in real 2010 dollars as opposed to our results which are in nominal dollars.

With one exception, PACE finds the Taylorville project is more expensive (or, in one case, about equal to) nuclear, coal and wind projects and less expensive than solar PV and natural gas combustion turbine projects. This matches our findings. The one exception is natural gas combined cycle projects, which PACE finds are less expensive than Taylorville only in the low capital cost case. It appears that this discrepancy is driven by the relatively low capacity factor that PACE assigns to combined cycle units (about 22% versus our 70%). A lower capacity factor means that there are less megawatt-hours to spread the facility costs over.

While no one can say for sure how often combined cycles will be run, our estimate was based on our experience and a simplified dispatch model. We think that PACE's assumed capacity factor for combined cycle is too low to be consistent with that for Taylorville. As we discussed in Task 7, Taylorville will be run at its full capacity only when it is economically dispatched as a combined cycle plant. For our Base Case that leads to about a 55% capacity factor. Taylorville runs at an overall capacity factor of about 68% because of must run requirements. We see no reason to use, as PACE has done, fundamentally different capacity factors for Taylorville and competing combined cycle plants.

PACE also tested various "states of the world". These are defined by PACE as "a distinct, internally consistent view of power sector market drivers, which incorporate a range of plausible economic recovery and growth outcomes, governmental policy, and technical innovation." Essentially each state is a different "story" about the future, with different values for key drivers such as natural gas prices and emissions costs. Here the story is very similar to the reference case. Taylorville is more expensive or similar in cost to wind, coal and nuclear facilities (in all cases with the exception of the RPS/DSM case) and less expensive than the Solar PV and natural gas combustion turbine. The relationship to a combined cycle varied depending on the assumption.

In conclusion, with the sometime exception of the combined cycle, these findings are similar to ours, showing that Taylorville is never a low-cost option even accounting for alternate paths for key cost drivers.

II. MARGINAL COST OF SNG AND ELECTRICITY

The purpose of this section is to discuss Taylorville's operating strategy, which would determine when the SNG produced by the gasifiers is used for SNG sales as opposed to being used for electricity generation.

The Task 3 and 4 Reports explain that Taylorville's operating strategy will be to run in three different modes with SNG playing a role in Mode 1 and Mode 2. In Mode 1, Taylorville's power plant will be run at full capacity and all SNG will be needed for electricity production; indeed, in Mode 1 substantial Pipeline Natural Gas (PNG) must be used to achieve full electric output. Only in Mode 2 will any SNG be sold rather than be used for electric generation. In Mode 3, Taylorville is run exclusively on PNG.

Taylorville will run at least in Mode 2 whenever the gasifier is available. This is a physical requirement – a must run requirement – because the gasifiers are not cycled (turned off and on). In Mode 2, then, there is no comparison of the marginal cost of SNG-power to the market price for power – Taylorville just runs at its must run level and takes the market price. For Mode 1, however, there is such a comparison in Taylorville's operating strategy. The marginal cost of SNG-power is calculated as the market price of natural gas times the heat rate of the Taylorville power plant (about 7,200 Btu per kWh.) If and when the forecasted market price for power in the PJM Market is at or above this marginal cost, Taylorville is run in Mode 1 when the gasifiers are operating or in Mode 3 when they are not.[2]

In our Base Case Model runs, after the two-year ramp up of availability, we estimate that Taylorville will run in Mode 1 about 4,088 hours a year, in Mode 2 about 3,358 hours a year, and in Mode 3 about 337 hours a year. As a result, the total annual SNG sales are 1.8 million MMBtu a year – this is about 9.3% of the total SNG produced by the gasifiers at Taylorville. With so little of the SNG being sold, as already pointed out in the Task 3 and 4 Reports, it is not clear why Taylorville chose to go to the capital expense of building a facility capable of producing pipeline quality SNG when a traditional IGCC would have been much less expensive. Moreover, Taylorville buys far more PNG than it sells SNG – our Base Case estimate is that 1.8 million MMBtu per year of SNG is sold while 7.6 million MMBtu of PNG is purchased each year.

[2] Again, with Tenaska's chosen operating strategy, the marginal cost of SNG is deemed to be the market price of pipeline natural gas. And the marginal cost of electricity from Taylorville is set at the deemed SNG marginal cost times the heat rate of the power island.

III. EFFECTS ON OTHER MARKET PARTICIPANTS

The purpose of this section is to give an idea of what other types of power are displaced by Taylorville generation. Our estimate is based on a review of market prices in PJM's energy Market over the last two plus years. It is when running in Mode 1 and Mode 3 that Taylorville is assumed to be displacing other power plants fueled by natural gas (or oil). In Mode 2, Taylorville is displacing coal and other fuels.

One way to determine what fuels are displaced is to ask what fuel is at the margin. Given this, our Base Case leads us to estimate that about 55% of Taylorville's generation displaces natural gas at the margin, 31% displaces coal, and 14% displaces other resources.

IV. CONCLUSIONS

For this Task Six Report we compared the Taylorville facility to a range of alternate generating technologies using a levelized cost model. We found that the Taylorville project is much more expensive than most competing alternate technologies, even accounting for key risks going forward. Finally, we reviewed PACE's levelized cost analysis and found that it generally agreed with our conclusions. We also discussed the marginal cost of SNG production and the effects the plant would likely have on other market participants.

TASK 7 REPORT

AN ANALYSIS OF THE LONG-TERM RATE IMPACTS OF TAYLORVILLE ON ILLINOIS CUSTOMERS

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

BY

BOSTON PACIFIC COMPANY, INC.
AND
MPR ASSOCIATES, INC.

June 8, 2010

TABLE OF CONTENTS

DISCLAIMER

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market, financial, or engineering advice. Boston Pacific Company, Inc. (“Boston Pacific”) and MPR Associates, Inc. (“MPR”) make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. Boston Pacific and MPR shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients’ or third parties’ reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

EXECUTIVE SUMMARY

A. Background and Introduction

As explained in our Task 2 Report, the Illinois Clean Coal Portfolio Standard Law (the "Law") limits the rate impact on some Illinois consumers when they buy power from Taylorville. Specifically, the Law limits the rate impact for Illinois consumers taking service from the Illinois electric utilities (eligible customers), but does not limit the rate impact for those consumers taking service from Alternative Retail Electricity Suppliers. The purpose of this Task 7 report is to forecast whether the Law's limit is likely to be met or exceeded over the thirty-year life of the proposed Taylorville facility. The report also draws out some key findings related to the rate impact estimate. Primarily, it draws out when and to what extent power prices from Taylorville are expected to exceed market prices and, thereby, it estimates the total above-market premium paid by Illinois electricity consumers to Taylorville. In addition, it allows us to estimate what portion of total Illinois electricity use is provided by Taylorville; the Law states that the intent is for that portion to be at least 5%.

The Law allows either of two alternatives for calculating an allowed rate impact from Taylorville's sales of power to Illinois electric utilities. One of the two alternatives appears to offer a less restrictive limit for the rate impact. Under that alternative, the Law sets a limit on how much of an increase in average rates can result from sales of power from Taylorville. That amount is set equal to 2.015% of the total average rate charged to eligible Illinois ratepayers in the year ending May 31, 2009 – the word "total" means the average rate includes not only the costs of generation, but also transmission and distribution costs. For Commonwealth Edison (ComEd) the allowed increase in average rates is $2.38 per megawatt-hour (MWh) and for Ameren it is $2.17 per MWh. The weighted average of the ComEd and Ameren allowed increases is $2.32 per MWh.[1] These limits are constant and apply in all years of operation.

It is important to describe how Taylorville sees this limit affecting what it can charge Illinois consumers. In effect, this is a limit on how much it can charge *above market prices* in any given year. For example, in the 2014/2015 planning year – Taylorville's first year of operation is 2015 – we forecast total electricity use in Illinois to be about 142 million MWh; this includes both sales to Illinois consumers served by ComEd and Ameren as well as sales by Alternative Retail Electric Suppliers. Given this, the total amount Taylorville can charge above market prices in that year is $329 million – this is calculated as $2.32 per MWh times 142 million MWh. If Taylorville's costs in that year exceed what it could earn in the market by less than $329 million, then the rate impact falls below that allowed by the Law. If their above-market costs exceed that amount, then Taylorville exceeds the Law's limit. As indicated above, that means it has a cap on what it can charge ComEd and Ameren for the electricity they buy from Taylorville. However, there is no limit on what can be charged to Alternative Retail

[1] For ComEd the average rate was $118.23 per MWh. For Ameren, the average rate was $107.66 per MWh. The allowed increase in average rates of $2.32 per MWh is a weighted average based on the two utilities' sales (roughly 40 million MWh for ComEd and 16 million MWh for Ameren).

Electric Suppliers. Therefore, the electricity ComEd and Ameren cannot buy because it would put the utilities over their cap may instead be purchased by Alternative Retail Electric Suppliers.[2]

While the final step in testing the rate impact limit prescribed in the Law appears to be straightforward, forecasting whether that limit will be met or exceeded is a complex effort. To do so we must forecast, for the thirty-year period from 2015 to 2044, the costs Taylorville will incur as well as market prices. We have developed a four-part model to produce the forecasts in a transparent manner.[3] The first part of the model computes the capital revenue requirement for Taylorville – that is, it forecasts what Taylorville will charge Illinois consumers to cover the return of and on its capital investment. The second part of the model adds to the capital revenue requirement all the other costs of operating Taylorville – the cost of coal input, variable and fixed operation and maintenance, and potential air pollution emission allowances. In addition, Taylorville intends to offset the operating costs of Taylorville by crediting any revenue earned, for example, on substitute natural gas that is produced at Taylorville, but sold to others rather than being used to produce electricity at Taylorville; these substitute natural gas sales and the prices paid for those sales also are forecasted in the second part of the model. The third part of the model forecasts market prices for both energy and capacity. The fourth part of the model forecasts the rate impact as described above. (A fifth part of the model is used in Task 5 when we discuss the ability of Taylorville to find financing.) Our Base Case Model run is explicitly meant to replicate Tenaska's Reference Case in major, bottom line findings such as Capital Revenue Requirement, total premium, etc. Since our model is different, a precise replication is not expected but we came very close in major respects. Once the Base Case was established, we conducted a wide range of sensitivity analyses to show the effect of changes in assumptions about cost, performance, and market conditions.

B. Summary of Rate Impact Estimates

Except for one year of operation – the year 2032 – the rate impact limit set by the Law is never exceeded in the Base Case run of the model. That is, the premium paid to Taylorville by all Illinois electricity consumers for its above-market costs never exceeds $2.32 per MWh. In the context of the Law this is an important bottom line showing Taylorville's compliance with the Law.

Other important bottom lines, in our view, include the following results from the Base Case. First, the total premium paid to Taylorville by Illinois electricity consumers in 2015 is $322 million. In 2020 the total premium is $277 million and in 2030 the total premium is $289 million. The total annual premium levelized over 30 years is $286 million per year. The broad point made by this permanent premium is that, under Base Case assumptions, Taylorville's net revenue requirements are always above market. Taylorville's costs exceed what it would have

---

[2] Taylorville's draft sourcing agreement and tariff would enable Taylorville, if it wished, to defer recovery of some of these excess costs to a later time period, in which case utility customers would only temporarily escape paying premiums in excess of $2.32 per MWh.

[3] Tenaska's consultant, Pace, provided to us its model and estimates of rate impact. We then met with Tenaska and Pace at our offices in Washington DC. We felt it was necessary to build our own model and to develop our own inputs to assure both independence and transparency.

received in market revenue by 105% in 2015, 72% in 2020 and 50% in 2030. Notable, too, is the forecast that Taylorville never reaches the statutory goal of providing 5% of all electricity used in Illinois. In the Base Case, Taylorville produces only 2.53% of Illinois electricity needs each year.

In addition to our Base Case, we also ran a number of sensitivity runs of the model to reveal the substantial uncertainties in any single estimate of the rate impact of Taylorville. One of the most important and uncertain assumptions is that of the natural gas forecasted price. The importance of the natural gas forecast is created by the fact that, the higher the natural gas price, the lower the premium and the lower the rate impact will be. Higher natural gas prices drive market prices up so Taylorville will require less of a premium – again, the premium refers to the amount by which Taylorville costs exceed market prices. In addition, higher natural gas prices mean Taylorville will earn more for its sales of substitute natural gas to others so its net costs to Illinois electricity consumers will be lower.

To reveal the impact of different natural gas prices, we used three different price forecasts. We used Pace's Reference case for our mid-level forecast. Pace is a Tenaska consultant. Then, to provide a range, we developed a lower and a higher price forecast based on a broad set of forecasts we have seen – these are stylized forecasts and we refer to them as BPC Low and BPC High.

A policy to address global climate change also is uncertain. To reflect this uncertainty, we used three forecasts of the resulting price of such policies for a carbon dioxide allowance – an allowance would grant the right to emit one ton of carbon dioxide. Again, for a stylized range of forecasts, we used three levels: $10 per ton, $30 per ton, and a Pace forecast which specified a price for each of the thirty years. Note that we escalated the $10 and $30 prices at about 5% each year.

With three different assumptions about natural gas prices and three about carbon dioxide allowances prices, we had a total of nine scenarios. Table One below shows key results for each scenario.

Table One
Sensitivity Analysis on Natural Gas and CO_2 Allowance Scenarios

Scenario		Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit
Natural Gas	CO2			2015-2044
BPC Low	$10 CO2	**$186.02**	**$332,601**	**21**
BPC Low	Pace Reference	**$203.83**	**$396,429**	**30**
BPC Low	$30 CO2	**$200.55**	**$384,680**	**30**
Pace Reference	$10 CO2	**$194.93**	**$222,131**	**0**
Pace Reference	Pace Reference	**$212.73**	**$285,959**	**1**
Pace Reference	$30 CO2	**$209.45**	**$274,210**	**1**
BPC High	$10 CO2	**$201.92**	**$134,059**	**0**
BPC High	Pace Reference	**$219.72**	**$197,887**	**0**
BPC High	$30 CO2	**$216.44**	**$186,139**	**0**

As can be seen in Table One, and as expected, the total levelized premium increased with lower natural gas prices and decreased with higher natural gas prices. Holding the assumed carbon dioxide price at Pace Reference, we see the BPC Low natural gas prices resulted in a levelized premium of $396 million. The BPC High forecast shows a levelized premium of $198 million. Recall that our Base Case yielded a levelized premium of $286 million per year (see the scenario in Table One with Pace Reference Assumptions for both natural gas and carbon dioxide prices.)

Variations in carbon dioxide allowance prices also affected the premium. The higher the assumed price of carbon dioxide allowances, the higher the premium.

We examined several other important uncertainties. Capital Costs are uncertain for this newly commercial technology, as are possible escalations in those costs from now through the construction period. As discussed in Tasks 3 and 4, other uncertainties involve pushing the gasifier beyond limits guaranteed by the manufacturer.

Table Two shows the effects of combinations of changes in Assumptions. Table Two also reveals the substantial uncertainty with Taylorville. Recall that the Base Case showed (a) a levelized net revenue requirement of $213 per MWh, (b) a levelized premium of $286 million per year, and (c) the rate impact limit to be exceeded in just one year. In the second row of the table we see that even moderate changes in assumptions result in a price of $249 per MWh, a premium of $415 million, and the rate impact limit to be exceeded in all 30 years.

Table Two
Sensitivity Analysis on Combination of Risks

Scenario	Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit 2015-2044
Base Case	**$212.73**	**$285,959**	**1**
Combination - 10% Capital Cost Overrun, 3% Construction Escalation, Reduction to Guaranteed Levels	**$230.77**	**$350,645**	**26**
Combination - 20% Capital Cost Overrun, 5% Construction Escalation, Reduction to Guaranteed Levels	**$248.75**	**$415,103**	**30**
Combination - Slow Ramp Up and Reduction to Guaranteed Levels	**$224.21**	**$310,273**	**8**
Combination - 10% Capital Cost Overrun, 3% Construction Escalation, Slow Ramp Up, Reduction to Guaranteed Levels	**$237.95**	**$358,258**	**26**

We also did a bill impact analysis. For ComEd ratepayers, for example, the premium to Taylorville is unlikely to increase the typical residential bill by more than $20 per year. Again, however, the point is not that the premium in total is small, but rather, that the impact on any one customer is relatively small because the total premium is spread across so many customers. It is essential that the Commission and General Assembly focus on the total premium and ask whether that substantial sum is warranted by Taylorville's contribution to the goals of the Law.

I. RATE IMPACT ESTIMATES

A. The Model Used for the Estimates

In this Section we will describe the four-part model that we developed for the purpose of estimating the rate impacts.[4] The first of the four parts is a detailed model of the annual capital revenue requirement of Taylorville. This model starts with an estimate of capital costs as if the facility was built overnight and then adds in escalation during construction and allowance for funds used during construction to estimate a total installed cost for Taylorville. The total installed cost is then used to estimate a year-by-year capital revenue requirement which includes, most notably, the return of capital in the form of book depreciation, interest on debt, the after-tax return on equity, and income taxes paid on that equity return. This is a traditional cost of service calculation of capital revenue requirement.

The second part of the model adds to the capital revenue requirement all the other costs included in total net revenue requirement for Taylorville. This includes coal costs, variable and fixed operating and maintenance costs, the cost for carbon allowances if necessary, and the costs for other air pollution allowances if necessary. Credited against these costs is the revenue from sales of excess substitute natural gas – excess meaning the substitute natural gas which is produced by Taylorville, but sold to others rather than being used to produce electricity at Taylorville. Credits against costs also include any revenue or tax benefits gained because of Taylorville's carbon capture and sequestration effort, revenues from nitrogen oxide (NOx) allowance sales[5], and revenues from sales of sulfur.

The third part of the model is used to forecast market prices for energy and capacity. For energy, the market price forecast is split into five segments in each year. The first three are periods of time in which natural gas-fired plants are setting the market price. These three periods are distinguished by the efficiency of the natural gas-fired power plants assumed to be setting the market price; efficiency is reflected in the assumed heat rates for each of these periods which are, in million British thermal units (MMBtu) per MWh, over 15, between 10.5 and 15, and between 7.5 and 10.5, respectively. The market price for each of these periods is calculated in any year as the forecasted natural gas price for that year times the average heat rate in each of the three time periods. The portion of time assumed for each of these three periods is based on a sample of PJM Day-Ahead market prices for the Northern Illinois Hub.

The fourth period for our market price forecast is one in which coal is assumed to be setting the market price. The market price in this time period is calculated as the average heat rate in those hours times the forecasted coal price in each year. The fifth and last period is one in

[4] While the model develops forecasts of market prices and the like, it is designed more to accurately assess the rate impact and to address other policy issues than it is to assume accurate forecasts of the future.

[5] The model uses Tenaska's assumptions for NOx allowance allocations which were provided up to year 2031, and as a result, the model calculates revenues from NOx allowance sales up to year 2031. Tenaska, however, assumes that beyond year 2031, revenues from NOx allowance sales will continue until year 2044, escalating at a rate of 2% a year (see Tenaska Financial Model, "1 TEC FCR2 O&M Costs 2-16-10 Reference Case.xls", Tab "Cair Nox".)

which the market price is less than what we would forecast for coal-fired or gas-fired generation. The price for this period is calculated as the current average price escalated with inflation.

Tenaska assumes the gasification part of Taylorville will run 85% of the hours in a year. And, that Taylorville will run one of its two combustion turbines whenever the gasifier is running. Since it will run in all time periods, the power generated by this single combustion turbine is assumed to receive a market price equal to the weighted average of prices in all five time periods. Beyond this, Taylorville has the choice to run the remainder of the power capacity based on economic dispatch.

The fourth part of the model conducts the rate impact test. Using the output from the previous three parts of the model, it takes the total net costs of Taylorville – the total net revenue requirements in each year – and deducts the revenue that would be would be earned for the Taylorville electric energy and capacity sold into the PJM Markets. If the total cost exceeds the market revenue, then this gives us the total above-market premium Illinois consumers would have to pay Taylorville. To determine whether all Illinois consumers pay an equal per MWh amount for this premium, we then calculate the premium per MWh across all MWh forecasted to be sold to all consumers in the State. As explained above, if the above-market cost for Taylorville, when spread across all electricity use in the State, is at or below the $2.32 per MWh calculated under the Law, then Taylorville meets the rate impact limit specified in the Law. If it is above $2.32 per MWh, the cost limit is exceeded which means the above market costs will either be deferred to a later year (subject to annual and aggregate deferral limits) or be paid more than proportionally by those Illinois consumers served by Alternative Retail Electricity Suppliers.

B. The Assumptions Used in the Base Case Model

We will describe here the assumptions used in the Base Case model run. Many if not all of the most important assumptions are listed in a Table entitled *Base Case Assumptions*, the sources for these key assumptions are also listed. This table is provided in the confidential work papers for our report as is the full printout out of our Base Case Model run. Also in the confidential work paper is a Table entitled *Forecasts of Natural Gas Prices and CO_2 Emissions Costs (Nominal $).*

For the first part of the model which estimates the capital revenue requirement, an important starting point is the cost to build the Taylorville facility. The overnight capital costs are the costs excluding both escalation during construction and the money needed to finance the project during construction. Boston Pacific's model adds in both escalation and interest during construction; note that for traditional cost of service rates, interest during construction is called Allowance for Funds Used During Construction and it reflects both the assumed cost of debt and equity. The shares of debt and equity used to finance Taylorville, as well as the return on equity are specified by the clean coal Law; since the facility is assumed to be financed by the U.S. Department of Energy's loan guarantee program, the cost of (the interest rate on) debt is tied to the U.S. Government cost of debt and we have assumed here that the length of the DOE loan is 20 years.

For the second part of the model, crucial assumptions include the amount of coal that is used, the amount of substitute natural gas that is produced, and the amount of electricity that is produced for delivery to Illinois electricity consumers. Also important are the amounts of carbon dioxide which is captured and the amount which is emitted by the power plant.

One of the most important and uncertain assumptions is that concerning the forecasted price for natural gas. We discussed our approach earlier in this report.

For the third part of the model which forecasts market prices, the most important assumption for energy prices concerns what portion of the time natural gas prices will drive market prices. Put another way, what portion of the time is natural gas-fired power needed to meet electricity demand so that it is at the margin. As already noted, to calculate the portion of time natural gas is at the margin, we analyzed a sample of PJM locational marginal prices.

The fourth part of the model calculates the rate impact as required by the Law as well as other metrics such as the total premium and the portion of total Illinois electricity needs supplied by Taylorville. The additional, crucial assumption for part four is the forecast of total electricity sales to Illinois consumers. For this purpose, we took actual sales in 2008 and escalated them by the historical load growth rate over the 1990 to 2008 period up to the year 2015. We then held sales constant for the 30-year operating period for Taylorville.

C. Results for the Base Case and Sensitivity Cases

For the Base Case we would draw attention to these results:

- The total ratebase is $3.7 billion.
- The levelized annual capital revenue requirement is $359.3 million per year.
- The total net revenue requirement is $763 million per year.
- The levelized annual premium to Taylorville is $286 million per year.
- The rate impact is exceeded in only one year (the year 2032).

As already shown in the Executive Summary of the Task 7 Report, we ran several sensitivities. Tables Three and Four below provide the results of additional individual sensitivities.

Table Three
Sensitivity Analysis on Capital Costs and Escalation

Scenario	Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit 2015-2044
Base Case	**$212.73**	**$285,959**	**1**
10% Capital Cost Overrun	**$222.72**	**$321,773**	**13**
20% Capital Cost Overrun	**$232.71**	**$357,587**	**26**
3% Construction Escalation	**$215.82**	**$297,023**	**2**
5% Construction Escalation	**$222.22**	**$319,971**	**11**

Table Four
Sensitivity Analysis on Operating Costs and Performance

Scenario	Levelized Total Net Revenue Requirement ($/MWh)	Levelized Total Subsidy ($000s)	No. of Years Above Impact Limit 2015-2044
Base Case	**$212.73**	**$285,959**	**1**
Slow Ramp Up in SNG Plant	**$219.71**	**$294,568**	**2**
Reduction in SNG Plant Performance to Guaranteed Levels	**$217.39**	**$302,659**	**5**
Increased O&M Costs	**$226.23**	**$334,344**	**22**
Higher Coal Transport Cost	**$219.84**	**$303,241**	**6**
Mt. Simon CO2 Storage	**$213.22**	**$287,715**	**7**

II. ESTIMATES OF BILL IMPACTS ON TYPICAL CUSTOMERS AND ESTIMATES OF MARKET IMPACTS

A. Estimated Bill Impacts

In this section, we estimate the impact on typical bills for residential and small commercial customers. Based on the rate impact estimates above, we expect the impact on typical residential and small commercial bills to be small. Again, the point is not that the premium to Taylorville in total is small, but rather, the bill impact on the typical customer is small because the total premium is spread across all electricity consumers in Illinois.

To illustrate the bill impact, we start with an itemized residential customer bill for bundled electric service presented by ComEd on December 16, 2008. Assuming 700 kWh use, the components of the bill are as shown in Table Five:

Table Five
Typical Residential Bill

Cost Type	Unit Cost	Total Cost
Customer Charge		$8.23
Standard Metering Charge		$2.24
Distribution Facilities Charge	700 kWh X 0.02407	$16.85
Transmission Services Charge	700 kWh X 0.00829	$5.80
Electricity Supply Charge	700 kWh X 0.07395	$51.77
Purchased Electricity Adjustment	700 kWh X 0.00000	$0.00
Environmental Cost Recovery	700 kWh X 0.00017	$0.12
Energy Efficiency Programs	700 kWh X 0.00053	$0.37
Franchise Cost	$26.73 X 7.60 %	$2.03
State Tax		$2.31
Municipal Tax		$4.40
Total Current Charges		**$94.12**

As explained above, the maximum rate increase Taylorville can cause for ComEd is $2.38 per MWh. Adding the maximum of $2.38 per MWh to this bill would add $1.67 to it or about 1.8%; for a full year's bill increase would be around $20. In our Base Case, the rate impact was below the maximum so the bill impact should be below this 1.8%, and it should decline over time as the total bill increases with market prices.

ComEd also presents a sample bill for a commercial (non-residential) retail customer. The components of the bill are as shown in Table Six:

Table Six
Typical Commercial Bill

Cost Type	Unit Cost	Total Cost
Customer Charge		$12.79
Standard Metering Charge		$6.73
Distribution Facilities Charge	84.00 kW X 4.86	$408.24
Transmission Services Charge	36000 kWh X 0.00821	$295.56
Electricity Supply Charge	36000 kWh X 0.07478	$2,692.08
Purchased Electricity Adjustment	36000 kWh X 0.0000	$0.00
Environmental Cost Recovery Adj.	36000 kWh X 0.00017	$6.12
Energy Efficiency Programs	36000 kWh X 0.00035	$12.60
Franchise Cost	$423.26 X 7.60 %	$32.17
State Tax		$115.06
Municipal Tax		$152.64
Total Current Charges		**$3,733.99**

Adding the maximum of $2.38 per MWh to this bill would add $86 to it or about 2.3%; for a full year's bill increase would be around $1,030. In our Base Case, the rate impact was below the maximum so the bill impact should be below this 2.3%, and it should decline over time as the total bill increases with market prices.

B. Estimates of Effects on Market Prices

Pace, a consultant to Taylorville, presented a report entitled Ratepayer Benefit Analysis.[6] In that report Pace argues that Taylorville will lower market energy and capacity prices and, thereby lead to cost savings for Illinois electric consumers.

We do not believe Pace's estimates are valid. As a threshold matter, any new power plant could have a downward effect on market prices. Given this, Pace would have to show Taylorville's impact as compared to another new entrant. For example, say a natural gas-fired combined cycle plant entered the market instead of Taylorville. Since Taylorville intends to run the power block of its facility in a manner comparable to a combined cycle, how would Taylorville's impact differ? Further, if the cost of building and operating a new combined cycle plant was less than Taylorville's, the market impact could be achieved at a lower cost to Illinois consumers. Pace does not appear to have considered either of these threshold issues.

More broadly, we have two other methodological concerns. First, we must go back to the basic point that Pace itself concludes Taylorville's electricity prices are well above market prices most of the time over its operating life. We just have a basic concern with Pace saying that Taylorville's above-market prices should be credited with *lowering* market prices. There may be

[6] Pace, *Draft Ratepayer Benefit Analysis*, October 14, 2009.

a need for baseload power, but that would not justify using the most expensive technology to provide it. In this sense it is best to stick with head-to-head cost comparisons.

Second, Pace takes us into the realm of cost benefit analysis, but looks only at select benefits. For example, Taylorville, as now designed, uses substantial pipeline natural gas. Relative to other technologies, does this increase natural gas prices and therefore electricity prices?

In sum, for these reasons, we do not believe Pace's appraisal is valid.

CONFIDENTIAL WORK PAPERS (REDACTED)