

TEC IGCC Feasibility Analysis

REPORT

PREPARED PURSUANT TO

**Agreement No. SIUC 04-15, FIXED COST CONTRACT BETWEEN
THE BOARD OF TRUSTEES OF SOUTHERN ILLINOIS UNIVERSITY
AND
THE ERORA GROUP, LLC**

The ERORA Group

January, 2005

DISCLAIMER

This report was prepared from work sponsored through a grant from the Clean Coal Review Board. The Clean Coal Review Board was established by Southern Illinois University and funded with a grant from Commonwealth Edison Company to assist and contribute to new growth of the Illinois coal industry through the application of advanced technologies and practices in new or existing facilities in the state of Illinois.

Neither the Clean Coal Review Board nor Southern Illinois University has made any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information set forth herein. Funding of this work by the Clean Coal Review Board does not constitute or imply its endorsement or recommendation of this Report.

The view and opinions expressed herein are solely those of The ERORA Group, LLC and other contributors and do not necessarily state or reflect those of the Clean Coal Review Board.

TABLE OF CONTENTS

Part I INTRODUCTION AND EXECUTIVE SUMMARY.....	1
A. Grant Purpose and Summary of Report Conclusions	1
B. The Need for the TEC	3
1. Need for Generation	3
2. Why Coal Makes Sense.....	5
C. The Case for IGCC	6
1. Technology Overview	6
2. Cost Competitiveness.....	7
3. Third-party Interest and Potential for Co-production	10
4. Environmental Benefits.....	11
5. Business Climate in Illinois	12
D. Conclusion	12
Part II PROJECT DESCRIPTION	15
A. Introduction/Overview.....	15
B. Developer.....	15
C. Description of Site	16
D. Local Zoning Requirements	16
E. Fuel Supply	17
F. Water Supply.....	17
G. Electric Transmission	18
H. Co-Production	18
Part III TECHNICAL ANALYSIS.....	21
A. Project Design Requirements.....	21
1. Price.....	21
2. Reliability	22
3. Environmental Characteristics/Risks.....	23
B. Comparison of Potential Combustion Technologies.....	24
1. Pulverized Coal.....	24
2. Fluidized Bed Combustion.....	26
3. Integrated Gasification Combined Cycle.....	26
C. Combustion Technology Screening	29
1. Pulverized Coal Design Package.....	30

TABLE OF CONTENTS

2.Integrated Gasification Combined Cycle Design Package	45
D. Balance of Plant Design.....	77
1.Pulverized Coal	77
2.IGCC	81
E. Operations and Maintenance	90
1. Pulverized Coal.....	90
2. IGCC.....	92
3. Safety Analysis	94
4. Required Permits	94
Part IV ECONOMIC ANALYSIS.....	97
A. Financial Summary	97
B. Detailed Review of Data.....	98
1. Plant Configuration and Operating Parameters	98
2. Capital Costs	99
3. Operating Costs.....	100
4. Financial Costs	102
5. Illinois Incentives.....	106
6. Other Costs/Parameters	107
7. Required Equity Returns.....	108
8. External Factors Affecting New Generation Development.....	109
Part V CONCLUSION	110
LIST OF TABLES.....	116
ACRONYMS AND ABBREVIATIONS.....	117
SELECT REFERENCES	119

TABLE OF CONTENTS

APPENDICES Volume 2

A. FINANCIAL PRO FORMA

- A-1 677 MW IGCC Facility
- A-2 500 MW PC Facility

B. NON-PROPRIETARY GE REPORT

C. BURNS & MCDONNELL BALANCE OF PLANT SCOPE DEFINITION

D. COMPARISON OF IGCC AND PC WARRANTIES AND GUARANTEES

E. Memorandum of McEvoy & Humke, P.C., Certified Public Accountants, dated August 25, 2004 outlining some of the business taxes and credits related to doing business in Illinois

F. Memorandum of Enterprise Consortium dated November 24, 2004, reviewing various tax laws and incentives

G. Results Summary of Tampa Electric Integrated Gasification Combined-Cycle Project

Part I INTRODUCTION AND EXECUTIVE SUMMARY

A. Grant Purpose and Summary of Report Conclusions

Development of the Taylorville Energy Center (“TEC”) was initiated by The ERORA Group in 2003. The TEC was initially slated to be developed as a conventional Pulverized Coal (“PC”) facility. However, the initial engineering work for the TEC resulted in the conclusion that a PC facility would be limited to 500 megawatts (“MW”) due to limitations on the availability of water.

While a 500 MW PC facility is more cost competitive than the 200 MW – 300 MW PC facilities being pursued by smaller power generators, it is disadvantaged on a capital cost basis with the 1,000 MW – 1,500 MW PC facilities currently being developed in the Midwestern United States which benefit from increased economies of scale. Accordingly, ERORA, with assistance from the Illinois Clean Coal Review Board, undertook this study to determine the technological and financial viability of using Integrated Gasification Combined Cycle (“IGCC”) technology at the proposed TEC. Our goal was to determine whether IGCC can compete with a 500 MW PC at the TEC and whether IGCC can compete regionally with larger (1,000 – 1,500 MW) facilities.

IGCC studies produced by developers to date have been undertaken reluctantly, generally at the request/demand of permitting agencies, and seem to have been designed to conclude that IGCC is not feasible. ERORA’s study is unique in that it is an integrated study, examining all aspects of the development of a site-specific IGCC project (development, design, construction, financing and power sales), with the purpose of trying to find a way to make IGCC work in Illinois using Illinois coal.

Based on engineering design work done by GE Gasification (“GE Gasification”) and Burns & McDonnell (“B&M”), and numerous discussions and site visits with

operators of gasification and IGCC facilities, the financial and banking community and potential power purchasers, ERORA has concluded that IGCC is feasible at the Taylorville site. Accordingly, ERORA will continue the development of the TEC as a state-of-the-art coal-fired IGCC electric generating facility. The decision to proceed with IGCC was premised upon:

1. Anticipated cost competitiveness with regional facilities under development:
 - capital costs are expected to be comparable with a 500 MW PC facility at the TEC;
 - Lower fuel costs at the site will offset, in part, the economy of scale benefits of larger PC plants;
2. Third-party interest in potential co-production of chemicals at the site which provides dispatch flexibility in a region with significant baseload nuclear generation;
3. Environmental benefits, both with respect to lower initial emissions and increased flexibility to deal with future regulations; and
4. The favorable business climate in Illinois which provides financial incentives to attract new coal-fired generation and other business which increase electrical demand.

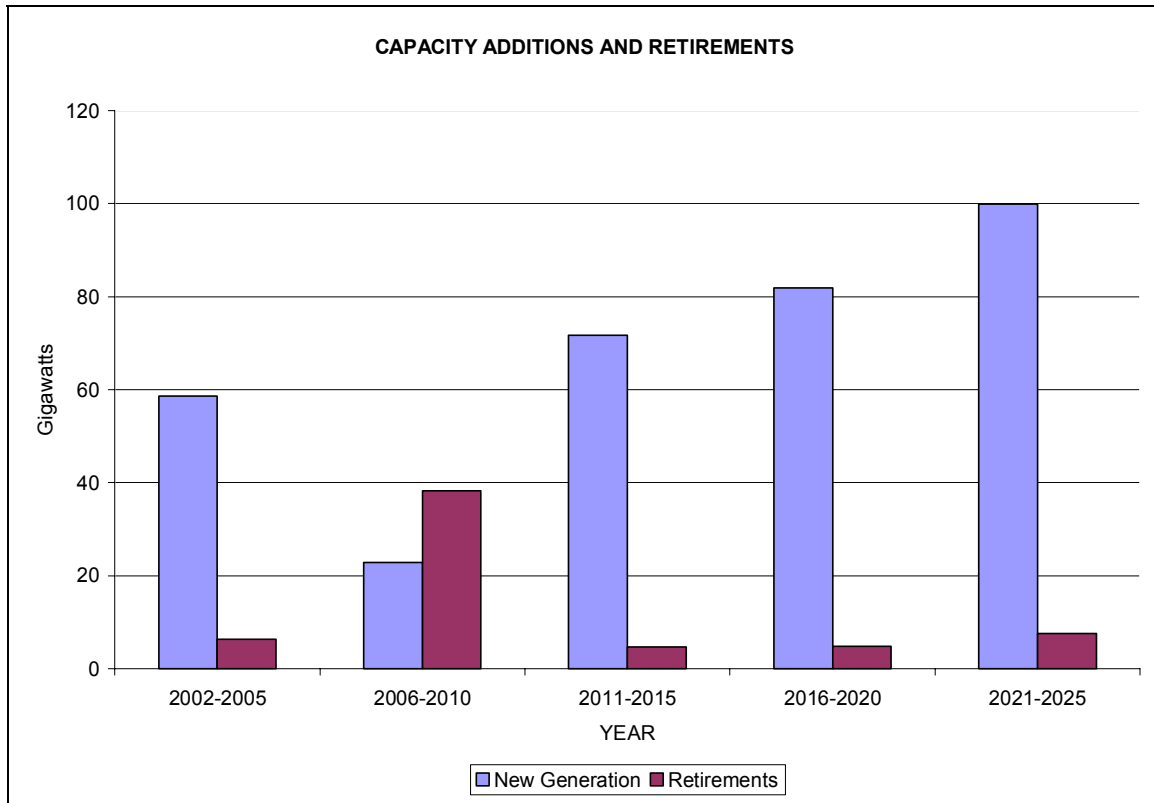
This decision does have consequences respecting the potential price of energy from the TEC. As set forth in further detail in this report, while the all-in cost on a \$/megawatt hour (“MWh”) basis for an IGCC facility is generally comparable to that of a PC facility, it is still approximately \$3.00 - \$5.00/MWh higher under several likely scenarios. Unless the market is willing to value the social benefits of IGCC (the value of the environmental externalities; as supported in the Illinois Commerce Commissions recommendations to the Illinois General Assembly in the Post 2006 Initiative Report – December 2004), and thus pay more for the energy, additional financial assistance will likely be needed for there to be widespread deployment of IGCC in the coal fields of central and southern Illinois.

The benefits to the state of Illinois, however, of successfully developing the TEC as an IGCC facility are tangible and extend beyond the reduced emission profile. Using IGCC technology in place of conventional PC technology will result in a larger facility (to accommodate commercially proven combustion turbines), annual consumption of an additional 315,400 tons of Illinois coal, and will create additional employment opportunities related to the operations and maintenance of the facility.

B. The Need for the TEC

1. Need for Generation

According to the Energy Information Administration, as of January 1, 2004, the total installed net summer generating capacity in the United States was 948,000 megawatts. The EIA reported in Annual Energy Outlook 2004 with Projections to 2025 that 356 gigawatts of new capacity would be needed by 2025 to meet rising demand. The need for new generation in the Midwest seems to be generally accepted. Most, if not all, of the load-serving entities in the region are exploring ways to either build or contract for additional generation resources.



Source: Annual Energy Outlook 2004 with Projections to 2025

At expected annual growth rates of 2.0%, 17,000 MW of new generation is needed each year to meet increasing demand. Despite a concern that the recent development boom would result in a nationwide overbuild situation, approximately 65% of this newly added generating capacity involves peaking projects (gas turbines operated in simple cycle mode) that effectively reduce price volatility but do little to serve increased energy needs. Further, the average coal-fired power plant in this country is now more than 30 years old. This aging of the base-load power production fleet coupled with ever more stringent environmental regulation suggests that many coal-fired plants may be retired over the coming decade. Interestingly, although there has been much speculation regarding power plant retirements, very few have actually been retired.

ERORA has completed a detailed market analysis based on publicly available information and private discussions with local economic development professionals at announced generation sites to resolve ambiguities in the publicly reported data. Based on its market analysis, ERORA believes there is a significant need for new generation during the 2009 – 2012 timeframe. In order to meet that need and accommodate required construction periods, an additional 80,000 MW¹ of new development must be ready to support construction during the 2005 – 2007 time period.

2. Why Coal Makes Sense

The use of coal as a feedstock to produce electricity is imperative for the United States due to the abundance of coal reserves in this country and the desire to strive for energy independence. These abundant coal reserves can mitigate dependence on foreign fuel sources (oil and liquefied natural gas) and can reduce the fuel/chemical feedstock price volatility associated with utility and manufacturer consumption of domestic natural gas. The key to unlocking coal's potential as an energy resource is mitigation of the environmental impacts associated with coal combustion. In addition, from Illinois' perspective, development and use of the 400 years of proven coal reserves will have a significant impact on employment and can serve to stimulate further economic growth in the state.

¹ This projection may be conservative. The EIA Annual Energy Outlook 2004 with Projections to 2025 states that 88 GW of new generating capacity is needed in the 2002-2010 timeframe.

C. The Case for IGCC

1. Technology Overview

Production of Electricity

In an IGCC power generation facility, an air separation plant, a coal gasification facility and a combined cycle power generation facility are integrated into a single highly-efficient electric generating station. The TEC will employ IGCC technology premised on the GE Gasification process (formerly Chevron-Texaco). A brief description of this process is set out below.

The IGCC design for the TEC is premised on a nominal 677 MW (gross output) unit encompassing three (3) technology blocks: air separation, gasification and syngas scrubbing, and power generation. The design for the TEC includes a spare gasifier that will significantly increase expected reliability for power generation and will be discussed in greater detail later in the report.

In the air separation block, air is cryogenically separated into oxygen and nitrogen. The oxygen is mixed with a coal slurry as the fuel feed to the gasification block. The nitrogen is used in the power block to lower gas turbine combustion temperature and reduce NO_x emissions. The gasifier block uses the coal slurry/oxygen feedstock to produce synthetic gas (syngas, principally hydrogen and carbon monoxide) with a heating value of approximately 250 Btu/cf. The syngas is scrubbed to remove particulate, treated to remove mercury and then enters an acid gas removal process. The acid gas removal stage removes sulfur compounds and produces elemental sulfur as a by-product. The cleaned syngas is then supplied to the power block where it fuels two GE 7FA combustion turbines to produce electric power. Heat Recovery Steam Generators are then used to produce steam from the turbine exhaust gases. This steam is combined with steam from the gasification and scrubbing processes, superheated, and expanded in a steam turbine to produce additional electric power.

Co-production of Chemicals

Chemical co-production involves the simultaneous production of electric power and chemicals or the option to produce either product with the same production plant. The rising cost of natural gas makes the co-production of chemicals from the syngas produced by coal gasification potentially attractive. A range of chemical co-production options are available to the TEC, including the production of sulfur, methanol or ammonia and other Fischer-Tropsch liquids. Ammonia is a basic chemical feedstock for fertilizer production and other ammonia-based chemicals. Methanol is a basic chemical feedstock that is primarily manufactured from natural gas.

Co-production has the potential to greatly enhance the financial performance of the TEC. Production can be varied between electric power and chemicals to optimize revenue generation within the constraints of sales contracts. In addition, the IGCC plant can more readily accommodate load changes by shifting production between electricity and chemicals without increasing the delivered electric price (fixed costs during co-production are covered by revenues from the co-produced product).

2. Cost Competitiveness

Capital Costs

Estimated costs to engineer and construct an IGCC facility have been falling in recent years and are expected to continue falling once GE Gasification and others move from first-generation design to standardized plants. However, it is anticipated that the engineering, procurement and construction (“EPC”) cost of an IGCC facility will still be higher than the costs of a *similarly*-sized PC facility. The

focus on size and resultant economies of scale is important as the table below illustrates.

Table 1: EPC Cost Comparison					
	677 MW IGCC First Generation	677 MW IGCC Standard	1,000 MW PC	500 MW PC	300 MW PC
Net Output (MW)	557	557	914	457	274
Cost (\$/kW-net)	\$1,602	\$1,469	\$1,319	\$1,430	\$1,668

An IGCC facility of the size being studied for the TEC is expected to be less expensive (on a dollar per kilowatt-net basis) to build than a smaller PC facility but more expensive than a larger PC facility. The capital costs of a 677 MW IGCC facility and a 500MW PC facility are fairly comparable on a net basis. This is the correct comparison for TEC since the site is limited by water availability, among other things.

It is important to examine *net* capacity rather than *gross* capacity because the IGCC facility consumes significantly more power internally (to power the air separation unit) than does a PC facility.

The table also highlights the savings GE Gasification anticipates being able to generate once its work on a standard plant design with Bechtel is complete. The financial analysis ERORA has undertaken has assumed the lower capital costs of the standard IGCC are available to the TEC.

Additionally, other fixed capital costs, including gas and electrical interconnections and land costs, remain virtually unchanged on a larger facility thus reducing the unit cost of the larger 677 MW IGCC facility in comparison to the smaller 500 MW

PC facility as there are more MWh generated over which to spread those fixed costs.

Operating Costs

Operations and maintenance (“O&M”) issues are more complex with IGCC facilities and the costs are greater, as set forth below.

Table 2: O&M Cost Comparison			
	677 MW IGCC	500 MW PC Stand alone	500 MW PC in fleet
Fixed and Variable O&M (\$/MWh)	\$8.62	\$6.89	\$5.49

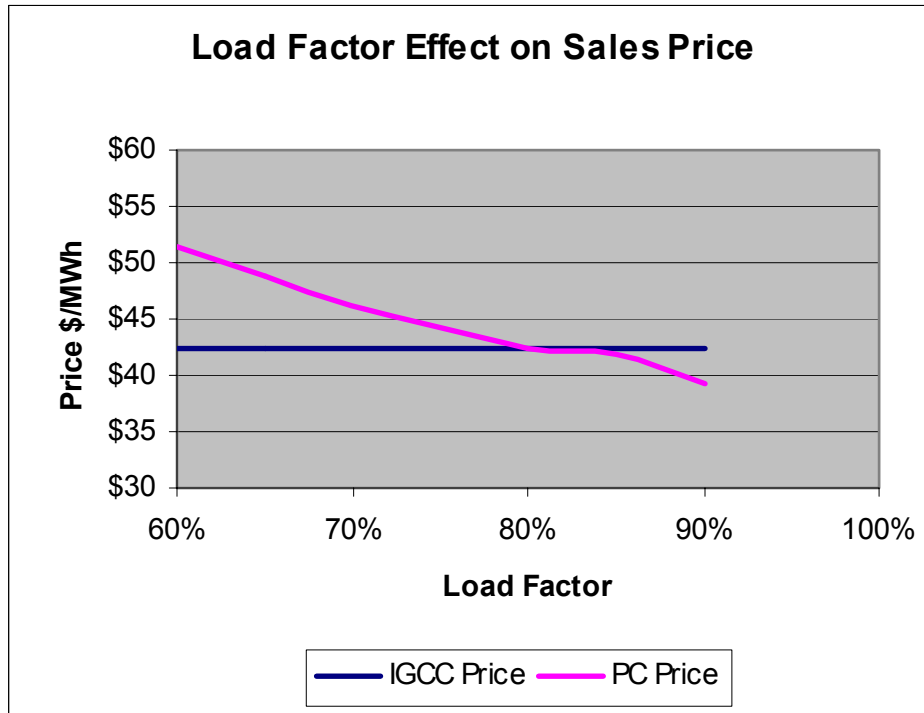
The fixed and variable O&M costs of the IGCC unit are roughly \$1.75/MWh higher than a stand alone coal facility. This is predominantly due to increased employee staffing and costs required to operate and maintain a chemical process plant as opposed to a conventional boiler/turbine set. The lower fuel cost of the Taylorville site is expected to reduce this cost differential by roughly \$0.30/MWh.

This operating cost differential increases to roughly \$3.15/MWh if some maintenance economies are presumed to accrue to an owner with a larger portfolio of coal facilities. These economies are highly specific to the equity investor and other geographic considerations and so they were not included in the financial analysis undertaken. Given the lack of comparable IGCC facilities, no economies are to be expected regardless of the ultimate owner.

3. Third-party Interest and Potential for Co-production

The Illinois region contains a significant amount of nuclear capacity which, on a variable cost basis, produces energy more inexpensively even than coal and which, operationally, can not be ramped up and down in response to changes in demand. Consequently, while coal plants in other regions of the country can expect dispatch rates of 85% or better, limited only by unit availability, coal plants in areas with significant nuclear energy generally face lower, and more variable, dispatch rates. Since coal plants have significant capital costs, reducing the amount of energy produced can significantly increase the all-in cost of that energy on a \$/MWh basis as the fixed costs are spread over fewer MWh.

With co-production, however, the TEC can produce chemicals during those times when the electrical demand is low and coal-fired generation is not economical. The ability to generate a second revenue stream allows TEC to keep its energy price fixed over a variety of dispatch levels as shown below. This is a decided cost advantage over a PC facility in this region and may be particularly beneficial in spurring competition for the aggregation of customers with different load factors in central and southern Illinois.



4. Environmental Benefits

Use of IGCC technology has the potential to provide significant air pollutant emission reductions as compared to PC technology. When contrasted with the emission limits of recently permitted PC facilities, the benefits of IGCC are most apparent with respect to sulfur dioxide, particulates, mercury, and carbon monoxide. In addition, IGCC technology provides tremendous flexibility to address anticipated environmental issues such as capture and sequestration of carbon dioxide. That being said, although IGCC is a clean coal technology, it is not, as the technology exists today, a zero-emissions technology. Interestingly, assuming that aggressive, but costly, environmental controls are utilized in a new PC facility, emissions of nitrogen oxides (NOx), sulfuric acid mist, and volatile organic compounds are very similar for IGCC and PC.

The tabular comparison below contrasts potential TEC IGCC emissions to the planned Prairie States PC project in Illinois that is served by a similar coal supply.

Table 3: Emissions Comparison		
Pollutant	Prairie States	TEC
	Emission Rate (lbs/mmBtu)	
NOx	0.07	0.058
H ₂ SO ₄	0.005	0.005
Hg	No specific control	> 95% removal
PM ₁₀	0.015	0.007
SO ₂	0.182	0.045
CO	0.12	0.036
VOC	0.004	0.006

5. Business Climate in Illinois

As its backing of this report and the legislation supporting financial incentives for new power plants demonstrate, Illinois is working diligently to find new ways for extracting the value inherent in its vast coal reserves. Finding the right business climate for investment is critical when contemplating the expenditure of roughly \$1 billion in an emerging technology on a scale never before achieved.

D. Conclusion

The electric industry has been reluctant to fully embrace IGCC as a viable combustion technology and remains hesitant to invest in the technology. Concerns about technical feasibility, costs, financiability, start-up emissions and reliability have all contributed to the industry's reluctance. However, the interest level among industry executives is rising, in large part due to GE Gasification's acquisition of the Chevron Texaco technology and a growing recognition that the

permitting process for competing technologies is becoming increasingly difficult, time consuming and expensive.²

As a result, many utilities and other participants are now considering IGCC. According to the National Energy Technology Laboratory website, “[t]he mounting interest in IGCC reflects a convergence of three changes in the electric utility marketplace:

- The increasing maturity of gasification technology
- The extremely low emissions from IGCC, especially air emissions, and the potential for lower cost control of greenhouse gases than other coal-based systems
- The recent dramatic increase in the cost of natural gas-based power, which is viewed as a major competitor to coal-based power.”

This growing acceptance is demonstrated by recent announcements made by AEP, Cinergy and First Energy that they were considering the technology as a means to satisfy growing energy demand.

As a result of the work done pursuant to the grant from the Clean Coal Review Board, ERORA has concluded that the Taylorville site is well suited to pursue the construction of one of the first IGCC facilities in the country. The site has the following important characteristics:

- Access to an abundant attractively priced fuel supply
- Potential for co-production addressing pricing impacts of significant regional nuclear base generation
- Significant concerns respecting air pollution issues in the region

² See, e.g., Clean Wisconsin Inc., et. al. v. Wisconsin Public Service Commission and Department of Natural Resources, Order Upon Judicial Review of Public Service Commission Order, Case No. 03 CV 3478, November 29, 2004.

These characteristics suggest the TEC is the right opportunity to undertake the inherent risks associated with not only commercializing a new application but also of scaling up that application.

Based upon the preliminary analysis performed by GE Gasification and B&M, ERORA believes the technological issues can be satisfactorily addressed. Furthermore, ERORA's discussions with potential operators, financing entities and power purchasers lead us to conclude that a complete IGCC package is possible to assemble. IGCC appears to be less costly than a 500 MW PC at load factors below 80%, and is competitive with a 500 MW PC at load factors of 80-85%. However, at load factors greater than 85%, IGCC is more expensive than PC by \$3.00-\$5.00/MWh.

The sales price required for the energy produced from each configuration is based upon the costs of building and operating each facility and the return to equity required of each equity investor. For ease of comparison, the revenue stream is modeled as a flat 30-year fixed price expressed in \$/MWh. While this is not the preferred manner in which to structure a contract for the sale of power, it is a simple and accurate way to compare the prices required by the respective technologies to support a viable project.

If ultimate power purchasers prefer higher load factors, and if the market will not support this price differential, additional support from governmental sources will be necessary. This support could take a number of forms including direct grants, additional government-backed financing or regulatory support for purchasing utilities among others. In continuing to pursue the TEC as an IGCC facility, ERORA anticipates that the attractive business climate in Illinois will provide a solution satisfactory to the market place, if necessary.

Part II PROJECT DESCRIPTION

A. Introduction/Overview

ERORA has initiated development efforts on the Taylorville Energy Center, a state-of-the-art coal-fired generating facility in Taylorville, Illinois. The TEC will be fueled with Illinois Basin coal from a new mine being developed adjacent to the generating facility. The generating facility will be a local source of inexpensive capacity that will further the initiatives of the Illinois retail access laws and will come on-line in the same time frame that the state-mandated freeze on power rates expires.

B. Developer

The Developer of the TEC is The ERORA Group, LLC, based in Louisville, Kentucky. ERORA was founded in 1999 by Mike McInnis, David Schwartz and Larry Watson to leverage their experience developing coal, gas and wind-fueled power generation facilities both domestically and abroad. ERORA's principals have over 60 years of combined industry experience and extensive backgrounds in utility management, energy marketing and generation asset development. They helped start and build two of the largest power marketing companies in the United States. They have experience in mergers, acquisitions, and the rationalization of electric service delivery. Together, they have developed, financed and sold generation projects; acquired, divested, and structured power supply agreements; and assisted numerous IOUs, cooperatives, municipals, and industrials in structuring and executing power supply arrangements.

C. Description of Site

There are several essential elements for a potential project site to be viable. Those infrastructure essentials are set out below:

- Public support for a power plant that is evidenced by zoning and conditional use approval.
- Available fuel supplies located in proximity to the site.
- Adequate water supply for process cooling needs.
- Available electric transmission capability.

These elements all exist at the site selected for the TEC.

The TEC will be located on a 329-acre site situated northeast of Taylorville, Illinois. Of this, approximately 150 acres will be used for plant and equipment with the balance serving as raw material storage and as a buffer area. ERORA currently has an option to acquire the TEC site, which has been successfully rezoned for the TEC. This property is located immediately north of the planned Christian Coal mine site.

D. Local Zoning Requirements

The land currently under option by ERORA as the site for the TEC was, at the time that the property was placed under option, zoned for agricultural use. In May and June of 2004, the City Council of the City of Taylorville amended the City's zoning code to provide a special use zoning classification for power generating facilities. Together with the land owners, ERORA filed an application to rezone the site to a heavy industrial use and applied for a special use permit as a power generating facility. Proper notice was published and hearings were conducted during June, 2004. At the conclusion of those hearings, the Zoning Board voted unanimously to recommend to the City Council that the requested rezoning and

special use be approved. The City Council accepted the Zoning Board's recommendation. The community continues to be supportive of the TEC.

E. Fuel Supply

The TEC will be fueled with Illinois basin coal. The primary coal supply for the TEC will be provided by Christian County Coal Company, which has the mineral rights to over 300 million tons of high-quality bituminous reserves in Christian County. Alternative sources of supply are also available, as is the possibility of fuel blending. The TEC, utilizing IGCC, will use approximately 1.8 million tons of 10,800 Btu/lb coal containing 10.5% ash and 4.4% sulfur annually.

Natural gas is available to the site from the Panhandle Eastern Interstate pipeline which is located approximately seven (7) miles northwest of the site. Natural gas will be used for preheating the gasifiers and could be used to fuel the combined cycle power block if there were an interruption of synthetic gas supply.

F. Water Supply

The City of Taylorville will supply water and related wastewater services to the TEC pursuant to a 25-year contract. The water supply source is the Sangamon River and/or associated wellfields. An alternative source of "greywater" has also been identified.

Importantly, IGCC water consumption is less per unit of electrical output than in a PC boiler because the IGCC generates 58% of its electricity (394 MW in the case of the TEC) from combustion turbines. This means that only 42% of an IGCC's output is produced in a steam turbine that requires condenser cooling water to maintain cycle efficiency. In a PC Boiler, 100% of the electrical output is generated by a steam turbine.

G. Electric Transmission

The TEC will be interconnected to GridAmerica at the NE Taylorville Substation. It is anticipated that the existing 138 kV feed to NE Taylorville will be upgraded from the TEC to its intersection with the 345 kV Pana to Kincaid circuit.

H. Co-Production

Chemical co-production involves the simultaneous production of electric power and chemicals or the option to produce either product with the same production plant. ERORA is currently analyzing the potential for the co-production of various chemicals at the TEC, including sulfur, methanol and ammonia. Methanol is a basic chemical feedstock that is primarily manufactured from natural gas. Ammonia is a basic feedstock for fertilizer or other ammonia based chemicals. The rising cost of natural gas makes the co-production of chemicals from syngas produced by coal gasification potentially attractive. To co-produce chemicals, a production facility would be constructed on an approximately five (5) acre site adjacent to the IGCC.

In addition to its uses as a chemical feedstock, methanol can also be used as a gas turbine fuel. Other uses include fuel blending with gasoline to power vehicles. Given the current price of natural gas, methanol use as a gas turbine fuel may be particularly attractive. In a position paper published in 2001, GE stated:

Methanol is considered a superior turbine fuel, with the promise of low emissions, excellent heat rate, and high power output. The gas turbine fuel system must be modified to accommodate the higher mass and volumetric flow of methanol (relative to natural gas or distillate). The low flash point of methanol necessitates explosive proofing. The low flash point also dictates that startup be performed with a secondary fuel such as distillate or natural gas.

Testing to date has been with methanol as a liquid. GE is comfortable with methanol as a liquid or vapor.

GE is prepared to make commercial offers for new or modified gas turbines utilizing methanol fuel in liquid or vapor form based on earlier experience.³

Two alternatives exist for co-production given TEC's design comprised of three gasifiers (two for base operations and one 50% spare for reliability), specifically:

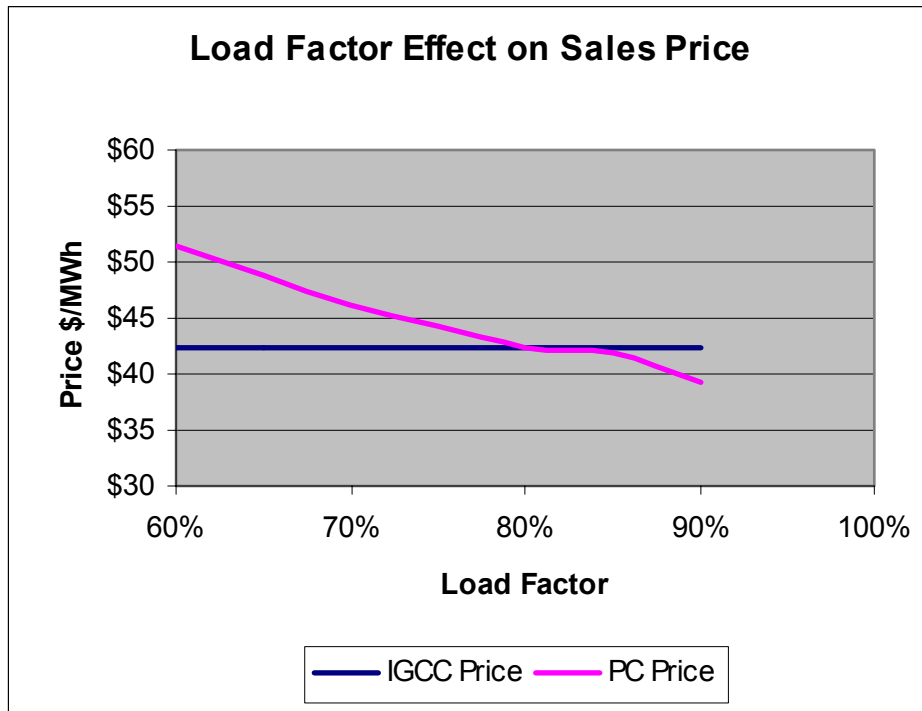
- Products could be co-produced from syngas generated from the spare gasifier while electric power is produced from syngas generated by the two gasifiers that are supplying the combustion turbines.
- Electricity could be produced during on-peak electric price periods from syngas produced by the two operating gasifiers. During off-peak electric price periods, syngas would be shifted to chemical production. The spare gasifier would remain in hot stand-by for reliability purposes.

Co-production has the potential to greatly enhance the financial performance of the TEC. Syngas produced in the gasification process can be varied between electric power and alternative products to optimize revenue generation within the constraints of sales contracts. In addition, the IGCC plant can more readily accommodate load changes by shifting production between electricity and chemicals without increasing the delivered electric price (fixed costs during chemical production are covered by chemical revenues).

Due to this ability to shift production between electricity and alternative products, the TEC will be positioned to offer electricity to customers at prices that are competitive with, and depending on the load factor of the customer, less expensive than, electricity generated from a new pulverized coal facility. As depicted in the graph below, the price of electricity from an IGCC is cheaper than electricity from a PC at load factors below approximately 80%. In light of the large amount of nuclear generation available to Illinois – which has the capacity to satisfy a large portion of Illinois' off-peak capacity needs -- new generating

³ GE Position Paper, Feasibility of Methanol as a Gas Turbine Fuel, February 13, 2001.

facilities with an ability to produce power at lower load factors without economic penalty, as will be the case with the TEC, should have a competitive advantage over new PC facilities.



Part III TECHNICAL ANALYSIS

A. Project Design Requirements

The Project's design parameters are driven by the need to produce a product, electric power, which is attractive to the consumers of that product – largely electric utilities and other load-serving entities. These electricity purchasers are primarily concerned with price, reliable delivery (is the power available when required), and the environmental characteristics/risks associated with generation of the electric energy.

During the past six (6) months, ERORA has discussed electricity supply needs and requirements with seventy eight (78) utilities and load-serving entities located in the East Central Area Reliability ("ECAR"), Mid-Atlantic Area Council ("MAAC"), Mid-America Interconnected Network ("MAIN"), and Southeastern Electric Reliability Council ("SERC") reliability council regions. Common themes that resonated with those electricity purchasers have formed the basis for the TEC's design requirements. Those requirements are set forth below.

1. Price

Not surprisingly, there is a wide divergence respecting what will constitute attractive pricing in the 2008 to 2012 time period. This divergence is due to a variety of factors including location, electric transmission issues, fuel (coal and natural gas) price expectations, environmental regulation (both effective and anticipated) and forward curve (the price at which a sale can be completed today for delivery in the future) variability. Depending on the electric consumer, prices ranging from \$35/MWh to \$45/MWh may be attractive in the 2008-2012 planning horizon. However, there were several common threads that surfaced in every price discussion, specifically:

- Price certainty was foremost in every purchaser’s mind. Price volatility related to fuel, production, or environmental costs should be avoided to the extent possible.
- Flexibility in dispatch is greatly prized. This means that the ability to change the purchase quantity rapidly (either via Automatic Generation Control (“AGC”) or via next hour scheduling) is imperative to most purchasers.
- Virtually all purchasers that are regulated by state utility commissions were keenly focused on how their regulatory commission would view their involvement in a new generating station. They felt that any participation as a plant owner or a power purchaser must be viewed by the regulators both as prudent and well reasoned.

The TEC’s design criteria related to price are as follows:

- *The conversion of coal to electricity (heat rate, measured in Btu/kWh) should be as efficient as possible to reduce the impact of fuel price volatility.*
- *The design selected should provide the greatest flexibility possible for load changes within the constraints inherent in a base-load generation station.*

2. Reliability

Historically, large (400 to 600 MW) coal-fired generating units have demonstrated equivalent availabilities (measured as the percentage of hours available to generate times the maximum generation level possible divided by total annual hours times the maximum generation potential) of 75 to 85%. These generating units are all sub-critical or super-critical PC units. Most entered commercial

operation between 1950 and 1980. Based on discussions with our engineer, B&M, ERORA believes that the new generation of PC plants will be capable of and expected to operate at 90% availability. ERORA's discussions with power purchasers have confirmed a similar expectation on their part.

The TEC's design criteria related to reliability is as follows:

- *The TEC shall be capable of achieving a minimum average annual availability of 90%.*

3. Environmental Characteristics/Risks

An environmental analysis of any new coal-fired facility located in an attainment area for National Ambient Air Quality purposes, must focus on emissions of priority pollutants (SO₂, NO_x, CO, VOC, and particulate) and Hazardous Air Pollutants ("HAPs", including heavy metals, chlorides, and fluorides). In addition, an air emission analysis must also seek to ascertain which emerging issues (mercury standards and CO₂ capture/sequestration) are likely to impact the facility.

In addition to air quality issues, water consumption, surplus water discharge, and storage/sale of combustion and air pollutant control by-products must also be considered.

The TEC's design criteria related to environmental characteristics is as follows:

- *Project design must accommodate Best Available Control technology ("BACT") for the combustion technology that is selected.*
- *The technology selected must be capable of achieving a mercury removal efficiency of at least 90%.*

- *Consideration must be given to the issues imposed by a potential requirement for CO₂ capture and sequestration.*
- *Water consumption must be minimized to reduce the impact on growth in the local community.*
- *Combustion by-products must either be saleable (preferred) or capable of on-site storage without potential for damaging groundwater resources.*

B. Comparison of Potential Combustion Technologies

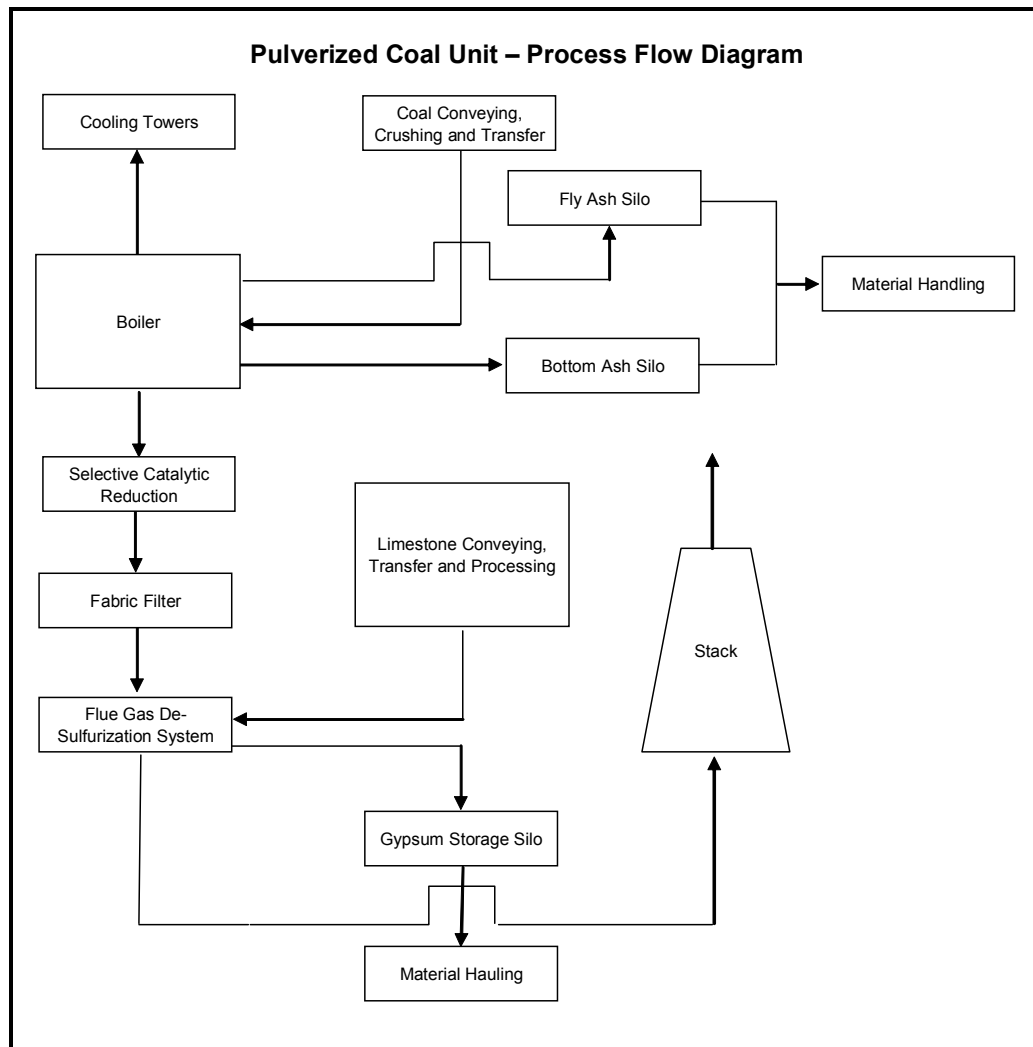
Three potential combustion technologies have been considered for use at the TEC: PC, Fluidized Bed Combustion (“FBC”), and IGCC. A brief description of each combustion technology follows:

1. Pulverized Coal

In a PC facility, as-received coal is ground finer than face powder and then blown into a boiler where it is combusted. The boiler is lined with water wall and steam tubes which absorb heat from the boiler and produce superheated steam which feeds a turbine/generator set that produces electricity.

The flue gas from the PC boiler is ducted to a Selective Catalytic Reduction (“SCR”) device to limit NO_x emissions. Sulfuric acid mist (H₂SO₄) and particulate are removed from the flue gas either through use of both a dry and a wet electrostatic precipitator or through sorbent injection (wet or dry) coupled with a fabric filter. PCs using bituminous coal then employ a wet flue-gas desulfurization unit (“WFGD”) to remove SO₂ and assist in the control of mercury emissions. Additional mercury control can be gained through use of an activated carbon injection process, located upstream of the fabric filter.

A PC equipped with the latest pollution control devices can be likened to a boiler with a chemical plant appended to treat the flue gas. A schematic of the process flow follows.



2. Fluidized Bed Combustion

The primary difference between an FBC unit and a PC unit is the means of combustion. In an FBC, coal is combusted with an alkaline material (usually limestone) in a fluidized bed (a managed combustion zone fluidized with combustion air). This form of combustion results in capture of SO₂ during the combustion process. FBC combustion offers the benefit of tremendous fuel flexibility as various low-rank coals and other materials (including biomass and municipal waste) can be used effectively in an FBC.

Historically, FBC was viewed as an inherently lower polluting combustion technology than PC. This was primarily because FBC could remove SO₂ without the need for a WFGD. In addition, NO_x emissions could be more effectively controlled since the furnace temperatures were lower in an FBC than in a PC. However, as BACT limits have continued to decrease, ERORA does not believe that FBC offers any advantages related to air emissions when compared to PC. In order to meet BACT, an FBC using Illinois basin coal would likely be required to install WFGD.

3. Integrated Gasification Combined Cycle

In an IGCC, coal is ground and slurried with water before being introduced to the gasifier. In the gasifier, the coal is mixed with pure oxygen from an air separation unit in a feed injector. The gasifier, operating in an oxygen deficient atmosphere, produces a vitreous slag waste product while generating synthetic gas (syngas, principally hydrogen and carbon monoxide) at very high temperatures (2,300 to 2,700 degrees F). A schematic of the gasifier follows.

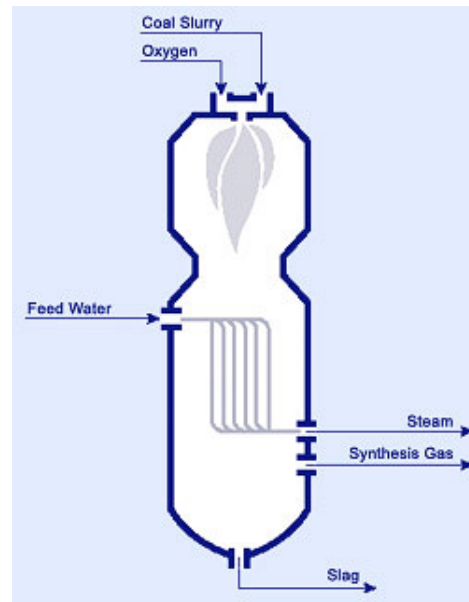
Texaco Entrained-Flow

Texaco coal gasification technology uses a single-stage, downward-firing, entrained-flow coal gasifier in which a coal/water slurry (60-70% coal) and 95% pure oxygen are fed to a hot gasifier. At a temperature of about 2700°F, the coal reacts with oxygen to produce raw fuel gas (syngas) and molten ash.

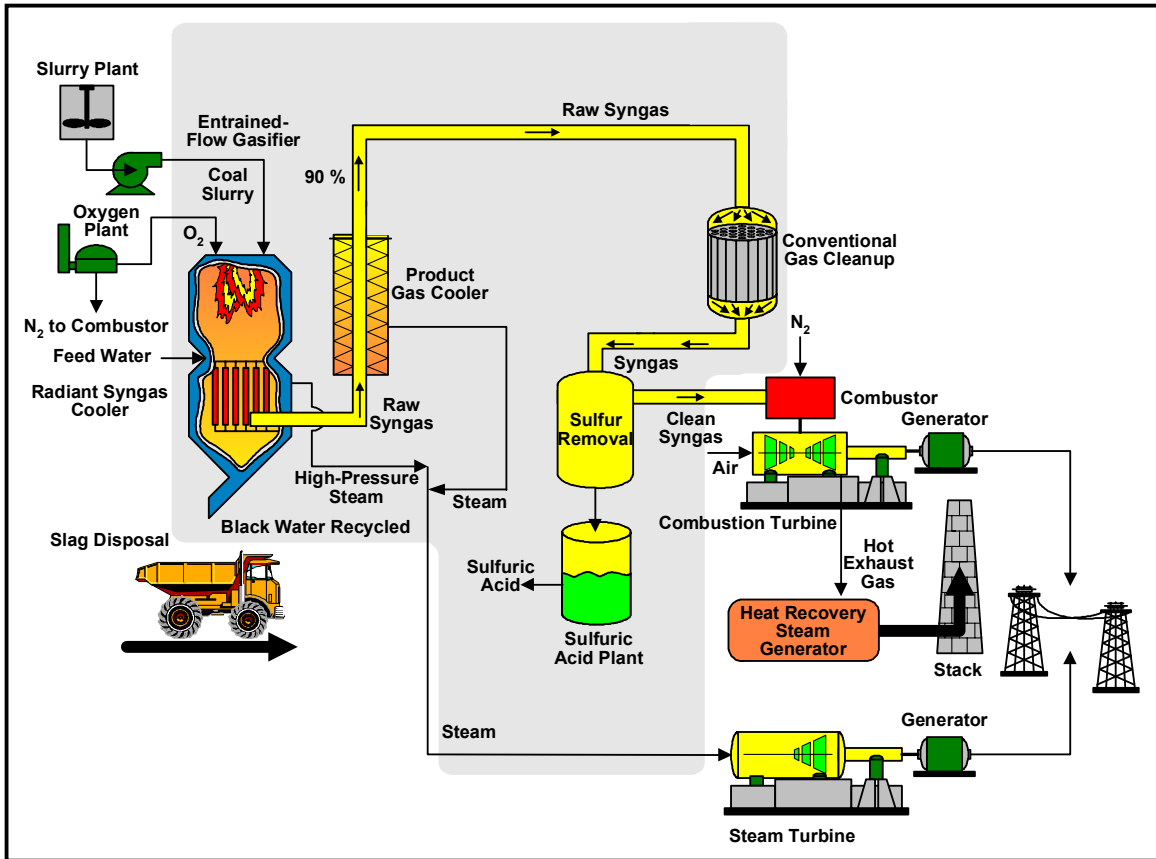
The hot gas flows downward into a radiant syngas cooler where high pressure steam is produced. The syngas passes over the surface of a pool of water at the bottom of the radiant syngas cooler and exits the vessel. The slag drops into the water pool and is fed from the radiant syngas cooler sump to a lock hopper.

The black water flowing out with the slag is separated and recycled after processing in a dewatering system.

Source: NETL



The syngas is cooled in a process that generates high pressure steam and then cleaned. Syngas cleaning includes removal of particulates (water scrubbing), mercury (mercury control beds) and acid gases (amine scrubbing). A Claus process is used to produce a molten sulfur byproduct from the acid gas. A further sulfur removal process occurs in a tail gas treatment unit. A schematic of the IGCC process flow follows.



Source: NETL

The power block uses synthetic gas to fuel combustion turbines and produce electric power. Heat Recovery Steam Generators (“HSRGs”) are used to produce steam from the turbine exhaust gases. This steam is combined with steam from the gasification and scrubbing processes, superheated, and expanded in a steam turbine to produce additional electric power.

C. Combustion Technology Screening

ERORA has determined that both PC and IGCC technologies are viable combustion technologies to serve the TEC. FBC has been eliminated from consideration because:

- It is less efficient in converting coal to electricity (has a higher heat rate) than either PC or IGCC.
- It is more expensive to build (higher capital cost) than PC.
- It offers no benefit in reducing air pollutant emissions when compared to either PC or IGCC.
- The fuel flexibility advantages of FBC are not of value to the TEC because the project plans to use a consistent fuel supply, Illinois #6 coal.

In this screening analysis, ERORA also limited the options to be considered with both PC and IGCC combustion technologies. For purposes of this study, performance and financial comparisons premised on PC technology were restricted to use of sub-critical PC combustion. While super-critical PC plants have proven to be effective in Korea and Japan and these plants have lower heat rates and higher cycle efficiencies than sub-critical units, preliminary analysis indicated that the increased capital cost of a super-critical plant tends to offset a significant percentage of those efficiency savings.

Also, in this analysis, ERORA limited its consideration of IGCC to the GE Gasification process. The GE Gasification process was selected over competing processes (Conoco/Phillips, Shell, KBR, etc.) on the basis of GE Gasification's successful operating experience in this country and abroad. GE Gasification

(through its predecessors) has licensed 134 gasification facilities (worldwide) and over 250 gasifiers since 1950.

1. Pulverized Coal Design Package

The PC design for the TEC is premised on a nominal 500 MW (gross output) sub-critical generating unit served by a single mechanical draft cooling tower. The pollution control train includes SCR (NO_x control), activated carbon injection (mercury control), Direct Sorbent Injection (“DSI”) (for control of acid gases including H₂SO₄), fabric filters (particulate control), and a WFGD (SO₂ control). Design parameters and cost estimates have been prepared by B&M and ERORA.

The design and performance parameters for the PC unit are set out in tabular fashion below.

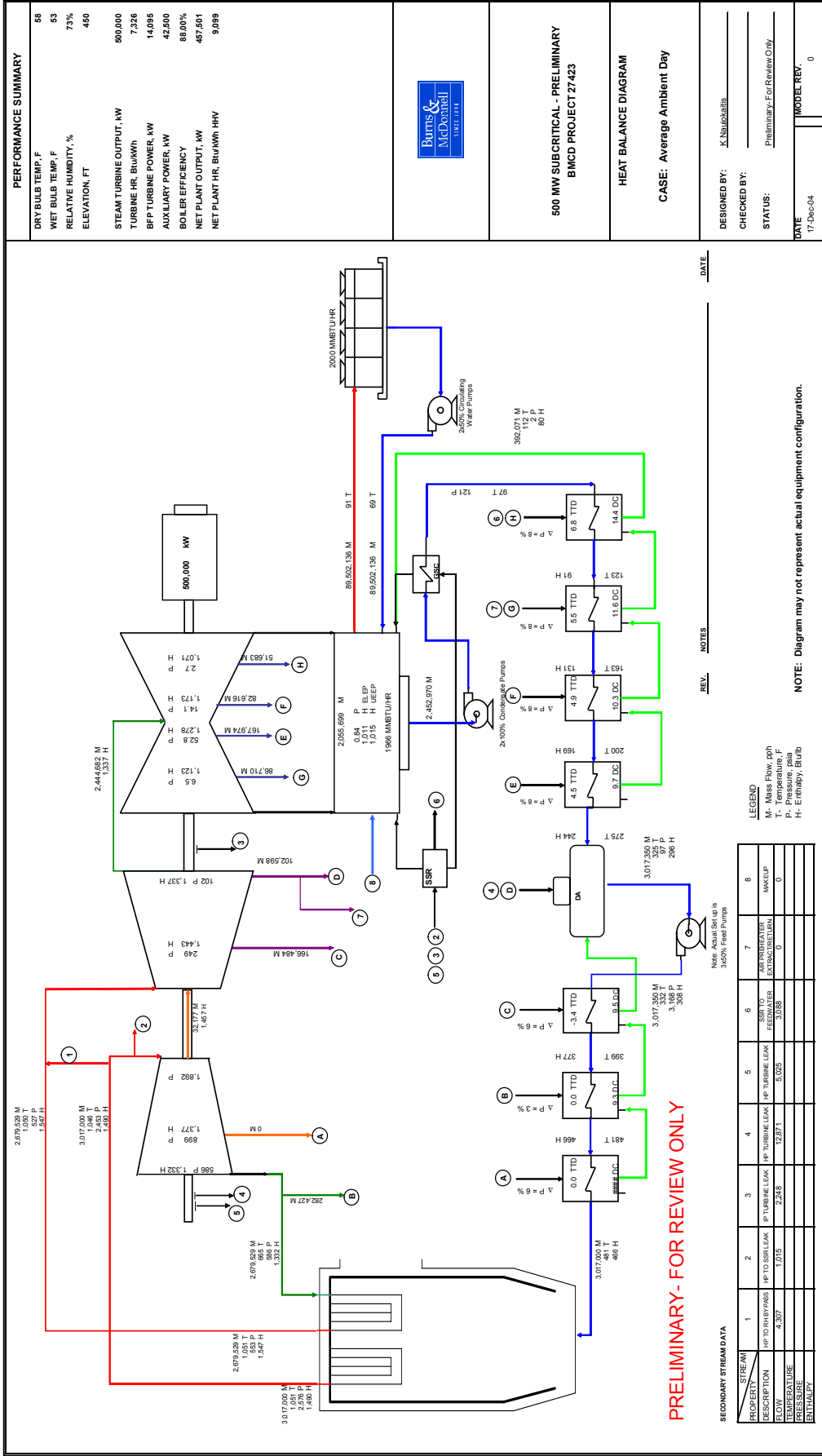
Table 4: PC Design and Performance Parameters	
Gross Output	500 MW
Auxiliary Power Consumption	43 MW (8.6%)
Net Output	457 MW
Average Annual Availability	90%
Heat Rate at 58 degrees F	9,100 Btu/kWh
Heat Rate at 95 degrees F	9,400 Btu/kWh
Water Required	4,972 gpm
Water Effluent	307 gpm
Coal Usage	193 tons/hr
Limestone Required (WFGD)	30.2 tons/hr
Lime Required (DSI)	1.25 tons/hr
Activated Carbon Required (Hg control)	3.0 lbs/mm ² cfm
Combustion/WFGD By-products	67.1 tons/hr
Employees (operation and maintenance)	105
Emission Rates:	
SO ₂	0.120 lbs/mmBtu
NO _x	0.050 lbs/mmBtu
CO	0.100 lbs/mmBtu

Table 4: PC Design and Performance Parameters

PM ₁₀	0.015 lbs/mmBtu
VOC	0.0036 lbs/mmBtu
H ₂ SO ₄	0.0040 lbs/mmBtu
Hg	90% removal

A site plan for a PC installation at the TEC and process heat balances for the PC design package follow.

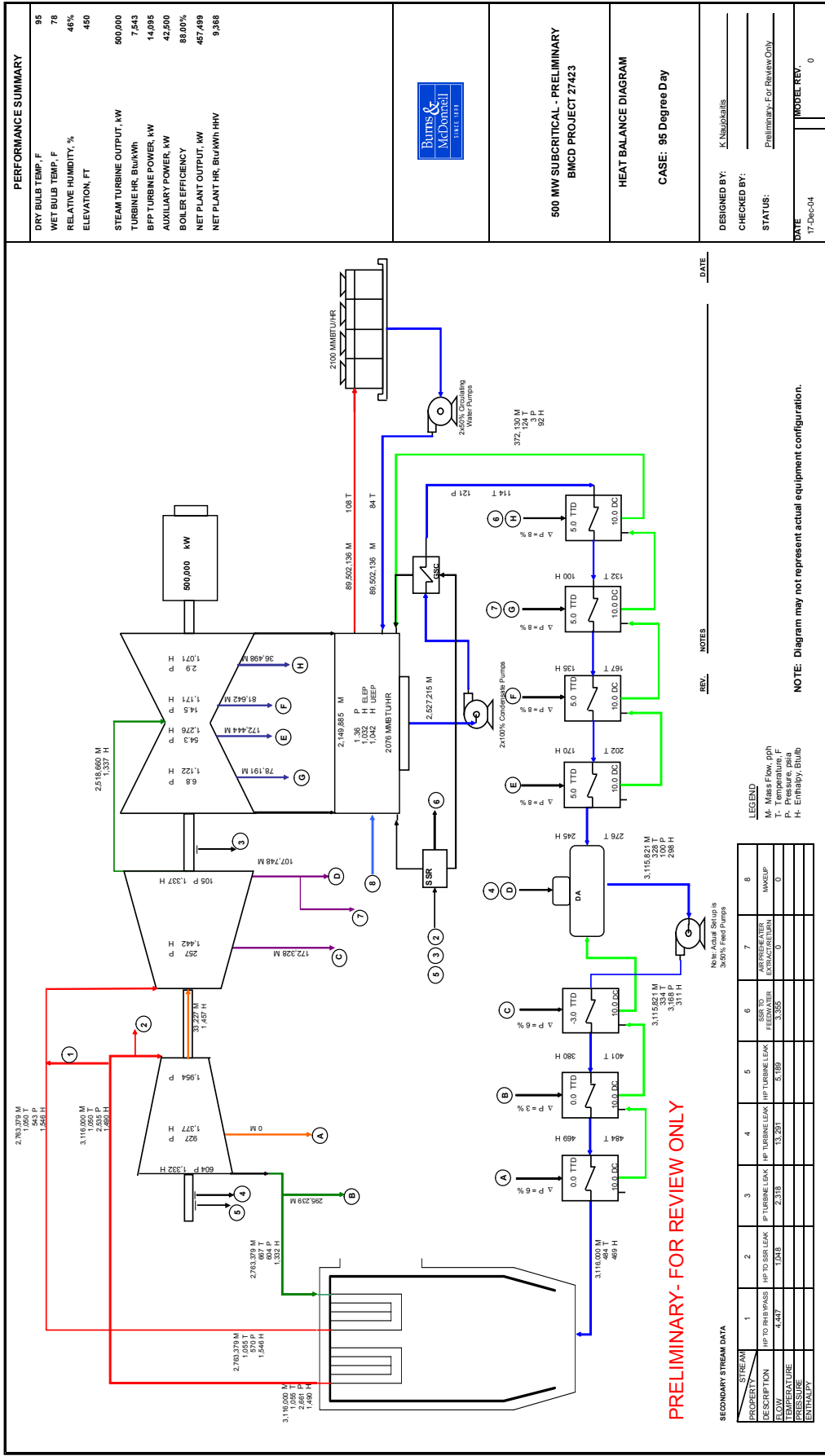
HEAT BALANCE AT 59°F - PULVERIZED COAL UNIT



PERFORMANCE SUMMARY	
DRY BULB TEMP, F	58
WET BULB TEMP, F	53
RELATIVE HUMIDITY, %	73%
ELEVATION, FT	450
STEAM TURBINE OUTPUT, KW	500,000
TURBINE HR, Btu/KWh	7,326
BPP TURBINE POWER, KW	14,095
AUXILIARY POWER, KW	42,600
BOILER EFFICIENCY	88.00%
NET PLANT OUTPUT, KW	457,601
NET PLANT HR, Btu/KWh, HHV	9,099

500 MW SUBCRITICAL - PRELIMINARY BIMCD PROJECT 27423	HEAT BALANCE DIAGRAM
CASE: Average Ambient Day	
DESIGNED BY: K. Neubeck	CHECKED BY:
STATUS: Preliminary For Review Only	DATE: 17-Dec-04
MODEL REV: 0	

HEAT BALANCE AT 95°F - PULVERIZED COAL UNIT



PERFORMANCE SUMMARY

DRY BULB TEMP., F	96
WET BULB TEMP., F	78
RELATIVE HUMIDITY, %	46%
ELEVATION, FT	460
STEAM TURBINE OUTPUT, KW	590,000
TURBINE HR. BW/MWH	7,643
BFP TURBINE POWER, KW	14,095
AUXILIARY POWER, KW	42,500
BOILER EFFICIENCY	88.00%
NET PLANT OUTPUT, KW	467,489
NET PLANT HR. BW/MWH HVV	9,968



500 MW SUBCRITICAL - PRELIMINARY
BMCD PROJECT 27423

HEAT BALANCE DIAGRAM

CASE: 95 Degree Day

DESIGNED BY:	K. Naugalis
CHECKED BY:	
STATUS:	Preliminary For Review Only
DATE:	17-Dec-04
MODEL REV.	0

REV. NOTES _____ DATE _____

Secondary Stream Data

STREAM	1	2	3	4	5	6	7	8
PROPERTY DESCRIPTION	HP TO MAINS	HP TO SSR LEAK	HP TURBINE LEAK	HP TURBINE LEAK	SSR TO WREPREATER FEEDWATER	WREPREATER EXTRACTION	MASSUP	MASSUP
TEMPERATURE	-4247	3245	2315	13297	3355	0	0	0
PRESSURE								
ENTHALPHY								

LEGEND
M - Mass Flow, gph
P - Pressure, psia
H - Enthalpy, Btu/lb

NOTE: Diagram may not represent actual equipment configuration.

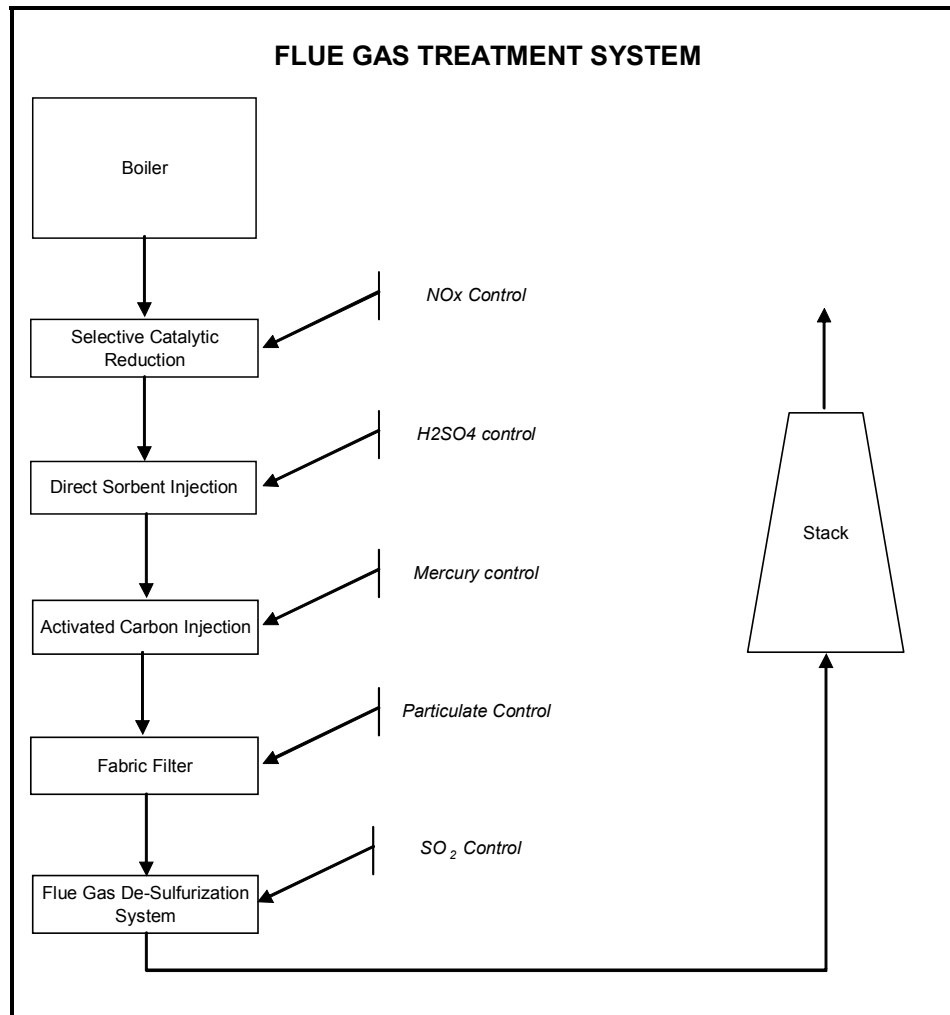
a. Design Issues and Alternatives

As PC technology is well-proven, there was only one design issue/alternative considered for this design package. That issue involved the optimum means for particulate and acid gas emission control. Two approaches are possible, DSI used in conjunction with fabric filters, or a dry electrostatic precipitator (“ESP”) combined with a wet ESP downstream from the WFGD. Neither technology is well proven for use with high sulfur Illinois Basin coals, and planned PC units under development have taken both approaches. The option selected, DSI/fabric filters, results in lower capital and operating cost but concerns exist that the maintenance expense may significantly exceed the cost associated with a dry/wet ESP.

b. Environmental Considerations

Air Pollutant Emissions

A schematic diagram of the flue gas treatment system for the PC boiler is set out below.



○ *Oxides of Nitrogen (“NOx”)*

NOx is formed in the combustion process from two sources: fuel content NOx and thermal NOx. Fuel content NOx is inherent in and dependent on the fuel being combusted. Thermal NOx is a function of the furnace temperature and amount of excess air in the flue gas. The same factors that inhibit thermal NOx formation (i.e. low temperature

and low excess air) increase Carbon Monoxide (“CO”) emissions. Therefore, an appropriate balance of furnace temperature and excess air must be managed to create the lowest possible combined emissions of NO_x and CO. In the TEC design, thermal NO_x emissions are initially limited in the PC boiler through the use of low-NO_x burners and furnace temperature control. The flue gas then enters the SCR which is designed to further reduce emissions of NO_x. SCR is an exhaust gas treatment process in which ammonia (NH₃) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, ammonia and nitric oxide (“NO”) react to form diatomic nitrogen and water. This reaction occurs within a temperature range of 575 to 750 degrees Fahrenheit.

- *Acid Gases (H₂SO₄, HCl, and HF)*

Acid gases are formed in the combustion process and through the formation of SO₃ in the SCR. Increasing the amount of SCR catalyst to reduce NO_x emissions will proportionally increase the rate of SO₃ and subsequent H₂SO₄ emissions. In the TEC, an alkaline reagent (most likely, lime or sodium bisulfite) will be injected (as a dry powder or liquid respectively) into the flue gas between the SCR and fabric filter. The reagent will react chemically with the acid gases to form particulate material which will then be captured in the fabric filter system. Additional acid gas control will be provided by the WFGD which is described below for the control of SO₂.

- *Mercury (“Hg”)*

Mercury is a naturally-occurring constituent of coal. When coal is burned, trace quantities of mercury can be vaporized by the high temperatures within the furnace. The capture of Hg by flue gas

cleaning devices is dependent on the chemical and physical forms of Hg involved. These forms include elemental mercury, divalent oxidized forms, and particulate-bound mercury. Particulate-bound mercury can be efficiently captured in fabric filters (as described below for particulate control). Divalent forms of Hg are water-soluble and can be effectively controlled by WFGD. Unfortunately, elemental mercury is insoluble in water, does not react with alkaline material, and can not be captured by a WFGD. Therefore, the TEC will use an activated carbon injection system to capture elemental mercury. Powdered activated carbon will be injected into the flue gas (upstream of the fabric filter) to absorb the elemental Hg on its porous surface. The activated carbon will then be captured in the fabric filter system.

- *Particulate*

Particulate matter can be emitted from the boiler, material handling devices and through cooling tower drift.

In the boiler, particulate is the result of material (often ash) in the coal which is not combusted but rather becomes entrained in the flue gas. The TEC will use a fabric filter system to remove boiler particulate from the flue gas. The fabric filter removes particulate by drawing the dust-laden gas through a bank of suspended filter tubes. A “filter cake”, composed of the captured particulate, builds up on the “dirty” side of the fabric filter. Periodically, the filter cake is removed through a physical mechanism (such as a blast of air from the clean side of the fabric filter) which causes the cake to fall into a hopper from which it is ultimately removed.

Particulate matter in material handling systems (coal, limestone, etc.) will also be collected by fabric filters or alternative dust control

equipment. Particulate entrained in the water vapor emitted from the cooling tower will be controlled through drift elimination devices.

- *Sulfur Dioxide ("SO₂")*

SO₂ emissions are directly related to the amount of sulfur contained in the coal. The TEC will use a WFGD system to minimize emissions of both SO₂ and H₂SO₄. The WFGD uses a calcium-based (limestone) alkaline slurry that is sprayed into the flue gas to react with the SO₂. Insoluble calcium sulfite and calcium sulfate salts are formed in this reaction. A forced oxidation system is then used to maximize the calcium sulfate salts by converting calcium sulfite to calcium sulfate. The salts are then dewatered and removed as a solid by-product.

- *Carbon Monoxide*

CO is produced in the boiler as a result of incomplete combustion. As mentioned above, CO can be minimized by increasing furnace temperature and excess air. However, this control approach increases the production of thermal NO_x. Since there is no viable method of removing CO from the flue gas, the most effective means of minimizing the emissions of CO without increasing NO_x emissions is proper boiler control. The TEC will use this control technique.

- *Volatile Organic Compounds ("VOCs")*

VOCs are formed from incomplete combustion of volatile matter contained in the coal. Thermal oxidation in a large PC boiler is an effective means of destroying VOCs. The TEC will use proper boiler design and operation as the control mechanism for VOC emissions.

- *Hazardous Air Pollutants*

HAPs include Volatile Organic Carbons (“VOCA”) and heavy metal particulates. The TEC will control emissions of HAPs through proper boiler design and operation (VOCA), fabric filters (heavy metals) and WFGD (heavy metals).

The following table delineates the control equipment that would be used to control air pollutant emissions from the PC boiler and expected pollutant emission rates.

Table 5: PC Boiler Control Equipment		
Pollutant	Control Device(s)	Emission Rate
NOx	Low-NOx burners and SCR	0.050 lbs/mmBtu
H ₂ SO ₄	DSI and WFGD	0.0040 lbs/mmBtu
Hg	Activated Carbon Injection, fabric filters, and WFGD	90% removal
PM ₁₀	Fabric Filters and WFGD	0.015 lbs/mmBtu
SO ₂	WFGD	0.120 lbs/mmBtu
CO	Proper Boiler Design and Operation	0.100 lbs/mmBtu
VOC	Proper Boiler Design and Operation	0.0036 lbs/mmBtu
HAPs:		Tons/Year (“TPY”)
VOCA	Proper Boiler Design and Operation	2.98
HC	DSI and WFGD	0.39
HF	DSI and WFGD	1.55
Benzene	Proper Boiler Design and Operation	0.09
Cadmium	Fabric Filters and WFGD	0.05
Chloroform	Proper Boiler Design and Operation	0.05
Formaldehyde	Proper Boiler Design and Operation	0.23
Lead	Fabric Filters and WFGD	0.38
Nickel	Fabric Filters and WFGD	0.95
Arsenic	Fabric Filters and WFGD	0.38
Beryllium	Fabric Filters and WFGD	0.08
Chromium IV	Fabric Filters and WFGD	1.52
Manganese	Fabric Filters and WFGD	3.59

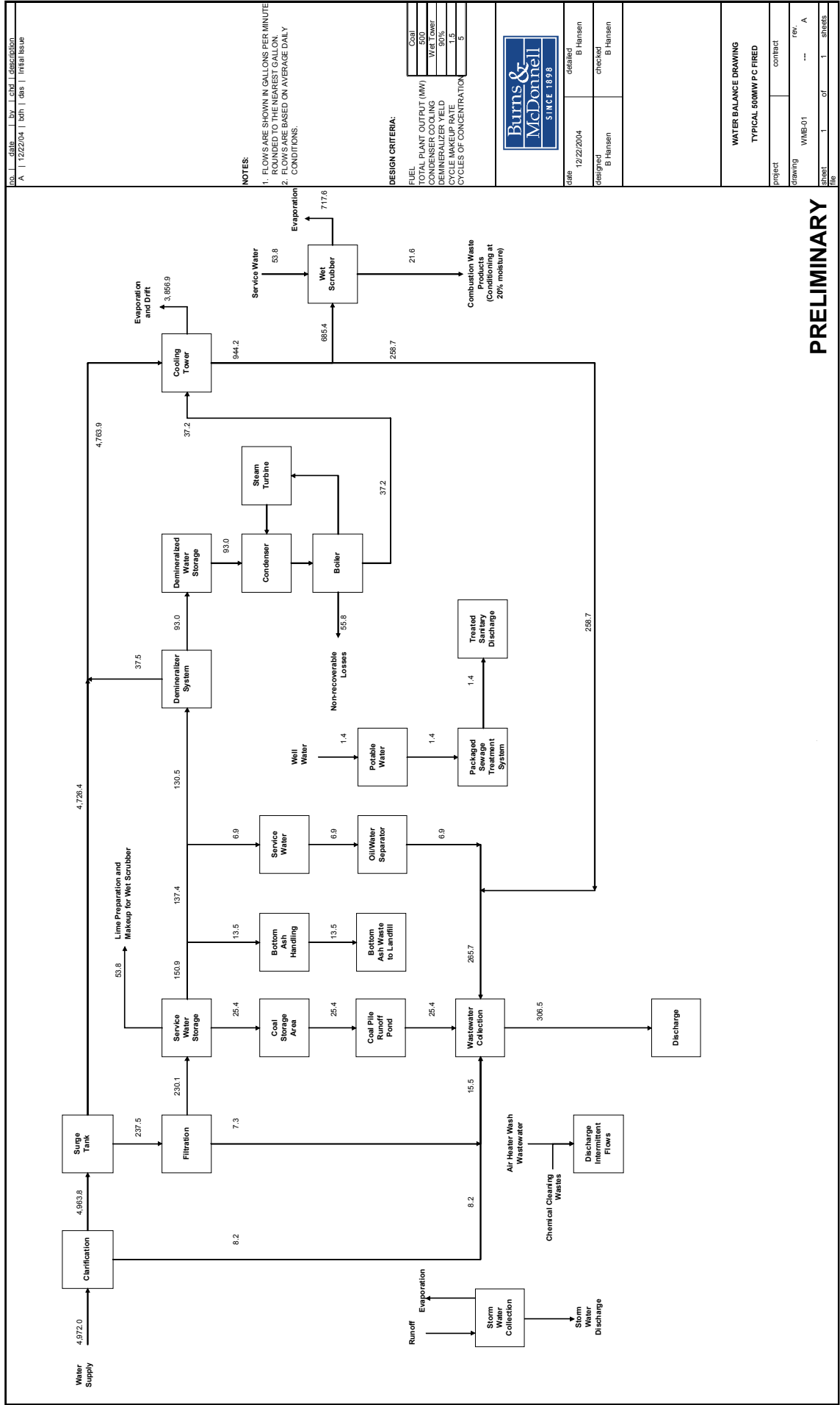
c. Water Consumption

Water consumption in a PC is a function of consumption in the boiler and losses of water vapor from the cooling tower. Consumption of water in the boiler is a function of boiler metallurgy. The amount of water consumed is dependent on the chemical concentration that the boiler tubes can withstand without suffering corrosion or erosion. There are also various losses in the boiler and ancillary systems related to evaporation and loss of water associated with combustion products (ash and WFGD solids).

Cooling tower drift involves the evaporation of water as the circulating water system removes the heat rejected when steam is condensed to water in the boiler/turbine steam cycle. Water consumption can be minimized through the use of high efficiency drift eliminators on the cooling tower. The TEC design incorporates this water saving feature.

A complete unit water balance is depicted below.

UNIT WATER BALANCE



NOTES:
 1. FLOWS ARE SHOWN IN GALLONS PER MINUTE
 2. FLOWS ARE BASED ON AVERAGE DAILY
 CONDITIONS.

DESIGN CRITERIA:

FUEL	Coal
TOTAL PLANT OUTPUT (MW)	500
CONDENSER COOLING	Wet Tower
DEMINERALIZER YIELD	90%
CYCLE MAKEUP RATE	1.5
CYCLES OF CONCENTRATION	3



date	12/22/2004
designed	B Hansen
checked	B Hansen
approved	B Hansen
drawn	B Hansen

WATER BALANCE DRAWING
 TYPICAL 500MW PC FIRED

project	contract
drawing	WMB-01
sheet	1 of 1
rev.	A
stage	1
sheet	1
stage	1

PRELIMINARY

Water consumption in the PC is summarized in tabular form below.

Table 6: Water Consumption		
Consumptive Process	Controls	Water Consumption (gallons/minute)
Boiler Processes	Proper Operation/Chemistry	1,115
Cooling Tower Losses	Drift Eliminators	3,857
Total Consumption		4,972

d. Solid Waste

Three types of solid waste will be produced by the PC boiler and its associated pollutant control devices: flyash, bottom ash and WFGD gypsum. The flyash consists of fine ash that is collected in the fabric filter system. The bottom ash is comprised of slag that is captured in the boiler. Gypsum is collected from the WFGD after the calcium salts have been forced oxidized.

All of these materials can be reused. Flyash can be used in the production of mortar mixes and concrete (although the activated carbon used for Hg capture will restrict potential uses). Bottom ash can be used as aggregate (a substitute for crushed limestone) in many application. The gypsum produced by the WFGD will be suitable for the manufacture of wallboard. The TEC will aggressively attempt to market each of these commodities.

Material that can not be marketed will be stockpiled on-site in a lined storage area with a leachate collection system. The liner/leachate collection systems will be designed to avoid any potential impact on groundwater resources.

e. Ability to Meet Design Requirements

The PC design, set out above, is capable of meeting all design requirements for the TEC. A tabular summary that contrasts PC performance with the design requirements follows.

Table 7: PC Design vs. Performance	
Design Requirement	PC Performance
The conversion of coal to electricity (heat rate, measured in Btu/kWh) should be as effective as possible to reduce fuel price volatility.	At a heat rate of 9,100 Btu/kWh (59 degrees F), this PC design is very competitive with existing or planned coal-fired generating units. At a coal cost of \$1.00/mmBtu, the fuel cost component of energy generated by this PC is \$9.10/MWh. For each \$0.10/mmBtu that fuel cost increases, the electric price increases by \$0.91/MWh. The PC design adequately addresses the need for price stability.
The design selected should provide the greatest flexibility possible for load changes within the constraints inherent in a base-load generation station.	A PC unit provides greater flexibility in dispatch than any other coal-fired technology. Output can be continuously varied within a range of maximum and minimum output limits and design ramp rates (the rate at which output can be varied).
The TEC shall be capable of achieving a minimum average annual availability of 90%.	This PC design can meet the 90% annual availability criterion for the TEC.
Project design must accommodate Best Available Control technology for the combustion technology that is selected.	The emissions limits proposed for the PC are equal to or lower than limits proposed for any planned PC unit under development. Therefore, this design will meet BACT requirements for a PC unit.
The technology selected must be capable of achieving a mercury removal efficiency of at least 90%.	This design will remove at least 90% of mercury emissions.
Consideration must be given to the issues imposed by a potential requirement for CO₂ capture and sequestration.	Carbon dioxide capture is very difficult with a PC unit. However, the design package will be as amenable to carbon dioxide capture as any existing PC unit that is in operation.

Table 7: PC Design vs. Performance	
Design Requirement	PC Performance
Water consumption must be minimized to reduce the impact on growth in the local community.	The design incorporates the latest mist elimination technology for use in the unit's cooling tower. Therefore, this design minimizes water consumption to the extent possible with a PC.
Combustion by-products must either be saleable (preferred) or capable of on-site storage without potential for damaging groundwater reserves.	All combustion by-products including bottom ash, fly-ash, and WFGD material (gypsum through forced oxidation in the WFGD) are saleable. Further, on-site storage is not expected to create groundwater issues.

2. Integrated Gasification Combined Cycle Design Package

The IGCC design for the TEC is premised on a nominal 677 MW (gross output) unit that can be described as encompassing three (3) technology blocks: air separation, gasification and syngas scrubbing, and power generation.

The air separation block is comprised of a single 100% capacity cryogenic Air Separation Unit (“ASU”) capable of providing 95% pure oxygen to the gasification block. In addition, low pressure nitrogen is produced for combustion dilution in the gas turbines to reduce NOx emissions.

In the gasification and syngas scrubbing block, coal is ground and mixed with water to create a fuel slurry. The slurry is then transferred to the gasifier, where it is mixed with oxygen in the gasifier feed injector. The coal/oxygen mixture is injected into the gasifier which has an oxygen deficient atmosphere. In this oxygen deficient environment, syngas (primarily comprised of hydrogen and carbon monoxide) is produced at a temperature of 2,300 to 2,700 degrees Fahrenheit. Coarse slag from the gasifier is captured and removed through the bottom of the vessel. The syngas is cooled in a radiant syngas cooler to generate high pressure steam.

The syngas is then scrubbed with water to remove entrained particulate. The dirty or “black” scrubbing water is flashed to lower temperature and pressure and concentrated in the fine slag handling section. This concentrated slurry is then filtered and the filter cake (fine slag) is captured and disposed of. The remaining water is treated to reduce chlorides and ammonia prior to disposal.

The scrubbed syngas is then subjected to low temperature cooling prior to entering the gas cleaning stage. In the gas cleaning process, the cooled syngas first passes through a mercury removal section where activated carbon removes the mercury that entered the gasifier in the coal feedstock. It then enters the acid gas removal process where sulfur is removed through interaction with an amine solvent. The acid gas removed from the syngas is processed in a Claus unit to produce a molten sulfur by-product. The syngas then enters a sulfur removal polishing stage in a hydrogenation reactor to provide tail gas treatment.

The power block uses syngas-fired combustion turbines (two (2) General Electric 7FA gas turbines) to produce electrical power. Heat Recovery Steam Generators are used to produce steam from the turbine exhaust gases. This steam is combined with steam from the gasification processes, superheated, and expanded through a steam turbine to generate additional power.

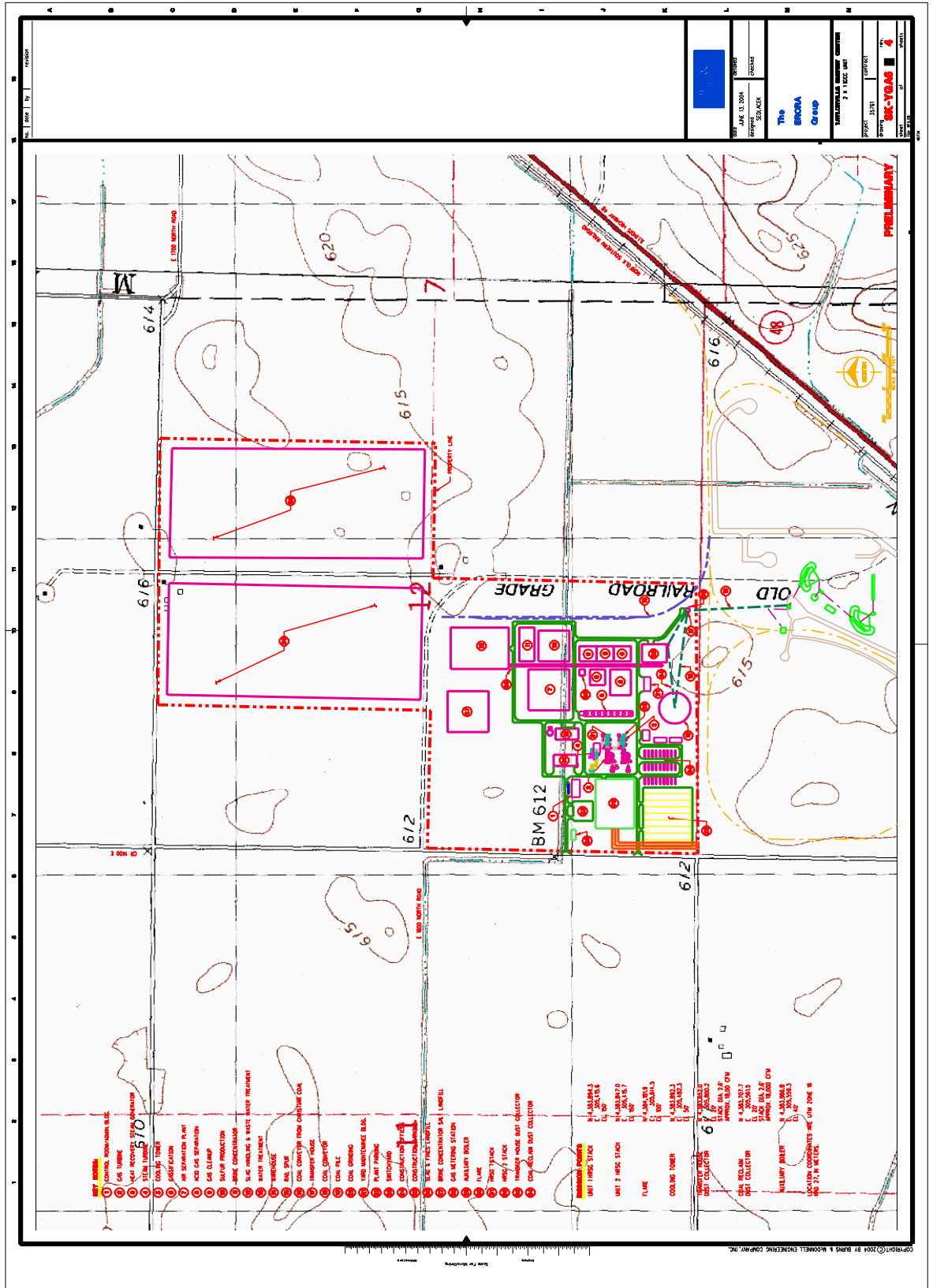
Design parameters and cost estimates for the IGCC package were prepared by GE Gasification, B&M and ERORA. A complete copy of the non-proprietary GE Gasification preliminary design package is attached as Appendix B.

The design and performance parameters for the IGCC unit are set out in tabular fashion below.

Table 8: IGCC Design and Performance Parameters	
Gross Output	677 MW
Auxiliary Power Consumption	120 MW (17.7%)
Net Output	557 MW
Average Annual Availability	91.0%
Heat Rate at 58 degrees F	9,039 Btu/kWh
Water Required	5,001 gpm
Water Effluent	1,029 gpm
Coal Usage	233 tons/hr
Fluxant Additive	Not required
Oxygen Feed Rate	175.1 tons/hr
Natural Gas Consumption (preheat spare gasifier)	3,250 lbs/hr
Natural Gas Consumption (thermal oxidizer burner)	1,200 lbs/hr
Combustion By-products:	
• Coarse Slag (wet basis)	39 tons/hr
• Fine Slag (wet basis)	13.9 tons/hr
• Molten Sulfur	9.4 tons/hr
Employees (operation and maintenance)	110
Emission Rates:	
SO ₂	0.045 lbs/mmBtu
NO _x	0.058 lbs/mmBtu
CO	0.036 lbs/mmBtu
PM ₁₀	0.007 lbs/mmBtu
VOC	0.006 lbs/mmBtu
H ₂ SO ₄	0.0051 lbs/mmBtu
Hg	> 95% removal

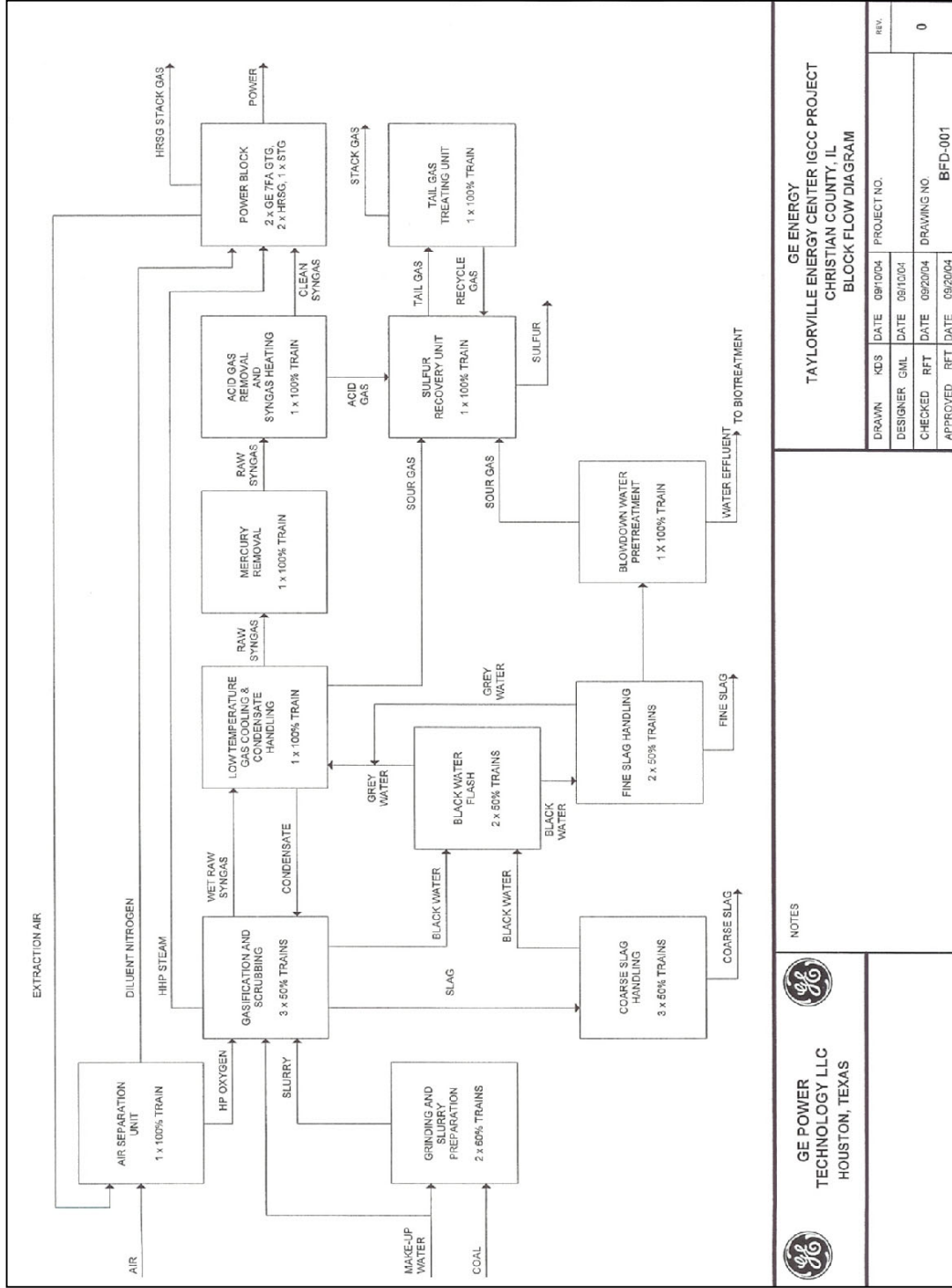
A site plan depicting the general arrangement of an IGCC installation at the TEC follows.

Site Plan - IGCC



The following tables and flow diagrams delineate the IGCC configuration, feed and product summary, project specifications, operating conditions, and major system specifications for the TEC.

Process Flow Diagram⁴



GE POWER TECHNOLOGY LLC HOUSTON, TEXAS		GE ENERGY TAYLORVILLE ENERGY CENTER IGCC PROJECT CHRISTIAN COUNTY, IL BLOCK FLOW DIAGRAM	
NOTES		DRAWN: KES DATE: 08/10/04 PROJECT NO.:	REV: 0
DESIGNER: GML DATE: 08/10/04	CHECKED: RFT DATE: 09/20/04	DRAWING NO.: BFD-001	
APPROVED:	RFT DATE: 09/20/04		

⁴ Source: GE Non-Proprietary Report

Table 9: IGCC Plant Configuration⁵	
Normal Operating Conditions¹	
Number of Gasifiers (Nominal reaction chamber volume 1,800 ft ³)	3 (2 operating + 1 spare)
% capacity Per Train	50%
Number of Trains and Capacities Per Train	
Grinding and slurry Preparation	2 x 60%
Gasification and Scrubbing	3 x 50%
Coarse Slag Handling	3 x 50%
Black Water Flash	2 x 50%
Fine Slag Handling	2 x 50%
Blowdown Water Pretreatment	1 x 100%
Low Temperature Gas Cooling	1 x 100%
Condensate Handling	1 x 100%
Mercury Removal	1 x 100%
Acid Gas Removal	
And Syngas Heating	1 x 100%
Sulfur Recovery Unit ²	1 x 100%
Tail Gas Treating Unit	1 x 100%
Power Block	2 x GE 7FA 1 x 100% ST
Air Separation Unit	1 x 100%
Notes:	
¹ “Normal Operating Conditions” comprise a consistent set of data for expected normal plant operation.	
² Two 50% SRUs may be required to meet local environmental regulations.	

Table 10: Feeds⁶	
Coal Feed Rate, Dry Tons Per Day (sTPD)	4,564
Oxygen Feed Rate to Gasification (pure O ₂ basis), sTPD	4,203

⁵ Source: GE Non-Proprietary Report Table 1.3.1 – IGCC Plant Configuration

⁶ Source: GE Non-Proprietary Report Table 1.2.1 – Feeds

Table 11: Products and Byproducts ⁷	
PRODUCTS	
Gross Power Generated, MW	676.8
Net Power Generated, MW ¹	557.3
BYPRODUCTS	
Coarse Slag, wet basis, sTPD ²	936
Fine Slag, wet basis, sTPD ²	333
Molten Sulfur, sTDP	226
Notes:	
¹ Net Power generated does not include Balance of Plant load.	
² Both slag products contain approximately 50 wt% water.	

Table 12: Charge to Gasifiers ⁸	
Normal Operating Conditions ¹	
Christian County Coal	
Charge Rate, sTPD ²	4,564
Ultimate Analysis, wt%, Dry Basis	
Carbon	72.01
Hydrogen	5.13
Nitrogen	1.20
Sulfur	5.02
Oxygen	4.54
Ash	12.08
Higher Heating Value, Btu/lb (Dry)	13,245
Moisture Content, wt%	12.81
Chloride content, ppmw	2,200
Oxygen	
Charge Rate, sTPD	4,203
Pure oxygen basis ²	
Oxidant Stream Purity, mol% oxygen	95
Notes:	
¹ "Normal Operating Conditions" comprise a consistent set of data for expected normal plant operation.	
² Values presented include no design margin. When feedstock information and operating conditions are finalized, appropriate design margins will be included in these values.	

⁷ Source: GE Non-Proprietary Report Table 1.2.2 – Products and Byproducts

⁸ Source: GE Non-Proprietary Report Table 1.3.2 – Charge to Gasifiers

Table 13: Gasification Operating Conditions⁹	
Normal Operating Conditions ¹	
Temperatures, °F	
Oxidant at Battery Limits	280
Gasifier Reactor Chamber Outlet	2.522
Pressure, psig	
Oxidant at Inlet of Control Valve	750
Gasifier Outlet	540
Notes:	
¹ "Normal Operating Conditions" comprise a consistent set of data for expected normal plant operation.	

Table 14: Syngas to Power Block¹⁰		
Normal Operating Conditions ¹		
Estimated Syngas Composition	MMscfd	mol%
Carbon Monoxide	148.4	45.12
Hydrogen	126.3	38.38
Carbon Dioxide	46.5	14.12
Water	0.63	0.19
Methane	0.40	0.12
Argon	2.6	0.80
Nitrogen	4.1	1.25
Hydrogen Sulfide	0.051	0.015
Carbonyl sulfide	0.0100	0.0031
Total	329.0	100.00
Syngas Rate, lbmol/hr, Wet Basis		36,123
Hydrogen plus Carbon Monoxide, MMscfd		274.7
Syngas Lower Heat Rate, MMBtu/hr		3,443
Syngas Lower Heating Value, Btu/scf		251
Notes:		
¹ "Normal Operating Conditions" comprise a consistent set of data for expected normal plant operation. and operating conditions are finalized, appropriate design margins will be included in these values.		

⁹ Source: GE Non-Proprietary Report Table 1.3.3 – Gasification Operating Conditions.

¹⁰ Source: GE Non-Proprietary Report Table 1.3.4 – Syngas to Power Block

Table 15: AGR Configuration¹¹	
Number of Trains	1
Capacity per Train	100
Total sulfur Spec, ppmv	100
Solvent Type	MDEA

Table 16: Power Block Configuration¹²	
Number of Combustion Turbine Generators and Capacity per Train	2 x 50% (2 x GE 7FA)
Number of Heat Recovery Steam Generators and Capacity per Train	2 x 50%
Number of Steam Turbine Generators and Capacity per Train	1 x 100%

Table 17: Combustion Turbine Feed Information¹³	
Conditions at Inlet to Each Combustion Turbine Feed Skid	
Pressure, psig	360
Temperature, °F	320
Syngas Rate, MMscfd, Dry Basis	164
Nitrogen Rate, MMscfd, Dry Basis	177
Syngas Lower Heat Rate, MMBtu/hr	1,721
Nitrogen Diluted Syngas LHV, Btu/scf	121
Backup Fuel	Natural Gas

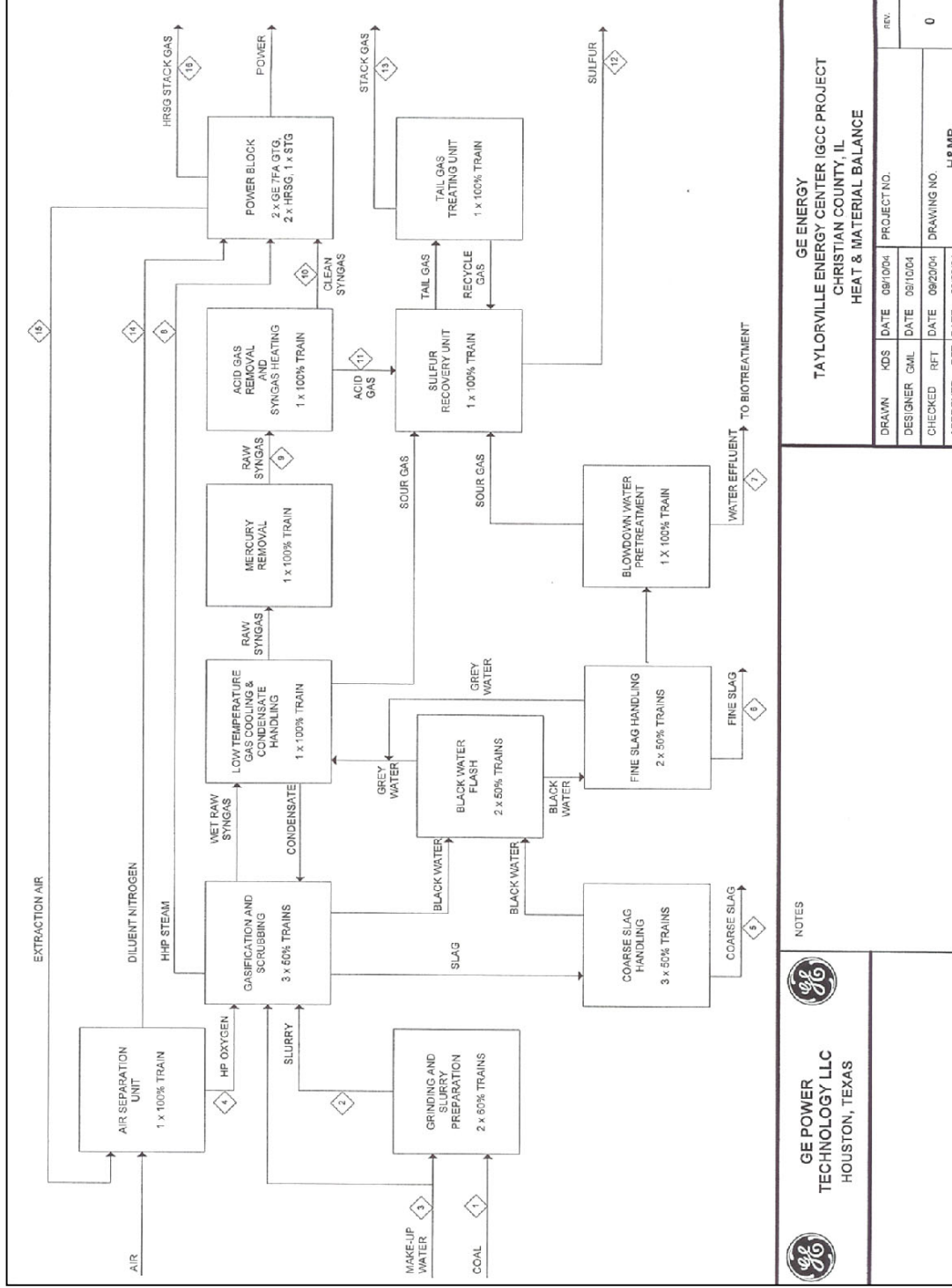
The heat and material balance for the IGCC package is depicted below.

¹¹ Source: GE Non-Proprietary Report Table 1.3.5 – AGR Configuration

¹² Source: GE Non-Proprietary Report Table 1.3.7 – Power Block Configuration

¹³ Source: GE Non-Proprietary Report Table 1.3.8 – Combustion Turbine Feed Configuration

HEAT AND MATERIAL BALANCE¹⁴



14 Source: GE Non-Proprietary Report Section

The heat and material balance for the IGCC facility are summarized in tables Table 18, Table 19, Table 20 and Table 21 below.

Table 18: Heat and Material Balance Table 1 ¹⁵		
	1	2
	Solid Feed	Slurry Feed
Flow STPD		
Dry Cool	4,564	
Water	670	
Total	5,234	

Table 19: Heat and Material Balance Table 2 ¹⁶						
	3	4	7	8	9	10
	Make-Up Water	Oxygen to Gasification	Water Effluent	HP Steam	Raw Syngas	Clean Syngas
Flow lbmol/hr						
CO						16,298
H ₂						13,864
CO ₂						5,101
H ₂ O	17,674			15,398		69
CH ₄						44
Ar		288				288
N ₂		288				451
H ₂ S						5.6
COS						1.1
O ₂		10,94				
Total	17,674	11,520	15,398			36,123
P, psig		750				360
T, °F		280				320

¹⁵ Source: GE Non-Proprietary Report Table 2.0.1

¹⁶ Source: GE Non-Proprietary Report Table 2.0.2

Table 20: Heat and Material Balance Table 3 ¹⁷						
	11	12	13	14	15	16
	Acid Gas	Molten Sulfur	TGTU Stack Gas	Diluent Nitrogen	Extraction Air	HRSG Stack Gas
Flow lbmol/hr						
CO	4					6
H ₂	3					
CO ₂	667		766			21,444
H ₂ O	69		327		46	20,387
CH ₄						
Ar					103	2,182
N ₂			1,949	38,035	8,228	189,283
H ₂ S	588.7					
COS	0.01					
O ₂			62	776	2,213	26,171
S		588				
SO ₂						
Total	1,333	588	3,105	38,811	10,591	259,480
P, psig	17			300	192	0.5
T, °F	120		650	350	817	-300

Table 21: Heat and Material Balance Table 4 ¹⁸		
	5	6
	Coarse Slag	Fine Slag
Flow lb/hr		
Slag	39,016	13,860
Water	39,016	13,860
Total	78,032	27,720

¹⁷ Source: GE Non-Proprietary Report Table 2.0.3

¹⁸ Source: GE Non-Proprietary Report Table 2.0.4

a. Design Issues and Alternatives

Several design issue/alternatives were discussed with GE Gasification in developing the IGCC package for the TEC. Each of those issues/alternatives is discussed below.

- *Reliability Benefits Related to a Spare Gasifier Module*

The design reliability requirement for the TEC is 90%. Therefore, one of the primary design considerations for an IGCC facility is the required equipment redundancy necessary to achieve this design requirement.

The only operating IGCC using GE Gasification technology primarily to produce electricity in the United States is Tampa Electric's Polk Station. That installation does not have a spare gasifier module. Reported availabilities for that installation are summarized below.

Table 22: Polk Station Availability	
Year	Gasifier Availability (%)
1996	27.5
1997	50.4
1998	63.3
1999	69.9
2000	80.1
2001	65.4

Experience at Cinergy's Wabash Station (which uses Conoco/Phillips gasification technology) has been similar with gasifier availabilities between 1995 and 1998 ranging between 22% and 60%. Recently,

Steelhead Energy submitted a Prevention of Significant Deterioration permit application for a Conoco/Phillips IGCC plant in Williamson County, Illinois. In that application, Steelhead stated that the anticipated availability for its installation, with no spare gasifier, is 81%.

Since the operating IGCCs have not demonstrated adequate availabilities to meet the TEC design criteria, ERORA requested that GE Gasification examine the use of a spare gasifier. GE Gasification determined that a spare gasifier would significantly increase expected reliability. This reliability increase is premised both on the use of the spare module when forced outages occur and on an enhanced proactive planned maintenance program. GE Gasification estimates that the TEC IGCC will have an average annual availability of 91 to 92%.

The cost associated with a spare gasification module (including construction and equipment) is estimated to be approximately 7.5% of total project cost or \$80 million. Despite this significant cost increase, ERORA has selected the spare gasifier option in order to meet the TEC's design availability criteria.

- *Integration Between Air Separation Unit and Power Block*

In order to increase cycle efficiency and reduce emissions of NO_x from the combustion turbines, integration of the ASU and power block must be examined. Typically, two forms of integration are investigated, use of nitrogen from the ASU for NO_x control in the combustion turbines and use of steam turbine compression to minimize required ASU compression. For the TEC, nitrogen from the ASU will be used to minimize NO_x emissions from the combustion turbines (by lowering combustion temperature and the formation of thermal NO_x). At

present, ERORA does not anticipate integration to lessen the compression requirements of the ASU. However, this view may change during the detailed design of the IGCC.

- *Syngas Cooling (radiant or quench)*

The third major decision related to the IGCC design involved the optimum method of syngas cooling. The choices studied included quench and radiant syngas cooling. The quench cooling system involves direct cooling of the syngas with water. In the radiant approach, indirect cooling is accomplished with a heat exchanger. The quench approach involves lower capital cost but also results in lower availability and reduced cycle efficiency. A comparison of the quench and radiant syngas cooling systems is set out below.

Table 23: Quench vs. Radiant Syngas Cooling Systems		
Performance Measure	Quench	Radiant
Capital Cost	base	+\$60 million
Reliability	base	+7.0 %
Net Power Output	base	+36 MW
Heat Rate (HHV)	base	-600 Btu/kWh

Economic analysis of the two options indicates that the benefits of radiant syngas cooling (increased reliability and output, decreased heat rate) more than offset the increased capital cost. Therefore, ERORA has preliminarily selected radiant syngas cooling for use at the TEC. During the detailed design phase, a more detailed analysis will be performed to examine both cooling approaches and select the optimum process.

- *SO₂ Removal*

During the gasification of coal, the sulfur constituents are released and converted to hydrogen sulfide (“H₂S”) and carbonyl sulfide (“COS”). These sulfur compounds must be removed from the syngas in order for the combustion turbines to achieve low SO₂ emission rates. There are two primary processes for removing these sulfur compounds from syngas, chemical absorption and physical absorption.

In a chemical absorption process, acid gases in the sour syngas are removed by chemical reactions with a solvent that is subsequently separated from the gas and regenerated. In the TEC, the amine solvent considered for chemical absorption is methyldiethanolamine (“MDEA”). In the MDEA process, the solvent forms a chemical bond with H₂S in the syngas. This chemical bond is then broken in a heat stripping process. The MDEA is regenerated while the H₂S is directed to the sulfur recovery process.

Physical absorption methods, including Selexol and Rectisol, use solvents that dissolve acid gases under pressure. The solubility of an acid gas is proportional to its partial pressure and is independent of the concentrations of other dissolved gases in the solvent. Therefore, increased operating pressures in an absorption column will facilitate the separation and removal of an acid gas like H₂S. The dissolved acid gas can be removed from the solvent, which is regenerated, by depressurization in a stripper. The Selexol process uses Union Carbide’s Selexol solvent while the Rectisol process uses cold methanol as the physical solvent.

In general, physical absorption methods can achieve greater sulfur removal than chemical absorption resulting in lower SO₂ emissions.

However, the resultant emission reduction comes at a very high price. A comparison of emission reductions associated with the three solvents discussed above and the associated costs of such removal is depicted below.

Table 24: Comparison of Emission Reductions				
Control Technology	SO₂ Emissions (lb/mmBtu)	Removal Efficiency (%)	Increase in Annual Cost (\$000)	Cost/Ton of Emissions Reduction (\$/ton)
MDEA	0.0455	99.4	Base	Base
Selexsol	0.0152	99.8	9,700	16,140
Rectisol	0.0076	99.9	16,000	21,277

Based on the extremely high cost associated with emissions reductions achieved through the use of physical solvents, the TEC will be designed with a chemical absorption system using MDEA.

- *Chemical Co-production*

Chemical co-production involves the simultaneous production of electric power and chemicals or the option to produce either product with the same production plant. At this stage of the TEC design, ERORA has preliminarily analyzed the co-production of methanol. For purposes of this study, we will restrict the discussion to co-production of methanol although various other chemical products including ammonia, sulfur and Fischer-Tropsch liquids can also be co-produced and will be analyzed prior to final facility design.

Methanol is a basic chemical feedstock that is primarily manufactured from natural gas. The rising cost of natural gas makes the production

of methanol from syngas produced by coal gasification potentially attractive. Methanol serves as the platform for the production of several higher value chemicals including acetic acid, acetate esters, methyl acetate, acetic anhydride, dimethyl ether, ethylene and propylene. These chemicals are used to produce a wide range of consumer products including transparent tape, camera film, artificial sweeteners, and pain relief medications.

The benefits of methanol co-production are dependent on the market price than can be achieved from the sale of this basic chemical. The TEC is not intended to be a merchant electric generation facility, meaning that both the electric and methanol output will be sold under some form of long-term contract prior to commencing construction.

To co-produce methanol, a production facility would be constructed on an approximately five (5) acre site adjacent to the IGCC. The methanol production facility would use syngas as the feedstock. For purposes of financial analysis, the capital cost associated with the methanol facility is assumed to be \$90 million (based on discussions with a methanol producer).

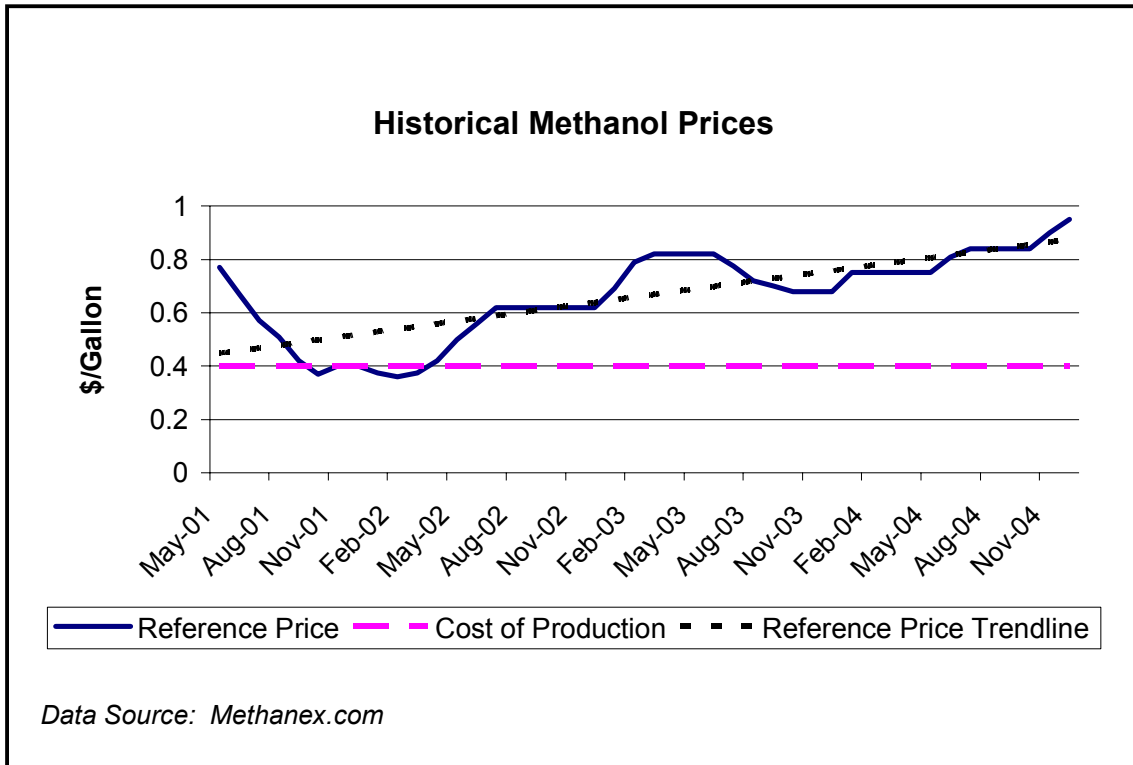
Two alternatives exist for co-production, specifically:

- Methanol could be produced from syngas generated from the spare gasifier while electric power is produced from syngas generated by the two gasifiers that are supplying the combustion turbines.
- Electricity could be produced during on-peak electric price periods (7:00 AM to 11:00 PM, Monday through Friday) from syngas produced by the two operating gasifiers. During off-

peak electric price periods, syngas would be shifted to methanol production. The spare gasifier would remain in hot stand-by for reliability purposes.

For methanol co-production to be financially attractive, the revenues from methanol sales must be adequate to cover variable production costs for methanol, the fixed cost associated with the methanol production facility, and that portion of the IGCC fixed cost that is related to methanol rather than electric power production. If this level of methanol revenues can be achieved, co-production becomes a very attractive option for an IGCC facility. Syngas production can be varied between electric power and methanol to optimize revenue generation within the constraints of sales contracts. In addition, the IGCC plant becomes more valuable to power purchasers because it can more readily accommodate load changes by shifting production between electricity and methanol without increasing the delivered electric price (fixed costs during methanol production are covered by methanol revenues). Likewise, the IGCC plant should be attractive to aggregators of industrial and commercial customers who could maintain consistent energy prices between customers even though their load profiles are different.

While much additional work needs to be done respecting methanol production, it appears to be a very attractive alternative for the TEC so long as Midwestern methanol prices continue to trade within their historical range of \$0.35 to \$0.90/gallon as shown in the graph below.



Prior to finalizing the design for the TEC, in addition to analyzing the economics and commercial feasibility of methanol co-production, the economics and commercial feasibility of other products, including sulfur and ammonia, will also be considered. It is anticipated that such analyses will yield similar results to the preliminary analysis of methanol; i.e., that using the syngas as a feedstock for such co-produced products is viable given current and projected natural gas prices.

b. Environmental Considerations

Air Pollutant Emissions

- *Oxides of Nitrogen (NO_x)*

NO_x is formed in the combustion process from two sources: fuel content NO_x and thermal NO_x. Fuel content NO_x is inherent in and dependent on the fuel being combusted. Thermal NO_x is a function of the combustion temperature and residence time in the combustion turbines.

Syngas has very little nitrogen content; therefore the primary form of NO_x created in the combustion turbine is thermal NO_x. To reduce the formation and minimize emissions of thermal NO_x, the TEC IGCC has been designed to inject nitrogen from the ASU to reduce combustion temperatures.

Low-NO_x burners are not currently available for combustion turbines fueled by syngas. In addition, SCR has not been proven to be effective with syngas-fired combustion turbines. There is significant concern that the oxidation of ammonia and SO₂ will result in the formation of sulfate salts, catalyst blinding, and the emission of sulfuric acid mist and other condensable particulate matter.

- *Acid Gases (H₂SO₄, HCl, and HF)*

Acid gases are removed in the acid gas removal and tail gas treatment sections of the gasification process using chemical absorption with MDEA reagent. In addition, since SCR is not used with the combustion

turbines, SO_3 formation and subsequent conversion to H_2SO_4 is minimized.

- *Mercury (Hg)*

Mercury is captured in the gasification process by means of a mercury removal bed that contains activated carbon.

- *Particulate*

Particulate matter from the combustion process primarily results from inert solids contained in the fuel. The gasification process, including the particulate scrubbing stage removes particulate as a vitrified slag or fine ash.

Particulate matter in material handling systems will be collected by fabric filters or alternative dust control equipment. Particulate entrained in the water vapor emitted from the cooling tower will be controlled through drift elimination devices.

- *Sulfur Dioxide (SO_2)*

Acid gases including H_2S are removed in the acid gas removal and tail gas treatment sections of the gasification process using chemical absorption with MDEA reagent. The removal of sulfur in the acid gas treatment process prevents the formation of SO_2 when the syngas is combusted in the gas turbine section of the power block.

- *Carbon Monoxide (CO)*

CO is produced in the combustion turbines as the result of incomplete combustion. However, combustion turbines are designed for efficient and complete combustion. CO will be controlled through good combustion turbine practices including proper air-to-fuel ratio, residence time, and temperature.

- *Volatile Organic Compounds (VOCs)*

VOC is produced in the combustion process as the result of incomplete combustion. However, combustion turbines are designed for efficient and complete combustion. VOC will be controlled through good combustion turbine practices including proper air-to-fuel ratio, residence time, and temperature.

- *Hazardous Air Pollutants (HAPS)*

HAPS include VOCA, acid gases, and heavy metal particulates. The TEC will control emissions of HAPS through proper gasifier and power block design and operation and an activated carbon bed (VOCA), acid gas removal (acid gases) and particulate scrubbing (heavy metals).

- *Transient Operations*

Transient operation occurs in three circumstances: gasifier start-up, planned gasifier/power block shut-down and forced gasifier/power block outages. A gasifier flare will be provided to burn on- and off-specification syngas (on-specification syngas is syngas that has been through the acid gas removal phase) produced from coal during planned and forced outages of the power block and gasification block.

The flare will include a natural gas pilot to ensure that gases can be flared when necessary.

The initial phase of a cold IGCC start-up requires pre-heating of the gasifiers. During this phase, the gasifiers will be heated with natural gas. Emissions associated with the natural gas pre-heating will be either aspirated from the gasifiers or vented to the flare. Pollutant emissions will be negligible since preheat requirements are limited to 19 MMBtu/hr and natural gas does not contain significant amounts of sulfur (the primary emissions will be NO_x and CO). The combustion turbines will also be fired with natural gas to warm the HRSGs and steam turbine. This will result in natural gas-fired emissions from the HSRG stacks that are similar to peaking combustion turbines which are not equipped with low-NO_x burners (25 ppm of both NO_x and CO).

During a planned or forced outage of the power block, on-specification syngas will be vented through the flare. Since this syngas has been treated, SO₂ emissions will not differ dramatically from emissions during normal operation. However, during a gasifier outage, off-specification syngas that is upstream of the acid gas removal section must also be flared. This syngas will produce untreated SO₂ emissions. Fortunately, the volume of off-specification syngas is quite small. Conservatively assuming 35 outages each year, cumulative SO₂ emissions during start-ups and shut-downs are expected to be approximately 6 tons annually.

The following table delineates the control equipment that will be used to control air pollutant emissions from the IGCC and expected pollutant emission rates.

Table 25: IGCC Control Equipment		
Pollutant	Control Device(s)	Emission Rate
NOx	Nitrogen dilution of combustion air.	0.058 lbs/mmBtu
H ₂ SO ₄	Acid gas removal by chemical absorption with MDEA solvent.	0.0051 lbs/mmBtu
Hg	Activated carbon bed.	> 95% removal
PM ₁₀	Syngas water scrubbing	0.0070 lbs/mmBtu
SO ₂	Acid gas removal by chemical absorption with MDEA solvent.	0.0455 lbs/mmBtu
CO	Proper combustion turbine operation.	0.0360 lbs/mmBtu
VOC	Proper combustion turbine operation.	0.006 lbs/mmBtu
HAPS:		
VOCA	Activated carbon bed	Non-detectable
HC	Acid gas removal by chemical absorption with MDEA solvent	0.00007 lbs/mmBtu
HF	Acid gas removal by chemical absorption with MDEA solvent	0.00003 lbs/mmBtu
Benzene	Activated carbon bed	0.00002 lbs/mmBtu
Cadmium	Water scrubbing	0.00002 lbs/mmBtu
Chloroform	Activated carbon bed	Non-detectable
Formaldehyde	Activated carbon bed	Non-detectable
Lead	Water scrubbing	Non-detectable
Nickel	Water scrubbing	Non-detectable
Arsenic	Water scrubbing	Non-detectable
Beryllium	Water scrubbing	0.000002 lbs/mmBtu
Chromium IV	Water scrubbing	0.00001 lbs/mmBtu
Manganese	Water scrubbing	0.0001 lbs/mmBtu

c. Water Consumption

IGCC water consumption is less per unit of electrical output (MW), at the TEC, than in a PC boiler because the IGCC generates 58% of its electricity (394 MW) from combustion turbines. This means that only 42% of an IGCC's output is produced in a steam turbine that requires condenser cooling water to maintain cycle efficiency. In a PC Boiler, 100% of the electrical output occurs in a steam turbine.

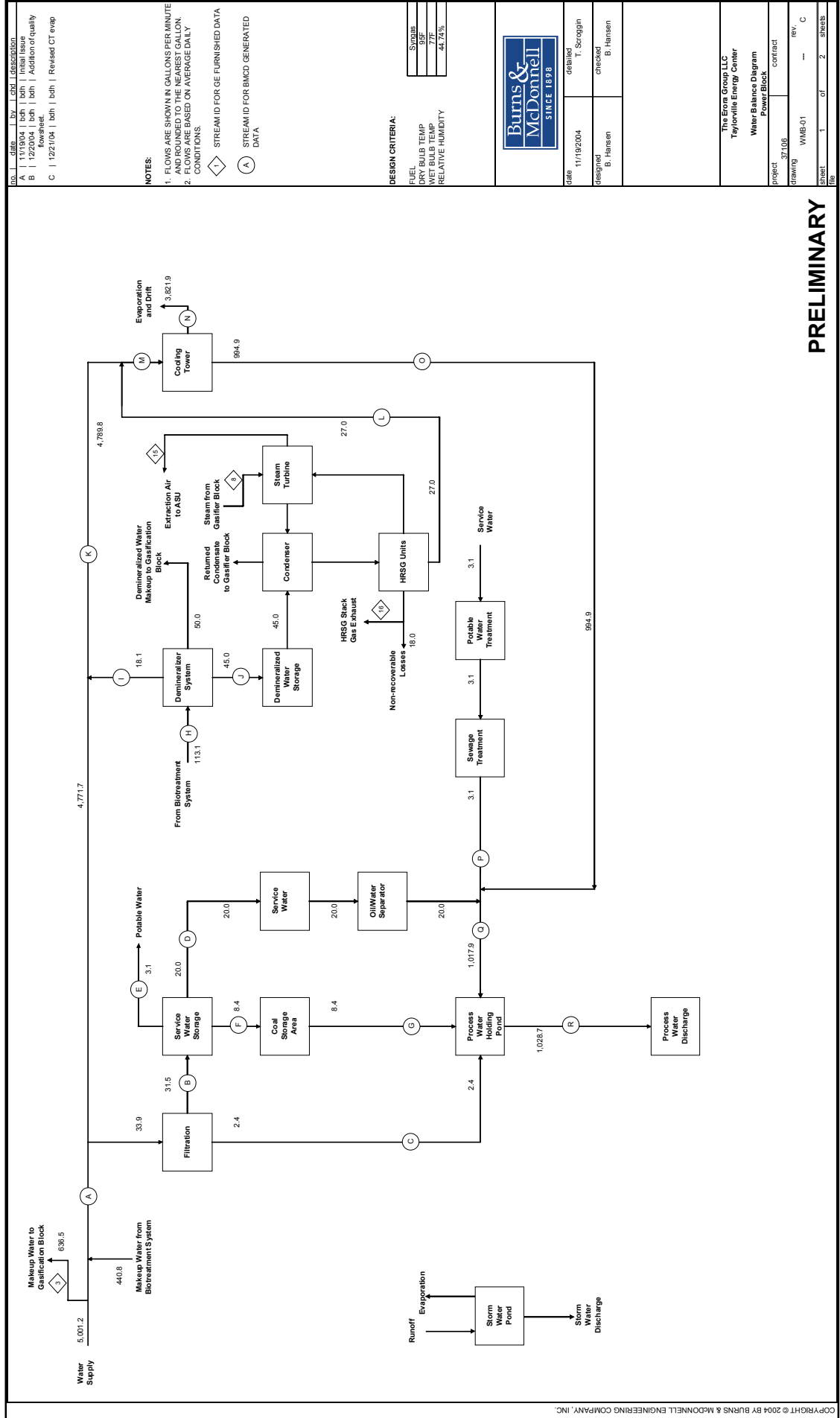
However, this water savings is partially offset by the need for water to slurry the coal feed to the gasifiers and the loss of water associated with combustion by-products. The IGCC consumes 7.4 gallons/MW minute as compared to 9.9 gallons/MW minute in the PC.

The IGCC experiences cooling tower drift in the same fashion that a PC Boiler does. As mentioned above for the PC Boiler, water consumption can be minimized through the use of high-efficiency drift eliminators on the cooling tower. The TEC design incorporates this water saving feature.

The IGCC process also requires treatment facilities to address control of ammonia, chloride, formate and other pollutants. The TEC is equipped with both a chemical pre-treatment and a bio-treatment facility to address potential pollutants in the effluent stream.

A complete unit water balance is depicted below.

UNIT WATER BALANCE – IGCC/POWER BLOCK



PRELIMINARY

Water consumption in the IGCC is summarized in tabular form below.

Table 26: IGCC Water Consumption		
Consumptive Process	Controls	Water Consumption (gallons/minute)
IGCC Processes	Proper Operation/Chemistry	1,179
Cooling Tower Losses	Drift Eliminators	3,822
Total Consumption		5,001

d. Solid Waste

Four types of solid by-products will be produced by the IGCC: coarse slag, fine ash, carbon and elemental sulfur. The coarse slag is a vitreous material collected from the bottom of each gasifier module. The fine ash and carbon are collected as a single product stream in the syngas scrubbing process and then separated in a hydroclone. Elemental sulfur is produced in a Claus process from the sulfur compounds that are captured in the acid gas removal process.

All of these materials can be reused. The coarse slag can be used in aggregate processes as a surrogate for crushed limestone. The fine ash can be used in the production of mortar mixes and concrete. The carbon can serve as a fuel in PC boilers and the elemental sulfur has many uses as a primary chemical. The TEC will aggressively attempt to market each of these commodities.

Material that can not be marketed will be stockpiled on-site in lined storage areas with leachate collection systems. The liner/leachate collection

systems will be designed to avoid any potential impact on groundwater resources.

e. Ability to Meet Design Requirements

The IGCC design, set out above, is capable of meeting all design requirements for the TEC. A tabular summary that contrasts IGCC performance with the design requirements follows.

Table 27: IGCC Design vs. Performance	
Design Requirement	PC Performance
The conversion of coal to electricity (heat rate, measured in Btu/kWh) should be as effective as possible to reduce fuel price volatility.	At a heat rate of 9,039 Btu/kWh (slightly better than the PC design), the IGCC design is very competitive with existing or planned coal-fired generating units. At a coal cost of \$1.00/mmBtu, the fuel cost component of energy generated by the IGCC is \$9.04/MWh. For each \$0.10/mmBtu that fuel cost increases, the electric price increases by \$0.90/MWh. The IGCC design adequately addresses the need for price stability.
The design selected should provide the greatest flexibility possible for load changes within the constraints inherent in a base-load generation station.	An IGCC unit provides less dispatch flexibility than a PC unit would. The IGCC requires significantly greater time to start up because of pre-heating requirements related to the refractory lined gasifier. In addition, since the gasification and syngas cleaning process are operated as a chemical process unit, fluctuations in operating throughput are much more difficult with an IGCC than with a PC. However, ERORA believes that chemical co-production in the TEC can greatly enhance the operational flexibility of the IGCC and can allow an IGCC to meet this design criterion.
The TEC shall be capable of achieving a minimum average annual availability of 90%.	This IGCC design is expected to exceed the 90% annual availability criterion for the TEC.

Table 27: IGCC Design vs. Performance

Design Requirement	PC Performance
<p>Project design must accommodate Best Available Control technology for the combustion technology that is selected.</p>	<p>The emissions removal efficiencies proposed for the IGCC are equal to or lower than limits proposed for any planned IGCC unit under development that is using amine scrubbing to remove SO₂. A recent Prevention of Significant Deterioration application, filed in Illinois by Madison Power for an IGCC installation, had a lower SO₂ emission rate than is currently proposed for the TEC (other pollutant emission rates were higher). However, the removal efficiency proposed by Madison is the same as is proposed for the TEC. The lower emission rate at Madison is the result of lower sulfur content in the coal being combusted. ERORA believes that amine scrubbing constitutes BACT (see SO₂ removal above) and we are confident that the TEC will achieve BACT.</p>
<p>The technology selected must be capable of achieving a mercury removal efficiency of at least 90%.</p>	<p>The design will remove at least 95% of mercury emissions.</p>
<p>Consideration must be given to the issues imposed by a potential requirement for CO₂ capture and sequestration.</p>	<p>Carbon capture in an IGCC can be accomplished more readily than with a PC. The IGCC design satisfies this design criterion.</p>
<p>Water consumption must be minimized to reduce the impact on growth in the local community.</p>	<p>The IGCC inherently consumes less water than a PC boiler since 58% of its output is produced by combustion turbines without the need for condensing water. That inherent advantage, coupled with the use of advanced mist elimination technology for use in the IGCC cooling tower represents the optimum approach to minimize water consumption at the TEC.</p>

Table 27: IGCC Design vs. Performance	
Design Requirement	PC Performance
Combustion by-products must either be saleable (preferred) or capable of on-site storage without potential for damaging groundwater reserves.	The IGCC process will produce four (4) combustion byproducts; elemental sulfur, carbon, coarse vitrified slag, and a fine ash filtercake. The first two by-products, sulfur and carbon, are marketable for use as a chemical feedstock (sulfur) and a fuel (carbon). The coarse slag is capable of being used in many applications such as aggregate use and sandblasting medium. However, established markets for this product are not mature at present. The fine ash is the least marketable product and will likely be stockpiled on site. The IGCC meets this design criteria in that all by-products can either be marketed or stored on-site.

D. Balance of Plant Design

1. Pulverized Coal

A description of the Balance Of Plant (“BOP”) design for a PC installation at the TEC follows.

Site Work –The BOP site work scope includes:

- Plant road from the local access road to the site boundary,
- On-site combustion waste storage,
- Site work required to produce a constructable site,
- Coal pile/runoff pond site work,
- Stormwater runoff pond, and
- Site drainage.

Stormwater System – The BOP scope includes site drainage and a stormwater detention pond.

Buildings – Several buildings are included in the BOP scope. These include:

- Water treatment building (for raw water/demineralized water treatment),
- Administration/control building,
- Coal transfer house building, and
- Warehouse and maintenance building.

Distributed Control System – The scope includes a distributed control system to manage and monitor all plant functions.

Switchyard – The BOP scope includes an on-site 138-kV switchyard in a 3-position ring bus configuration. These 4 positions are allocated as follows:

- Connection to Electrical Power Grid
- Steam Turbine Generator: Generator Step Up Transformer (GSU), and
- Unit Auxiliary Transformer.

The switchyard scope includes the necessary breakers, switches, and protective relaying to implement the ring bus configuration. The interface point for connection to the grid is at the ring bus at the position designated for that use. The interfaces to the on-site electrical distribution system are at the ring bus at the positions designated for the GSU and the Auxiliary Transformer.

Electrical Distribution – Electrical distribution to the facility is provided by the auxiliary transformer (138-13.8 kV) located in the switchyard which

supplies power to 13.8 kV switchgear. This 13.8 kV distribution switchgear feeds switchgear at the major load centers.

Coal Handling System – The coal handling system consists of the following components:

- A 42" belt conveyor from Christian Coal Handling System to the TEC coal handling system. The conveyor will be provided with a belt scale and an as-received sampling system.
- A receiving transfer tower complete with surge bin, variable speed belt feeders, chute work and a dust collection system.
- A 42" stock out conveyor complete with belt scale, an intermediate drive/take-up tower and a dust suppression system. The stock out conveyor discharges to a concrete stacking tube and will form a 70,000 ton stock pile (15 days of storage).
- An in-ground reclaim system consisting of 3 reclaim hoppers with variable speed belt feeders, a 42" reclaim conveyor, all hoppers and chutes, duplex sump pumps, emergency egress and ventilation and dust control.
- A 42" conveyor to the crusher house with a crusher and all ancillary equipment.
- A 42" transfer conveyor from the crusher house to the coal silo.

The coal handling system will be complete with fire protection, electrical, controls, and all foundations.

Cooling Water System – A mechanical draft cooling tower, distribution piping, pumps, etc., for steam turbine condenser cooling loads is included.

Interconnecting Piping – Required piping respecting boiler, turbine and cooling tower operations is included in the BOP scope.

Service Air/Instrument Air – Service and Instrument Air for the entire plant are provided.

Raw Water – The BOP raw water scope includes piping from the interface with the municipal water source, raw water treatment, and a 1.5 million gallon raw water storage tank with fire water reserve. Water is treated as required for direct supply to the demineralized water system and to provide utility water for other uses.

Wastewater Treatment – Wastewater treatment for the entire site is included in the BOP scope. Wastewater from the power block drains is routed through an oil-water separator. The water stream from the oil-water separator is discharged to the cooling tower. Blowdown from the cooling tower is routed to an interface with the municipal water system.

Demineralized Water – The BOP scope includes a demineralizer system to provide demin-quality water to the steam generator. A 300,000 gallon demineralized water holding tank is included.

Sanitary Waste – Sanitary waste from the admin/control building is routed to an on-site septic system. This cost is included in the cost of the administration building.

Fire Protection System – The BOP scope includes fire water supply from the raw water storage tank, fire protection pumps (electrical, natural gas, and jockey), and fire water piping.

Natural Gas – The BOP scope includes a pressure regulating and metering station. No gas compression, heating, or clean-up is included.

2. IGCC

B&M based the scope for the IGCC BOP on supplying the interconnecting systems, utilities, and infrastructure for the Gasification Unit, ASU, and Power Block. This includes site-work for the greater project area, coal handling, interconnecting piping between blocks, electrical substation and power distribution to each of the units, utility distribution between units, water treatment (demineralization and wastewater), and additional buildings and structures required for the BOP equipment and systems. A detailed description of the BOP scope of supply is described in the following paragraphs.

Site Work –The BOP site work scope includes:

- Plant road from the local access road to the site boundary,
- On-site gasification by-product storage,
- Site work required to produce a constructable site,
- Coal pile/runoff pond site work,
- Stormwater runoff pond, and
- Site drainage.

All other civil/site work required is included in the power block, gasification unit, and ASU design as provided by GE Gasification.

Stormwater System – The BOP scope includes site drainage and a stormwater detention pond.

Buildings – Several buildings are included in the BOP scope. These include:

- Water treatment building (for raw water/demineralized water treatment),

- Coal transfer house building, and
- Wastewater treatment (brine concentrator) building.

All other buildings required are included in the Power Block, Gasification, and ASU packages as provided by GE Gasification including the Power Block admin/control building, warehouse, and maintenance building.

Distributed Control System – The power block provided by GE Gasification includes a DCS for a standard combined cycle application. DCS upgrades are included in B&M's scope as required to upgrade control and display functions for an IGCC facility. The ASU and gasification system as provided by GE Gasification includes controls systems that are capable of interfacing with the plant DCS. B&M has included data links from gasification and ASU control systems to the plant DCS.

Switchyard – The BOP scope includes an on-site 138-kV switchyard in a 6-position ring bus configuration. These 6 positions are allocated as follows:

- Connection to Electrical Power Grid
- Gas Turbine Generator #1: Generator Step Up Transformer (GSU)
- Gas Turbine Generator #2: GSU
- Steam Turbine Generator: GSU
- Gasification Unit Auxiliary Transformer, and
- Air Separation Unit Auxiliary Transformer

The switchyard scope includes the necessary breakers, switches, and protective relaying to implement the ring bus configuration. The interface point for connection to the grid is at the ring bus at the position designated for that use. The interfaces to the on-site electrical distribution system are

at the ring bus at the positions designated for the GSUs and the Auxiliary Transformers.

Electrical Distribution – The auxiliary loads of the power block are fed by auxiliary transformers located after the generator breaker (before the GSU) of each gas turbine. These auxiliary transformers and all power cable, switchgear, motor control centers, etc., are provided in the GE Gasification power block scope.

Electrical distribution to the Gasification and Air Separation Units is provided by two 100% auxiliary transformers (138-13.8 kV) located in the switchyard that supply power to 13.8 kV switchgear. This 13.8 kV distribution switchgear feeds switchgear at the four major load centers (ASU, coal handling/slurry prep, gasification, and gas cleaning).

The BOP scope includes the two 100% 138-13.8 kV auxiliary transformers located in the switchyard, 13.8 kV distribution switchgear, non-seg bus duct (from the 13.8 kV distribution switchgear to the ASU switchgear), power cable, and additional auxiliary transformers (13.8-4.16 kV and 13.8-0.480 kV) as required for supply to the four major load centers.

Coal Handling System – The coal handling system consists of the following components:

- A 42" belt conveyor from Christian Coal Handling System to the TEC coal handling system. The conveyor will be provided with a belt scale and an as-received sampling system.
- A receiving transfer tower complete with surge bin, variable speed belt feeders, chute work and a dust collection system.
- A 42" stock out conveyor complete with belt scale, an intermediate drive/take-up tower and a dust suppression system. The stock out

conveyor discharges to a concrete stacking tube and will form a 84,000 ton stockpile (15 days of storage).

- An in-ground reclaim system consisting of 3 reclaim hoppers with variable speed belt feeders, a 42" reclaim conveyor, all hoppers and chutes, duplex sump pumps, emergency egress and ventilation and dust control.
- A 42" transfer conveyor from the transfer building to the Grinding & Slurry Preparation Building (furnished as part of the Gasification Unit scope and cost). The transfer conveyor will be provided with a belt scale.

The coal handling system will be complete with fire protection, electrical, controls, and all foundations.

Coarse Slag System – The BOP scope interface is at the outlet of the three coarse slag screens. The scope includes coarse slag storage (racquetball court type) at the outlet of each of the three screens

Fine Slag System – The BOP includes hydrocyclones and a drum filter to separate and dewater the intermediate high-carbon portion of the fine slag waste stream from the remaining fines. The hydrocyclones and dewatering equipment will be integrated into the gasification process. The BOP scope interface for handling the intermediate and fine slags is at the outlet of their respective drum filters. The scope includes storage at the outlet of each of the drum filters.

Sulfur Loadout System – The BOP interface point for Sulfur loadout is at the outlet of the molten sulfur pit of the Gasifier unit. The BOP scope includes insulated/heat traced piping from the pit to the loadout rack, piperack, and rail loadout system.

Auxiliary Boiler – A small package boiler (approx. 5,000 lb/hr, 300 psig) has been included in the BOP scope for Gasifier preheat aspiration. The scope for the auxiliary boiler includes the boiler, natural gas supply, feedwater piping, and steam piping to the Gasifier aspirator.

Cooling Water System –The mechanical draft cooling tower, distribution piping, pumps, etc., for Power Block cooling loads are included in the Power Block provided by GE Gasification.

Additional cooling capacity (approximately 300 MMBtu/hr) is required for the Gasification Unit and the ASU. The Power Block cooling tower and basin will be increased in capacity to provide the additional cooling capacity. The incremental cooling tower cells, basin footprint, and enlarged basin pump pit is included in the BOP. Dedicated auxiliary circulating water pumps will be located in the expanded cooling tower pump pit to serve the ASU and Gasification Unit loads.

Interconnecting Piping – All inside-battery-limits (ISBL) piping for the ASU, gasification Unit, and Power Blocks are included in GE Gasification's scope. This piping includes, but is not limited to, the following services:

- Blackwater flash,
- Slurry piping,
- Lockhopper circulating water to gasifier,
- LTGC piping to syngas scrubber,
- Syngas to LTGC,
- Grey water from fine slag handling to lockhopper flash drum,
- Water from blackwater flash to condensate handling and fine slag handling,
- Cooling water piping within the individual units, and
- Syngas piping within the gas clean-up area.

The BOP interconnecting piping scope includes only the piping to interconnect the ASU, Gasification Unit, and Power Block. This pipe includes the following:

- WBHHP boiler feedwater from power block to HP steam drum of gasifiers.
- WBHP boiler feedwater from power block to reaction furnace waste heat boiler (SRU).
- SCHHP condensate from first reheater of sulfur recovery unit to power block.
- SCHHP condensate from tail gas treating unit to power block.
- SCHP condensate from second reheater of sulfur recovery unit to power block.
- SCHP condensate from tail gas treating unit to power block.
- SCHP condensate from acid gas heater and air heater of sulfur recovery unit to power block.
- SCHP condensate from COS hydrolysis feed heater (low temperature gas cooling).
- SCHP condensate from the sweet gas heater (AGR) to the power block.
- WBLP feedwater to fine slag drum filter package.
- WBLP feedwater to stripper reflux pumps (AGR process).
- WBLP feedwater from power block to tail gas treating unit.
- WBLP feedwater to amine make-up system (TGTU).
- SCLP condensate from blowdown water pretreatment.
- SCLP condensate from AGR process to the power block.
- WBLP feedwater to first condenser, and second condenser of sulfur recovery unit.
- WBLP feedwater from the power block to the low temperature gas cooling system (LP steam generator #1 and #2).

- SCLP condensate from the mercury removal bed preheater to the power block.
- SCLP condensate from amine stripper reboiler (TGTU) to power block.
- Oxygen and nitrogen piping from ASU to gasification and power block.
- Syngas piping to power block from AGR.
- Service air/instrument air piping from ASU to gasification and power block areas.
- SHHP steam from radiant syngas cooler to power block.
- SHHP steam to tail gas treating unit.
- SHHP steam from power block to first reheater of sulfur recovery unit.
- SHHP steam to gasifier (for hot standby).
- SHP steam from power block to acid gas heater and air heater of sulfur recovery unit.
- SHP steam from reaction furnace waste boiler (SRU) to power block.
- SHP steam to COS Hydrolysis feed heater (low temperature gas cooling).
- SHP steam from the power block to sweet gas heater (AGR).
- SHP steam to tail gas treating unit from power block.
- SHP steam from power block to second reheater of sulfur recovery unit.
- SLP steam to preheat aspirator.
- SLP steam from power block to AGR process.
- SLP steam to sulfur pit.
- SLP steam to amine stripper reboiler (TGTU).
- SLP steam generated in the tail gas treating unit to power block.
- SLP steam to grey water stripper reboiler (blowdown water pretreatment).

- SLP steam generated in the low temperature gas cooling system (steam generator #1 and #2) to power block.
- SLP steam to the mercury removal bed preheater from the power block.
- SLP steam generated in first condenser, and second condenser of sulfur recovery unit to power block.

Service Air/Instrument Air – Service and Instrument Air for the entire plant are provided by the ASU. BOP scope includes piping from ASU to the Power Block and Gasification Unit (including the gas clean-up area). Piping within each of these areas is included in the ASU, Gasification, and Power Block provided by GE Gasification. Air compression equipment (including compressors, receivers, dryers, etc) are included in the ASU.

Flare System – The BOP scope interface for the flare system is at a single point within the Gasifier Unit. The BOP scope includes the flare header piping, pipe rack, and common end-of-pipe flare.

Nitrogen and Oxygen Distribution – BOP scope includes nitrogen piping from the outlet of the ASU to the power block and oxygen piping to the Gasifier Unit.

Raw Water – The BOP raw water scope includes the interface with the raw water piping from the municipal water source, raw water treatment, and 1.5 million gallon raw water storage tank with fire water reserve. Water is treated as required for direct supply to the demineralized water system and to provide utility water to the Power Block, Gasification Unit and ASU fence lines.

Wastewater Treatment – Wastewater treatment for the entire site is included in the BOP scope. The wastewater interface with the Gasification Unit and Power Block is at their respective fence lines.

Wastewater from the Gasification Unit is collected in a blowdown / reaction tank. Blowers are used to aerate the wastewater in the reaction tank(s) where chemicals are added to adjust the pH and assist with coagulation and flocculation in a clarifier. Precipitated and suspended solids are collected and removed from the clarifier in the sludge blowdown. Sludge blowdown is further dewatered in a thickener. Overflow from the thickener is returned to the clarifier. Sludge blowdown from the thickener is routed through a filter press where it is dewatered and produces a suitable solid for disposal of in a landfill.

Overflow from the clarifier is treated by additional chemical feed then routed to a reverse osmosis (RO) system. Permeate from the RO system is routed to a 300,000 gallon demineralized water storage tank that is used to supply demineralized water to the Gasification Unit.

Concentrated wastewater from the RO system is routed to a brine concentrator/crystallizer system. Distillate from the brine concentrator/crystallizer is routed to the demineralized water storage tank. The crystallizer produces a solid waste product suitable for disposal in an on-site landfill.

Wastewater from the power block drains is routed through an oil-water separator. The water stream from the oil-water separator is discharged to the cooling tower. Blowdown from the cooling tower is routed to an interface with the municipal water system.

Demineralized Water – The BOP scope includes demineralizer system to provide demin-quality water to power block and gasification fence lines. A 300,000 gallon demineralized water holding tank is included in Burns & McDonnell scope.

Sanitary Waste – Sanitary waste from the admin/control building is routed to an on-site septic system.

Fire Protection System – The BOP scope includes fire water supply from the raw water storage tank, fire protection pumps (electrical, natural gas, and jockey), and fire water piping to the ASU, Gasification Unit (including the gas clean-up area), and Power Block fence lines.

Natural Gas – The BOP scope includes a natural gas backup supply to the power block boundary. This scope includes a pressure regulating and metering station. No gas compression, heating, or clean-up is included.

E. Operations and Maintenance

1. Pulverized Coal

Operation and Maintenance expenses for a PC unit were estimated by ERORA based on input from B&M and our experience in the operation of PC facilities. The estimated O&M costs, delineated below, represent the costs necessary to provide total PC plant O&M including surplus combustion waste storage on site. Certain expenses that are common to both the PC or IGCC installation and that are the responsibility of the equity investors in the plant are not addressed in the cost information.

Those investor costs include:

- Fuel cost.
- The cost of emissions credits for SO₂ and NO_x. These costs will be dependent on the owner’s emission portfolios and whether emission “bubbling” strategies are employed.
- Property Taxes.
- Transmission expense.
- Back-up power expense.

Table 28: O&M Expenses		
Annual PC Operations and Maintenance Expense		
Fixed O&M		
Labor	Staffing (105 employees@ 60,000/year)	\$6,300,000
Office & Admin		<i>included</i>
Other Fixed O&M		\$2,467,000
Employee Expenses/Training		
Contract Labor		
Environmental Expenses		
Safety Expenses		
Buildings, Grounds, and Painting		
Other Supplies & Expenses		
Communication		
Control Room/Lab Expenses		
Total Fixed O&M Annual Cost		\$8,767,000

Table 28: O&M Expenses		
Annual PC Operations and Maintenance Expense		
Non-Fuel Variable O&M		
Water Consumption		
Makeup Water	0.3 MMGal/hr @ \$1,369/MMGal	\$3,238,000
Water Disposal	0.02 MMGal/hr	Included in make-up water cost
Other Variable O&M	\$0.63/MWh	\$2,270,000
Electronics, Controls, BOP Electrical		
Steam Generators		
Steam turbine Generators		
BOP		
Misc. Maintenance Expenses		
Consumables		
Limestone Consumption	30.2 TPH @ \$12/ton	\$2,857,000
DSI and Hg reactant injected		\$2,054,000
SCR Ammonia & Replacements	\$0.56/MWh	\$2,017,000
WFGD By-Product Storage	67.1 tph @ \$1.00/ton	\$529,000
Ash Storage	Included with WFGD	<i>included</i>
Total Non-Fuel Variable O&M		\$12,965,000
Total Fixed and Variable O&M		\$21,732,000
Total Fixed O&M (\$/kW-yr)		\$17.53
Total Non-Fuel Variable O&M (\$/MWh)		\$3.29

2. IGCC

IGCC O&M costs are premised on estimates from GE Gasification and discussions with Eastman Gasification Services (“EGS”), one of the most experienced operators of coal-fired gasification equipment in the world. Both GE Gasification and EGS discuss IGCC O&M costs as a function of the total EPC cost of the IGCC plant. While this approach seems foreign to the power industry, it appears to be well accepted in the chemical process industry. Within this framework, both GE Gasification and EGS believe that annual O&M expense should fall within a range of three (3) to five (5) percent of total IGCC EPC cost. They define total EPC cost as “overnight” cost meaning that interest during

construction is not included. The cost estimates shown below, exclude the common costs that were excluded above for the PC (fuel, emission credits, etc.)

GE Gasification provided an aggressive staffing estimate for the IGCC, which is shown below.

Table 29: Typical IGCC Staffing¹⁹	
Category	Staffing Level
Office – Management/Supervision	6
Office – Engineering	7
Office – Other	11
Operations	52
Maintenance	6
Lab Support	4
	86
Contract Labor	
O&M Related	20
Other	4
Total Contract	24
Total Staff	110

ERORA believes that the staffing levels, proposed by GE Gasification, reflect a total annual O&M approach that is closer to 3% of total EPC cost than the upper range of 5%.

EGS suggested a more conservative approach, based on their operating experience with a bituminous coal-fired gasifier in Kingsport, TN. They estimate a total staffing requirement (full time equivalent employees including contractors) of approximately 215 employees. With this more conservative approach, EGS estimates that total annual O&M expense will be in the range of 4.2 to 4.5% of total EPC cost.

¹⁹ Source: GE Non-Proprietary Report Table 7.0.1.

For the purposes of this study, ERORA has estimated total annual O&M expense to be 3.5% of the total EPC cost or \$28,633,000.

3. Safety Analysis

Like all industrial facilities, power generation plants have the potential to create safety issues if they are not operated with a view that safety of employees and the surrounding community are paramount. The IGCC in particular, requires an enhanced safety program since pure oxygen (from the ASU) is extremely flammable and H₂S in the sour syngas is toxic. The O&M estimates, provided above, are premised on a safety paradigm that ensures not only employee safety but also will address any community concerns.

4. Required Permits

Both the PC and the IGCC designs will be subject to virtually identical local and environmental permitting requirements. Those requirements are set out below.

Table 30: Permits

Issue	Required Permits
Land Use	Local Zoning (complete) Conditional Use Authorization (complete) Building Permit Site Environmental Study (endangered species, wetlands, historic artifacts) Noise and Lighting Plans Traffic Plan Septic or Sewer Connection Permit
Air Pollution	PSD Permit Title V Operating Permit Acid Rain Permit Continuous Emissions Monitoring System (“CEMS”) Certification Alternative Fuels Capability Certification IL SIP Requirements
Water Withdrawal	No requirements, water will be provided by the City of Taylorville
Water Discharge	IL requirements for return water to Taylorville NPDES Stormwater Run-off Permit Wastewater Facility Approval
Combustion By-Product Storage	Solid Waste Landfill Permit
Hazardous Waste	RCRA Permit and Regulations

Table 30: Permits	
Issue	Required Permits
Storage Tanks	Storage Tank Permits (above and below ground) Facility Response and Risk Management Plans
Air Safety	FAA Stack Height Permit

In addition, the TEC may need to be certified by the Federal Energy Regulatory Commission (“FERC”) as either a Qualifying Facility (“QF”) or an Exempt Wholesale Generator (“EWG”). The need to be FERC-certified depends on the composition of the TEC’s equity investors and customers.

Part IV ECONOMIC ANALYSIS

A. Financial Summary

The financial pro formas which follow are based upon seven general data sets:

1. plant configuration and operating parameters;
2. capital costs;
3. operating costs;
4. debt financing parameters;
5. state of Illinois incentives;
6. other costs/parameters; and
7. required equity returns.

Based upon these inputs, for each plant configuration, the revenue stream necessary to earn the required return is generated. For ease of comparison, the revenue stream is modeled as a flat 30-year fixed price expressed in \$/MWh. While this is not the preferred manner in which to structure a contract for the sale of power, it is a simple and accurate way to compare the prices required by the respective technologies to support a viable project.

While the specific data within the general data sets is set forth in the following section, the table below summarizes the sales price (\$/MWh) required to support the base configuration as well as several sensitivities which were examined.

	Table 31: Sales Price							
	Base		Sensitivity Capital Cost plus 10%		Sensitivity O&M Cost plus 15%		Sensitivity Fuel Cost plus 10%	
	IGCC	PC	IGCC	PC	IGCC	PC	IGCC	PC
Energy Sales Price	\$42.50	\$39.35	\$44.80	\$41.50	\$43.75	\$40.80	\$43.20	\$40.25
Equity Return	19%	17%	19%	17%	19%	17%	19%	17%
Leverage	72%	73%	72%	74%	72%	73%	72%	73%
Minimum Debt Coverage Ratio	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Average Debt Coverage Ratio	1.9	1.8	1.9	1.8	1.9	1.8	1.9	1.8

B. Detailed Review of Data

1. Plant Configuration and Operating Parameters

Plant configuration and operating data were provided by GE Gasification and B&M. The most significant inputs are set forth in the table below.

Table 32: Plant Configuration and Operating Data		
	IGCC	PC
Gross plant output (MW)	677	500
Auxiliary power consumption (MW)	120	43
Net plant output (MW)	557	457
Net plant heat rate (Btu/kWh)	9,099	8,999

Additional data respecting water usage, the volume of waste products generated, start up requirements, and environmental control costs, are included in the modeling and set forth in the above sections.

Operating data was supplemented by EGS and ERORA based upon detailed experience with gasification islands and PC units. Expected availability for the two configurations is set forth below.

Table 33: Expected Availability		
	IGCC	PC
Expected Availability Year 1	70%	80%
Expected Availability Over Complete Maintenance Cycle	91%	90%

Availability in any given year will vary depending upon scheduled maintenance cycles. The PC unit is expected to undergo regular three-year maintenance cycles while the IGCC is expected to experience regular maintenance annually.

2. Capital Costs

Costs specific to the plant configurations, as well as monthly construction timelines and monthly capital expenditures, were provided by GE Gasification and B&M. Additional costs for land acquisition and electrical and gas interconnections were provided by ERORA. Financing costs, as discussed further below, are based upon discussions with financial institutions. A summary of the capital costs are set forth in the table below.

Table 34: Summary of Capital Costs				
	IGCC		PC	
	\$000	%	\$000	%
Land	3,200	0.3	3,200	0.4
Spare Parts	15,000	1.4	15,000	1.7
Debt Service Reserve	29,595	2.8	24,517	2.8
EPC	818,084	77.1	653,655	75.3
Interconnections	22,600	2.1	22,600	2.6
Sales Tax	21,124	2.0	13,154	1.5
Total Overnight Costs	909,602	85.7	732,127	84.4
IDC	111,085	10.5	97,661	11.3
Fees	40,240	3.8	37,722	4.3
Total Costs	1,060,928	100.0	867,510	100.0
<hr/>				
Total EPC Costs (\$/kW-net)	1,469		1,430	
Total Overnight Costs (\$/kW-net)	1,633		1,602	
Total Costs (\$/kW-net)	1,905		1,898	

The capital costs for the IGCC reflect savings of 8.3% over the costs provided by GE Gasification in the study. GE Gasification suggested these savings as those anticipated to be achieved through the standard plant design currently being prepared in conjunction with Bechtel.

3. Operating Costs

Operating costs include both fixed and variable components many of which vary substantially between the technologies.

Expenses common to both configurations include fuel and water.

Fuel - Coal cost and quality are premised upon a Coal Supply Agreement discussed by ERORA and Christian Coal company and analysis performed by GE Gasification on core samples provided from the site of the proposed mine. The price set forth in the agreement equates to \$0.89/MMBtu.

Water - Costs for water are premised upon the executed Memorandum of Understanding between the City of Taylorville and ERORA. The effective cost is \$1,369/million gallons.

Expenses which vary substantially between the configurations include labor and incremental environmental controls.

Labor - The number of individuals required to operate the two configurations has the potential to be significantly different. B&M estimates that 105 employees will be required to staff the PC unit. GE Gasification estimates that it will take 110 employees to staff the IGCC plant, while EGS estimates total equivalent staffing at 215. The average annual salary, fully-burdened, is assumed to be \$60,000.

Environmental Control Train - The PC unit incurs additional costs for SCR ammonia, limestone, sodium bisulfite or lime and activated carbon to control NO_x, Sulfur dioxide, Mercury and acid gas mist respectively, post combustion. Control of these pollutants occurs before combustion of the synthetic gas with the IGCC making it difficult to succinctly compare the costs between configurations as the PC unit incurs costs on both a capital and operating basis while the IGCC incurs the costs predominately on a capital basis with significant operating costs limited to activated carbon for mercury removal and MDEA reagent for sulfur capture.

In total, the operating costs for both technologies, assuming stable operation (i.e. outside of first year startup issues) are set forth below. All costs, except for coal and water, are premised upon annual escalation of 2% per year.

Table 35: Annual Operating Costs		
	IGCC	PC
Annual Operating Costs (\$000)	\$37,559	\$25,142
Annual Operating Costs (\$/MWh)	\$8.62	\$6.89

4. Financial Costs

In the course of the last six months, ERORA has spoken with numerous financial institutions in Chicago, New York and other locations, including boutique investment banks with specific expertise in the power industry, boutique investment banks with specific expertise in project finance, global commercial banks providing capital on an international basis to numerous industries including the power industry, and global investment banks with particular strength in the power industry. Included in the discussions were two of the three largest global project finance arrangers in 2003, and four of the five largest Americas-mandated lead arrangers in 2003. Several of the institutions are financing coal facilities currently under construction.

The goals of these discussions were two-fold:

1. to determine whether financial institutions are willing to finance IGCC facilities; and
2. if so, under what terms.

Based upon these discussions, ERORA concludes that an IGCC facility can be financed on either a project basis or “on balance sheet”. The main focus of the

discussions with financial institutions, however, was to determine whether the traditionally more favorable approach of project financing would be available. To the extent the ultimate equity owners are municipal organizations with access to tax-exempt financing or utility cooperatives, “on balance sheet” financing may be both preferable and less expensive.

Not every financial institution is willing to finance IGCC facilities on a project basis, but a sufficient number have stated a willingness to finance IGCC that ERORA believes it to be possible. This willingness, however, is based upon several critical prerequisites:

1. There must be a credit-worthy purchaser of the power (this is required regardless of the technology).
2. There must be a credit-worthy EPC contractor providing a full wrap of the construction with liquidated damages. The level of those damages is currently a point of discussion among developers, constructors and financial institutions. Not surprisingly, for IGCC projects, financial institutions would like to see liquidated damages that exceed those typically provided for conventional coal technologies. Ultimately, the industry will drive EPC contractors and will drive financial institutions to agree on the appropriate warranties and guarantees. (See Appendix D for a comparison of IGCC and PC warranties and guarantees.)
3. There must be additional provisions for liquidity in the first year or two of operations in anticipation of problems with start up.
4. In a deregulated environment such as Illinois, a mechanism must be adopted by the Illinois Commerce Commission to encourage new generation development in a post 2006 environment for electric procurement through long term power purchase agreements or other means.

Traditionally, there are three separate markets in which power projects can be financed on a project basis. Those markets and their historic advantages and disadvantages are set forth below.

Table 36: Capital Markets			
	Capital Markets	Commercial Bank	Institutional Loan
Advantages	Post construction permanent financing with extended maturities (25+ years)	Generally lowest cost	Market will take construction risk
	Greater covenant flexibility	Prepayment flexibility	Tenors up to 10 years
	High-yield investor interest very high now	No credit rating required	Flexible amortization schedules
Disadvantages	Require two investment grade ratings	Pool of syndicate banks shrinking—fewer investors	Generally needs two credit ratings
	Limited construction financing	More restricted covenants	
	Limited prepayment flexibility	Short maturities (2 years) means refinancing risk	

The current environment, however, is somewhat different, with the markets being further stratified domestically and internationally. U.S. banks are much more reluctant to provide project financing now than they have been historically, in part due to the losses suffered from financing merchant natural gas-fired plants over the last five years. European banks, however, are currently much more aggressive. Some, in fact, have indicated a willingness to provide longer tenors consistent with those of the capital markets as well as construction financing consistent with the institutional market.

Accordingly, the financing package upon which the project economics have been based is set forth below.

Table 37: Financial Package			
Item	Range	Selected	Rationale
Target Leverage	60% - 90%	75%	middle of range, lower than traditional project finance leverage of 80+%
Interest Rate	Libor + 150-175bp Treasuries + 150 - 250bp	7%	higher than current rates, reflects more reasonable average long-term rate
Tenor (Yrs)	15 - 25	30	term highly dependent upon PSA term; fees for refinancing in year 20 have no economic impact
Debt Amortization	Can be structured	Mortgage-style	conservative
Debt Coverage Ratio - Minimum	1.35 -2.0	1.5	2.0 figure was outlier; consistent data at 1.4-1.5
Debt Service Reserve (Months)	6	6	most frequent response
Financing Fees	100-150bp	200bp	expectation that fees will run high, especially for first IGCC
Construction Financing	0%-100%	100%	only available to very best credits; may require equity LOC

The figures above reasonably reflect a debt package achievable through a structured financing.

These assumptions were held constant for both configurations because most institutions cited a belief that the decision to project finance was binary i.e. you will or you won't, but if you do, it becomes just another project finance deal. That binary decision is guided by the criteria set forth above. If those criteria are met, some market participants have indicated a willingness to finance IGCC and to finance it under the same terms as conventional coal technology.

In addition to the project finance package set forth above, the project was assumed to receive \$100 million from Illinois state-backed bond proceeds under P.A. 93-167. This debt was included in setting the overall project debt level target of 75%. This financing is captured below in the Illinois Incentives.

5. Illinois Incentives

The financials incorporate the following incentives from the state:

Table 38: State Incentives			
	IGCC	PC	Basis
	<u>\$000</u>	<u>\$000</u>	
Grants			
Coal Revival Program	23,229	19,585	legislation formula
Illinois Department of Transportation (EDP/TARP/RFP)	5,000	5,000	50% of estimated cost of road/rail upgrades

Table 38: State Incentives			
	IGCC	PC	Basis
Tax Abatement			
EDGE Tax Credit	198	189	employees and salaries
Enterprise Zone Benefits			
Investment Tax Credit	4,309	3,447	PP&E and real estate improvements
Jobs Tax Credit	33	32	qualified new hires
Replacement Tax Investment Credit	4,309	3,447	PP&E and real estate improvements
Financing	100,000	100,000	1/3 of moral obligation bonds under P.A. 93-167; interest rate set at 4%

Also, the model reflects two additional benefits:

- As set forth under the tax summary below, the financials reflect the sales tax exemption for building materials in the State of Illinois.
- Real Estate Taxes are abated on a sliding scale over the first ten years of the project. In the first year, property taxes are abated 100%. In succeeding years, the abatement is reduced 10% from the previous year. In year 11, the abatement ends and taxes are payable at the full, unabated amount.

6. Other Costs/Parameters

Timeline - Both configurations are anticipated to take 36 months to construct. It is assumed that ground is broken in February 2007 and that the facility reaches commercial operations in February 2010.

Taxes - The taxes paid by the project are set out below.

Table 39: Taxes		
Tax	Rate (%)	Basis
Federal Income Taxes	35.00	Federal Income
State Income Taxes	7.30	State Income
State Sales Tax	6.25	All equipment purchases (materials exempt under Enterprise Zone)
Real Estate Tax	7.82	Land, fixtures and structures
Fuel Tax	6.25	Coal purchased

Tax Credits - It is assumed that all tax credits can be used in the year generated.

Depreciation - All plant and equipment is depreciated on a 35-year book basis and a 20-year MACRS basis for taxes with the exception of the gasification island for the IGCC configuration. It is depreciated on a 10-year MACRS basis for tax purposes.

Period to turn Payables and Receivables – Accounts receivable and payable are assumed to turn in 30 days.

7. Required Equity Returns

Target equity returns for the PC configuration were set at 17% which is consistent with the returns needed to interest potential equity investors in development stage PC units. Given the added complexities and historical difficulties of IGCC units, the market wants a higher return on its money for an IGCC unit. The financials are based upon a 19% return for IGCC, a 200bp premium. It is believed that this

premium, in conjunction with a turnkey EPC contract, a fully-contracted power off-take agreement and a financial institution providing debt financing will be sufficient to attract equity capital.

8. External Factors Affecting New Generation Development

It bears noting that the foregoing financial analysis is premised on a number of assumptions. Changes in one or all of these assumptions can have a significant impact on the analysis. For example, a precipitous rise in any of the following costs are likely to negatively impact development of this (and other) projects: coal prices, steel prices, interest rate increases. Conversely, a significant long-term drop in natural gas prices coupled with producers' willingness to enter into long-term contracts may result in the development of natural gas combined cycle ("NGCC") to satisfy future demand and impede development of coal projects.

Finally, public policy decisions will also have an impact on the future development of the TEC and IGCC generally. Examples of this include the nature of a national energy policy, the mechanisms for long term power contracts in a vertical style (NJ) auction currently under serious consideration in Illinois, and transmission issues between MISO & PJM West.

Part V CONCLUSION

To date, four IGCC facilities, totaling 797 MW have been constructed in the United States. The first two were built in the 1980s and operated for three and seven years respectively. The second two were built in the 1990s, and only one of them, Tampa Electric's Polk Plant, is operating today. Currently, there is approximately 950,000 MW of electric generating capacity in the United States and only 250MW of that total capacity (0.000026%), employs IGCC technology.

Given IGCC's limited operating history, the electric industry's reluctance to fully embrace IGCC as a viable combustion technology and to make substantive investments in the technology is understandable. The decision to invest \$1.0 billion on a technology seen by many as unproven, and on a scale larger than that ever undertaken, is not made lightly.

Nevertheless, the interest level among industry executives is rising as recent announcements by AEP, First Energy and Cinergy attest. This increased interest is attributable to several factors:

1. *Joint ventures undertaken by technology licensors and construction companies.*

These ventures are viewed by many as eliminating the warranty seams which previously existed when disparate technologies (air separation unit, coal gasification facility and combined cycle power block) were integrated physically but not contractually. GE's acquisition of Chevron-Texaco's technology and subsequent venture with Bechtel, and Conoco-Philips venture with Fluor are the two prime examples of such ventures.

2. *Growing experience with operating gasification facilities.*

Eastman Chemical's impressive success with its gasification facility (producing chemicals rather than electricity), achieving availability factors approaching 98% by using a spare gasifier train has eased some of the anxiety respecting reliability. In addition, the Polk Plant and Cinergy's Wabash Station (currently shut-down in a contractual dispute) have demonstrated IGCC operation in a utility environment.

3. *Increased focus on coal as a fuel source.*

The United State's coal reserves are vast. Coal provides energy independence and coal prices have historically experienced significantly less volatility than natural gas prices which have risen to \$10.00/mmBtu at times over the last several years and have remained consistently above \$6.00/mmBtu over the past two years.

4. *Increasing difficulty of permitting conventional coal technologies.*

As a fuel, coal is currently less expensive than gas, but the time and expense of permitting new pulverized coal facilities, and the subsequent litigation which often accompanies the issuance of air permits, threatens the industry's ability to meet future electric needs with coal-fueled generation in a timely fashion.

These issues began converging, just as ERORA was initiating development of the TEC, and ERORA has watched this convergence with growing interest. The TEC was initially slated to be developed as a conventional PC facility. Based on this convergence and initial engineering work for the TEC, which identified water availability as a constraint, ERORA became interested in the potential application of IGCC technology at the TEC. Accordingly, ERORA, with assistance from the

Illinois Clean Coal Review Board, undertook this integrated study to determine the technological and financial viability of using IGCC technology at the proposed TEC.

Based on engineering design work done by GE Gasification and B&M, and numerous discussions with technology vendors, operators of gasification facilities, the financial and banking community and potential power purchasers, ERORA has concluded that IGCC is feasible at the Taylorville site.

Furthermore, ERORA has concluded that the Taylorville site is well suited to pursue the construction of one of the first IGCC facilities in the country as the site has the following important characteristics:

- Access to abundant attractively priced coal supply.
- Potential for chemical co-production or polygeneration to address the pricing impacts of significant regional nuclear base-load generation.
- Significant concerns respecting air pollution issues in the region.

These characteristics suggest the TEC is the right opportunity to undertake the inherent risks associated with not only commercializing a new application but also of scaling up that application.

Accordingly, ERORA will continue the development of the TEC as a state-of-the-art coal-fired IGCC electric generating facility.

The decision to proceed with IGCC was premised upon:

1. Anticipated cost competitiveness with regional facilities under development:
 - Electric production costs are expected to be better than or comparable with a 500 MW PC facility at capacity factors of 60 to 85%; and
 - Lower fuel costs at the site have the potential to offset economy of scale cost advantages of larger PC (1,000 to 1,500 MW) facilities.
2. Third-party interest in potential chemical co-production at the site which provides dispatch flexibility in a region with significant baseload nuclear generation;
3. Environmental benefits, both with respect to lower initial air pollutant emissions and increased flexibility to deal with future air emission regulations; and
4. The favorable business climate in Illinois which provides financial incentives to attract new coal-fired generation and other business which increase electrical demand.

The benefits to the state of Illinois, of successful development of the TEC as an IGCC facility are tangible and extend beyond the reduced emission profile. Using IGCC technology in place of conventional PC technology at the TEC will result in a larger facility (to accommodate commercially proven combustion turbines), annual consumption of an additional 315,400 tons of Illinois coal, and will create additional employment opportunities related to operation and maintenance of the facility.

This decision does have consequences respecting the potential price of energy and therefore the viability of the TEC. While the all-in cost on a \$/MWh basis for the TEC IGCC facility is generally comparable to that of a PC facility at capacity factors below 85%, it is still approximately \$3.00 - \$5.00/MWh more expensive (a 10 to 13% economic penalty) at higher capacity factors and under other possible scenarios related to capital and operation/maintenance costs. Unless the market is willing to value the social benefits of IGCC (the value of the environmental externalities; as supported in the Illinois Commerce Commissions recommendations to the Illinois General Assembly in the Post 2006 Initiative Report – December 2004), and thus pay more for the energy, additional legislative or financial assistance may be needed for the TEC to reach fruition or for other IGCC facilities to achieve success in the coal fields of central and southern Illinois.

This support could take many forms including:

- *Direct assistance.* This could include direct grants in aid of construction, or additional bond programs making low cost financing available to facilities utilizing IGCC.
- *Tax incentives.* Examples of tax incentives include expanding the existing sales tax credit for pollution control equipment to include the entire gasification island and tax credits for purchasers of power from green coal sources such as coal gasification.
- *Environmental Regulations.* Enacting more stringent environmental regulations which would make existing generation sources uneconomical and would make permitting and operating other coal technologies more difficult and expensive.

- *Portfolio Standards*. The implementation of renewable green energy and “green” coal portfolio standards which encourage the purchase of energy generated from renewable resources and clean coal technologies.

LIST OF TABLES

Table 1: EPC Cost Comparison	8
Table 2: O&M Cost Comparison	9
Table 3: Emissions Comparison	12
Table 4: PC Design and Performance Parameters	30
Table 5: PC Boiler Control Equipment	40
Table 6: Water Consumption	43
Table 7: PC Design vs. Performance	44
Table 8: IGCC Design and Performance Parameters	47
Table 9: IGCC Plant Configuration	51
Table 10: Feeds	51
Table 11: Products and Byproducts	52
Table 12: Charge to Gasifiers	52
Table 13: Gasification Operating Conditions	53
Table 14: Syngas to Power Block	53
Table 15: AGR Configuration	54
Table 16: Power Block Configuration	54
Table 17: Combustion Turbine Feed Information	54
Table 18: Heat and Material Balance Table 1	56
Table 19: Heat and Material Balance Table 2	56
Table 20: Heat and Material Balance Table 3	57
Table 21: Heat and Material Balance Table 4	57
Table 22: Polk Station Availability	58
Table 23: Quench vs. Radiant Syngas Cooling Systems	60
Table 24: Comparison of Emission Reductions	62
Table 25: IGCC Control Equipment	70
Table 26: IGCC Water Consumption	74
Table 27: IGCC Design vs. Performance	75
Table 28: O&M Expenses	91
Table 29: Typical IGCC Staffing	93
Table 30: Permits	95
Table 31: Sales Price	98
Table 32: Plant Configuration and Operating Data	98
Table 33: Expected Availability	99
Table 34: Summary of Capital Costs	100
Table 35: Annual Operating Costs	102
Table 36: Capital Markets	104
Table 37: Financial Package	105
Table 38: State Incentives	106
Table 39: Taxes	108

ACRONYMS AND ABBREVIATIONS

<hr/>		HRSG28
A		I
AGC 22	ASU 45	IGCC..... 1
<hr/>		M
B		MAAC21
B&M 1	BACT 23	MAIN.....21
BOP 77		MDEA61
<hr/>		MWh.....2
C		N
CO 37	COS 61	NGCC 109
<hr/>		NO 37
D		NOx 36
DSI..... 30		
<hr/>		O
E		O&M9
ECAR 21	EGS 92	
EPC 7	ESP..... 35	P
EWG 96		PC 1
<hr/>		Q
F		QF96
FBC..... 24	FERC 96	
<hr/>		S
G		SCR.....24
GE Gasification..... 1		SERC Council21
<hr/>		SO ₂39
H		T
H ₂ S 61	HAPS 23	TEC 1
HG 37		

V

VOCs	39
Volatile Organic Carbons.....	40

W

WFGD.....	24
-----------	----

SELECT REFERENCES

AN ANALYSIS OF THE INSTITUTIONAL CHALLENGES TO COMMERCIALIZATION AND DEPLOYMENT OF IGCC TECHNOLOGY IN THE U.S. ELECTRIC INDUSTRY: Recommended Policy, Regulatory, Executive and Legislative Initiatives, Final Report, Prepared by Global-Change Associates March 2004

“Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process”, Final Report (Volume 2: Project Performance and Economics)”, Prepared by Air Products Liquid Phase Conversion Co., L.P., DOE Cooperative Agreement No. DE-FC22-92PC90543, June 2003.

Major Environmental Aspects of Gasification-Based Power Generation Technologies, Final Report, December 2002, U.S. DOE, NETL.

“IGCC – LEADERSHIP IN CLEAN POWER FROM SOLID FUELS”, POWER-GEN International 2002, Orlando, Florida, Norman Z. Shilling, Leader, Process Power Plants, Robert M. Jones, Manager, Process Power Marketing, GE Power Systems, Energy Products, General Electric Company