

Kemper IGCC Plant with CCS



Report out of the Technical Review

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Executive Summary

Overview

Mississippi's Kemper Integrated Gasification Combined-Cycle (IGCC) Plant with Carbon Sequestration and Storage (CCS) is an important and timely case study for the technical community. In June 2010, the Kemper Plant was approved for construction by the Mississippi Public Service Commission (MSPSC). In June 2017, an arrangement was reached between Mississippi Power and MSPSC to halt the operation of the integrated plant (involving primarily the coal gasification and carbon separation aspects) and to redirect certain operational steps to fire the plant's combustion turbine solely by natural gas, instead of from syngas derived from lignite coal as originally intended. While the contemporary economics associated with the operation of the plant and the other remaining start-up risks were cited as significant factors influencing the decision, the project did yield important technical findings. These findings will be of value to a range of stakeholders, including the research community and energy policy decision makers. Furthermore, there is merit in evaluating the technical performance of the plant against key design parameters, independent of the complex economic and regulatory considerations associated with the project.

As an example, operational data collected during the 2016-2017 demonstration phase will inform future decisions regarding carbon separation and sequestration from low rank coal. The project also revealed major technical challenges associated with the integration of multiple, complex sub-systems. At the same time, a variety of technical lessons and best practices learned are now publically available to be shared with stakeholders to help inform future steps. As a result, Georgia Tech's Energy Policy and Innovation Center (EPICenter) identified a set of experts and convened a technical review of the Kemper IGCC project in August 2017. Selected Southern Company experts from the project's technical and program management team were invited to provide presentations in an interactive roundtable format with experts from academia and major research organizations. In keeping with EPICenter's regional "ecosystem approach" to energy collaboration, a majority of the invited participants represented institutions in the Southeast region. The siting of the plant was influenced by important regionally distinct resources, such as coal supplies, CO₂ pipelines, geological and oil formations, which were all viewed in consideration of Southeastern electricity generation and grid demands. However, additional experts participated from other regions with deep expertise and interest in carbon sequestration including West Virginia, Pennsylvania, California, and North Dakota.

This document summarizes major technical accomplishments, key challenges, and insights for future consideration that derive from the Kemper IGCC project. For the purposes of the August review and this summary report, the focus is strictly upon technical findings of the demonstration as an emerging technology. Scale-up and integration of raw lignite coal as a feedstock, sub-systems, and unit and continuous processes for both proven and previously unproven engineering technologies are included. Key technical performance indicators for plant operations and emissions are presented and compared against design criteria and established regulatory references. In order to maximize the time among technical experts and to keep the scope manageable, economics and policy considerations are largely excluded.



What is IGCC with CCS?

IGCC is a multi-step process in which coal is gasified and separated into various intermediate streams, including a syngas stream consisting primarily of hydrogen and carbon monoxide. Coal gasification is often considered an attractive technology, because it provides a means of converting relatively abundant and inexpensive domestic coal into a gas suitable for burning in a highly efficient gas turbine combined cycle power plant. Additionally, this process is different from more widespread coal-combustion methods, as it removes a portion of the pollutants and emissions typically associated with coal fired generation. IGCC can enable both higher thermal efficiency and the capture of CO₂ pre-combustion, making the technology increasingly valuable to society in light of more stringent pollution and emissions standards.

Selected Specifications and Technical Metrics for Kemper

The power generation portion of the Kemper Plant consists of two Siemens SGT6-5000FCT gas turbines, which are individually coupled to two heat recovery steam generators that feed steam to a single Toshiba Steam Turbine. The plant is capable of producing 582 MW when firing syngas in the gas turbines, followed by burning natural gas in the duct burners in the exhaust of the gas turbines, increasing steam power production. Additionally, the plant is capable of producing 526 MW when operating syngas in the gas turbine, without duct firing. Kemper differs from traditional combined cycles that use natural gas or liquid fuel (oil), as Kemper can be fired on either natural gas, gasified coal, or a mixture of the two^{i, ii}. The Kemper IGCC plant leverages the gasification of coal to enable the removal of CO₂ prior to combustion, a design strategy not inherent to all IGCC plants. This process reduces the effective carbon-dioxide output per megawatt-hour (CO₂/MWh) to that comparable to a natural gas fired combined cycle.

The Kemper IGCC Plant generated a large quantity of technical data before operations ceased. In several instances, these data suggest that the plant met or exceeded its technical objectives or successfully demonstrated first of its kind technologies. In certain areas however, technical objectives were not sufficiently met or challenges were encountered, which are more fully discussed below. Finally, for a few distinct performance metrics, results are not yet conclusive, as data are either insufficient due to the truncated demonstration period, or are still being analyzed for more insights and implications. For more on key technical milestones that were not met, please refer the body of the present report and see References 1 and 2.

Included among the major achievements were: successful gasification of coal, meaning the conversion of lignite coal to syngas, over a 224 day period, 100% of the design coal feed capacity

ⁱ This fuel flexibility is obviously an important factor in the conversion to natural gas that has been directed by the MSPSC.

ⁱⁱ During the initial operation phase, the gas turbine OEM (Siemens) limited the load at which the gas turbine could operate on pure syngas to 70%. This meant that operation at full load required the addition of natural gas to the fuel stream to maintain a fuel mixture of approximately 2/3 syngas and 1/3 natural gas. This limitation was slated to be removed as more experience was gained firing on syngas. Ultimately, the plant was expected to run on 100% syngas, but was shutdown before this occurred.



to the gasifiers, and a carbon capture and transport rate of 65%ⁱⁱⁱ. The Kemper IGCC Plant generated a total of 164,900 MWh while operating on syngas. Beyond these technical metrics, Southern Company designed and/or developed and/or integrated at the commercial scale several novel pieces of hardware. Certain Kemper IGCC technologies were the first known demonstrations of their scale and kind, including the Transport Integrated Gasification (TRIG) technology, pressure decoupled advanced coal (PDAC) coal feeder, coarse ash cooling and depressurization (CCAD) systems, the demonstration of the largest Selexol system for CO₂ capture, and the coal fine cooling and depressurization systems (CFAD). For more on technical performance, accomplishments as well as remaining project challenges, please see References 1 and 2.

Challenges and Lessons Learned

The major challenges faced by the Kemper IGCC Plant fell predominantly into three categories of issues: general integration, first of a kind scale-up of technology, and scale-up issues with commercially available hardware. One significant yet surmountable integration challenge was the inconsistent quality of raw coal. Leaks in the syngas cooler superheated tubes and spalling in the gasifier seal leg outlet were also observed. Such leaks and heat exchanger issues are thought to be somewhat isolated events that may be typical of such first of a kind technology scale-up. Another scale-up related issue was the limited refrigeration capacity in the CO₂ removal system. A series of issues were encountered related to water treatment, including salt formation, sour water processing, pH imbalances, and water conductivity in the cooling towers, many of which revealed that sustained operation at high rates would be compromised or not possible on the “as-built” equipment at the established conditions. Fixes to address these problems were conceived and preliminarily attempted, but not yet fully implemented as the decision then halted relevant operations. Other minor problems and variances from expected targets were experienced, and are discussed in the body of this report. Many of these problems were analyzed in real-time from design, system engineering, manufacturing and shake-down perspectives. In some cases, proposed design and/or processing solutions were developed, but were not implemented due to June 2017 decision to halt further gasifier operations. Despite the decision to convert the project to natural gas, the Kemper project team plans to continue analyzing the large amount of data collected during the plant operation and develop best-practices for the design and operation of future IGCC plants.

Discussion Highlights and Key Points Raised

Technical readiness “on a normal pace” but some questions remain

The final demonstration phase for the Kemper IGCC Plant was 224 days, but there had been a planned schedule of demonstrations to prove increases in reliability that would have extended several years. The impact of this abrupt end to the demonstration schedule on technical insights and readiness of the project was mixed. In some sense, the collected data was sufficient to

ⁱⁱⁱ Carbon capture indicates the total ratio of carbon, in any molecular combination, removed from the fuel prior to combustion. This is in contrast to CO₂ capture which is indicative of the amount of CO₂ removed from the syngas stream pre-combustion in the Selexol™ process.



suggest confidence in many sub-systems and the integrated performance of the system as a whole. The trend of overall plant availability was shown to be “on a normal pace”, based upon actual plant readings and in comparison to other IGCCs, to reach the system-level program goals within a 2-3-year timeframe. However, due to the unexpected and early cessation of the project, there remains some uncertainty of the degree to which Kemper’s goals would have been reached or surpassed. Yet, it was agreed among participants that (a) further evaluation of the acquired data is needed, and therefore is on-going; and (b) the insights from that analysis will probably reflect areas of both achievement and challenge, the specifics of which are somewhat currently unknown.

Kemper IGCC with CCS “very unlikely” to operate as originally designed

Given the formal program review and subsequent agreement reached between public regulators and plant operators to switch the plant over to natural gas, discussants commented that it is “very unlikely” that the Kemper IGCC technology with CCS will operate as originally designed. While the combustion turbines will be able to burn natural gas and generate electricity, the majority^{iv} of the Kemper plant assets (as a whole) will not enter service, and the outlook for utilizing them in the future is uncertain. The Kemper plant demonstrated its project goal of meeting a nominal 65% carbon capture rate overall, which would meet the requirements under the EPA Clean Power Plan and the net carbon emissions rate of a typical modern NGCC plant without CCS.

Kemper as means of informing needs in higher education as well as research

The subject roundtable hosted faculty from Georgia Tech, Mississippi State University, Massachusetts Institute of Technology, Auburn University, University of Alabama, Penn State University, University of California Irvine, West Virginia University, and the University of North Dakota, Energy & Environmental Research Center. Two Georgia Tech faculty members noted that projects like Kemper, which are complex and expensive, are timely opportunities to assess the efficacy with which universities are educating young engineers. The Kemper project may provide not only an opportunity to assess technical readiness by industry and the research community to implement holistic solutions for energy and the environment, but can also provide insights for education in terms of adapting curriculums to consider timely engineering and technical challenges of import to the energy sector. It was also noted that the opportunities for young engineers to engage in such complex challenges, particularly around the integration of sub-systems, are limited. As a result, stakeholders would do well to take more complete advantage of technological insights and best practices from such projects to not only inform future research roadmaps but also to address educational goals, preparedness, and workforce development over the longer term.

^{iv} Majority of the assets⁹ by share of the total fixed investment costs



Closing thoughts and the complexity of isolating technical performance from the overall project

As noted throughout, the August 22 technical review excluded discussions of economic and regulatory factors, yet the decision to convert the Kemper Plant was clearly influenced by both. For example, at the time the project broke ground (June 2010), the price of natural gas was in a range at or above \$5/MMBTU (US EIA, Henry Hub), whereas at the time the decision was made by project management to convert the plant to a natural-gas fired combustion turbine (June 2017), the price of natural gas had fallen by more than 40%. Southern Company officials state that “the fuel price differential between natural gas and lignite was the primary reason for suspension of operations.” While the price of natural gas is likely a key driver, the project also incurred substantial capital cost overruns. According to an independent report contracted by the MSPSC in June 2017, “primary concerns are additional schedule slippage and associated cost increases and unknown startup and technology risks” [3]. Accordingly, the MSPSC began a legal process to ensure the project would incur no rate increase to customers and remove cost risk from customers, suggesting that overall economic impacts of the project were critical factors in the eventual decision to suspend coal gasification and CCS operations in June 2017. The report does not independently address all economic factors (such as the price of natural gas or the capital costs of the plant’s assets), nor how they may have been inter-related, and such issues are beyond the scope of this summary.

The regulatory context also evolved substantially from 2010 to 2017. For instance, after imposing standards on both existing and new plants (ca. 2015), the pursuit of the Obama’s Administration’s Clean Power Plan requiring states to implement state-wide emissions programs had stalled in the courts even before the 2016 elections, introducing considerable uncertainty into the regulatory mandate to attain specified targets. The project as a whole involved multiple, interacting factors that make the disaggregation of any individual aspect extremely complicated. Nonetheless, the technical review provided insights into both technical accomplishments, as well as major challenges and lessons learned that will prove valuable. The review also revealed that regional approaches to energy technology through collaborative, academically rigorous discourse can be effective in disseminating learning and accelerating progress toward national energy goals.



Introduction to the Integrated Gasification Combined Cycle Process

In very broad terms, Integrated Gasification Combined Cycle (IGCC) is a multi-step process in which coal is gasified and converted into various gases, primarily a stream consisting of hydrogen [H₂], water [H₂O] and carbon monoxide [CO]. Through additional chemical process, the water and carbon monoxide are converted to additional hydrogen and carbon dioxide. This allows for removal and processing of carbon dioxide upstream of the power generation process, as described below. Coal gasification is often considered an attractive technology, because it provides a means of converting relatively abundant and inexpensive domestic coal into a gas suitable for burning in a conventional gas turbine. Additionally, this process is different from more widespread, traditional coal-combustion methods, as it removes a proportion of the pollutants and emissions typically associated with coal fired generation. The process begins with a series of intermediate reactions, resulting in a gaseous fuel that is fed into a combined cycle gas turbine. This turbine is coupled with a steam generator to produce electricity at high efficiency. The resulting CO₂ and pollutant streams are separated (i.e., do not enter the combustion pathway), pressurized and/or stored for various purposes, such as enhanced oil recovery (EOR). This process can enable both higher thermal efficiency and the capture of CO₂ pre-combustion. For these reasons, coal gasification has recently received considerable attention in light of the 2015 EPA standards, shown in Figure 1, which require that new coal power plants emit no more than 1,400 pounds of CO₂ per gross MWh of power produced [4]. For comparison, new natural gas combustion turbine-fired combined cycle power plants have CO₂ emissions in the range of 800 to 850 pounds per MWh, whereas most modern coal fired plants emit almost 1,700 pounds of CO₂ per MWh. The operating target for Kemper (550 pounds of CO₂ per MWh on a gross basis) is significantly lower than existing coal plants.^v This goal was achieved and is achieved through capturing 65% of carbon dioxide upstream of the combustion process. Caution is advised when making direct comparisons of emissions and net efficiencies among different generating technologies and fuel sources. Gross technical performance of a plant is ultimately highly sensitive to variable factors, such as coal rank and fuel composition.

^v The operating target for Kemper (550 lbm of CO₂/MWh gross) was set at the beginning of the project, before the Obama administration coal power plant regulations were finalized. This was based on an anticipated (at the time) government regulatory limit of 800 lbm of CO₂/MWh net. The 550 gross and 800 net targets are roughly equivalent when accounting for parasitic losses due to running the gasifier portion of the plant. Ultimately, the EPA limit was set at 1,400 lbm of CO₂/MWh gross, which means that Kemper would have operated significantly below the final regulatory limit; however, due to the necessity of a Selexol process to remove Sulfur from the syngas and the ancillary revenue from CO₂ sales for enhanced oil recovery, aiming for the 550 lbm of CO₂/MWh gross target still makes economic sense.

Standards for Coal Plant CO ₂ Emissions Among Selected Alternative Technologies	
Technology Class	CO ₂ Emission Intensity lbs/MWh (Gross)
Integrated Gasification Combined-Cycle (IGCC) Plant without CCS	1540
EPA Reference Standard	1400
IGCC Plant with High- Quality Coal	1380
Integrated Gasification Supercritical CO ₂ Brayton Cycle Plant	1330
IGCC Plant with 1700C Combustion Turbine	1250
Target for Kemper	550

Figure 1: CO₂ Coal Plant Standards

To fully exploit the key advantages of gasifying coal, it is important to note that thermodynamic processes, such as those that convert combustion gasses to useful electricity, are more efficient when they operate at higher temperatures. Typical coal power plants emit 1,600 to 1,730 pounds of CO₂ per MWh, whereas typical natural gas fired combined cycle turbines emit 850 to 950 pounds of CO₂ per MWh [5]. This difference is partially due to the differences in fuel chemical composition, but is also due to the fact that the efficiency of coal fired steam turbines is limited by the ferrous materials used in the steam turbine itself. Increasing the steam temperature beyond today's limit would require more exotic metals to be used in the steam turbine. This would involve additional cost, maintenance, and engineering complexity. On the other hand, gas turbines operate at higher temperatures, leading to more efficient operation. Via innovation pioneered by analogous aerospace applications, these temperatures and their associated efficiencies are likely to continue to increase. Gasifying coal enables the fuel to be burned at a higher temperature within a gas turbine. Higher combustion temperatures are generally associated with more efficient (e.g., lower CO₂ production) power plants.

As noted, after gasification of coal, there is a conversion of carbon monoxide to CO₂, followed by a separation and isolation of the CO₂ from the main syngas stream before the fuel is burned. This allows most of the carbon to be removed pre-combustion and allows the gas turbine to run using primarily hydrogen. Because running in a premixed mode with hydrogen is difficult (because of flashback concerns), achieving low NO_x in a diffusion flame combustion mode requires diluting the hydrogen with a diluent, such as nitrogen. The resulting combustion product of the gas turbine is mostly water. Owing to its combination with a steam turbine coupled with precombustion CO₂ capture, an IGCC plant can operate efficiently, with a carbon dioxide output similar to a modern natural gas plant. Without carbon capture, the carbon dioxide output would

be similar to a conventional coal plant. This trend is true regardless of the coal rank, though fuel composition is a critical variable in determining overall technical performance of a power plant.

To further explain the justification for converting coal to a gaseous fuel, one must understand that different fossil fuels contain varying amounts of hydrogen and carbon. These elements undergo a series of intermediate reactions when combustion occurs. Ultimately, these elements are broken down and then burned (combined) with oxygen to form H₂O (water) and carbon dioxide (CO₂). Obviously, if the fuel contains only hydrogen, no carbon dioxide is generated. The amount of CO₂ released upon combustion is determined by the composition of the fossil fuel. As a means of comparing across various fuels, the CO₂ output can be normalized per million British thermal unit (BTU) of fuel, shown in Table 1[6]. Releasing one BTU of heat will raise one pound of water (just under one pint) by one degree. The fuels lower in Table 1 typically have a higher hydrogen to carbon ratio, which translates into lower CO₂ emissions per unit energy.

Table 1: CO₂ Contained within MMBTU of Fuel

<i>Fuel</i>	<i>Pounds of CO₂ per Million BTUs</i>
Coal (anthracite)	228.6
Coal (bituminous)	205.7
Coal (lignite)	215.4
Coal (subbituminous)	214.3
Diesel fuel and heating oil	161.3
Gasoline (without ethanol)	157.2
Propane	139.0
Natural gas	117.0

The ratio of the mass of CO₂ per million BTUs of fuel seen in Table 1 is representative of what would be achieved through a complete (ideal) combustion. However, to understand these levels in terms of the EPA-standard a detailed knowledge of the process by which heat is converted to electricity is required. There are two common mechanisms for achieving this conversion. First, a gas turbine can combust liquid or gaseous fuel directly and then expand the hot, pressurized air through a turbine, which is connected to an electrical generator (a.k.a. Brayton Cycle). The resulting hot gasses may then be used to boil water, creating steam before then expanding through a steam turbine connected to a generator (a.k.a. Rankine Cycle). To simplify this process, a gas turbine and steam turbine are frequently coupled together. This arrangement is known as a ‘combined cycle’, because the gas turbine and steam turbine operate on different thermodynamic cycles. Due to mechanical, thermodynamic, and physical limitations, the gas turbine is unable to extract all of the energy released by combustion. Any remaining hot exhaust gas is therefore used to superheat steam, which is then used to drive a steam turbine, which in turn produces electricity. Combining a steam turbine with a gas turbine increases net electrical

production efficiency from about 40% to more than 60%^{vi}. (i.e., 1.5 times electricity is produced for the same amount of combusted fuel).

2.1 Gasification and Associated Processes

The conversion of solid coal to a clean combustible gas requires a number of integrated steps. Some of these steps require heat as an input to cause a specific chemical reaction. Others generate large quantities of heat that must be removed. Heat that is not used in another process is a waste and reduces the net efficiency of the overall plant. While the details of these heat interactions are not described here, they were considered in the tightly integrated design of the Kemper IGCC. The degree of thermal (heat) integration between the gasification steps is a direct driver of the plant CO₂ output per MWh. Figure 2 a general overview of the overall gasification, and its required sub-processes. A general description is provided, but the reader should be aware there are many variations on each step in the process that make the details of any site specific.

The first step entails coal and oxygen or air being fed into a gasifier. The gasifier then uses heat to initiate a chemical process that converts the coal into a syngas. This syngas is a combination of gaseous carbon monoxide, hydrogen, and carbon dioxide, nitrogen, methane and trace amounts of contaminants that are removed later in process. Key to the gasification process is heating the coal at a temperature high enough to drive the gasification reactions, while still consuming less oxidant than required for full combustion. This prevents the conversion of the CO and H₂O to CO₂ and water too early in the process. While the CO and hydrogen could be combusted directly, the CO would simply be converted to CO₂, negating many advantages of the gasification process for an IGCC. Therefore, the syngas is cooled and any remaining particulate matter (coal not completely converted to syngas) is removed. Next, a water-gas-shift reactor is used to convert the CO and H₂O to CO₂ and H₂. This process requires steam to be introduced to convert the CO. The amount of steam required varies by the details of the catalyst, gasifier, and operating temperatures. Next, the resulting CO₂ and H₂ is cooled and an acid gas removal process (Selexol™ in the case of Kemper) uses a solvent to dissolve and remove the CO₂ from the fuel before it is sent to the turbine to be combusted. A more detailed accounting of this process also discusses the requisite removal and management of trace species, such as ammonia and hydrogen sulfide. Details pertinent to the Kemper plant are provided in Section 3.0.

vi GE quotes a 9HA.02 gas turbine as 42.7% efficient when run alone and up to 62.8% efficient in a combined cycle mode. - GE Power Product Catalog, 2016, https://www.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/2016-gas-power-systems-products-catalog.pdf

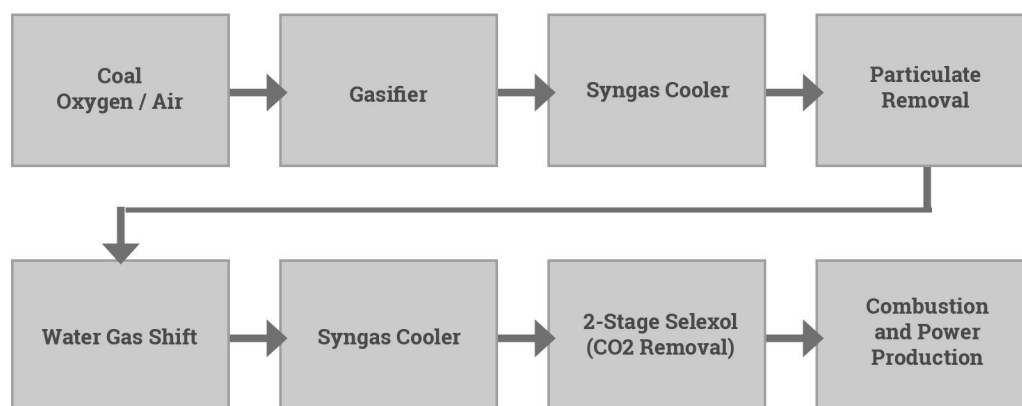
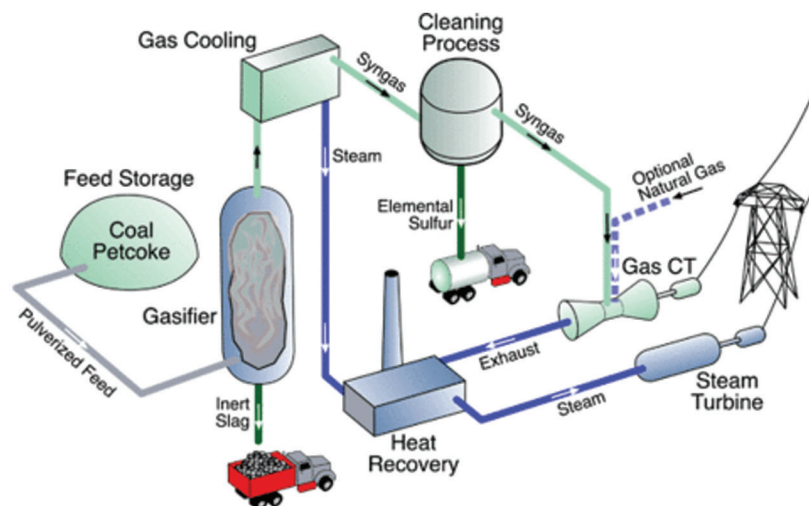


Figure 2: Summary of Gasification Process [7]

2.2 Key Nomenclature and Performance Metrics

Several metrics and terms are used throughout this technical summary. A more complete set of definitions is provided in the glossary; however, some of the most important terms are summarized here.

- **Availability:** A measure of how often the plant is available to produce power, considering the impacts of both planned and unplanned maintenance. Availability can also be calculated for individual components. Throughout this summary, the term ‘plant availability’ will be used when referring to the availability of the Kemper plant as a whole. ‘Component availability’ will be used when referring to the availability of an individual component.
- **CO₂:** Carbon dioxide is a product of combustion whenever the fuel contains carbon. Efficient combustion requires that the greatest possible quantity of carbon in the fuel is converted to CO₂. For an overall process, CO₂ production can therefore be reduced through more efficient power plants (reducing the amount of fuel required per unit of electricity), or by altering the fuel through the removal of carbon before it is combusted.

- CO₂ per MWh_{gross}: Pounds of carbon dioxide emitted divided by the gross shaft output power of the steam and gas turbines
 - CO₂ per MWh_{net}: Pounds of carbon dioxide emitted divided by the useful electrical power generated by the unit. This is higher than CO₂ per MWh_{gross} since it accounts for produced power that must be used to drive plant equipment.
- Efficiency: Efficiency, or thermal efficiency in this context, is the percentage of useful heat in a given quantity of fuel that is converted to useful energy, or electricity, compared to the theoretical maximum energy content of the given quantity of the given fuel.
 - Emission Capture Rate: The relative fraction of CO₂ removed from the fuel pre-combustion
 - Flexibility: The ability for a system to operate at varying load levels. This is critical to modern power plants since the recent introduction and prioritization of renewable energy sources requires that traditional fossil fuel powered plants be more responsive to changes in demand.
 - Gross Efficiency: This is the efficiency of converting fuel potential energy to the total, or gross, amount of power that the gas or steam turbine produces (at the output shaft).
 - Maintainability: The ease of maintaining a certain piece of equipment. Maintainability drives the availability of a plant.
 - MWh (Megawatt-hours): A unit of energy. The amount of electrical energy produced if a plant is run at one Megawatt for one hour.
 - (Gross MWh) MWh_{gross}: The total amount of power produced at the output shaft of the steam and gas turbines.
 - (Net MWh) MWh_{net}: The Gross MWh minus power used to drive plant components such as pumps and valves.
 - Net Efficiency: Net Efficiency is the Gross Efficiency minus any efficiency losses (or “parasitic losses”) due to power generated that must be used to drive plant equipment, such as pumps.
 - Reliability: The percentage of time the plant is operating or ready to operate, excluding planned maintenance time. For example, simple cycle gas turbines typically have high reliability (>90%), even though they operate only 20% of the year on average, because they operate solely when power demand is high.
 - Syngas: A synthesis gas produced by the gasification of a fuel that contains carbon for the purpose of producing heat. The mixture typically consists of a varying combination of carbon monoxide, carbon dioxide, and hydrogen ^{vii}.
 - Sour Syngas: contains significant sulfur and must be purified before use.
 - Sweet Syngas: can be used without additional purification.
 - Water Effluent: Any water-based liquid that is produced by the plant. These outputs are typically processed in a wastewater treatment facility or are fully evaporated.
 - Zero Liquid Discharge: Water treatment process wherein all the water consumed is purified, recycled, and may be reused ^{viii}.

vii <http://biofuel.org.uk/what-is-syngas.html>

viii <http://www.aquatech.com/solutions/zero-liquid-discharge/>

3.0 The Kemper IGCC Plant as a Technical Case Study

3.1 Overview of Operation

The Kemper IGCC plant is a combined cycle power plant in Kemper County Mississippi. The power generation portion of the plant consists of two Siemens SGT6-500FCT gas turbines, which are individually coupled to two heat recovery steam generators that feed steam to a single Toshiba Steam Turbine. The original design allowed the plant to produce 526MW when firing syngas in the gas turbines, and this generation capacity increases to 582MW when also firing natural gas in the duct burners, which are located between the gas turbines and the HRSG.^{ix} The use of a heat recovery steam turbine in tandem with the two gas turbines is a common architectural strategy that increases plant net efficiency by approximately 20%, while simultaneously increasing total power output by approximately 50%. Kemper differs from traditional combined cycles that use natural gas or liquid fuel (oil), as Kemper can be fired on either natural gas, gasified coal, or a mixture of the two. During the course of operation, the ratio of syngas to natural gas varied as they transitioned to 100% natural gas to 100% syngas. The plant was able to achieve 65% CO₂ capture on syngas output, although no CO₂ capture occurred for natural gas. As noted beforehand, an IGCC plant utilizes the gasification of coal to remove carbon-dioxide (CO₂) prior to combustion. This lowers the effective carbon-dioxide output per megawatt-hour (CO₂/MWh) to 800 lbm CO₂ / MWh_{net}. Net MWh takes into account that a portion of the generated power is required to drive plant components, such as pumps.

The Kemper site is in proximity to a lignite coal mine, which granted it easy access to the fuel source. Additionally, the CO₂ captured pre-combustion was transported via a 60-mile CO₂ pipeline for future use in enhanced oil recovery (EOR). In addition to a productive downstream use of pre-combustion CO₂, the plant was designed to generate 139,000 tonnes per year (TPY) of sulfuric acid and 17,500 TPY of ammonia, both of which can be sold for industrial purposes. In addition to having engaged in the commercial reuse of process byproducts, the plant was also classified as “zero liquid discharge” and produced no water effluent.

The Kemper plant process flow architecture is shown in Figure 3 below. A brief description of the entire process is provided. The components in dark blue are the primary technologies were associated with innovations unique to Southern Company and are discussed in more detail in subsequent sections. Yellow highlighted technologies were tested at PSDF, but are commercially available. White technologies are commercially available proven technologies. There is one gasifier island (group) per gas turbine (two per plant).

First, due to the relatively high natural water content of lignite, the coal is dried from roughly 45% moisture down to 20%. This is accomplished by using 6 bed dryers, 3 per gasifier, and is a necessary step for efficient gasifier operation. Once dried, the coal is fed by a high-pressure coal feed into the Transport Integrated Gasification (TRIG) gasifier at a rate of more than 200 tons per

^{ix} While designed, and ultimately planned, to run on 100% syngas, the gas turbine OEM limited operation to 70% load while running on syngas while learning about impacts on turbine operation. During the described demonstration phase, load from 70% to 100% was achieved through mixing natural gas with the syngas, for up to a 70/30 syngas/natural gas ratio.

on future operations. The current low price of natural gas compared to projections when the project was initiated played a major role in this decision [8].

3.2 Technical Goals of the Project

The Kemper IGCC plant sought to achieve the following plant level metrics:

- 65% (or more) CO₂ capture before combustion (i.e., <35% gross CO₂ emissions through the final flue stack)^{xi}
- 800 lbm CO₂ / MWh_{net} CO₂ production rate
- Heat Rate of 12,150 BTU/kWh_{net}
- 3,000,000 TPY CO₂ for EOR
- 139,000 TPY commercial grade sulfuric acid
- 17,500 TPY commercial grade ammonia
- Demonstrate 35% syngas production plant availability in the first year; 50% in year 2; and 70% in year 3.

While the operation ceased before a full year of operation, the following goals were achieved:

- 224 total days of successful conversion of lignite coal to syngas
- Tested and achieved 100% gasifier design coal feed capacity
- Demonstrated 65% rate of CO₂ capture and transport for EOR
- Combustion Turbine operated on full syngas at 73% capacity at (170MW)
- A total of 164,900 MWh were generated while operating on syngas
- Achieved on-spec production of ammonia, CO₂, and sulfuric acid

^{xi} This target of 35% net CO₂ emissions was driven by a combination of technical objectives and EPA regulations that had been developed at the time the project was approved.

3.3 Major Technical Challenges and Lessons Learned

There were several technical challenges and lessons learned throughout the project. These are summarized in the table below. Many of the challenges were due to the learning curve associated with operating a new design and would not necessarily pose a challenge to a future commissioning. Such issues are typical for a major, integrated process and power plant and do not represent insurmountable or inherent challenges associated with the gasification and CO₂ capture technology. The actual potential for future risk is dependent on the effectiveness of the solution or redesign of the affected system.

Table 2: Major Technical Challenges and Lessons

Type of Issue	Challenge	Impact on Plant	Description	Mitigation Action?	Potential Future Risk?
General Integration	Inconsistent Raw Coal Quality	Reduced coal feeding capacity	Coal was frequently outside the specified range for moisture and particle size	Finer coal screens installed at mine; Redesign of dryer and addition of air cannons	Yes, but manageable; highly dependent on coal mine
First of a Kind Scale-Up of Technology	Gasifier seal leg outlet spalling	Reduced availability	Refractory improperly installed in shop	Install replacement refractory in-place on site	Yes, but manageable; reduced risk by installing on site rather than in shop
	Syngas Cooler Superheat Tube Leaks	Reduced combined cycle power output and efficiency	Leaks developed in the tubes designed to transfer heat from the hot syngas from the gasifier to steam used to partially power the steam turbine	Shut down outer heat transfer tube coil; other tubes had sufficient design margin to operate at full load	No; would increase tube thickness/design margin in future design
Other Scale-Up Issues	Limited Refrigeration Capacity in the CO ₂ Removal System	Limits gasifier operation at high load/capacity	Limited refrigeration limits the amount of CO ₂ that can be removed pre-combustion. This was caused by a hydraulic issue	New pumps would have resolved this issue	Yes, but manageable.

3.4 Next Steps

The Kemper IGCC plant successfully demonstrated two train (both gas turbines and gasifiers) simultaneous operation at the full coal feed design rate during its final month of operation. The initial plant availability was 35%, which is at the upper end of total plant availability when compared to prior projects of this type at a similar point in their execution and operation. This plant availability however, is subject to a learning curve that tends to be quite variable during the first several years of a plant's operation. This goal and comparison to historical data from other IGCC sites (grey shading) is shown in Figure 4 below.

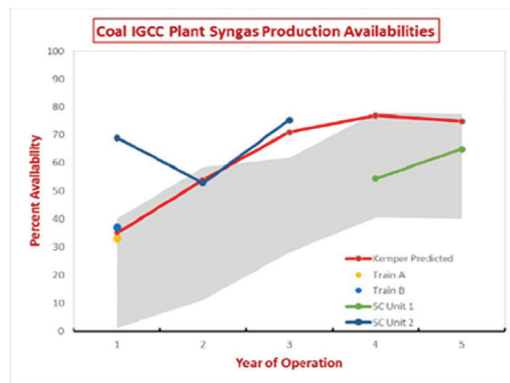


Figure 4: Measured and Predicted Plant Availability^{xii}

As greater understanding and practice of Kemper’s technologies was obtained, this plant availability would likely have fluctuated in the following years. Despite the decision to convert the project to natural gas, the Kemper project team plans to continue analyzing the large amount of data collected during the plant operation and develop best-practices for the design and operation of future IGCC plants. The following sections provide a more in-depth technical analysis of the key plant components related to coal gasification and pre-combustion CO₂ capture.

3.5 Summary of Technical Accomplishments –Equipment Developed by Southern Company

Several pieces of hardware required to meet the overall project goals were designed and developed by Southern Company. This was done in order for them to utilize their own gasification technology, which previously had only been demonstrated at much smaller scales. These items are colored in dark blue in Figure 3 and include the Transport Gasifier (TRIG), the pressure decoupled advanced coal (PDAC) coal feeder, the coarse ash cooling and depressurization (CCAD) systems, and the coal fine cooling and depressurization systems (CFAD). Each technology is described in turn, with a summary of the goals of the individual technology and hardware, its relation to project goals and plant operation, and specific technical challenges and lessons learned.

3.5.1 Transport Integrated Gasification (TRIG™) Gasifier Relation to High level Project Goals

The gasifier is the heart of the gasification process, responsible for converting the pressurized coal feed into syngas for use downstream as combustion turbine fuel. The general operation of the gasifier is described with reference to Figure 5. First, coal solids of 300 to 600 microns (1/100 to 2/100 of an inch) are fed into the gasifier at high pressure. As Kemper does not have oxygen-blown capabilities, an air/oxygen stream is introduced below the coal. The air from this is used to produce power and oxygen for the generation of liquid fuels or chemicals.

^{xii} Courtesy of Southern Company

The objective of the TriG is to create a large amount of heat at a high circulation rate. The combustion below the coal introduction zone heats the coal at 50,000 degrees Fahrenheit per minute. The coal then moves through the riser, where it absorbs a large portion of this heat. The high circulation rate means that a more consistent temperature can be maintained across the riser, allowing for a more efficient conversion process with far less tar generation. At the top of the riser, the cracked coal still contains particulate matter that must be removed before the syngas is sent downstream for the additional conversion into combustion turbine fuel. The pre-salter cyclone removes 99.5% of solids, which are sent to the standpipe to be removed or recirculated. Approximately 50% of the removed ash is then withdrawn from the gasifier, while the other 50% is recirculated. Finally, the standpipe cyclone removes the remaining particulate matter for a total solid capture efficiency of greater than 99.9%. Clean syngas is sent downstream to be cooled in the high temperature syngas cooler and is then converted into combustion turbine fuel.

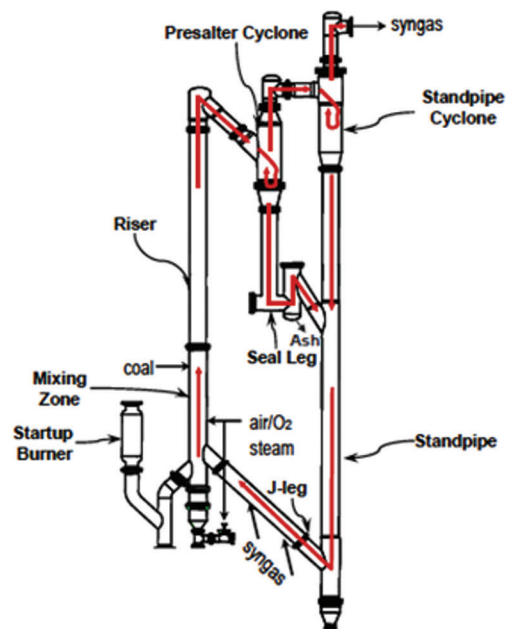


Figure 5: TRIG Gasifier Major Components ^{xiii}

^{xiii} Courtesy of Southern Company

Technology Goals and Progress Towards Goals

The TRIG gasifier was successfully demonstrated at the design feed rate of 200 tons per hour. Technical experts from Southern Company noted that this is twice the coal feed rate of any other demonstrated gasifier in the world. This was achieved through a solids recirculation rate within the gasifier of up to forty million pounds per hour. This means coal moves rapidly through the riser, which leads to a higher coal throughput rate. This rapid recirculation rate also allows the transport reactor design to be used for chemical process applications. Ultimately, the TRIG gasifier achieved a 98% carbon conversion rate from coal to syngas.

Technical Performance Successes

The TRIG gasifier was operated successfully at the full design coal rate. A hydrogen rich syngas was produced that was suitable for additional processing and ultimately for combustion in a combustion turbine. During operation, the gasifier was tested over a wide range of operating conditions including variations in pressure, temperature, and coal feed rate. During these operating variations, it achieved consistent performance and maintained key independent variables within their desired set point ranges. The efficient operation of the gasifier resulted in negligible tar formation, which was critical to avoiding fouling in downstream components, as this can affect reliability.

In addition to overall gasifier operations, several of the sub-components also operated up to design standards. The pre-salter cyclone operated up to a 60 mass ratio of solid to gas loading and experienced no erosion of the inlet portions, which is indicative of high reliability of a system. Additionally, the fluidization nozzles for the ash removal systems did not plug and operated as designed. Finally, the high achieved circulation rate resulted in a good temperature profile across the riser, contributing to high throughput and efficient operation.

Technical Challenges and Lessons Learned

The lower portion of the gasifier experienced spalling (flaking of the metal surface) during initial refractory drying in the shop, but the project construction schedule did not permit resolution at the time and the original parts were installed nonetheless. The lower portion of the gasifier was eventually replaced with refractory dry out, which had to be performed onsite. The upper portion however, was not initially replaced and still experienced spalling. This caused blockage in the ash removal system, which led to an unplanned outage. Despite this event, component availability of the gasifier was greater than 90%. Moreover, a planned replacement of the upper portion of the gasifier would have likely raised component availability to near 100%. Future installations would likely have the refractory performed in-place during the summer months, when it is easier to control temperature gradients.

3.5.2 Pressure Coupled Advanced Coal Feeder (PDAC)

Relation to High level Project Goals

The PDAC is responsible for raising the pressure of the dried coal so it can then be fed into the gasifier. This is necessary, as large pieces of coal cannot efficiently be converted to syngas. The PDAC is a non-mechanical, dry solid feed with no moving parts, containing three main subcomponents, shown in Figure 6 [9]. The storage silo contains coal from the dryer beds, meaning coal that has previously been dried to achieve a moisture content reduced down to 12-22%. The storage silo is at atmospheric pressure and contains reserve coal for additional capacity when required. Coal from the storage silo then drops into the

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lock vessel, where it is pressurized using high pressure nitrogen that is above the operating pressure of the downstream TRIG gasifier. The dispense vessel uses transport air to send this high-pressure coal to the gasifier. Proper operation of the PDAC is necessary to keep a high supply of coal to the TRIG gasifier.

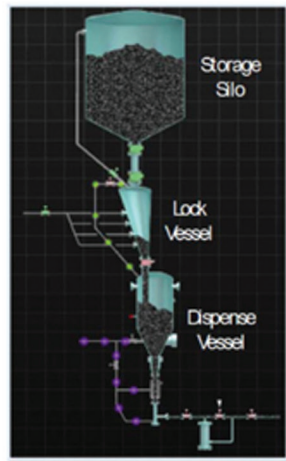


Figure 6: PDAC Components

Technology Goals and Progress Towards Goals

The PDAC system was able to safely demonstrate the transport of lignite to the gasifier through automatic coordination of the feed loading system amongst the six available feeders, based upon coal demand from the gasifier. The PDAC demonstrated high availability and was always available to feed the gasifier. The system was demonstrated at up to 62.5 tons per hour, representing a feed rate 25% greater than the design rating. A turndown ratio of 25:1 was also demonstrated. (i.e., the operational feed rate could be successfully lowered to 1/25 of the design rate). This is important to providing the load flexibility required of modern combined cycle power plants as more renewables enter the grid.

Technical Challenges and Lessons Learned

The lock vessel, where high pressure nitrogen is used to pressurize the coal, is a sequential process. Coal is fed from the silo into the lock vessel, locked, pressurized, and then the pressurized coal is released into the dispense vessel. The top lock then opens and the process repeats. During operation, the lock vessel sometimes required more than one cycle to empty completely. This was identified as an issue with fluidizing the lowest section of the lock vessel and a design modification was proposed to address this flaw in the next outage. Regardless, the PDAC operated with 100% availability.

3.5.3 Coarse Ash Cooling and Depressurization System (CCAD)

Relation to High level Project Goals

Figure 3 shows that the hot syngas from the gasifier is first cooled in a syngas cooler for further processing before moving forward in operations. The CCAD removes the high-pressure hot coal ash from the gasifier for safe storage and removal.

Technology Goals and Progress Towards Goals

The CCAD performed well and achieved transfer rates up to 80 tons per hour while maintaining a circulating solids inventory in the gasifier. This is necessary to prevent large particles from clogging in the gasifier. The CCAD consequently maintained 90% component availability.

Challenges and Lessons Learned

The issues with the gasifier refractory sent small pieces of metal to the CCAD, which caused some plugging in the mechanisms. This issue however, did not force an outage, because there was spare capacity. This concern would not likely represent a further issue in the future, as there was a plan to fix refractory issues in the upstream gasifier. The inner screens designed to filter out the ash also failed as a result of a design issue. The screens were subsequently replaced with more robust screens and the system was able to ultimately operate as designed.

3.5.4 Coal Fines Cooling and Depressurization System (CFAD)

Relation to High level Project Goals

After being cooled, the hot syngas enters the CFAD system in order to remove any remaining coal ash before it undergoes additional processing before use in the combustion turbine. The subsystem is responsible for removing particulate matter not caught in the TRIG gasifier separators. The ash is removed from the syngas, cooled, and depressurized.

Technology Goals and Progress Towards Goals

The CFAD was successful in removing and cooling fine coal matter from 500 degrees F to 200 degrees Fahrenheit. Availability was 100% during operation.

Technical Challenges and Lessons Learned

The CFAD had the same issue with screen failure as the CFAD, but replacement screens were installed. The unit operated as designed even before the screens were replaced.

3.6 Summary of Technical Accomplishments – Commercial Equipment

3.6.1 Water-Gas Shift and Syngas Cleanup

Relation to High level Project Goals

While the gasifier was efficient at converting coal to syngas, further processing work must be done before the fuel is suitable for combustion in the gas turbine. Figure 7 provides an overview of the syngas cleanup process.

Kemper Syngas Cleanup Process Overview

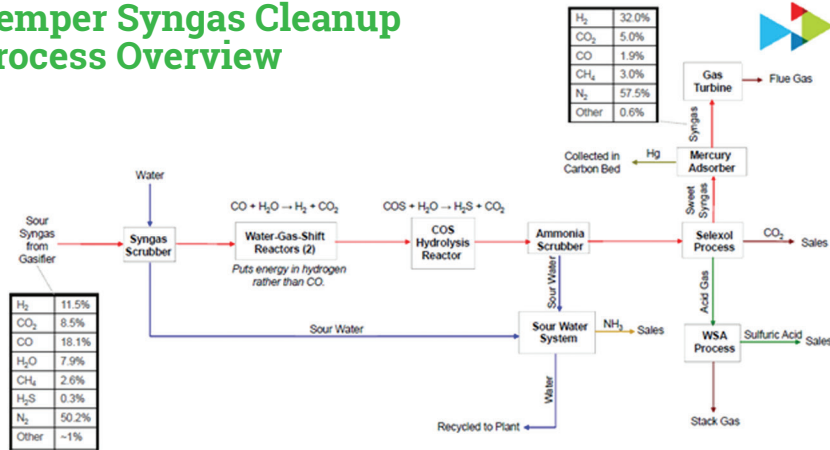


Figure 7: Syngas Cleanup Process Overview ^{xiv}

Recall, at this stage, the syngas has had fine particulate matter removed and consists of a variety of gaseous species including hydrogen, carbon dioxide, carbon monoxide, water, methane, and nitrogen. From this mixture, trace amounts of fluoride and chloride as well as ammonia are removed in a syngas scrubber. Water containing these trace species is dissolved and then sent to a sour water processing system that removes ammonia for commercial sales. The cleaned water is then recycled to the plant for reuse.

The scrubbed syngas, although sulfur is still present, is then sent to two, two-stage water-gas-shift reactors. Two identical parallel two stage water-gas-shift reactors are needed to maintain the overall desired throughput of the plant as a system. This system converts the CO and H₂O in the syngas to H₂ and CO₂. This conversion is necessary for two reasons. Firstly, if the carbon monoxide is combusted, it will simply form carbon dioxide. Second, by converting the carbon monoxide to carbon dioxide, it facilitates removal of the pre-combustion CO₂ further downstream in the Selexol™ process.

After the initial water-gas-shift reaction, an additional carbonyl sulfide (COS) reactor is used to convert any remaining COS to hydrogen sulfide and carbon dioxide. The hydrogen sulfide is then removed and the CO₂ is later removed in the Selexol™ process. The processed and cleaned syngas is sent to the Selexol™ process, where the CO₂ is essentially dissolved out from the gas. This produces the syngas that is sent to the turbine for combustion. The final product gas contains a large amount of hydrogen and nitrogen with smaller amounts of carbon dioxide, carbon monoxide, and methane that were not completely removed in the cleaning and CO₂ removal process.

^{xiv} Courtesy of Southern Company

Technology Goals and Progress Towards Goals

Water Gas Shift Process

The water-gas-shift converts carbon monoxide and water in the syngas from the gasifier into hydrogen and carbon dioxide. A two-stage process is used and almost 90% of the CO is converted to CO₂. The reaction is exothermic, meaning it releases heat, which must be removed to prevent the products from reverting back to their original chemical states. The Kemper process ran at a water-to-CO ratio of 1.7, which is low compared to other reactors, which typically run a water-to-CO ratio of ~2.5.

The COS Hydrolysis reactor successfully reduced the COS from the water-gas-shift reactor from an estimated 21 parts per million (ppm) to 1 ppm.

Selexol™ (CO₂ Removal) Process

The Kemper Selexol™ process used the two largest Selexol™ units in the world at time of commissioning. They operate by using a dry solvent filtration system. The solvent is compressed and chilled before being mixed with the syngas. The CO₂ in the syngas then dissolves and the processed syngas is able to continue onwards to the combustion turbine to be burned. The dissolved CO₂ that was removed is released by expanding the solvent which releases the purified CO₂ for use in EOR or sequestration activities. The Selexol™ process includes a hydrogen sulfide absorber. Ultimately, each Selexol™ unit (one per train) is capable of processing 1.4 million pounds per hour of syngas, while capturing 470,000 pounds per hour of CO₂ and 20,000 pounds per hour of acid gas.

The Selexol™ processes operated as designed and the plant achieved a nominal carbon capture rate of 65%. Additionally, all byproducts (CO₂, H₂S) were on specification. The Selexol™ unit was able to directly capture 76% of CO₂ from the syngas.^{xv} The availability of both Selexol™ process units was greater than 90% in 2017. The final (actual) emissions produced vs. the expected emissions are summarized in Table 3. Also included for reference are the limits associated with existing IGCC plants and the levels that were permitted for the Kemper operation. Table 4 shows emissions for both combustion turbines relative to the permit limits for the site. The results shown were collected as a test condition of 185 MW load (80% of rated load for each unit).^{xvi}

^{xv} Note this capture rate of CO₂ is higher than the stated carbon capture rate of 65%. This is because some amount of methane and carbon monoxide remain in the combusted syngas stream. As a result, the CO₂ capture rate will be slightly higher than the overall carbon capture rate, which takes into account all molecular forms of carbon.

^{xvi} Unit A was fired on a 60/40 syngas/natural gas mixture and Unit B was fired on a 50/50 syngas/natural gas mixture. Note that this load and fuel mixture was used for emission testing, but does not represent the design limit of the plant which is 100% load for each unit on 100% syngas.

Table 3: Kemper Actual vs. Expected Emissions

IGCC MACT Evaluation	PM	Mercury	HCL
Final Limits for Existing IGCC	0.040 lb/MMBtu Gross	2.5 lb/TBtu Gross	0.00050 lb/MMBtu Gross
Kemper Permitted Emissions	52 lbs/hr 228 tons/yr	No emissions limits at time PSD Permit was issued.	No emissions limits at time PSD Permit was issued.
Kemper Expected Emissions	0.0080 lb/MMBtu Gross (HHV)	0.460 lb/Tbtu Gross (HHV)	No current estimates. HCl is not expected to present unless it is picked up from piping, catalyst, etc.
Kemper Actual Emissions	11 lbs/hr 0.0056 lb/MMBtu Gross (HHV)	0.003 lb/Tbtu Gross (HHV)	<0.00008 lb/MMBtu

Table 4: Summary of Emission Test Results ^{xvii}

		Permit Limit	CT- A	CT - B
Total Particulate Matter	lb/hr	52	4.81	22.4
Nitrogen Oxides	lb/hr	210	20.7	12.6
Sulfur Dioxide	lb/hr	13.1	3.6	<1.8
Carbon Monoxide	lb/hr	105	41.7	36.5
Volatile Organic Compounds	lb/hr	17.1	<6.4	<0.19
Sulfuric Acid Mist	lb/hr	1.8	<0.794	<1.134
Visible Emissions	%	20	0	0

Technical Challenges and Lessons Learned

Hydraulic issues in the refrigeration piping would have limited operation at high capacities. Recall that the plant was only operated at 73% capacity on 100% syngas, a limitation imposed by Siemens in order to gain operating experience before fully loading their turbines. During this period, the plant could be operated up to 100% capacity with a mixture of syngas and natural gas. The final operation plans called for operating at 100% capacity on 100% syngas. The integration of additional pumps could have eliminated these issues, but were never tested before operations ceased.

^{xvii} Courtesy of Southern Company

3.6.2 CO₂ EOR and Sequestration

More than 3 million tons of CO₂ per year could be captured by a Kemper sized IGCC. There are two viable options for the resulting CO₂ product. First, the CO₂ can be sold for enhanced oil recovery operations, which is how Kemper was intended to be operated. The second option is to sequester the CO₂ underground in deep geologic formations.

CO₂ Enhanced Oil Recovery

Oil recovery from a well typically involves three phases. In primary recovery, the natural oil pressure inside the well is high enough for natural flow out of the well or for conventional pumps to extract the oil. After primary recovery declines, secondary recovery injects water into the well in order to force out additional oil. Finally, tertiary recovery uses CO₂ or another solvent, which reduces the viscosity of the oil and makes it easier to pump and recover. Tertiary recovery has actually increased well output beyond the levels achieved through secondary recovery. While using CO₂ to extract oil, which may ultimately be combusted, might be viewed as using CO₂ to generate additional CO₂, the net effect can still yield a 20% CO₂ reduction. However, oil produced through EOR displaces oil that would likely have otherwise been produced from new wells, therefore the CO₂ produced from combustion of this oil is not a net increase of CO₂.

The Kemper project was the first IGCC plant to capture and sell CO₂. This milestone is especially important since it was noted that approximately 50% of the oil in Mississippi is recovered by CO₂-EOR. Moreover, despite numerous potential industrial sources, about 80% of existing CO₂ supplies (by volume) in the United States derive from natural sources. The project provided data and lessons learned about how to integrate industrial CO₂ supplies at required pressures and purity levels needed by the EOR market.

Many concerns, however, persist regarding the direct and indirect costs of EOR. These may range from EOR issues to saline storage issues, including the per ton cost to store CO₂ and the potential for current or expanded 45Q tax credits for saline reservoir storage. The market for CO₂ in EOR is well established, but still subject to volatility based upon the price of crude oil. It should be noted, however, that since CO₂ EOR is a proven process and is already established, even with the Kemper plant's CO₂ production on hold, oil formations in Mississippi will continue to be supplied at design conditions to the existing pipeline by other sources.

CO₂ Sequestration

Through the DoE/NETL Carbon Storage Assurance Facility Enterprise (CarbonSAFE), SSEB and Southern Company were selected to perform a CO₂ storage complex feasibility study during a Phase II, Project ECO₂S. Three wells, marked by MPC 26-5, 34-1, and 10-4 in Figure 8. The sites have an average porosity of 27%, indicating that the sites are capable of storing a maximum of 5,720 million metric tonnes of CO₂.

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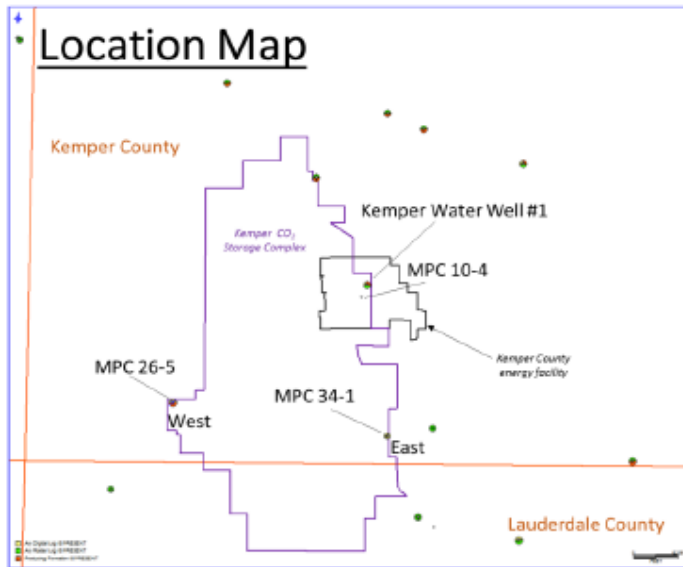


Figure 8: Kemper CO₂ Sequestration Well Locations^{xviii}

The cost to store CO₂ at this location is estimated to be \$2 - \$4 per ton. Drilling is relatively easy at these sites with no showstoppers. Furthermore, given current and potential tax credits ranging from \$22 to \$50 per ton of CO₂, the site provides an attractive alternative to CO₂ EOR depending on oil demand and prices. This ensures that there is always somewhere to store CO₂ captured pre-combustion from an IGCC plant such as Kemper. However, the impact that Kemper's closure will have on the pending feasibility study or other relevant CCS efforts at the Kemper site is currently unknown.

Implications for IGCC Plant Efficiency

The pressurization of the CO₂ stream—whether it is ultimately used for EOR or goes to storage for sequestration—requires compression that reduces the efficiency of the plant system as a whole. The pressure in an EOR pipeline, such as the one designed for use at Kemper, is significantly higher than the pressure required for a geological formation. For example, the two CO₂ compressors installed at the Kemper site were rated at 28,500 hp each, and supplied CO₂ to the pipeline at pressures up to 1770 psig. These compressors were claimed to be the largest ever used for CO₂ pressurization to date.

This level of pressurization is a significant source of parasitic energy loss, which serves to reduce net plant efficiency when CO₂ for EOR is the capture method. According to experts at the forum, pressurization levels for geological storage would be expected to be lower than those used for CO₂ for EOR. In general, pressurization (and by extension, energy expended) can be somewhat site and project dependent, making it complicated to perform standardized comparisons for all performance metrics of interest.

^{xviii} Courtesy of Southern Company

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4.0 Discussion Highlights and Key Points Raised

Recap of Scope and Primary Objectives

To recap, the objective of the August 22 event at Georgia Tech was to convene a group of domain experts and review the Kemper IGCC operations from a purely technical perspective. In order to keep the scope manageable and maximize time management among our gathered technical experts, extensive discussions of economic or regulatory factors were intentionally excluded. Despite this exclusion, the critical importance of economic and regulatory factors remained implicitly acknowledged. As a first step toward the stated objectives, operating data for key performance indicators were discussed and compared to design estimates based upon actual demonstrations and experience. This overview prompted discussions about technical lessons learned, including achievements and challenges. An overarching objective was to stimulate constructive discussion and feedback among experts, and to consider ways of leveraging these recent demonstrations to enhance and benefit current research of this technology, particularly as a means of informing future roadmaps. This section highlights points raised by participants and organizes comments and themes toward advancing on these objectives.

On the quantity and implications of data from the actual demonstration phase

The demonstration phase for the Kemper IGCC Plant was 224 days, but production had been planned for multiple years. The impact this brevity had on technical insights and readiness was mixed. In some sense, the collected data was sufficient to suggest confidence in many sub-systems, as well as the integrated performance of the system as a whole. The trend of overall plant availability was shown to be “on a normal pace”, based upon actual plant readings, to reach the system-level program goals within a 3-5 year timeframe. However, due to the early cessation of the project as planned, there remains uncertainty regarding the extrapolated availability trend. In another sense, there was a significant quantity of data generated from the actual demonstration, which will continue to be evaluated for insights and lessons learned. The timing of this review essentially provided an early glimpse into the technical performance. Yet, it was agreed among participants that (a) further evaluation of the acquired data is needed, and therefore is on-going; and (b) the insights from that analysis will probably reflect areas of both achievement and challenge, the specifics of which are somewhat uncertain as of today.

On the inconsistent quality of raw coal and initial impacts on the process

Presenters noted that the utilized lignite resource (a rank of coal that is already naturally high in moisture) was outside the initial design range for moisture and particle size. Part of this was a function of the raw material, as experts stated that “contract values” for coal characteristics were not entirely met. However, the discussion also revealed that the raw coal may have been within tolerable ranges and that sub-system integration, transport issues, and discontinuous operations were also factors. In particular, it was noted that early operation in semi-batch or interrupted batch modes proved problematic, unintentionally adding moisture and adversely affecting the delivery of the low rank coal feedstock. Modifications to the coal preparation and drying systems were made, and attention was paid to streamline and integrate the fuel preparation process, allowing the plant to operate continuously at design rates. Such changes improved the reliability and consistency just prior to program suspension in June 2017. Project managers noted that lessons learned resulted in a set of recommendations that would be required in future plant design to ensure full-load sustained operations.

Refractory validation issues

On multiple occasions during the demonstration phase, issues were encountered with the refractory in the gasifier. The first two incidents resulted in rejection of the original equipment, followed by concurrent installation of the refractory with the gasifier the third time. When this iteration was evaluated, additional issues were encountered as a result of solid circulation in the gasifier, causing spalling of the lower portion of the refractory. This condition was observed before coal entered the gasifier. In general, it is known by those familiar with the technology that refractory failures are not uncommon, nor exceedingly costly, but can have an impact on component performance and availability. One expert noted that “refractories are an art,” and that best practices suggest that it is imperative to work with multiple experts and to pull the refractory after the reactor is installed in the structure. (As was eventually learned by the Kemper team). Finally, it was noted that it is preferable to “cure the refractory in summer, not in winter.” Finally, discussants commented on the expected lifespan of the TRIG refractory. It was noted that typical refractory life (in a Fluid Catalytic Cracking operation) is about 15-20 years, whereas the refractory lifespan estimate for Kemper was reported to be “10+ years.” Without additional data, experts agreed it would be difficult to comment further on a more refined estimate at this time.

Superheater and heat exchanger leaks

Tube failures were identified in both the superheaters and the syngas cooler steam generator. Original designs were assessed and revealed insufficient wall thicknesses and thermal expansion respectively, as the root causes. The superheater tube failures were concentrated on the outermost coil, which were noted to be under highest relative stress. Finite element analysis (FEA) was therefore used to inform more robust designs. While such improvements to the original designs, accomplished by blocking off the tubes, were developed, such fixes were not implemented due to insufficient validation time. It was also noted that the system had enough excess design capacity to operate as designed without the outer coil in operation.

Combustion Turbine operation, validated levels of coal firing and rated capacity

A major objective of coal firing and turbine evaluation was to validate what could be considered acceptable performance standards across a wide range of coal feed rates, as well as up to a specific percentage of full nameplate capacity. Coal feed rates were varied, delivering syngas from 30 to 90% of design levels. This evaluation proved that the process was effective at ramping up at down within these ranges without experiencing adverse issues. For the majority of the demonstration phase, the combustion turbine was limited to operation at approximately 70% by the turbine supplier, although some preliminary tests were performed at 80% in June 2017. The result of these evaluations confirmed a combustion turbine operation on 100% syngas generation output of about 170MW at 73% capacity. Had the plant continued to operate, the gas turbine would have eventually been cleared for operation at full capacity on 100% syngas.

Unresolved system challenges

Wastewater and related issues processing sour water represent an on-going technical concern. Water leakage through the syngas scrubber chimney trays resulted in an excessive flow of sour water into the system, causing damage to the scrubbers and to chimney trays. This then resulted in overload at high load rates. In addition, salts were found to have formed in the system, which further limited capacity. This in turn impacted the capacity to process the amount of sour water that was being produced at high loads and prevented adequate separation of ammonia, CO₂ and H₂S, as the system was not designed to handle such an excess. Improper metallurgy and water pH in excess of design limits led to heat exchanger tube failures and extended downtime. Effective solutions were conceived and designed, but the project schedule did not permit resolution or validation in physical systems.

Production of on-spec byproducts (Ammonia, CO₂, Sulfuric Acid)

Experts sought to confirm that by-products, including: ammonia, CO₂, and sulfuric acid were produced to specifications. It was also noted that high sour water pH prevented adequate separation of the various byproducts. In addition, for ammonia and CO₂ specifically, salts formed in various equipment and ultimately limited capacity and reliability at high loads. Countermeasures were implemented to address this issue, such as acid and caustic injections to increase pH and improve separation, but long term implications of these technical remedies were less definitive.

Other highlights of the environmental performance and associated separations

As noted, most major targets relative to the separation of process by-products were met or exceeded, yet experts noted that often the most difficult engineering challenge was to validate multiple parallel pathways in order to sustain proven outputs at a system level. For example, two water-gas-shift reactors were operated, each with 2 stages. Demonstration of these sub-systems generally yielded favorable results, but at the time the project was halted, uncertainty remained concerning the continuous operation of the fully integrated systems. For example, waste heat is recovered during the various water-gas-shift reactions to conserve net energy, but that heat must be harmonized among stages and parallel paths for optimal performance. CO conversion was discussed with the design target of converting 90% of the CO to CO₂, and no significant problems were encountered. It was noted that temperature and conversion rates would be traded-off to meet target conversion goals. Carbonyl Sulfide (COS) target levels were designed to be reduced from 21 to 1 ppm after COS hydrolysis. Also, naphthalene (tar) was present, but much lower than seen with bituminous coals, and thus any chance of the gasifiers emitting tar was very low. Mercury and Toxics Standard (MATs) suggest that expectations were exceeded, though participants noted that the plant used a “new bed,” whose performance may decline at production capacity over time. Finally, acid formation and tar deposits were deemed to not be concerns due primarily to the low temperatures post-gasification at the AGR. There were no observed condensations of unwanted by-products and the technology appeared to maintain these levels as rates were scaled up.

Highlights of the CO₂ Sequestration Discussion

Experts discussed the two primary options for captured CO₂: sell to oil companies for use in Enhanced Oil Recovery (EOR) operations, or sequester in permitted geological formations. It was noted that approximately 50% of the oil in Mississippi is recovered by CO₂-EOR. Despite numerous potential industrial sources, about 80% of existing CO₂ supplies (by volume) in the United States derive from natural sources. Therefore, the Kemper project provided information and options for the variety of methods that can be adopted to integrate largely industrial supplies at required pressures and purity levels needed by the market. An existing geological CCS storage project in Kemper County, Mississippi was funded in 2016 by the DOE/NTEL, with a further feasibility study slated for completion in 2017-2018. The impact that Kemper's closure will have on the pending feasibility study or other relevant CCS efforts at the Kemper site is currently unknown. Technologically, the structural integrity of the geological formation, permeability, depth, and confining properties were addressed and no major hurdles are expected. Uncertainties however, persist regarding costs of saline storage, including the per ton cost to store CO₂ and the potential for current or expanded 45Q tax credits for saline reservoir storage. The market for CO₂ in EOR is well established, but still subject to volatility based upon the price of crude oil. Participants inquired about the typical pressures needed for EOR in comparison to geological storage. The pressure in an EOR pipeline, such as the one designed for use at Kemper, is "much higher" than the pressure required for a geological formation. For example, the two CO₂ compressors installed at the Kemper site were rated at 28,500 hp each, and supplied CO₂ to the pipeline at pressures up to 1770 psig. This level of pressurization is a significant source of parasitic energy loss, which serves to reduce net plant efficiency when CO₂ for EOR is the capture method. In general, pressurization (and by extension, energy expended) can be somewhat site and project dependent, making it complicated to perform standardized comparisons for all performance metrics of interest.

Kemper IGCC with CCS "Very Unlikely" to Operate as Planned

Given the formal program review and subsequent decision by public regulators to switch the plant over to natural gas in June 2017, discussants commented that it is "very unlikely" that the Kemper IGCC technology with CCS will operate as originally designed. While the combustion turbines will begin burning solely natural gas, the majority of the Kemper plant assets (as a whole) will not enter service, and the outlook for using them in the future is uncertain. Although there is no conversion necessary to transition the turbines to natural gas operations, the combustors could be switched out to enable a premixed type that is able to achieve lower NO_x without using steam injections. The Kemper plant demonstrated a nominal 65% carbon capture rate overall and designed 550 lb/MWh on a gross basis. This surpassed the EPA limit of 1100 lb/MWh, and is similar to the net carbon emissions rate of a typical modern NGCC plant without CCS. Also noted, running the turbines with natural gas may incur a small reduction in efficiency, as the turbo-machinery was designed for syngas. However, experts agreed that it would not be significant enough to adjust operating parameters and/or adjust the design over time to optimize performance for natural gas. NO_x production could be another aspect in which firing with natural gas would differ from syngas (H₂). Regardless, the plant has been capable of operating on either natural gas or syngas since 2014.

Reflections on Kemper Gaps for Academic Institutions

The subject roundtable hosted multiple professors from universities including: Georgia Tech, Mississippi State University, Massachusetts Institute of Technology, Auburn University, University of Alabama, Penn State University, University of California Irvine, West Virginia University, and the University of North Dakota, Energy & Environmental Research Center. Two Georgia Tech faculty members noted that projects like Kemper, which are complex and expensive, are timely opportunities to assess how universities are doing at educating young engineers to understand system integration challenges, suggesting that we can and should do better. The realization that our current (Chemical Engineering) curriculum does not consider most of the engineering/technical challenges discussed in light of Kemper was the catalyst towards reflecting on the ways that educators and institutions can better prepare graduates. Traditionally, a focus on fundamentals, sub-systems and unit operations understandably has taken priority, whereas heightened attention to integration, system-analysis, and technical problem solving for large, complicated and often high-risk projects will be increasingly valued in the workforce. Finally, it was noted that the opportunities for young engineers to engage in such complex challenges are limited. For example, in coal gasification and other large, capital intensive energy technologies, one participant noted that the “world is not in a place to aggressively push forward with this kind of thing” at the moment. Of course, this sentiment is heavily influenced by today’s geopolitical and economic realities, but in terms of technology, the group agreed on the merits of disseminating best practices and informing future research roadmaps and educational goals based on these discussed and timely insights.

5.0 Appendix A – Glossary of Terms

5.1 Acronyms

BTU	-	British Thermal Unit – The amount of energy needed to raise one pound of water (just under one pint) one degree Fahrenheit. Natural gas typically contains 20,000 BTU per pound.
CCAD	-	Course Ash Cooling and Depressurization
CCS	-	Carbon Sequestration and Storage
CFAD	-	Coal Fine Cooling and Depressurization Systems
DoE	-	Department of Energy
EOR	-	Enhanced Oil Recovery – Use of CO ₂ to increase the yield of oil wells
EPA	-	Environmental Protection Agency
EPICenter	-	Georgia Tech’s Energy Policy and Innovation Center
IGCC	-	Integrated Gasification Combined-Cycle
Lbm	-	Pounds mass
MMBTU	-	Millions of BTUs. Natural gas is typically priced per MMBTU
MSPSC	-	Mississippi Public Service Commission
MW	-	Megawatt(s)
NETL	-	National Energy Technology Laboratory
NGCC	-	Natural Gas Combined Cycle (power plant)
NOx	-	Nitric Oxide Emissions
PDAC	-	Pressure Decoupled Advanced Coal (feeder)
pH	-	Measure of the acidity or basicity of a liquid
PSDF	-	Power Systems Development Facility
TPY	-	Tonnes per year (1 tonne = 2,204 pounds)
TRIG	-	Transport Integrated Gasification



5.2 Important Terms

Availability-	<p>A measure of how often the plant is available to produce power, considering the impacts of both planned and unplanned maintenance.</p> <p>Availability can also be calculated for individual components. Throughout this summary, the term ‘plant availability’ will be used when referring to the availability of the Kemper plant as a whole. ‘Component availability’ will be used when referring to the availability of an individual component.</p>
Brayton Cycle-	<p>The thermodynamic cycle used to describe the physical working of a gas turbine</p>
Carbon Capture Rate-	<p>The percentage of Carbon that is removed before the combustion process</p>
Carbon Sequestration-	<p>Long term storage of carbon dioxide in plants, soils, geologic formations, or the ocean</p>
CO₂-	<p>Carbon dioxide is a product of combustion whenever the fuel contains carbon. Efficient combustion requires that the greatest possible quantity of carbon in the fuel is converted to CO₂. For an overall process, CO₂ production can therefore be reduced through more efficient power plants (reducing the amount of fuel required per unit of electricity), or by altering the fuel through the removal of carbon before it is combusted.</p>
CO₂ per MWh_{gross}-	<p>Pounds of carbon dioxide emitted divided by the gross shaft output power of the steam and gas turbines</p>
CO₂ per MWh_{net}-	<p>Pounds of carbon dioxide emitted divided by the useful electrical power generated by the unit. This is higher than CO₂ per MWh_{gross} since it accounts for produced power that must be used to drive plant equipment.</p>
Combined Cycle-	<p>The combined use of a Rankine (steam) cycle to recover waste heat from a Brayton (gas turbine) cycle</p>
Efficiency-	<p>Efficiency, or thermal efficiency in this context, is the percentage of useful heat in a given quantity of fuel that is converted to useful energy, or electricity, compared to the theoretical maximum energy content of the given quantity of the given fuel.</p>

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Emission Capture Rate-	The relative fraction of CO ₂ removed from the fuel pre-combustion
Exothermic-	A reaction which releases heat
Flexibility-	The ability for a system to operate at varying load levels. This is critical to modern power plants since the recent introduction and prioritization of renewable energy sources requires that traditional fossil fuel powered plants be more responsive to changes in demand.
Gasification / Gasified-	Conversion of solid coal into gaseous form
Gross Efficiency-	This is the efficiency of converting fuel potential energy to the total, or gross, amount of power that the gas or steam turbine produces (at the output shaft).
(Gross MWh) MWh_{gross}-	The total amount of power produced at the output shaft of the steam and gas turbines.
Lignite Coal-	A brown coal formed from naturally compressed peat which contains 60-70% carbon
Maintainability-	The ease of maintaining a certain piece of equipment. Maintainability drives the cost of operating a plant.
MWh (Megawatt-hours)-	A unit of energy. The amount of electrical energy produced if a plant is run at one Megawatt for one hour.
Net Efficiency -	Net Efficiency is the Gross Efficiency minus any efficiency losses (or “parasitic losses”) due to power generated that must be used to drive plant equipment, such as pumps.
(Net MWh) MWh_{net}-	The Gross MWh minus power used to drive plant components such as pumps and valves.
Particulate Matter-	Term typically used to describe small (micron sized) particles that are undesirable in the process
Premixed Mode-	A method of combustion which mixes fuel and air before igniting. This results in a lower flame temperature which in turn lowers NO _x emissions



Rankine Cycle-	The thermodynamic cycle used to describe the physical working of a steam turbine
Reliability-	The percentage of time the unit functions, without forced down time, when running. For example, a 99% reliability means that the plant shuts down 1% of the time while operating. Reliability can also be calculated for individual components.
Selexol™-	A process using a physical solvent to remove CO ₂ from the gas stream
Sour Syngas-	Contains significant sulfur and must be purified before use.
Sour Water-	Water which contains hydrogen sulfide and ammonia, typically treated to remove contaminants
Sweet Syngas-	Can be used without additional purification.
Syngas-	A synthesis gas produced by the gasification of a fuel that contains carbon for the purpose of producing heat. The mixture typically consists of a varying combination of carbon monoxide, carbon dioxide, and hydrogen
Water Effluent-	Water pollution, most commonly liquid waste that is expelled to natural bodies of water.
Water-gas-shift reactor-	Chemical reactor which converts carbon monoxide and water to hydrogen and carbon dioxide
Zero Liquid Discharge-	Water treatment process wherein all the water consumed is purified, recycled, and may be reused.

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6.0 Appendix C- Participants in the Review Meeting, August 22, 2017

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7.0 Appendix B- References

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Kemper IGCC Plant with CCS

Report out of the Technical Review



