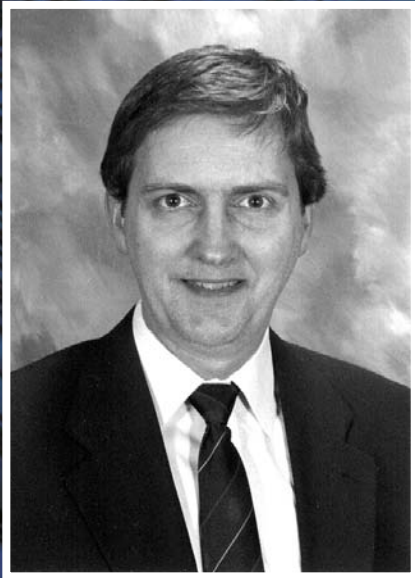# 1.2.1

Different Types of Gasifiers and Their Integration with Gas Turbines

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1.2.1-1 Introduction

What is gasification?

Gasification is a process in which combustible materials are partially oxidized or partially combusted. The product of gasification is a combustible synthesis gas, or syngas. Because gasification involves the partial, rather than complete, oxidization of the feed, gasification processes operate in an oxygen-lean environment. As figure 1 indicates, the stoichiometric oxygen-to-coal ratio for combustion is almost four times the stoichiometric oxygen-to-coal ratio for gasification of Illinois #6 coal.
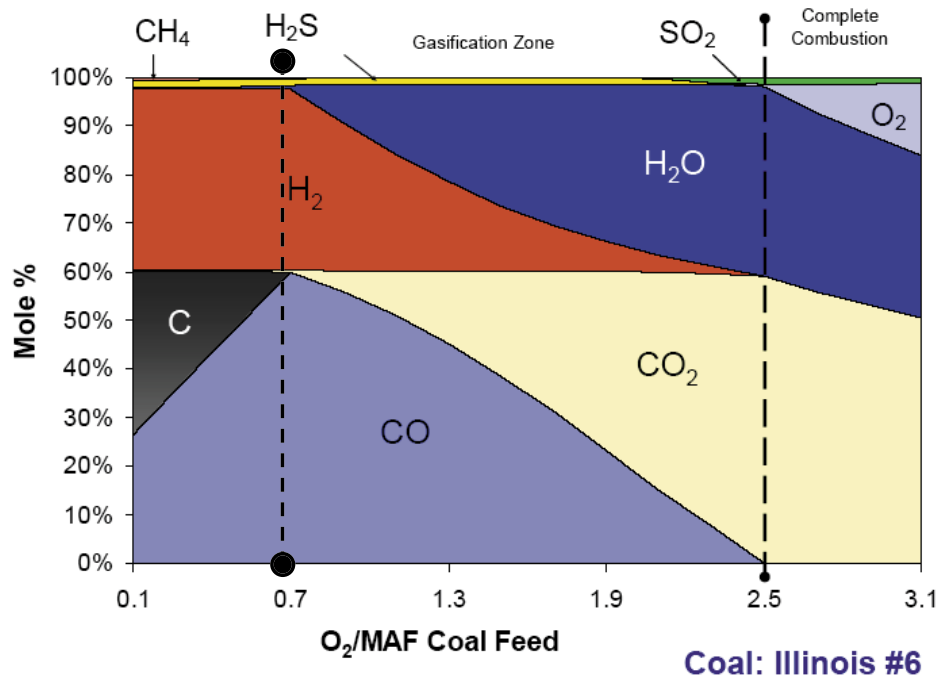

Fig. 1. Diagram showing the products of reaction as a function of oxygen-to-coal ratio (Reprinted from M. Ramezan, "Coal-based Gasification Technologies: An Overview" NETL Gasification Technologies Training Course, Sept. 2004.)

Just as most combustion-based processes such as power plants operate with excess oxygen to ensure complete conversion of the fuel, gasification processes also typically operate above their stoichiometric oxygen-to-fuel ratio to ensure near complete conversion to syngas. The amount of oxygen used in gasification, however, is always far less than that used in combustion and typically is less than half.

In addition to coal, gasification processes can use petroleum coke, biomass, heavy oil, or even natural gas as the feedstock; however, this document will focus on coal gasification processes.

Comparison to coal combustion (advantages/disadvantages)

As indicated in figure 1, the products of reaction change significantly as the oxygen-to-fuel ratio changes from combustion to gasification conditions. These changes are summarized in table 1. Because the mixture under gasifying conditions is fuel-rich, there are not enough oxygen atoms available to fully react with the feed. Consequently, instead of producing CO_2, the carbon in the feed is converted primarily to CO, and the hydrogen in the fuel is converted mostly to H_2 rather than H_2O. Both CO and H_2 are excellent fuels for use in a combustion turbine; however, their combustion characteristics are significantly different from natural gas.

Table 1 Comparison of the primary products created by the main fuel constituents in combustion and gasification

	Combustion	**Gasification**
Carbon	CO_2	CO
Hydrogen	H_2O	H_2
Nitrogen	NO, NO_2	HCN, NH_3 or N_2
Sulfur	SO_2 or SO_3	H_2S or COS
Water	H_2O	H_2

The fate of the fuel's nitrogen and sulfur in a gasification process has important and beneficial consequences on the environmental performance of an IGCC. Fuel-bound nitrogen, which is predominantly converted to NOx in combustion, is converted to N_2, NH_3 or HCN in gasification. As discussed in the "Syngas Clean-up Requirements" section of this chapter, both NH_3 and HCN can be removed to very low levels with the resulting cleaned syngas having essentially no fuel-bound nitrogen. This significantly limits NO_x emissions of an IGCC.

The sulfur in fuel produces SO_x in combustion processes but is converted to H_2S and COS in gasification conditions. As will be described further on, both H_2S and COS can be removed from the syngas using technology developed for the natural gas industry to levels of less than 20 ppm, which means that more than 99% of the sulfur can be removed from the fuel and will not be emitted as SO_x.

Another major difference between combustion and gasification is the amount of heat that is released by the chemical reactions. In combustion, all of the fuel's chemical energy is released as heat (assuming it is fully converted), but in gasification most of the fuel's chemical energy is not released as heat. In fact, an important measure of the efficiency of a gasification process is the fraction of the feedstock's chemical energy, or heating value, which remains in the product syngas. This fraction is termed the "cold gas efficiency," and most commercial-scale gasification processes have a cold gas efficiency of at least 65% and some exceed 80%.

Because significantly less heat is released by the gasification process, it is important to limit the amount of heat that is transferred out of the zone where the gasification reactions are occurring. If not, the temperatures within the gasification zone could be too low to allow the reactions to go forward (a minimum of 1000°C or 1800°F is typically needed to gasify coal). Consequently, unlike a boiler where the entire firebox is lined with water-filled tubes that capture the heat released by the process and produce steam, many gasifiers are refractory-lined with no water cooling to ensure as little heat loss as possible. Gasifiers also typically operate at elevated pressure, sometimes as high as 6.2 MPa (900 psia), which allows them to have very compact construction with minimum surface area and minimal heat loss.

1.2.1-2 Generic Types of Gasifiers

Moving Bed

A diagram of a generic moving bed gasifier is shown in figure 2. Moving bed gasifiers are countercurrent flow reactors in which the coal enters at the top of the reactor and air or oxygen enters at the bottom. As the coal slowly moves down through the reactor, it is gasified and the remaining ash drops out of the bottom of the reactor. Because of the countercurrent flow arrangement, the heat of reaction from the gasification reactions serves to pre-heat the coal before it enters the gasification reaction zone. Consequently, the temperature of the syngas exiting the gasifier is significantly lower than the temperature needed for complete conversion of the coal.
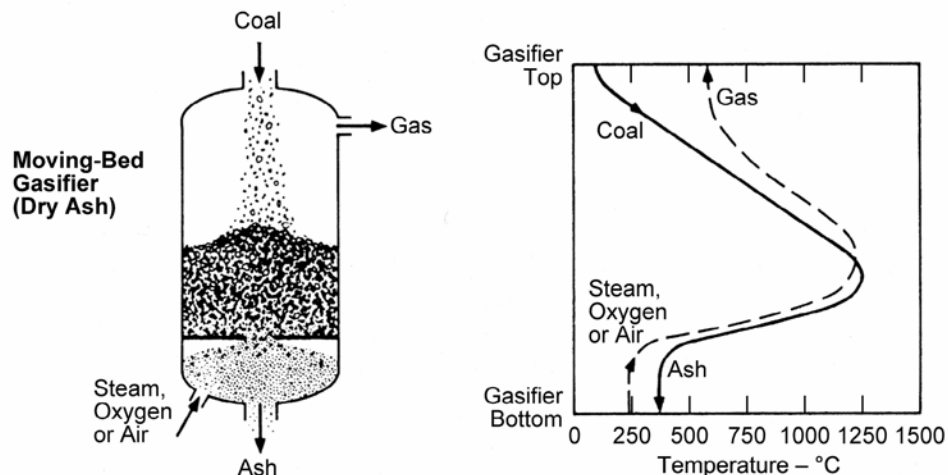

Fig. 2. Diagram of a generic moving bed gasifier

The residence time of the coal within a moving bed gasifier may be on the order of hours.

Moving bed gasifiers have the following characteristics:[1]

*   Low oxidant requirements;
*   Relatively high methane content in the produced gas;
*   Production of hydrocarbon liquids, such as tars an oils;
*   High "cold gas" thermal efficiency when the heating value of the hydrocarbon liquids are included;
*   Limited ability to handle fines; and
*   Special requirements for handling caking coal.

Fluidized Bed

A diagram of a generic fluidized bed gasifier is shown in figure 3. A fluidized bed gasifier is a back-mixed or well-stirred reactor in which there is a consistent mixture of new coal particles mixed in with older, partially gasified and fully gasified particles. The mixing also fosters uniform temperatures throughout the bed. The flow of gas into the reactor (oxidant, steam, recycled syngas) must be sufficient to float the coal particles within the bed but not so high as to entrained them out of the bed. However, as the particles are gasified, they will become smaller and lighter and will be entrained out of the reactor. It is also important that the temperatures within the bed are less than the initial ash fusion temperature of the coal to avoid particle agglomeration.

Typically a cyclone downstream of the gasifier will capture the larger particles that are entrained out and these particles are recycled back to the bed. Overall, the residence time of coal particles in a fluidized bed gasifier is shorter than that of a moving bed gasifier.
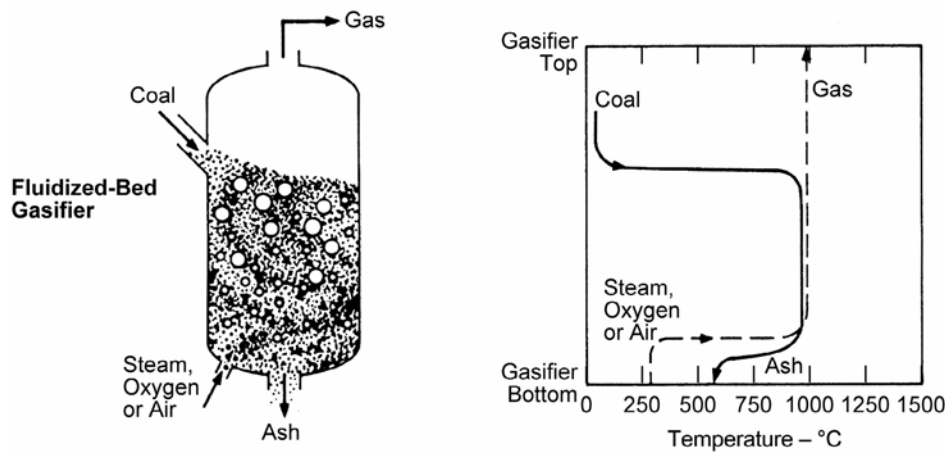

Fig. 3. Diagram of a generic fluidized bed gasifier

Generic characteristics of fluidized bed gasifiers include:[2]

*   Extensive solids recycling;
*   Uniform and moderate temperature; and
*   Moderate oxygen and steam requirements.

Entrained Flow

A diagram of a generic entrained flow gasifier is shown in figure 4.   Finely-ground coal is injected in co-current flow with the oxidant. The coal rapidly heats up and reacts with the oxidant. The residence time of an entrained flow gasifier is on the order of seconds or tens of seconds. Because of the short residence time, entrained flow gasifiers must operate at high temperatures to achieve high carbon conversion. Consequently, most entrained flow gasifiers use oxygen rather than air and operate above the slagging temperature of the coal.

Generic characteristics of entrained flow gasifiers include:[3]

*   High-temperature slagging operation;
*   Entrainment of some molten slag in the raw syngas;
*   Relatively large oxidant requirements;
*   Large amount of sensible heat in the raw syngas; and
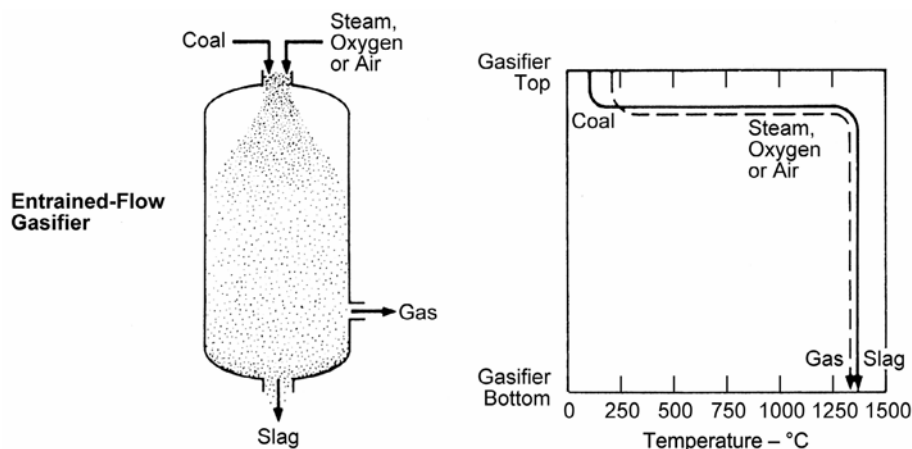*   Ability to gasify all coal regardless of rank, caking characteristics or amount of fines.

Fig. 4. Diagram of a generic entrained flow gasifier

Hybrid & Novel Gasifiers

In addition to the three main classifications of gasifier types (moving bed, fluidized bed, and entrained flow) there are also gasifiers that are based on either hybrid combinations of those three classifications or novel processes such as a molten metal bath.

The transport reactor-based gasifier developed by Kellogg Brown & Root (KBR) is an example of a hybrid gasifier as it has characteristics of both a fluidized bed and an entrained flow gasifier. The KBR gasifier will be described in more detail in the sub-section covering "pre-commercial" gasifiers.

1.2.1-3 Other Design Options

In addition to the generic reactor designs of a gasification process, there are several other design options that a gasification process can have. Each of these options can have important impacts on the downstream processes in an IGCC including the combined cycle.

Atmospheric vs Pressurized

Gasifiers can operate at either atmospheric pressure or at pressures as high as 62 bar (900 psia). Pressurized gasifiers are better suited for IGCC operation since the pressure of product syngas will be sufficient to be fed directly into the GT fuel control system. Low pressure or atmospheric pressure gasifiers will require a fuel gas compressor after the syngas clean-up processes.

High pressure gasifiers also have a positive impact on the cost and performance of the syngas clean-up section. Because the volumetric flow of the syngas is much smaller than it would be for an atmospheric process, the size of the clean-up equipment is smaller. For example, Hg capture can be accomplished by passing the syngas through a sulfur-impregnated, activated carbon bed. The size of the bed is dictated by the residence time of the syngas in the bed. Therefore, a smaller volumetric flow of syngas will result in a smaller carbon bed.

If CO_2 capture is required in future IGCCs, high pressure gasifier operation will improve the performance of physical absorption processes that can remove CO_2 from the syngas.

Dry Feed vs Slurry Feed

Coal is typically fed into a pressurized gasifier either pneumatically as a dry solid or pumped as coal-water slurry. Slurry-fed feed systems have a lower capital cost, but result in less efficient conversion of coal to syngas (referred to as the "cold gas efficiency" of the gasifier). This is because some of the syngas must be "burned" in order to generate the heat needed to vaporize the water in the slurry. Consequently, the syngas produced by a slurry-fed gasifier typically has more CO_2 in it than a dry-fed gasifier. This is not detrimental to GT operations since the CO_2 can act as an effective diluent for NOx control; however, it does impact the design of the "acid gas removal" section of the IGCC as that process must use a solvent which allows the CO_2 to pass through with the syngas rather than being stripped out with the sulfur species.

Air-blown versus Oxygen-blown

Oxygen for the gasification reactions can be provided by either air or high purity oxygen produced by a cryogenic air separation unit (ASU). Air-blown gasifiers avoid the large capital cost of an ASU but produce a much lower calorific value syngas than oxygen-blown gasifiers. The nitrogen in the air typically dilutes the syngas by a factor of 3 compared to oxygen-blown gasification. Therefore, while a syngas calorific value of 300 Btu/scf might be typical from an oxygen-blown gasifier, an air-blown gasifier will typically produce syngas with a calorific value of 100 Btu/scf. This has a significant impact on the design of the combustion system of the GT.

Because the nitrogen in air must be heated to the gasifier exit temperature by burning some of the syngas, air-blown gasification is more favorable for gasifiers which operate at lower temperatures (i.e. non-slagging).

Air-blown gasifiers also have a negative impact on CO_2 capture. Because of the dilution effect of the nitrogen, the partial pressure of CO_2 in air-blown gasifier syngas will be one-third of that from an oxygen-blown gasifier. This increases the cost and decreases the effectiveness of the CO_2 removal equipment.

Quench versus Heat Recovery

A final design option involves the method for cooling the syngas produced by the gasifier. Regardless of the type of gasifier, the exiting syngas must be cooled down to approximately 100ºC in order to utilize conventional acid gas removal technology. This can be accomplished either by passing the syngas through a series of heat exchangers which recover the sensible heat for use in the steam cycle of the IGCC, or by directly contacting the syngas with relatively cool water. This latter process is called a "quench" and it results in some of the quench water being vaporized and mixed with the syngas. The quenched syngas is saturated with water and must pass through a series of condensing heat exchanges which remove the moisture from the syngas (so it can be recycled to the quench zone).

Quench designs have a negative impact on the heat rate of an IGCC as the sensible heat of the high temperature syngas is converted to low level process heat rather than high pressure steam. However, quench designs have much lower capital costs and can be justified when low cost feedstock is available. Quench designs also have an advantage if CO_2 capture is desired. The saturated syngas exiting a quench section has near the optimum H_2O/CO ratio for feed into a water-gas shift catalyst which will convert the CO in the syngas to CO_2. Non-quench designs that require CO_2 capture will have to add steam to the syngas before it is sent to a water-gas shift reactor.

1.2.1-4 Integrating with a Combined Cycle

Syngas Clean-Up Requirements

Before syngas can be fed to a GT, it must pass through a series of clean-up steps in order to remove species that would either harm the environment or the GT itself.

Particulate Matter qualifies as being both bad for the environment and the gas turbine. Particulates can be removed by "dry" processes such as a cyclone and rigid barrier filter or by "wet" processes such as a venturi scrubber.

Gas turbines are fairly tolerant of sulfur species in the fuel. A typical OEM specification will call for no more than 250 ppmv of sulfur in the fuel. Concentrations of sulfur greater than that will cause unacceptably rapid corrosion of hot section parts. Even 250 ppmv of sulfur in the fuel would result in a relatively high sulfuric acid dewpoint in the exhaust gas. This would limit the amount of heat that could be recovered from the exhaust in the HRSG. To allow stack gas temperatures that are typical of natural gas fired combined cycles, the sulfur content of the syngas should be no more than 30 ppmv.

A coal with 1wt. % sulfur will typically produce a syngas with 3000 ppmv sulfur. Obviously a sulfur removal step is required in order to meet the OEM's fuel sulfur specification. As described earlier, well-proven technologies from the natural gas industry exist that can remove more than 99% of the H_2S and COS in the syngas. This also allows IGCCs to beat US New Source Performance Standards for sulfur emissions from coal-fueled power plants by a comfortable margin.

Nitrogen-containing species other than N_2 must be removed to a low level to prevent formation of "fuel-bound NO_x" in the GT combustor. HCN and NH_3 concentrations typically are on the order of hundreds of ppmv in raw syngas. Because of its high solubility in water, NH_3 can be easily washed out of the syngas by contacting it with water in a counter-flow packed column (the water then must be treated with neutralizing chemicals). Catalysts have been developed which promote the reaction of HCN with water vapor to produce NH_3 and CO. Therefore, a HCN conversion catalyst is typically installed upstream of the NH_3 water wash column.

Chlorides must be removed from the syngas to prevent corrosion in the GT hot section. HCl is quite soluble in water, and therefore the same water wash which removes NH_3 for NOx control, will also remove chlorides to an acceptable level.

While it is not necessary for protection of the GT, mercury vapor in the syngas can be removed by passing the syngas through an activated carbon bed. This bed will also remove heavy metal species such as arsenic, which can cause problems in the GT.

Air-Side Integration

For oxygen-blown gasifiers in an IGCC, the air for the ASU can be supplied by a stand-alone, electric motor-driven compressor or it can be extracted from the discharge of the GT compressor. It could also be supplied by a combination of those two options.

Extracting the air from the GT has efficiency advantages (the electrical losses in the GT generator and compressor motor are avoided), but experience at two European IGCCs which rely solely on GT compressor discharge air for their ASUs has shown that it can be operationally difficult, particularly during start-up.

Consensus is growing that using a combination of a stand-alone, electric motor-driven compressor and GT air extraction is the best option for supplying the ASU. Typical designs call for at least 50% of the air to be supplied by the stand-alone compressor.

Steam-Side Integration

For IGCC which have a syngas cooler to recover heat from the hot syngas, there are two options for the steam that is produced by the syngas cooler. The first option is to send the steam to the HRSG of the combined cycle for superheating and reheating. The steam is combined with the steam produced by the HRSG and drives a single steam turbine. The second option is to provide some level of superheat within the syngas cooler and send the steam to a separate steam turbine which only accepts the steam from the gasification block.

To date, all IGCCs have utilized the first option. However, with growing interest in retrofitting existing natural gas fired combined cycles, the second option may be of interest because an HRSG and steam turbine of an existing combined cycle will have to be modified to accommodate the additional steam produced by the syngas cooler. The separate steam turbine option may also be attractive for applications in which the gasification block must be located considerable distance away from the combined cycle.

1.2.1-5 Commercially Available Large-Scale Gasifiers

Four gasification technologies have been proven at the large scale (>1250 tpd) needed for IGCC applications:

Lurgi

Lurgi gasifiers have gasified more coal than any other commercially available gasification process. Lurgi gasifiers use a moving bed design and operate below the ash melting point of the feed. The coal does not have to be finely milled, only crushed. In fact, one of the disadvantages of the Lurgi process is its inability to handle coal fines.

The coal is fed into the top of the gasifier via lockhoppers. Oxygen is injected at the bottom of the gasifier and reacts with the coal which has been pre-heated by the hot syngas rising through the coal bed. Ash drops off the bottom of the bed and is depressurized via a lockhopper.

The process was originally developed by Lurgi GmbH in the 1930s in Germany. In total more than 150 Lurgi gasifiers have been built with the largest being able to process 1000 tpd of coal on a moisture & ash-free basis.

The two most prominent applications of the Lurgi process are not IGCCs: the coal-to-gasoline refineries of Sasol in the Republic of South Africa and the Dakota Gasification Synthetic Natural Gas plant in North Dakota. Both applications feature a series of oxygen-blown gasifiers and use low rank coal from nearby mines as the feedstock.

A key disadvantage of the Lurgi process in IGCC applications is the production of hydrocarbon liquids in addition to syngas. The liquids represent about 10% of the heating value of the feed and therefore must be utilized in order to achieve competitive efficiencies. At Sasol and Dakota Gasification the size of the gasification operations (14,000 tpd at Dakota) makes it economical to recover the liquids and convert them into high value products such as naphtha, phenols and methanol. It is not clear that the economies of scale for a 500 to 600 MW IGCC (4000 to 5000 tpd of coal) would allow those by-products to be recovered competitively.

The other drawback of the Lurgi process is the need to stay below the ash melting point of the coal. For lower reactivity coals such as bituminous coal from the eastern US, this will result in lower carbon conversion due to the lower gasification temperatures. Conversely, low rank, high ash coals provide a competitive advantage for the Lurgi process versus its higher operating temperature competitors.

GE Energy

The GE Energy gasification process has the most extensive track record in IGCC applications. Originally developed by Texaco in the 1950s, the technology was purchased by GE from Chevron-Texaco in 2004.

The process uses an entrained flow, refractory-lined gasifier which can operate at pressures in excess of 62 bara (900 psia). The coal is fed to the gasifier as coal-water slurry and injected into the top of the gasifier vessel. Syngas and slag flow out the bottom of the gasifier.

Three options are available for heat recovery from the GE Energy process: Quench, Radiant, and Radiant & Convective.   In the Quench option, both the syngas and slag are forced into a water bath where the slag solidifies and the syngas is cooled and saturated with water vapor. The slag is removed from the bottom of the quench section via a lockhopper while the saturated syngas is directed to gas clean-up equipment.

In the radiant option, the syngas and slag enter a long, wide vessel which is lined with boiler tubes. The vessel is designed to cool the syngas below the melting point of the slag. At the end of the radiant vessel both the syngas and slag are quenched with water.

In the radiant plus convective option instead of having a water quench for both the syngas and slag, only the slag drops into a water bath at the bottom of the radiant vessel. The syngas exits at the side of the vessel and enters a convective syngas cooler. Both fire tube boiler and water tube boiler designs have been used for the convective cooler.

More than 100 commercial applications of the GE Energy gasification process have been licensed since the 1950s. Some of the most notable examples are described below.

It was used in the first US IGCC, the Cool Water project, which was built in the early 1980s by a consortium of power industry organizations including Southern California Edison and EPRI. It also received production subsidies from the federal synfuels program operated by the Treasury Department. The Cool Water IGCC operated for five years starting in 1984 and gasified a total of 1.1 million tons of bituminous coal while proving the IGCC concept. After the demonstration period, the gasification block was sold, dismantled and moved to Kansas where it became the heart of a petroleum coke-to-ammonia plant.

The GE Energy process was also used at Tampa Electric Company's Polk County IGCC. That plant received DOE funding in Round III of the Clean Coal Technology program. The Polk plant is designed to produce approximately 250 MW of power and began commercial operations in July 1996. It has continued to operate after the end of the DOE-subsidized demonstration period and currently has the lowest dispatch cost of electricity in the Tampa Electric fleet.

The GE Energy process has also been used in several coal and petroleum coke-to-chemicals applications. Besides the Kansas coke-to-ammonia plant, GE Energy gasifiers featuring the water quench design have been installed at the Ube Industries coke-to-ammonia plant in Japan and the Eastman Chemical coal-to-chemicals facility in Tennessee. These plants have operated with the very high availability factors expected in the chemicals industry for more than 20 years.

The GE Energy gasifier can also be used to gasify petroleum refinery liquid by-products such as asphalt residues. Several IGCC projects based on these feedstocks have been built at refineries around the world.

Shell Coal Gasification Process (SCGP)

The Royal Dutch Shell group of companies (Shell) has developed two different gasification processes. The first, called the Shell Gasification Process or SGP, was developed to gasify liquid and gaseous feedstocks. It features a refractory-lined gasifier with a single feed injection point at the top of the gasifier. The gasification products pass through a syngas cooler before entering a wet scrubber.

The second process, called the Shell Coal Gasification Process (SCGP), was developed specifically to gasify solid feeds. The SCGP gasifier features a water-cooled "membrane wall" similar to the membrane walls used in conventional coal boilers. There are four feed injectors oriented horizontally in the mid-section of gasifier vessel. Slag flows out of a slag tap at the bottom of the vessel where it falls into a water bath and syngas flows out the top of the vessel. As the syngas exits the gasifier it is quenched with cool, recycled syngas to a temperature well below the ash melting point of the coal. The quenched syngas is still quite warm (typically 900°C) and passes through a syngas cooler and a dry solids filter before a portion of the gas is split off for recycle to the quench zone.

The coal is fed to the SCGP gasifier pneumatically using high pressure nitrogen as the transport medium. The coal must first be dried and finely ground in a roller mill where warm, inert gas flows through the mill to remove the coal's moisture. The dried coal is then pressurized via a system of lockhoppers. SCGP gasifiers operate at pressures up to approximately 40 bar.

Shell began development of the SGP process in the 1950s, and work on the SCGP process started as a joint project with Krupp Koppers in the mid-1970s. Both companies agreed to go their separate ways in the development of coal gasification in 1981, and Krupp Koppers developed a competing dry-feed, membrane wall gasifier with the trade name PRENFLO. The only commercial application of the PRENFLO process has been the 280 MW Elcogas IGCC in Puertollano Spain. In 1999, Shell and Krupp Uhde agreed to join forces again in coal gasification. However, now only SCGP is being offered commercially by the two organizations.

The first commercial application of SCGP was the 250 MW Demkolec IGCC built in 1994 in Buggenum, The Netherlands. The plant was originally owned by a consortium of Dutch electric utilities, but was sold to Nuon in the late 1990s. It is now operating as an independent power producer in the deregulated Dutch electricity market.

Shell has also sold licenses for 12 SCGP gasifiers which will be used in coal-to-chemicals projects in China. The first of those projects is expected to begin operations in 2006.

Perhaps the greatest advantage of Shell's coal gasification process is its feed flexibility. The 240 tpd SCGP demonstration built at Shell's refinery in Deer Park, Texas in the 1980s was able to process a full range of feedstocks including lignite, sub-bituminous coal, bituminous coal and pet coke. The reason for SCGP's flexibility is the coal milling and drying process which eliminates the impact of moisture on the gasifier performance (however, the fuel for the drying process has a negative impact on thermal efficiency).

The biggest disadvantage of the SCGP has been its higher capital cost which is inherent in the more expensive nature of the gasifier design (boiler tubes are more expensive than refractory brick) and its dry feed system.

ConocoPhillips E-Gas

ConocoPhillips owns the E-Gas gasification technology which was originally developed by Dow Chemical. The E-Gas process features a unique two-stage gasifier design. The gasifier is refractory-lined and uses coal-water slurry feed. The first stage of the gasifier has two opposed, horizontally-oriented feed injectors. The syngas exits the top of the first stage and slag flows out of the bottom into a water bath. The syngas produced by the first stage enters the second stage at temperatures comparable to the exit temperatures of the other two entrained flow gasifiers, GE Energy and SCGP. Additional coal-water slurry is injected into this hot syngas in the second gasifier stage, but no additional oxygen is injected. Endothermic gasification reactions occur between the hot syngas and the second stage coal feed. This lowers the temperature of the syngas and increases the cold gas efficiency of the process. Upon exiting the top of the second stage of the gasifer, the syngas passes through a syngas cooler which features a firetube design. The cooled syngas then enters a rigid barrier filter where any unconverted char from the second stage is collected and recycled back to the first stage of the gasifier where the hotter temperatures ensure near complete carbon conversion.

Dow began development of the E-Gas process in 1976 with a bench scale reactor. The work progressed to a 36 tpd pilot plant and then a 550 tpd "proto plant" located at Dow's chemical manufacturing complex in Plaquemine, Louisiana. The main feedstock tested in these early gasifiers was lignite.

In 1984 Dow entered an agreement with the federal US government's Synthetic Fuels Corporation in which Dow received a price guarantee for syngas to be produced from a commercial scale E-Gas gasification plant built in Plaquemine. The plant began operation in 1987 and was operated by the Dow subsidiary Louisiana Gasification Technology Inc. (LTGI). The LGTI facility was designed to process 1600 tpd (dry basis) of sub-bituminous coal from the Powder River Basin. The clean syngas was sent to two Westinghouse 501D gas turbines which were already operating on natural gas at the Plaquemine complex. The total power output from the two turbines was 184 MW.

LGTI operated from 1987 through 1995 and received a total of $620 million in price support payments from the Synthetic Fuels Corporation (SFC). It was shutdown after SFC support ended. In total, more than 3.7 million tons of sub-bituminous coal was gasified at the LGTI facility.

The E-gas process has also been used at the Wabash River IGCC repowering project in West Terre Haute, Indiana. In 1991 the project was selected to receive partial funding from the US DOE as part of the Clean Coal Technology program. The plant featured a new air separation unit, gasifier, clean-up system, gas turbine and heat recovery steam generator, but it utilized an existing, 30-year old, 100 MW steam turbine in Public Service of Indiana's coal-fired Wabash River Generation Steam. The coal boiler that was originally built to supply steam to the steam turbine was retired when the IGCC equipment started up.

The Wabash River IGCC began operation in 1995 on bituminous coal from the Illinois basin. However, today it operates exclusively on petroleum coke.

Unlike the Polk County IGCC owned by TECO, ownership of the Wabash IGCC is split in two. The electric utility (Cinergy PSI) owns and operates the combined cycle plant while SG Solutions LLC owns and operates the gasification plant including the air separation unit. A commercial dispute between the previous owners of the gasification plant and Cinergy PSI led to a prolonged shutdown of the gasifier in 2004. However, with the recent change in ownership to SG Solutions, gasification operations began again in May 2005.

ConocoPhillips is actively developing several new IGCC projects; among those are the Mesaba IGCC and the Steelhead Energy project.. The Mesaba project is being developed by Excelsior Energy in northern Minnesota. The project was awarded $36 million by the US DOE in 2004 as part of Round Two of the Clean Coal Power Initiative (CCPI). The money will support the cost of the Front End Engineering Design (FEED) and Permitting activities for the project.

The Steelhead project, located in southern Illinois, will produce 600 MW of electricity as well as synthetic natural gas. The project recently received $2.5 million in funding from the State of Illinois to support its FEED effort.

1.2.1-6 Near-Commercial Gasifiers of Interest

Several other gasification technologies, which have not yet been tested at sizes of 1250 tpd or larger, have the potential for being used in IGCCs or have been proposed for IGCCs that are under development. They are reviewed in this sub-section.

KBR Transport Gasifier

The Kellogg Brown and Root (KBR) Transport Gasifier has been under development at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama. PSDF is a clean coal technology test facility built with US DOE sponsorship and has been operated by Southern Company Services since 1996. The KBR Transport Gasifier is a hybrid gasifier that has characteristics of both an entrained flow and a fluidized bed reactor. The technology is derived from KBR's catalytic cracker technology which has been used for decades in petroleum refineries. The KBR gasifier operates at considerably higher circulation rates, velocities, and riser densities than a conventional circulating fluidized bed, resulting in higher throughput, better mixing, and higher mass and heat transfer rates.

What is now the PSDF transport gasifer was mechanically completed in 1996; however, it originally operated as a combustor. In 1999 it was modified to operate as an air-blown gasifier. The PSDF also includes a small gas turbine which has been modified to burn the low Btu syngas produced by the air gasification process.

Figure 5 is a diagram of the KBR gasifier. Dried, pressurized, pulverized coal is fed into the mixing zone of the gasifier. The oxidant is added at the bottom of the mixing zone. The gasifier temperature is maintained below the ash melting point of the coal, and this favors the use of air rather than oxygen as the nitrogen in the air serves to moderate the temperatures within the fluidized bed, while also supplying the velocity needed to entrain the solids. Oxygen-blown operation has also been tested at the PSDF and would be the preferred mode for poly-generation applications in which chemical products were produced as well as power.
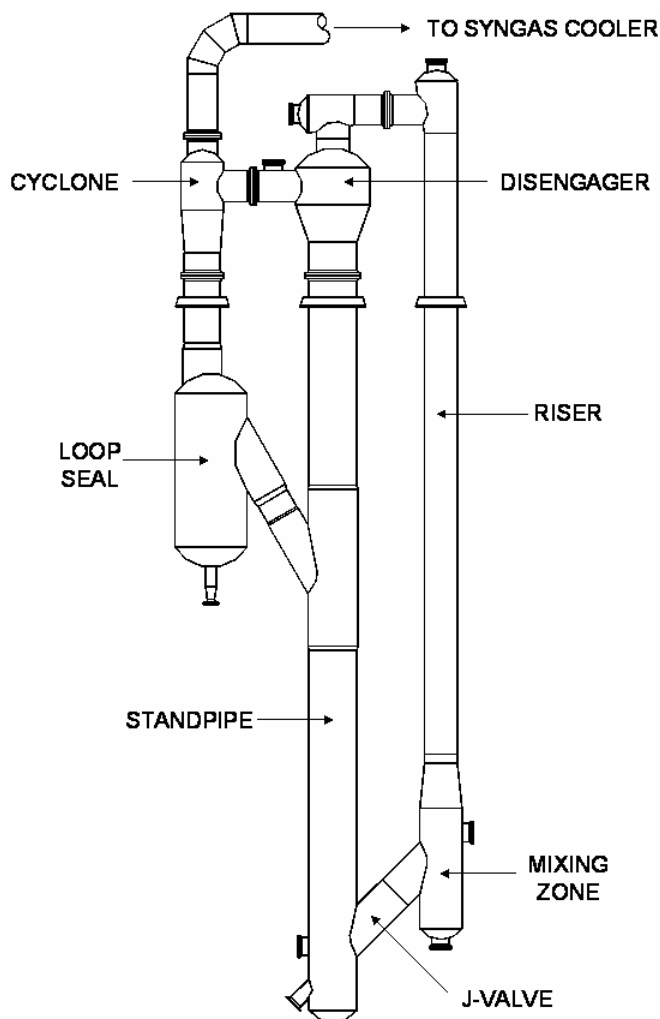

Fig. 5. Schematic Diagram of the KBR Transport Gasifier

The riser section provides sufficient residence time at hot temperatures to crack any tars which may be produced during devolatilization of the coal. This gives the design a distinct advantage over fixed bed gasifiers which also operate below the ash melting point.

Solids which are entrained out of the mixing zone of the gasifier are captured in a hot cyclone and returned to the fluidized bed. To maintain constant reactor inventory, gasifier ash is removed periodically from the lower region of the standpipe. If required, sand can be fed to increase reactor solids inventory.

Because of its lower operating temperature and its dry feed arrangement, the KBR reactor is most attractive for lower rank, high moisture coals.   The lower temperatures also eliminate the need for refractory lining of the gasifier vessel. The PSDF Transport Gasifier can process 38 tpd of coal in air-blown mode. Coals which have been gasified at the PSDF include Powder River Basin Sub-bituminous, Illinois #6 and North Dakota Lignite.

The KBR Transport Gasifier will be used in the 285 MW Stanton IGCC project which was selected by the US Department of Energy as part of Round Two of the CCPI in 2004. Southern Company Services, KBR, and the Orlando Utilities Commission (OUC) are sponsors of the project, which will be located at an existing combined cycle power plant owned by the OUC. Nonetheless, the IGCC will be a Greenfield project rather than a retrofit of the existing combined cycle.   Powder River Basin coal will be the feedstock for the gasifier.

Future Energy

The Future Energy entrained flow gasification process, formerly known as the Noell process, employs a single stage, downward firing gasifier that operates on a variety of liquid and solid feedstocks. The reactants are fed in at the top of the gasifier, which is cylindrical in shape and operates at temperature above ash fusion temperatures. At the bottom of the reaction chamber is a quench section, in which water is injected to cool the slag and the syngas. The solidified and granulated slag accumulates and is discharged via a lockhopper; the cooled syngas then exits the gasifier for further processing.

There are two variations of the gasifier, depending on the ash content of the feeds. For high ash content feeds, the gasification chamber is enclosed by a tube screen that carries cooling water to ensure a long life of the gasifier. The screen wall is coated with a thin layer of protective coating; as the slag flows down the wall towards the quench section, a layer of solid slag is formed next to the wall due to the cooling effect.   In applications with low ash content feeds, the cooling screen is replaced with a refractory lining cooled with a water jacket screen.

Unlike other gasification processes, the Future Energy process allows the option of using either dry feed or slurry feed. The process is currently used in a 440 MW Vresova IGCC plant in the Czech Republic. The plant has 24 Lurgi gasifiers processing brown coal and 360 tpd of tars produced by those gasifiers are pumped to a single Future Energy gasifier for conversion into syngas.

BGL Slagging Gasifier

The British Gas/Lurgi (BGL) coal gasifier is a dry-feed, pressurized, fixed-bed, slagging gasifier. The reactor vessel is water cooled and refractory lined. Each gasifier is provided with a motor-driven coal distributor/mixer to stir and evenly distribute the incoming coal mixture. Oxygen and steam are introduced into the gasifier vessel through sidewall-mounted tuyeres (lances) at the elevation where combustion and slag formation occur.

The coal mixture (coarse coal, fines, briquettes, and flux) which is introduced at the top of the gasifier via a lock hopper system gradually descends through several process zones. Coal at the top of the bed is dried and devolatilized. The descending coal is transformed into char, and then passes into the gasification (reaction) zone. Below this zone, any remaining carbon is oxidized, and the ash content of the coal is liquified, forming slag.

Slag is withdrawn from the slag pool by means of an opening in the hearth plate at the bottom of the gasifier vessel. The slag flows downward into a quench chamber and lock hopper in series. The pressure differential between the quench chamber and gasifier regulates the flow of slag between the two vessels.

Product gas exits the gasifier at approximately 1050°F (566°C) through an opening near the top of the gasifier vessel and passes into a water quench vessel and a boiler feed water (BFW) preheater designed to lower the temperature to approximately 300°F (150°C). Entrained solids and soluble compounds mixed with the exiting liquid are sent to a gas-liquor separation unit. Soluble hydrocarbons, such as tars, oils, and naphtha are recovered from the aqueous liquor and recycled to the top of the gasifier and/or reinjected at the tuyeres.

A 720 tpd BGL gasifier has been built recently in Germany by SVZ as part of a waste-to-methanol plant. The BGL technology was originally developed by British Gas, which built two demonstration gasifiers in the 200 to 500 tpd range in Westfield, Scotland. Those gasifiers are now owned by Global Energy of Cincinnati, OH, which for a time owned the rights to the BGL technology. The rights were recently acquired by the Allied Syngas Corporation (ASC) based in Wayne, PA. ASC is currently pursuing projects based on a 1000 tpd BGL gasifier.
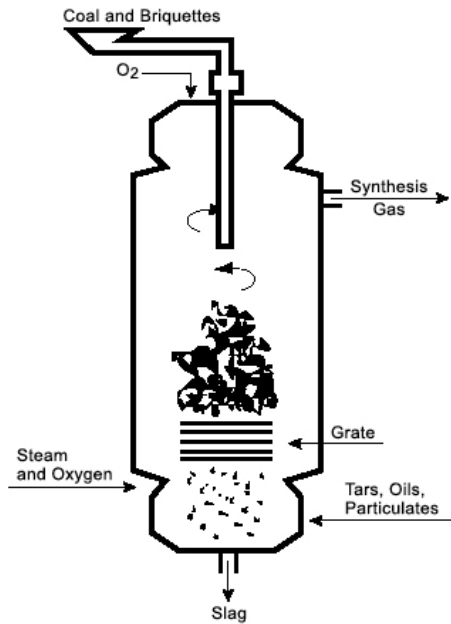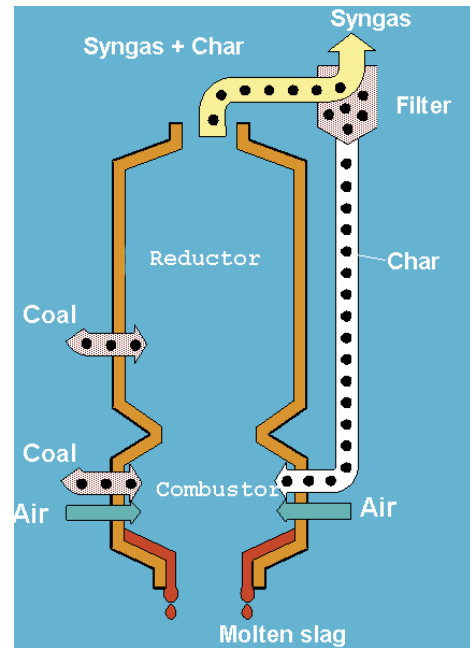
Fig. 6. BGL Slagging Gasifier

Fig. 7. Diagram of the MHI air-blown gasifier (with permission from Clean Coal Power R&D Co., Ltd.)

MHI Air-Blown Gasifier

MHI has developed a two-stage, air-blown gasifier which will be used in the 250 MW Clean Coal Power R&D Co. Ltd. IGCC being built near Iwaki City in Japan. Construction began in 2004, and the plant is scheduled to begin operation in 2007.

The MHI gasifier operates in slagging conditions and, like the E-Gas process, injects coal without oxidant in the second stage. However, the gasifier features a water-cooled membrane wall rather than refractory lining and uses dry feed of coal rather than coal-water slurry. Unconverted char exiting the second stage is captured by a dry solids filter and returned to the first stage where coal and air are injected (see figure 7).

The MHI gasifier has also been tested in the 1990s at a 200 tpd demonstration unit located at the same site where the Clean Coal Power R&D IGCC plant is being built.

1.2.1-7 Conclusions

Four gasification technologies have been developed and demonstrated at sizes compatible with large scale IGCCs. Three of these technologies are based on entrained flow reactors which rapidly convert coal to a hot syngas. The fourth is based on a moving bed reactor which uses long residence times to convert the coal and produces a more moderate temperature syngas along with liquid hydrocarbons.

Several other gasification technologies are nearing demonstrations of large scale gasifier which could be used in IGCCs. The most appropriate gasifier to use in an IGCC is probably more a function of the type of coal to be gasified than anything else. Lower rank, high moisture coals are more capable with dry-fed gasifiers, while high temperature slagging gasifiers are best for high rank coals which are less reactive.

1.2.1-8 Notes

1. D.R. Simbeck, et al., "Coal Gasification Guidebook: Status, Applications, and Technologies," EPRI Final Report TR 102034 (Electric Power Research Institute).
2. Ibid.
3. Ibid.

BIOGRAPHY

1.2.1 Different Types of Gasifiers and Their Integration with Gas Turbines
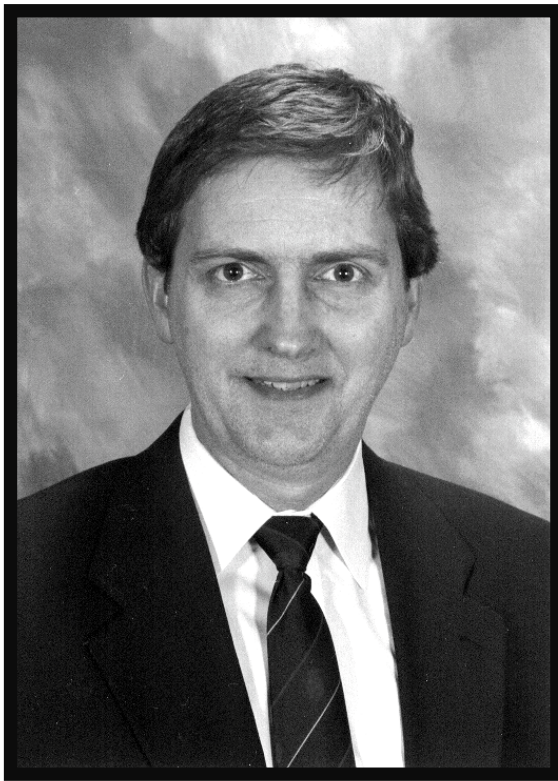
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Dr. Phillips began his involvement with IGCCs when he did his PhD research at Stanford on the off-design performance of IGCCs. He then spent 10 years working in the Royal Dutch/Shell group assisting in the development of the Shell Coal Gasification Process and then became an independent consultant, specializing in combustion turbine and combined cycle performance analysis. Among his consulting projects was an analysis of the suitability of current combustion turbine technology for oxy-fuel cycles. He recently accepted a position as project manager at EPRI where he directs projects related to IGCCs.