Notes on Integrated Gasification Combined Cycle

Introduction

Natural gas fired combined cycle systems are the present commercial choice for adding new fossil-fueled electric generation capacity. There are, however, problems with relying on a natural gas based technology. These include high demand for natural gas from other sectors (primarily residential, commercial, and industrial heating), and a finite and somewhat inelastic supply (*i.e.*, a gas shortage can be cured only by new drilling, which takes time). In the 1990's, natural gas was relatively inexpensive, costing about $2.5/10^6$ Btu to electricity generators. The natural gas shortage of 2001 resulted in price spikes to around \$10. This winter prices are again up. Since about 75% of the cost of electricity in combined cycle plants comes from the cost of the fuel, the generators are concerned about the impact of future instability in gas prices. The manufacturers are looking to where the market could be in the next 10 years if gas prices permanently increase.

Coal is a vast energy resource, with domestic reserves capable of lasting around 400 years at current consumption rates. The supply is elastic in the sense that increased demand can be easily met by simply increasing the mining rate at each individual mine. This has led to a nearly constant price for coal to the utility industry over many years, about $1.25/10^6$ Btu. The thought is that an efficient, clean, coal-based approach to electricity generation would free operators from the vulnerability to high natural gas prices. It is technically possible to burn coal in a relatively clean way. Carbon dioxide emissions, however, remain an important problem, as they do for all fossil-based power generation approaches.

The idea of integrated gasificaiton combined cycle (IGCC) is to use coal to power a high-efficiency combined cycle gas turbine. In its simplest form, the coal is reacted with substoichiometric air or oxygen to yield a fuel gas that consists primarily of CO and H_2. The fuel gas is cleaned of nitrogen, sulfur, and mineral matter, and is then burned in a combined cycle system. The approach is equally applicable to biomass.

Cycle Description

When you burn a hydrocarbon fuel with substoichiometric oxygen, instead of getting CO_2 and H_2O, you tend to get CO and H_2. For example, we can treat coal as acetylene (C_2H_2) because most coals tend to have a C:H atomic ratio of unity. If we react our surrogate coal with O_2 we get:

$$C_2H_2 + O_2 \ \text{-->} \ 2CO + H_2$$
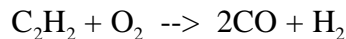
Running the equilibrium code with this input composition in the TP mode with T=1700 K (a typical entrained-flow gasifier temperature) shows that the equilibrium composition is close to this. This sets the nominal stoichiometry of the gasifier.

The next issue is what to use as the oxidant. Many systems use an air separation plant to provide pure O_2 to the gasifier. This significantly decreases the volume of the fuel gas since you do not carry along the diluent N_2. An advantage of this is that the fuel gas cleanup equipment can be sized smaller. To do so does, however, require installing the air plant. Besides the capital cost, these plants require significant amounts of energy to operate, and this is a parasitic burden on the plant (typical numbers are 1.33 MJ/kg O_2 produced). Both O_2-blown gasifiers and air-blown units are in use, although the O_2 systems are more common.

The most common air separation technologies are (1) membrane separation and (2) cryogenic separation. The membrane units use a semi-permeable membrane that preferentially passes the smaller N_2 molecule. Pumping is required to maintain a partial pressure differential across the membrane. In cryogenic systems the air is liquefied, and then distilled to separate the O_2 from the

N_2. (The argon tends to go with the O_2 as they have similar boiling points, but this is not a problem for gasification. The product is nominally 95% O_2 and 5% Ar.) The cryogenic systems are used almost exclusively for the large O_2 flows needed by gasification systems. This is because the cost of membrane systems tend to scale linearly with capacity since the principal cost is the membrane surface area. In cryogenic systems, substantial energy savings can be achieved through the use of regenerative heat exchangers, and these tend to work better as scales are increased. Thus, the economics of O_2 production tend to favor cryogenics for larger systems.

The three principal options for the gasifier itself are:

1. Fixed bed gasifiers. Here lump coal is placed on a grate and burned under substoichiometric air. These systems are not used in IGCC.
2. Fluidized bed gasifiers. The coal is crushed to 3-6 millimeter size and placed into a vessel where the oxidizer is introduced from the bottom. This results in a fluidization of the bed of crushed coal, providing mixing while the reaction takes place. These operate at about 900 K
3. Entrained flow gasifiers. Here the coal is ground to 50-70 µm (the same size as that used in pulverized coal combustion), and is introduced with the oxidizer to react in suspension. These run at around 1700 K.

The gasifier can either be operated at high pressure or at atmospheric pressure. The advantages of high pressure operation include (1) smaller size for the gasifier and the downstream fuel gas cleanup equipment, and (2) injection of the fuel gas into the combustor without further compression. The disadvantages include the expense of building a high-temperature pressure vessel and the problems of introducing a solid fuel into a high pressure system. The latter problem is sometimes approached through the use of cumbersome pressurized hopper feeder systems. More commonly, the fine coal is mixed with water to produce a slurry, which is introduced into the system as a fluid. The principal advantage of an atmospheric gasifier is its simpler construction and operation, although it requires compression of the fuel gas before its introduction into the gas turbine combustor.

The gasification reaction is highly exothermic. If we run the equilibrium code on the reaction listed above in the HP mode, we find an adiabatic equilibrium temperature of 3560 K. Thus, a significant amount of heat must be extracted from the gasification process to hold the temperature to the 1700 K typical of the entrained flow gasifier or the 900 K for the fluidized bed. This is most commonly done by raising steam that is either added to the steam from the HRSG or it is expanded across a separate steam turbine. Although it would seem logical to use this heat to increase the fuel gas temperature and the air temperature before the combustor, this is not commonly done. First, gas on gas heat exchange is a very inefficient process, so large heat exchanger areas would be needed. Second, the high temperatures involved would require fairly exotic materials. As we have discussed before, boiling water to steam is a very efficient heat transfer process, with a very high h value. Thus, only relatively small heat transfer surface areas are needed. Only normal boiler tube materials are needed, even when exposed to 1700 K gases, since the high heat transfer coefficient prevents the tube temperature from rising above the steam temperature.

At the temperatures present in the entrained flow gasifier, the mineral matter is molten, and it is allowed to flow out of the bottom of the gasifier. Here it is introduced into a water quench pot where it forms a slag that is shipped for disposal.

The gases exiting the gasifier are predominantly CO and H_2, although they do contain the sulfur from the coal (as mostly H_2S and a little COS), the nitrogen as NH_3, and fine mineral particles that were not collected in the gasifier. The sulfur and nitrogen need to be cleaned out of the fuel gas as otherwise they will be converted to SO_2 and NOx in the combustor. Also, the fine mineral particles must be cleaned from the gas to prevent turbine blade erosion. A particular problem is the

simultaneous presence of sulfur and sodium. Sodium is one of the mineral constituents that is sufficiently volatile to vaporize in the combustor. The combination of vapor phase sodium and sulfur leads to an extreme turbine blade corrosion problem. None of the turbine manufacturers will guarantee their products unless the Na is taken to a very low level.

As we shall shortly see, the present methods for cleaning these gases require that they be cooled to near room temperature. Thus, a large heat exchanger is required at the outlet of the gasifier. From a cycle efficiency point of view this is a problem as less 1700 K fuel gas is needed in the combustor to reach a given combustor outlet temperature than if 300 K fuel gas is used. Thus, hot fuel gas results in less fuel consumption and a better efficiency. In response to this, there has been a significant research effort directed towards developing hot fuel gas cleanup techniques. At present, none of these are practical and the fuel gas must be cooled to room temperature.

Ceramic filters are normally used to remove particulate matter. An amine scrubber will remove H_2S, while an acid scrubber will remove the NH_3. Note that it is the use of these wet scrubbers that require the fuel gas to be cold. These products are converted to sulfuric acid and fertilizer for sale as byproducts.

From this point the fuel is introduced into the gas turbine combustor. Because of the lower heating value of the fuel, and its inferior combustion properties compared to natural gas, the common practice is not to use the state-of-the-art lean premixed combustors. These systems are simply too unstable when operating on this poorer fuel. Instead, traditional diffusion flame burners are used. Since these tend to have higher temperatures and produce much more NOx, some of the N_2 from the air separation plant is often supplied to the burner to reduce flame temperatures and NOx.

The balance of the system (gas turbine, HRSG, steam system) is similar to a natural gas fired combined cycle.

Current efficiency numbers range from 40-45% based on the fuel heating value. Research and engineering activities are direct towards increasing this efficiency.

Current capital costs are quoted in the $1200-1300/kW range, with the expectation that they will drop to about $1050 with economies of manufacturing scale in place. Thus, a 600 MW plant would cost $630,000,000. With a 20 year life and at 6% interest, the annual cost of the capital would be $55,000,000. At 45% efficiency, a 100% capacity factor, and a coal cost of $1.25/10^6 Btu, the annual fuel cost would be $50,000,000, for a total annual cost of $105,000,000. An equivalent natural gas combined cycle plant would cost $300,000,000. At the same life and interest, the annual cost of capital would be $26,000,000. This means that at the break-even point with the IGCC system, the annual natural gas cost would be $79,000,000. Applying a 60% efficiency results in a break-even unit cost for the natural gas of $2.64/10^6 Btu. This is close to the lower end of present natural gas price fluctuations. Thus, we see that significant rises in natural gas prices do move IGCC to the favored position in advanced fossil-based electricity generation. This logic is what is driving the manufacturers in this direction.