INTEGRATED GASIFICATION COMBINED CYCLE POWER PLANTS

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Outline

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Glossary

Gasification A process for converting a solid or liquid fuel into a gaseous fuel useful for power generation or chemical feedstock with an oxidant and steam.
Gasifier Cold Gas Efficiency (CGE) The percentage of the coal heating value that appears as chemical heating value in the gasifier product gas.
Air Separation Unit (ASU) A plant that separates oxygen and nitrogen from air usually by cryogenic distillation.
Syngas A gas produced by the gasification of a solid or liquid fuel that consists primarily of carbon monoxide and hydrogen.
Acid Gas Removal (AGR) A process for the removal of hydrogen sulfide, H_2S, other sulfur species and some CO_2 from syngas by absorption in a solvent with subsequent solvent regeneration and production of an H_2S rich stream for sulfur recovery.
Combustion (or Gas) Turbine A device in which fuel is combusted at pressure and the products of combustion expanded through a turbine to generate power (the Brayton cycle). It is based on the same principle as the jet engine.
Heat Recovery Steam Generator (HRSG) A heat exchanger that generates steam from the hot exhaust gases from a combustion turbine.
Combined Cycle (CC) A combustion (gas) turbine equipped with a HRSG that produces steam for the steam turbine. Power is produced from both the gas and steam turbines – hence the term combined cycle.
Integrated Gasification Combine Cycle (IGCC) A power plant in which a gasification process provides syngas to a combined cycle under an integrated control system.
Refuse Derived Fuel (RDF) The combustible portion of municipal solid waste after removal of glass and metals.

Opening

The pioneer 100 MW Cool Water project that was operated 1984-9 demonstrated the essential key IGCC characteristics of low emissions and stable integral control of the gasification process with a combined cycle in a power utility setting. In the 1990s additional larger commercial size coal based IGCC plants have been built and are operating in the U.S. and Europe. More recently several additional commercial IGCC projects based on the use of petroleum residuals have entered service in the U.S., Europe and Asia supplying power, steam and hydrogen to refineries and additional grid power. With the increasing concern over emissions from fossil fuel power plants, including the potential effect on global climate, the low emissions and high efficiency attributes of IGCC provide many market opportunities for this technology.

I. Technology Description

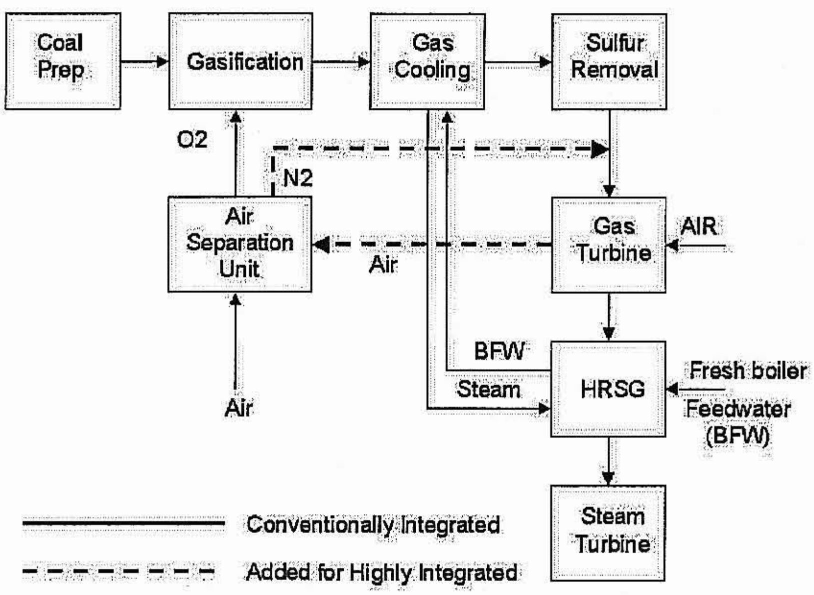
A. Technology Description of IGCC

The integrated gasification combined cycle (IGCC) technology allows the use of solid and liquid fuels in a power plant that has the environmental benefits of a natural gas-fueled plant and the thermal performance of a combined cycle. In its simplest form, the solid or liquid fuel is gasified with either oxygen or air, and the resulting raw gas (called syngas, an abbreviation for synthetic gas) is cooled, cleaned of particulate matter and sulfur species, and fired in a gas turbine. By removing the emission-forming constituents from the gas under pressure prior to combustion in the power block, IGCC plants can meet extremely stringent air emission standards. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbines. A block flow diagram of an IGCC system is shown in **Figure 1.**

There are many variations on this basic IGCC scheme, especially in the degree of integration. Four major commercial-sized, coal-based IGCC demonstration plants are in operation that each use a different gasification technology, gas cooling and gas cleanup arrangement, and integration scheme between the plant units. All of the current coal based plants integrate the steam systems of the gasification and power block sections. Typically boiler feed water (BFW) is preheated in the HRSG and passed to the gasification section where saturated steam is raised from cooling of the raw syngas. The saturated steam passes to the HRSG for superheating and reheating prior to introduction, with additional HRSG superheated steam, to the steam turbine for power production.

The aspect of integration design that is most varied among the four coal based IGCC plants has been the degree of integration of the gas turbine with the Air Separation Unit (ASU). There is a major design difference between the two European IGCC plants and the U.S. plants that derives from the gas turbine selection and design philosophy differences regarding the relative importance of efficiency compared to availability. The European plants at Buggenum (Netherlands) and Puertollano (Spain) are both highly integrated designs with all the air for the ASU being taken as a bleed of extraction air from the combustion turbine compressor. In contrast, the U.S. plants at Tampa and Wabash are less integrated, and the ASUs have their own separate air compressors. The more highly integrated design results in a higher plant efficiency since the auxiliary power load is lowered by the elimination of the separate air compressor. However, there is a loss of plant availability and operating controllability for the highly integrated system. Start up time is also longer with this design since the combustion turbine must be run on the more expensive secondary fuel (natural gas or oil) before extraction air can be taken to the ASU for its cool-down and start-up. In Europe where fuel prices are higher, efficiency is a major driver and that has favored capital investment for the highly integrated plant. In the U.S., fuel prices are lower and availability is more important than efficiency. It is now the general consensus among IGCC plant designers that the preferred design is one in which the ASU derives part of its air supply from the gas turbine compressor and part from a separate dedicated compressor. This provides the necessary flexibility for quicker start up, less usage of expensive secondary fuels, and an auxiliary power load intermediate between the two options.

Figure 1. Block Flow Diagram of an Integrated IGCC Power Plant



Several IGCC plants based on the gasification of petroleum residuals (vacuum resid, deasphalter bottoms and petroleum coke) have entered commercial operation during1998-2000 located adjacent to petroleum refineries. However because of the demand for an overall plant availability >95% these plants have been designed as multi train plants with no integration between the ASU and gas turbine. Most of these plants also use the less complex Texaco quench gasification process which does not include a syngas cooler for high pressure (HP) steam raising but which does raise some low pressure (LP) steam from cooling of the quenched syngas.

The commercial scale IGCC projects that are currently operating, under construction and in advanced engineering are shown in **Table I.**

Table I Commercial IGCC Plants 2000

Owner	Location	GasificationTechnology	MWe Output	Startup Year	Feed
Demkolec BV	Buggenum, Netherlands	Shell (Coal)	250	1994	Coal
Global Energy /Public Service of Indiana (PSI)	Indiana,U.S.	E-GAS^{TM} (formerly Destec)	260	1995	Coal and Petroleum Coke
Tampa Electric Co.	Florida, U.S.	Texaco	250	1996	Coal and Pet. Coke
ELCOGAS SA	Puertollano, Spain	Prenflo	300	1998	Coal and Pet. Coke
Sierra Pacific	Nevada,U.S.	KRW	100		Coal
SUV/EGT	Vresova, Czech Republic	Lurgi Dry Ash	400	1996	Lignite
SVC	Schwarze Pumpe, Germany	Lurgi Dry Ash, GSP, BGL,MPG	60	1996	Lignite, Wastes and RDF
Global Energy	Kentucky, U.S.	BGL	500	2004	Coal, RDF
Shell	Pernis, Netherlands	Shell (Oil)	127	1997	Visbreaker Bottoms
ISAB/ Mission Energy.	Sicily, Italy	Texaco	512	1999	Deasphalter Bottoms
Sarlux Saras/ Enron	Sardinia, Italy	Texaco	545	2000	Visbreaker Residue
API /ABB/ Texaco	Falconara, Italy	Texaco	280	2000	Visbreaker Residue
Repsol/ Iberdrola	Bilbao, Spain	Texaco	800	2004	Vacuum Residue
Total/EdF/ Texaco	Gonfreville, France	Texaco	400	2004	Residual oils
Motiva	Delaware, U.S.	Texaco	240	2000	Petroleum Coke
Esso Singapore	Singapore	Texaco	180	2001	Steam Cracker Tar
NPRC	Japan	Texaco	343	2004	Residual oils
TECO Power Svcs,/ Texaco/Citgo	Louisiana, U.S.	Texaco	650	2004	Petroleum Coke

In many of these plants most of the steam is supplied directly to the refinery rather than being used for power production. Many of the plants also use some of the product syngas to make hydrogen, via the water gas shift reaction and subsequent CO_2 removal, for use in refinery processes such as hydrotreating and hydrocracking.

The only air blown IGCC project listed in **Table I** is the Sierra Pacific 100 MW Piñon Pine project near Reno, Nevada. Air blown gasification was also used at the Biomass IGCC 6 MW demonstration plant at Varnamo, Sweden and is planned for use in other biomass IGCC projects in Europe. In air blown IGCC designs the air for gasification is taken as bleed extraction air from the gas turbine compressor and boosted by another compressor if the gasifier is pressurized.

B Gasification Technologies
B 1 Chemistry and Reactions

The following reactions are important in coal gasification:

- Coal Devolatilization = $CH_4 + CO + CO_2$ + Oils + Tars + C (Char)
- $C + O_2 = CO_2$ ((exothermic – rapid)
- $C + 1/2O_2 = CO$ (exothermic – rapid)
- $C + H_2O = CO + H_2$ (endothermic – slower than oxidation)
- $C + CO_2 = 2CO$ (endothermic – slower than oxidation)
- $CO + H_2O = CO_2 + H_2$ Shift Reaction(slightly exothermic – rapid)
- $CO + 3H_2 = CH_4 + H_2O$ Methanation (exothermic)
- $C + 2H_2 = CH_4$ Direct Methanation (exothermic)

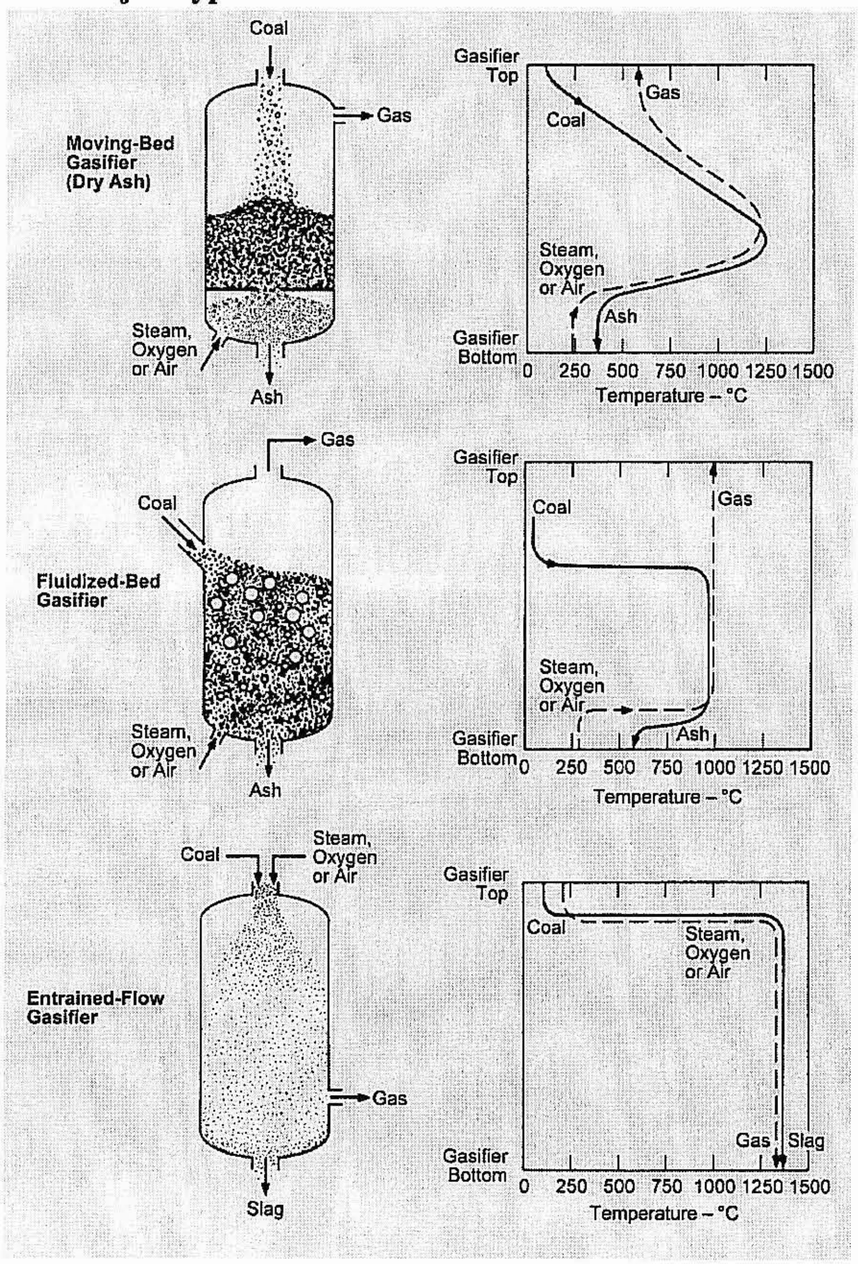
The first six of these reactions are the most important in the entrained gasification processes used in the current IGCC plants. Methane formation is more important in lower temperature systems. High pressures and lower temperatures favor the methanation reactions. However in most cases the methane content is higher than equilibrium would predict because methane is also formed during devolatilization.

Under the reducing conditions of gasification, the sulfur in the coal is converted primarily to hydrogen sulfide, H_2S, with ~3-10% of the sulfur converting to carbonyl sulfide, COS. This typically necessitates the use of a COS hydrolysis reactor to convert the COS to H_2S prior to H_2S removal by well known solvent absorption processes widely used in the gas processing and petroleum industries. Gasification conditions favor the conversion of fuel bound nitrogen to gaseous nitrogen and ammonia, NH_3. Higher temperatures favor the further destruction of ammonia to nitrogen and hydrogen so that the ammonia content of the raw syngas is primarily a function of the gasifier outlet temperature. Small amounts of HCN are also formed but may be removed in the COS hydrolysis reactor. Tars, oils, and phenols survive in the lower temperature outlets of moving bed gasifiers and these species contain some of the fuel's oxygen, nitrogen, and sulfur as more complex molecules.

B 2 Gasification Processes

Three major types of gasification are used today—moving bed, fluidized bed, and entrained flow. These processes are illustrated in **Figure 2.**

Figure 2. The Three Major Types of Gasification Processes



A database of the worldwide commercial gasification facilities has been prepared by SFA Pacific for the U.S. DOE and the Gasification Technologies Council (GTC). A report "Worldwide Gasification Industry Report" and a data base package are available from DOE. The database contains records for 161 real and planned commercial scale gasification projects , representing a total of 414 gasifiers with a combined rating of 446 million Nm^3/day of syngas. If all this syngas was converted to electricity using IGCC it would equate to ~33,300 MWe.

Pressurized gasification is preferred for IGCC to avoid large auxiliary power losses for compression of the syngas up to gas turbine inlet pressure. Most gasification processes currently in use or planned for IGCC applications are oxygen blown.

In moving bed reactors, sized coal (typically in the size range 6-50 mm) moves slowly downwards reacting with gases ascending counter-currently through the bed. At the top, the entering coal is heated and dried, and in turn cools the gas that leaves the reactor. The dried coal then devolatilizes as it descends through the carbonization zone. The devolatilized coal is then gasified by reaction with steam and carbon dioxide in the gasification zone. In the bottom zone oxygen reacts with the remaining char to produce heat by oxidation which drives the endothermic gasification reactions. In the dry ash mode of operation excess steam is injected with the oxygen so that the temperature is maintained below the ash slagging temperature. In the slagging version steam and oxygen is introduced through a series of tuyeres and molten slag is removed from a pool in the base of the gasifier.

The feed coal moisture controls the gas discharge temperature. For high moisture lignite the raw gas temperature is ~ 315°C whereas for a low moisture bituminous coal it is ~ 540°C. The raw gas leaving the reactor is directly quenched with recycle water to condense the tars and oils.

The Lurgi moving-bed dry ash gasifier is a pressurized oxygen-blown countercurrent gasifier in widespread use around the world in South Africa, the United States, Germany, the Czech Republic, and China. The plants in Germany and the Czech Republic use some of the gas to fuel gas turbine combined cycle power plants. A slagging version of the Lurgi gasifier has been developed by British Gas and Lurgi (BGL). A large commercial-sized unit based on this BGL technology is now being commissioned in Germany and a 500 MW IGCC plant is planned in Kentucky under the U.S. DOE clean coal demonstration plant program.

The moving bed gasifiers have high cold gas efficiencies, low oxygen requirements and a raw gas of relatively high methane content. Tars and oils are also produced as byproducts. There is only a limited ability to process fines in the top feed however briquettes or pellets of fine coal can be used. The slagging version also offers the opportunity to recycle the tars and oils to extinction and the gasification of coal fines through introduction in the tuyeres can be practiced.
Fluidized bed gasifiers are back-mixed reactors in which fine coal particles are mixed with coal particles already undergoing gasification. The fluidized bed temperature must

be held lower than the ash fusion temperature (typically <900°C) to avoid agglomeration, deposition and defluidization of the bed, yet not so low as to produce tars. Coal particles reduce in size through gasification and some are entrained in the hot raw gas as it leaves the reactor. These char particles are recovered in a cyclone and recycled to the reactor. Some ash particles are removed from below the bed and are cooled by incoming steam or recycle gas. Fluidized bed gasifiers may differ in the manner that ash is discharged (dry or agglomerated) and in design aspects that improve char utilization.

By operating at a higher temperature agglomerated ash operation improves the ability to process high rank, but less reactive bituminous coals. Historically dry ash fluidized bed gasifiers have usually been operated on low rank coals, peat or biomass. More recently the focus of new designs for fluidized bed gasifiers has shifted from the lower velocity bubbling beds to higher velocity circulating or transport type designs which feature higher char recirculation rates with consequent improvements to the overall carbon conversion.

Fluidized-bed gasifiers have been developed to a lesser extent than the other types. Winkler gasifiers that operate at atmospheric pressure have been used in Germany, India, Turkey, and elsewhere. Several "U" Gas gasifiers developed by IGT and operating at ~0.4 MPa pressure have been installed in the Shanghai Coking and Chemical Plant. A high-temperature HT Winkler gasifier operating at ~1 MPa pressure was developed by Rheinbraun and used commercially in Germany for methanol manufacture and in Finland for ammonia manufacture. Both of these plants are now shut down. Plans are being developed for an IGCC plant in the Czech Republic based on the HT Winkler process operating at ~ 3 MPa pressure. The 100-MW IGCC Piñon Pine Plant near Reno, Nevada, in the U.S., uses the Kellogg-Rust Westinghouse (KRW) ash agglomerating fluid bed process. Foster Wheeler has also supplied atmospheric fluidized bed gasifiers for use in the forest products industry on wood chips, and also supplied a pressurized version to the 6 MW biomass IGCC demonstration plant at Varnamo, Sweden.

In entrained flow gasifiers the fine coal particles react with the concurrently flowing steam and oxygen. Residence time is very short (a few seconds) and the operating temperature is above the ash fusion temperature to ensure destruction of tars and oils and to achieve high carbon conversion. Entrained gasifiers have relatively high oxygen requirements and the raw gas is of high sensible heat content. The various designs of entrained flow gasifiers differ in their feed systems (dry pneumatic or coal/water slurries), vessel containment for the hot conditions (refractory or water wall), and configurations for recovery of the sensible heat from the raw gas. Some gasifiers use two stages to improve thermal efficiency and to reduce the sensible heat in the raw gas and to lower the oxygen requirements.

Entrained-flow gasifiers have been selected for the majority of commercial sized IGCC project applications. These include the coal/water-slurry-fed processes of Texaco (Cool Water, and Tampa, U.S.) and E-GAS™ (formerly Destec – Dow, Plaquemine, and Wabash plant, USA) and the dry-coal-fed processes of Shell (Buggenum, Netherlands), Prenflo Krupp-Uhde (Puertollano, Spain), GSP (Schwarze Pumpe, Germany), and

Mitsubishi (Nakoso, Japan). The Mitsubishi and E-GAS™ processes employ two stages of gasification. The atmospheric pressure Koppers-Totzek process was developed in the 1950s, and commercial units operated in Greece, Turkey, India, South Africa, Zambia, and elsewhere, mostly for ammonia manufacture. A major advantage of the high-temperature entrained-flow gasifiers is that they avoid tar formation and its attendant problems. The high reaction rate also allows single gasifiers to be built with large gas outputs sufficient to fuel the large commercial gas turbines now entering the marketplace. The IGCC projects based on petroleum residuals all use entrained downflow refractory lined gasifiers from either Texaco or Shell. There are over a hundred of these gasifiers in operation worldwide for the manufacture of ammonia, methanol, hydrogen and other chemicals.

C Oxidant Production

All gasification processes require an oxidant to maintain the high temperatures needed for gasification. The oxidant can be air, oxygen or oxygen-enriched air. The choice depends on the application, gasification technology and system integration.

The first gasifiers were air-blown atmospheric pressure moving bed gasifiers known as gas producers. However since the development of the Linde-Frankl process in the 1930's economical large scale cryogenic distillation plants producing oxygen have become available and few additional air-blown gasifiers have been built.

Air-blown gasifiers produce a gas high in nitrogen (~50%) and of low heating value (~ 4.5 GJ/Nm^3) that is unsuitable for many applications. The low heating value also increases the size of the gasification and gas cooling equipment and the high nitrogen content reduces the cold gas efficiency of the gasifier and makes sulfur removal more difficult. In order to operate air-blown gasifiers in the slagging region the air would have to be heated to very high temperatures and for this reason air-blown gasifiers are usually moving or fluidized bed systems. The successful development of advanced hot gas clean-up systems for particulate and sulfur removal would further improve the efficiency of air blown gasification for IGCC applications.

The great majority of commercial gasification plants built since World War II have been oxygen blown. The gas heating value is typically 9-13 GJ/Nm^3 and it can therefore be used as natural gas replacement or for synthesis of higher value chemicals such as ammonia, methanol and oxo-alcohols. The size of the gasification, gas cooling and gas clean-up and distribution systems are much smaller than for air blown processes since the gas volume is approximately halved. The gasifier cold gas efficiency is also 7-10% higher for oxygen blown systems than for air blown systems because of the need to heat up the nitrogen in the latter.

Single train cryogenic Air Separation Units (ASU) have been supplied up to a production capacity of 3175 Metric tons/day of 98% purity oxygen. The major suppliers are Air Products, Air Liquide, British Oxygen, Praxair and Linde. The air and oxygen compressors/drivers account for about half of the ASU capital cost and the operating costs are mostly for the electricity or steam to drive the compressors.

The ASU is a significant capital cost item in the overall cost of an IGCC plant and it can represent 10-15% of the Total Plant Cost (TPC) or ~ 120-170$/kW.

There are some advantages to be gained by using air extracted as a bleed from the combustion turbine air compressor to supply all or part of the air feed to the ASU thereby reducing the auxiliary power load by eliminating some of the ASU air compressor duty. In such a configuration the extracted air is cooled and is fed to an ASU operating at a higher column pressure of ~1 MPa rather than the more usual 0.5-0.6 MPa. The nitrogen product also leaves the ASU at a pressure of ~ 0.5 MPa and can be effectively utilized by additional compression and feeding to the combustion turbine where it provides additional mass motive power and NOx control by reducing the flame temperature of the syngas. The combustion turbine air compressor must be able to handle the increase in back pressure due to the extra gas flow, however several of the more recent designs of the F type can handle the increased flow and thereby increase power output.

D Gas Cooling and Heat Recovery

Sensible heat in the hot raw syngas can represent >15% of the energy in the feed coal and its recovery increases the overall IGCC plant efficiency. Since gasification is usually conducted under pressure the heat flux is significantly higher than traditional heat recovery in a conventional Pulverized Coal (PC) boiler. The reducing gas containing hydrogen and H_2S may also need different metallurgy. Heat recovery from the raw syngas can be by radiation and/or convection heat exchange. As in direct combustion, radiant heat exchange is only used for very high temperature operation. Some gasification processes use a metal liner in the gasifier that recovers heat by generating high or medium pressure saturated steam. This design avoids the use of expensive refractory linings but does reduce the cold gas efficiency. However by allowing a layer of solidified coal ash slag to build up as an insulator the heat losses can be minimized.

In nearly all IGCC plant designs, the saturated steam raised from cooling the raw gasifier gas is sent to the HRSG for superheat and reheat. The higher metal temperatures required for superheated steam raising from the hot raw syngas make this form of heat recovery much more difficult and expensive than saturated steam raising. The steam and water systems are integrated between the gasification island and the power block and superheated steam is generally better generated in the HRSG than in the raw syngas coolers.

The current IGCC projects use different equipment designs for the gas cooling. The Texaco/Tampa project uses a vertical downflow water tube radiant cooler followed by horizontal firetube convection coolers. The Shell/Buggenum, and Krupp-Uhde/Puertollano plants use recycle gas cooling to reduce the raw gas temperature to ~ 820°C and water tube syngas coolers for steam raising. The E-GAS™/ Wabash and the KRW/Sierra Pacific Piñon Pine projects use lower cost downflow firetube syngas coolers.

The syngas coolers used in the Texaco and Shell processes for the gasification of residual oils are of an upflow helical firetube design available from several manufacturers (Steinmuller, MAN, EVT etc)

The cost of the syngas coolers can be a very significant portion of the overall IGCC capital, and in several of the currently operating plants with large water tube syngas coolers it represented as much as 10 % of the total IGCC capital cost. If the downflow firetube coolers can be used successfully without fouling they markedly reduce the capital cost since they are only about a quarter of the weight of comparable water tube designs. The Wabash experience has been quite positive in this regard and the recent development of effective on line cleaning has markedly improved availability.

Fouling of the gas cooling heat exchangers on the Tampa project has also been a cause of significant downtime. However removal of the two lower temperature gas/gas exchangers from service and recent improvements in reducing the deposition in the horizontal convection coolers has improved availability at this site also.

All of the syngas coolers supplied to the current IGCC plants are of European design and manufacture. Suppliers include MAN, Steinmuller, Deutsche Babcock Borsig, and EVT. Total water quench of the raw syngas can also be effective as a low cost way of removing particulate matter (ash/slag) and cooling the gas to a moderate temperature (~ 250°C). Heat as medium or low pressure steam can still be economically recovered from the quenched gas when the quenched water is condensed out of the syngas. In addition water quench is attractive if the syngas is to be used in a shift reactor to increase the H_2/CO ratio. The majority of the IGCC plants based on petroleum residual feedstocks use the Texaco quench type gasifiers and shift a portion of the syngas to produce hydrogen that is used in the petroleum refinery.

E Gas Cleanup

E 1 Particulate Removal

Most processes remove the entrained particulate matter from the raw gas at higher temperatures before cooling the gas to allow removal of sulfur compounds. In fluid bed gasifiers cyclones are used at the gasifier exit to recover the bulk of the particulates and char material for recycle to the gasifier. Many developers are using barrier filters of the candle (either ceramic or metallic) type. Some of the initial development efforts focused on high temperatures (800-900°C) filtration as would be required for a pressurized fluidized bed combustion (PFBC) application. However the vapor pressure of the alkali metal species is sufficiently high at these temperatures that the resultant alkali content is unacceptable for high temperature combustion turbines. Consequently the filtration temperatures are reduced to < 650°C for the gasification application. Most of the benefits of hot gas clean-up can be realized at temperatures of 250-400°C. At these conditions the volume of gas is lower, and less corrosive and water is not condensed from the gas that would wet the fly ash. Chlorides and some other trace components can be removed in the dry form with the fly ash. Dry fly ash recovery significantly reduces the build-up of fixed salts in the recycle process water and the cost of wastewater clean-up.

Three of the IGCC commercial demonstration projects (Demkolec/Buggenum, Global/Wabash, and Elcogas/Puertollano) use candle filters operating at 250–350°C for removal of particulate matter. A candle filter was also used successfully at ~ 350°C for several years on the HT Winkler gasifier at Berrenrath, Germany before the plant was closed in 1998.

The main suppliers of hot gas candle filters are Schumacher, Lurgi Energie und Entsorgung (formerly LLB), and Siemens Westinghouse.
Texaco offers two versions of their gasification process a) with syngas cooler heat recovery and b) with direct water quench of the gasifier outlet gas. In both versions Texaco uses direct water quench for final particulate removal. Water scrubbers also remove chlorides, ammonia and trace components. The scrubber blowdown water is subsequently steam stripped and the stripped gas is either sent to the Claus plant or an incinerator. However at the Global/Wabash plant the stripped gas is recycled to the gasifier.

E 2 Removal and Recovery of Sulfur Species

E 2 a Sulfur Removal

The four oxygen blown coal –based IGCC demonstration projects and all the IGCC projects based on petroleum residuals use conventional Acid Gas Removal (AGR) processes (~ 40°C) for gas desulfurization. These AGR processes are already widely used commercially in the natural gas processing and petroleum industries worldwide. The AGR processes are very effective at removal of H_2S (the major sulfur species) down to very low levels but are usually less effective at COS removal. Accordingly most IGCC plants incorporate a water wash step for ammonia and trace component removal followed by a fixed bed of catalyst for carbonyl sulfide (COS) hydrolysis to H_2S (at ~ 180°C). Traces of HCN can also be removed from the gas in this step. Subsequent removal of the sulfur species (now almost entirely H_2S) is then accomplished in the downstream AGR processes (MDEA, Sulfinol, etc).

In the typical AGR process the syngas (sometimes called sour gas at this point in the process) is contacted counter-currently with a solvent in an absorption tower which absorbs or chemically reacts with the acid gas components. Most of the commoner processes operate at near –ambient temperature ~40°C. The treated gas (sometimes called sweet gas) leaving the absorber then passes on to the combustion turbine (perhaps after saturation with hot water from low temperature heat recovery) or subsequent processing to other products. The solvent leaving the absorber is heated and reduced in pressure to flash the acid gas in a stripper regenerator. The acid gas leaving the stripper is cooled to condense water and is then most typically sent to the sulfur recovery process. The acid-gas free lean solvent from the bottom of the stripper is cooled and pumped back to the absorber.

The MDEA (Methyl-Di-Ethanol-Amine) process (licensed by several companies Dow, Shell, Texaco, Union Carbide) is used at the Tampa, Wabash and Puertollano coal based IGCC plants. The Sulfinol M process licensed by Shell is used at the Buggenum IGCC plant. In many of the petroleum residual IGCC plants some of the syngas is used for making hydrogen and deeper sulfur removal is required. For this reason the Rectisol (Lurgi, Linde) and Selexol (UOP, Carbide) processes, which operate at sub- ambient lower temperatures are often selected for their deeper sulfur removal capabilities down to < 1 ppmv of total sulfur compounds.

Hot gas cleanup for removal of sulfur species is not yet sufficiently developed for commercial use. The proposed sorbents are often mixed metal oxides of Fe, Zn, Ti, or Ni and to date the formulations have been expensive and generally not very resistant to the attrition they would see in actual service in moving or fluid bed contactors. Most of the proposed hot gas sorbents and processes also have the drawback of being unable to remove other components such as ammonia, chlorides, and volatile trace metal species. The Sierra Pacific Piñon Pine project aims at some in-situ capture of sulfur in the KRW fluid bed gasifier by the addition of limestone and subsequent hot fuel gas desulfurization by contact with a sorbent in a transport type fast fluid bed contactor at ~ 600°C. However this transport contactor unit has not yet been operated.

E 2 b Sulfur Recovery

The H_2S recovered from the solvent regeneration is usually converted to elemental sulfur using the Claus process. Elemental sulfur has much lower transportation costs than sulfuric acid, it main use, and therefore sulfur is generally the preferred form of the sulfur byproduct in IGCC plants. However at Tampa, the H_2S is converted into sulfuric acid for convenient sale to the adjacent phosphate fertilizer industry.

The classic Claus process involves the partial oxidation of H_2S to elemental sulfur and water. The oxidant is usually air although in some plants oxygen has also been used when the H_2S content is low.

One-third of the feed gas is burnt in the burners of the Claus kiln to produce SO_2 by the reaction: $H_2S + 1.5\ O_2 = SO_2 + H_2O$.

The remaining two-thirds of the acid gas react in the Claus kiln with the SO_2 to form elemental sulfur according to the Claus reaction: $2H_2S + SO_2 = 3S + 2H_2O$.

The Claus kiln is also equipped with a catalyst bed where nitrogen-containing species are decomposed according to the following reactions:

$$NH_3 = 3/2H_2 + 1/2N_2$$

$$HCN + H_2O = 3/2H_2 + CO + 1/2N_2$$

The sensible heat from the high temperature (~1300°C) Claus kiln is used to generate steam in a waste heat boiler. The condensed sulfur is separated and typically discharged to a liquid sulfur pit for subsequent transport and sale.

The process gas from the waste heat boiler is further reacted in additional catalytic reactor stages (2, 3 or 4) to produce additional sulfur. A three stage Claus plant usually achieves ~97% sulfur recovery.

The tail gases still contain unrecovered sulfur species so that a tail gas treatment unit or incinerator is usually required to meet the stringent emission standards. However at the Wabash plant the Claus plant tail gases are recycled to the gasifier. These tail gas treatment processes usually need some of the syngas to provide the hydrogen necessary to reduce the sulfur species in a catalytic reactor to H_2S which is then absorbed in an AGR process and recycled to the Claus plant. Several licensors offer Claus Tail Gas Treatment processes. The SCOT (Shell Claus Off gas Treatment) process is widely used. Other commercially available processes include wet oxidation systems such as Stretford, LO-CAT, Sulferox etc.

F Fuel Gas Expansion

Texaco and other organizations have proposed the use of a high efficiency quench (HEQ) IGCC design in which the gasification is conducted at high pressure (~7 MPa). Additional power is generated by expansion of the clean fuel gas from 7 to ~ 2 MPa followed by gas reheat and firing in the combustion turbine. This scheme is being used in two of the heavy oil IGCC plants at Api Falconara and ISAB in Italy. About 10 MW of additional power is generated on each gasification power train at these locations.

G NO_x Emissions Control

NOx emissions from the combustion turbine can result from two sources a) fuel bound nitrogen in such species as ammonia and b) thermally produced NOx. In most of the commercial sized IGCC plants there is a water wash step in the cold gas clean up that removes ammonia and HCN from the syngas before entering the AGR process thereby removing the components of fuel bound nitrogen.

Due to its high flame temperature, the clean syngas can lead to high NO_x emissions in the combustion turbine unless controlled by other means. Two main techniques are used to lower the flame temperature for NO_x control in IGCC systems. One is to saturate the syngas with hot water derived from low-temperature heat recovery elsewhere in the process. The other is to use nitrogen from the ASU. In both cases, mass is also added to the syngas and additional power is thereby generated in the gas turbine and steam cycle. At Wabash, NO_x control is by saturation and some steam injection. At Tampa, the NO_x is controlled by nitrogen injection, while at Buggenum and Puertollano, a combination of saturation and nitrogen is used.

At the Sierra Pacific project, the nitrogen in the low-heating-value syngas from the air-blown gasifier should reduce the flame temperature sufficiently to meet the NO_x limits. However this has not yet been demonstrated and there may also be some NOx production from ammonia at this plant since there is no water wash step in the gas clean up.
If extremely low NOx levels, such as 1-2 ppmv, are required a selective catalytic reduction (SCR) bed can be placed within the HRSG at a suitable temperature.

H Combustion Turbines

A natural gas –fired combustion turbine combined cycle power generation system has clear advantages over a natural gas based boiler system. Modern combustion turbines offer low capital cost and high efficiency and have demonstrated high reliability and availability. Similarly gasification for power generation is usually based on combustion turbines fired with gasification-derived fuel gas.

The electric power output of an IGCC plant is largely determined by the combustion turbine. The three U.S. coal-based IGCC projects all use General Electric (GE) gas turbines of the F or FA series with can-annular combustors and firing temperatures of ~ 1260°C. Both of the European projects use Siemens turbines with external silo combustors. At Buggenum the V 94.2 model has a firing temperature of ~ 1100°C, while Puertollano uses a V 94.3 turbine with a firing temperature of ~ 1260°C. It should be noted that Siemens often quotes an ISO firing temperature. This is a calculated number that can differ by 60°C or more (lower) from the firing temperature as defined by GE. Gas turbines differ in output depending on the frequency of the electricity produced, since combustion turbine rotors are usually designed for a specified tip speed. The U.S. and half of Japan operate at 60 Hz and the GE 7FA gas turbine output in an IGCC application is about 192–196 MW. Europe, the other half of Japan, China, and many other countries operate at 50 Hz, and in these countries the equivalent gas turbine would be a GE 9FA with an output in the IGCC application of 276–282 MW. The equivalent net total output for single-train IGCC plants would be ~ 275 MW in the U.S. and ~ 400 MW for Europe and China. The plant net IGCC efficiency with these current (year 2000) turbines is typically 43–46% on an LHV basis, depending on coal, location and configuration.

Larger and more efficient gas turbines are now entering the marketplace with firing temperatures of about 1500°C. These advanced turbines should produce additional economies of scale, reduced IGCC capital costs, and higher overall net efficiencies of ~ 46-50% (LHV basis). The IGCC plant net output for these G- or H-class combustion turbines will be 400–450 MW for the U.S and 500–550 MW for Europe and much of the rest of the world.

Tables II and **III** list the large combustion turbines generally considered for the IGCC application and their standard ratings for natural gas firing as listed in the Gas Turbine World 1999-2000 Handbook. The turbine rating for syngas in the IGCC application can be higher than for natural gas due to the higher mass flow for a given heat input. For example, GE rates the 7 FA at 192 MW for syngas versus 171.7 MW on natural gas. To use a combustion turbine effectively the syngas must be supplied at a pressure higher than the combustion turbine's firing pressure. In addition turbine manufacturers usually specify a substantial pressure drop across the fuel control valve to assure excellent control and symmetrical distribution of the syngas to the multiple burners. The combustion turbines that have experience in the IGCC application are specifically identified in **Tables II and III.**

The major large gas turbine candidates in the 60 Hz market are the General Electric (GE) 6 FA, 7 FA, Westinghouse 501 F, and Alstom KA 24-1. Westinghouse has also introduced the 501-G with a firing temperature of 1430°C (2600°F) and has obtained several orders in natural gas service. General Electric has introduced their 107-H with a similar firing temperature that features steam cooling of the first row of blades. The first order for this turbine has also been placed. Existing gas turbines are designed primarily for operation with natural gas or #2 fuel oil. Air blown IGCC designs usually extract air from the combustion turbine air compressor to supply air to the gasifier. This feature is needed to balance and match the air and turboexpander mass flows for which most combustion turbines are designed. The extraction air must be cooled and further compressed to operate the gasifier at sufficient pressure necessary to fire low heating value gas in a controlled manner.

Table II Heavy Frame Gas Turbine Characteristics – 60 Hz

Model	Simple Cycle MW (ISO conditions)	Combined Cycle MW (ISO conditions)	Combined Cycle heat rate kJ/kWh (Btu/kWh) LHV basis	Used in IGCC Plant/Location
GE 106 B	42.1	59.8	7390(7005)	El Dorado/U.S.
GE 106 FA	70.14	107.4	6775(6420)	Sierra Pacific/U.S Motiva /U.S
GE 107 EA	85.4	130.2	7175(6800)	CoolWater 7 E
GE 107 FA	171.7	262.6	6425 (6090)	Tampa/U.S Wabash /U.S.
GE 107 FB		280.3	6280(5950)	
GE 107 H		400	6000 (5690)	
Alstom KA 24-1	183	271	6270 (5872)	
Siemens Westinghouse 64.3A	68	100	6870 (6510)	
Siemens Westinghouse W501D5A	120.5	172	7170(6800)	Dow Plaquemine/U.S
Siemens Westinghouse 501F	186.5	273.5	6490 (6150)	
Siemens Westinghouse 501G	253	365	6210 (5880)	
Mitsubishi 501 F	185.4	280.4	6351(6019)	
Mitsubishi 501G	254	371.1	6208(5884)	

Table III Heavy Frame Gas Turbine Characteristics – 50 Hz

Model	Simple Cycle MW (ISO conditions)	Combined Cycle MW (ISO conditions)	Combined Cycle heat rate kJ/kWh (Btu/kWh) LHV basis	Used in IGCC Plant/Location
GE 106 B	42.1	59.8	7390(7005)	Shell/Pernis SVZ/Germany
GE 106 FA	70.14	107.4	6775(6420)	
GE 109 E	123.4	189.2	6935(6570)	Vresova/Czech Republic, SARAS/Italy
GE 109 EC	169.2	259.3	6660(6315)	
GE 109 FA	255.6	390.8	6350 (6020)	
GE 107 H		480	6000 (5690)	
Alstom KA 13E2	165.1	242.5	6767(6409)	Api Falconara/Italy
Alstom KA 26-1	265	393	6150 (5830)	
Siemens V 64.3A	68	100	6870(6510)	
Siemens V 94.2	157	232.5	6990(6630)	
Siemens V 94.2A	189	293.5	6520(6180)	
Siemens V 94.2K		~256		ISAB/Italy
Siemens V 94.3	200	335		ELCOGAS Puertollano/Spain
Siemens V94.3A	258	380	6207 (5883)	
Mitsubishi 701 F	270.3	397.7	6317(5988)	
Mitsubishi 701 G	334	484.4	6208(5884)	

Oxygen blown gasification requires less integration and fewer modifications to the combustion turbine. Air extraction is not a requirement since medium heating value gas more closely balances the air and turbo expander flows for which existing turbines have been designed. However there is a mass flow increase in the turboexpander relative to the airflow. This requires either an increase in pressure or a reduction in firing temperature. Higher pressure is preferred but this requires operation of the air compressor closer to the stall conditions (surge line) than for natural gas fuel. However it appears that several of the large combustion turbines (e.g. GE 7 FA) have sufficient stall margin in their air compressors to avoid derating in the IGCC application.

The GE 7 FA combustion turbines at Tampa and Wabash have generally performed well. The 7 FA air compressor failure at Wabash in March 1999 was not related to the IGCC application. The Siemens combustion turbines at Buggenum and Puertollano have had vibration ("humming") and overheating problems in the combustors. The use of large silo combustors in these Siemens turbines meant that full-scale combustion tests were not conducted prior to full plant start up. Whereas the multiple can type combustors of the GE turbines enabled full scale testing of an individual combustor can prior to completion of design.

With the current availability of natural gas in the U.S. and Europe combined cycle plants have been the preferred choice of most power companies for generation additions. The market demand is high and there has been a noticeable increase in the larger combustion turbine based combined cycle costs in 2000 to about 500 $/kW.

I Heat Recovery Steam Generation (HRSG) and Steam Turbines

The exhaust gas temperature of modern combustion turbines is ~ 600°C. At this temperature the addition of a bottoming steam cycle for additional power generation is economically effective for intermediate and base load application. Steam is raised by cooling the exhaust gas in a Heat Recovery Steam Generator (HRSG) typically generating steam at conditions of 12.5 MPa/540°C superheat/540°C reheat without supplemental firing of the HRSG. This quality steam is efficiently used to generate electric power in the steam turbine. The HRSG is also typically used in the IGCC application to superheat the high pressure saturated steam that is generated from heat recovery in the gasification section raw syngas coolers.

The major suppliers of HRSG's include Vogt-NEM, Nooter-Eriksen, Foster Wheeler, Aalborg Industries, and Deltak.

J Advanced Power Cycles

Advanced power generation systems based on fuel cells or advanced combustion turbines promise higher efficiencies but all require a clean fuel. In gasification based systems the prior to power generation so that there are very low emissions. Integration with gasification is the only way that such high efficiency systems can be used with coal or petroleum residue fuels.

Various innovative advanced cycles have been suggested but are beyond the scope of this article. However the Humid Air Cycle (HAT) is of particular interest in that it offers the potential for effective integration with the lower cost quench type gasification processes. The development of combined fuel cell/ combustion turbine power blocks offer the prospect of efficiencies up to 70% on natural gas.

In the HAT cycle a flue gas heat recuperator replaces the HRSG and is used to preheat humidified combustion air and water. The combustion turbine air compressor is also intercooled and cooled after final compression (aftercooling). The heat recovered in these cooling steps preheats additional water, and the hot water humidifies the pressurized combustion air in a multistage, countercurrent saturator. Analysis of the HAT cycle integrated with Texaco Quench gasification showed a significant reduction in capital cost at comparable efficiencies to the IGCC with full heat recovery syngas coolers. However development of new combustion turbine cycles that require compressor intercooling and higher pressure operation could be costly.

Fuel cells convert the chemical energy in the fuel gas directly into electricity. Current development work is focused on the development of the fuel cell itself and on the use of hydrogen from natural gas reforming. Several types of fuel cell are being developed including solid oxide, molten carbonate, phosphoric acid and proton exchange membranes. At this stage of development it appears that the higher temperature solid oxide and molten carbonate systems would best integrate with gasification based systems for central station power production.

Westinghouse (now Siemens Westinghouse) has developed a tubular solid oxide fuel cell (SOFC) that promises to be competitive at the megawatt scale. Packaged units that integrate pressurized SOFC modules with a combustion turbine (CT) could achieve efficiencies of 70%. An SOFC – CT test unit of 250 kW is under test at the fuel cell test center in Irvine, California. In the typical SOFC fuel gas conversion in the anode is ~85%. However a new SOFC unit has been developed by Siemens Westinghouse with Shell Hydrogen that incorporates an additional step that completes the conversion of the anode gas to 100% so that the emissions are just CO_2 and water. A 250 kW SOFC unit of this design is to be tested in Norway. This could be a very significant development if CO_2 emissions become a major issue and if CO_2 removal from power plants for subsequent sequestration becomes necessary. When using coal or petroleum residues, gasification plants using fuel cell systems promise the highest efficiency and lowest emissions. Capital cost reduction of the fuel cell power block is a major challenge.

K Other Gasification Derived Products

The syngas produced by oxygen blown gasification contains mainly CO and hydrogen and sometimes methane. Besides being an excellent fuel gas it can readily be processed into pipeline quality natural gas (as in North Dakota), premium liquid fuels (gasoline and diesel in South Africa), methanol, oxo alcohols and ammonia (worldwide). The use of gasification for synthesis gas chemical production has traditionally been in areas of the world where low cost natural gas was unavailable.

Most synthesis gas reactions require H_2/CO ratios >2/1 and very high pressure. These requirements favor liquid or slurry fed entrained flow gasification that assure easier operation at the high pressure. The use of coal/water slurries also leads to a higher H_2/CO ratio in the gas and the quench adds water for further shifting of the CO to H_2.

A concept that has been studied by EPRI and Air Products co-produces methanol in an IGCC plant using the once through liquid phase methanol, LPMEOH™, reaction system. This process is currently being commercially demonstrated using coal-derived syngas at the Eastman Chemical plant in Kingsport, Tennessee under the U.S. DOE clean coal technology demonstration program. This system avoids the shifting and gas recycling typically needed in conventional methanol synthesis. It requires almost total removal of sulfur species from the gas even though only ~15-20% is converted to methanol. The methanol could be sold or used as a fuel for peaking combustion turbines.

Syngas can also be used in the reduction of iron ore to iron and steel in basic oxygen furnaces. Eventually syngas could replace coke in the metallurgical industries.

Currently the largest market for IGCC systems is in the petroleum refining and petrochemical industries using petroleum residual feedstocks such as vacuum residual oil, deasphalter bottoms and petroleum coke. Several IGCC plants of this type have been brought into commercial operation since 1998 and more are scheduled to start up over the next 5 years. These plants typically feature multi-train designs for high reliability and the co-production of power, steam and hydrogen for the refinery. A portion of the syngas is shifted for hydrogen production and CO_2 is removed (and currently typically is vented). Partly because of the need for hydrogen most of these IGCC plants that are adjacent to or within refineries use quench type gasifiers.

Power is generated from the gas turbine for refinery use or sale. Some steam is also often used for additional power generation however refineries are large steam consumers and this is often supplied directly to the refinery from the HRSG. The separate revenue streams generated from the sale of the various products are an obvious economic advantage of this concept. Furthermore it represents a highly efficient utilization of fossil resources.

These gasification based systems at refineries can be regarded as forerunners of future industrial complexes for highly efficient and ultra clean centers to supply electric power and clean transportation fuels. The possibility of a future based on electric power and hydrogen as the main energy carriers is being increasingly discussed as concerns are raised about the potential global warming effect of traditional fossil fuel usage. In such complexes fossil fuels would be processed, power generated, the CO_2 recovered for use or sequestration, and hydrogen supplied for transportation and distributed generation.

II Commercial Operating Experience

A Coal –based IGCC plants

The pioneer 100 MW IGCC plant was operated at Southern California Edison's Cool Water station from 1984-9. The major sponsors of this project were EPRI, Southern California Edison, Texaco, General Electric, Bechtel and a Japanese Consortium (Toshiba, CRIEPI, IHI and Tokyo Electric). The essential characteristics of low emissions and integrated control were demonstrated. A second less integrated IGCC project was operated by Dow Chemical Co.(later Destec) at Plaquemine, Louisiana from 1987-1995. Both of these projects had financial support for operations from the U.S. Synthetic Fuels Corporation.

The coal –based IGCC plants that have been developed to commercial size over the past decade were also built and operated first as demonstration plants. However the demonstration period for many of these plants is now over and they are entering the competitive market place. These units have now accumulated several years of operating experience and have shown that an IGCC plant can meet extremely stringent air emission standards while also achieving high plant efficiencies. The main barriers to the widespread adoption of IGCC technologies are: (1) demonstration of high availability, at least equal to existing pulverized coal (PC) plants; and (2) capital cost reduction to compete with state-of-the-art PC plants and natural gas–based combined cycles.
Three coal-based, commercial-sized IGCC demonstration plant projects are currently operating in the U.S and two in Europe, as summarized in **Table IV**.

Table IV. Coal-Based, Commercial-Size IGCC Plants

Project /Location	Combustion Turbine	Gasification Technology	Net MW output	Startup Date
Wabash River, Indiana, USA	GE 7 FA	Global E-Gas^{TM} (formerly Destec)	262	10/95
Tampa Electric Company, Florida, USA	GE 7 F	Texaco	250	9/96
Sierra Pacific Piñon Pine,Nevada, USA	GE 6 FA	KRW fluid bed	100	1/98
SEP/Demkolec, Buggenum, The Netherlands	Siemens V 94.2	Shell	253	Early 1994
ELCOGAS, Puertollano, Spain	Siemens V 94.3	Krupp-Uhde Prenflo	310	12/97 on coal

The U.S. projects had partial government funding support from the DOE Clean Coal Technology demonstration program. The European projects have also had some governmental support.

The three ongoing US IGCC projects are all based on different gasification technologies and illustrate different application opportunities. All three plants are based on General Electric 'F' gas turbines with turbine inlet temperatures of about 1260°C (2300°F) and equipped with multiple can combustors in an annular arrangement. The European IGCC projects are both based on Siemens gas turbines equipped with dual silo combustion chambers with turbine inlet temperatures of 1100°C (Buggenum) and 1260°C (Puertollano).

The following discussion provides a brief summary of the operational experience at these five sites.

The Sierra Pacific Piñon Pine project has seen only limited gasification operations to date and has not yet delivered syngas to the gas turbine. However the GE 6FA has been running very well on natural gas at the design output.
The key design and major component features of the four plants with longer-term operation are summarized in **Table V**. The overall design performance of these plants, and the comparison with the operational results achieved to date are shown in **Table VI.** A block flow diagram of the Tampa IGCC plant is shown in **Figure 3.**

Both the Texaco gasifier at Tampa and the E-GAS^{TM} gasifier at Wabash River have demonstrated that they have been sized appropriately and can supply sufficient syngas to fully fuel their combustion turbines. Although only extended multi-year operations can really test the durability of gas turbines in an IGCC application, the results to date from the projects with the GE F-class gas turbines are very encouraging. The problems encountered in the combined cycle power blocks in 1999-2000 have been unrelated to the IGCC application (distillate supply at Tampa, and compressor damage and HRSG leaks at Wabash).

At Tampa, fouling downstream of the gasifier was a major cause of outage in early operation that led to the removal from service of the gas/gas exchangers in 1997. In 1998-9 fouling of the horizontal syngas coolers was a major cause of outage but there have been considerable improvements recently (summer 2000). Early corrosion and erosion problems in the lower temperature range are also now under control. The Texaco gasifier has so far generally shown a lower than design carbon conversion. The developers and plant operators are addressing these problems, and the plant continues to perform well, albeit at lower than design efficiency.

At Wabash River, corrosion in the lower gas temperature range also caused outages in the early operations but has been subsequently controlled by process and metallurgical changes. The main remaining problem area seems to be the dry gas particulate filter, where corrosion and blinding of the metallic candles continue to occur.

Table V Design Aspects of Major Coal based IGCC Projects

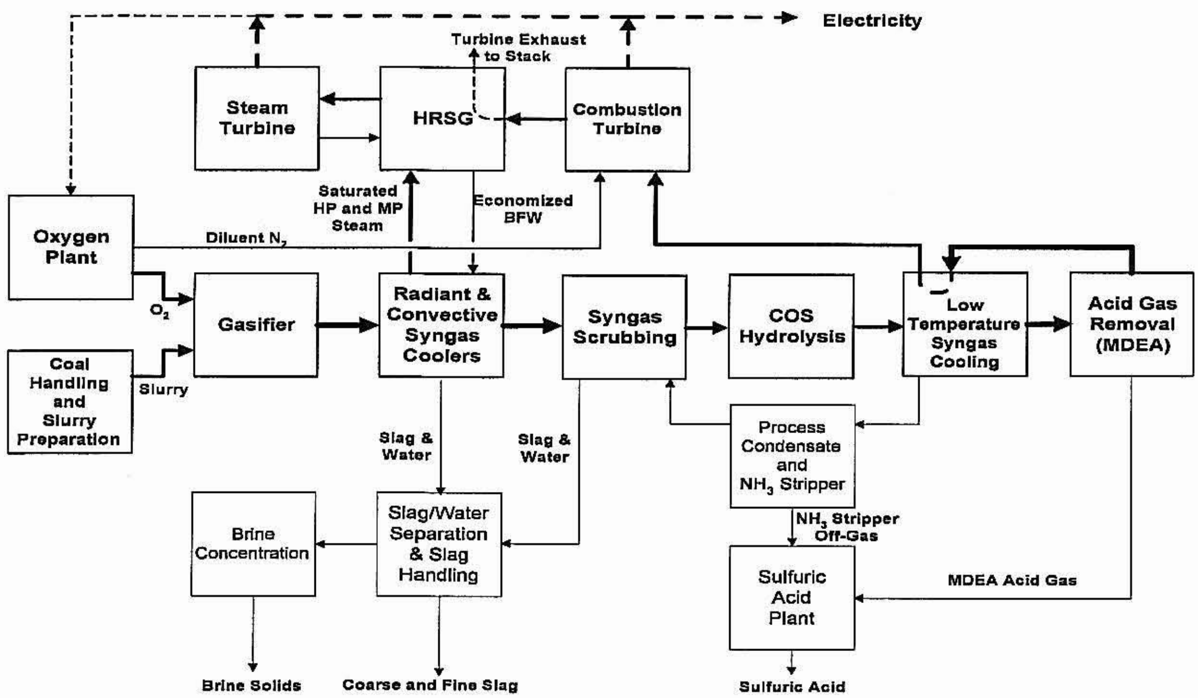
Project Name	Wabash River	Tampa	SEP/Demkolec	ELCOGAS
Location	Indiana	Florida	The Netherlands	Spain
Gasification Technology	Dynegy (Destec)	Texaco	Shell	Prenflo
- gasifier type	two stage upflow entrained	single stage downflow entrained	single stage upflow entrained	single stage upflow entrained
- feed system	coal water slurry	coal water slurry	dry coal lock hoppers	dry coal lock hoppers
- slag removal	continuous	lock hoppers	lock hoppers	lock hoppers
- slag fines recycle	yes	yes	yes	yes
- recycle gas quench	some to second stage	none	large recycle quench to 900°C (1650°F)	large recycle quench to 900°C
Syngas Cooler	downflow firetube	downflow radiant water tube and convective firetube	downflow concentric coil water tube	upflow/downflow (two pass) radiant water tube and convective water tube
- supplier	Borsig (DB)	MAN - radiant Steinmuller-convective	Steinmuller	Krupp Uhde – radiant Steinmuller - convective
Structure Height, meters (feet)	55 (180)	90(295)	75 (246)	80 (262)
Air Separation Unit				
- supplier	Liquid Air	Air Products	Air Products	Air Liquide
- pressure (bar)	conventional (5)	high (10)	high (10)	high (10)
- air supply compressor	100% separate	100% separate	100% from gas turbine	100% from gas turbine
- nitrogen use	mostly vented	GT NOx control	syngas saturator for GT NOx control	syngas saturator for GT NOx control
Gas Clean Up				
- particulate removal	candle filter at about 350°C	water scrub, no filter - except on 10% HGCU slipstream	candle filter at 230°C	candle filter at 240°C
- chloride removal	none initially, water scrub added late '96	water scrub,NaHCO3 on slipstream	water scrub	water scrub
- COS hydrolysis	Yes	Added 1999	Yes	Yes
- acid gas removal process solvent	MDEA	MDEA	Sulfinol M	MDEA
- Sulfur recovery	Claus plant with tail gas recycle to gasifier	Sulfuric acid	Claus plant with tail gas treating unit (SCOT)	Claus plant with tail gas treatment and recycle to COS
Clean Gas Saturation	Yes	No	Yes	Yes
Gas Turbine	GE 7 FA	GE 7 F	Siemens V 94.2	Siemens V 94.3
- combustors	multiple cans	multiple cans	twin vertical silos	twin horizontal silos
- firing temperature,°C(°F)	1260 (2300)	1260 (2300)	1100 (2012)	1260 (2300)
- NOx control	saturation and steam injection	nitrogen to combustors	saturation and nitrogen dilution	saturation and nitrogen dilution

TABLE VI
Design and Actual Performance of Major Coal based IGCC Projects

Project	Wabash	Tampa	SEP/Demkolec	ELCOGAS
Gas turbine MW design (achieved)	192 (192)	192 (192)	155 (155)	182.3 (185) 200 at ISO
Steam turbine MW design (achieved)	105 (98)	121 (125)	128 (128)	135.4 135 at ISO
Auxiliary power MW design (achieved)	35.4 (36)	63 (66)	31 (31)	35 at ISO
Net power MW design (achieved)	261.6 (252)	250 (250)	252 (252)	300 at ISO
Total IGCC operating hours thru' December '99	13,800	16,000	19,400	~2800
1998 IGCC Operating hours	5139	5328	4939	
1999 IGCC Operating hours	3400	6044	5595	1127
Major cause of outage	Candle filter blinding	Exchanger fouling	Gas turbine vibration	Gas turbine vibration, Filter blinding,
Net plant heat rate HHV design (achieved)				
- Btu/kWh	9030(8600)*	8600(9100)**	8240 (8240)	8230
- kJ/kWh	9530(9071)*	9075(9599)**	8695 (8695)	8681
Net plant efficiency, % LHV basis design (achieved)	39.2 (41.2)*	41.2(38.9)**	43 (43)	42.2
HHV basis Design(achieved)	37.8 (39.7)*	39.7(37.5)**	41.4(41.4)	41.5

* Adjusted for HRSG feedwater heaters in service
** Adjusted for gas/gas exchangers in service.

Figure 3 Block Flow Diagram of Tampa Electric 250 MW IGCC Plant



The most recent operations at these sites (Tampa and Wabash) are encouraging and show considerable progress with both projects now experiencing long runs and higher availability of the gasification plant. However both projects experienced unusual outages in the ASU and power blocks in the past year or so that were unrelated to the IGCC application. (See subsequent **Section A 2**).

The Wabash plant has completed its demonstration period under the agreement with the U.S.DOE in late 1999. It was subsequently acquired by Global Energy and a new syngas supply agreement was negotiated with PSI/Cinergy in June 2000. The plant has been running since that time at high availability supplying syngas to the PSI 7 FA gas turbine. It is currently using petroleum coke as feedstock.

The SEP/Demkolec (Buggenum) project started operations in early 1994. The tight integration of the ASU with the Siemens combustion turbine led to some operational sensitivities and complexities, and SEP/Demkolec has subsequently recommended only partial integration for future installations. This recommendation agrees with EPRI's general analysis of the merits of various degrees of integration, although the optimum performance/operability trade-off depends on the specific characteristics of the gas turbine and its compressor. The ASUs at Wabash and Tampa are supplied by their own compressors, so this problem did not arise at these locations.

The main problem encountered at the Buggenum plant (also later encountered at Puertollano) has been combustion-induced vibrations and overheating in the gas turbine combustors. Design changes made at Buggenum in early 1997 have markedly improved the vibration problem, and since that time several long runs have been conducted. In the third and fourth quarters of 1998, the gasification island was in continuous operation for over 2000 hours. The Shell gasifier has generally performed well and achieved its design output and cold gas efficiency. The successful scale-up from the 225 tonnes/day gasifier at Houston (SCGP-1 operated 1987–91) to the 2000 tonnes/day unit at Buggenum has been amply demonstrated. The raw syngas from dry-coal-fed gasifiers such as Shell has lower water content than the syngas from the slurry-fed gasifiers of Texaco and E-GAS™. Because of this, dew point corrosion in the lower temperature ranges is less likely to occur and, consequently, has not been a problem at Buggenum.

Both the Wabash River and Buggenum plants have met their overall IGCC design efficiencies. However, Tampa has experienced lower-than-design overall efficiency chiefly due to lower carbon conversion in the gasifier and removal of the gas/gas exchangers from service due to fouling and corrosion.

The ELCOGAS project in Puertollano started up later than the other three projects and has much less operating experience. The areas of current concern are coal feeding, slag removal and gas turbine vibrations, particularly during start up and shutdown. Fouling of the dry particulate filter was experienced in early operations but has been recently improved with new candle filters.

In summary, these demonstration plants show that IGCC systems can provide power at higher efficiency than PC plants, with significantly lower air emissions and a more benign solid by-product. While the reliability/availability of these units has improved since they were first brought on line, they have not yet operated at their target annual availability levels of 80% although Tampa, Wabash and Demkolec have each experienced individual quarters at this level. The developers and sponsors of these projects understand this concern and are addressing it through continuing engineering efforts. Based on past experience in the development of new technologies it is reasonable to expect that the remaining problems will be solved in the near future. Coal based IGCC plants can now be procured on a commercial basis, however the capital cost competition with PC plants remains a challenge in many locations.

A 1 Operator Training

The Coolwater plant in California and the other demonstration projects in the U.S. and Europe have shown that, with proper training, operators with a typical power plant background can run these plants very competently. A work background in process operations, such as those used in petroleum refining and natural gas processing, is obviously desirable but not crucial. It is strongly recommended that a dynamic simulation model of the plant be developed and used during the design and construction period for control system optimization and for later use in a plant simulator for operator training. The IGCC plants that used a simulator for final control system design checkout and operator training (Wabash, Tampa) during the design and construction period experienced a much reduced startup period and more rapid attainment of design output than those that did not.

A 2 Availability and Reliability

The three coal-based IGCC plants with the most operating experience had annual on-stream IGCC availability factors of about 60% in 1998-9. In this period the Buggenum plant experienced the best availability of any of the gasification sections. In 1998 it was reported as 95% for the gasification island and 85% for the power block. In the same period the Wabash and Tampa plants experienced a reverse pattern, with the power block having an availability around 95% while the gasification plant was generally lower—about 75% at Wabash and 70% at Tampa. Although each of these plants experienced extended periods at much higher availability than these annual figures. Causes of forced outages in the gasification section of the current IGCC plants bear a striking similarity to the problems encountered in PC plants. The fouling and corrosion of heat exchange surfaces, the changed fuel characteristics of blended fuels, and slagging have been common problems.

The Wabash project team has developed an "Industry Standard Projection" for IGCC downtime and availability by breaking the IGCC plant into its major component units and developing and measuring availability of these individual units. This projection and the 2000 year to date data for the Wabash and Tampa projects are shown in **Table VII.**

Table VII IGCC Projected and Actual Downtime and Availability 2000

Plant Name / Plant Area	Industry Standard Projection	Wabash Year 2000 Availability January through September 2000 *	Tampa Year 2000 Availability October 1999 through September 2000
Air Separation Unit	98.0%	93.8%	94.5%
Coal Handling and Feeding	98.8%	98.8%	98.8%
Gasification	92.5%	92.5%	83.3%
Total Gasification Block	89.3%	85.1%	77.8%
Combined Cycle Power Block	95%	89.9%	95.3%
IGCC Overall Total	84.3%	75.0%	74.1%

- The period April – June 2000 was downtime at the Wabash site while the new syngas supply contract was completed.

It can be seen from **Table VII** that both the Wabash and Tampa plants experienced unusual problems in the ASU area in the past year that detracted from the overall performance. There was a cold box piping failure at Tampa and a moisture related ground fault at Wabash. The long term availability of ASU's in industry has been 98%.

Both of these plants also experienced unusual problems in the combined cycle areas. At Tampa, where the back up fuel is distillate oil, there was a failure of the atomizing air compressor and coking deposition problems in the fuel oil piping. At Wabash the power block availability was badly impacted by HRSG tube leak failures due to expansion issues with the bottom supported unit. (HRSG's are usually top supported.) There was a compressor damage failure of the 7 FA compressor at Wabash in March 1999 that was unrelated to the IGCC application. The turbine was returned to operation in June 1999 and has continued to operate well since then.

Over the past year the performance at Buggenum has deteriorated in part because improvement investments have not been made due to uncertainty over the future plant ownership.

Although these availabilities are not as high as planned, they are already similar to those of many PC plants. Additional experience will be gained in the next few years on these coal-based plants and on the many IGCC plants coming into operation using petroleum residuals. Although there will probably always be a lower availability for solid-fuel plants than for liquid-fuel plants, the experience gained in the integrated operation of these plants should be of considerable benefit to the improved design and future availability of all IGCC systems.

A 3 Safety

The presence of toxic gases containing CO and H_2S in the pipework of IGCC plants requires additional precautions. However, safety procedures for handling these toxic gases have been effectively used in the natural gas and petroleum refining industries for over 70 years. The use of local and portable CO and H_2S sensors is crucial to safe operations. Additional attention is also required during startup and in the transition from startup fuels to coal and coal-based syngas. The use of appropriate control and simulation training is very important in this regard.

A 4 Coal Quality Impacts

IGCC plants can be designed to handle a wide range of coals. Wabash, Tampa and Buggenum have each processed a variety of coals satisfactorily. However each of these plants have also encountered surprise problems associated with the slagging property changes with blended coals. It is important to keep informed of such changes in feed properties through regular sampling and testing for the key properties.

However, the high ash content of many coals would make them economically unsuitable as feedstocks for the major commercially developed entrained-flow gasifiers such as Texaco, E-GAS™, Shell, and Krupp-Uhde Prenflo designs. The coal/water-slurry-fed gasifiers rapidly degrade in performance as the ash content increases due to the reduced energy content of the slurry feed and the resultant higher oxygen usage. Lower-ash-content coals of consistent quality are preferred for entrained-flow gasifiers just as they are also preferred for PC plants. The high moisture content of many lower rank sub-bituminous coals and lignites may also make them uneconomic for slurry fed gasifiers due to the lower achievable slurry concentrations. However this could be offset in several mine mouth locations by the low cost of the low rank coal.

For most higher-ash coals, low-rank coals and lignites, fluidized-bed gasifiers would be the preferred choice; however, these gasifiers are at a much earlier stage of development and are not ready for commercial IGCC application at this time.

Moving bed gasifiers can handle a range of coal properties however the strength of the sized coal or briquettes must be sufficient to provide a stable bed without excessive fines production in the gasifier that could produce channeling and maldistribution. Gasification test runs are recommended on the candidate design coals for these gasifiers.

A 5 Air Emissions

By removing the emission-forming constituents (sulfur and nitrogen species and particulates) prior to the combustion turbine, IGCC plants can meet extremely stringent air emission standards.

Sulfur emissions can be almost completely eliminated by use of commercial solvent absorption processes such as Rectisol, Selexol, etc., for syngas desulfurization. The somewhat lower-cost processes, such as MDEA and Sulfinol, used in the current coal-based IGCC plants, remove > 99% of the sulfur from the syngas. The Wabash plant uses the MDEA process for sulfur removal and when firing high-sulfur Indiana coal has reported IGCC SO_2 emissions as low as 13 g/GJ and always less than 40 g/GJ of coal used. Expressed on an equivalent basis for PC plants—namely at 6% excess oxygen—these emission levels are 37–115 mg/Nm^3 of SO_2. (Since the gas turbine exhaust is about 15% O_2, the actual concentration of SO_2 in its flue gas is approximately one-third of these values.). Since the addition of a COS hydrolysis unit in 1999 Tampa has reported similar levels of SO_2 emissions.

For NO_x control, the Tampa plant uses nitrogen dilution of the syngas and the Wabash plant uses syngas saturation and steam injection. Both plants consistently achieve flue gas NO_x emissions < 20 ppmv at 15% oxygen. This translates to < 43 g/GJ of coal used or < 123 mg/Nm^3 of NO_x when put on a 6% excess oxygen basis. The combustion turbine in the IGCC plant at Buggenum (and also at the pioneer 100 MW Coolwater Plant in California) has a lower firing temperature of ~ 1100°C and reports NO_x emissions of about 10 ppmv, or about half of those cited for the Wabash and Tampa plants. Recently GE has claimed that < 10 ppmv can also now be achieved with the higher firing temperature (~ 1260°C) GE FA gas turbines. If still lower NOx emissions are required the addition of a Selective Catalytic Reduction (SCR) unit at an appropriate flue gas temperature location within the HRSG can reduce the NOx emissions to as low as 1-2 ppmv.

Carbon monoxide (CO) emissions are extremely low with measured levels typically about 1–3 g/GJ or ~ 3–10 mg/Nm^3 when stated on the same basis as PC plants (6% O_2). If still lower CO emissions are required then a catalytic oxidation step can be added at an appropriate location in the HRSG to achieve the desired level.

Particulate emissions are also extremely low, generally < 5 g/GJ or < 15 mg/Nm^3 when stated at 6% O_2.

CO_2 emissions per kWh are generally proportionate to the heat rate (kJ/kWh) or coal usage in coal plants. However, when compared at the same coal input PC plants with flue gas desulfurization (FGD), or fluidized bed combustion plants (either atmospheric AFBC or pressurized PFBC) with limestone addition, have higher CO_2 emissions in kg/kWh than IGCC due to the CO_2 released from the limestone.
If CO_2 removal ever becomes a requirement for coal fired plants then IGCC plants will have a distinct cost advantage over PC or FBC plants. Several studies have shown that it is much lower cost to remove CO_2 from the syngas under pressure prior to combustion than from the huge flue gas flows at atmospheric pressure in PC and FBC plants. This aspect is also discussed in **Section III Economics.**

A 6 Solid By-products

The sulfur in the coal is generally converted to elemental sulfur via the Claus process. At Tampa, sulfuric acid is produced as a byproduct. Both sulfur and sulfuric acid are commodity chemical products and a source of revenue for IGCC plants.
The ash from dry-ash moving bed Lurgi gasifiers is usually of low carbon content and can be used in many of the same applications as other bottom coal ash. The slag from the BGL gasifier is of low carbon and can be used in many applications. If the feed coal contained some pyrite, FeS_2, elemental iron can often be magnetically separated from the BGL slag.

Because of their lower temperature operation fluid bed gasifiers do not achieve as high a carbon conversion as the other gasifier types. The bottom and fly ash from fluid bed gasifiers still have significant carbon content and heating value and are usually fed to another combustor (AFBC, PFBC or PC) or sold for their fuel value.
The main coal ash from entrained-flow slagging gasifiers is produced as an inert slag (frit) and is also generally sold as a by-product. It resembles the slag obtained from "wet bottom" (slagging) PC boilers and can be used in the same applications, such as road fill, blasting frit and construction material. Some work has also been done on the potential use of the slag for low-density aggregates. Fines collected in the slag recovery system are typically recycled to the gasifier if their carbon content makes this worthwhile. The fly slag recovered in the particulate filter at Buggenum is very low carbon and has found a ready market.

Even if the slag cannot be sold, the gasification process solid waste is just the ash from the coal and is markedly less in weight and volume than the discharge from AFBC units with limestone addition or PC plants equipped with FGD.

A 7 Water Effluents

IGCC plants have two principal sources of water effluents. The first is wastewater from the steam cycle, including blowdowns from the boiler feedwater purification system and the cooling tower. The amount depends on the quality of the raw water and the size of the steam cycle.

The second source is the process water blowdown from the scrubbing of the coal-derived gas to remove trace particulates and/or water soluble gases. The raw process water, which contains various components such as ammonia and H_2S, is usually steam-stripped, and the stripped gases are sent to the Claus plant, incinerated or recycled to the gasifier. The cleaned water is usually recycled. The net amount of blowdown depends on the amount of water-soluble inorganics (particularly chlorides) in the coal. Dry-coal-fed gasification processes that use dry cleanup systems produce less process water effluent. Some plants use the process water effluent as cooling water makeup.

The Tampa and Buggenum plants are both designed as zero-discharge facilities. In these plants the process water effluent is further treated for removal of trace components and evaporated to produce a salt cake for disposal.

A 8 Additional Coal based IGCC Projects in Development

In late 1999 DOE announced that financial support from the Clean Coal Technology demonstration program would be awarded to Global Energy's proposed 400 MW IGCC project in Kentucky. The project plans to use the BGL slagging gasifier fed with briquettes made from coal and refuse derived fuel (RDF). The co-production of transportation fuels via Fischer-Tropsch synthesis from syngas and the side stream testing of a fuel cell are also planned for this project. Global Energy is also planning similar IGCC projects in Scotland using briquettes of coal and refuse derived fuel in BGL gasifiers. In 2000 Global Energy acquired the SVZ plant at Schwarze Pumpe in Germany where briquettes of coal and refused derived fuel are gasified in Lurgi dry ash gasifiers and where a 3.6 meter diameter BGL slagging gasifier is being commissioned.

In August 1999 DOE announced the selection of three projects for "Early Co-production Energy Plant" design studies as envisaged in the Vision 21 program. These studies are for IGCC plants to co-produce liquid fuels and electricity. The first of these awards was to a team led by Waste Management & Processors Inc. of Frackville, PA including Bechtel, Texaco Global Gas & Power, and Sasol for a study using coal residues to produce transportation fuels and electricity. The second award was to a team led by Dynegy (now Global) including Dow, Dow-Corning, Methanex and Siemens Westinghouse for a study on the co-production of methanol and power at the Wabash location. The third award was to a team led by Texaco Natural Gas of Houston including Kellogg, Brown & Root (KBR), GE, Praxair, Texaco Development Corp. and Rentech, for a study of the co-production of transportation fuels and power from coal and petroleum coke.

In 1996 two GE 9 E gas turbines were installed at the SUV town gas plant at Vresova in the Czech Republic to run on syngas produced from the Lurgi type fixed bed gasifiers using the local lignite thus creating a 400 MW IGCC plant. The gasification plant has 26 fixed bed reactors and although working reliably they produce an undesirable tar byproduct and need a sized coal or briquettes as feed stock. It has therefore been proposed that the old Lurgi type gasifiers should be replaced by two oxygen blown HTWinkler gasifiers in order to avoid tar formation and to utilize all the mined lignite. The gasifiers are to be designed for 82 tonnes /hour of lignite, 2.75 MPa pressure and a gas outlet temperature of 920°C (1700°F). Support for this project is being sought from the European FIFTH FRAMEWORK PROGRAM under the acronym VreCoPower, and from the World Bank.

A nominal 300 MW IGCC based on the scale-up of the 200 tonne/day Mitsubishi gasifier tested at Nakoso, Japan in 1989-94 is being considered in Japan. A smaller project of ~ 50 tonnes/day based on the HYCOL entrained gasifier (that had been earlier tested at 25 tonnes/day capacity) has been built by EPDC. This project (EAGLE) will use conventional cold gas cleanup and the clean gas will feed a gas turbine and later a solid oxide fuel cell (SOFC).

A 400 MW IGCC project is planned by the PRC Ministry of Power to be located at Yantai in Shandong Province, China.

The development of the KBR transport reactor as a gasifier and the further testing of hot gas particulate removal systems is being conducted at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama under the joint sponsorship of the U.S. DOE, the Southern Company, EPRI and other industrial companies.

B IGCC based on Petroleum Residuals

Over 75% of the World's petroleum reserves are heavy oils. Over the past two decades the average refinery crude slate has become heavier and increasingly higher sulfur content. Emission regulations have become more stringent and the permissible sulfur contents of fuel oils (particularly residual fuel oil) have been reduced to generally below 1%. This combination of circumstances has meant that the market for residual fuel oil (e.g., No. 6 fuel oil) has shrunk considerably and many refineries are faced with having to add conversion and hydrotreating units to satisfy the demand for cleaner lighter fuels. This has led to many IGCC projects being initiated at refineries. The gasification of petroleum residuals can supply the refinery's needs for power, steam and hydrogen. It can also serve as a source of synthesis gas for ammonia, methanol, acetic acid, oxo-alcohols, and Fischer-Tropsch liquid fuels.

In Europe and Asia most of the refinery IGCC projects today are based on various refinery heavy residual oil streams (e.g., vacuum residual oil, deasphalter bottoms, visbreaker residue) as shown in **Table VIII**. In the U.S. the refineries typically have more conversion units (e.g. cokers) and accordingly petroleum coke is more often considered as the IGCC feedstock. However cokers are now being added to refineries worldwide.

Table VIII IGCC Projects based on Petroleum Residuals

Project	Gasification Technology	Combustion Turbine	Net MW output /Coproducts	Status September 2000
Shell Pernis, Netherlands	Shell with Heat recovery	2 X GE 6 B	142 / Steam, Hydrogen	Operating since Oct.1997
ISAB Sicily	Texaco Quench	2 X Siemens V 94.2K	512 / Steam	Operating Summer 2000
Api Falconara, Italy	Texaco Quench	Alstom 13 E 2	284	Start up Summer 2000
SARAS, Sardinia	Texaco Quench	3 X GE 9 E	545 /Steam, Hydrogen	Start up Summer 2000
Total/EDF/ Texaco, Normandy, France	Texaco Quench	Not yet identified	365 /	Estimated start up 2003
Repsol/Iberdrola/ Texaco, Bilbao,Spain	Texaco Quench	2 X GE 9 FA	824 / hydrogen	Estimated start up 2004
Exxon Singapore (Ethylene Cracker Bottoms)	Texaco Quench	2x GE 6 FA	180/CO, Hydrogen	Startup late 2000
Motiva, Delaware Pet. Coke	Texaco Quench	2 x GE 6 FA	240/ Steam	Startup Summer 2000
NPRC, Japan	Texaco Quench	NA	343	Startup 2004
TECO Power Services/Texaco/ Citgo	Texaco Quench	Not yet identified	650	Start up 2004

Heavy oil gasification has been practiced commercially since the 1950's. Texaco and Shell both offer heavy oil gasification technology and each have licensed over 100 units worldwide. Most of the previous applications have been to supply synthesis gas for chemical manufacture or hydrogen to refineries. The IGCC application only emerged in the 1990's. Both the Texaco and Shell heavy oil gasifiers are based on a single fuel injector, downflow, oxygen blown, refractory lined, entrained flow reactors. Texaco licenses the technology either as quench units or with heat recovery. In recent years Shell marketed its technology mainly through Lurgi and the Shell/Lurgi gasifiers were usually licensed with the heat recovery steam generators (i.e.syngas coolers). However in 1998 Shell terminated its licensing arrangement with Lurgi and is now licensing the technology itself. Lurgi is now offering for license a very similar technology called Multi Purpose Gasification (MPG). This is based on a gasifier design that has been operated for many years at the former town gas plant at Schwarze-Pumpe, Germany (now Global SVZ). The heat recovery units for both Texaco and Shell gasifiers are available from several suppliers including Steinmuller, MAN, etc. Texaco has larger gasifier unit sizes in operation than does Shell or Lurgi. The three Italian, the French and the Spanish projects all selected Texaco quench gasifiers.

The Shell heavy oil gasification units and gas turbines at Shell's Pernis refinery have been operating well since their startup in early 1998. Three heavy oil IGCC plants in Italy, and a petroleum coke IGCC in the U.S (all based on the Texaco technology) started up in 2000. The Shell gasifiers at Pernis and the Texaco gasifiers at ISAB, API and Motiva (Delaware) all operate at a high pressure of about 7 MPa. The ISAB and API plants also generate some additional power from expansion of the syngas. The API and Sarlux plants use Selexol while the ISAB and Motiva plants use MDEA for sulfur removal. All four projects have different gas turbines. NOx control is by nitrogen dilution at API and Motiva and primarily by syngas saturation at ISAB and Sarlux. The ASU's all have their own 100% main air compressors and there is no supply of air from the gas turbines to the ASUs. The operating history of these plants with their different design configurations will provide considerable experience for future IGCC design optimization.

C IGCC based on Biomass and Wastes

The conventional use of biomass fuels for combustion has always been an important component of energy use and one that is being given increasing attention in view of global climate concerns about the continued use of fossil fuels. There are programs underway sponsored by the U.S DOE and the European Commission on the more efficient use of biomass. There is a major demonstration effort ongoing for the co-firing of biomass in conventional coal boilers in both the U.S and Europe. The incentive for gasification of biomass is generally attributed to the potential for much higher power generation efficiency with biomass IGCC than can be accomplished with direct combustion boilers and steam turbines in the smaller size range appropriate for dedicated biomass projects. Because of the nature of biomass, and the economics and logistics of its gathering and supply, such projects are generally considered in the much smaller 10-60 MW size range rather than the 250-330 MW (or larger) coal based IGCC plants or other coal fired units. There are a number of biomass gasification projects active in the US and Europe with governmental funding. Most of these are based on the use of fluidized bed gasification technologies. Entrained high temperature gasifiers are less suitable due to the high alkali content of most biomass ash and the difficulty of feeding high moisture and/or fibrous solid biomass to such gasifiers. Although in dried form some biomass or wastes such as sewage solids and chicken litter can be used as a partial feed in coal based units (as planned at Buggenum).

Historically there have been a large number of small fixed or moving bed gasifiers (both downdraft and updraft) used fairly widely throughout the world in both developed and developing nations on a variety of biomass feedstocks, particularly wood chips. Some of these have used the produced gas in kilns or diesel and internal combustion (IC) engines for power generation generally in about the 1 MW size or less. However these fixed bed gasifiers do have several limitations and drawbacks. They need a sized feedstock and can tolerate only small amounts of fines without experiencing maldistribution problems. The gases contain particulate matter and tars that can produce problems in the downstream cleanup equipment and must be disposed of or possibly recycled in briquetted or pelletized form. In many applications the gasifiers are close coupled to kilns or to the engines to minimize the opportunities for deposition and fouling. Because of these limitations such gasifiers are not generally considered as prime candidates for biomass conversion to power in the OECD countries where more stringent emissions regulations would require very considerable additional cleanup equipment, labor and operating costs.

C 1 Biomass IGCC Projects

The pioneer biomass IGCC project at Varnamo in Sweden (6 MWe + 9 MWth) conducted a test program from 1993 –1999 but is now shut down. It accumulated ~ 9000 hours of gasifier operation and ~4000 hours of IGCC operating experience. The project used a pressurized fluid bed gasifier supplied by Foster Wheeler and a Typhoon gas turbine from Alstom. The gasifier operated at a pressure of 19 bar and the gas was cooled by steam raising in a downflow firetube syngas cooler and the particulates removed in a candle filter at 350-400°C before firing in the gas turbine. The use of magnesite in the gasifier was found to be effective in controlling deposition and fouling in the syngas cooler. The gas was of low heating value ~5-6 MJ/NM^3, but this proved acceptable for stable combustion in the gas turbine. Primary testing was on wood chips and forest residues but tests were also conducted on straw, willow, bark, sawdust and refuse derived fuel. All were gasified satisfactorily.

Two other biomass IGCC projects are in construction in Europe. The Energy Farm (Bioelectrica) project near Pisa in Italy has an atmospheric air blown Lurgi circulating fluid bed gasifier rated at 41 MWth coupled to a heavy duty 10.9 MWe gas turbine from Nuovo Pignone and a HRSG to provide steam to a condensing steam turbine of 5 MWe. The raw gasifier fuel gas is to be cooled in a gas cooler to ~230°C, de-dusted in a bag filter and routed to a two stage wet scrubber. The cleaned gas is then compressed to the pressure required for the gas turbine. The design fuel is short-rotation copse wood. The project is now being designed and it is anticipated that the plant will be commissioned in late 2000.

The ARBRE project in the UK is a joint venture of Yorkshire Water and TPS Termiska Processor AB of Sweden. From 1993-7 TPS conducted CFB gasification tests on various woods and wood residues and has developed a circulating fluid bed for the catalytic cracking of tars in the raw gas. The project is to be located in Eggborough in North Yorkshire. An 8 MWe IGCC plant using short-rotation copse feedstock is planned for commissioning in 2001 using an Alstom Typhoon gas turbine (as used at Varnamo). The TPS atmospheric CFB gasifier has also been selected for a biomass- gasification – gas-turbine (BIG-GT) project in Brazil. This project is supported by the Brazilian Government, Electrobras and the UNDP with part of the investment to be financed by the Global Environmental Facility (GEF) of the World Bank. A 30 MWe project has been proposed using a GE LM2500 gas turbine. The GEF supported the engineering phase of the project and is evaluating the financial arrangements for the construction phase.

However these three additional biomass IGCC projects are all based on atmospheric fluid bed gasifiers and the syngas therefore requires compression for the gas turbine. The additional auxiliary power for this compression is 10-15% of the gross power and the net efficiency of such plants is therefore considerably reduced. It is also generally necessary to pre-dry the biomass before feeding to the gasifier in order to achieve a gas of sufficient heating value acceptable to the gas turbine. The capital costs for these plants suffer from the diseconomies of small scale and they will probably need subsidies for economic operation.

C 2 Parallel Gasification adjacent to Boilers

There are also several biomass gasification projects in Europe in which the product gas from atmospheric fluid bed gasification of biomass and wastes is co-fired in existing boilers. This approach has the advantage that it avoids having to build a completely dedicated biomass power plant. Given the vagaries of biomass supply this is quite a prudent way of utilizing biomass and wastes. It also has the advantages that the biomass energy is used in a more efficient steam cycle and that, unlike the IGCC application, no pre-drying of the fuel is required.

Unlike co-gasification or co-combustion the biomass ash is kept separate and does not contaminate the coal ash.

In much of Europe there are benefits to be derived from such projects because of regulations requiring recycling of wastes and the credits for reduction of emissions including CO_2. This is the lowest cost and simplest approach to biomass gasification. As the environmental regulations inevitably tighten in all OECD countries it is anticipated that this will become more widely used.

A project of this type with Lahden Lampovoima Oy at a coal fired combined heat and power (CHP) plant in Lahti, Finland started up in 1998. The gasifier unit supplied by Foster Wheeler to the 350 MWth Kymijarvi power plant is ~70 MWth input. It can substitute for ~15% of the annual energy input to the Benson type once-through boiler, which is capable of 167 MWe if optimized for power production or a maximum of 240 MWth of district heat production. The boiler operates ~7000 hours/year. The biomass available in the region includes sawdust, dry wood and forest residues and bark. Recycled fuel (REF) composed of plastics, paper, cardboard and wood equivalent to 300 GWh/year is also available in the region. Shredded tires have also been used. The initial operations have been very successful. NOx and SO_2 emissions were reduced and there was no increase in CO emissions.

Foster Wheeler considers that in Europe there will generally be 30-150 MWth of this type biofuels available within a 50-km transportation radius of most power plants.
A wood gasification plant has been built by Essent (formerly EPZ) in the Netherlands at their co-generation unit Amercentrale 9. This coal fired unit has a net production 600 MWe and 350 MWth heat. An 85 MWth Lurgi CFB gasifier with downstream gas purification for removal of HCl and ammonia is under construction. The feedstock is demolition wood. The gasifier is due to start up in late 2000.

There is a third project (BIOCOCOMB) in Austria at Daurkraft's Zeltweg 137 MWe power plant with a 10 MWth CFB gasifier supplied by Austrian Energy. The biomass substitutes for ~3% of the coal input.
There is also a waste-fueled gasification plant in Greve-in-Chianti, Italy. This plant has a capacity of 200 tonnes/day of RDF (Refuse-Derived Fuel) pellets and comprises two TPS CFB gasifiers each of 15 MWth capacity operating at close to atmospheric pressure. The raw gas passes through two stages of solids separation before being fed to a boiler. Alternatively the gas can be fed to a cement kiln. The boiler flue gas is scrubbed in a three-stage dry scrubber system. This plant was commissioned in 1992.

C 3 Co-Gasification of Wastes

Several kinds of wastes can be briquetted either on their own or with coal. At the SVZ plant in Schwarze Pumpe, Germany briquettes of this type are fed to Lurgi dry ash moving bed gasifiers. Some of the gas is used in a GE 6 B combustion turbine. A similar approach is planned for the Global Energy IGCC projects in Fife, Scotland and in Kentucky, U.S.A. In these projects briquettes of coal and wastes will be gasified in British Gas/Lurgi (BGL) slagging gasifiers.

C 4 U.S. Forest Products Industry IGCC Initiative

One of the major potential markets for biomass gasification is with the pulp and paper (forest products) industries where the biomass (wood) is already gathered to a central location for processing so that no additional fuel transportation costs need be attributed to the biomass. The two applications that seem to be most worthy of further consideration are (i) fluid bed gasification of tree bark, trimmings, foliage and branches (to the extent that they are not required for replenishment of the forest floor) and (ii) gasification of the black liquor. These applications for biomass gasification would potentially replace (i) the direct burning of bark etc. in inefficient hog boilers and (ii) the direct combustion of black liquor in Tomlinson boilers (a troublesome and high maintenance operation).
In 1998 the American Forest, Wood and Paper Association endorsed and launched an IGCC initiative. If successfully completed and commercially deployed these technologies could turn the typical paper mill from being a net importer of power to a substantial exporter of power. Projects are planned to demonstrate biomass and black liquor gasification. The U.S. DOE has issued a solicitation for such projects and is currently evaluating the proposals.

III Economics – IGCC Cost and Performance

A Construction/Installation Time

Most of the large components of an IGCC plant (such as the cryogenic cold box for the ASU, the ASU compressors, the gasification vessel, the gas coolers, the absorption towers, the gas turbine, and the HRSG sections) are usually shop-fabricated and transported to the site. The construction/installation time is estimated to be about the same three years as for a comparable-sized PC plant.

Construction time for a natural gas combined cycle plant can be as short as 18 months. If natural gas is available and there is an urgent need for power, it may be worthwhile to construct the combined cycle first and add the ASU and gasification section later. In such a case, special consideration needs to be given to the design of the HRSG, since in most IGCC designs the gasifier section provides most of the heat to evaporate the water, while this duty must be borne by the HRSG in a natural gas combined cycle plant.

B IGCC Capital Cost and Performance Estimates from EPRI

Over the past ten years EPRI has conducted many IGCC engineering economic evaluations of the major gasification processes, various configurations and degrees of integration with most of the major gas turbine manufacturers. These have been updated and brought to a common basis of assumptions with regard to location, size, feed coal and cost basis. Over the past 2 years there has been a marked increase in the cost of gas turbines and this has resulted in higher IGCC costs than were shown in the some previous studies.

Texaco, Shell and E-GAS^{TM} (formerly Dynegy and Destec) technologies have been evaluated with full heat recovery (HR) as well as the Texaco Quench(Q) system. Results are shown below in **Table IX** (Pittsburgh #8 coal) and **Table X** (Illinois #6) for each of these technologies integrated with the GE 7FA gas turbines. The nominal 500 MW size is comprised of two full trains, the location is central U.S., costs are updated to 2nd half 1999$, condenser pressure 67.8 mbara (2 in. Hga) and the plant performance is evaluated at ISO conditions (15°C = 59°F). With the GE 7FA gas turbine the Texaco and Shell technologies with full heat recovery (HR) optimize with regard to cost and efficiency at about 25-50% integration i.e., 25-50% of the air for the ASU is taken as a bleed from the exhaust of the gas turbine compressor.

The capital costs are very similar for Shell and Texaco, however the E-GAS^{TM} capital costs are lower. The main contributors to the lower costs for E-GAS^{TM} are 1) the smaller fire tube syngas cooler (only 20-25% the weight of the water wall designs) 2) the lower height of the gasification structure due to the smaller syngas cooler and the absence of lock hoppers for slag removal and 3) the lower auxiliary power use with the conventional pressure ASU without nitrogen compression. The higher pressure ASU with nitrogen compression for NOx control adds considerably to the auxiliary power requirements and

Table IX TPC (2nd half 1999 $) and Heat Rates for Coal Based IGCC plants (Pittsburgh #8)

Gasification Technology	Total Plant Cost (TPC), $/kW	Heat Rate, Btu/kWh		Heat Rate, kJ/kWh		Efficiency, %	
		HHV	LHV	HHV	LHV	HHV	LHV
Shell HR	1348	7880	7604	8312	8021	43.30	44.87
Texaco HR	1320	8110	7826	8554	8255	42.07	43.60
E-GAS™ HR	1230	8070	7788	8512	8214	42.28	43.81
Texaco QN2 (1)	1223	9320	8994	9831	9487	36.61	37.94
Texaco Qsat (2)	1168	9080	8762	9578	9243	37.58	38.94

1. QN2 denotes NOx control by Nitrogen dilution + saturation
2. QSat denotes NOx control by saturation

Table X TPC(2nd half 1999 $) and Heat Rates for Coal Based IGCC plants (Illinois #6)

Gasification Technology	Total Plant Cost (TPC), $/kW	Heat Rate, Btu/kWh		Heat Rate, kJ/kWh		Efficiency, %	
		HHV	LHV	HHV	LHV	HHV	LHV
Shell HR	1416	8230	7934	8681	8368	41.46	43.00
Texaco HR	1389	8220	7924	8670	8322	41.51	43.06
E-GAS™HR	1296	8250	7953	8702	8246	41.36	42.90
Texaco QN2	1277	9620	9274	10147	9782	35.47	36.79
Texaco Qsat	1220	9360	9023	9873	9518	36.45	37.81

is not completely offset by the higher HRSG steam make with the nitrogen addition. These cases are based on the designs put forward by the gasification licensers in 1993-4 and may not reflect all the latest advances. The cost improvements cited above are not necessarily unique to E-GAS™ and in this highly competitive field it is quite possible that Shell and Texaco could adopt similar improvements. It must also be emphasized that the degree of integration, or the use of a conventional ASU and NOx control by steam and saturation (as used in the E-GAS™ designs) are decisions that depend very much on the specific characteristics of the gas turbine that is selected.

A preliminary estimate has been made of the potential improvements in cost and performance with the "H" gas turbines if optimized for the IGCC application. It is estimated that the net efficiency would increase to 45-49% LHV basis and that the TPC would be 150-200$/kW lower.

C EPRI Comparison of IGCC with Pulverized Coal and Natural Gas Combined Cycle Plants

The TPCs and heat rates shown in the **Tables IX and X**, together with estimates of operating and maintenance costs, have been used to calculate the cost of electricity (COE) using a 20 year levelized TAG™ methodology. A plant capacity factor of 85% was assumed for all plants although it is acknowledged that since dispatch is often conducted on incremental (variable) costs that the higher cost of the natural gas fuel could inhibit dispatch at such a high capacity factor. A coal price of $1.42/GJ (1.50$/Mbtu) HHV and a natural gas price of $2.84/GJ (3.00$/Mbtu) HHV have been used for illustration. The results are shown in **Table XI** and compared to a supercritical PC plant and natural gas combined cycle (NGCC) plant of similar size.

Table XI E-Gas™ IGCC, Supercritical PC and Natural Gas Combined Cycle -- Levelized Cost of Electricity Comparison

Technology	E-GAS™ IGCC F	E-GAS™ IGCC H*	Supercrit. PC	Comb.Cycle 2X 7FA	Comb.Cycle 7 H
Location	Central	Central	Central	Central	Central
Fuel	Illinois #6	Illinois #6	Illinois #6	Natural Gas	Natural Gas
Plant Size, MW	500	460	500	470	400
Carrying Charge Factor	0.142	0.142	0.142	0.135	0.135
Fuel Cost, $/GJ	1.42	1.42	1.42	2.84	2.84
Fuel Real Escalation rate, %/year	0	0	0	2	2
Fuel Levelization Factor	1.0	1.0	1.0	1.202	1.202
Levelized Fuel Cost, $/GJ	1.42	1.42	1.42	3.42	3.42
Total Plant Cost (TPC),$/kW	1296	1146	1,165	450	440
Heat Rate-Design, kJ/kWh HHV	8702	8069	9443	7278	6856
Heat Rate – Average Annual kJ/kWh HHV	8964	8312	9726	7476	7062
Capital, mills/kWh	24.7	21.9	22.2	8.2	8.0
O&M, mills/kWh	7.7	6.9	6.8	4.2	4.1
Fuel, mills/kWh	12.7	11.8	13.8	25.6	24.1
Levelized COE, mills/kWh ('99$)	45.1	40.5	42.7	38.0	36.2

*Preliminary estimate based on projected improvements to H gas turbines optimized for the IGCC application.

The supercritical PC plant used in this comparison is a 500 MW unit with flue gas desulfurization (FGD) and SCR for NOx control. A single reheat supercritical cycle with steam conditions of 24.2 MPa/565°C/565°C (3500 psig/ 1049°F/1049°F) was used. NGCC plants with both 7 FA and 7 H gas turbines are shown.
The COE for the E-GAS^{TM} IGCC with the 7 FA and 7 H gas turbines is shown in **Table XI** in comparison with the supercritical PC and NGCC plants.

The COE for Shell and Texaco IGCC plants with 7 FA and 7 H gas turbines is shown in **Table XII.**

Table XII Shell and Texaco IGCCs, Levelized Cost of Electricity

Technology	Shell IGCC F	TexacoHR IGCC F	TexacoQS IGCC F	Shell HR IGCC H*	TexacoHR IGCC H*	TexacoQS IGCC H*
Location	Central US	Central US	Central US	Central US	Central US	Central US
Fuel	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6
Plant Size, MW	500	500	500	500	500	500
Plant Book Life, years	20	20	20	20	20	20
Carrying Charge Factor	0.142	0.142	0.142	0.142	0.142	0.142
Levelized Fuel Cost, $GJ	1.42	1.42	1.42	1.42	1.42	1.42
Total Plant Cost (TPC),$/kW	1416	1389	1220	1,266	1,239	1070
Heat Rate – Design kJ/kWh HHV	8675	8664	9873	8016	8038	9177
Heat Rate – Annual Average kJ/kWh HHV	8936	8924	10169	8257	8279	9452
Capital, mills/kWh	27.0	26.5	23.3	24.1	23.6	20.4
O&M, mills/kWh	8.1	7.9	7.7	6.9	6.9	6.9
Fuel, mills/kWh	12.7	12.7	14.5	11.7	11.8	13.4
Levelized COE, mills/kWh ('99$)	47.8	47.1	45.4	40.0	39.9	40.2

* Preliminary estimate based on projected improvements to the H gas turbines optimized for the IGCC application.

Based on these capital and operating cost estimates it would appear that IGCC using the FA gas turbine technology is close to but still more expensive than the state of the art supercritical PC plants at the 500 MW size. Since there are many supercritical plants in

operation at these steam conditions the financing costs currently charged by banks will also be much lower than for new IGCC plants. These results also show that for Shell and Texaco the cost of heat recovery equipment from the raw syngas needs to be further reduced from these estimates. These estimates are based on the designs used in the Buggenum and Tampa projects and do not yet reflect any reductions that could be achieved as a result of the lessons learned in operating these plants. At these fuel cost assumptions it also appears that the lower capital cost lower efficiency Quench IGCC is competitive, from a COE standpoint, with the currently used full heat recovery (HR) designs. The very preliminary estimates for IGCC's based on the H gas turbine suggest a potential reduction of 8-9% in COE over that estimated for the FA technology.
The figures also show that new coal based power can only compete with natural gas based combined cycles if the levelized cost differential (natural gas to coal) is \$2.50/MBtu or greater.

D IGCC Cost and Performance Estimates from Texaco, GE and Praxair

At the Gasification Technologies Conference held in San Francisco in October 2000 Texaco, GE and Praxair presented updated cost and performance estimates for Texaco IGCC Plants for both coal and heavy oil feedstocks. The main results are shown in below in **Table XIII.**

Table XIII Texaco/GE/Praxair IGCC Cost and Performance 2000

Case Designation	9F HEQ O	9H HEQ O	9H HR O	9F HEQ C	9H HEQ C	9H RO C
Feedstock	Heavy Oil	Heavy Oil	Heavy Oil	Coal	Coal	Coal
Gas turbine/ASU Integration %	50	100	100	50	100	100
Net MW Output	435.8	505.7	510.5	449.2	520.9	527.0
Net IGCC Efficiency % HHV/ LHV	42.8/45.1	44.7/47.2	46.0/48.6	41.8/43.3	43.1/44.6	43.7/45.2
Total Plant Cost (TPC) \$/kW U.S. Gulf Coast	800	792	824	860	852	935

The design coal was 1% sulfur of 29.2 MJ/kg (12,559 Btu/lb) HHV, and the heavy residual oil was 4.4% sulfur and 42.0 MJ/kg (18,060 Btu/lb) HHV. The HEQ designation is the latest High Efficiency Quench design with a gasifier pressure of 8.5 MPa (1230psia) and with an expansion turbine on the raw gas. The heat recovery IGCC design uses a gasifier pressure of ~4.0 MPa (570 psia) and a radiant only syngas cooler (RO designation). Both 9 FA and 9 H gas turbines were evaluated. The H gas turbine reflects the current design for natural gas applications and is not optimized for the IGCC application. The costs in this paper were presented as first quarter 2000 Gulf Coast costs without contingency. In **Table XIII** these costs are shown as reported by Texaco, GE and Praxair. The team seems to have focussed on a comprehensive approach to bring the costs down to meet the competition from PC and NGCC plants. When adjusted to reflect the EPRI standard mid-west location and to include contingency as applied to the other IGCC cases these costs are still lower than the EPRI estimates reported in the Section III B and C. For example, the HEQ coal case with the 9 FA increases from \$860/kW to \$1042/kW and the COE with coal at \$1.42/GJ (\$1.50/Mbtu) is estimated at 39.4 mills/kWh. At these costs IGCC coal plants should compete with supercritical PC plants.

As expected the TPC cost for heavy oil IGCC is lower than coal IGCC by about \$60/kW. This is due to the added cost of coal preparation and slag handling. The improvement in cost and performance with the 9 H over the 9 FA reported by this team is less than has been previously estimated, however this is because the H gas turbine used in this study reflects the current design for natural gas applications and is not optimized for the IGCC application.

E Global Climate - Economics of CO_2 Removal for Sequestration

Concern over the potential effect of CO_2 emissions from fossil fuel power plants on global climate is a key issue for the future of power generation worldwide. In 1990-1991 EPRI and the International Energy Authority (IEA) conducted pioneering studies on the effect of CO_2 removal on the COE from PC and IGCC plants that showed an advantage for the IGCC plants.

The main advantage that IGCC has over PC plants for CO_2 removal is that it is far less expensive to remove CO_2 under pressure prior to combustion that from the large volume of post combustion flue gas. CO_2 removal is achieved by absorption in a solvent by a process driven by partial pressure and where the size of equipment is set by the volumes of gas to be processed. In conventional gas and coal-fired units, CO_2 can be removed from the exhaust gas following heat recovery in an absorber/stripper system. As such, the partial pressure of CO_2 is usually low due to the near ambient pressure of the stack gas as well as the dilution effect of substantial amounts of nitrogen contained in the flue gas. Low CO_2 partial pressure yields large and costly removal equipment. In an oxygen-blown IGCC, CO_2 may be removed from the synthesis gas prior to combustion power generation. The high pressure of the synthesis gas stream, as well as the absence of diluent nitrogen, yields high CO_2 partial pressures. This, in turn, results in smaller equipment and less expensive separation due to increased driving force.

Since the 1990-2 time of the original study all coal technologies have markedly improved but natural gas fired combustion turbines and combined cycle plants are currently the preferred choice for additional low-cost generation. Therefore in 1998 EPRI initiated a new study with Parsons to update the evaluations of the clean coal technologies and natural gas fired combined cycle plants both with and without CO_2 removal using the latest technical information. Subsequently the U.S. Department of Energy (DOE) joined as a cosponsor this work.

The interim results of this study are summarized in **Table XIV**. They show that, if CO_2 removal is required for new fossil fuel power plants, and if coal stays at its current price of $1.18/GJ, NGCC plants with post combustion removal of CO_2 offer the lowest COE up to a natural gas price of $3.8/GJ ($4.0/Mbtu). Above that price IGCC plants with CO_2 removal would have a lower COE than NGCC plants. IGCC plants would also have a COE 1.4-1.8c/kWh (~ 20%) lower than PC plants if both were designed for CO_2 removal. The cost of CO_2 emissions avoided with IGCC ($17.5/metric ton) was markedly less than with NGCC ($60.7/metric ton) or ultra-supercritical PC Plants ($43.1/metric ton). The conclusions of this study are consistent with the work of several other authors that have examined fossil fuel technologies incorporating CO_2 removal for subsequent sequestration or use.

Table XIV Cost of CO_2 Removal from IGCC, Supercritical PC and NGCC Plants

Technology	IGCC H	Supercritical PC	NGCC H
<u>With CO_2 Removal</u>			
Total Plant Cost (TPC) $/kW	1642	1981	943
Heat Rate kJ/kWh HHV	9732	12,464	8311
COE c/kWh *	5.64	7.22	4.88
<u>Without CO_2 Removal</u>			
TPC $/kW	1264	1143	496
Heat Rate kJ/kWh HHV	8349	8882	6715
COE c/kWh*	4.51	4.50	3.07
$/tonne CO_2 avoided *	17.5	40.9	60.7

* Evaluated at 80% Capacity Factor, coal $1.176/GJ HHV, natural gas $2.56/GJ HHV

The high-pressure design of the gasifier and the water added by the quench in the Texaco, GE, Praxair flow scheme described in **Section III D** would be very advantageous for the shift reaction and subsequent CO_2 removal. This would probably lead to further cost advantages to IGCC if CO_2 removal is required from fossil fueled plants.

IV IGCC Market Opportunities

A Petroleum Residuals

The majority of new IGCC projects announced in 1999-2000 and in the near to mid term development pipeline are based on petroleum residuals. About 75% of the World's crude oil reserves are considered heavy crudes and the slate of crude oils supplied to refineries continues to increase in gravity and sulfur content. The U.S. refineries historically have been much more of the conversion type including cokers and hydrocrackers for the conversion of heavy oil streams such as vacuum residues, visbreaker and deasphalter bottoms, etc. to more valuable lighter oils. Whereas much of the rest of the world historically had refineries more of the fuel oil type because there used to be a large residual fuel market.

However the increased concern over the use of high sulfur heavy fuel oils has markedly reduced this market in recent years. In response to this market change existing refineries are adding conversion units and the new refineries (which are increasingly being built in the non-OECD countries) are including conversion units in the original design configuration. The addition of hydrocracking and deep hydrodesulfurization of heavy oils requires additional hydrogen. The expansion of the refinery requires more steam and power. The deregulation of power production permits the sale of power by other industries. The IGCC projects in operation in Europe, those in commissioning and those recently announced fall into this category. The Shell refinery at Pernis added a hydrocracker and the gasification units provide syngas for power, steam and hydrogen. The three IGCC projects at the Italian refineries – Api-Falconara, ISAB and Sarlux – and the more recently announced projects in Normandy, France by Total, EDF and Texaco and the project near Bilbao, Spain by Repsol, Iberdrola and Texaco are also of a similar poly-generation nature. They are all based on the use of liquid petroleum heavy oils or pitches such as vacuum residue, visbreaker residues, and deasphalter bottoms.

The use of coking (delayed and fluid) in refineries has historically mostly been in the U.S and currently the major production of petroleum coke is still from U.S refineries (~65%). However this is also changing and several new coker units in Venezuela and Asia are due to come on line over the next few years that will probably take away some of the export markets for petroleum coke in Europe away from the U.S. suppliers. The value of petroleum coke in the U.S. will therefore continue to be under continued price pressures. In addition, because of its high sulfur content and the limitations on SO_2 emissions, there are only limited opportunities for the blending off with coal in existing power plants. This opportunity therefore mainly applies to power plants equipped with flue gas desulfurization – a minority of domestic U.S. power generation.

There are several petroleum coke gasification projects underway in the U.S.. The Motiva IGCC project in Delaware was started up in summer 2000 and its operation will be watched closely as the first large size petroleum coke IGCC. Petroleum coke has also been used for many years in the Texaco gasifiers at Ube Ammonia in Japan. It also constitutes 50% of the feedstock to the Prenflo gasifier at the ELCOGAS Puertollano IGCC plant in Spain and is the current feedstock in the 250 MW Wabash IGCC plant. Several other petroleum coke based gasification projects are being considered at the large coke producing refineries particularly (but not only) in the Texas – Louisiana area. The heavy oil producing countries (Mexico, Venezuela and Saudi Arabia) have partial refinery ownership or special crude oil supply arrangements with many of the refineries in this area.

There is also some competition for petroleum coke usage in circulating AFBC units and several plants have been built. The two 100 MW units of NISCO at Lake Charles, LA and the four 20 MW units operating in the Sacramento delta area have been operating for several years. The units at Texas- New Mexico have also run on petroleum coke. New projects are underway in Ohio, Southern Chile and elsewhere. The selection of AFBC or IGCC will depend on many factors but predominantly will depend on the refinery needs (such as hydrogen), local environmental rules and the sulfur content of the petroleum coke. If the coke is about 8% sulfur then the amount of limestone required in an AFBC unit to conform to Federal SO_2 regulation will be very substantial and the amount of solid waste to be disposed of will be about the same tonnage as the petroleum coke feedstock.

There are many older gasification units in all parts of the World mostly based on Texaco and Shell heavy oil gasification that are used for ammonia, hydrogen, methanol and oxo-chemicals production. In the 1990's both Texaco and Shell have licensed heavy oil gasification units in China for such products. More recently IGCC polygeneration projects have been announced by Exxon in Singapore based on ethylene plant cracker residue (Exxon) and and by Nippon Oil in Japan based on petroleum heavy residual oils. Additional projects are being considered in the Asia- Pacific region based on petroleum residuals. These include IGCC polygeneration at coastal refineries or petrochemical complexes in China, India, Taiwan, and Australia. Other refineries in Europe are also considering such projects.

B Biomass and Wastes

The pioneer biomass IGCC project at Varnamo, Sweden (6 MWe + 9 MWth) completed its demonstration program in early 2000. Additional biomass IGCC projects in the UK and Italy based on atmospheric fluid bed gasification will be started up in the next two years with support from the European Commission. However in the shorter time frame the gasification of biomass and wastes in atmospheric pressure fluid bed gasifiers adjacent to existing boilers is a more cost effective way of using such feedstocks. There are also gasification opportunities in the forest products industry and longer term for IGCC based on larger scale farmed biomass. The gasification of wastes in the chemical industry can also be a source of energy and prevent the use of more expensive and less desirable methods of disposal.

In some PC plants a portion of the fuel can be biomass or wastes such as RDF. However the coal ash will have the biomass or waste ash constituents and this may produce problems for sale or disposal. Biomass and wastes can also provide a portion of the feed to gasifiers, as is currently practiced at SVZ and intended to be used at Global Energy's

IGCC project in Kentucky and at the Demkolec IGCC plant at Buggenum. The use of biomass and wastes as partial feed in larger plants provides the economies of scale that would not occur with smaller plants dedicated to only biomass or waste feedstocks.

C Coal

All of the existing coal based IGCC demonstration projects face competition in continuing to operate over the next few years as deregulation expands and subsidies are reduced or removed. In the U.S and Europe they must compete with power from natural gas based gas turbines and combined cycles.

Several coal based IGCC plants are planned around the World but currently they will probably need subsidies to compete. China has the highest use of coal, ~1300 million tonnes per year, and there are major opportunities for coal gasification in the non-power sector particularly the chemical and fertilizer industry. Co-production of power and chemicals should also be attractive in China.

In the current U.S and European market situation of deregulation and natural gas availability power generation companies are paying little attention to new coal fired units. However coal fired power plants currently supply 56% of the U.S power and there is a continuing dependency on older units. In 2000 about 30% of the units are > 30 years old. The competitiveness, reliability and efficiency of these units will continue to decrease. There is a growing concern that the increasing environmental pressures on these older plants, coincident with most of the nuclear plants coming to the end of their 30 year licensing period, will result in a huge shortfall in power supply. For the immediate future it seems clear that the majority of the new power generation plants in the U.S. are going be natural gas fired combustion turbines and combined cycles. The next window of opportunity for new coal fired power plants will probably occur 2008 – 2020 when many nuclear plants and older conventional coal plants will be shut down. The amount of natural gas required for replacement of this power in addition to that required for satisfying overall growth of power demand would place great logistical strain on the delivery infrastructure. The use of this much gas would also seriously undermine the strategically desirable diverse fuel security currently enjoyed.

IGCC plants are being constructed at refineries based on petroleum residuals – petroleum coke in the U.S. and heavy residual oil in Europe and Asia - and this trend will continue. The increase in this market should assist in bringing the IGCC costs into a range to compete more effectively with PC plants in the 2008-2020 period. The deployment of the G, H and ATS gas turbines will also increase efficiency and reduce cost for IGCC plants. However coal based IGCC plants are faced with the "chicken and egg" problem that until a fully commercial plant is operated IGCC will be charged higher finance costs than a conventional supercritical or sub-critical PC plant. Some additional incentives (such as those put forward by the Coal Utilization Research Council (CURC)) will be needed for the First-of-a-Kind (FOK) plant. The ability of IGCC to meet more stringent air emission standards than PC plants can also be an advantage. Several studies have shown that it is much less costly to remove CO_2 from an IGCC plant than from a PC plant. If CO_2 related legislation was enacted this would make IGCC the preferred coal to power technology.

In the longer time frame the greatest opportunity for coal based IGCC is one analogous to its current use in the petroleum refineries – i.e. for the co-production of power, steam, syngas and hydrogen. However for the next 20 years or so the bulk of transportation fuels and chemicals will be from petroleum refineries and later from remote natural gas-to-liquids (GTL) plants. Coal based plants with current state-of-the art technology will find it hard to compete until oil and gas prices rise to about the $4/GJ level. The once through GTL technology can be important to help establish the use of coal IGCC for these liquid fuel and chemical markets.

These gasification based systems at refineries presage future industrial complexes that have been suggested by several organizations as models for highly efficient and ultra clean centers for the supply of electric power and clean transportation fuels. The EPRI Roadmap and the U.S. Department of Energy (DOE) Vision 21 program are two such examples. The possibility of a future based on electric power and hydrogen as the main energy carriers is being increasingly discussed as concerns are raised about the potential climate effects of traditional fossil fuel usage. In such complexes fossil fuels would be processed, power generated, the CO_2 recovered for use or sequestration, and hydrogen supplied for transportation and distributed generation.

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