The Integrated Plasma Fuel Cell (IPFC) Energy Cycle

A Highly Efficient Combined Cycle Fossil and Biomass Fuel Power Generation and Hydrogen Production Plant with Zero CO_2 Emission

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Abstract

An advanced combined cycle for fossil and biomass fuel power generation and hydrogen production is described. An electric arc hydrogen plasma black reactor (HPBR) decomposes the carbonaceous fuel (natural gas, oil, coal and biomass) to elemental carbon and hydrogen. When coal and biomass feedstocks are used, the contained oxygen converts to carbon monoxide. Any ash and sulfur present are separated and removed. The elemental carbon is fed to a molten carbonate direct carbon fuel cell (DCFC) to produce electrical power, part of which is fed back to power the hydrogen plasma. The hydrogen produced is used in a solid oxide fuel (SOFC) cell for power generation and the remaining high temperature gas energy in a back-end steam Rankine cycle (SRC) for additional power. Any CO formed is converted to hydrogen using a water gas shift reactor. This is called the Integrated Plasma Fuel Cell (IPFC) combined cycle. The plasma reactor is 60% process efficient, the direct carbon fuel cell is up to 90% thermally efficient, the solid oxide fuel cell is 56% efficient and the steam Rankine cycle is 38% efficient. Depending on the feedstock, for electric power production the IPFC cycles have efficiencies ranging from over 70% to exceeding 84% based on the higher heating value of the feedstock and are thus twice as high as conventional plants. The CO_2 emissions are proportionately reduced. Since the CO_2 from the direct carbon fuel cell and the water gas shift is highly concentrated, the CO_2 can be sequestered to reduce emission to zero with much less energy loss than required by conventional plants. The combined cycle plants can produce hydrogen for the FreedomCAR program in addition to electrical power production at total thermal efficiencies reaching into the range of 87-92% which is considerably greater than can be obtained with fossil fuel reforming and gasification plants producing hydrogen alone. Preliminary economic analysis and

comparison with various conventional power cycles indicated that IPFC can produce electric power and hydrogen at significantly lower cost than conventional steam and combined cycle plants especially when coproducing both power and hydrogen. This provides sufficient incentive to continue development of IPFC.

Hydrogen Fuel Cell

The most efficient thermal to electrical energy conversion device is the electrochemical fuel cell. It can convert the free energy of oxidation of fossil fuel to electrical energy in one step without moving parts. (Faraday's Law Δ F = nfe). The problem is to match the fuel with an electrolyte that would produce the optimum electrochemical effect. The most advanced fuel cells operate with a clean elemental hydrogen fuel. For power generation the most efficient fuel cell developed to date has been the high temperature solid oxide fuel cell (SOFC).(1) The oxide electrolyte (transfers oxygen ions to the hydrogen) is a ceramic (stabilized zirconia) which operates at temperatures in the range of 900-1000^oC, yielding a thermal efficiency of up to 56%.(1) For mobile purposes, the polymer electrolyte membrane (PEM) appears to be the preferred fuel cell electrolyte. The current U.S. administration has declared the hydrogen powered fuel cell automobile (The FreedomCAR) (2) to eventually replace the gasoline powered internal combustion engine.

Carbon Fuel Cell

The problem with the utilization of fossil fuels and biomass for fuel cells is that the predominant element is carbon. Thus it becomes necessary to convert the carbon to hydrogen which can be accomplished by reaction with water (steam) resulting in the emission of the carbon as CO_2, a prime greenhouse gas. However, recently a fuel cell has been under development which utilizes elemental carbon directly.(3,4) A schematic of the direct carbon fuel cell is shown in Figure 1. The electrolyte is a molten carbonate salt which transfers carbonate ions from the oxygen cathode to the anode through a porous membrane (zirconia felt) where it reacts with the carbon fuel particulates dispersed in the molten salt and forms pure CO_2. The cell operates in the range of 750^oC to 800^oC. The unique feature of this fuel cell based on the direct oxidation of carbon to CO_2 is that the theoretical efficiency of conversion of the enthalpy (heating value) of the carbon to electricity can be 100%. This is because the entropy of oxidation of carbon is zero ($\Delta S = 0$) and thus the enthalpy of oxidation equals the free energy ($\Delta H = \Delta F$). This is not the case for the hydrogen fuel cell because the entropy of oxidation of hydrogen is such that the theoretical thermal efficiency can only be 70%. ($\Delta F/\Delta H = 0.70$ for H_2 oxidation). Efficiencies of 85% to 90% have already been obtained in laboratory carbon molten salt fuel cells at power densities sufficient for stationary power production (0.8 kW/cm^2).[(3)] An additional advantage of the cell is that the product CO_2 emerges from the anode side of the cell at 100% concentration ready for sequestration without the need to separate and concentrate the CO_2 as required by conventional steam power and combined cycle power plants which is diluted with atmospheric nitrogen. The critical factor for developing a highly efficient DCFC is to produce a carbon having good reactive properties, i.e., small particle size and active surface properties.

Conversion of Fossil Fuels to Carbon and Hydrogen

The problem of applying fossil fuels for powering fuel cells is the processing of the hydrocarbons in fossil fuels to produce elemental hydrogen and elemental carbon. This can be accomplished by means of thermal cracking (decomposition) and pyrolysis processes. For example, the well known method of producing carbon black is to heat methane (natural gas) in a firebrick furnace to temperatures of between 800^oC to 1400^oC which decomposes the methane to carbon and hydrogen.[(5)] This is a discontinuous process in which two tandem furnaces are alternately heated for cracking the methane. Other processes have also been developed in which some partial oxidation of the fuel is used to provide the endothermic heat required to crack the hydrocarbon. The problem of designing a continuous reactor is to be able to heat the fossil fuel to high temperatures (>800^oC) and to extract and separate the carbon from the H_2, CO and other gases in a continuous manner. It has been suggested that carbon can act as a catalyst in thermally decomposing methane.[(9)] Hydropyrolysis processes have also been developed to produce methane from solid fossil (coal) and biomass (wood) fuels which is subsequently decomposed to carbon and hydrogen, part of which is recycled to provide the hydropyrolysis reaction.[(4)]

Plasma Black Process

Recently, a hydrogen electric arc plasma has been developed which accomplishes a continuous fossil fuel cracking process to form carbon and hydrogen. This process has originally been developed to produce carbon black from natural gas and oil on a commercial scale.[(6)] A hydrogen plasma black reactor appears to be ideal for cracking fossil fuels and biomass to carbon and hydrogen. Temperatures of the order of 1500^oC are achieved in the hydrogen plasma between the carbon electrodes where the fossil fuels are introduced. At these temperatures, the hydrocarbons are completely cracked to carbon and hydrogen in one pass while any oxygen in the fuel, as exists in coal and biomass (wood), is converted to carbon monoxide (CO). A simplified schematic of the plasma reactor is shown in Figure 2. A full scale plasma black plant producing 20,000 tons per year of carbon black and 2,500 million cu. ft. of hydrogen per year has been built and operated outside of Montreal [7] using both natural gas and heavy oil feedstocks. The process efficiency for decomposing the fuel has been found to be very high (>50%). The thermal efficiency for producing carbon and hydrogen exceeds 90%.[6,7]

The main problem with the plasma decomposition process is the need for electrical power. Supplying conventional electric power generated from fossil fuel by the steam Rankine Cycle (SRC) is at most 38% efficient which means that the overall fuel to product cycle efficiency of utilizing the plasma process is degraded. However, if the direct carbon fuel cell (DCFC), is used, the electric power generated from carbon produced by the plasma, can be increased to as high as 90% efficiency. Furthermore, the carbon formed in the plasma reactor is of a quality suitable for the molten carbonate cell. There is, thus, a good match between the hydrogen plasma black reactor (HPBR) and the direct carbon fuel cell (DCFC) for producing electric power and/or hydrogen and maximizing the power cycle efficiency. The two reactors complement each other. The HPBR supplies the carbon to the DCFC and the DCFC supplies the electric power to the HPBR.

IPFC for Electrical Power Production

Flow sheets for the IPFC combined electric power generation system are shown in Figure 3 for the fluid fuels, natural gas and oil, and Figure 4 for the solid fuels, coal and biomass. In the Karbomont Montreal plasma black reactor, the gases are cooled by means of a water-cooled coil directly under the concentric tubular electrodes where the DC arc is struck.[7] The carbon is separated from the gases after further cooling in bag filters. It is proposed for the HPBR/DCFC power cycle, that the molten Li/K or Na/K carbonate salt at 750^{o}C be circulated in a section below the carbon arc electrodes in direct contact with the hydrogen in an entrained fashion to scrub the carbon particulates out of the hydrogen stream. The carbon then becomes dispersed in the molten carbonate forming a slurry required to feed the DCFC at the anode. The molten salt is thus circulated between the HPBR and DCFC and transfers the carbon directly. If circulating molten salt is not feasible, the fine carbon particulates can be removed from the hydrogen stream in a cyclone separator and the collected carbon can be pneumatically transferred either with hydrogen or CO_2 gas to the molten salt in the anode compartment of the DCFC.

Because of the high temperature developed in the arc, all types of feedstock can be completely decomposed to hydrogen, carbon and CO. From data presented by Karbomont[(7)] it is estimated that the process efficiency can be as high as 60% of the thermal decomposition energy of the feedstock. The particulate carbon dispersed in the molten salt is converted to CO_2 which emerges from the anode compartment of the DCFC at 100% concentration. The DCFC can operate at up to a maximum of 90% efficiency favored by low pressure operation producing electricity. The hydrogen from the HPBR is sent to a solid oxide fuel cell (SOFC) as shown in Figure 3 where thermal to electrical efficiencies up to 56% can be obtained. In the case of coal and biomass as shown in Figure 4 where oxygen is present in the feedstock, CO is formed in addition to hydrogen. For power production the H_2 and CO hot gas from the HPBR is sent directly to the SOFC. Oxygen ion is transmitted through the SOFC ceramic membrane and oxidizes the CO and H_2 to CO_2 and H_2O with the production of DC power. Alternatively, CO can be converted to additional hydrogen in an energy neutral water gas shift (WGS) reactor with recycled steam and then sent to the SOFC for DC power production. WGS is used when hydrogen production for the market is preferred. The CO_2 can be removed from the hydrogen by pressure swing adsorption (PSA) or by scrubbing with MEA. The ash present in the coal and biomass will either be separated by density difference in the HPBR or in the effluent hydrogen stream. Because of the high temperature, it is possible that the ash will form a larger glassy particulate, which can be separated from the fine carbon particulates. The sulfur will be removed as H_2S from the hydrogen stream and the hydrogen subsequently recovered. Any ash contamination can also be removed from the molten carbonate in a slipstream for cleaning the molten salt.

To complete the cycle in both Figures 3 and 4, a backend steam Rankine cycle (SRC) is used to convert the high temperature heat capacity remaining in the CO_2 and H_2O emitted from the fuel cells into AC power. There is no combustion boiler, however, there is a heat exchanger to raise high-pressure steam from water to 550^{o}C and 68 atm to drive a turbo-generator. The thermal efficiency is equivalent to a conventional steam Rankine cycle plant at 38% efficiency.

Energy Efficiency of the IPFC

The energy efficiency for conversion of the thermal energy in the fossil fuel feedstock to electrical energy is thermodynamically evaluated as follows. The compositional and thermal energy functions of a series of coal and biomass feedstocks derived from handbook data[8] and other private sources are given in Table 1. Additional thermodynamic data for other carbonaceous feedstocks are given in Table 2 which includes the natural gas and petroleum feedstocks. Based on the stoichiometry of the various feedstocks, the enthalpy or heat of reaction for each of the unit operations of the power cycle are given in Tables 3 and 4 for natural gas and oil and for coal and biomass feedstocks, respectively. The HHV thermal efficiency of the power cycle is then calculated based on the following equation.

$$\%\ Thermal\ Efficiency = \frac{Net\ Enthalpy\ to\ Electrical\ Energy}{HHV\ of\ Fuel} x100$$

$$Net\ Enthalpy\ to\ Electrical\ Energy = Enthalpy\ for\ DCFC + Enthalpy\ for\ SOFC$$
$$+ Enthalpy\ for\ SCR - Enthalpy\ for\ HPBR$$

$$Enthalpy\ for\ DCFC = n_C\ E_{DCFC}\ \Delta H_{DCFC}$$

$$Enthalpy\ for\ SOFC = n_{H2}\ E_{SOFC}\ \Delta H_{SOFC}$$

$$Enthalpy\ for\ SRC = E_{SCR}\ [(1 - E_{DCFC})\ n_C\ \Delta H_{DCFC} + (1-E_{SOFC})\ n_{H2} \Delta H_{SOFC}]$$

$$Enthalpy\ of\ HPBR = \frac{\Delta H_{HPBR}}{Proc.\ E_{HPBR}}$$

ΔH = Enthalpy of reaction kcal/gm.mol

HHV = Higher Heating Value of fuel = Enthalpy of combustion

E = Thermal efficiency

$Proc.\ E_{HPBR}$ = Process efficiency of decomposition energy in plasma.

n_C = gm. mol of carbon. Basis is n_c = 1.0 for fuel feedstock

n_{H2} = gm. mol of hydrogen produced in HPBR and WGSR

DCFC = Refers to Direct Carbon Fuel Cell

SOFC = Refers to Solid Oxide Fuel Cell

HPBR = Refers to Hydrogen Plasma Black Reactor

SRC = Refers to Steam Rankine Cycle

WGSR = Refers to Water Gas Shift Reactor

Table 5 then summarizes the distribution of energy generation for each unit of the IPFC combined power cycle, based on the data and efficiencies given in the previous tables. The energy units are in kcal/gm mol of fuel feedstock because it is easier to trace the energy through the cycle based on the stoichiometry and the reactions involved. The highest combined cycle efficiency is obtained using oil as feedstock at 84.1%. This is more than twice the efficiency of the 38% that is currently obtained with a steam Rankine cycle. Lignite coal results in a close second efficiency of 83.3% and bituminous coal somewhat less at 81.3% efficiency. Biomass and natural gas indicate a lower efficiency at 76.3 and 74.1%, respectively, but still high, in the order of twice the efficiency of conventional SRC plant. It appears that the reason these two feedstocks are lower in efficiency is because of the larger amount of energy required to decompose these feedstocks compared to the oil and coal. Also, these feedstocks have a higher hydrogen content, which goes to the SOFC operating at a lower efficiency (56%) than the carbon fuel cell (90%). The lower decompositions of energy have been confirmed for oil compared to natural in the Karbomont plant.[7] The decomposition energy of the coals are slightly higher than that of petroleum.

The CO_2 emission in lbsCO_2/kWh(e) is also given in Table 5. The values are proportionately a function of the feedstock and the thermal efficiency. The lowest emission 0.53 lb CO_2/kWh(e) is obtained with natural gas and that is because natural gas has the highest hydrogen content of all the fuels. Because the CO_2 is emitted from the DCFC and the steam boiler after water condensation, at essentially 100% concentration, no energy is needed to separate CO_2 from nitrogen as is required by the flue gas from a conventional fuel combustion steam plans, for purposes of sequestering the CO_2 in order to obtain zero emission. However, in order to sequester CO_2 in deep saline water aquifers or in depleted oil or gas wells or in the ocean, it is necessary to compress and/or liquefy the CO_2. It takes an equivalent of about 0.112 kWh(e) of electrical energy to separate and liquefy 1 lb of CO_2.[9] About 58% of the energy is in the separation by absorption/stripping with a solvent such as MEA and 42% is for the liquefaction of the separated CO_2. Thus, the energy required to sequester CO_2 from a conventional natural plant is 12.4% of the energy generated. With the combined cycle plants because the CO_2 emitted is concentrated this is reduced to 2.5%. For a lignite coal plant the conventional plant sequestering energy consumption is as much as 23.0% of the power plant output. With the above combined cycle plant this is reduced to 4.0%. These reductions constitutes considerable savings in energy and production cost of electrical power to achieve zero CO_2 emission. Later at these factors are applied for evaluating the economics of the various systems.

IPFC for Combined Hydrogen and Electrical Energy Production

Because of the advent of the FreedomCAR program, the above combined cycle plants can be configured to produce both hydrogen and electric power. The solid oxide fuel cell which converts the hydrogen to electricity is eliminated and the backend SRC is also eliminated so that only the DCFC produces electricity from the carbon formed in the HPBR. The WGSR converts any CO formed in the HPBR into additional hydrogen and the CO_2 is separated for sequestration. Figure 5 shows the power and hydrogen combined cycle plant and table 6 gives an evaluation of the energy and thermal efficiency distribution between the hydrogen and electrical production for three feedstocks. Hydrogen production is shown in terms of its higher heating value (HHV = 68 kcal/gmol). The efficiencies for coproduction range from 86.0% to 92.2%. The total efficiency for hydrogen and electricity production is greater than for electricity production alone. This is because electricity production from hydrogen in the SOFC is only efficient to the extent of 56% whereas when hydrogen is counted in terms of its total thermal energy content. Of course what really counts is what the market is willing to pay for hydrogen gas versus electrical power. For comparison the production of hydrogen by conventional natural gas reforming is 78.5% efficient and from bituminous coal by gasification it is 63.2% efficient.[10] The combined cycle IPFC plants thus offer much higher efficiency reaching into the nineties for combined hydrogen and power production with corresponding reduction in CO_2 emission.

IPFC for Hydrogen Production Alone

By adding a water electrolyzer to flowsheet Fig. 5, flowsheet Fig. 6 then takes the DC power from the DCFC and electrolyzes water in an alkaline water electrolyzer to produce hydrogen and oxygen. Flowsheet fig. 6 produces hydrogen from the WGS and from the electrolyzer. The electrolyzer has a thermal efficiency of 80%.[10] Table 6A evaluates the energy distributions and overall thermal efficiency of the IPFC for hydrogen production alone for the various fuel feedstocks. The thermal efficiencies vary from a low of 75% for the Kentucky bituminous coal to a high of 86.7% for biomass (wood) fuel.

Preliminary Economic Analysis

The system described earlier starts with a hydrogen plasma black reactor (HPBR), converting fossil fuels (coal, oil and gas) and biomass (wood and ag. waste) to elemental carbon and hydrogen. With coal and biomass, CO is also formed. The carbon is used to produce electrical power in a Direct Carbon Fuel Cell (DCFC). The hydrogen can either be marketed as a hydrogen fuel for the automotive fuel cell or used in a solid oxide fuel cell for stationary electric power production. As developed earlier, thermal efficiencies ranging from 70% to 84% can be obtained for plants producing only electricity; or coproducing hydrogen and electricity, thermal efficiencies ranging from 87 to 92% can be obtained and for producing hydrogen alone the efficiencies can range from 75% to 87%. Flowsheets in Figures 3 and 4 are for electrical power production alone, Figure 5 for electrical power and hydrogen production and Figure 6 for hydrogen alone. Energy balances are developed in Tables 5, 6, and 6A. Based on this information a preliminary economic analysis of the integrated plasma fuel cell (IPFC) combined cycle plants is made and compared to conventional and combined cycle plants.

The preliminary production cost estimate analysis for production of electrical power and hydrogen is made using a standard procedure as follow:

Electricity and Hydrogen Unit production cost in mills/kWhr

= Feedstock Fuel Cost + Fixed Charge (FC) + Operations and Maintenance (O&M)

$$\textit{Feedstock Fuel Cost Per Unit Energy} = \frac{\textit{Cost of Fuel \$/MMBTU x } 3413 \textit{ BTU/kWh}}{\textit{\% Efficiency x BTU Value of Feedstock, BTU/lb mol}}$$

$$\textit{Fixed Charge Per Unit Energy} = \frac{A \ \textit{x Unit Capital Investment \$/kWh}}{\textit{Capacity Factor x } {}^{\textit{Hours}}\!/_{\textit{Yr}}}$$

A is a factor operating on Capital Investment including depreciation 20 year life (5%/yr), returns (6%) on investment, taxes (6%), insurance (2%), general and administration charges (1%) 20 yr plant lifetime. Total FC = 20% of unit investment, A = 0.20, Capacity factor is 80% or 7000 operating hours/yr.

Operation & Maintenance per Unit Energy = 0.15 x Fixed Charge = 15% of Fixed Charges

As given earlier, Table 7 lists the efficiency (from Table 5) and the unit capital cost assumed for each of the major units of the combined cycle plant. The capital cost estimate for the HPBR was derived from the Karbomont plant and an additional amount was added for using coal as a feedstock.[7] For the DCFC, projected large scale molten carbonate cell operating with hydrogen fuel is used for estimating capital investment.[11,3] The SOFC is projected from large scale fuel cell usage.[1] The capital cost for steam Rankine cycle conventional plants are well known for coal fired power plants at about $1000/kW(e) but is reduced to $500/kW because the steam boiler is eliminated and a heat exchanger is substituted. Estimates are also made for the water gas shift (WGS) at about $100/kW energy equivalent to hydrogen produced.

Table 8 gives an example of the production cost calculation for electrical power based on lignite coal feedstock. It should be noted that the capital investment is derived by prorating the fractional distribution of electrical power production among each power generator, in accordance with the energy balance shown in Table 5. Table 9 summarizes the economic and environmental parameters for IPFC electric power production for the entire range of fossil and biomass fuel feedstocks. For the natural gas case, because gas prices are volatile these days, the power production costs were calculated over a range of gas costs varying from $2 to $6/MMBTU. It is noted that the estimates range from a low of 29.28 mills/kWh(e) for lignite to a high of 51.78 mills/kWh(e) for the $6 natural gas case. Considering that a conventional steam Rankine cycle plant using various fuel sources generates power in the range of 50 mills/kWh(e) (based on the same economic factors as in this paper), the IPFC plants are significantly lower in cost mainly because of their higher efficiency and lower capital investment. For coal fuel there is a cost savings of about 40% lower for IPFC vs. conventional coal fired steam plants (30 mills/kWh(e) for IPFC vs. 50 mills/kWh(e)) for conventional. However, it is now necessary to make a comparison of our high efficiency integrated plasma fuel cell (IPFC) plant with other advanced combined cycle plants. This is done in Table 10 and Table 11. Table 10 shows that the current well developed natural gas combined cycle (CC) plant at 60% efficiency is competitive with the IPFC with electricity production costs about the same with natural gas costs varying from $2 to $6/MMBTU. The higher efficiency for the IPFC is offset by the lower capital cost of the combined cycle. However, because of the higher efficiency IPFC shows a 19.1% reduction in CO_2 emissions compared to combined cycle. For integrated gasification combined cycle with petroleum fuel there is a greater IPFC advantage with a 3.5 mill lower electricity production cost (8% lower) and a 34.6% lower CO_2 emission. This is due to the higher efficiency of the IPFC system.

Table 11 shows the combined cycle plant cost comparison for coal and biomass. For bituminous coal the IPFC at 81.8% efficiency indicates a 7.77 mills/kWh(e) lower electrical power production costs which is a 20% lower cost for IPFC than for the well developed 55% efficient integrated gasification combined cycle plant (IGCC). Besides the improved efficiency, the capital investment for IGCC is higher than the estimates for IPFC by 20%. Similar results are obtained for lignite feedstock. Biomass costs are a little higher but still less than IGCC coal. A significant factor is that the CO_2 emissions are 32.7 and 34.0% respectively lower for IPFC than for IGCC. These lower CO_2 reductions must reflect lower cost penalties when sequestering the CO_2. A more extensive table which summarizes the efficiency and CO_2 emissions for the various fuel feedstocks comparing the conventional steam cycle with the IGCC and the lbsCO_2/kWh(e) IPFC cycle for electrical power production alone is shown in Table 12. The CO_2 emissions is given in terms of actual lbsCO_2/kWh(e). This shows the IPFC emissions ranging between 48.7 and 54.8% below the conventional steam Rankine cycle electric plant. This is a greater reduction than obtained with IGCC, which ranges only between 24.0 and 36.7%.

Turning to hydrogen production in addition to electricity as shown in Figure 5, it is noted that the solid oxide fuel cell (SOFC) and the backend steam Rankine cycle (SRC) are eliminated. The electricity only comes from the carbon fuel cell (DCFC). Table 6 gives the distribution of electricity and hydrogen production for the various fuel feedstocks. The thermal efficiencies range very high from 86.8% to 92.2% which is higher than the values for generating electricity alone (Table 5). The reason is that the full thermal energy of the hydrogen is counted and is not degraded in the SOFC and SRC for power production. It is interesting to note that natural gas produces more hydrogen than electricity while for lignite and bituminous coal the opposite is true. This is because natural gas has a higher hydrogen content relative to carbon whereas coal has less carbon content relative to hydrogen.

For the preliminary cost estimate, Table 13 gives a breakdown of the capital cost distribution and the production cost for natural gas feedstock. The capital cost is prorated in accordance with energy production for each major unit operation. Using the standard cost estimating procedure, the production cost of hydrogen and electricity is estimated in Table 13 for a natural gas cost of \$4/MMBTU. The electricity cost is 31.59 mills/kWh(e) and the equivalent hydrogen cost is computed from this value both in \$/MMBTU, \$/MSCF and in \$/gal equivalent gasoline. The U.S. Department of Energy likes to quote hydrogen in \$/gal equivalent gasoline units because of hydrogen's projected use in fuel cell automotive vehicles replacing gasoline currently in internal combustion engines. Table 14 then projects the equivalent $/gal for the cost of hydrogen as a function of the natural gas cost varying from $2 to $6/MMBTU. Currently, the cost of natural gas runs between $4 and $5/MMBTU. At this cost, the hydrogen is between $1.11 and $1.25/gal gasoline equivalent. It is estimated that a natural gas steam reforming plant at $4/MMBTU could produce hydrogen for as low as $1.03/gal, at a thermal efficiency of 78.5%. However, the IPFC plant also produces power at 31.59 mills/kWh(e). Currently the combined cycle natural gas power plant produces power at about 50 mills. Therefore, if the power from the IPFC plant is sold at 50 mills/kWh the hydrogen cost can be reduced to $0.84/gal equivalent to maintain the total revenue to the plant at the same level as if all the energy is sold at 31.59 mills/kWh. This points out the value of a plant that produces two products, i.e., electricity and hydrogen. As one product, i.e., electricity can be sold at a competitively higher price than the coproduct, hydrogen can compete with the lowest hydrogen cost from conventional natural gas reforming. Table 14 shows how the costs of hydrogen is reduced as the electricity price increases to 50 mills/kWh for the range of natural gas costs from $2 to $6/MMBTU. The CO_2 emission is also reduced by 33% compared to the combined cycle plant.

A similar comparison is made for lignite coal as a feedstock. Table 15 indicates that the equivalent production cost for electricity and hydrogen is 24.08 mills/kWh, which in terms of equivalent gasoline cost for hydrogen is $0.85/gal. The equivalent cost of a coal gasification hydrogen plant at 63% efficiency is $1.34/gal for equivalent hydrogen cost. The capital cost for a coal gasification plant is much more expensive ($1030/kW) than a natural gas reforming plant ($360/kW) because of the need for an oxygen plant and coal handling.(10)

The DOE future generation program has set a target goal of achieving a cost of hydrogen of $0.48/gal equivalent to gasoline.(11) Table 16 presents a sensitivity analysis to show how this can be accomplished. As seen from the foregoing economic analysis the two most important parameters for a given feedstock in determining hydrogen cost is the unit capital investment in $/kW followed by the selling price of electricity. The base case for lignite is $650/kW giving a selling price (cost) for hydrogen of $0.85/gal equivalent. Following in Table 16, if the capital investment goes up to $800/kW then the hydrogen cost goes to $1.00/gal which is still lower than the coal gasification cost of $1.34/gal. To obtain a $0.48/gal hydrogen cost the selling price of electricity must be elevated to $31.62 mills/kWh at a capital investment of $650/kW. If the electricity can be sold for $41.50 mills/kWh(e) then the hydrogen becomes essentially free. The hydrogen also becomes free for a capital cost of $800/kWh and a selling price of electricity at 50 mills/kWh(e).

In Table 17 the CO_2 emissions is listed in lbs/kWh(e&t) units for producing both electric (e) power and hydrogen (t) by the IPFC cycle and compared these to the emissions from the combined cycle natural gas (CC), partial oxidation petroleum (POX) and the (integrated gasification combined cycle) plants (IGCC), the latter for coal and biomass. Because IPFC produces power in addition to hydrogen, it is necessary to split out some hydrogen for electric power production in a combined cycle and apply efficiency factors for production of electricity. The ratio of electric power to hydrogen thermal energy is kept the same for the conventional processes as for the advanced IPFC plants. It thus can be seen that the overall CO_2 emission reduction varies from 20% with natural gas fuel to 40% for North Dakota lignite as a fuel, compared to the conventional integrated power cycles.

Because the IPFC puts out less CO_2 than conventional plants, some credit must accrue to the IPFC either as an emission trading value or as a credit. Current estimates indicate that CO_2 capture and sequestration from conventional power plants costs about $25/ton of CO_2. A DOE target in the future is a very low value of $3/ton which maybe impossible to achieve for a stand-alone plant. It is also known that most, 80% or more, of the sequestration cost is due to capturing concentration and compressing the CO_2 from the power plant stack gases and the disposal ocean or terrestrial sites is less, 20% or less, of the total sequestration cost. The IPFC puts out highly concentrated CO_2 gas so that the sequestration cost for disposal should be about $5/ton CO_2. The effect of applying these cost penalties for capture and sequestration is dealt with in Summary Table 18 for electric power production. The efficiencies and production costs are summarized from the previous tables for the conventional, combined cycle, and integrated combined cycle (conventional IGCC and advanced IPFC). Some of the conclusions that can be drawn from Table 18 are as follows:

1. The natural gas conventional steam Rankine cycle plants indicate the highest cost of power reduction because of the high cost of the fuel ($4/MMBTU) compared to lignite at a cost of ($0.73/MMBTU) and the low efficiency (38%). Even though CO_2 emissions for natural gas is about half that of the conventional coal plants (Table 12), the CO_2

sequestration penalty add-on cannot beat the coal burning plant costs (84.7 for natural gas versus 74.8 mills/kWh(e) for bituminous coal).

2. The coal integrated gasification combined cycle (IGCC) plants are more economical (37.4-38.2 Mills/kWh(e)) than the natural gas combined cycle (CC) plant (42.5-42.6 Mills/kWh(e)). The IPFC coal plants at 29.3-30.5 Mills/kWh(e) are lower than the IGCC. Even though the efficiency is higher for the combined cycle (CC) plant (60 and 74% versus 55%), the cost of natural gas increases the production cost.
3. The integrated plasma fuel cell (IPFC) plants are more economical than the integrated combined cycle (IGCC) plants operating with coal. The IPFC cost is 40% lower than the conventional steam plants and 21% lower than the IGCC plants. By taking into account the CO_2 emission sequestration, the total cost the IPFC becomes 57% lower than steam plants and 25% lower than the IGCC plants. The main reason for these savings are the much higher thermal efficiency and the lower capital investment for the IPFC compared to conventional and IGCC. Furthermore, the CO_2 cost penalties for the conventional air combustion plants are obviously much greater than the integrated combined cycle plants because of the dilution of CO_2 with atmospheric nitrogen.

Table 19 summarizes the estimates for the coproduction of power and hydrogen for two fuel feedstocks in natural gas and lignite. The data are given in mills/kWh both for electricity and for hydrogen production. The hydrogen energy units are also converted to $/gal of equivalent gasoline since the hydrogen is being considered as a substitute motor fuel replacing gasoline. Conclusions drawn from Table 19 are as follow:

1. Estimates for steam reforming natural gas and coal gasification, which produces hydrogen alone, are $1.03 and $1.34/gal. equivalent respectively.
2. The natural gas IPFC plant hydrogen is less costly ($1.11/gal) than the IGCC plant ($1.36/gal) but is not lower than the conventional steam reforming plant, which only produces hydrogen ($1.03/gal). IPFC is about 18% less than IGCC and 25% less than IGCC taking into account CO_2 sequestration costs. However, the natural gas IPFC plant becomes hydrogen competitive with the steam reforming plant when power can be sold for 50 mills/kWh ($0.84/gal vs. $1.03).
3. With coal as fuel, the IPFC plant is more competitive in hydrogen ($0.85/gal) than the coal gasification plant ($1.34/gal). The IPFC hydrogen costs are very much lower than

the IGCC plant cost ($1.63/gal) by about 50%. This is due again to the much higher thermal efficiency and lower unit capital cost of the IPFC plant. The CO_2 sequestration costs are lower for both integrated IPFC and IGCC plants because they both emit highly concentrated CO_2 and do not incur any CO_2 gas separation costs.

Table 20 gives an example of the preliminary cost estimate for producing hydrogen alone (Fig. 6) with a lignite fuel feedstock. The capital investment is estimated by prorating each of the unit operation in accordance with the energy distribution given in Table 6A. Finally, Table 21 summarizes the economic and environmental factors for the IPFC plants producing hydrogen alone. The following conclusions can be drawn.

1. The IPFC plants are about equal in cost in hydrogen as with the conventional natural gas reforming and petroleum partial oxidation plants and with only a small reduction in CO_2 emission.
2. The coal lignite IPFC hydrogen cost ($1.12/gal gasoline equivalent), is lower by 20% than that for the lignite gasification hydrogen ($1.34/gal equivalent). Also the CO_2 emission is significantly reduced.
3. Biomass at $2/MMBTU appears to be the lowest hydrogen cost ($0.85/gal equiv.). The biomass estimates are about 20% to 50% lower than the natural gas and petroleum partial oxidation for hydrogen production respectively. This is attributed to the fact that 89% of the hydrogen comes from the water gas shift reactor and only 11% from the electrolyzer.

Production Yields per Unit of Fuel Feedstock

For purposes of sizing production plants, Table 22 presents the production yields of electricity and hydrogen per unit of fuel feedstocks for each fuel feedstock and for the three production modes based on the data previously developed for each of the fuel cycles. The units are those usually used in commerce; for gas, MSCF; for electricity, kWh(e), for oil bbl (barrels) and for coal, tons. Fuel feedstock feedrates can be used as multipliers with this data to determine the production capacity for any given plant.

Summary Conclusion

The Integrated Plasma Fuel Cell (IPFC) combined cycle plants offer lower electric power production costs than the conventional steam Rankine cycle and combined cycle plants especially when using coal as a fuel feedstock. This is mainly due to the higher thermal efficiencies for the IPFC plant which are in the range of 74 to 84% depending on the HHV of the fuel. The IPFC indicates a 40% lower electric power production cost than coal fired steam plants. When adding a penalty for sequestration of CO_2, IPFC shows a 57% lower production cost for electricity than for conventional steam plants. The IPFC is also 21% lower than the IGCC plant cost and 25% lower than IGCC when taking into account CO_2 sequestration costs.

When the IPFC plants are configured to produce both electric power and hydrogen, by eliminating the solid oxide fuel cell (SOFC), the thermal efficiencies increase into the range of 87% to 92%. There is a 50% cost advantage for IPFC over IGCC when using coal. The IPFC cost of hydrogen is estimated to cost $0.85/gal of equivalent gasoline when selling electric power at 26.2 mills/kWh(e). Furthermore, by selling power at a higher costs (43.6 mills/kWh(e)) which is still competitive with steam plants (at 50 mills/kWh(e)), the hydrogen cost becomes essentially free. The CO_2 sequestration costs included in these costs are small because the CO_2 emissions are concentrated requiring only disposal but no gas separation cost penalties.

By addition of an electrolyzer, the IPFC can be configured to produce hydrogen alone. The electric power from the DCFC is used to electrolyze water and the gas from the HPBR when converting CO is converted to hydrogen in the water gas shift reactor (WGS). The IPFC ranges in efficiency from 75-87% and is about equal in cost and CO_2 emissions to the natural gas reforming and petroleum partial oxidation (POX) plants for producing hydrogen. However, for biomass, the hydrogen costs are 20 to 50% lower than the natural gas and petroleum plants for hydrogen production. There is also a 20% cost advantage for IPFC compared to coal gasification plants for hydrogen production alone.

These design and preliminary cost estimates provide sufficient incentive to continue developing and validating the technology and economics of the direct carbon fuel cell (DCFC) and the hydrogen plasma black reactor (HPBR) and integrating these units into an integrated plasma black fuel cell (IPFC) combined cycle plant for production of both electricity and hydrogen.

Table 1
Composition and Thermodynamics of the Feedstocks Used in this Study

Feedstock	Biomass Wood	Bituminous Kentucky Coal	Lignite N. Dakota Coal	Sub Bituminous Wyodak Coal	Alaska Beluga Coal	Sewage Sludge
Composition (wt%)						
C	45.86	67.02	43.37	49.95	49.33	28.55
H	5.27	4.54	2.78	3.51	4.00	4.09
O	36.07	7.22	13.97	12.58	15.56	16.03
H_2O	11.67	8.60	30.10	26.40	21.78	9.82
Ash	0.66	8.34	8.30	6.03	8.67	36.53
S	0.04	2.85	0.81	0.60	0.12	1.36
N	0.43	1.43	0.67	0.93	0.54	3.62
Heating Value (Higher)						
(BTU/lb-MF)	-8800.0	-13650	-10254	-11730	-11082	-5510
(kcal/kg-MF)	-4888.9	-7583.3	-5696.7	-6516.7	-6156.7	-3061.1
Heat of Formation (kcal/kg-MAF)	-1214.4	183.0	-593.0	-461.7	-584.9	-1769.7
Heat Capacity (kcal/kgMF/^{o}C)	0.570	0.315	0.315	0.315	0.315	0.250

MAF Moisture Ash Free
MF Moisture Free

Table 2
Thermodynamics of Various Carbonaceous Feedstocks

Feedstock	Stoichiometric Formula(1)	Heat of Combustion(2) (kcal/Mole) HHV	Heat of Combustion(2) (kcal/Mole) LHV	Heat of Formation(2) (kcal/Mole)	Heat of Cracking(2) Cracking Products(3)	Heat of Cracking(2) (kcal/Mole)
Natural Gas	CH_4	-212	-192	-18	$C(s) + 2H_{2(g)}$	+18
Petroleum Medium Crude Resids, Tar, Sands, Shale	$CH_{1.7}$	-149	-141	-3	$C(s) + 0.85H_{2(g)}$	+3
Wood (Biomass)						
Sawdust	$CH_{1.44}O_{0.66}$	-105	-98	-38	$C(s) + 0.06H_{2(g)} + 0.66H_2O_{(\ell)}$	-7
Pine (12% Moisture)	$CH_{1.44}O_{0.66}$	-127	-120	-16	$C(s) + 0.06H_{2(g)} + 0.66H_2O_{(\ell)}$	-29
MSW and Paper Waste						
Rubber						
Styrene-Butadiene (Synthetic)	$CH_{1.15}$	-142	-136	+9	$C(s) + 0.58H_{2(g)}$	-9
Natural Rubber (Isoprene)	$CH_{1.6}$	-144	-136	-5	$C(s) + 0.8H_{2(g)}$	+5
Coal						
Bituminous	$CH_{0.8}O_{0.08}$	-116	-112	-5	$C(s) + 0.32H_{2(g)} + 0.08H_2O_{(\ell)}$	-1
Lignite	$CH_{0.8}O_{0.22}$	-113	-109	-8	$C(s) + 0.18H_{2(g)} + 0.22H_2O_{(\ell)}$	-7

(1) Representative formulae, based on unit atom of carbon in feedstock. Specific samples will vary in composition.

(2) All heats of combustion, formation, and cracking (at 298.2^{o}K) are based upon one gram-mole of feedstock containing one gram-atom of carbon. HHV represents higher heating value and LHV is lower heating value.

(3) Note cracking products in this table are to H_2 and H_2O, whereas at high temperature the cracking products are to CO and H_2 as shown in Table 3.

Table 3
Natural Gas or Oil Fired Combined Cycle Hydrogen Plasma Black Reactor (HPBR)
With Direct Carbon Fuel Cell (DCFC) and Solid Oxide Fuel (SOFC) and
Backend Steam Rankine Power Generation (SRC)
Enthalpy and Efficiency of Unit Reactions

Unit and Reactions		$\Delta H_{298.2}$ kcal/gmol	Efficiency %
HPBR – Hydrogen Plasma Black Reactor – 1500°C-atm			
Natural gas	$CH_4 = C + 2H_2$	+18.0	Process 60
Oil	$CH_{1.7} = C + 0.85H_2$	+ 3.0	Process 60
DCFC – Direct Carbon Fuel Cell – 750°C-atm			
$C + O_2 = CO_2$ ($CO_3^=$ ion transport)		-94.0	Thermal 90
SOFC – Solid Oxide Fuel Cell – 900°C-atm			
Hydrogen:	$H_2 + 1/2\ O_2 = H_2O$ ($O^=$ ion transport)	-68.0	Thermal 56
SRC – Steam Rankine Cycle – 550°C-68 atm			
$H_2O_{(\ell)} = H_2O_{(g)}$ (Steam Pressure)		Remaining ΔH	Thermal 38

Table 4
Coal and Biomass Fueled Combined Cycle
Hdrogen Plasma Black Reactor (HPBR)
With Direct Carbon Fuel Cell (DCFC) and Solid Oxide Fuel (SOFC) and
Backend Steam Rankine Power Generation (SRC)
IPFC
Enthalpy and Efficiency of Unit Reactions

Unit and Reactions		$\Delta H_{298.2}$ kcal/gmol	Efficiency %
HPBR – Hydrogen Plasma Black Reactor – 1500°C-atm			
Lignite Coal:	$CH_{0.77}O_{0.24} = 0.76\ C + 0.24\ CO + 0.385\ H_2$	+3.6	Process 60
Kentucky Bit Coal:	$CH_{0.81}O_{0.08} = 0.92\ C + 0.08\ CO + 0.4\ H_2$	+4.8	Process 60
Biomass:	$CH_{1.38}O_{0.59} = 0.41\ C + 0.59\ CO + 0.69\ H_2$	+12.7	Process 60
WGS – Water Gas Shift – 450° C			
Lignite:	$0.24\ CO + 0.24\ H_2O = 0.24\ CO_2 + 0.24\ H_2$	0	Conversion 100
Bituminous:	$0.08\ CO + 0.08\ H_2O = 0.08\ CO + 0.08\ H_2$	0	Conversion 100
Biomass:	$0.59\ CO + 0.59\ H_2O = 0.59\ CO + 0.59\ H_2$	0	Conversion 100
DCFC – Direct Carbon Fuel Cell – 750°C-atm			
Carbon:	$C + O_2 = CO_2$ ($CO_3^{=}$ ion transport)	-94.0	Thermal 90
SOFC – Solid Oxide Fuel Cell – 900°C-atm			
Hydrogen:	$H_2 + 1/2\ O_2 = H_2O$ ($O^{=}$ ion transport)	-68.0	Thermal 56
SRC – Steam Rankine Cycle – 550°C-68 atm			
	$H_2O_{(\ell)} = H_2O_{(g)}$ (Steam Pressure)	Remaining ΔH	Thermal 38

Table 5
Electrical Power Production in the Integrated Plasma Fuel Cell IPFC Combined Power Cycle Plant
Thermal Efficiency Evaluation and CO_2 Emission
Basis: -1 gmol of Fuel

Fuel Feedstock		Natural Gas	Petroleum	N. Dakota Lignite Coal	Kentucky Bituminous Coal	Biomass Wood
Molar Composition (MAF)		CH_4	$CH_{1.7}$	$CH_{0.77}O_{0.24}$	$CH_{0.81}O_{0.08}$	$CH_{1.38}O_{0.59}$
Plasma Decomp. Products Mole/Mole Fuel						
C		1.0	1.0	0.76	0.92	0.41
CO		-	-	0.24	0.08	0.59
H_2		2.0	0.85	0.39	0.41	0.69
Ash, S, N (wt%)		-	~1.0	9.8	12.6	1.1
Enthalpy of Decomposition kcal/gmol		+18.0	+3.0	+3.6	+4.8	+12.7
Electrical Energy Generation All Energy Values in kcal/gmol fuel						
Unit	Eff. %					
DCFC	90	84.6	84.6	64.3	77.8	34.7
SOFC	56	76.2	32.4	23.8	18.7	48.7
SRC	38	26.3	13.3	9.8	8.8	16.2
HPBR	60 - Consumed	-30.0	-5.0	-6.0	-8.0	-21.2
Net Electricity Generation, kcal(e)		157.1	125.3	91.9	97.3	78.4
HHV of Fuel, kcal(t)		212.0	149.0	110.3	119.0	112.8
Heat Exch. for Preheat* kcal(t)		14.8	16.2	7.7	6.5	18.9
Thermal Efficiency - %		74.1	84.1	83.3	81.8	69.5
CO_2 Emission, Lbs/kWh(e)		0.531	0.666	0.908	0.857	(1.064)**
CO_2 Reduction from conventional 38% SRC cycle - %		48.7	54.8	54.4	53.5	100.0

HPBR = Hydrogen Plasma Black Reactor
DCFC = Direct Carbon Fuel Coal
SOFC = Solid Oxide Fuel Cell
SRC = Steam Rancine Cycle

* This is the amount of heat unconverted from high temperature gas and can be used to preheat the incoming feed to reactor temperature by heat exchange.
**For biomass this is the amount of CO2 emitted from power cycle, however, because of the photosynthesis of biomass there is a zero net emission of CO_2.

Table 6
Hydrogen and Electrical Power Production in the Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plant Energy and Thermal Efficiency Distribution for Hydrogen and Electrical Power Production

Fuel Feedstock	Natural Gas	Petroleum	N. Dakota Lignite Coal	Kentucky Bit. Coal	Biomass (Wood)
Electricity Production (from DCFC only)					
Electrical Energy kcal(e)/gmol fuel	54.6	79.6	58.3	69.8	13.5
Hydrogen Production from HPBR					
Thermal energy in H_2 kcal(t)/gmol fuel*	136	57.8	42.2	33.4	87.0
HHV of Fuel Feedstock kcal(t)/gm mol	212	149.0	110.3	119.0	112.8
Thermal Efficiency					
Electricity Production - %	25.8	53.4	52.9	58.7	12.0
Hyrdrogen Production - %	64.2	38.8	38.3	28.1	77.1
Total Efficiency - %	90.0	92.2	91.2	86.8	89.1

*HHV of hydrogen = 68 kcal/mol

Table 6A
Energy Distribution and Thermal Efficiency Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plant – Hydrogen Production Alone

Fuel Feedstock	Natural Gas	Petroleum	N. Dakota Lignite	Kentucky Bituminous	Biomass (Wood)
Hydrogen from Electrolyzer [(1)] in Kcal/gmol Fuel	43.7	63.7	46.6	55.8	10.8
Hydrogen Production from HPBR Kcal/gmol Fuel	136.0	57.8	42.2	33.4	87.0
Total Hydrogen Production Kcal/gmol Fuel	179.7	121.5	88.8	89.2	97.8
HHV of Fuel Feedstock Kcal/gmol	212.0	149.0	110.3	119.0	112.8
Thermal Efficiency % for Hydrogen Production	84.8	81.5	80.5	75.0	86.7

1) Electrolyzer operates at 80% thermal efficiency for production of hydrogen and oxygen. All the net power from the DCFC is used in the electrolyzer.

Table 7
Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plant for Fossil and Biomass Power and Hydrogen Production

Efficiency and Preliminary Unit Cost

	Unit	Thermal Efficiency - %	Unit Capital Cost - $/kW
HPBR	Hydrogen Plasma Black Reactor Converts Fuel to Hydrogen and Carbon	Proc. Eff. 60	Gas and Oil - 200(1) Coal and Biomass 250(2)
DCFC	Direct Carbon Fuel Cell Converts Carbon to Elec. Power Molten Carbonate Electrolyte	90	500(3)
SOFC	Sold Oxide Fuel Cell Converts Hydrogen to Elec. Power	56	500(4)
SRC	Steam Rankine Cycle Converts Steam to Elec. Power	38	500
WGS	Water Gas Shift Reactor Converts CO to H_2	100	100
Electrolyzer	Electrolyzer Converts Water to H_2 and O_2 Alkaline Cell	80	500(5)

1) Based on Karbomont Plant Unit Investment for Liquid and Gaseous Feestock. Total Plant = $1100/kW; for Plasma Reactor = 18% of Plant = $200/kW

2) For Solid fuel feedstock coal and biomass add $50/kW to Unit Plasma Reactor.

3) LLNL Report UCRL – SCC146774 (Jan. 2002).

4) Fuel Cell Handbook USDOE/FETC - 99-1076 (1999).

5) IJHE 14 797-820 (1989).

Table 8
Integrated Plasma Fuel Cell Combined Cycle Plant (IPFC)
Preliminary Cost Estimate Electricity Production
Feedstock - Lignite Coal (17 MMBTU/ton - MF Montana)

Thermal Efficiency	83.3% (HHV)
Capital Cost[2]	$/kW (e)
Plasma Reactor (HPBC)	250[1]
Carbon Fuel Cell (DCFC)	330
Solid Oxide Fuel Cell (SOFC)	120
Steam Rankine Plant (SRC)	50
Total	750
Contingency	50
	800
Electricity Production Cost	Mills/kWh(e)
Lignite ($12.40/ton)	2.99
Fixed charges @20% of Capital/annum[3]	22.86
O&M at 15% of FC	3.43
Total Production Cost	29.28

CO_2 emission reduction is 54.4% compared to coal fired Steam Rankine Cycle Plant

1) Estimate based on Karbomont Plant 60 MW equiv. Power
Total plant cost = $65 million = $1100/kW, the plasma reactor only makes up 18% of investment or $200/kW for natural gas. For solid fuel coal and natural gas $50/kW is added or $250/kW.

2) Each unit prorated in accordance with its fractional contribution to the total production.

3) Capacity operating factor = 80% or 7000 hrs/per annum.

Table 9

Summary of Economic and Environmental Parameters
Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plants
Electricity Production Alone

Feedstock Fuel	Thermal Efficiency % (HHV)	Capital Cost $/kW(e)	Fuel Cost $/MMBTU	Electricity Prod. Cost Mills/kWh(e)	CO_2 Emission Reduction %(1)
Natural Gas	74.1%	735	2.00	33.36	48.7
			4.00	42.57	48.7
			6.00	51.78	48.7
Petroleum	84.1	740	4.31 ($25/bbl)	41.83	54.8
Bituminous Coal	81.8	800	1.00 ($25/ton)	30.46	53.5
Lignite Coal	83.3	800	0.73 ($12.40/ton)	29.28	54.4
Biomass (wood)	69.5	800	2.00	36.11	100.0(2)

1) CO_2 reduction per unit electricity produced compared to a conventional steam Rankine cycle at 38% efficiency.

2) Biomass generated by photosynthesis of CO_2 emitted to atmosphere resulting in no net CO_2 increase in atmosphere.

NOTE: Conventional steam plants generate power at 50 mills/kWh(e) using the same economic parameters as in this report for coal plants and a capital investment of $1300/kW.

Table 10
Summary of Economic and Environmental Parameters for Integrated Combined Cycle Plants
IPFC Comparison with Conventional Combined Cycle Plants
Electricity Production Only - Feedstocks Natural Gas and Oil

Feedstock	Process	Thermal Efficiency % (HHV)	Unit Capital Cost $/kW(e)	Fuel Cost $/MMBTU	Electricity Prod. Cost Mills/kWh(e)	O_2 Emission Reduction %[1]
Natural Gas	IPFC	74.1%	$735	2.00 4.00 6.00	33.36 42.57 51.78	48.7 19.1[2]
Natural Gas	Conventional Combined Cycle (CC)	60.0	600	2.00 4.00 6.00	31.08 42.45 53.82	36.7 36.7 36.7
Petroleum	IIPFC	84.1	740	4.17 ($25/Bbl)	45.12	54.5 34.6[2]
Petroleum	Conv. IGCC	55.0	700	4.17 ($25/Bbl)	48.88	30.9

1. % CO_2 emission reduction per unit of electricity produced compared to a conventional Steam Rankine Cycle Plant which operates at 38% thermal efficiency.

2. CO_2 emission reduction of IPFC compared to conventional combined cycle and IGCC.

Table 11
Summary of Economic and Environmental Parameters for
Integrated Combined Cycle Plants (IPFC)
Comparison with Conventional Combined Cycle Plants
<u>Electricity Production Alone - Feedstock Coal and Biomass</u>

Feedstock	Process	Thermal Efficiency % (HHV)	Unit Capital Cost $/kW(e)	Fuel Cost $/MMBTU	Electricity Min. - Max Mill/Kwh(e)	CO_2 Emission Reduction %(1)
Bituminous Coal	IPFC	81.8	800	1.00 ($25/ton)	30.44	53.5 32.7%(2)
Bituminous Coal	Conventional IGCC	55.0	1000	1.00 ($25/ton)	38.21	30.9
Lignite Coal	IPFC	83.3	800	0.73 ($12.40/ton)	29.28	54.5 34.0%(2)
Lignite Coal	Conventional IGCC	55.0	1000	0.73 ($12.40/ton)	37.39	30.9
Biomass Wood	IPFC	69.5	785	2.00	35.61	100.0(3)

1) %CO_2 emission reduction per unit of electricity produced compared to a conventional Steam Rankine Cycle Plant at 38% efficiency.

2) CO_2 emission reduction of IPFC compared to conventional IGCC.

3) Biomass generated by photosynthesis from an equal amount of CO_2 emitted from the ICCP, results in a zero emission of CO_2.

Table 12
Efficiency and CO_2 Emissions from Conventional and Advance Cycle (IPFC) Power Plants – Electricity

Fuel	Power Cycle	Thermal Efficiency %	CO_2 Emissions Lbs/kWh(e)	% Reduction of CO_2 Emissions from Steam Rankine Cycle
<u>Conventional</u>				
Natural Gas –	Steam Rankine Cycle	38	1.036*	-
Crude Oil	“	38	1.473*	-
N. Dakota Lignite	“	38	1.991*	-
Kentucky Bit. Coal	“	38	1.844*	-
Biomass Wood	“	38	1.946*	-
<u>Conventional</u>				
Natural Gas –	Combined Cycle (CC)	60	0.656	36.7
Crude Oil –	Integrated Gasification Combined Cycle (IGCC)	55	1.018	30.9
N. Dakota Lignite	“	50	1.513	24.0
Kentucky Bit. Coal	“	50	1.403	24.0
Biomass Wood	“	50	(1.479)**	100.0
<u>Advanced</u>				
Natural Gas –	Integrated Plasma Fuel Cell Cycle (IPFC)	74.1	0.531	48.7
Crude Oil	“	84.1	0.666	54.8
N. Dakota Lignite	“	83.3	0.908	54.4
Kentucky Bit. Coal	“	81.8	0.857	53.5
Biomass Wood	“	69.5	(1.064)**	100.0

* The CO_2 from the steam Rankine cycle is diluted with nitrogen. There is a cost of concentrating the 10 to 15% CO_2 in flue gas to 100% for compression and for sequestration. All the other cycles produce highly concentrated streams of CO_2, which do not require concentration but does require compression for sequestration.

** For biomass this is the amount of CO_2 emitted from the Power Cycle, however, because of the photosynthesis biomass formation from atmospheric CO_2 there is no net emission of CO_2.

Table 13
Integrated Plasma Fuel Cell (IPFC) Combined Cycle
Preliminary Cost – Electricity and Hydrogen Production
Fuel – Natural Gas – Fig. 5

Thermal Efficiency	%
Electricity Production	25.8
Hydrogen Production	64.2
Total Efficiency	90.0
Capital Cost Distribution (Prorated)	$/kW
Plasma Reactor	200
Carbon Fuel Cell	190
Water Gas Shift	60
Contengency	50
Total Unit Capital Investment	500
H_2 and Electricity Production Cost	Mills/kWh
Natural Gas @ $4/MMBTU	15.16
Fixed Charges @20% Capital/annum	14.29
O&M @ 15% of FC	2.14
Total	31.59
H_2 Product Cost	
$/MMBTU	9.26
$/MSCF	2.96
$/gal Equiv. Gasoline	1.11

Table 14
Integrated Plasma Fuel Cell (IPFC) Combined Cycle
Preliminary Costs Estimate – Electricity and Hydrogen Production
Feedstock Natural Gas – 90% Thermal Efficiency (Fig. 5)
H_2 Production Cost as a Function of Natural Gas Cost and Electricity Selling Price

Total Unit Capital Cost $/kW	Natural Gas Cost $/MMBTU	Electricity Cost Mills/kWh(e)	Hydrogen Cost $/MMBTU	Hydrogen Cost $/gal Equiv. Gasoline	Electricity Selling Price Mills/kWh(e)	Hydrogen Cost $/MMBTU	Hydrogen Cost $/gal Equiv. Gasoline
500	2.00	24.01	7.03	0.84	50.00	4.00	0.48*
	4.00	31.59	9.26	1.11	50.00	7.08	0.84
	6.00	39.17	11.48	1.38	50.00	10.20	1.22

Note: H_2 cost from conventional natural gas reforming plant at $4/MMBTU = 29.22 Mills/Kw = $8.56/MMBTU = $1.03/gal equiv. gasoline.
Thermal efficiency = 78.5% and Capital Investment = $360/Kw equivalent.
*$0.48/gal. equiv. gasoline is the target production cost that DOE has set for the future generation coal fired combined cycle plant.[11]

Table 15
Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plant
Preliminary Cost Estimate – Electricity and Hydrogen Production (Fig. 5)
Feedstock Lignite Coal (17 MMBTU/ton-MF Montana)

Thermal Efficiency	%
Electricity Production	52.9
Hydrogen Production	38.3
Total Efficiency	91.2
Capital Cost Distribution (Prorated)	$/KW
Plasma Reactor	250
Carbon Fuel Cell	300
Water Gas Shift	50
Contengency	50
Total Unit Capital Investment	650
Combined Hydrogen and Electricity Production Cost	Mills/KWhr
Lignite @$12.40/ton	2.73
Fixed Charges @20% Capital/annum	18.57
O&M @ 15% of FC	2.78
Total	24.08
Hydrogen Product Cost	
$/MMBTU	7.05
$/MSCF	2.27
$/gal Equiv. Gasoline	0.85

Table 16
Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plant
Preliminary Cost Estimate – Electricity and Hydrogen Production
Feedstock – Lignite Coal (17 MMBTU/ton – MF Montana $12.40/ton)
H_2 Production Cost as a Function of Electricity Selling Price and Capital Cost
See Fig. 5-91.2% Thermal Efficiency

Electricity Selling Price Mills/kWh(e)	Capital $/kW	Hydrogen Cost			
		Mills/kWh	$/MMBTU	$/MSCF	$/gal Gasoline Equivalent
24.08	650	24.08	7.05	2.25	0.85
31.62	650	13.66	4.00	1.29	0.48(1)
41.50	650	0.00	0.00	0.00	0.00
29.02	800	29.02	8.50	2.73	1.00
50.00(2)	800	0.00	0.00	0.00	0.00

1) DOE Target H_2 cost for Future Generation Project = $0.48/gal = $4/MMBTU.
2) 50 mills/kWh is cost of electricity from a Lignite Conventional Rankine Cycle Plant at 38% efficiency.

Note: A H_2 cost from Texaco gasification plant = $1.34/gal gas equiv.
Capital Cost = $1036/kW
IPFC CO_2 emission is 37% less than Texaco gasification plant.

Table 17
Efficiency and CO_2 Emissions from Conventional and Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plants for Production of Electricity and Hydrogen

Fuel	Cycle	Product Ratio Electricity / Hydrogen	Thermal Efficiency %	CO_2 Emission Lbs/kWh(e&t)	% Reduction of CO_2 Emission from IGCC
Advanced					
Natural Gas	Integrated Plasma IPFC(1)	0.40	90.0	0.437	19.5
Crude Oil	"	1.37	92.2	0.607	79.8
N. Dakota Lignite	"	1.38	91.2	0.829	39.8
Kentucky Bit. Coal	"	2.09	86.8	0.807	37.5
Biomass (wood)	"	0.16	89.1	(0.830)**	100.0
Conventional					
Natural Gas	Combined Cycle IGCC(2)	0.40	72.4	0.543	-
Petroleum	"	1.37	64.7	0.865	-
N. Dakota Lignite	"	1.38	54.9	1.378	-
Kentucky Bit. Coal	"	2.09	54.3	1.291	-
Biomass (wood)	"	0.16	58.5	(1.264)**	100.0

1) IPFC is the advanced Integrated Plasma Fuel Cell Plant or HCE plant.
2) IGCC is the Integrated Gasification Combined Cycle Plant.

** For biomass, this is the amount of CO_2 emitted from power cycle, however, because of the photosynthesis of biomass formation from CO_2 there is no net emission of CO_2.

Table 18
Production Cost Comparison IPFC with Conventional Electrical Power Production Alone

Fuel	Power Cycle	Thermal Efficiency %	Cap. Cost $/kW	Electricity Production Cost Mills/kWh	CO_2 Sequestration Cost Mills/kWh	Electricity Total Mills/kWh(e)
Natural Gas						
$4/MMBTU	Conventional Steam Rankine Cycle	38.0	1000	68.7	13.0[(1)]	81.7
"	Combined Cycle (CC)	60.0	600	42.5	8.2[(1)]	50.7
"	Integrated Plasma Fuel Cell (IPFC)	74.1	735	42.6	6.6[(2)]	49.2
Coal						
$0.73/MMBTU Lignite	Conventional Steam Rankine Cycle	38.0	1300	49.3	24.9[(1)]	74.2
$1.00/MMBTU Bituminous	- Rankine Cycle	38.0	1300	51.7	23.1[(1)]	74.8
Lignite	Integrated Gasification Combined Cycle (IGCC)	55.0	1000	37.4	3.8[(2)]	41.2
Bituminous	"	55.0	1000	38.2	3.5[(2)]	41.7
Lignite	Integrated Plasma Fuel Cell Cycle (IPFC)	83.3	800	29.3	2.3[(2)]	31.6
Bituminous	"	81.8	800	30.5	2.1[(2)]	32.6
Biomass	"	69.5	800	36.1	- [(3)]	36.2

1) Cost for CO_2 capture and sequestration $25/ton
2) Cost for CO_2 sequestration alone $5/ton
3) No penalty for biomass because CO_2 regenerates biomass feed by atmospheric photosynthesis.

Table 19
Production Cost Comparison IPFC with Conventional Electric Power and Hydrogen Production

Fuel	Power Cycle	Thermal Efficiency %	Cap. Cost $/kW	Hydrogen Gasoline Equivalent $/gal	Electricity Mills/kWh	CO_2 Sequestration* Mills/kWh	Electricity Total Mills/kWh
Natural Gas							
$4/MMBTU	Steam Reforming**	78.5	360	1.03	-	-	-
“	Integrated Gasification Combined Cycle (IGCC)	72.4	600	1.36	38.6	1.4	40.0
“	Integrated Plasma Fuel Cell Cycle (IPFC)	90.0	500	1.11	31.6	1.1	32.7
“	“	90.0	500	0.84	50.0	1.1	51.1
Lignite	Coal Gasification**	63.0	1036	1.34	-	-	-
$12.40/ton	Integrated Gasification Combined Cycle (IGCC)	54.9	1300	1.63	46.4	3.4	49.8
“	Integrated Plasma Fuel Cell Cycle (IPFC)	91.2	650	0.85	24.1	2.1	26.2
“	“	91.2	650	0.00	41.5	2.1	43.6

* Since all these plants produce highly concentrated streams of CO_2 emissions the sequestration cost is $5/ton CO_2.
** These plants produce only hydrogen.

Table 20
Integrated Plasma Fuel Cell (IPFC) Combined Cycle Plant
Preliminary Cost Estimate – Hydrogen Production Alone (Fig. 6)
Feedstock - Lignite Coal (17 MMBTU/ton-MF Montana)

Thermal Efficiency	80.5% (HHV)
Capital Cost[(1)]	$/kW(e)
Plasma Reactor (HPBR)	250
Carbon Fuel Cell (DCFC)	263
Electrolyzer	363
Water Gas Shift (WGS)	48
Total	824
Contingency	50
	874
Hydrogen Production Cost	Mills/kWh(e)
Lignite ($12.40/ton)	3.10
Fixed Charges @20% of Capital/annum	24.97
O&M @15% of FC	3.75
H_2 Total Production Cost	31.82
$/MMBTU	9.32
$/MSCF	3.00
$/gal equivalent gasoline	1.12

1) Each unit prorated in accordance with its fractional contribution to the total production.

Table 21
Summary of Economic and Environmental Parameters for Integrated Plasma Fuel Cell (IPFC) Compared to Conventional Combined Cycle Plants
Hydrogen Production Alone (Fig. 6)

Feedstock Fuel	Thermal Efficiency % (HHV)	Capital Cost $/kW(e)	Fuel Cost $/MMBTU	Equivalent Hydrogen Cost $/gal Gasoline Equivalent	CO_2 Emission[(1)] % Reduction from Conventional Plants
			IPFC Plants for Hydrogen		
Natural Gas	84.8	490	4.00	1.14	7.4
Petroleum	81.5	690	4.31 ($25/bbl)	1.51	5.8
Lignite Coal	80.5	874	0.73 ($12.40/ton)	1.12	21.5
Bituminous Coal	75.0	970	1.00 ($25/ton)	1.28	15.7
Biomass	86.7	500	2.00	0.85	-
			Conventional Plants for Hydrogen		
Natural Gas	Steam Reforming 78.5%	360	4.00	1.03	-
Petroleum	Partial Oxidation 76.8%	850	4.31 ($25/Bbl)	1.59	-
Lignite Coal	Texaco Gasification 63.2%	1036	0.73 ($12.40/ton)	1.34	-

1) This % CO_2 emission reduction refers to reduction of CO_2 compared to conventional plants for the same fuel feedstock.

Table 22
IPFC Integrated Plasma Fuel Cell Plant
Production Yields Per Unit of Fuel Feedstock

Fuel Feedstock Process Units	Product	All Electricity HPBR-SOFC-DCFC-SRC	Electricity & Hydrogen HPBR-WGS-DCFC	All Hydrogen HPBR-WGS-DCFC-ELEC
Natural Gas MSCF	Elec., kWh	218 kWh/MSCF	76 kWh/MSCF	-
	H_2, MSCF	-	2.0 MSCF H_2/MSCF	2.6 MSCF H_2/MSCF
	H_2, Gal. Gas Equiv.	-	5.4 H_2 Gal Gas Equiv./MSCF	7.1 H_2 Gal Gas Equiv./MSCF
Petroleum, Bbl	Elec., kWh	1337 kWh/Bbl	849 kWh/Bbl	-
	H_2, MSCF	-	6.5 MSCF H_2/Bbl	13.7 MSCF H_2/Bbl
	H_2, Gal. Gas Equiv.	-	17.4 H_2 Gal Gas Equiv./Bbl	36.9 H_2 Gal Gas Equiv./Bbl
N. Dakota Llignite, maf-Ton	Elec., kWh	5840 kWh/maf ton	3700 kWh/ton	-
	H_2, MSCF	-	28.2 MSCF H_2/ton	59.6 MSCF H_2/ton
	H_2, Gal. Gas Equiv.	-	76.2 H_2 Gal Gas Equiv.	161.4 H_2 Gal Gas Equiv./ton
Kentucky Bituminous maf-Ton	Elec., kWh	7280 kWh/maf ton	5225 kWh/ton	-
	H_2, MSCF	-	26.5 MSCF H_2/ton	70.8 MSCF H_2/ton
	H_2, Gal. Gas Equiv.	-	71.1 H_2 Gal Gas Equiv./ton	190.0 H_2 Gal Gas Equiv./ton
Biomass (wood) maf-Ton	Elec., kWh	3620 kWh/maf ton	620 kWh/ton	-
	H_2, MSCF	-	42.6 MSCF H_2/ton	47.9 MSCF H_2/Ton
	H_2, Gal. Gas Equiv.	-	114.4 H_2 Gal. Gas Equiv./Ton	128.5 H_2 Gal. Gas Equiv./Ton

HPBR – Hydrogen Plasma Black Reactor
SOFC – Solid Oxide Fuel Cell
DCFC – Direct Carbon Fuel Cell
SRC – Steam Rankine Cycle
ELEC – Electrolyzer

MSCF – 1000 Standard Cubic Feet Gas
Bbl – Barrel of oil = 42 gal
Ton – Ton = 2000 Lbs
maf = moisture and ash free
H_2 Gal. Gas Equiv. – Hydrogen in terms of equivalent gallon of gasoline

Note: H_2 when used in fuel cell vehicles obtains 3 times the mileage/gal obtained in conventional IC vehicles.

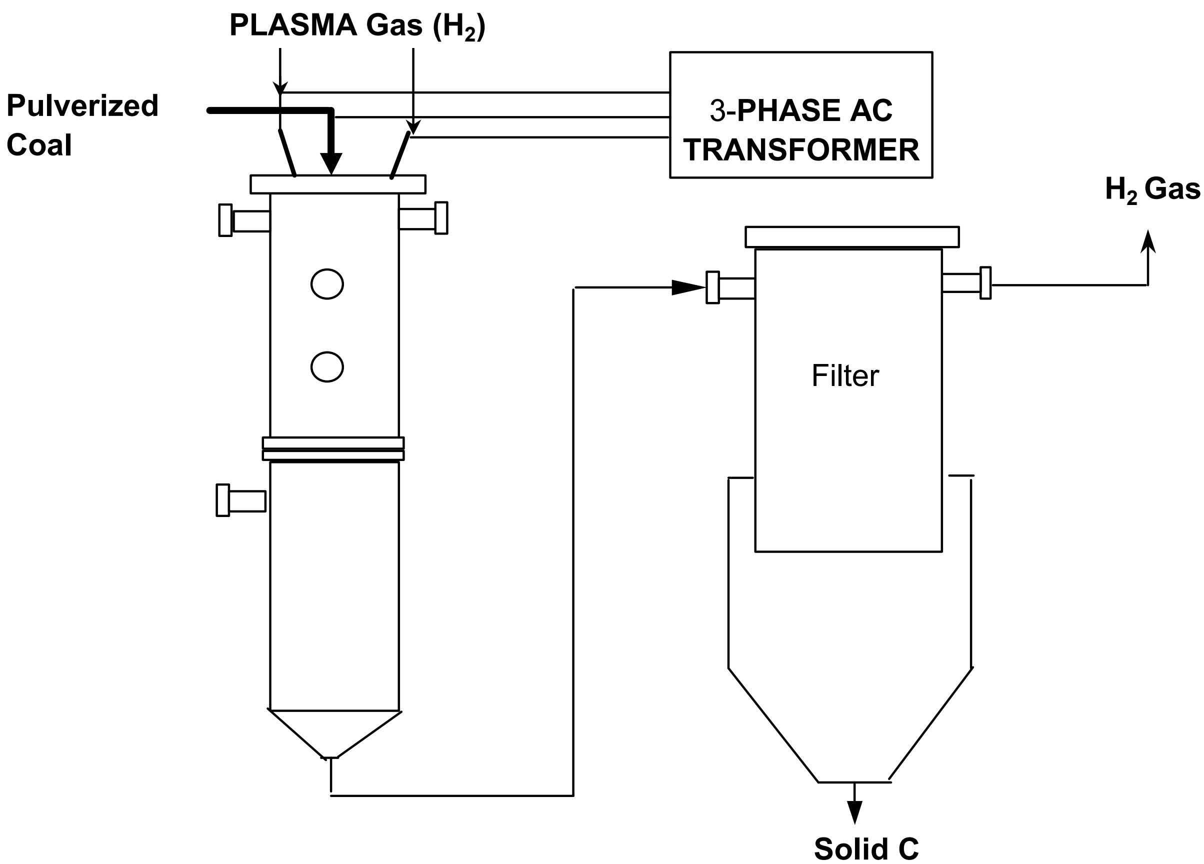
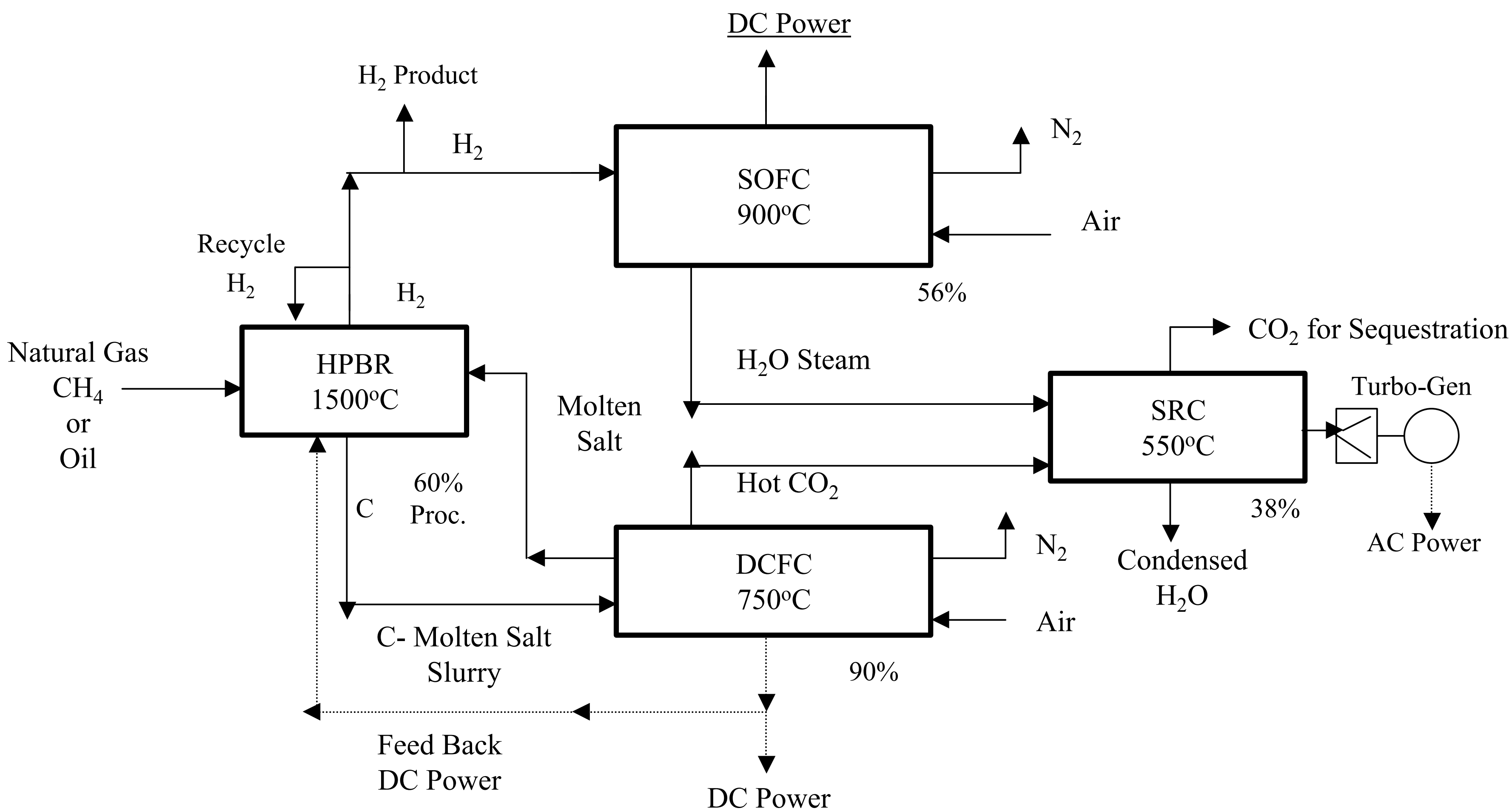


Figure 2. THE HYDROGEN PLASMA BLACK REACTOR



<u>HPBR – Hydrogen Plasma Black Reactor</u>

Natural Gas $CH_4 = C + 2H$

Oil $CH_{1.7} = C + 0.85\ H_2$

<u>DCFC - Direct Carbon Fuel Cell</u>

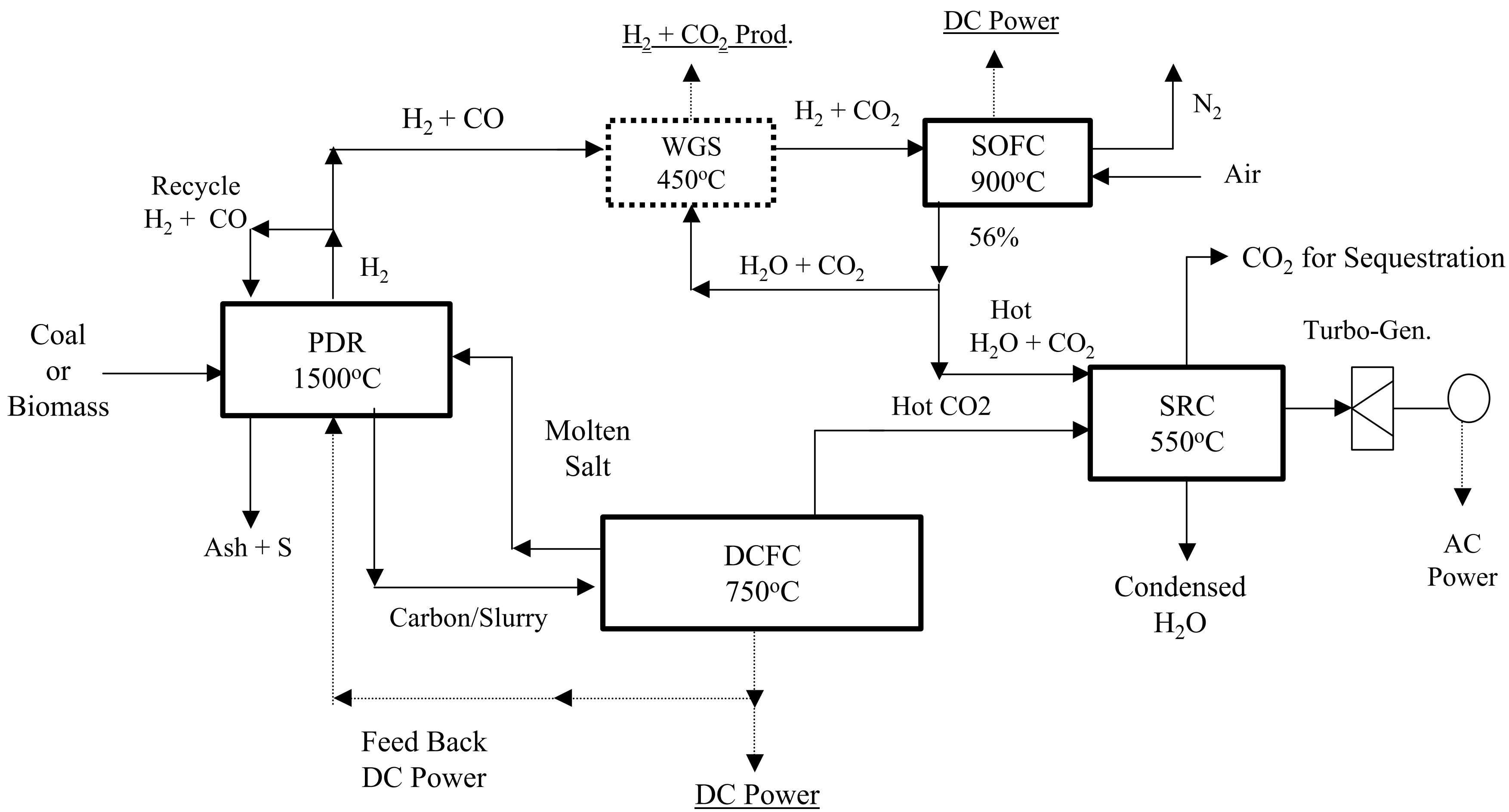
$C + O_2 = CO_2$ ($CO_3^{=}$ Ion Transport)

<u>SOFC - Solid Oxide Fuel Cell</u>

$H_2 + 1/2\ O_2 = H_2O$ ($O^{=}$ Ion Transport)

<u>SRC - Steam Rankine Cycle</u>

Figure 3 – <u>Intergrated Plasma Fuel Cell (IPFC) Plant</u>
Natural Gas or Oil Fueled Combined Cycle Hydrogen Plasma Black Reactor (HPBR) with Direct Carbon Fuel Cell (DCFC), Solid Oxide Fuel Cell (SOFC) and Backend Steam Rankine Cycle (SRC) Power Generation



HPBR - Hydrogen Plasma Black Reactor
Lignite Coal $CH_{0.77}O_{0.24} = 0.76C + 0.24\ CO + 0.385\ H_2$
Kentucky Bit. Coal $CH_{0.81}O_{0.08} = 0.92\ C + 0.08\ CO + 0.40\ H_2$
Biomass: $CH_{1.38}O_{0.59} = 0.41\ C + 0.59\ CO + 0.69\ H_2$
WGS - Water Gas Shift
Lignite $0.24\ CO + 0.24\ H_2O = 0.24\ CO_2 + 0.24\ H_2$
Bituminous $0.08\ CO + 0.08\ H_2O = 0.08\ CO + 0.08\ H_2$
Biomass: $0.59\ CO + 0.59\ H_2O = 0.59\ CO_2 + 0.59\ H_2$
SOFC - Solid Oxide Fuel Cell
$H_2 + 1/2\ O_2 = H_2O$ (High Transport)
DCFC - Direct Carbon Fuel Cell
$C + O_2 + CO_2$ ($CO_3^=$ Ion Transport)
SRC - Steam Boiler Rankine Cycle

Figure 4. Integrated Plasma Fuel Cell (IPFC) Plant Coal or Biomass Fueled Combined Cycle Plasma Composition (PDR) with Direct Carbon Fuel Cell (DCFC), Hydrogen Solid Oxide Fuel Cell (SOFC) Backend Steam Rankine Cycle (SRC) Power Generation

Hydrogen Plasma Black Reactor (HPBR) in Combination with Direct Carbon Fuel Cell (DCFC)

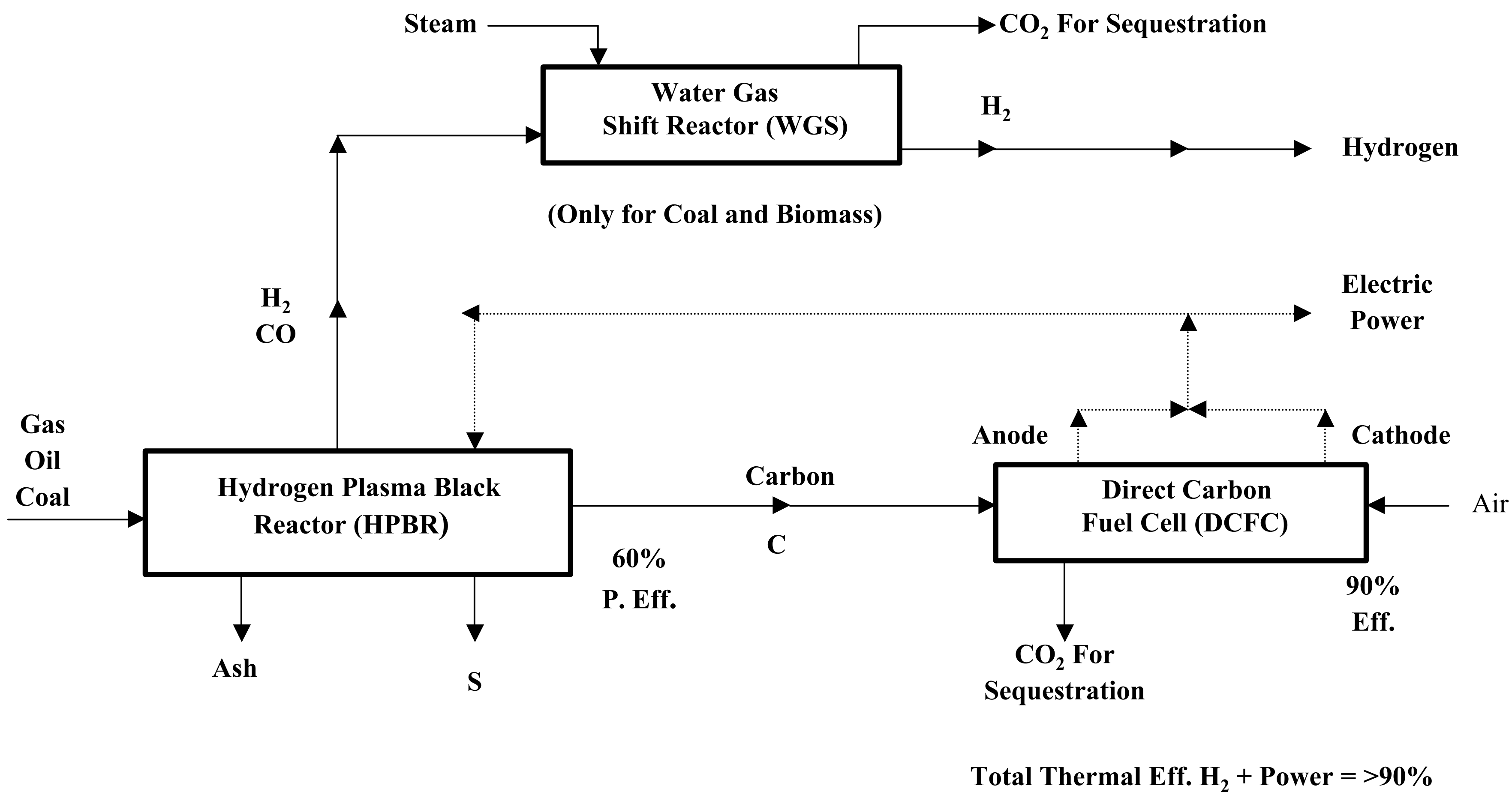


Figure 5. IPFC Plant - Integrated Plasma Fuel Cell Combined Cycle
Electric Power and Hydrogen Production

Hydrogen Plasma Black Reactor (HPBR) in Combination with Direct Carbon Fuel Cell (DCFC)

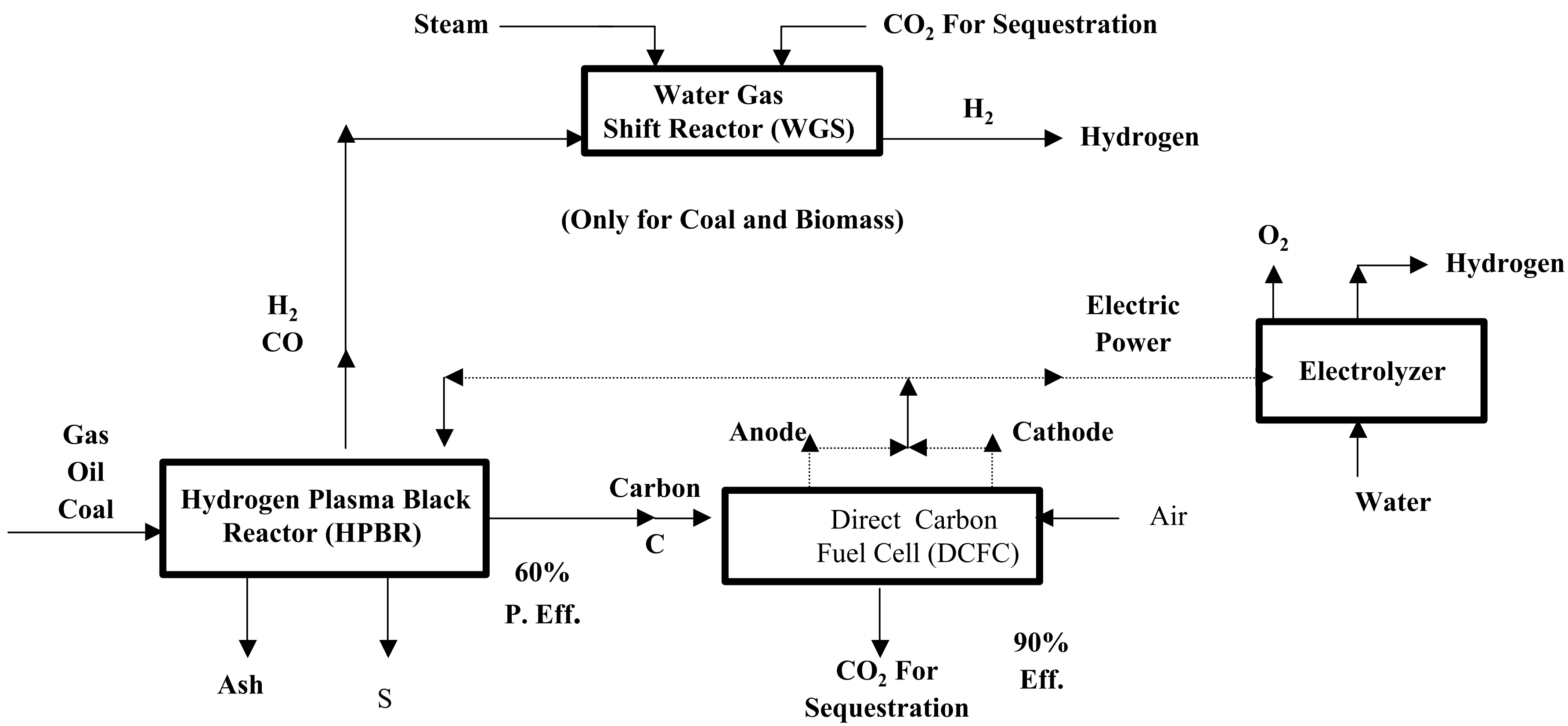


Figure 6. IPFC Plant - Integrated Plasma Full Cell Combined Cycle for <u>Hydrogen Production Only</u>