VISION 21 SYSTEMS ANALYSIS METHODOLOGIES

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PRINCIPAL AUTHORS

DR. G. S. SAMUELSEN
DR. A. RAO
DR. F. ROBSON
MR. B. WASHOM

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PREPARED BY

ADVANCED POWER AND ENERGY PROGRAM
UNIVERSITY OF CALIFORNIA
IRVINE, CALIFORNIA 92697-3550

KRAFTWORK SYSTEMS, INC.
P.O. BOX 115
AMSTON, CONNECTICUT 06231

SPENCER MANAGEMENT ASSOCIATES
24 SANDSTONE CT.
ALAMO, CALIFORNIA 94507

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ABSTRACT

Under the sponsorship of the U.S. Department of Energy/National Energy Technology Laboratory, a multi-disciplinary team led by the Advanced Power and Energy Program of the University of California at Irvine is defining the system engineering issues associated with the integration of key components and subsystems into power plant systems that meet performance and emission goals of the Vision 21 program. The study efforts have narrowed down the myriad of fuel processing, power generation, and emission control technologies to selected scenarios that identify those combinations having the potential to achieve the Vision 21 program goals of high efficiency and minimized environmental impact while using fossil fuels. The technology levels considered are based on projected technical and manufacturing advances being made in industry and on advances identified in current and future government supported research. Included in these advanced systems are solid oxide fuel cells and advanced cycle gas turbines. The results of this investigation will serve as a guide for the U. S. Department of Energy in identifying the research areas and technologies that warrant further support.

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EXECUTIVE SUMMARY

Under the sponsorship of the U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL), a multi-disciplinary team led by the Advanced Power and Energy Program (APEP) of the University of California at Irvine is defining the system engineering issues associated with the integration of key components and subsystems into power plant systems that meet performance and emission goals of the Vision 21 program.

The overall objectives of the Vision 21 program sponsored by the NETL of the U. S. DOE are:

- produce electricity and transportation fuels at competitive costs
- minimize environmental impacts associated with fossil fuel usage, and
- attain high efficiency

The efficiency targets for natural gas fueled plants is 75% on a LHV basis while that for coal fueled plants is 60% on an HHV basis while producing electricity only, that is, without CO_2 capture and sequestration nor coproduction of any transportation fuels, while the goal for coal based plants producing H_2 or transportation fuels only consists of achieving a minimum fuel utilization of 75% on an LHV basis.

Specifically, the objective of this program being conducted by the multi-disciplinary team led by the APEP is to identify natural gas and coal based system configurations that meet the above Vision 21 goals. The results of this investigation will serve as a guide for the U. S. DOE in identifying the research areas and technologies that warrant further support.

The myriad of fuel processing, power generation, and emission control technologies were narrowed down to selected scenarios in order to identify those combinations that had the potential to achieve the Vision 21 program goals of high efficiency and minimized environmental impact while using fossil fuels. The technology levels considered were based on projected technical and manufacturing advances being made in industry and on advances identified in current and future government supported research. Examples of systems included in these advanced cycles are solid oxide and molten carbonate fuel cells, advanced gas turbines, ion transport membrane separation and hydrogen-oxygen combustion. The following describes the various tasks being performed in this study:

1. Sub-system Selection – the selection of the fuel processing, power generation and emission control technology scenarios with potential to achieve the Vision 21 goals.
2. Screening Analysis – analyze and optimize selected technology scenarios at a screening level to select cycle configurations. The optimization includes the selection of the cycle configuration as well as the cycle operating conditions. The approach taken in performing this analysis is to start with basic designs with relatively near term technology and when the Vision 21 targets are not realized, incorporate more advanced designs.

3. Detailed Analysis – the selected promising cycles are next analyzed to develop detailed design point performance, off-design performance (sensitivity to ambient conditions and part-load performance) and rough order of magnitude capital and operating costs.

4. The Sub-system Selection task for both natural gas and coal based plants was completed during the first year of this program while the Screening Analysis task was completed for the natural gas cases during this reporting period.

During this reporting period, the analyses of the selected five natural case cases were completed and the analyses of the selected five coal-fired systems were begun. The natural gas fired hybrid systems, consisting of fuel cells and gas turbine bottoming systems were able to attain the DOE goal of 75% (LHV) efficiency. The natural gas fired systems with CO_2 removal for subsequent sequestration did not attain the efficiency goal, but did have essentially zero emissions. The use of coal requires a gasification and cleanup system to provide very clean gas to the fuel cell. While effort in this area continues, analyses to date indicate that the commercially available oxygen-blown entrained flow gasification systems, both slurry fed and dry fed, when integrated with the hybrid power system do not achieve the DOE goal of 60% (HHV). Efficiencies in the 55-58% (HHV) range do appear attainable. The use of an air-blown fluid bed gasifier as typified by the Advanced Transport Reactor (ATR) being developed under DOE sponsorship appears to reach the DOE goal (as long as high carbon conversions can be demonstrated with this gasifier). All the analyses, however, have not been completed. Preliminary analysis indicates that the Foster-Wheeler partial gasifier, also a fluid bed-type gasifier, can be used in a hybrid system to attain the 60% DOE goal. Analyses of coal-based systems with CO_2 removal and of a co-production facility using Fischer-Tropsch technology to produce premium liquid fuels and electricity have just been initiated.

EXPERIMENTAL

No experimental work was conducted as part of this program.

RESULTS AND DISCUSSION

SUB-SYSTEM SELECTION

Options for the sub-systems for natural gas and coal are depicted in Figure 1 along with various combinations for linking of the fuel with the fuel processing technology, power generation technology and emissions control technology. The characteristics of pipeline quality natural gas allow it to be used directly in gas turbine based cycles such as an intercooled (ICGT) gas turbine, a combined cycle, a Humid Air Turbine (HAT) cycle [Rao, 1989], or combusted in steam boilers, typically without any fuel processing. Natural gas may also be used in fuel cells after some treatment (desulfurization, humidification and reforming). Among the various power generation options for natural gas as shown in Figure 1, direct combustion in a steam boiler may be eliminated, the thermal efficiency of the other options consisting of utilizing gas turbines or fuel cells being significantly higher while NOx emissions being lower, especially with the HAT cycle and the fuel cell options. The HAT cycle does not require any form of NOx control because of the large concentration of water vapor present in the combustion air which minimizes the formation of thermal NOx [Bhargava, 1999]. The fuel cells, which oxidize the fuel predominantly by electrochemical reactions do not require any form of NOx control either; combustion of the depleted fuel leaving the cell produces very low amounts of NOx.

These same options consisting of gas turbine based technologies or fuel cells can be used in coal based plants if the coal is gasified to produce syn gas and the contaminants removed from the syn gas prior to supplying the gas to the power block, fuel specifications for fuel cells and high performance gas turbines being very stringent (high performance gas turbines have stringent limits on levels of contaminants that include sulfur, alkaline metals, vanadium). Alternately, if coal is directly used as in various types of fluid beds or in pulverized steam boilers or in indirectly fired cycles, the effluent from the power generation systems will require extensive post combustion emission controls such as flue gas desulfurization, NOx, particulate and trace element removal devices. In gasification on the other hand, the syn gas cleanup to remove contaminants such as the sulfur and nitrogen compounds, and particulates is performed on a gas stream with a significantly smaller volume and with contaminant concentrations significantly higher, making it much easier to remove. Heavy petroleum fractions and biomass must also be processed and cleaned in a similar manner before these fuels can be "integrated" with the power generation system.

The gasification sub-system is further divided into number of processing units including the oxidant supply unit. Whether the gasification process uses oxygen or air depends on the operating temperature of the gasifier and whether hot syn gas clean up is utilized. With air blown systems, the efficiency of the gasifier (by itself) is lower and larger down stream equipment is required for processing the syn gas which is diluted with nitrogen. For a gasifier operating at high temperatures (in excess of 1000C), the nitrogen accompanying the oxygen in the air increases the degradation of the chemically bound energy of the coal into sensible heat energy within the gasifier which is carried away with the syn gas, thus reducing the cold gas efficiency of the gasifier. On the other hand, the air separation unit is eliminated along with its parasitic loads and high capital cost.

This initial Sub-system Selection task has eliminated from consideration the direct combustion of the fuels, indicated that fuel processing in case of coal will be either oxygen or air blown gasification depending on the gasifier operating temperature and syn gas cooling, and set the requirements for gas clean up based on the specifications dictated by the high performance gas turbines and fuel cells. Note that the gasification option makes the power cycles fuel flexible.

With respect to the power generation technology option, cycles based on a gas turbine alone without fuel cells cannot meet the efficiency goals of the Vision 21 program as evidenced by the efficiencies calculated for the gas turbine based cycles as a function of the combustor exhaust temperature (Figure 2). The efficiency of an advanced combined cycle utilizing a steam cooled gas turbine, even with a combustor exhaust temperature as high as 1900C (3450F), is in the neighborhood of 65% (LHV), which is significantly lower than the 75% (LHV) goal for natural gas. With the HAT cycle, a higher combustor exhaust temperature may be utilized since the cycle is not as much constrained by NOx emissions as the combined cycle [Chen, et al., 2002]. Still, the efficiency is limited to less than 70% (LHV) for natural gas.

Thus, gas turbines integrated with fuel cells (hybrids) are required for these Vision 21 power plants. Three hybrid cycles were identified for the natural gas based plants that had the potential to reach the Vision 21 efficiency goal:

1. High pressure solid oxide fuel cell (SOFC) integrated with a high-pressure ratio intercooled gas turbine
2. High pressure solid oxide fuel cell (SOFC) integrated with the HAT cycle
3. Atmospheric pressure molten carbonate fuel cell (MCFC) integrated with a high-pressure ratio intercooled gas turbine.

Two “zero emission” natural gas based plants, that is, plants recovering the carbon dioxide for carbon sequestration were also identified for the screening analysis:

1. O_2 breathing high pressure SOFC integrated with HAT cycle and CO_2 recycle
2. Advanced Rankine cycle (using gas turbine technology) combusting H_2 with O_2 in rocket engine technology combustor.

Three cases were initially identified for the coal-based plants that had the potential to reach the Vision 21 efficiency goal:

1. Shell gasifier with hot gas cleanup providing syn gas to a high pressure SOFC based hybrid
2. Texaco gasifier providing syn gas to a high pressure SOFC integrated with the HAT cycle
3. Foster-Wheeler partial gasifier integrated with a SOFC based hybrid.

Two “zero emission” coal based plants were also identified for the screening analysis:

1. Shell gasifier with hot gas cleanup providing syn gas to an O_2 breathing high pressure SOFC integrated with HAT cycle and CO_2 recycle
2. Shell gasifier with hot gas cleanup and H_2 separation using high temperature membranes (precombustion

CO_2 recovery) and the advanced Rankine cycle (using gas turbine technology and H_2/air combustor derived from the rocket engine technology).

An additional case that coproduces Fischer-Tropsch liquids (in addition to electric power) was also identified for the screening analysis:

1. Texaco gasifier with cold gas cleanup providing syn gas to a Fischer-Tropsch synthesis unit with unconverted gas supplied to an advanced HAT system.

This case represents an advanced coal-based power system in which a high value liquid fuel is produced along with electric power. Because the main product is the liquid fuel, the power system may not operate as a base load plant and may, in fact, operate with several stops and starts per day. This means that the plant is not tightly integrated and that fuel (syn gas) is delivered "across the fence" to the power system. Because of the probable need for on/off and extensive part-load operation, a lower cost, less complex, but still highly efficient power system such as a HAT would be the choice. The part load performance of the HAT cycle has been compared to that of a combined cycle; the heat rate of an integrated gasification HAT (IGHAT) remains essentially constant down to 50% load whereas in the case of an integrated gasification combined cycle (IGCC), the heat rate increases by as much as 30% on a single train basis [Rao et.al., 1993].

SCREENING ANALYSIS

NATURAL GAS CASES

The nominal power output for the plant has been selected as 300 MW to be representative of the minimum economic size for central power stations, especially those with gasification. Each of the systems has a gas turbine component. The design values for the turbines used in the screening analyses are given in Table 1. Note that the screening analyses considered a variety of gas turbine and fuel cell configurations and operating conditions. The complex interaction of air/steam/fuel streams often resulted in several configurations for each case that had similar performance, i.e., efficiencies within +/- 2%, well within the "noise" of the analyses. The results presented below are for the configurations with the highest efficiency for each case and may not represent the best configuration when all operating constraints are considered. That is the goal of the next task of this study – a more detailed analysis of selected configurations to identify operability and economic considerations.

Table 1: Gas Turbine Design Basis

Ambient Conditions	ISO
Firing Temperature	$\leq$ 1700 C
Compressor Isentropic Efficiency	$\geq$ 90%

Turbine Isentropic Efficiency	$\geq$ 93%
Turbine Materials	Ceramics and Thermal Barrier Coatings

High Pressure SOFC Integrated with High Pressure Ratio Intercooled Gas Turbine

The system as depicted in Figure 3 consists of an intercooled gas turbine integrated with a pressurized tubular SOFC. Atmospheric air is compressed in an intercooled compressor, comprised of a low pressure compressor (LPC) and a high pressure compressor (HPC). The discharge air from the high pressure (HP) compressor is supplied to the SOFC as its oxidant. The fuel utilization in the SOFC was set at 85%. Desulfurized fuel is humidified in a column where it is counter-currently contacted with hot water. A portion of the water is evaporated into the fuel stream, the heat required for the humidification operation being the heat recovered from the intercooler and the stack gas by circulating water leaving the humidifier. The humidified fuel is then preheated in the turbine exhaust and supplied to the SOFC. The exhaust from the cells, consisting of the depleted air and the depleted fuel is supplied to a combustor that may physically be part of the SOFC system or the gas turbine. The exhaust from the combustor enters the high pressure turbine (HPT) which drives the HP compressor and is expanded to a pressure which is higher than atmospheric. The exhaust from the HP turbine is supplied to the low pressure turbine (LPT) where it is expanded to near atmospheric pressure and then supplied to the heat recovery unit. The LP turbine drives the low pressure (LP) compressor and the generator.

It was determined that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a low air to fuel ratio. If higher air to fuel ratio were used in the HP SOFC, then in order to meet the efficiency goal, an alternate approach consisting of installing a second SOFC between the HP and LP turbines would be required (a "reheat cycle"). This alternative configuration, however, would increase the plant cost and complexity.

The optimum efficiency of the cycle occurred at a pressure ratio greater than 50, while the gas turbine firing temperature was modest, <1200 C. As mentioned above, several configurations resulted in nearly equal performance, e.g., a non-intercooled gas turbine with a pressure ratio of 20 had an efficiency only 0.3 points lower, well within computational error. When efficiency was a toss up, the intercooled gas turbine was chosen because of its higher power density (kW/air flow), a factor that would mitigate the system costs. This is especially true with the hybrid since the optimum cycle efficiency occurs when the only heat to the gas turbine is from the SOFC – the hot exhaust further heated by combustion of the remaining hydrocarbons in the exhaust. Since these temperatures seldom exceeded 1150 - 1200 C, power (kW/air flow) is somewhat limited.

High Pressure SOFC Integrated with HAT

The system as depicted in Figure 4 is similar to the previous case consisting of an intercooled gas turbine integrated with a pressurized tubular SOFC except that it incorporates humidification of the air and the humidified air is preheated in a recuperator in the turbine exhaust before it is fed to the SOFC. The fuel utilization in the SOFC was again limited to 85%. The air leaving the HP compressor is first cooled in an aftercooler and then introduced into the humidifier column where it comes into counter-current contact with hot water. A portion of the water is evaporated into the air stream, the heat required for the humidification operation being recovered from the intercooler and the stack gas by circulating water leaving the humidifier. The desulfurized fuel is also humidified in a similar manner.

It was determined also for this configuration that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a low air to fuel ratio while if higher air to fuel ratios are to be utilized in the SOFC, then in order to meet the efficiency goal, the alternate approach consisting of installing a second SOFC between the HP and LP turbines is required. This alternate cycle configuration as pointed out earlier would increase the plant cost and complexity and was discarded from further consideration.

The optimum efficiency of the cycle occurred at a pressure ratio of approximately 20, which is much lower than the previous case, while the gas turbine firing temperature remained at a modest value of <1200 C.

Atmospheric Pressure MCFC Integrated with Intercooled Gas Turbine

A number of configurations of the atmospheric MCFC were considered including several in which the exhaust of the MCFC was cooled, compressed to gas turbine operating conditions, recuperated and further heated by combusting the remaining hydrocarbons. The configuration with the best performance, however, is that shown in Figure 5. This system consists of an intercooled gas turbine integrated with an atmospheric pressure MCFC. Atmospheric air is compressed in an intercooled compressor, comprised of a LP compressor and a HP compressor. The discharge air from the HP compressor is preheated in a high temperature heat exchanger transferring the heat released from combustion of the depleted fuel leaving the MCFC (MCFC anode exhaust gas). This hybrid case may require a catalytic combustor because the depleted fuel is at lower temperature (typically in the neighborhood of 600C in the case of MCFC versus 1000C in the case of SOFC) and also lower pressure when compared to the SOFC based hybrids. Furthermore, it was found that in order to reach the 75% (LHV) efficiency target for this hybrid case, the fuel utilization had to be increased from the 85% value that was employed in the two SOFC hybrid cases to 90% fuel utilization resulting in a correspondingly lower heating value for the depleted fuel for the MCFC hybrid.

A blower provides the required amount of air for the combustion of the depleted fuel gas; the combustion air being first preheated against the MCFC cathode exhaust gas and then against the combusted depleted fuel gas. This configuration was found to be more efficient than a configuration where the combustion air is also supplied by the gas turbine exhaust; utilizing a separate combustion air blower increases the amount of heat that may be recovered from the cathode exhaust gas. In addition to providing heat for preheating the depleted fuel combustion air, the cathode exhaust gas provides heat for preheating the humidified fuel gas supplied to the MCFC. Preheating of the circulating water for the humidification of the desulfurized natural gas is accomplished by heat exchange against the combusted depleted fuel gas. A portion of the heat rejected by the intercooler is also recovered for the humidifier.

The optimum pressure ratio for the gas turbine from an efficiency standpoint for the proposed selected case was 25 while the gas turbine inlet temperature remained at a modest value of < 1100C.

O_2 Breathing High Pressure SOFC Integrated with HAT cycle

This case as depicted in Figure 6 is similar to the previously described HP SOFC integrated with the HAT cycle except that the SOFC utilizes pure O_2 supplied by an ion transport membrane (ITM) unit [Richards, 2001] instead of air. The exhaust gas consisting of water vapor and CO_2 is cooled by direct contact with circulating water in a dehumidifier after heat recovery, a portion of the CO_2 is purged from the cycle while the remainder is combined with the O_2 supplied by the ITM unit and recycled to the suction of the HAT (assisted by the induced draft fan) in order to moderate the temperature within the SOFC. The CO_2 purged from the cycle may be compressed and to a pressure dictated by the ultimate disposal method chosen for sequestration. For this evaluation, a pressure of 60 bar was used in order to make a direct comparison with the advanced Rankine cycle case described next which produces the CO_2 at 60 bar. This cycle in addition to producing CO_2 also produces water on a net basis for export. The resulting efficiency of the cycle is > 60% on a LHV basis.

The pressure ratio for the cycle and the gas turbine firing temperature were kept at the same values as those for the SOFC/HAT hybrid case. The SOFC operating temperature sets the amount of CO_2 recycled.

Advanced Rankine Cycle Combusting H_2 with O_2

This cycle as depicted in Figure 7 utilizes a high temperature and high pressure reheat steam turbine operating with inlet conditions of 1760C and 222 bar to expand the steam produced by combustion of H_2 with stoichiometric amount of O_2 in rocket engine technology derived combustor [Anderson, 2001]. The H_2 is produced in a steam/methane membrane reformer [Lou, 2001] in which the H_2 chemically diffuses through a high temperature membrane as it is formed. Thus, the membrane reformer not only provides a separated pure H_2 product stream but also drives the reforming reaction to completion since one of the products of reaction (H_2) is continuously removed from the reaction mixture. The O_2 is produced in an ITM unit similar to the previous case. The steam turbine is similar to the turbine of a gas turbine because of the very high temperature of the working fluid. Both the HP and the reheat combustors utilize water injection to moderate the combustion temperature.

The CO_2 is recovered from the membrane reformer effluent for export at a pressure of 60 bar. The resulting efficiency of the cycle is 52% on a LHV basis.

COAL-BASED SYSTEMS

Analyses of coal-based systems have been initiated. These analyses include consideration of a co-production system that provides both electrical power and high value chemicals. The cycle configurations for the gas-fueled systems form the basis the coal-fueled systems. These power cycles are coupled with a coal gasification process to form an integrated power plant.

Gasification System Technology

There are a number of integrated gasification combined cycle (IGCC) power plants in operation or under construction. These systems for the most part are using gasifiers based on technology developed by Texaco (now Chevron-Texaco) and Shell. These gasifiers are oxygen-blown entrained flow types. They operate at temperatures above the slagging point for the feed coal, generally in the 1350 – 1450 C (2500-2700 F) range. The Texaco solids gasifier is fed coal as a coal-water slurry while the Shell gasifier is fed coal in a dry (carrier gas) form. Both systems have advantages, depending on the end use of the product synthesis gas. Prior studies carried out by the team members have indicated that the Shell type gasifiers are generally somewhat more efficient (burn 1 to 2% less feed) than the Texaco-type gasifiers. This is mainly due to the evaporation of the slurry water which utilizes the chemical energy of the coal in the Texaco gasifier.

There are other gasification technologies that are being developed, but not yet commercial, that may offer better efficiency. These are generally of the fluid bed type that operate with air, versus oxygen, and have bed materials that can help in the sulfur removal process. Of particular interest are two versions of the circulating fluid bed gasifier being developed under DOE sponsorship. These are the Foster Wheeler (F-W) Partial Gasifier and the Advanced Transport Reactor. These gasifiers operate with temperatures usually ranging from 900 C to 1000 C (1650 F to 1830 F).

Approach in Selecting Gasification Technology

As in the case of the gas-fired systems, the analyses of the coal-fueled systems were first done with technology that is commercially available; e.g., the oxygen-blown entrained flow Texaco slurry and the Shell dry feed gasifiers. Selexol or Rectisol low-temperature cleanup were also considered. The major reason for this is that if the DOE goals can be attained with some of the major gasification and cleanup system components requiring little or no additional development, the overall system risk would be reduced.

The two other gasification technologies included, the Foster Wheeler Partial Gasification process and the Advanced Transport Reactor unlike the entrained flow gasifiers are air blown, requiring very close coupling of the power system and the gasification system. These gasifiers operate at lower temperatures and offer the potential for higher overall system performance compared to the entrained flow gasifiers.

The simulation models of the F-W partial gasifier are based on information received from Foster Wheeler. Repeated requests have been made to Kellogg, Brown and Root for information on operation of the ATR gasifier at Wilsonville, Alabama on bituminous coal. A preliminary model of the this gasifier has been constructed using information and data on a laboratory-scale version of the ATR operating at the University of North Dakota operating on sub-bituminous Western coals and on lignite.

Syn-Gas Cleanup

In the operation of the SOFC on natural gas, the primary concern for the fuel cell is the sulfur content of the fuel. For pipeline natural gas, the sulfur content is usually quite low because of corrosion considerations in the pipeline and it can be specified for values on the order of 4 ppmv. Prior to use in the SOFC, the sulfur must be reduced to the 0.1 ppmv level. This can be done by passing the gas through an adsorption bed, typically activated carbon operating at room temperatures or zinc oxide operating at around 350 – 400 C (660 –750 F).

In the case of coal gasification, there are considerably more potential contaminants than sulfur. These include particulates/dust, ammonia and other nitrogen-bearing compounds, alkali metal vapors, and trace elements such as Hg and Se. Also, because the gas from the gasification process is at elevated temperature, possibly as much as 1000 C (1800 F), it would be thermodynamically advantageous to clean it at high temperature.

Low Temperature Cleanup

The cleanup of synthesis gas to very low levels of sulfur, particulate, alkalis, etc. has been carried out in petrochemical operations for many years. The gas is cooled and particulates removed by water scrubbing and sent to a COS hydrolysis unit where the COS is converted to H_2S. Any HCl and essentially all the ammonia in the gas stream are also captured in this process in the water scrubbing operation. The gas is then sent to the sulfur cleanup section where the H_2S is removed. Generally amine or ether based absorber-stripper processes are used. These systems work at low temperatures, < 40 C (100 F), and require the cooling of the synthesis gas thereby losing some of the sensible heat in the stream. While the majority of this heat is recovered either by recuperation or by raising steam, there is a modest thermodynamic penalty. The sulfur removal from these systems is generally sufficient for subsequent use in a gas turbine (say < 10 ppm), but not for use in a SOFC. As in the case of natural gas, a final ZnO polishing process would be included for that purpose. If Retisol, a refrigerated methanol based system is used, deep sulfur removal can be achieved without the need for ZnO treatment. The Rectisol unit, however is very expensive and typically an amine or a Selexol based system with ZnO treating is more cost effective.

The acid gas from the low temperature cleanup is sent to a Claus plant where the sulfur compounds are converted to elemental sulfur. The tail gas from the Claus plant is then sent to a Scot unit for further sulfur recovery.

The foregoing low temperature systems have operated with demonstrated efficacy in numerous applications including IGCC plants. In our simulations, we have developed modules that represent the operation of the Selexol process including utility requirements. For this part of the study, the Claus and Scot processes are simply additional utility loads.

High Temperature Cleanup

In the past several decades, considerable effort has been devoted to developing medium (~ 400 C –750 F) and high temperature (> 400 C –750 F) particulate and sulfur cleanup systems for use in IGCC plants. Generally, these cleanup systems are, in themselves, not adequate for use with the SOFC in that sulfur levels are in the 10’s of ppmv, two orders of magnitude above the SOFC requirement. It is only in the last several years that effort has been given to considering cleanup systems for use with SOFC’s. Requests were made to DOE to provide information on these cleanup systems; at this time, no information has been received. A survey of the literature has identified two approaches that are aimed at fuel cell applications: an Ultra-Clean Gas Cleanup Process proposed by Siemens Westinghouse and an Integrated Modular Approach championed by Research Triangle Institute that uses membranes and ZnO for sulfur and sorbents for chlorine and nitrogen removal. Neither of these processes have sufficient detail in the available reports to allow more than high-level representation. In our models, they are simply represented by pressure drops and, where data are available, by temperature changes. It is assumed that the cleanup required by the SOFC can be attained in these systems at the desired temperature level. The next task will address this issue in more detail, given that information is received from DOE.

Configuration Analysis – SOFC Hybrids

As previously mentioned, the analyses of the hybrid power systems begins with use of as much existing technology as possible to reduce the technical risk. Thus, the first attempts at the IG/Hybrid were undertaken using commercial gasification. Because of the additional complexity of the power plant with gasification, process diagrams identifying components and process interconnections were prepared.

As with the natural gas cases, a variety of GT configurations and pressure ratios were evaluated. The best results are with the configurations shown in Figure 8 and 9. Note that the performance of the system with low-temperature cleanup is essentially the same as that of the system with the high-temperature cleanup. Again, this is in line with prior studies that have shown that low-temperature cleanup can regain nearly all of the thermodynamic advantages of the high-temperature cleanup. It does require more heat exchangers and other equipment than the high-temperature system. Furthermore, the heat exchange equipment should consist of a design incorporating double tube sheets and special welds between the tubes and the tube sheets to avoid leakage of the raw syn gas into the clean syn gas (leak detection devices would be prudent to add). An added advantage is that CO_2 may be removed during the clean up process at significantly reduced thermodynamic penalty and reduced costs.

Since coal-based configurations with the commercially available gasifiers have not reached the DOE goal, a newer gasifier type being developed under DOE sponsorship, the Advanced Transport Reactor circulating fluid bed gasifier has been investigated as a possible component. Unlike the commercial applications of the entrained flow gasifiers, these gasifiers are air blown, requiring very close coupling of the power system and the gasification system. These fluid bed gasifiers operate at lower temperatures and offer the potential for higher overall system performance compared to the entrained flow gasifiers as long as comparable carbon conversions may be achieved.

A model of the ATR gasifier continues to be developed based on information and data from a laboratory-scale version operating at the University of North Dakota. These data are for lignite and western sub-bituminous coals and the model is being extended to coals such as Illinois No. 6 using information from the open literature. Requests to DOE contractor Kellogg, Brown and Root for information on the PDR/ATR gasifier at Wilsonville, Al have not resulted in data other than those in the open literature. The model is being modified to consider bed material reactions.

One down side of lower temperature gasifiers is that the carbon conversion is not 100%, except in the case of very reactive materials. With sub-bituminous coals, a carbon conversion of around 95% is attainable and a value of 98% is potentially possible. With bituminous coals, the value is around 92% with a potential of over 95%. The latter value was used in our analyses. The unburned char is combusted in an atmospheric pressure fluid bed and the heat used in the cycle.

A flow sheet for the ATR configuration is shown in Figure 10. In this configuration, air is extracted from the gas turbine compressor discharge, further pressurized, and sent to the gasifier. The resulting syn gas has a LHV of ~ 4.1 – 4.5 MJ/m^3 (110-120 Btu/ft^3) and is at a temperature of 955 C (1750 F). This gas is cooled by superheating and reheating steam, sent to a high temperature filter desulfurizer (e.g., the Siemens Westinghouse

Ultra-Clean system) at approximately 650 C (1200 F) and then to the SOFC. The air for the SOFC is supplied at approximately 535 C (1000 F) from the GT compressor discharge.

Since much of the reforming reactions take place during gasification, there is little or no reforming in the gasifier and the heat balance (cooling) must be accomplished with excess air. Whereas in the gas-fired SOFC, the heat required by methane reformation reduced the SOFC cooling load, thus, the gas-fired SOFC could run closer to stoichiometric. In the syn gas cases, more excess air is required. Another way of looking at this is that for a given amount of air (GT flow), less of the air is available for reaction (heat producing) because it must be used to cool the SOFC. This reduces the fraction of overall power produced by the SOFC. Nonetheless, the air-blown ATR hybrid has an efficiency above the DOE goal of 60%.

In an attempt to increase SOFC participation (more air/oxygen for reaction) and, hopefully, the efficiency, oxygen enrichment was investigated. The configuration is shown in Figure11. It is similar to the previous configuration with the exception that an ASU supplies oxygen to enrich the compressor discharge. Two cases were investigated: air enriched by 50% and all oxygen. In the 50% case, the fuel cell increased participation by 9% and the gross efficiency increased by 1.5 points. However, the net efficiency (60.7% HHV) was lower as the ASU consumed additional power. The same occurred with all oxygen, i.e., a 21% increase in SOFC output. The gross efficiency increased, but the net decreased (59.7% HHV) because of the larger demand of the ASU. The air-blown system appears to be the better choice as the performance is higher than the oxygen-blown versions and the cost should be significantly less.

Because of the simplicity of construction and the lower temperatures involved, the ATR gasifier should be significantly lower in cost than entrained flow gasifiers. Also, since oxygen blowing is not particularly advantageous, costs will be further reduced. By putting limestone or dolomite in the ATR as bed material, the sulfur loadings to the cleanup system are reduced and reactions in the gasifier essentially eliminate alkali metal vapor emissions and also reduced chlorides.

Foster Wheeler has provided a great deal of information on their process consisting of a partial gasifier and char combustor. The lower carbon utilization in the F-W partial gasifier requires a more sophisticated char combustor than the ATR. Using their gasifier descriptions, three cycle configurations were initially identified for consideration:

1) FW gasifier/SOFC/"F" level GT technology
2) FW gasifier/SOFC/low temperature GT
3) FW Gasifier/SOFC/ATS level GT/HITAF

After a preliminary analysis, it was decided that Configuration 3 (Figure 12) was the same as that already examined by F-W and thus, full analysis would not be repeated herein. Also, this configuration uses a steam-cooled SOFC and it was decided among the team members that only air-cooled versions of the SOFC would be considered considering the developmental nature of a steam cooled SOFC.

In configuration 1, a portion of the cleaned syn gas stream is diverted from in front of the fuel cell and sent to the gas turbine combustor to provide enough energy to reach the desired combustor outlet temperature. While F-W has supplied considerable data, it was still necessary to develop a gasifier model and validate it using the supplied information. The gasification reactions are essentially the same (steam/oxygen/carbon equilibrium and shift), but the fluid bed gasifiers (including the ATR) have bed material that can enter into the reactions, both in the reactor and in subsequent carbon burn up devices. These reactions have been incorporated into the gasifier representation. Since these reactions consume oxygen, they do have an affect on the subsequent SOFC and GT performance, albeit small.

In the F-W partial gasification system, all the compressor discharge air is sent to a booster compressor and then split, some going to the gasifier and the remainder to a circulating flow, pressurized fluid bed combustor (CPFBC) that burns the large char fraction (approximately 20% un-reacted carbon) from the partial gasifier. The fuel gas is cleaned at high temperature, as is the air exiting the CPFBC. The fuel gas and the heated air are combusted and expanded in the gas turbine expander. In the hybrid version of configuration 1, the heated air and majority of the fuel gas are sent to the SOFC where they react to produce electricity. The SOFC exhaust has some unburned hydrocarbons and excess oxygen, which react to raise the temperature of this stream. This combusts with the fuel fraction sent to the GT to raise the flow temperature to the GT design point. The efficiency is estimated to be 54.4 % (HHV). This includes losses for coal preparation, cleanup, and internal compression.

A variation of this configuration, configuration 2 was then investigated. Prior analyses have shown that the highest efficiencies occur when all the fuel is used in the topping portion, i.e., the SOFC. Thus, an unfired version was analyzed. Here, all the fuel gas is sent to the SOFC and the GT temperature is that resulting from combusting remaining fuel components in the SOFC exhaust. This system has an efficiency of 54.8%, marginally better than the fired version.

With both heated air and heated fuel being sent to the SOFC, cooling becomes an issue. The team has defined the method to cool the SOFC as excess air and by using some of the SOFC heat to reform the hydrocarbons present in the syn (fuel) gas. As previously described with the other gasifiers, there is not enough methane fraction to adequately cool the SOFC without high excess air. Thus, SOFC participation (amount of fuel "burned" in the SOFC) is limited, i.e., the syn-gas fueled SOFC's cannot be run as near to stoichiometric conditions as the methane fueled systems. The issue with the F-W partial gasifier with the air-cooled SOFC is how to best use the heat represented by the char.

The partial gasifier produces two energy streams, a primary energy stream represented by the syn gas and a secondary stream, the char. The primary stream can be used in the SOFC, whereas the secondary stream could be used in various parts of the cycle, depending on how it is recovered. For a typical case, the energy is:

Q in coal (HHV)	100 Btu
Q Product Gas (LHV)	63.5 Btu
Q Char burner	19.6 Btu
Q to power system	83.1 Btu

Since the hot pressurized air, especially air that has to be clean of particulates, alkalis and sulfur, has no benefit, other configurations are possible. Instead of the CPFBC, a configuration using an atmospheric fluid bed combustor (AFBC) has been defined. The use of an AFBC simplifies the system. There is no longer a need for high-pressure transport of hot char from the gasifier to the char combustor, nor is there a need for the highly efficient cleanup of hot air from the PFBC prior to going to the SOFC. The down side is that the AFB would probably operate with bed temperatures of 850 – 900 C (1560 – 1650 F) to maximize sulfur capture in the bed. This limits the bed coolants to 815 – 840 C (1500 – 1550 F). The air and the steam for the gasifier are heated in the AFB char burner, leaving the majority to be recovered as steam for use in the steam bottoming cycle. In this case, the heat to the power system is:

Q in syn gas	76% of total available
Q to gasifier (air and steam)	5% of total available
Q to steam cycle	19% of total available

Once again with this configuration, a series of analyses were made to determine the best efficiency. The fuel flow was split between the SOFC and the GT burner. For a given fuel split, steam flow was varied. The steam is heated and partially evaporated in the HRSG, then sent to the char burner where it is fully evaporated. The fuel gas from the gasifier is cooled by superheating this stream. After expansion, the steam is reheated in the char burner. As steam flow is reduced, the fuel gas temperature increases limiting the amount of power from the fuel cell (cooling limit). At any given fuel split, the performance would increase, peak, and then decrease as steam flow was varied. The highest performance was obtained when all the fuel went to the SOFC and steam flow was adjusted to the point of maximizing efficiency. Since maximum use of the fuel is taking place, any cycle efficiency gains rest with the steam cycle. With the 165.5-bar/565 C/565C (2400 psi/1050 F/1050 F) steam cycle, the system performance was 59.3%. An advanced supercritical steam cycle 310 bar/565 C/565 C (4500 psi/1050 F/1050 F) was used and the efficiency climbed to 60.5%, meeting the DOE performance goal. Using the steam system that F-W has in their analyses, 414 bar/705 C/705C/705 C (6000 psi/1300 F/1300 F/1300 F) the efficiency reached 61.7%. Thus, the F-W partial gasifier with char burner has the potential to reach the DOE goal. Additional analyses would no doubt identify a more modest steam system that would allow the F-W system to reach the 60% goal.

Configuration Analysis - CO_2 Recovery

The two CO2 recovery configurations considered with natural gas also have been selected as candidates for use with coal gasification. Preliminary analyses have been undertaken for these systems, but at this time no performance figures are available. This is in part due to the great complexity of these systems and in part because they depend on membrane separators for which we have insufficient data at this time. For example, Figure 13 shows the preliminary flow sheet for Clean Energy Systems advanced Rankine cycle configuration. Since the goal of the configuration is to isolate CO_2 for subsequent sequestration, it would seem appropriate to recover the CO_2 at pressure, rather than from the exhausts of the power equipment as proposed by CES. This means that the syn-gas must be shifted and the H_2 separated for use in the CES combustors and also for use in the combustors of the ITM that supplies the O_2 for both gasification and for combustion in the CES system.

A shift-separator is the device chosen to supply the H_2. Information has been requested from DOE on this device, but not yet received. Our model is based on information obtained from various sources in the literature and may not reflect the best component performance. The syn gas is cooled and cleaned in a Selexol system that also removes CO_2 as well as the sulfur compounds, etc. This is done at pressure (approximately 30 bar) providing one HP stream of CO_2. The syn-gas stream is reheated to > 450 C (810 F) and sent to the shift-separator, which is based on use of a palladium membrane. Here the shift reactions go to equilibrium since H_2 is continuously removed through the membrane. At this time, we are assuming essentially 100 % H_2 removal. This means that the nonpermeate consists of water and CO_2 only. The H_2 stream is also 100% pure.

The H_2 stream is then split, one stream going to compressors where it is raised to 103 bar for use in the HP combustor of the CES system, another recompressed to GT combustor level, a third stream is let down to the pressure of the reheat combustor in the CES system, another goes to the combustor in front of the ITM, with the remainder going to the second reheat combustor in the CES system.

Similarly, the permeate O_2 stream from the ITM is compressed from exit pressure (assumed to be ~ 0.5 bar) to a number of levels. The major portion is compressed to the 103 bar level for the CES combustor. Another stream is compressed to ~ 30 bar for the gasifier. Other streams go to the two reheat combustors at the requisite pressure levels.

The key to the system performance is the H_2 membrane separator. If significant H_2 flow is in the nonpermeate, the coal flow and associated gasification equipment must be increased resulting in both a performance and cost penalty. If that flow is too high, a value yet to be determined, but probably >10%, then the configuration would be changed and the carbon bearing fuels burned in the various combustors and the resulting CO_2 removed at atmospheric (ITM exhaust) and sub-atmospheric (CES condenser) pressure and compressed to the desired recovery pressure. This compression power would be considerably greater than that required if the CO_2 were removed as originally configured.

The second system with CO_2 recovery is an IGHAT/Hybrid. A preliminary flow for this configuration is shown in Figure 14. In this configuration, a GT compressor supplies air used in the ITM where O_2 is separated. The O_2 stream at ~ 0.5 bar and 855 C (1575 F) is cooled and compressed to 1.1 bar and a part of the stream is sent to a mixer where it is mixed with the recycle CO_2 and subsequently compressed in the HAT compressor. The remainder of the O_2 stream is compressed to >30 bar for use in the gasifier.

Coal is prepared and sent to the Shell gasifier under a blanket of recycled CO_2. The syn-gas is cleaned in a low temperature system. The fuel gas, cooled by recycle gas and by raising steam, goes to a COS hydrolyzer and part is recycled for cooling with the rest going to the Selexol system where the sulfur is removed and part of the CO_2 is removed at pressure. The fuel gas is further cleaned of sulfur in a ZnO bed and sent to a fuel gas saturator for humidification prior to use in the SOFC.

The compressed CO_2/O_2 mixture is sent to a humidifier, saturated and then regenerated against the GT exhaust before going to the SOFC. The SOFC exhaust products are then expanded in the GT.

Configuration Analysis – Fischer-Tropsch Systems

The last coal-based system to be considered couples a Fischer-Tropsch (F-T) process with an advanced power system to provide both power and high value chemicals. A final configuration for this system has not yet been determined, but a general process diagram has been prepared, see Figure 15. The fuel gas has to be cleaned very thoroughly for the F-T process, as is the case of the SOFC. There is also a question of what fuel will be sent to the power system as it is possible to use some intermediate from the F-T as a GT fuel. The final configuration will also consider operating scenarios as in some schemes the F-T will operate in base load manner while the power system must respond to grid requirements.

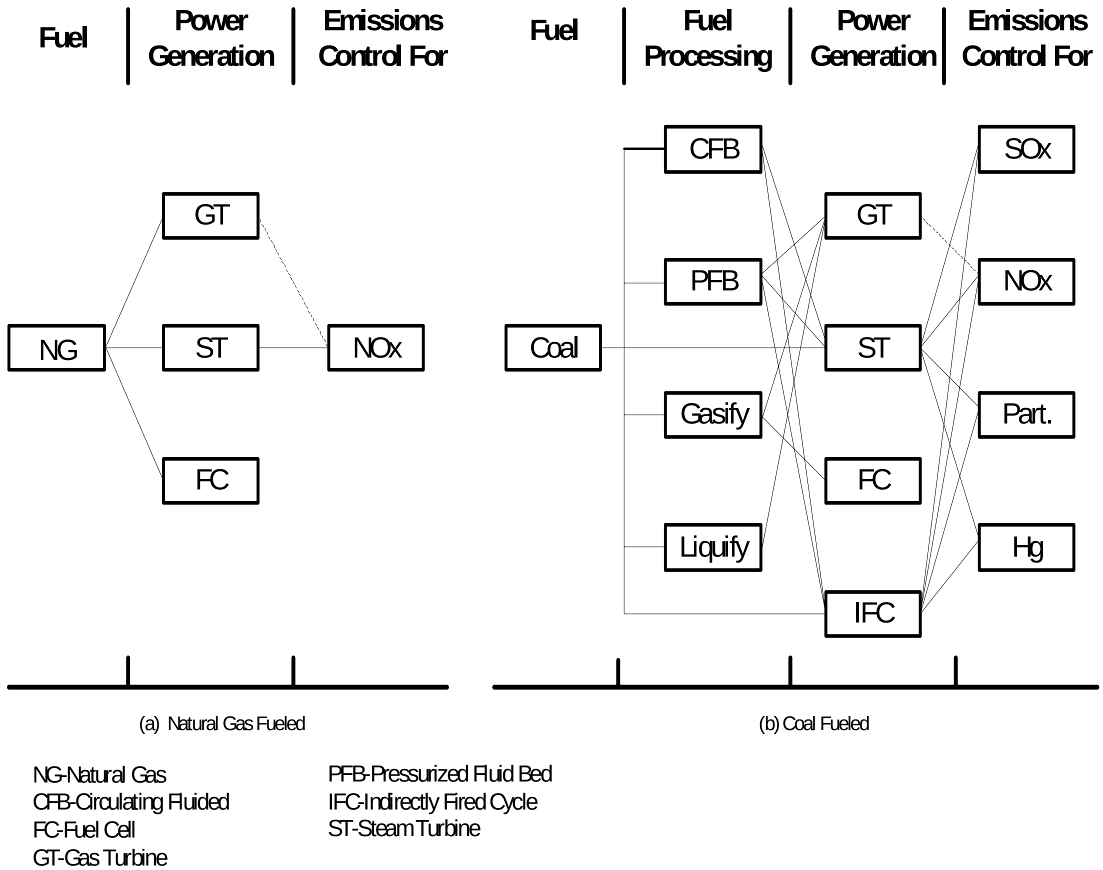

FIGURE 1 – SUB-SYSTEM SELECTION

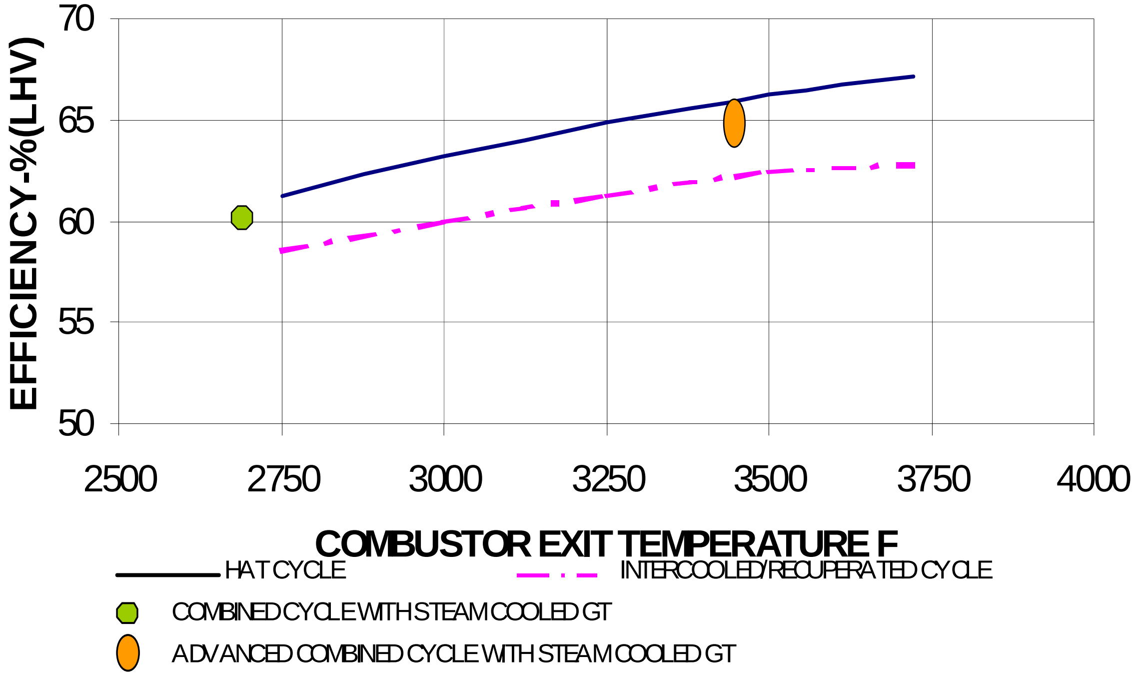

FIGURE 2 – THERMAL EFFICIENCY OF VARIOUS GAS TURBINE BASED CYCLES

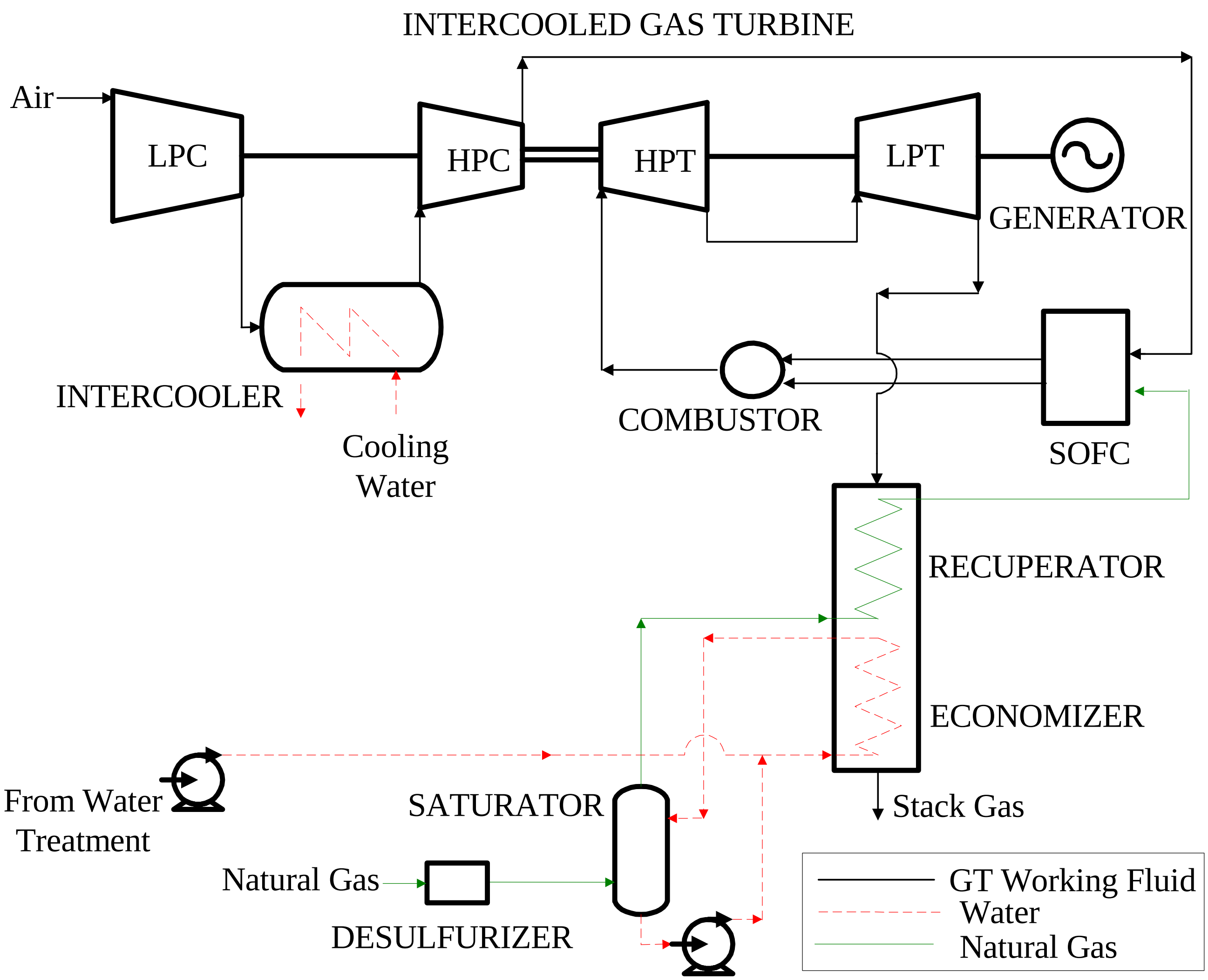

FIGURE 3: HIGH PRESSURE SOFC/INTERCOOLED GAS TURBINE HYBRID

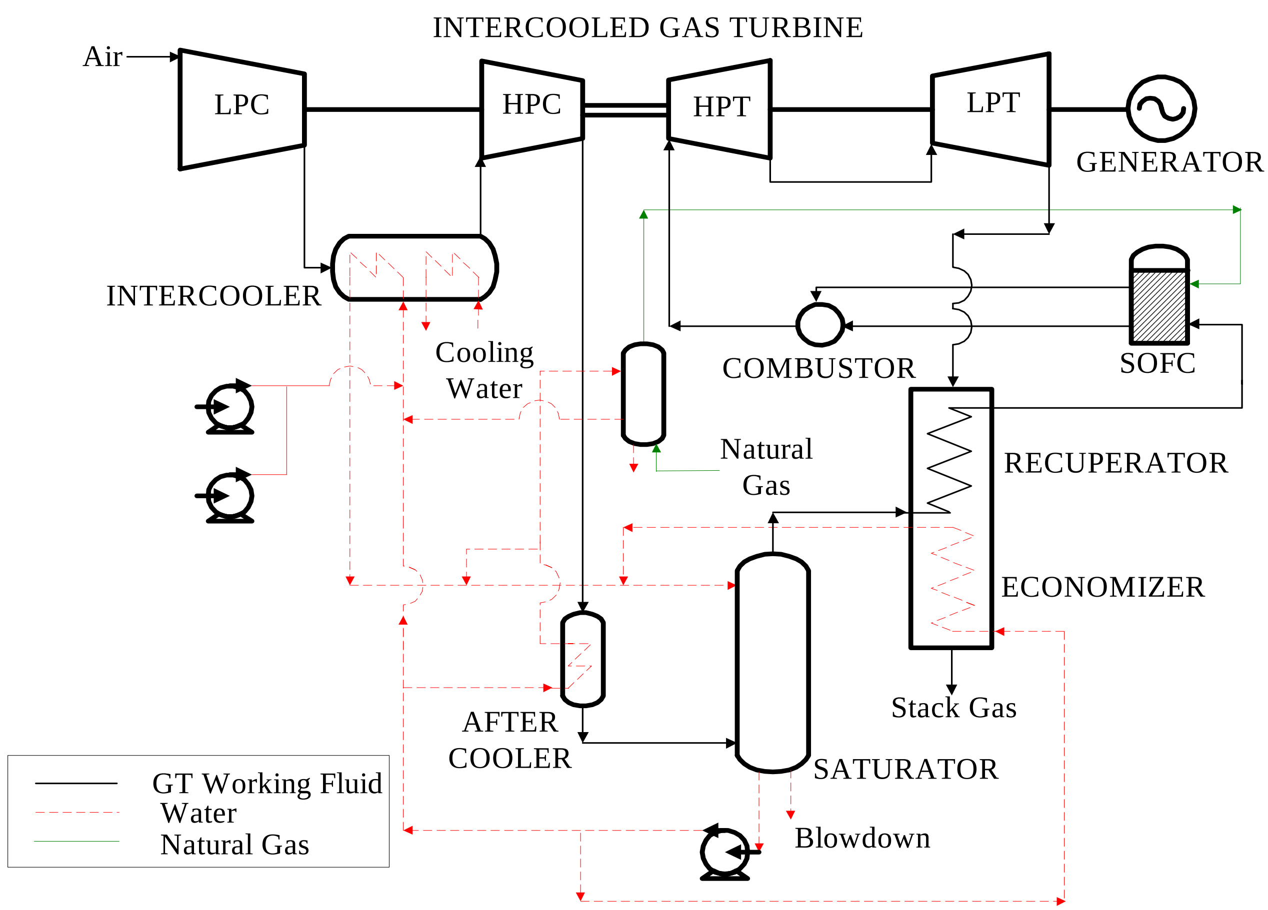

FIGURE 4: HIGH PRESSURE SOFC/HAT HYBRID

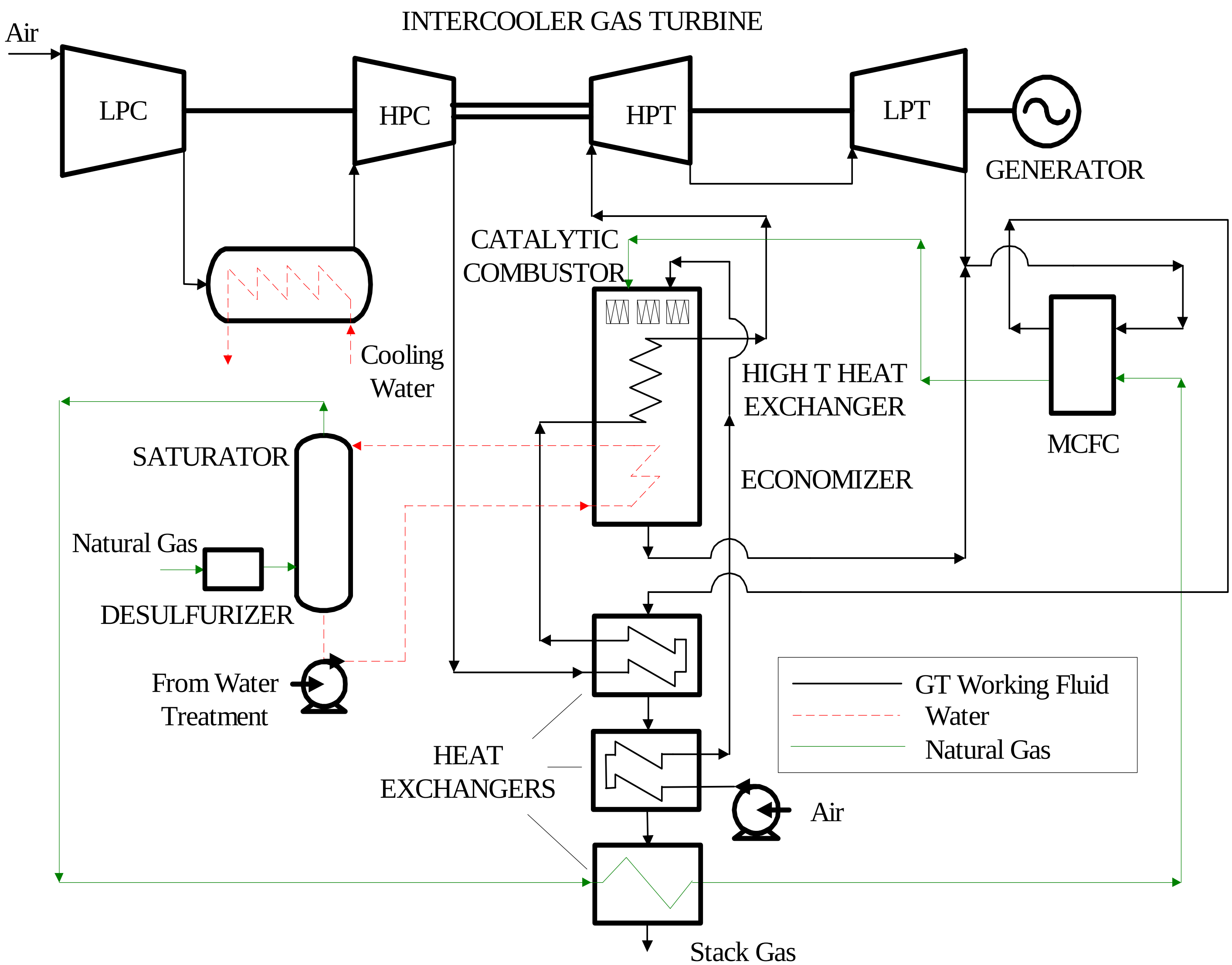

FIGURE 5: ATMOSPHERIC PRESSURE MCFC/INTERCOOLED GAS TURBINE HYBRID

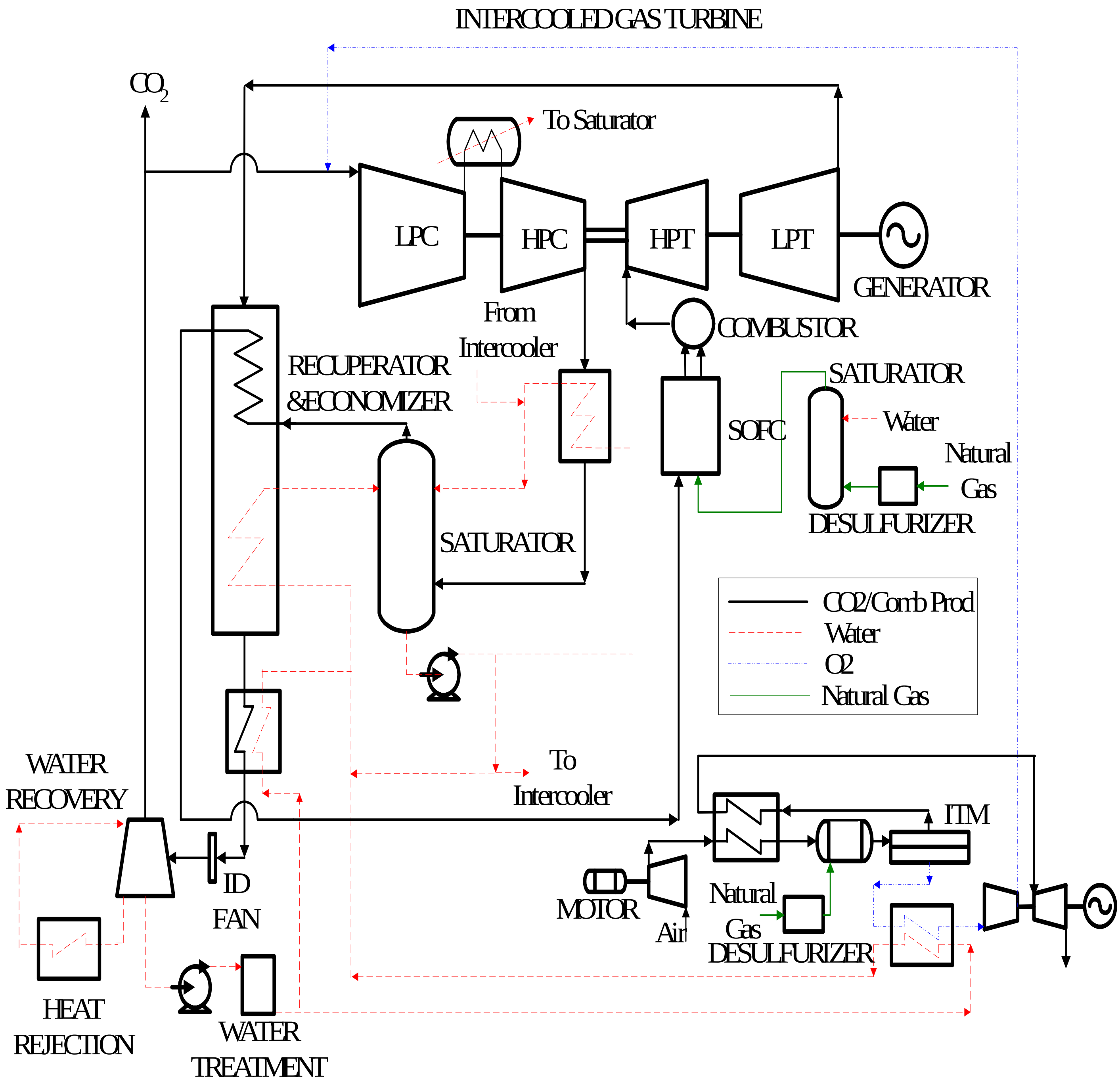

FIGURE 6: O_2 BREATHING HIGH PRESSURE SOFC/HAT HYBRID WITH CO_2 RECYCLE

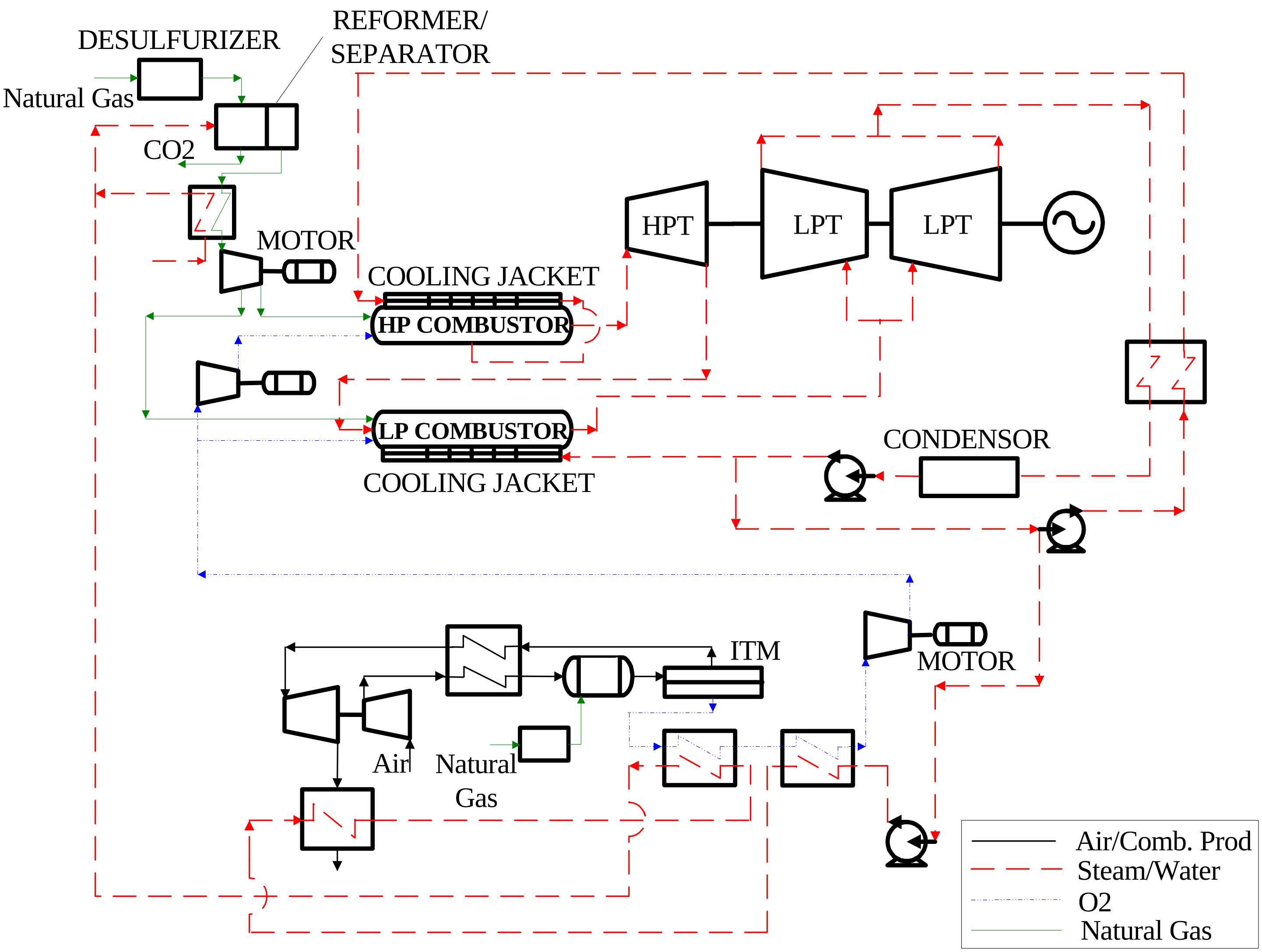

FIGURE 7: ADVANCED RANKINE CYCLE/COMBUSTING OF H_2 WITH O_2

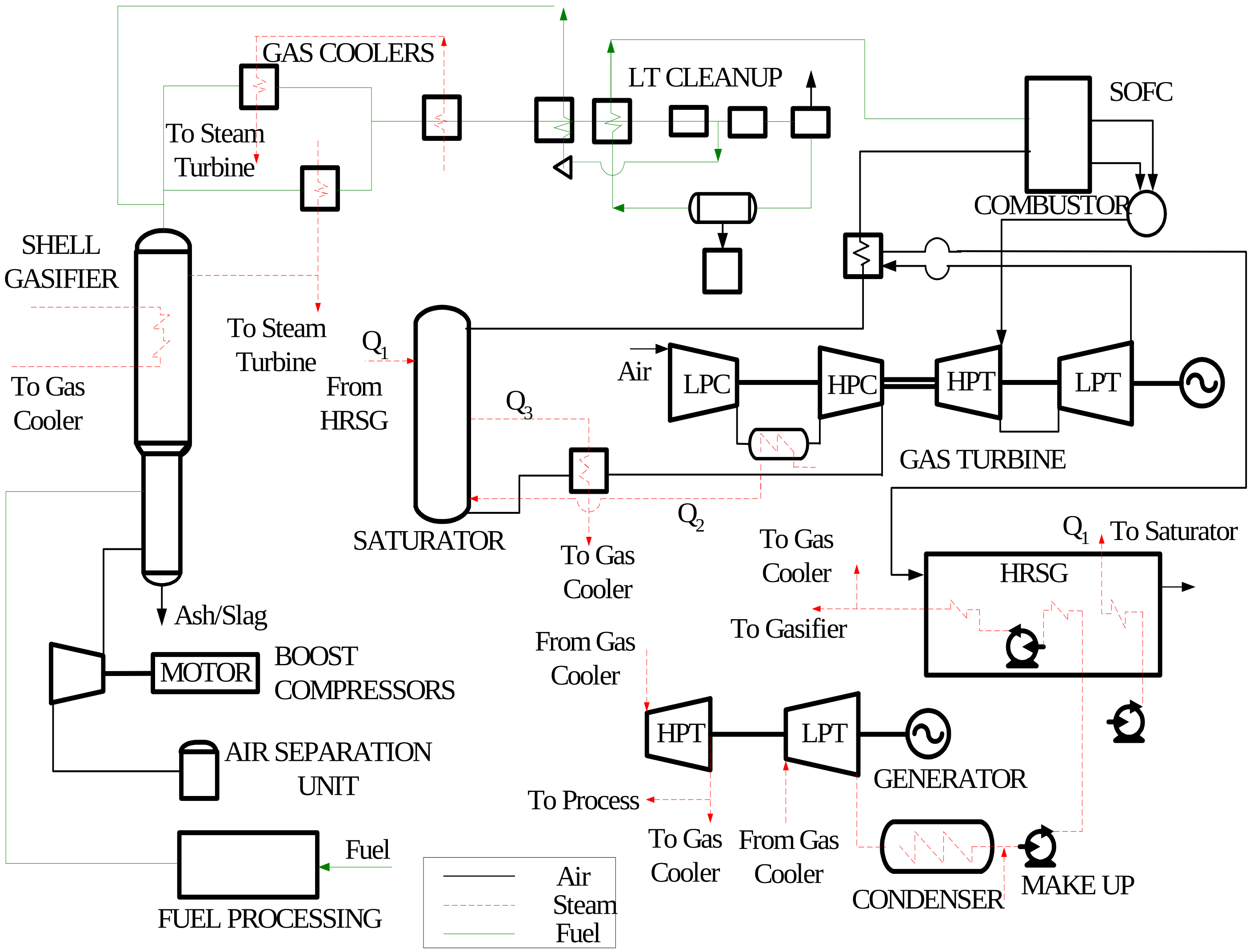

FIGURE 8: SHELL IGHAT HYBRID WITH LT CLEANUP

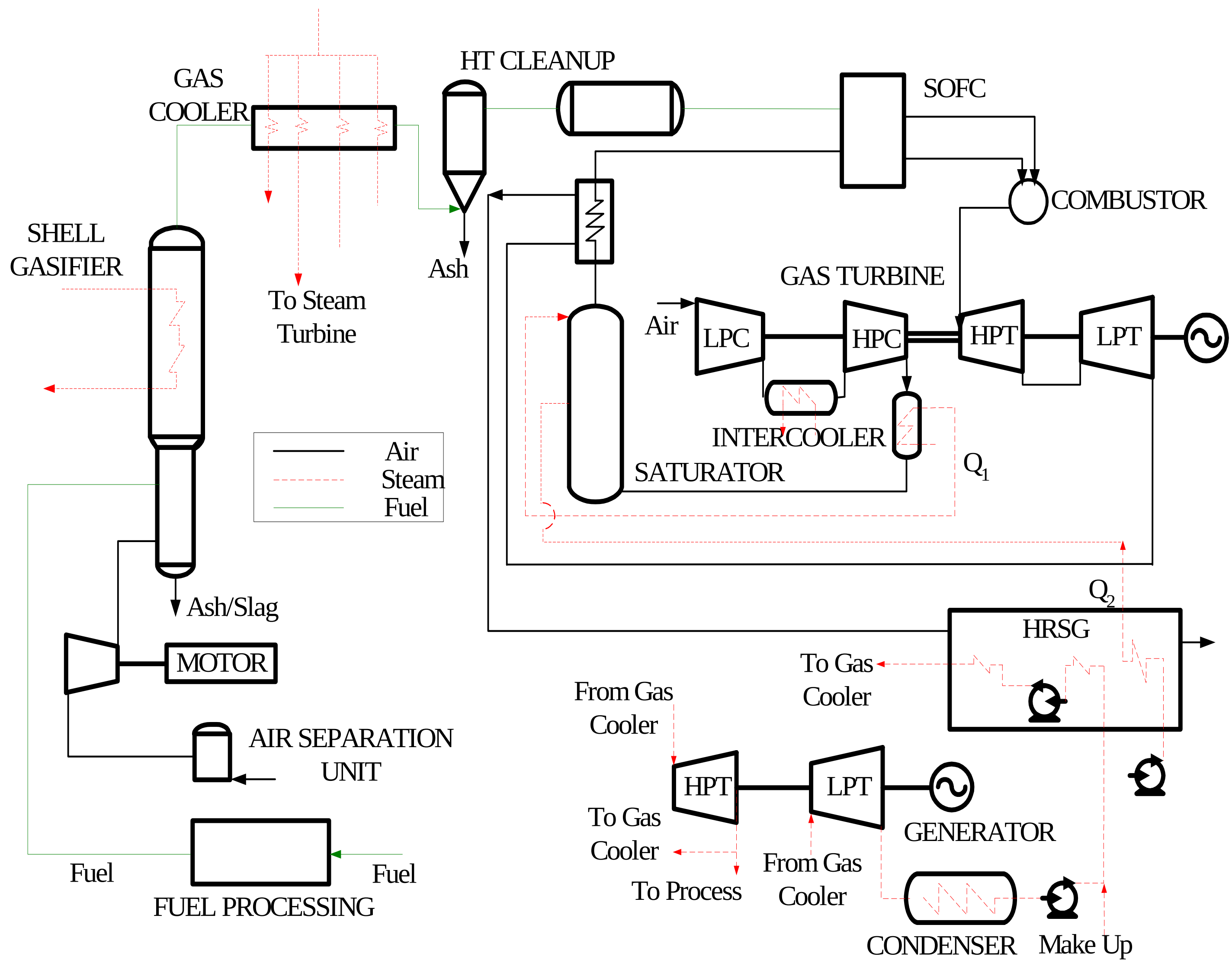

FIGURE 9: SHELL IGHAT HYBRID WITH HT CLEANUP

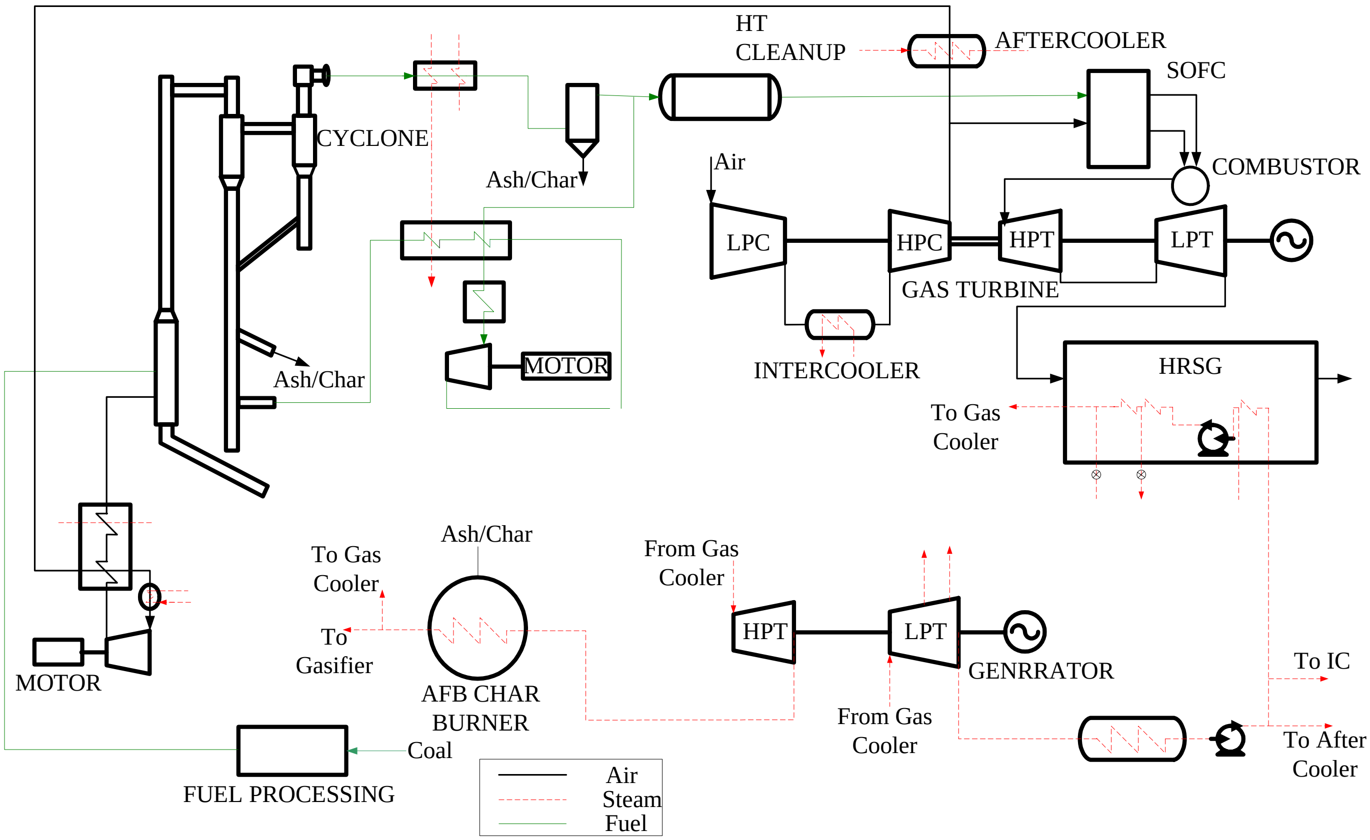

FIGURE 10: AIR BLOWN ATR CC HYBRID

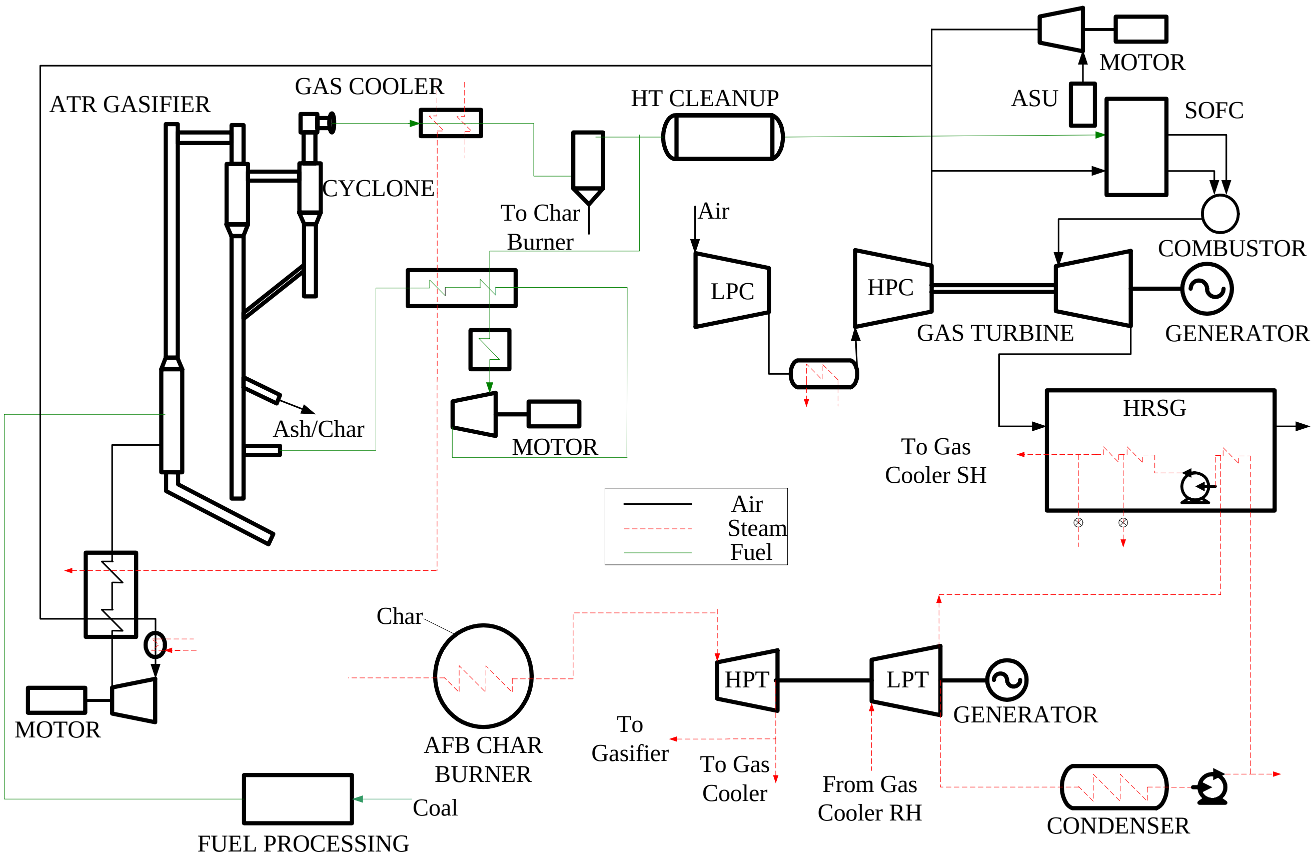

FIGURE 11: OXYGEN ENRICHED ATR CC HYBRID

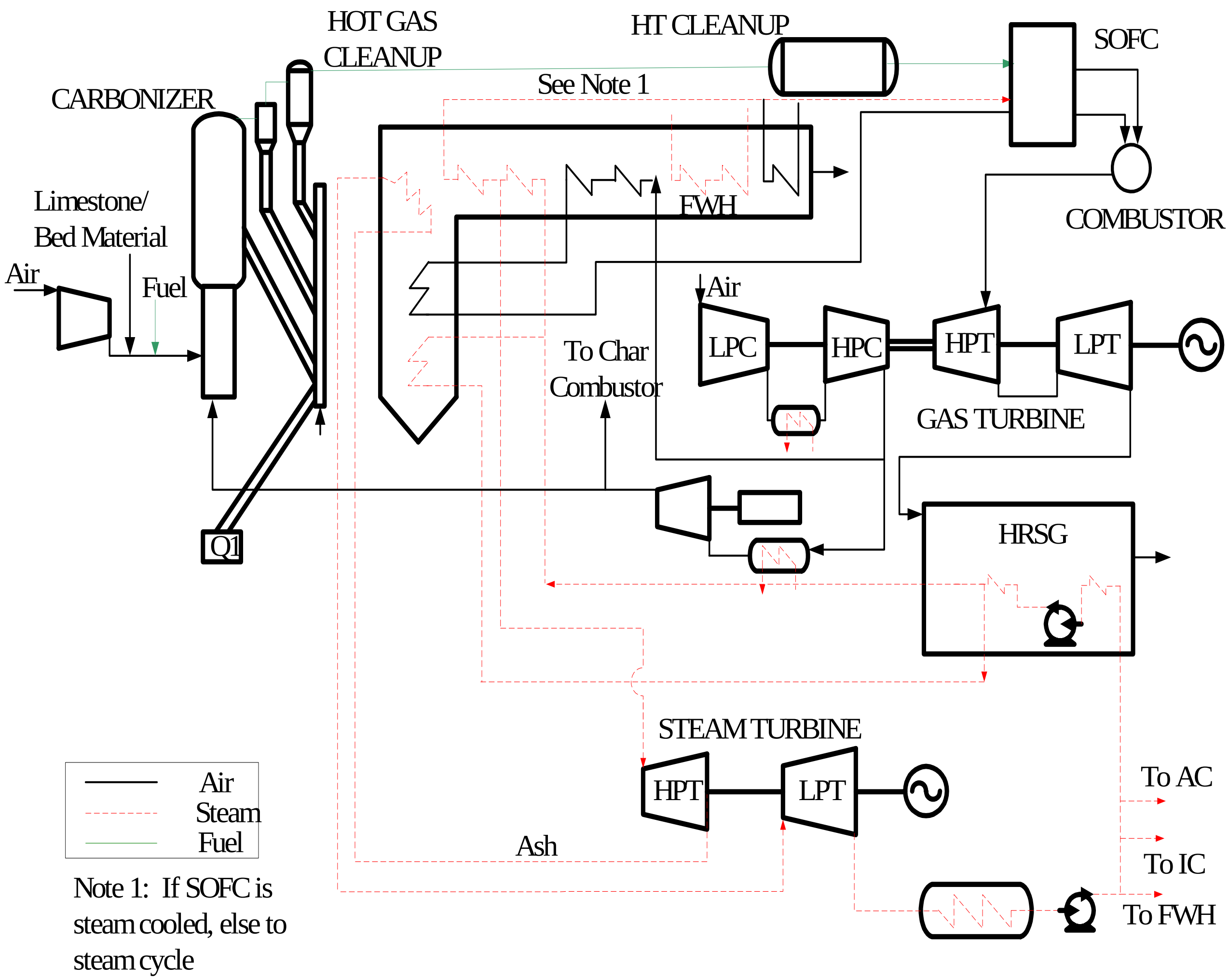

FIGURE 12: FOSTER WHEELER PARTIAL GASIFIER WITH AFBC AND UNFIRED GT HYBRID AND HITAF

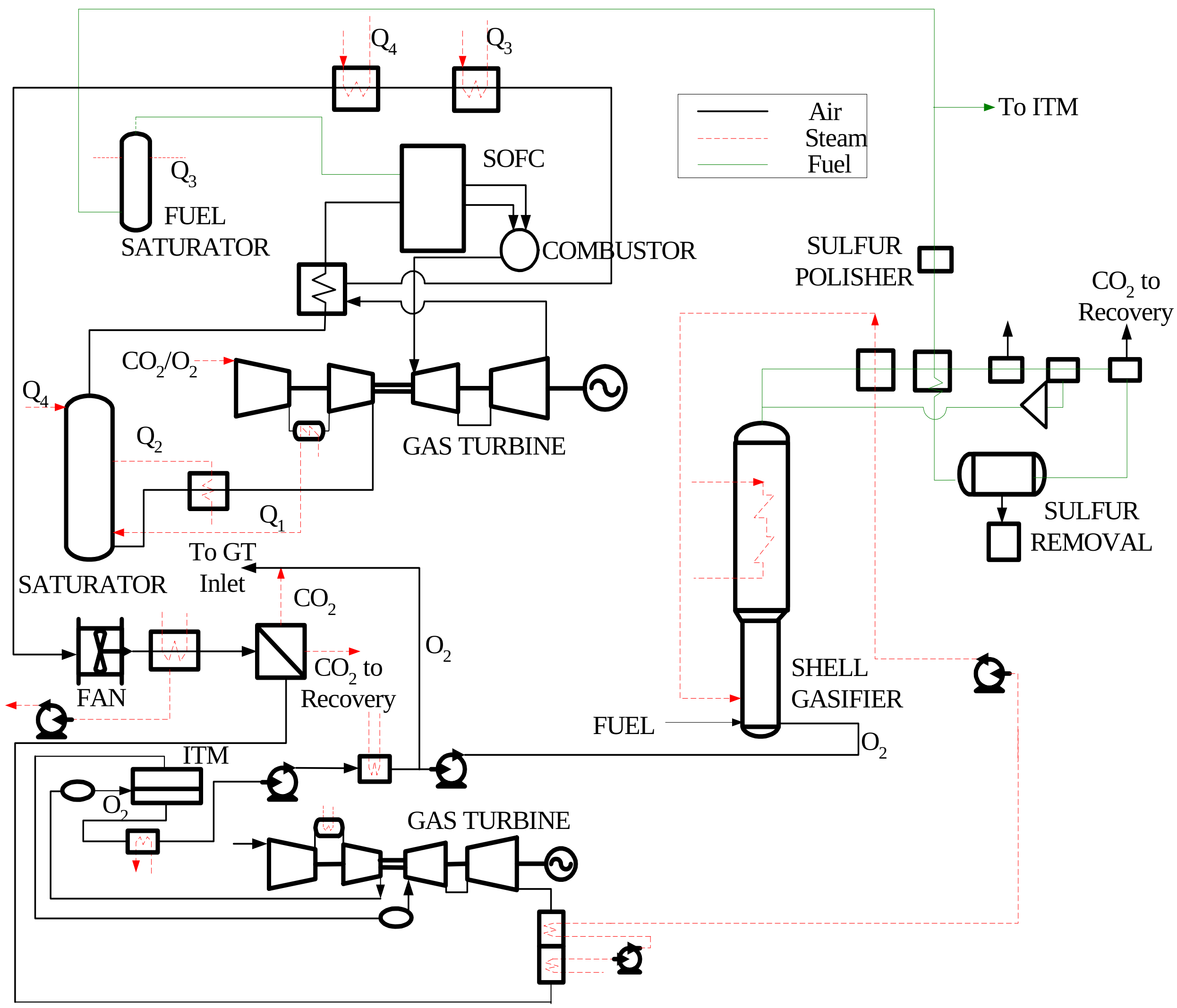

FIGURE 13: SHELL GASIFIER CES ADVANCED RANKINE CYCLE WITH CO_2 RECOVERY

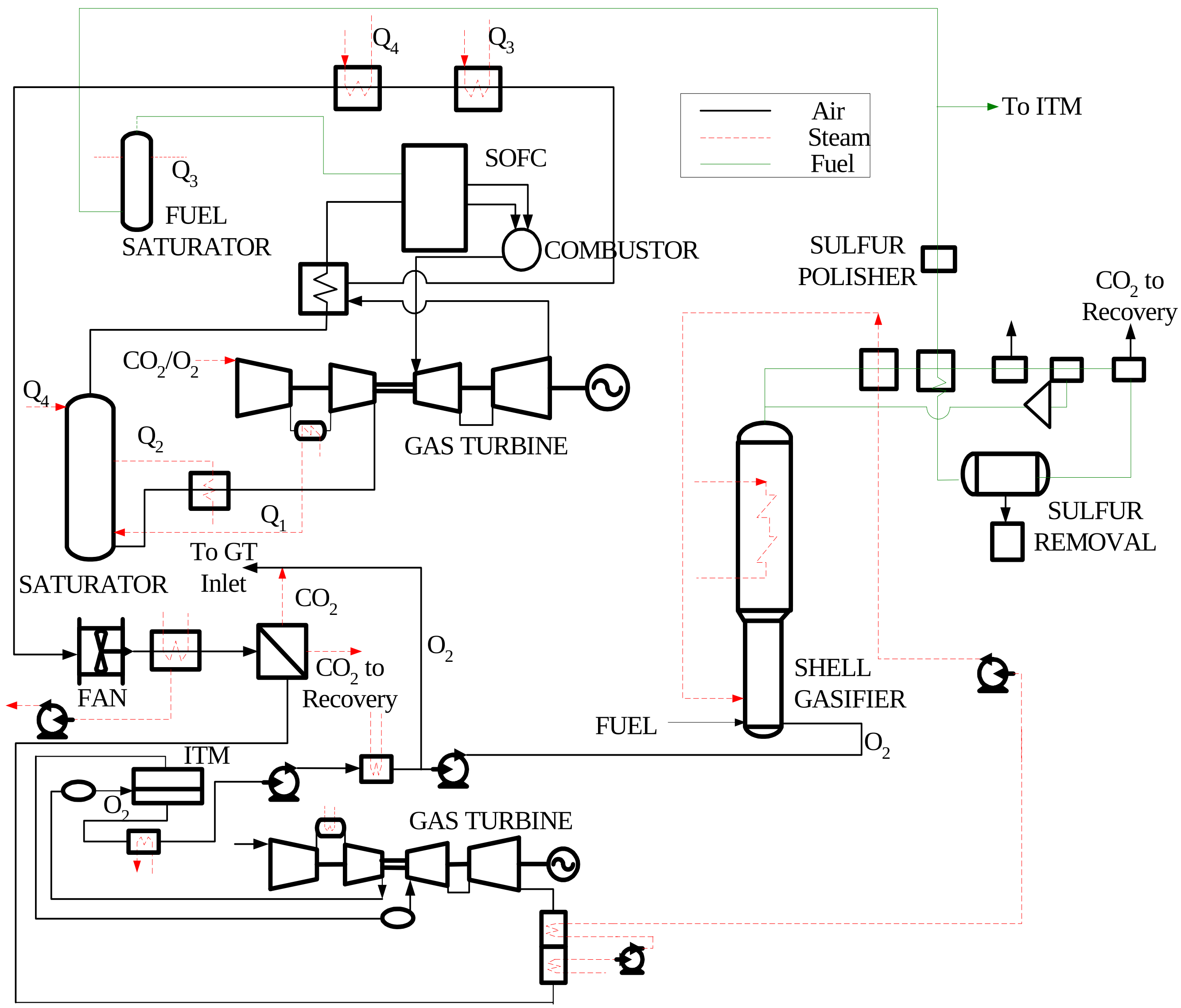

FIGURE 14: SHELL IGHAT HYBRID WITH CO_2 RECYCLE AND RECOVERY

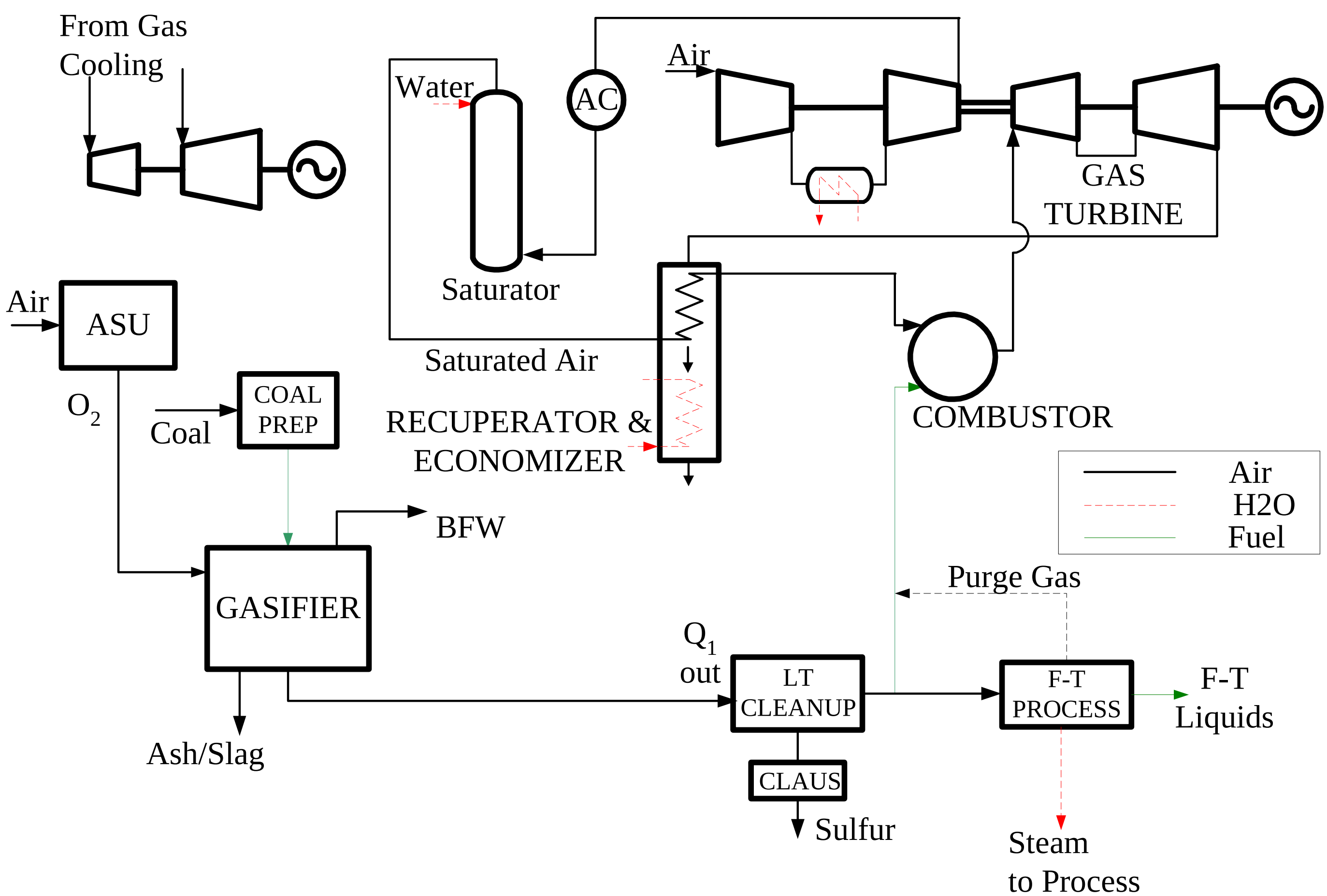

FIGURE 15: IGHAT WITH F-T LIQUIDS COPRODUCTION

CONCLUSIONS

CYCLE ANALYSIS

NATURAL GAS CASES

The performance estimates of the natural gas cases are summarized in Table 2.

TABLE 2: SUMMARY OF PERFORMANCE ESTIMATES - SCREENING ANALYSIS OF NATURAL GAS CASES

		Efficiency Maximization Cases		CO_2Rrecovery Cases	
	SOFC + ICGT Hybrid	SOFC + HAT Hybrid	MCFC + ICGT Hybrid	SOFC + HAT Hybrid	Adv. Rankine Cycle
Fuel Cell Power, %	72	68	74	68	-
Gas Turbine Power, %	28	32	26	32	100
Thermal Efficiency, % LHV	>75	>75	70	>60	52
Specific Power, kW/lb/s	985	1000	830	800	-

The operating pressure of the SOFC has to be significantly higher than what has been demonstrated so far, in the neighborhood of 50 bar if integrated with the intercooled gas turbine or in the neighborhood of 20 if integrated with the HAT cycle. Low air to fuel ratios are required if gas turbine development is to be limited to nonreheat cycles. The air supplied to the fuel cell in addition to providing the oxidant to the cell also provides a means for removing the heat generated within the cell to limit its operating temperature. For example, with the Siemens-Westinghouse tubular SOFC design [Bevc and Parker, 1995], the air is supplied to a central injection tube located within each of the tubular cells where the air is preheated to the operating temperature of the cells by absorbing the heat generated within the cells. As the amount of air supplied to the cells is reduced, management of the heat generated within the cells becomes more challenging. Internal reforming of the natural gas to absorb the heat generated by the cells will be required as practiced by FuelCell Energy's MCFC. Reducing the temperature of the preheated air supplied to the central injection tube located within each of the tubular cells (where the air is further preheated to the operating temperature of the cells) increases the amount of heat that may be absorbed by the air. Large temperature gradients within the injection tube should, however, be guarded against. Addition of large amounts of water vapor to the natural gas stream entering the cells also assist in absorbing the heat generated within the cell. Note that in case of the HAT cycle, the water vapor added to the air supplied to the cells further assists in absorbing the released heat. The water vapor also increases the amount of motive fluid for expansion within the turbines. Note that this water vapor is introduced into the natural gas or air streams in a thermodynamically efficient manner, by utilizing a counter-current humidifier operating on low temperature heat generated within the cycle.

With the atmospheric pressure MCFC based hybrid, the Vision 21 efficiency goal may be realized if the fuel utilization approaches 90% economically. Note that as the fuel utilization increases, the chemical potentials remaining for driving the electrochemical reactions within the cells decrease which in turn decrease the current density. As the chemical potentials decrease the Nernst potential also decreases and the cell polarizations increase resulting in a decrease of the cell voltage for a given current draw.

In order to limit the physical size of the fuel cells which would be required to have outputs in excess of 200 MW for large central station power plant applications (of total output in the neighborhood of 300 MW) to physical sizes that may be considered practical and to limit the number of stack modules to minimize the piping and any mal-distribution, research and development is required in the area of fuel cell materials such that significantly higher current densities may be achieved. The cost of the fuel cell which is one of the major barriers for its wide-spread commercialization at the present time will also be reduced as materials with higher current densities are developed for fuel cell applications as long as these materials do not contain high concentrations of exotic materials.

The zero emission HAT integrated with the O_2 breathing HP SOFC resulted in an efficiency of >60 % on a LHV basis which is significantly higher than the advanced Rankine cycle combusting H_2 with O_2 which had an efficiency of 52% on a LHV basis.

NON-TECHNICAL ISSUES

HIGH ELEVATION OVERVIEW

International Forecasts to 2020

The international marketplace, and specifically OECD countries, are emerging as strong candidates for being the earlier adopters and the initial commercial beachhead for the attributes of the Vision 21 project. Despite the US rejection of the Kyoto Protocol to limit Greenhouse Gas (GHG) emissions, the other OECD countries have expressed a strong support for the Kyoto Protocol as well as technological innovation to meet the aggressive goals in reducing GHG emissions. European countries and LNG importers such as Japan recognize the value of not only the LHV efficiency of new gas fired plants, but also the associated value of reducing GHG's and regulated pollutants. The Former Soviet Union (FSU) nations are also expected to replace old and inefficient capital stock and increasingly use less carbon-intensive natural gas for electricity generation and other end uses in place of more carbon-intensive oil and coal.

There are a select number of non-OECD countries that share this perception and are willing to commit to the additional capital expenditures to abate GHG's. Unfortunately, much of the projected increase in carbon dioxide emissions is expected to occur in the developing world, where emerging economies are expected to produce the largest increases in energy consumption. Developing countries alone account for 77 percent of the projected increment in carbon dioxide emissions between 1990 and 2010 and 72 percent between 1990 and 2020. Therefore, the Vision 21 Project needs to make a greater appeal and penetration into the developing world market if it is to contribute to the reduction of carbon dioxide emissions.

The US market is somewhat unique at this particular moment in history, and greater detail is afforded in the next section. In an international context, the US has a long term, high demand for new generating capacity due to growth in consumption and the forthcoming retirement of a significant portion of the existing generating capacity; however, the economic decision of deploying innovative technology is driven by reliability, warranted efficiency and firm capital cost of the new generating unit. This economic decision currently is being made in what can only be referred to as a "Perfect Storm" of greater competition, federal and state policy ambiguity, fuel supply uncertainty, deregulation failures, illiquidity of utility and non-utility generators and relative economic insensitivity to GHG abatement. The share of generation from natural gas is projected to increase from 16 percent in 2000 to 32 percent in 2020, and the share from coal is projected to decline from 52 percent to 46 percent as a more competitive electricity industry invests in the less capital-intensive and more efficient natural gas generation technologies. Carbon dioxide emissions from energy use are projected to increase at an average rate of 1.5 percent per year, from 1,562 million metric tons carbon equivalent in 2000 to 2,088 million in 2020. Projected emissions in 2020 are higher by 47 million metric tons carbon equivalent.

Because estimates indicate that approximately 80 percent of all human-caused carbon dioxide emissions currently come from fossil fuel combustion, world energy use has emerged at the center of the climate change debate. In the IEO2002 reference case, world carbon dioxide emissions are projected to rise from 6.1 billion metric tons carbon equivalent in 1999 to 7.9 billion metric tons per year in 2010 and to 9.9 billion metric tons in 2020. Much of the projected increase in carbon dioxide emissions is expected to occur in the developing world, where emerging economies are expected to produce the largest increases in energy consumption. Developing countries alone account for 77 percent of the projected increment in carbon dioxide emissions between 1990 and 2010 and 72 percent between 1990 and 2020. Continued heavy reliance on coal and other fossil fuels, as projected for the developing countries, would ensure that even if the industrialized world undertook efforts to reduce carbon dioxide emissions, worldwide carbon dioxide emissions would still grow substantially over the forecast horizon.

US Carbon dioxide emissions from energy use are projected to increase at an average rate of 1.5 percent per year, from 1,562 million metric tons carbon equivalent in 2000 to 2,088 million in 2020. Projected emissions in 2020 are higher by 47 million metric tons carbon equivalent than in AEO2001, due to higher projected energy demand in the commercial and transportation sectors and more coal fired electricity generation than in AEO2001. The higher projection for nuclear generation in AEO2002 offsets some of the increase that would be expected to result from these trends, but carbon dioxide emissions still are expected to increase more rapidly than total energy consumption, as a result of increasing use of fossil fuels, a slight decline in nuclear generation, and slow growth in renewable generation.

Domestic Forecasts to 2020

The US energy market is experiencing an almost unparalled set of dynamics, or “Perfect Storm” that is greater in magnitude and implications than predicted last February. Without question, the aftermath of California's energy problems, suspended state deregulation programs, and the demise of Enron, as well as the downgrading of credit ratings at many major U.S. utilities, has changed most energy scenarios greater than 2 years old. Needless to say, the Vision 21 Design needs to adjust, to the best of its ability, to the long term implications of the current energy crisis.

Balance Sheet Strengthening

The “capacity lite, commodity trading heavy” strategy of energy wholesalers like Enron and others has devastated the market, and created an extremely adverse liquidity crisis and a return to actual ownership of generating capacity by energy traders. These events have in turn cascaded down to a reversal from previous merchant plant financing of new generating capacity to securing more long-term supply contracts that provide debt service coverage ratios resembling levels of the early 1990’s. Presented in the Annual Report is an appendix that has the Fitch Ratings' ongoing review of liquidity constraints affecting participants in the wholesale power and gas market, and it presents credit comments on recent adverse liquidity developments since Fitch's July 26 conference call for investors on AES Corp., Aquila Corp., Duke Energy, Mirant Corp., Reliant Energy, Inc. and Reliant Resources Inc., and Xcel Energy Inc. Figure 16 illustrates the dramatic decline in the Utility Index over the last three years. It presents the last three years of the Dow Jones Electric Utility Index and selected major energy traders. It captures the severe reduction in market capitalization of the major IOU and NUG players in the US market.

With respect to Vision 21, the liquidity crisis in the IOU and NUG markets will need to be rectified before there is an appeal for a capital intensive, high efficiency innovative technology unless if sufficient reliability, capital cost and performance guarantees by bankable suppliers can be offered.

Foreign Investment

Foreign Direct Investment in U.S. Energy 2001 Acquisitions and Divestitures was released by the, and this report discusses foreign acquisitions and divestitures of companies and assets in the U.S. energy industry in 2001.[1] Total foreign direct investment (FDI) acquisitions of U.S. energy assets equaled $11 billion in the year 2001, one-fourth the level of 2000 and the lowest level since 1997. Electricity related transactions, which were characterized by large purchases in both 1999 and 2000, were almost nonexistent during 2001 in comparison, totaling $515 million in 2001 after reaching $13 billion in 1999 and $12 billion in 2000. Canadian companies were purchasers in both FDI-related electricity transactions in 2001. TransCanada Pipelines acquired a hydroelectric power plant from International Paper Co. for $285 million in July and Emera, a Canadian electric utility, acquired the Bangor (Maine) Hydro-Electric Company in October for $230 million. In 2001, divestitures of U.S. energy assets by foreign direct investors reached their second-highest level in the last decade.

Federal Energy Regulatory Commission Chairman Pat Wood's proposal to open a single, flexible transmission structure to facilitate competitive wholesale energy markets with the Standard Market Design (SMD) which aims to make it easier to connect buyers and sellers of electricity, as well as to bring down prices and to create more reliable service. FERC position is that a more efficient market with regulatory certainty would prompt new investment in generation, transmission and distribution. The new proposal is a continuation of two earlier FERC rulings: Orders 888 and 2000, which gave competitive suppliers open access to transmission lines in 1996 and which grants independent system

[1] http://www.eia.doe.gov/emeu/finance/fdi/advance/2001/adindex.html .

operators (ISOs) the muscle to manage transmission wires in 1999, respectively. A new order is necessary to assure efficient and competitive wholesale markets.

Among the issues that could thwart the proposal is whether low-cost power states such as those in the Northwest and the Southeast would end up subsidizing states in the Midwest and Northeast where electricity is typically priced higher. Low-cost areas don't want to have to pay for new power lines that are necessary to ensure a seamless transmission grid and Western states don't want to lose their inexpensive hydropower to other regions.

FERC Regional Transmission Organizations (RTO)

FERC has been working for nearly three years on its consolidation plan for regional transmission organizations (RTOs). Under its plan, FERC sees only four or five large standardized RTOs across the United States, replacing the multiple systems that presently operate under different market rules and tariff structures. However, achieving that vision has been easier said than done as transmission-owning utilities across the country have either resisted FERC's efforts outright by offering their own, often contrary plans for consolidation or become effectively paralyzed by the complex policy prerequisites that must be in place to achieve FERC's plan.

Emissions Trading

Emissions trading is a regulatory program that allows firms the flexibility to select cost-effective solutions to achieve established environmental goals. With emissions trading, firms can meet established emissions goals by: (a) reducing emissions from a discrete emissions unit; (b) reducing emissions from another place within the facility; or (c) securing emission reductions from another facility. Emissions trading encourages compliance and financial managers to pursue cost-effective emission reduction strategies and incentivizes emitting entrepreneurs to develop the means by which emissions can inexpensively be reduced.

In recent years, emissions trading has replaced command and control as the method of choice to reduce emissions from existing sources. Under such programs an "emissions budget" is developed for all sources in a defined area. The area could be an air shed, a state, a group of states, an entire country, or, the entire world. The emissions budget is then divided among emitting companies. Depending upon the program, each company’s share of the budget can be based on historical emissions, capacity, or units produced. Political and legislative deliberations also influence the distribution of the allocations. Over time, the overall budget and each company’s allocation declines. To operate within the declining budget, a firm can under-control and buy credits, emit less than allowed or over-control and sell credits, use a mixture of controls and credit acquisitions, or curtail operations on a schedule that is parallel with the declining budget. New entrants (companies not granted an initial allocation of emissions) generally must "buy-in" by securing an allocation of air credits from companies with allocations.

President Bush wants to expand emissions trading and has introduced legislation to that effect. His bill would cut by 2018 certain power-plant pollutants by 70 percent. Under Bush's plan, utilities would have the right to buy, sell and trade "pollution credits" for nitrogen oxide (NOx) and sulfur dioxide (SO2) emissions, which causes acid rain. It would also require cuts in mercury but it would not touch carbon dioxide. Companies that have exceeded the targets could sell their "surplus" to those that have failed to meet the minimum requirements.

The price of one credit that can be banked or sold is contingent on several factors that include not just the supply and demand of credits but also the technologies that are implemented to reduce pollution. The cost of an SO2 credit, for example, has dropped recently from about $185 to $145. Traders say the price will fall even further because of the steps that companies are taking to cut their emissions.

Exchanges seeking to create a national market for NOx and a global one for greenhouse gases such as methane and carbon dioxide (CO2) could also develop. The World Bank predicts that the market for all greenhouse gases will be worth $10 billion by 2005. The European Union, for instance, plans to regulate greenhouse gases and implement a trading program to exchange CO2 credits by 2005, although Denmark and Great Britain already trade that commodity on a small scale.

Supply – Demand Boom Bust Cycle

When the economy rebounds, one can expect new power-generation projects to fire up. Demand for electricity may have slowed and investors may be a lot warier, but American productivity is on an upward trajectory that will compel new development. It will not only meet the needs of consumers but will also comply with the wishes of those investors who expect higher returns.

The pall that has hovered over the industry, particularly since the collapse of Enron, will have a long term impact, but it will not last forever. The decline in construction, which is the result of tight-fisted bankers and increasingly critical investors, will eventually cause supplies in many regions to restrict in two to five years. It is commonly held that new plants are therefore paramount, particularly because existing plants are aging.

The current vector to maximize productivity is consistent with the Vision 21 goals. Specifically, companies are trying to achieve size and scope and are building state-of-the-art facilities that burn fuel cleanly and efficiently. It's all to win fast approval and to cut the cost of operations. During the late-1990s, companies perceived an energy shortage and worked to acquire or build such plants to meet the expected demand at 2.5-percent annual growth.

Texas Deregulation and shut down of plants

Texas' deregulation is being touted as a potentially successful program. One important bellwether from Texas would be, American Electric Power's September 18, 2002 announcement that it wanted to idle 16 older (1960's), gas-fired generating plants in Texas because it can buy power more cheaply on the open market. The 16 plants can produce 3,866 megawatts, or 5 percent of the state's generating capacity. ERCOT noted that Texas has a very substantial capacity margin right of about 30%. This situation validates that Texas' electric deregulation, which began on January 1, 2002 is working by attracting new gas fired capacity to drive out older, more costly sources of power.

Municipalization

With all the uncertainties in today's electric markets, municipally owned power companies are providing an element of stability. Their solid credit ratings reflect that, particularly when compared to those of hallmark investor-owned utilities (IOUs) that are seeing their ratings downgraded to junk status in some cases.

But despite the fact that municipals have the legal authority to raise rates when financial conditions warrant, they are exposed to some of the same volatile wholesale electric markets affecting all other utilities, as well as counter-party risk. The result could be the payment of high power prices or the non-payment of obligations owed them, both of which would reduce their reserves and possibly affect the credit quality of their debt.

A definite implication to Vision 21 is the role of major energy players, e.g Chevron/Texaco, getting into generation business by encouraging "municipalization". Municipalities can take over distribution network through eminent domain and shelter themselves from wholesale price fluctuations by building advanced generating systems. Chevron Energy Services is attractively marketing to municipalities help with generation assets that are generally install smaller power plants (40-150 MW), but certainly within the capacity range of the Vision 21 Project.

Therefore, given the attributes of the municipalities in the financial arena, the presence of major energy players in the game, and the existence of "early adopters" of environmental beneficial technologies (e.g. LADWP and SMUD), this should become a significant focus for Vision 21 applications in the future.

<u>LOW ELEVATION OVERVIEW</u>

Vision 21 Specific Valuation of Environmental Benefits

As previously stated the OECD countries, particularly European members, are the markets that have the greatest valuation of environmental benefits of a Vision 21 design, and the competition for efficient generating assets is greater than the US. Therefore, the potential market application for a the Vision 21 should fully embrace the European market as an “early adopter” and long term growth market.

Valuation of Emerging Technologies

The present financial and market conditions in the US can best be described as the “Perfect Storm”, and it will undoubtedly take several years to unwind the present dilemma. In the interim, one can anticipate a risk adverse mentality by project developers and lenders. This will be somewhat reduced if a corporation with a strong balance sheet warrants the performance, reliability and capital cost of the Vision 21 design, but this is presently regarded as unlikely. Therefore, the Vision 21 Project would be served by ripening the technology with demonstration and early adopters projects that will have crucial operating data when demand once again outstrips supply. Fortuitously, this will probably occur as a more stable and transparent market for emission trading evolves.

Even though very few companies are now willing to absorb technological risk, the good news is that V21 plant sizes are of interest to both early adopters and green municipalities. The plants can be introduced at small scale and then increased in size in a stair step manner as technology become proven. This can also do this in a “genealogical” fashion. This forthcoming year, the Vision 21 Project will devise a development path that demonstrates the technology in stages, documented in both categories of (1) maturity of component technology, and (2) integration risk. Proven components can then be demonstrated to have very little technological risk, while integration and juvenile components can be shown as having technological risk. Technology maturity will be shown in a generic chart that color codes the maturity of components and integration aspects.

In the interim, reducing the component risks with the Vision 21 design will substantially assist the commercialization of the technology as noted in the EIA study entitled "Impacts of Energy Research and Development (S. 1766 Sections 1211-1245, and Corresponding Sections of H.R.4) With Analyses of Price-Anderson Act and Hydroelectric Relicensing" on March 7, 2002.[2]

Valuation of Environmental Benefits

The most conservative and controversial assumption made by the Vision 21 Project Team was to initially assign a minimal value of the environmental benefits of the selected designs. Since the valuation of emission controls are so fluid, initially no credit enhancements, no price or tax break will be applied to US destined plant, but there are possible valuations for the European case. The rationale for this conservative approach is

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[2] http://www.eia.doe.gov/oiaf/servicerpt/erd/pdf/sroiaf(2002)04.pdf

based upon the belief that environmental performance is a “binary” issue. Either the new generating capacity meets the emissions and thus are permitted, or they fail to meet the emission standards and are not permitted. This conservative approach is also consistent with the observation that the rate of environmental regulations is decelerating, and if fact some regulations will be loosened. Should future events indicate a reliable valuation of the environmental benefits, the modeling proposed in one of the following sections will be quite accommodating to rerunning the financial and output performance.

Valuation of Fuel Flexibility

The third key feature that will be a huge asset for these types of plants will be fuel flexibility. The previously presented “dash for gas” will undoubtedly have long term price escalation impacts unless additional supplies of natural gas are developed. The higher the price of natural gas, the greater the value of the asset if it has an extremely low LHV. It should also be noted that a particular generating asset of the future will probability be bought and sold five times during its 30 year life. Major players will seek to balance their generation portfolio given the prevailing market conditions. The Vision 21 possesses the attitudes that will consistently have value, i.e., high fuel efficiency, great partial load efficiency and ultra low emissions. It is difficult to devise a scenario where these three attributes would not command a premium for any generation portfolio.

If one can demonstrate the a certain plant is “insulated” from fuel price fluctuations (by fuel flexibility) it will become a superior technology, banks will support, and competitors may be forced to adopt similar technology or have the banks refuse to accept the risk of fuel price variability.

The Vision 21 Project should consider not only natural gas and coal, but also biomass, municipal waste which ties back to the municipalization scenario discussed previously.

Valuation of Performance Output

Auction Time Frames. Regardless of the final state or federal competitive market structure that is instated, what can be reasonably predicted is that the time period between auction to delivery will radically shorten. Four years ago, day ahead bidding was a radical idea, but today it is commonplace. Hourly auctions for spot markets are common, and one can envision 15 minute ahead auctions in the future.

Therefore, The first key feature that future systems should offer is good efficiency over a broad range of operating conditions (good part-load and great capacity to step up the power output to much greater levels). This will include having versatility with respect to duct firing, cycle selection (e.g. HAT) or having the fuel operate at higher stoichiometry to leave more air for firing gas turbine when increased output is required.

There is no fundamental reason why the value of V21 plants will not be dramatically advanced by this feature. Forecasting the future price of value of electricity has proven to be elusive, but flexibility will allow the best use of the asset and the best value to the grid, under any scenario of bidding. It is hard to argue against the companies that advocate that 80% of a plant's profitability may be made in only 20% of its operating hours, and the balance is at their marginal costs. It should be remembered that day-ahead bidding favors large base-load plants. Bidding and increased price fluctuations favor a very flexible plant.

Economic Modeling Selection. After a few iterations with Rodney Geisbrecht of NETL it was decided by the Vision 21 Project team that this study will best be understood in the context of the Financial Model contained in the Excel workbook on the NETL Gasification Financial Model[3], and a source of parameters and factors to consider will best be obtained for consistency purposes from the Parsons report[4].

This document provides an overview of the installation, start-up, and operation of the financial model developed by Nexant, Inc. as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices task. The financial model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of projects using IGCC systems. By conducting analysis with the financial model, the DOE will be able to evaluate different IGCC applications on a uniform basis. The IGCC financial model consists of 20 spreadsheets that were created in a Microsoft Excel 2000 workbook format, with interfaces and supporting code developed in Visual Basic. The spreadsheets in the model are organized into four main sections: data input sheets, supporting analysis sheets, financial statements, and project summary result sheets. After taking into account the benefits of the higher efficiency of the Vision 21 design, there is a strong likelihood that there will be a cost disparity of the hybrid systems. Therefore, the study would then need to indicate the magnitude of the a) the reduction in the fuel cell cost, b) the increase in the value of the environmental benefits assigned, or c) a mixture of A and B. Our conservative, but valid, approach to minimal value for environmental benefits will in all likelihood change in the future.

The Vision 21 team elected to prepare COE estimates for an ATS-based CC at 60% (LHV) and an IGCC using literature supplied numbers. The team then will extrapolate the V21 systems at 77% (LHV) and 63% (HHV) respectively that have to compete with the emerging CC/IGCC designs. Their capital costs will have to fall within a defined bandwidth that will make them economically competitive.

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[3] http://www.netl.doe.gov/coalpower/gasification/index.html

[4] Report on Market Based Advanced Coal Power Systems
http://www.fe.doe.gov/coal_power/special_rpts/market_systems/market_sys.shtml

Bellwether Events

A bellwether event acts as an early warning system of either negative or positive developments that are significant when forecasting market penetration and acceptance of emerging energy technologies. The bellwether events identified this year, include:

- It is imperative that the US market have a half a dozen demonstrated and sustainable deregulated energy market that benefits the consumer in measurable terms; otherwise, a "cost of service" regulated pricing scheme may return. As Jeff Skillings, the former President of Enron Corp, presented in congressional testimony, until come up with insulated bidding system that is thorough enough to wring out the gaming, then will not have a successful bidding process.

- More municipalities will consider expanding their generation portfolio to insulate themselves from radical swings in the wholesale commodity market.

- A National Energy Plan will not be approved by Congress in this session, and if a bill reaches the White House, it will not be signed nor will it be veto proof.

- The balance of the OECD, FSU and EE countries will proceed to ratify the Kyoto Protocol over the objections of the US. This will open markets for the Vision 21 designs in Europe, but necessarily the US.

- The cost of the distribution in customer's bill is extraordinary relative to cost of electron. This disparity will be politicized during the next 2-5 years within a burden that the T&D system is decaying from an abundance of deferred maintenance.

- Restructuring of transmission systems will be achieved, but the roles of the states will be greater than currently envision by FERC, and the regions and sub regions will be less interdependent.

- The public resistance to installation of transmission lines will continue. This provides an opportunity for V21 to make 40-100MW power plants that can be installed more locally and allow greater flexibility and lower vulnerability to terrorist attack on transmission systems.

- There will be a military conflict with Iraq that will remind the US the price that it pays to continue to receive the majority of its energy from an unstable and questionably loyal region of the world. $120-150B was spent on Desert Storm , but the consequences of this have gone by wholly unrecognized.

- The vulnerability to terrorist attack on the transmission grid will be exposed (e.g. a disgruntled former utility employee used commonly available technology to break into the utilities SCADA system.)

FIGURE 16: DJ ELECTRIC UTILITY INDEX AND MAJOR ENERGY TRADERS, LAST 3 YEARS

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