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NASA LEWIS CLOSED-CYCLE MAGNETOHYDRODYNAMICS PLANT ANALYSIS

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The NASA Lewis Research Center is presently managing two study contracts to analyze coal-fired closed cycle MHD power plants. The studies will serve to quantify the effects of various system parameters on plant performance, capital cost, and cost of electricity. In support of the contracted studies, the Lewis Research Center has conducted plant analysis of a preliminary nature to survey the basic effects of various system parameters on plant performance. This presentation briefly reviews the assumptions and results of the analyses to date.

Each of the main subsystems, i.e., the inert gas (argon) MHD loop, the steam bottoming cycle and the combustion system, was considered in detail. The combined cycle, consisting of the inert gas MHD and steam cycles was first analyzed and then interfaced with three types of combustion systems.

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To provide an overview of combined cycle thermal analysis, several cycle parameters were varied and several configurations examined. Variations were made in the steam plant such as level of regenerative feedwater heating and condenser back pressure; and in the inert gas MHD loop such as compressor intercooling, recuperation, MHD generator efficiency and inlet temperature, and component heat and pressure losses. Also, the effect of constraining the design point parameters and the cycle interfacing such that the steam plant power output matched the argon compressor power requirement was considered. The generation of additional steam in the combustion loop for use in the steam plant was also examined.

Generally, the trends are that steam cycle regenerative feedwater heating, compressor intercooling and combustion loop steam generation tend to degrade performance. The benefit of MHD loop recuperation is marginal, with cycle efficiency highly dependent on recuperator pressure loss. Lowering steam plant back pressure enhances overall cycle performance, as does raising MHD generator efficiency and inlet temperature. A design point without the constraint of balancing steam cycle and compressor power to allow for maximum MHD channel enthalpy extraction can improve cycle performance.

A very important aspect in the determination of plant performance and capital cost is the type of combustion system used to supply heat to the combined cycle. To focus on the effect that various combustion systems have on plant performance, a combined MHD/steam cycle was selected as a reference power producing cycle and coupled to each of three combustion systems. The design point for the reference cycle was chosen as the point at which the steam plant output power exactly matched the argon compressor power requirement. The MHD channel was parametrically assigned an isentropic efficiency of 78% and an inlet temperature of 1977 K (3100° F).

The reference combined cycle is shown schematically in figure 1 and is similar to a GE ECAS system (refs. 1 to 3). The condition of a balance between steam plant and compressor power dictates a channel pressure ratio of 4.8, a corresponding enthalpy extraction of 36%, and a diffuser exit temperature of 1257 K (1804° F). The steam bottoming plant extracts waste heat from the argon exiting the channel and diffuser in a series of heat recovery components. Continuing through the cycle, the argon is further cooled with cooling tower water prior to being compressed to a pressure ratio of 5.5 to overcome system pressure losses. Following compression, the argon is heated in an array of refractory brick regenerative heaters that are alternately valved between combustion gas and argon. For the sake of brevity, seed recovery and reprocessing, argon purifying, and regenerative heater evacuation equipment necessary for a functioning plant are not shown in figure 1.

The bottoming plant is a 24.1 MN/m^2/811 K/841 K (3500 psia/1000° F/1000° F) supercritical, reheat steam cycle with an argon loop interface consisting of a reheater, superheater, deaerator, and economizer. The minimum temperature difference between argon and steam in these heat exchangers was limited to 28 K (50° F). Condenser back pressure was set at 8.5 kN/m^2 (2.5 in. Hg) for a feedwater temperature of 316 K (110° F). To maximize heat extraction from the topping cycle, no regenerative feedwater heating was used. For the given steam plant conditions, efficiency based on shaft power is 38% as derived from the NASA steam cycle performance code.

The thermal efficiency of the combined cycle for the given conditions is 51.7%, defined as gross electrical power divided by heat input to the topping cycle. An energy flow diagram for the cycle is illustrated in figure 2.

Three different combustion systems to supply heat to the MHD/steam cycle were investigated. The first used a direct coal-fired combustor, the second used a fluidized bed gasifier with in-situ desulfurization, and the third used a fluidized bed gasifier with external product gas cleanup. The heat and mass balances for the gasifiers were obtained from the ECAS study (ref. 5). All three combustion systems were pressurized, representing advanced systems, and used recuperation to most advantageously recover sensible heat from product and/or flue gas in lieu of generating steam. Also, flue gas recirculation was incorporated in each case to limit combustor exit temperature to 2116 K (3350° F) and, hence, NO_x formation.

The direct coal-fired combustion system is shown in figure 3. The system is pressurized by an air compressor driven from a flue gas turbine. Compressed air is delivered to the combustor together with dried coal (Illinois #6 for all cases) and recirculated flue gas. The combustion products heat the regenerative ceramic heaters, with the residual thermal energy exiting the heaters used for air preheat, turbine drive, and coal drying. An electrostatic precipitator (ESP) removes particulates carried over from the combustor upstream of the turbine and a dry spray scrubber/ESP removes SO_2 and particulates downstream of the turbine prior to coal drying and stack exhaust.

The combustion system incorporating the Westinghouse gasifier is shown in figure 4. The gasifier consists of two main stages: an upper devolatilizer/desulfurizer bed fluidized by gases from a lower gasification bed. Dolomite sorbent is injected in the upper bed to remove hydrogen sulfide formed in both beds from sulfur in the coal. Two stages of cyclones and a granular bed filter remove particulates from the 1136 K (1585° F) fuel gas. Process steam is generated and water heated by cooling the product gas prior to combustion. Gasifier process air and combustor air are preheated by hot flue gas leaving the refractory argon heaters. The system is pressurized by an air compressor driven by a flue gas turbine.

The combustion system using the IGT gasifier is shown in figure 5. The gasifier is comprised of a main vessel and two stages of cycles for particulate removal. The fuel gas exits the unit at 1311 K (1900° F) containing sulfur in the form of hydrogen sulfide. The fuel gas is cooled to 877 K (1120° F) by transferring heat to the process steam and air and to the combustor air. An array of iron oxide beds removes sulfur from the gas by converting hydrogen sulfide to iron sulfide. Periodically, the iron oxide beds are regenerated with air to oxidize the iron sulfide deposits. The sulfur dioxide in the regeneration air is then reduced to elemental sulfur in an Allied Chemical plant which requires 4.6% of the clean fuel gas. The system is pressurized by a compressor-turbine set similar to the preceeding case.

Energy diagrams comparing the combustion systems are shown in figure 6. The systems are compared on a common base of 100 heat units input to the combined MHD/steam cycle. The direct coal-fired case has the highest combustion loop efficiency followed by the Westinghouse and IGT gasifier systems. The direct coal-fired combustor is potentially the highest efficiency combustion system but does present the formidable technical problems of operating regenerative heat exchangers with ash laden gas and operating a turbine on gas containing sulfur, particulates and alkalies. Gasifiers result in a lower combustion system efficiency but provide the potential for lesser operational problems of downstream components.

Overall plant efficiencies using the three combustion systems coupled to the combined MHD/steam cycle are shown in figure 7. The direct coal-fired combustor plant has an overall efficiency (excluding auxiliaries) of 44.5%, the Westinghouse gasifier plant 43%, and the IGT gasifier plant 41%. For purposes of comparison, two GE cases, one utilizing a direct coal-fired combustor, ECAS case 102A (ref. 2), and the other a pressurized moving bed gasifier with in-bed desulfurization (ref. 3) are also shown on the figure. The differences in plant efficiency between the corresponding GE and NASA cases are reconcilable and lie in assumed MHD loop pressure and heat losses, steam plant conditions, and combustion system losses. The basic trends are similar, with the GE cases also showing that a pressurized coal combustor plant has the highest potential efficiency.

As plant performance and costs are dependent on many varied and interrlated factors, a wide range of parameters, components and configurations will be considered in the contracted studies. Such variations as type of coal, gasifiers, cleanup methods, pressure level and losses, MHD channel efficiency, component arrangements, plant size, and so on will be made to three base case plants and performance, capital cost and cost of electricity calculated for each particular case. The studies should result in further definition of coal-fired closed cycle MHD plants beyond the level of ECAS.

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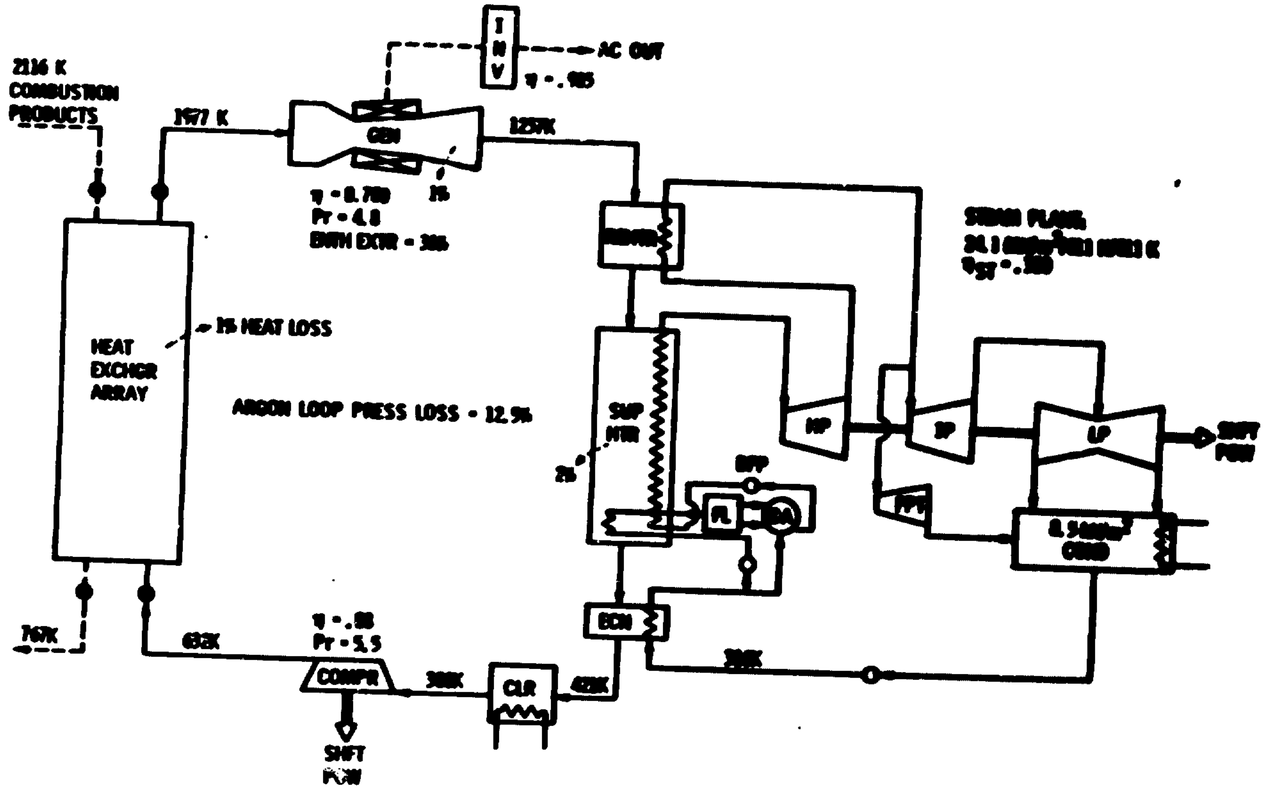


Figure 1. - MHD/Steam combined cycle (EFF = .507).

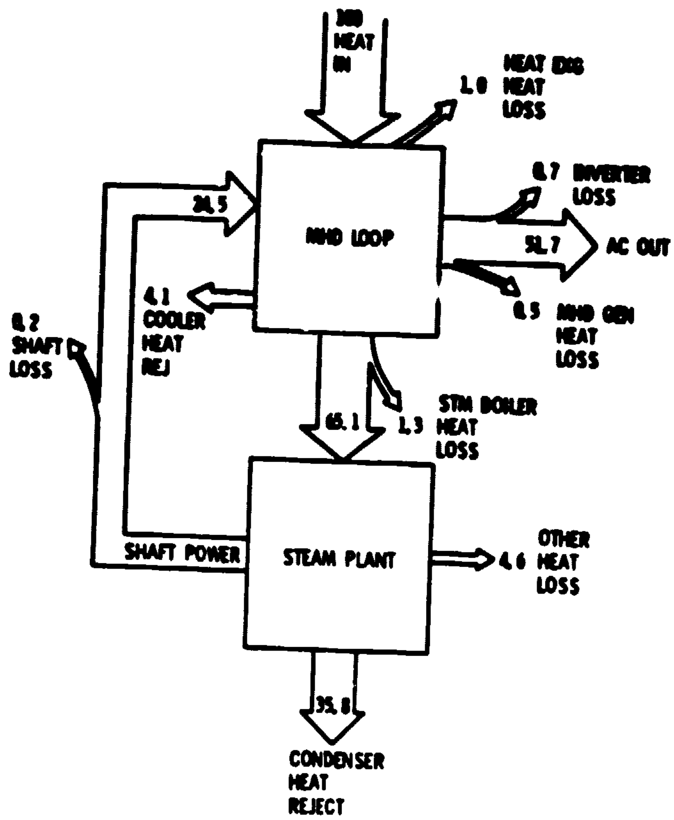


Figure 2. - MHD/Steam energy diagram.

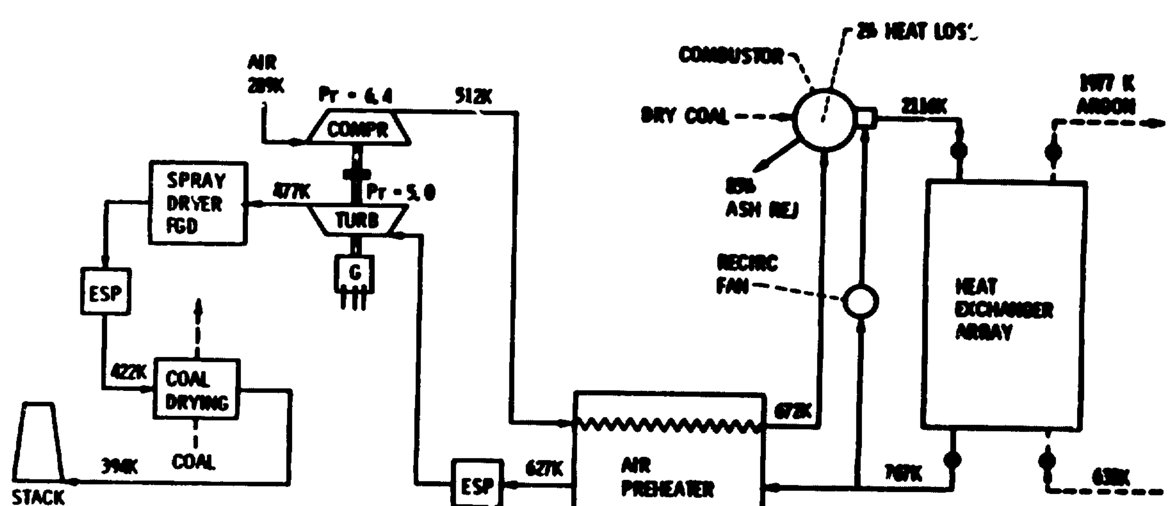


Figure 3. - Direct coal-fired combustion system.

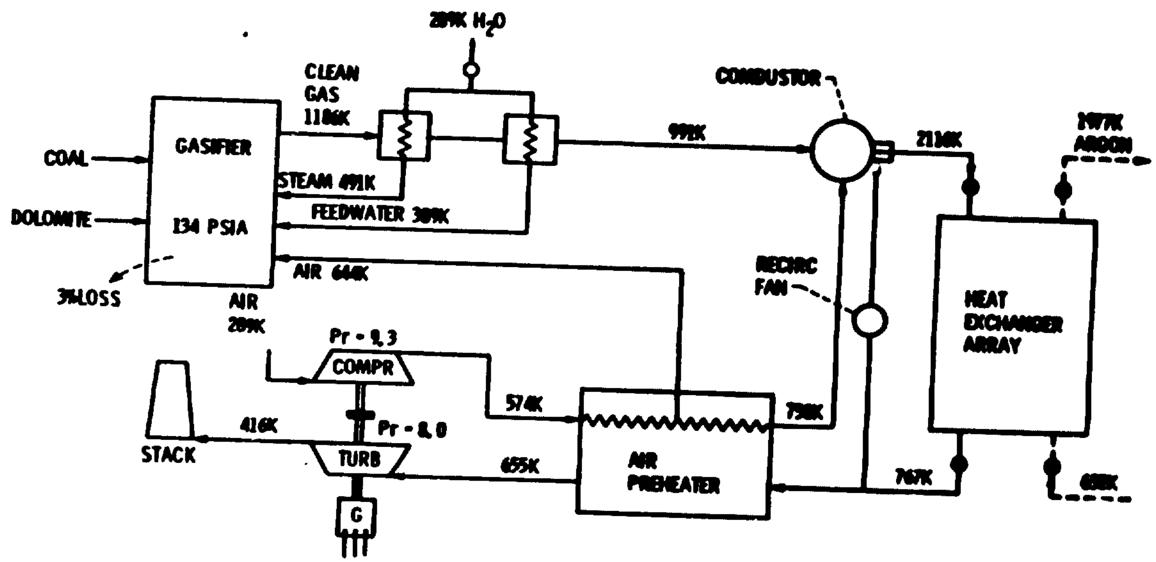


Figure 4. - Westinghouse gasifier combustion system.

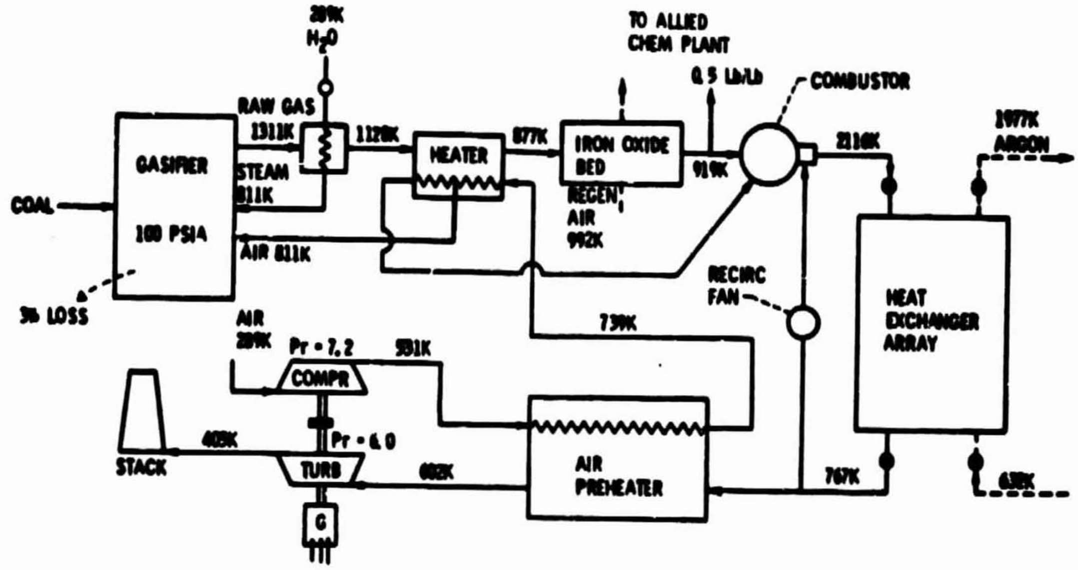
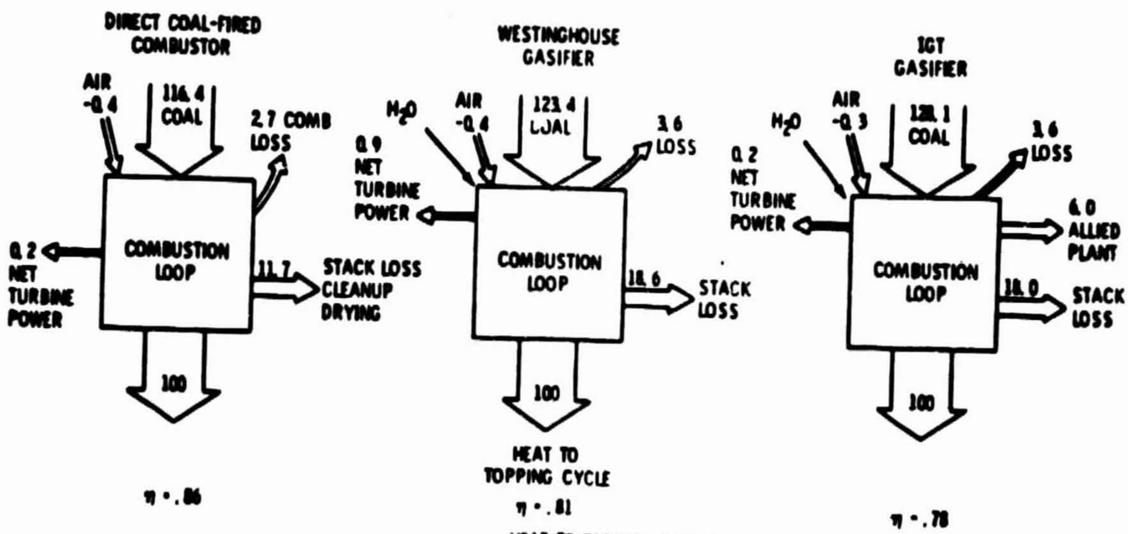
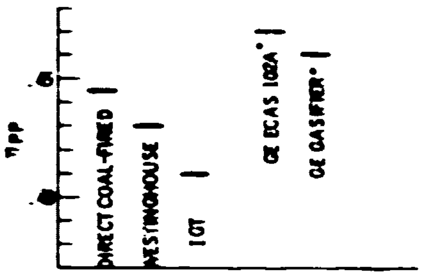


Figure 5. - IGT gasifier combustion system.



NOTE: $\eta = \frac{\text{HEAT TO TOPPING CYCLE}}{\text{HHV COAL}}$

Figure 6. - Combustion loop energy diagrams.



$\eta_{PP} = \frac{\text{GROSS AC POWER OUT}}{\text{HHV COAL}}$ (AUX. POWER NOT DEDUCTED)

* - GE CASES INCLUDE AUX. POWER

Figure 7. - Power plant efficiency.