NASA TECHNICAL MEMORANDUM

NASA TM -73775

NASA TM -73775

(NASA-TM-73775) PERFORMANCE POTENTIAL OF COMBINED CYCLES INTEGRATED WITH LOW-Btu GASIFIERS FOR FUTURE ELECTRIC UTILITY APPLICATIONS (NASA) 42 p HC A03/MF A01 CSCL 10A G3/44

N78-23557

Unclas 16682

PERFORMANCE POTENTIAL OF COMBINED CYCLES INTEGRATED WITH LOW-Btu GASIFIERS FOR FUTURE ELECTRIC UTILITY APPLICATIONS

by Joseph J. Nainiger and Raymond K. Burns
Lewis Research Center
Cleveland, Ohio 44135

TECHNICAL PAPER presented at the
Sixty-Ninth Annual Meeting of the
American Institute of Chemical Engineers
Chicago, Illinois, November 28 - December 2, 1976

PERFORMANCE POTENTIAL OF COMBINED CYCLES INTEGRATED WITH LOW-Btu GASIFIERS FOR FUTURE ELECTRIC UTILITY APPLICATIONS

by Joseph J. Nainiger and Raymond K. Burns

National Aeronautics and Space Administration
Lewis Research Center
Cleveland, Ohio 44135

E-9567

ABSTRACT

In the Energy Conversion Alternatives Study (ECAS) of 10 advanced utility power systems, fired with coal or coal-derived fuels, the objectives were a comparison and an assessment of the candidate systems on a consistent basis and to a common level of detail. Substantial emphasis was given to combined-cycle systems integrated with low-Btu gasifiers. Performance and cost results from that study are presented for these combined cycle systems, together with a comparative evaluation. The effect of the gasifier type and performance and the interface between the gasifier and the power system are discussed.

SUMMARY

The Energy Conversion Alternatives Study had as its primary objective the comparison and assessment of advanced base-load utility power systems fired with coal or coal-derived fuels. One type of system investigated was gas turbine/steam combined cycles integrated with low-Btu gasifiers. In the Phase I parametric analysis of ECAS, these systems displayed relatively high overall efficiency and moderate bus bar cost of electricity (COE). As a result, two combined-cycle conceptual designs with integrated gasifiers were studied in Phase 2 to further define and examine these systems in comparison with other alternatives. Both resulted in attractive performance and COE in relation to the other systems studied. One of the designs, performed by General Electric, consisted of air-cooled gas turbines at a rotor-inlet temperature of 2400° F, bottomed by an 1800 psig/950° F/950° F reheat steam cycle and integrated with an advanced fixed-bed gasifier using a water wash and cold-

STAR Category 44

gas-cleanup desulfurization system. This configuration resulted in an overall efficiency (coal pile to bus bar) of 39.6 percent, with a capital cost of $770.8/kWe and a COE of 35.1 mills/kW-hr. Another design option investigated by Westinghouse consisted of air-cooled gas turbines at a turbine inlet temperature of 2500° F, bottomed by a 2400 psig/1000° F/1000° F reheat steam cycle utilizing steam induction and integrated with an advanced fluidized-bed gasifier using in-bed desulfurization and a hot-gas particulate cleanup system. This powerplant had an overall efficiency of 46.8 percent, a capital cost of $613.5/kWe and a COE of 29.1 mills/kW-hr. The powerplant costs quoted were estimated in mid-1975 dollars before the addition of escalation and interest during construction.

In this report, a detailed comparison of these two designs is discussed. The performance differences between the General Electric and Westinghouse designs have been quantitatively explained in terms of differences in their technical approach, such as the type of gasifier used, the turbine cooling technology assumed, and the method of integrating the powerplant with the gasifier/cleanup system.

Calculations were also done by NASA to investigate the effects of turbine inlet temperature on the performance and cost of a combined cycle integrated with the General Electric gasifier/cleanup system. Three turbine-inlet temperatures were investigated (2000° F, 2200° F, and 2500° F). Performance and cost of these systems were calculated using the fixed-bed gasifier and steam bottoming cycle as used by General Electric in their Phase 2 conceptual design. It was shown that the combined-cycle plants with advanced fixed-bed, low-Btu gasifiers appear to maintain costs of electricity and efficiencies competitive with conventional steam systems, at current turbine firing temperatures, and superior performance and COE at the higher temperatures.

INTRODUCTION

The Energy Conversion Alternatives Study (ECAS) was undertaken by NASA for the National Science Foundation (NSF) and the Energy Research and Development Administration (ERDA). The overall objective of this study was to investigate advanced energy-conversion techniques for baseload electric utility applications that can use coal or coal-derived fuels and to evaluate their relative merits and potential benefits, using a common set of ground rules. The ECAS was an integrated government-industry effort that combined the expterise and experience of the Westinghouse Electric Corp., the General Electric Co., and the United Technologies Corp./Burns and Roe, Inc.

The study was conducted in two phases. Phase 1 consisted of parametric analysis and Phase 2 treated conceptual designs of certain selected powerplants together with development plans and an implementation assessment.

In phase 1, emphasis was placed on a broad coverage of the energy-conversion systems over wide ranges of parametric conditions. Approximately 900 parametric points were calculated by contractor teams led by the General Electric Company and the Westinghouse Electric Corporation. The results were compared and evaluated by NASA. Systems studied in Phase 1 included steam plants with advanced furnaces, open-cycle recuperated and combined gas-turbine/steam-turbine cycles, helium and supercritical-carbon-dioxide closed-cycle gas turbine systems, liquid-metal-Rankine topping cycles, open- and closed-cycle inert-gas and liquid metal magnetohydrodynamic (MHD) systems, and high- and low-temperature fuel cells.

Based on the results of the Phase 1 parametric analysis, 11 concepts were selected for more detailed evaluation in Phase 2. These included steam systems with both atmospheric- and pressurized-fluidized-bed boilers; combined-cycle gas-turbine/steam systems with integrated gasifiers or fired by semi-clean liquid fuel; a potassium/steam system with a pressurized-fluidized-bed boiler; a closed- cycle gas-turbine/organic system with a high-temperature, atmospheric-fluidized-bed furnace; a direct-coal-fired open- cycle MHD/steam system; and a molten-carbonate fuel-cell/steam system with an integrated gasifier.

The Phase 2 contractor studies were conducted by teams led by General Electric, Westinghouse, and United Technologies/Burns and Roe and were supplemented by Lewis Research Center analyses and evaluation.

In parallel with Phase 2, General Electric also did a conceptual design of a steam system with a conventional pulverized-coal furnace and wet-lime stack-gas scrubbers. This was done on the same basis and with the same ground rules used for ECAS. This effort was performed for and jointly managed by the TVA with funding provided by EPA.

Focus on a relatively small number of advanced conversion concepts in Phase 2 permitted technical and economic evaluations to be made in much greater depth than was possible in the Phase 1 parametric analyses.

Estimates were made of performance, cost, environmental intrusion, and natural resource requirements for these systems. In addition, the ECAS contractors defined the state of the technology, identified technological advances required, and prepared preliminary research and development plans for selected advanced system concepts.

After each phase the contractors' results were published (refs. 1, 2, and 4 to 6) and a report was prepared at NASA which summarized, compared and evaluated the contractors' results (refs. 3 and 7).

Two of the conceptual designs done in Phase 2 of ECAS were gas-turbine/steam-turbine combined cycles with integrated low-Btu coal gasifiers. One was done by the General Electric Company and included an advanced fixed-bed gasifier with cold-gas sulfur removal, and the other by the Westinghouse Electric Corporation included an advanced fluid-bed gasifier with in-bed sulfur removal. The performance and cost of these two combined cycles with gasifiers are described and compared in this report. The overall performances of the systems are explained in terms of their subsystems and the manners in which they are interfaced. Some additional analysis done at NASA concerning modifications of these designs to show the influence of turbine inlet temperature is also described.

ECAS PHASE 2 LOW-Btu-GASIFIER/COMBINED CYCLES

The overall efficiency and COE results for all the Phase 2 conceptual designs and for the steam system with stack gas scrubbers are shown in figure 1. The results for the low-Btu-gasifier/combined-cycle systems are indicated by the solid symbols. The ground rules specified for the study are summarized in table I. The capital cost estimates included all component and balance of plant materials, direct construction site labor, and also factors to account for indirect labor, A&E services and contingency (the latter factors were specified by the contractors). As indicated in table I escalation and interest costs during plant construction were also included.

As shown in figure 1, the low-Btu gasifier/molten-carbonate fuel cell/steam system, the coal/open-cycle MHD/steam system, and the low-Btu gasifier/gas turbine/steam combined-cycle system, as studied by Westinghouse, are grouped together. They have efficiencies in the high-40-percent range and COE's competitive with the advanced steam systems. The gas turbine/steam combined cycle with the integrated gasifier as studied by General Electric (which uses a nearer term gasification system) has lower efficiency and higher COE. The two gas turbine/steam combined-cycle systems fired by

H-coal have COE's competitive with the advanced steam systems and overall efficiencies in the high-30-percent range. The powerplant efficiencies of these two cases exceed 50 percent, but the overall efficiencies are considerably lower due to the 74-percent coal-to-semiclean-fuel conversion efficiency. The two PFB/steam systems have efficiencies near 40 percent and show a significant difference in estimated COE. This is partly due to differences in cost estimates in the PFB-subsystem cost category and partly due to differences in A and E services, contingency, interest, and escalation. The COE's for the PFB/potassium/steam system and the AFB/closed-cycle gas turbine/organic system are significantly higher than those for the steam systems primarily because of higher capital cost associated with the furnace-subsystem and primary-cycle cost categories.

In the steam systems with stack gas scrubbers, steam is extracted from the turbine for reheat of the stack gases after sulfur removal. This steam extraction reduces the power output and hence the efficiency. As shown, reheating the stack gases to 250° F, which requires more steam extraction than the 175° F case, results in significantly lower efficiency and higher COE.

In comparing the results in figure 1, it should be remembered that these assume that each powerplant has reached a state of commercial maturity but they represent different levels of technology. The R and D plans and implementation assessment described in reference 7 deal with the time, cost, and other issues involved in reaching this state.

The difference in performance and COE of the two low-Btu-gasifier/combined cycle systems shown in figure 1 is the result of different design choices made by General Electric and Westinghouse. These systems are described in this section and the differences in the results are explained in terms of differences in subsystems or parameters chosen for study.

Description of General Electric Case

The simplified cycle schematic for the General Electric system is shown in figure 2(a) and some of the characteristics are listed in table II. The 2400° F gas-turbine inlet temperature is defined by General Electric as the inlet total temperature to the first-stage rotor blades. The gas temperature at the inlet to the first-stage stator vanes is higher and is reduced to 2400° F by mixing with the cooling air exiting the first-stage vanes. The gas turbines have three stages, all cooled. The turbine vanes and blades are cooled by a combination of convection and impingement techniques with some pressure-side film cooling of the first-stage vanes. Some of the compressor air extracted for cooling is precooled by passing through a cooling module that rejects heat to cooling towers.

Four heat-recovery steam generators (HRSG's) raise steam for a single main steam turbine-generator by recovering exhaust heat from the four gas turbines. The HRSG consists of a superheater-reheater, an evaporator, and a high- and low-pressure economizer. Water heated in the low-pressure economizer is flashed to steam for use in the deaerator-evaporator. Thus, steam extractions from the main steam turbine are not needed for this purpose. The temperature of the feedwater entering the low-pressure economizer is 251° F. The feedwater temperature to the high-pressure economizer is 259° F. The temperature of the exhaust gases is reduced to 334° F at the HRSG exit. A portion of the exhaust gas is then used to dry the coal before crushing. This gas is returned to the stack, and the resulting stack temperature is 312° F.

The advanced fixed-bed gasifier is based on a current General Electric development program. The ECAS gasifier design uses Illinois #6 coal. Twenty-five percent of the coal is injected into the gasifier vessels by extruders and 75 percent by pressurized lockhoppers. Of the 14 gasifiers, 12 operate at one time and 2 are available as standby for maintenance or repair. The gasifier receives air from the gas-turbine compressors and water from the steam plant. Boost compressors are required to further compress the air from the gas-turbine compressor exit to the gasifier operating pressure and to overcome pressure losses in the gasifier and cleanup system. These boost compressors are driven by steam turbines expanding steam that is extracted from the main steam turbine. After expansion, this steam is condensed and part of the condensate is injected into the air blast to satisfy part of the gasifier water requirements. The rest goes back to join the main-steam-turbine feedwater stream.

The fuel gas cleanup system consists of an Alkazid plant for hydrogen sulfide adsorption and a Claus plant for sulfur recovery. The Alkazid cleanup system requires a considerable amount of steam, which is also supplied by steam extraction from the main steam turbine. Some heat energy from the cleanup system is used to heat gasifier process feedwater. A considerable amount of heat from the cleanup system is rejected to cooling towers. The low-Btu gas leaves the gasifier at 865° F and goes through wash coolers to remove heavy tars, light oils, and phenols. Most of the heavy tar is recirculated back to the gasifier. The light oils and phenols are reinjected into the low-Btu gas after cleanup. The low-Btu gas leaves the cleanup system at 275° F and is heated in a fuel preheater to 300° F by steam extracted from the main steam turbine. This avoids condensation of the water vapor in the low-Btu gas. The fuel gas flow rate to each of the gas turbines is 103.24 lb/sec. A more detailed description of this gasifier is presented in appendix B.

Description of Westinghouse Case

The simplified cycle schematic for this system is shown in figure 2(b) and some of the characteristics are summarized in table II. The 2500° F gas-turbine inlet temperature is defined by Westinghouse to be the temperature at the inlet to the first-stage vanes. The turbines are four-stage designs. The blading in both the rotor and stator of all stages is cooled, except for the last-stage rotor blades. The first stage is transpiration cooled; the remaining stages are cooled by a combination of impingement-convection cooling methods. Some of the cooling air is precooled in an air cooler that evaporates gasifier feedwater.

There are four HRSG units, one for each gas turbine. The heat-exchanger sections of each HRSG unit are shown in figure 2(b). The deaerator-evaporator raises steam that is used to heat the gasifier feedwater and to deaerate the incoming feedwater. Part of the steam raised in the intermediate-pressure evaporator is used in the gasifier and the remainder is further heated in the intermediate-pressure superheater and then mixed or "inducted" with the main cold reheat steam flow ahead of the reheater. There is one closed feedwater heater, requiring a steam extraction from the steam turbine. The temperature of the feedwater to the deaerator-evaporator is 117° F, and the temperature of the water entering the intermediate-pressure economizer is 260° F. The exhaust-gas temperature at the HRSG exit is 287° F, which is the resulting stack temperature.

The four Westinghouse fluidized-bed gasifiers are each made up of two stages: One stage consists of a 2000° F agglomerating gasifier bed and the other is a 1600° F desulfurizer/devolatilizer bed. Coal is devolatilized in the 1600° F bed, and the char and fines from this bed are gasified in the 2000° F bed in the presence of air and steam. The gas exiting the gasifier fluidizes the desulfurizer/devolatilizer. In-bed desulfurization is accomplished by injecting dolomite into the 1600° F bed.

Process air is supplied to the gasifiers by the gas-turbine compressors; process steam is supplied by the HRSG and the gas-turbine cooling air coolers. After extraction from the main compressor exits, the process air is first cooled by air-to-air recuperators and then by process air coolers that reject heat to cooling towers. This is done to minimize the boost compressor power requirements. The boost compressors are operated by electric motors and the power used is accounted for as an auxiliary power requirement of the plant. The air from the process air coolers then enters the boost compressors and is heated in the air recuperators. The hot air then enters the gasifiers.

The low-Btu gas exiting the gasifier vessels passes through three stages of particulate cleanup consisting of cyclone separators, multi-clone separators (which consist of a number of small cyclone separators), and granular bed filters. The flow rate of the 1585° F low-Btu gas to each combustor is 139.13 lb/sec. This gasifier is also further described in appendix C.

Comparison of Performance Results

As shown in table II, the overall efficiency calculated for the General Electric case is 39.6 percent and that for the Westinghouse case is 46.8 percent. In order to understand the 7.2 percentage point difference, the assumptions and performance differences of the individual subsystems as well as the methods of integration of the various subsystems must be examined. The overall differences in the system efficiencies can be explained by expressing the overall efficiency in terms of the subsystem efficiencies. This will be done by considering the energy flows of each system and using them to define subsystem efficiencies and some terms relating to their interfaces. The overall efficiency of each system will then be expressed as a function of these terms and subsystem efficiencies. In this way the different overall performance predictions of General Electric and Westinghouse are displayed in terms of the subsystem efficiency differences.

The energy interfaces between the various combined cycle subsystems are shown in figure 3 and were prepared from the contractors' data. The energy values shown correspond to the sum of the higher heating value, the sensible and latent energies associated with the flow streams between components, and the sensible heat transferred by heat exchangers from one subsystem to another. Also shown are the various losses from the subsystems, along with the electrical energy being produced. The relative widths of the various energy flow arrows approximately indicate the relative amount of energy transfer between subsystems. The crosshatched areas of the arrows indicate the amount of energy due to the higher heating value of the fuel. The remaining areas correspond to the sensible energy of the streams and the latent energy of the water vapor in those streams.

The complexity and high level of integration between the gasifier and the gas turbine/steam turbine systems is displayed. As shown in figure 3, the gasifier/cleanup system is "coupled" to the power system in four ways:

(1) Gasifier process steam is supplied by the power system.

(2) Gasifier air is supplied by the gas turbines.

(3) The sensible heat of the low-Btu gas is used in the power system.

(4) Gasifier auxiliary requirements are supplied by the power system.

From the energy flow diagrams (fig. 3), several subsystem efficiencies can be defined. A thermodynamic power system efficiency can be defined as:

$$\eta_{th} = \frac{P_{gt} + P_{st}}{(Q_{HHV} + Q_{sens})_{\text{clean LBtu gas}}} \tag{1}$$

(see appendix A for definition of symbols). The denominator includes the sensible heat as well as the heating value of the gas, since this energy is used by the power system. There is a considerable difference in the amount of sensible energy of the low-Btu (LBtu) gas between the General Electric and Westinghouse designs, and this will be discussed later.

The gasifier/cleanup system efficiency can be defined as:

$$\eta_g = \frac{(Q_{HHV} + Q_{sens})_{\text{clean LBtu gas}}}{Q_{HHV,\text{coal}} + Q_{sens,\text{air}} + Q_{gps}} \tag{2}$$

The numerator of equation (2) represents the total heating value and sensible energy of the low-Btu gas leaving the gasifier/cleanup system envelope, which is shown in figures 2 and 3. The denominator represents the total heat input (higher heating value) of the coal, the sensible energy of the air to the gasifier, and the total energy input of the gasifier/cleanup system process steam. The defined efficiency is thus the total useful energy of the LBtu gas to the power system divided by the total energy input to the gasifier/cleanup system. In order to make the comparisons consistent, the gasifier/cleanup system envelope has been drawn as shown in figure 3 to include the associated heat exchangers and the boost compressor and its drive.

The auxiliary power requirements are accounted for by the following efficiencies:

$$\eta_{p,aux} = \frac{P_{gross} - P_{p,aux}}{P_{gross}} \tag{3}$$

$$\eta_{g,aux} = \frac{P_{gross} - P_{p,aux} - P_{g,aux}}{P_{gross} - P_{p,aux}} \tag{4}$$

By using these subsystem efficiencies, the overall system efficiency can be written as:

$$\eta_{oa} = \eta_g \; \alpha \; \eta_{g,aux} \eta_{p,aux} \eta_{th} \tag{5}$$

The term (alpha) in equation (5) is defined as

$$\alpha = \frac{Q_{HHV,coal} + Q_{sens,air} + Q_{gps}}{Q_{HHV,coal}} \tag{6}$$

This is the ratio of the total heat input to the gasifier divided by the coal input energy charged to the overall power system. Alpha accounts for the sensible heat energy of compressed air, and latent and sensible heat of process steam from the power system to the gasifier envelope.

The values for the terms in equation (5) were calculated for the contractors' data by using the energy flow diagrams and are listed in table III. The most notable differences are in the gasifier/cleanup system efficiency, the gasifier auxiliary power, and the thermodynamic efficiency.

The difference in the gasifier/cleanup efficiency is due primarily to the differences in cleanup approach. In the General Electric cleanup system, a large portion of the low-Btu gas sensible heat is lost when the gas is water washed prior to the cold gas sulfur removal. This sensible heat cannot be recovered in a heat exchanger because of tars in the fuel gas which would condense and plug the heat exchanger passages. If a gasifier which produces a tar-free fuel gas were used, much of the gas sensible heat could be recovered and the losses attributed to this cold gas cleanup system could be reduced. In the Westinghouse system, desulfurization is done within the fluid bed and the hot fuel gas is filtered to remove particulates, with little loss in gas sensible heat. The fuel gas sensible heat available for use in the power system is consequently higher and the gasifier/cleanup efficiency, as defined in equation (2), is also higher.

The auxiliary power requirement estimated for the Westinghouse gasifier system is larger than that for the General Electric system. The difference appears even larger in table III, however, because of a difference in accounting. The boost compressors are motor driven in the Westinghouse system and are thus accounted for as an auxiliary power requirement (about 45 percent of the total gasifier system auxiliary power requirement). In the General Electric system, they are steam turbine-driven and the steam requirements are charged to the gasifier/cleanup efficiency.

The factors affecting the thermodynamic efficiencies are shown in table IV. The gas-turbine efficiency is defined as the electric power output of the gas turbines divided by the sum of the higher heating value and sensible heat energies of the low-Btu gas entering the gas-turbine combustors. In table IV, the General Electric gas-turbine efficiency is 0.296 and the Westinghouse efficiency is 0.318, a difference of 2.2 points. This difference is primarily due to two factors. First, the Westinghouse gas turbine has a higher compressor pressure ratio (16) than the General Electric gas turbine (12), and this higher pressure ratio results in higher efficiency. Second, the General Electric gas-turbine design uses more compressor bleed air for cooling than the Westinghouse design, where more effective transpiration cooling in the first stage is assumed. Impingement convection cooling is assumed for the General Electric design, except for some film cooling in the first-stage vanes.

The steam-cycle efficiency is defined as the electric power output of the steam turbine divided by the heat input to the steam cycle from the HRSG's. From table IV, there is a 4.2-point difference in steam-cycle efficiencies between General Electric and Westinghouse. This difference can be explained in part by the difference in steam-cycle parameters (1800 psig/950° F/ 950° F for General Electric; 2400 psig/1000° F/1000° F for Westinghouse) and also by the use of induction by Westinghouse in their steam cycle. A large part of the difference can also be attributed to the large amount of steam extracted from the General Electric steam turbine for gasifier/cleanup processes, with the resulting penalty in steam-turbine output and thus efficiency. For Westinghouse, the gasifier process steam is raised in the HRSG's, thus eliminating the need for steam-turbine extractions for this purpose. If it were possible to eliminate the extractions from the General Electric steam cycle, the steam-cycle efficiency would become 0.375, an increase of 3.4 points in bottoming-cycle efficiency. The steam-cycle efficiency for Westinghouse would remain essentially unchanged if no steam extractions from the HRSG were assumed, since the steam cycle is charged with only the heat input to the bottoming cycle and not the heat recovered in the HRSG to raise gasifier steam (fig. 3(b)).

When using this uncoupled steam-cycle efficiency for General Electric (which assumes no steam extractions from the steam turbine for gasifier/cleanup processes), a new thermodynamic efficiency of 0.457 is calculated. This is what the General Electric combined-cycle thermodynamic efficiency would be if the power system were partially uncoupled from the gasifier/cleanup system by severing the process-steam interface. For Westinghouse, the thermodynamic efficiency is not changed when the system is similarly partially uncoupled.

The differences in the thermodynamic efficiencies between General Electric and Westinghouse are due to differences in the gas-turbine and steam-cycle efficiencies, as well as to the thermodynamic fit between the topping and bottoming cycles. This thermodynamic fit is related to the amount of waste heat from the gas turbines that can be recovered in the HRSG's to raise steam for the bottoming cycle. For the particular configurations considered, the Westinghouse system has a slightly better thermodynamic fit since a slightly higher percentage of the waste heat is recovered in the HRSG's. This, then, also contributes to the difference in thermodynamic efficiencies.

Equation (5) is not entirely satisfactory, since it involves the thermodynamic efficiencies which, in the case of General Electric, are heavily influenced by the gasifier/cleanup system interface with the power system. Hence, this expression does not completely isolate the power system and gasifier/cleanup system effects. However, this can be corrected by using the thermodynamic efficiency for the partially uncoupled configuration explained previously. To do this, two terms for General Electric and one term for

Westinghouse in equation (5) must be changed. For General Electric, of course, the thermodynamic efficiency will be changed. Also, for both Westinghouse and General Electric, the alpha term will now be defined as

$$\alpha' = \frac{Q_{HHV,\,coal} + Q_{sens,\,air} + Q_{gps}}{Q_{HHV,\,coal} + Q_{gps}} \tag{7}$$

This new definition is necessary since, when partially uncoupled, the gasifier/cleanup system is not receiving process steam from the power system. So the energy of the gasifier process steam must be considered an additional heat input to the overall system.

The values of the terms in equation (5), when partially uncoupled, are shown in table V for General Electric and Westinghouse. The primed symbols denote that these values apply to the partially uncoupled cases. As can be seen, the overall efficiency for these uncoupled cases is slightly lower than shown in table III for both cases. The difference in the overall efficiencies shown in tables III and V gives an indication of the efficiency gains expected by coupling the gasifier/cleanup system to the power system. For General Electric, the gain in overall efficiency in going from partially uncoupled to coupled is 0.7 point; for Westinghouse it is 1.4 points. Using table V, the 7.2-point difference in overall system efficiency shown in table III can be interpreted in terms of differences in the gasifier/cleanup systems, power systems, and interfaces. First, there is a 2.8-point difference in thermodynamic efficiency. This is due to the differences in the gas-turbine performance, the partially uncoupled steam-cycle efficiency, and the differences in the percentage of the available waste heat input to the steam cycle (i.e., thermodynamic fit). By multiplying the thermodynamic efficiency by the powerplant auxiliary efficiency, the effects of the differences in auxiliary power requirements can be seen. This number becomes 0.444 for General Electric and 0.473 for Westinghouse, a difference of 2.9 points. Thus, 0.1 point (i.e., from 2.9 to 2.8) is due to differences in the power system auxiliary requirements. Multiplying out the remaining terms of equation (5), and thus calculating the overall efficiency of the partially uncoupled system, gives a 6.5-point difference in efficiency (0.454 to 0.389). Since these remaining terms are related to the gasifier/cleanup systems, the differences in the gasifier/cleanup system are seen to contribute 3.6 points to the overall difference of 7.2 points. Finally, the remaining efficiency difference of 0.7 point (from 7.2 to 6.5) is due to the coupling of the gasifier/cleanup systems with the power systems through the coupling of the steam requirements of the gasifier/cleanup systems with the steam bottoming cycles.

This allocation of the overall performance difference to the subsystems is shown in figure 4. Differences in the gasifier/cleanup systems include both the differences in the gasifier system efficiency, and the differences in the methods of integrating the power system with the gasifier. Taken together, these differences account for 4.3 percentage points of the total overall energy difference between the systems.

Comparison of Cost Results

A listing of the cost categories which were used by NASA to insure the comparable treatment of the contractors' cost results is shown in table VI. The capital costs rearranged according to the six NASA cost categories for the combined cycles integrated with low-Btu gasifiers are shown in tables VII(a) and (b) for General Electric and Westinghouse, respectively. The items for each major category of table VII are listed in the footnote. Each category is separated into major components, BOP material, and total labor. The costs for each category are expressed in dollars per kilowatt of net electric output. Also, the cost in dollars per kilowatt of the energy appropriate to each category is shown in parentheses. It is desirable to compare total material costs (major-component and BOP materials) since the contractors define these subdivisions somewhat differently.

A difference of 20.4 percent in total capital cost on a $/kWe basis ($770.8/kWe for General Electric; $613.5/kWe for Westinghouse) is shown between tables VII(a) and (b). The capital costs, before the charges for architect and engineering services, contingency, and escalation and interest are added (subtotal line) differ by 13.2 percent. The particular values for A and E services and contingency were selected by the architectural and engineering firm supporting each primary contractor. The escalation was specified for this study as $6\frac{1}{2}$ percent per year and the interest at 10 percent per year, and the factors for escalation and interest were calculated from a standard cash flow curve over the construction time of the plant. The last column in table VII indicates the percentage of the subtotal costs attributed to each category, as well as the charges added onto the subtotal. These added charges increase the cost by

96 percent for General Electric and by 80 percent for Westinghouse. The contribution of the A and E services is 10 percent for both contractors. The General Electric estimate for A and E services assumed that 15 percent applied to BOP material and site labor costs (but not to major-component costs), as compared with 10 percent applied by Westinghouse to major-component, BOP material, and site labor costs. The contingency estimated by the contractors was different, with General Electric assuming 20 percent and Westinghouse assuming 10 percent. Both contractors assumed a 5-year construction period. However, the percentage increase in capital cost due to interest and escalation shown in the last column of table VII is different as a result of the preceding differences.

A difference of $51.9/kWe in the subtotal capital costs is shown. The material cost differences account for $24.2/kWe of the subtotal cost difference, with the labor cost differences accounting for $27.7/kWe.

The most notable cost difference (not shown in the table) among the major components is the difference in HRSG costs ($17.0/kWt duty for General Electric; $43.6/kWt duty for Westinghouse). In the heat-exchanger sections of the HRSG's, Westinghouse selected smaller log mean temperature differences between the gas and steam sides than the General Electric design. This results in more heat transfer area per unit of energy transferred for the Westinghouse design. Also, the Westinghouse estimate is higher on a cost per unit weight basis.

There are also major differences in electrical plant and instrumentation costs and labor costs associated with the topping cycle (gas turbines). The difference in electrical equipment costs is due to differences in the cost estimates for cables, conduit, and trays and similar electrical equipment, as well as in the labor estimates for installation of this equipment. These equipment costs are sensitive to differences in the plant layout between the two contractors. The labor costs for the gas turbines are also considerably different. However, this portion is a small part of the overall cost and does not significantly affect the results. Differences in gasifier and cleanup system costs can be expected because of the different designs of the systems, although the total costs for category 2.0 in table VII are similar on a dollar-per-kilowatt-of-coal-input basis.

The capital costs and the resulting costs of electricity for the two designs are summarized in table VIII. From the table, it is seen that most of the cost of electricity is due to the capital portion of COE. As shown previously in table VII, the category 2.0 cost (coal/handling and gasifier/cleanup system) is the biggest single contributor to the capital cost. In comparing these two systems, it should be remembered that the designs were done as if each had reached a level of commercially mature technology. The fixed-bed gasifier with cold-gas cleanup represents a nearer term system option.

EFFECT OF TURBINE INLET TEMPERATURE ON A COMBINED CYCLE WITH FIXED BED GASIFIER

The General Electric ECAS results were used as a basis for additional calculations to show the influence of turbine inlet temperature on system performance and cost. The costs were estimated by scaling the General Electric cost estimates. The General Electric performance estimates for the gasifier/cleanup system and steam bottom cycle were used (with minor changes due to differences in steam extractions). The gas turbine performance was calculated at NASA for turbine stator inlet temperatures of 2000°, 2200°, and 2500° F. NASA generated cooling schedules were used and a 0.9-turbomachinery polytropic efficiency and 0.9 loss pressure ratio (i.e., turbine pressure ratio divided by compressor pressure ratio) were assumed.

The Phase 2 General Electric cost estimates were used whenever possible. Phase 1 cost trends were used for the 2000° F and 2200° F gas-turbine operation and maintenance costs. The gas-turbine costs estimated by General Electric for their 2400° F (first-stage rotor inlet) air-cooled gas turbine in Phase 2 were modified for the NASA 2500° F case to take into account the different electric power outputs of the two cases. Capital costs of components and related BOP materials and labor were scaled by duty for all modifications from General Electric's Phase 2 cost estimates. All capital costs were expressed in mid-1975 dollars before the addition of escalation and interest during construction.

The gas-turbine and overall system performance results for these modifications are shown in table IX. The compressor pressure ratios chosen for these cases are compatible with their respective turbine inlet temperatures in terms of sufficient gas-turbine exhaust temperatures suitable for the specified steam bottoming cycle. The amount of turbine coolant extracted from the compressor is expressed in terms of a percentage of the compressor inlet airflow rate. The difference in the steam-cycle efficiency for these modifications (compare tables IX and IV) is that, for these three cases, no steam extraction for the boost-compressor drive steam turbine is assumed. For convenience it was assumed that the boost compressor is motor driven and the power requirement is accounted as an auxiliary requirement of the plant.

The stack-gas temperatures shown in table IX are somewhat high for the 2000° F and 2200° F modifications. This is so because the steam bottoming cycle used was not the best one for these two cases as regards the thermodynamic fit (the amount of heat capable of being recovered from the turbine exhaust gases). A calculation was made to determine this effect on overall efficiency, and it was found that, if the exhaust-gas temperature could be lowered to 300° F (assuming the same steam plant efficiency), the 2000° F and 2200° F cases would have overall efficiencies of 38.4 and 40.3 percent, respectively. To achieve this stack-gas temperature, however, a new steam-cycle configuration would be needed.

The capital cost estimates for these three cases are shown in table X. The electric power output levels for the three modifications (2000°, 2200°, and 2500° F) are 457, 540, and 653 MWe, respectively, resulting in the $/kWe values shown. The compressor airflow rates for these cases were assumed the same as for the General Electric combined cycle with integrated-gasifier, 570 lb/sec for each gas turbine.

Comparing tables X(c) and VII(a), the NASA 2500° F case is shown to have a lower capital cost estimate in $/kWe than that of General Electric in ECAS Phase 2. This is due to the higher efficiency estimate of the NASA modification. This case has a higher overall efficiency, primarily as a result of more optimistic NASA assumptions for cooling flow schedules and turbomachinery efficiencies. Also, as a result of these more optimistic assumptions, the thermodynamic fit between the topping and bottoming cycles is improved in the NASA 2500° F case, with a stack gas (HRSG exit) temperature of 310° F as compared with 334° F for General Electric (table II). The combination of lower capital cost (on a $/kWe basis) and higher overall efficiency results in a lower COE for the NASA modification at a turbine inlet temperature of 2500° F.

The performance, capital cost, and cost of electricity of the three modified cases are summarized in table XI. The operation and maintenance costs were determined from Phase I cost trends. The effect of temperatures and pressure ratios on efficiency and COE is shown in figure 5. It should be recognized that these modifications only affect changes in the gas-turbine portion when the gasifier/cleanup technology is held constant. The results shown in this figure illustrate the effect of changes in the gas-turbine technology from current firing temperatures. At a 2000° F turbine inlet, the overall efficiency and COE are competitive with the steam systems using stack gas scrubbers which are shown in figure 1. This case represents the performance of a state-of-the-art gas turbine system integrated with a fixed-bed gasifier and cold-gas desulfurization. The comparison of the General Electric and Westinghouse designs shows the influence of gasifier/cleanup technology.

CONCLUDING REMARKS

The low-Btu-gasifier/combined-cycle systems studied in ECAS Phase 2 have been described and compared. The overall efficiency and cost of electricity for each of these systems were attractive in relation to the other systems studied. The combined-cycle system studied by General Electric with an advanced fixed-bed gasifier and cold-gas desulfurization resulted in an overall efficiency of 39.6 percent. The system studied by Westinghouse with a fluid-bed gasifier with in-bed desulfurization and hot-gas particulate removal resulted in an overall efficiency of 46.8 percent. Differences in overall system performance are due primarily to differences in the fuel-gas cleanup as well as to differences in the gas-turbine and steam cycle performance and in the integration of these with the gasifier/cleanup system.

By considering the overall efficiency in terms of the efficiencies of the subsystems and the way they are interfaced, it has been indicated that about 4.3 percentage points of the 7.2-point difference in overall efficiency can be attributed to the gasifier/cleanup system and the method of integration.

The gasifier/cleanup system efficiency for the General Electric design is lower than that for the approach used by Westinghouse because of the loss in sensible heat of the fuel-gas prior to cold-gas desulfurization. This sensible heat is not recoverable in a heat exchanger because of the presence of tars in the fuel gas. Therefore, the fuel gas is water-washed prior to desulfurization. If a gasifier which is not expected to produce tars is used with a cold-gas desulfurization process, the system could be configured to recover some of the sensible heat and performance losses attributable to cold-gas cleanup would be lower

The performance differences between the General Electric and Westinghouse designs were shown to be the direct result of differences in technical approach, such as choice of gasifier/cleanup type, turbine cooling type, and method of plant integration. In comparing them it should be noted that all of the ECAS Phase 2 conceptual designs were done as if they had reached a level of commercially mature technology. But the present state of technology involved in some of the design choices differs. Other factors such as time and resources required to bring these plants to commercial readiness and more qualitative factors that would affect their implementation, should also be considered.

Three NASA modifications consisted of varying the turbine inlet temperatures and compressor pressure ratios of a combined cycle using the General Electric gasifier/cleanup system. These modifications show the advantage of higher turbine inlet temperatures and compressor pressure ratios in terms of cost of electricity and performance. For the range of firing temperatures discussed (2000° F to 2500° F), the combined cycles with integrated gasifiers appear to offer costs of electricity and efficiencies that are superior to steam systems using stack-gas scrubbers.

APPENDIX A

SYMBOLS

$P_{g,aux}$	gasifier/cleanup system electric power requirements
P_{gross}	powerplant gross electric power output
P'_{gt}	power output of gas turbine
$P_{p,aux}$	powerplant auxiliary electric power requirements
P_{st}	power output of steam turbine
Q_{gps}	energy of the process steam to the gasifier/cleanup system envelope
Q_{HHV}	energy due to higher heating value of fuel
Q_{sen}	sensible energy of gas
α(alpha)	ratio of heat input to gasifier divided by coal input energy charged to the power system
η_g	gasifier/cleanup system efficiency
$\eta_{g,aux}$	gasifier auxiliary power efficiency
η_{oa}	overall system efficiency
$\eta_{p,aux}$	powerplant auxiliary power efficiency
η_{th}	thermodynamic efficiency

Superscript:

'	denotes partially uncoupled results

APPENDIX B

DESCRIPTION OF GASIFIER/CLEANUP SYSTEM USED BY

GENERAL ELECTRIC

The gas turbine/steam, combined-cycle system studied by General Electric in ECAS Phase 2 has an integrated, advanced, fixed-bed gasifier. The gasifier design is based on a current General Electric development program. A simplified schematic of the gasifier/cleanup portion of the powerplant is shown in figure 6(a).

Coal is added by lockhoppers and extruders at the top of the gasifier vessel, and ash is removed at the bottom. The coal is first dried and then crushed. The coal is dried so that fines can be separated out and injected, with the recycled tar, into the gasifier by extruders. Approximately a quarter of the total coal input is by extrusion, the remaining input being by pressurized lockhoppers. Before the coal enters the gasifier, the moisture is restored. Air from the gas-turbine compressor is introduced near the bottom of the vessel after being further compressed in a boost compressor. As the coal moves downward. it is heated, devolatilized, and gasified by the counterflowing gases. Combustion of some of the coal occurs just above a rotating grate near the bottom to provide heat for the reactions in the reduction zone located above. The vessel contains two stirrer mechanisms, or rabble arms, to break clinkers and to allow greater throughput and the use of caking coals.

The raw, low-Btu gas leaving the gasifier vessel is at 865° F and 263 psi and contains oils, tars, phenols, ammonia, hydrogen sulfide, and particulates. It then passes through two vessels, where it is washed and cooled and the particulates, tars, oils, and phenols are removed. A large part of the heavy tars is recycled to the gasifier, and the oils and phenols are put back into the fuel gas after the sulfur cleanup. The fuel gas leaves this wash step at 307° F and 256 psi and enters an Alkazid sulfur-recovery system.

The Alkazid plant envelope, as indicated in the figure, includes several steps. In the first step of the Alkazid process, the fuel gas is further cooled to 100° F. It is then passed through absorbing towers where hydrogen sulfide and some carbon dioxide are absorbed from the gas by the Alkazid fluid. The cleaned fuel gas is then reheated and rewatered, in part by exchanging heat with the incoming fuel gas, to 275° F. After the addition of oils and phenols and further heating to 300° F, the fuel gas enters the gas-turbine combustor. The hydrogen-sulfide-rich Alkazid fluid is stripped of the hydrogen sulfide and carbon dioxide gas and is recirculated to the absorbing towers. The hydrogen sulfide - carbon dioxide acid gas is then input to a standard Claus sulfur-recovery plant.

In the Claus plant about a third of the gas is combusted to form sulfur dioxide. This is then reacted with the remaining hydrogen sulfide to form elemental sulfur. Heat released in oxidizing part of the hydrogen sulfide and in solidifying the liquid sulfur is used to generate steam for the Alkazid plant and to heat feedwater for the gasifier.

General Electric assumed that the Alkazid plant will remove enough hydrogen sulfide from the fuel gas to permit the power-system gasifier/cleanup system to meet the emission standards for oxides of sulfur. According to the information provided by General Electric, about 95.3 percent of the hydrogen sulfide and about 12.7 percent of the carbon dioxide in the raw fuel are removed. Not all the sulfur in the coal appears in the fuel gas and not all the sulfur in the fuel gas appears as hydrogen sulfide. (Carbonyl sulfide is formed and is not removed from the fuel gas by the Alkazid plant.) Thus, in this design about 11 percent of the sulfur in the coal remains in the fuel gas used in the power system.

Of the hydrogen sulfide removed by the Alkazid plant, the Claus plant then converts 95 percent to elemental sulfur, which is then disposed of in solid form. The remaining 5 percent leaves the Claus plant in the tail gas and is oxidized to sulfur dioxide in an incinerator that uses leak gas from the coal hoppers and some of the tar from the gasifiers.

Considering the sulfur dioxide released in the powerplant exhaust and that released from the tail-gas incinerator, the overall system just meets the environmental standard for sulfur dioxide of 1.2 lb/MBtu.

In the General Electric gas turbine/steam, combined-cycle system, 14 gasifier modules are used, 12 of which operate during full-power-level operation of the plant. Two modules can be down at any time for maintenance. Each gasifier vessel is 14 feet in diameter. In the Alkazid plant, the fuel-gas, heat-exchanger series consists of 11 tube-in-shell vessels, each about 8 feet in diameter and 20 feet long. Two 11-foot-diameter Alkazid absorption towers and one 13-foot-diameter Alkazid hydrogen-sulfide-recovery tower are used. Three 100-long-ton-per-day Claus plants are used, with two operating at any given time and one serving as a spare.

APPENDIX C

DESCRIPTION OF GASIFIER/CLEANUP SYSTEM USED BY WESTINGHOUSE

The gas turbine/steam, combined-cycle system studied by Westinghouse in ECAS Phase 2 has an advanced, integrated, multistage, fluidized-bed gasifier. The design is based on current development work at Westinghouse. A simplified schematic of the gasifier/cleanup system is shown in figure 6(b).

The process consists of two main stages: the devolatilizer/desulfurizer bed operating in the 1600° F range, and the gasifier bed operating in the 2000° F range. The coal is crushed and dried to a 3-percent moisture content and put through a lockhopper into the devolatilizer/desulfurizer bed. The coal is injected into a draft tube within this bed, through which the bed solids are continuously recirculated. The coal is converted to char, which is withdrawn from this bed and injected into the lower gasifier bed. The gasifier bed is fluidized by air from the power-system compressor. After it is extracted from the gas-turbine topping cycle, the air is first cooled in a recuperator and precooler, further compressed in the boost compressor, and then reheated in the recuperator before it enters the gasifier. Steam is injected into this bed to serve as gasifier process steam and to control temperatures in the lower zone. In this lower zone, part of the char is combusted to supply heat for the gasification reactions, and the ash agglomerates into particles large enough to gravitate to the bottom, where it is removed.

The 2000° F fuel gas from the lower bed fluidizes the upper devolatilizer/desulfurizer bed. Additional air from the power system and the dolomite sorbent is also injected into the upper bed. When the dolomite is heated in the bed, carbon dioxide is driven off to form lime. This in turn reacts with the hydrogen sulfide that was formed in the gasifier from the sulfur in the coal. The spent sorbent (calcium sulfide) is then removed from the bed. Before disposal, the spent sorbent is oxidized to calcium sulfate. The heat of this reaction is used to dry the incoming coal and to raise some of the process steam.

Westinghouse assumed that 90 percent of the hydrogen sulfide formed would be removed by reaction with the sorbent. Since they estimate that about 3 percent of the sulfur will appear as carbonyl sulfide (COS) and not be recovered, the overall percentage of sulfur recovery is about 87 percent. This results in overall powerplant sulfur emissions of 0.91 lb/MBtu, less than the specified standard of 1.2 lb/MBtu.

Westinghouse expects the desulfurized fuel gas leaving the second fluidized bed to be free of tars. Three stages of particulate removal are shown in figure 6(b). The first stage is a cyclone designed for 1600° F operation. The second stage is a multi-clone separator (a cluster of cyclones contained within one large vessel). The third stage is a Ducon granular bed filter. The fuel gas at the exit of the particulate-removal system is at 1585° F and 300 psi.

In the Westinghouse gas turbine/steam, combined-cycle system, four complete gasification subsystems are used in the total plant. Each gasifier vessel, which contains both fluidized-bed stages, is about 14.5 feet in diameter and 100 feet high. Each vessel has its own particulate-removal system. The multi-clone separators are about 17 feet in diameter, and the Ducon filters are about 25 feet in diameter. The gasifier subsystem includes, in addition to the gasifier vessel and the three-stage particulate-removal system, the process steam drum; the process-air boost compressor and motor drive; the process-air recuperator and cooler; the lockhopper systems for coal, dolomite, and ash; the coal and dolomite preheaters; the spent-sorbent oxidizer; and the oxidizer-output-gas scrubber. A large part of the gasifier auxiliary power is for the booster compressor, which is motor driven.

REFERENCES

1. "Energy Conversion Alternatives Study (ECAS), General Electric Phase I." Final Report, NASA CR-134948, 1976.

2. "Energy Conversion Alternatives Study (ECAS), Westinghouse Phase I." Final Report, NASA CR-134941, 1976.

3. "Comparative Evaluation of Phase I Results from the Energy Conversion Alternatives Study (ECAS)." NASA TM X-71855, 1976.

4. "Energy Conversion Alternatives Study (ECAS), General Electric Phase II." Final Report, NASA CR-134949, 1977.

5. "Energy Conversion Alternatives Study (ECAS), Westinghouse Phase II." Final Report, NASA CR-134942, 1977.

6. "Energy Conversion Alternatives Study (ECAS), United Technologies Phase II." Final Report, NASA CR-134955, 1977.

7. "Evaluation of Phase 2 Conceptual Designs and Implementation Assessment Resulting from the Energy Conversion Alternatives Study (ECAS)." NASA TM X-73515, 1977.

TABLE I. - SUMMARY OF ECASE PHASE 2 STUDY GROUNDRULES

Fuels	Coal: Illinois #6 Coal-derived fuels: H-coal
Site	Middletown, USA
Ambient conditions:	
For performance calculations	
Cooling water, °F	75
Air, °F	59
Emission targets (lb/MBtu):	
SOX - Solid fuel	1.2
Liquid fuel	.8
Gaseous fuel	---
NOX - Solid fuel	.7
Liquid fuel	.3
Gaseous fuel	---
Particulates - all fuels	.1
Economic base year	Mid 1975
Escalation during construction, percent/yr[a]	6.5
Interest during construction, percent/yr[a]	10
Composite labor rate, $/hr	11.75
Fixed charge rate, percent/yr	18
Capacity factor	0.65
Coal cost, $/MBtu	1.00
H-coal cost, $/MBtu	2.25

[a]Applied using specified S-shaped cash flow curve.

TABLE II. - SUMMARY OF GAS TURBINE/STEAM COMBINED-CYCLE

SYSTEMS WITH INTEGRATED LOW-Btu GASIFIERS

	General Electric	Westinghouse
Gasifier/cleanup system:		
Gasifier type	Fixed bed	Fluidized bed
Number of gasifier modules	14	4
Low-Btu gas delivery temperature to gas turbines, $^{\circ}F$	300	1585
Higher heating value of low-Btu gas, Btu/lb	3063	2398
Sulfur-recovery method	Alkazid H_2S/Claus	In-bed desulfurization
Particulate-removal method	Water wash	Cyclones; granular bed filters
Gas turbine:		
Turbine inlet temperature, $^{\circ}F$	2400 (at first-stage rotor blades)	2500 (at first-stage stator vanes)
Compressor pressure ratio	12	16
Number of gas turbines	4	4
Compressor inlet airflow per gas turbine, lb/sec	570	750
Power output per gas turbine, MWe	101.8	135.8
Gas-turbine cooling medium	Air	Air
Steam turbine:		
Cycle, psig/$^{\circ}F$/$^{\circ}F$	1800/950/950	2400/1000/1000
Steam-turbine power output, MWe	200	285
Feedwater temperature at economizer, $^{\circ}F$	259	260
Heat-recovery steam generator exit gas temperature, $^{\circ}F$	334	287
Steam-turbine induction	No	Yes
Stack-gas temperature, $^{\circ}F$	312	287
Overall results:		
Auxiliary power requirements, MWe	22.4	42.0
Net power output, MWe	584.8	786.4
Overall energy efficiency, percent	39.6	46.8
Capital cost, \$/kWe	770.8	613.5
Cost of electricity, mills/kW-hr	35.1	29.1

TABLE III. - PERFORMANCE COMPARISON OF GAS TURBINE/

STEAM COMBINED-CYCLE SYSTEMS WITH INTEGRATED

LOW-Btu GASIFIERS - COUPLED RESULTS

	General Electric	Westinghouse
Overall energy efficiency, η_{oa}	0.396	0.468
Coupling factor, α	1.078	1.071
Gasifier/cleanup system efficiency, η_g	.862	.949
Gasifier auxiliary power efficiency, $\eta_{g, aux}$	.992	.972
Powerplant auxiliary power efficiency, $\eta_{p, aux}$	.971	.976
Thermodynamic efficiency, η_{th}	.442	.485

TABLE IV. - FACTORS AFFECTING THERMODYNAMIC EFFICIENCY

	General Electric	Westinghouse
Gas turbine:		
Efficiency, percent	29.6	31.8
Compressor pressure ratio	12	16
Turbine cooling procedure	Film and convection	Transpiration and convection
Steam turbine:		
Coupled efficiency, percent	34.1	38.3
Uncoupled efficiency, percent	37.5	38.3
Cycle, psig/^{o}F/^{o}F	1800/950/950	2400/1000/1000
Induction	No	Yes
Extraction for gasifier	Steam turbine	Heat-recovery steam generator

TABLE V. - PERFORMANCE COMPARISON OF GAS TURBINE/STEAM COMBINED-CYCLE SYSTEMS WITH INTEGRATED LOW-Btu GASIFIERS - PARTIALLY UNCOUPLED RESULTS

	General Electric	Westinghouse
Overall energy efficiency, η'_{oa}	0.389	0.454
Coupling factor, α'	1.024	1.039
Gasifier/cleanup system efficiency, η'_g	.862	.949
Gasifier auxiliary power efficiency, $\eta'_{g,aux}$	.993	.972
Powerplant auxiliary power efficiency, $\eta'_{p,aux}$	.972	.976
Thermodynamic efficiency, η'_{th}	.457	.485

TABLE VI. - NASA COST CATEGORIES

1.0	Land improvement and structures
2.0	Furnace and solids handling
3.0	Topping cycle equipment
4.0	Bottoming cycle
5.0	Electrical plant and instruments
6.0	Cooling towers

TABLE VII. - SUMMARY OF POWERPLANT CAPITAL COSTS FOR AIR-COOLED, OPEN-CYCLE GAS TURBINE/

STEAM COMBINED-CYCLE SYSTEMS WITH INTEGRATED LOW-Btu GASIFIERS

(a) General Electric (Specific costs in parentheses are based on appropriate electrical or thermal power specified in column 1. Other specific costs are based on system net power of 584.8 MWe.)

Category[a]	Major components		Balance-of-plant materials		Site labor (direct and indirect)		Total		
	Cost, dollars	Specific cost, $/kWe	Cost, dollars	Specific cost, $/kWe	Cost, dollars	Specific cost, $/kWe	Cost, dollars	Specific cost, $/kWe	Percent of subtotal
1.0 - Land improvements and structures	------	------	9.6	16.4	15.9	27.3	25.5	43.7	11.1
2.0 - Coal handling, gasification, and cleanup systems (1477 MWt (coal))	25.0	42.7 (17.0)	39.4	67.4 (26.7)	33.0	56.4 (22.3)	97.4	166.5 (66.0)	42.4
3.0 - Topping cycle (407.2 MWe (gas turbine))	32.4	55.4 (79.6)	.4	.7 (.9)	1.2	2.1 (3.0)	34.0	58.2 (83.5)	14.8
4.0 - Bottoming cycle (200 MWe (steam))	19.7	33.7 (98.5)	4.9	8.4 (24.4)	10.0	17.1 (50.2)	34.6	59.2 (173.1)	15.1
5.0 - Electrical plant and instrumentation	------	------	13.4	23.0	20.5	35.1	33.9	58.1	14.8
6.0 - Cooling towers (427.1 MWt (rejection))	------	------	2.4	4.1 (5.5)	1.8	3.1 (4.2)	4.2	7.2 (9.7)	1.8
Subtotal	77.1	131.8	70.1	120.0	82.4	141.1	229.6	392.9	100.0
Architect and engineering services	------	------	10.5	18.0	12.4	21.2	22.9	39.2	10.0
Contingency	15.4	26.4	16.1	27.5	19.0	32.4	50.5	86.4	22.0
Escalation and interest	45.1	77.1	47.0	80.4	55.5	94.8	147.6	252.3	64.3
Total	137.6	235.3	143.7	245.9	169.3	289.5	450.6	770.8	196.3

TABLE VII. - Concluded.

(b) Westinghouse (Specific costs in parentheses are based on appropriate electrical or thermal power specified in column 1. Other specific costs are based on system net power of 786.4 MWe.)

1.0 - Land improvements and structures	----	----	12.3	15.6	18.0	22.9	30.3	38.5	11.3
2.0 - Coal handling, gasification, and cleanup systems (1680 MWt (coal))	29.0	36.9 (17.3)	26.4	32.3 (15.1)	38.4	48.8 (22.9)	92.8	118.0 (55.2)	34.6
3.0 - Topping cycle (543.3 MWe (gas turbine))	45.8	58.2 (84.3)	.8	1.0 (1.5)	6.2	7.9 (11.4)	52.8	67.1 (97.2)	19.7
4.0 - Bottoming cycle (285.0 MWe (steam))	46.8	58.2 (160.8)	4.7	6.0 (16.4)	14.3	18.2 (50.0)	64.8	82.4 (227.2)	24.2
5.0 - Electrical plant and instrumentation	----	----	12.4	15.8	9.3	11.8	21.7	27.6	8.1
6.0 - Cooling towers (482.4 MWt (rejection))	----	----	2.8	3.6 (5.8)	3.0	3.8 (6.3)	5.8	7.4 (12.1)	2.1
Subtotal	120.6	153.3	58.4	74.3	89.2	113.4	268.2	341.0	100.0
Architect and engineering services	12.1	15.3	5.8	7.4	8.9	11.3	26.8	34.0	10.0
Contingency	13.3	16.9	6.4	8.2	9.8	12.5	29.5	37.6	11.0
Escalation and interest	71.1	90.3	34.4	43.8	52.5	66.8	158.0	200.9	58.9
Total	217.1	275.8	105.0	133.7	160.4	204.0	482.5	613.5	179.9

[a]Items in each category are as follows, where asterisks denote items that are or include major components:

1.0 - Land improvements and structures:
- Land cost
- Site preparation and improvements
- Roads and railroads
- Concrete substructures and foundations
- Superstructures
- Station buildings
- Water treatment ponds
- Turbine hall cranes
- Yard fire protection, fences, and gates

2.0 - Coal handling, gasification, and cleanup systems:
- General Electric:
  - Other large piping
  - Heaters, exchangers, tanks, and vessels
  - Booster air compressor
  - Coal handling
  - Hangers and miscellaneous labor operations
  - Ash handling
  - Sulfur handling
  - Large fuel-gas pipe
  - Gas cleanup
    - Pumps and drives
    - Heaters and exchangers
    - Tanks and vessels
    - Claus plant
  - *Gasifiers
    - Gasifiers
    - Process mechanical equipment (wash coolers and air saturator)
    - Civil and structural
    - Piping
    - Coal handling
- Westinghouse:
  - On-site process waste disposal
  - Coal handling system
  - Dolomite handling system
  - Fuel oil or oil distillate handling system
  - *Coal and dolomite preparation and live storage
  - Process waste handling system
  - *Gasifiers and auxiliaries
  - *Gas system cleanup
  - Hot-gas piping systems

3.0 - Topping-cycle plant equipment:
- *Gas turbine-generator
- Stacks

4.0 - Bottoming cycle:
- *Heat-recovery steam generators
- *Steam turbine-generator
- Boiler feedwater pumps
- Other pumps
- Condenser
- Steam and feedwater piping
- Feedwater heaters

5.0 - Electrical plant and instrumentation:
- Main transformer
- Other transformers and motors
- Buswork
- Switchgear and control boards
- Conduit, cable trays, wire, and cables
- Instrumentation and controls
- Lighting and communications

6.0 - Cooling towers:
- Main circulating-water pumps
- Circulating-water-system structure, piping, and auxiliary
- Cooling towers

TABLE VIII. - COST-OF-ELECTRICITY COMPARISON OF GAS TURBINE/STEAM COMBINED-CYCLE SYSTEMS WITH INTEGRATED LOW-Btu GASIFIERS

	General Electric	Westinghouse
Plant capital cost, \$/kWe	770.8	613.5
Overall energy efficiency, percent	39.6	46.8
Cost of electricity, mills/kW-hr:		
Capital	24.4	19.4
Fuel	8.6	7.3
Operation and maintenance	2.1	2.4
Total	35.1	29.1

TABLE IX. - PERFORMANCE OF GAS TURBINE/STEAM COMBINED-CYCLE SYSTEMS WITH INTEGRATED LOW-Btu GASIFIERS

	Turbine inlet temperature, °F		
	2000	2200	2500
Compressor pressure ratio	8	10	12
Percentage of compressor inlet flow used for turbine cooling	6.68	10.16	16.18
Gas-turbine efficiency, percent	26.8	29.2	31.7
Steam-turbine efficiency, percent	36.1	36.1	36.1
Overall energy efficiency, percent	37.0	39.3	42.0
Stack-gas temperature, °F	375	352	310

TABLE X. - CAPITAL COST ESTIMATE BY CATEGORY FOR GAS TURBINE/STEAM COMBINED-CYCLE SYSTEMS WITH INTEGRATED FIXED-BED GASIFIERS

(a) 2000° F turbine inlet temperature (457 MWe net)

Category	Major-component materials	Balance-of-plant materials	Site labor (direct and indirect)	Total
	Capital cost, $/kWe			
1.0 - Land improvements and structures	-----	16.6	27.8	44.4
2.0 - Coal handling, gasification, and cleanup systems	46.8	73.7	61.7	182.2
3.0 - Topping-cycle plant equipment	45.5	.7	2.4	48.6
4.0 - Bottoming cycle	39.4	9.6	19.9	68.9
5.0 - Electrical plant and instrumentation	-----	23.4	35.9	59.3
6.0 - Cooling towers	-----	4.6	3.5	8.1
Subtotal	131.7	128.6	151.2	411.5
Architect and engineering services	-----	19.3	22.7	42.0
Contingency	26.3	29.6	34.8	90.7
Escalation and interest	76.9	86.4	101.6	264.9
Total	234.9	263.9	310.3	809.1

(b) 2200° F turbine inlet temperature (540 MWe net)

Category	Major-component materials	Balance-of-plant materials	Site labor (direct and indirect)	Total
1.0 - Land improvements and structures	-----	16.3	27.2	43.5
2.0 - Coal handling, gasification, and cleanup systems	43.1	67.8	56.7	167.6
3.0 - Topping-cycle plant equipment	45.4	.6	2.0	48.0
4.0 - Bottoming cycle	36.1	8.9	18.3	63.3
5.0 - Electrical plant and instrumentation	-----	23.0	35.2	58.2
6.0 - Cooling towers	-----	4.1	3.1	7.2
Subtotal	124.3	120.7	142.5	387.5
Architect and engineering services	-----	18.1	21.4	39.5
Contingency	24.9	27.8	32.8	85.5
Escalation and interest	72.7	81.1	95.8	249.6
Total	221.9	247.7	292.5	762.1

(c) 2500° F turbine inlet temperature (653 MWe net)

Category	Major-component materials	Balance-of-plant materials	Site labor (direct and indirect)	Total
1.0 - Land improvements and structures	-----	16.4	27.3	43.7
2.0 - Coal handling, gasification, and cleanup systems	40.3	63.4	53.0	156.7
3.0 - Topping-cycle plant equipment	49.6	.6	1.8	52.0
4.0 - Bottoming cycle	34.2	8.4	17.3	59.9
5.0 - Electrical plant and instrumentation	-----	23.0	35.1	58.1
6.0 - Cooling towers	-----	4.0	3.1	7.1
Subtotal	124.1	115.8	137.6	377.5
Architect and engineering services	-----	17.4	20.6	38.0
Contingency	24.8	26.6	31.6	83.0
Escalation and interest	72.5	77.8	92.4	242.7
Total	221.4	237.6	282.2	741.2

TABLE XI. - COMPARISON OF COMBINED CYCLES WITH ADVANCED FIXED-BED GASIFIERS AT VARIOUS TURBINE INLET TEMPERATURES

Turbine inlet temperature, ^{o}F	2000	2200	2500
Powerplant capital cost, $/kWe	809.1	762.1	741.2
Overall energy efficiency, percent	37.0	39.3	42.0
Cost of electricity, mills/kW-hr:			
Capital	25.6	24.1	23.4
Fuel	9.2	8.7	8.1
Operation and maintenance	2.7	2.5	2.2
Total	37.5	35.3	33.7

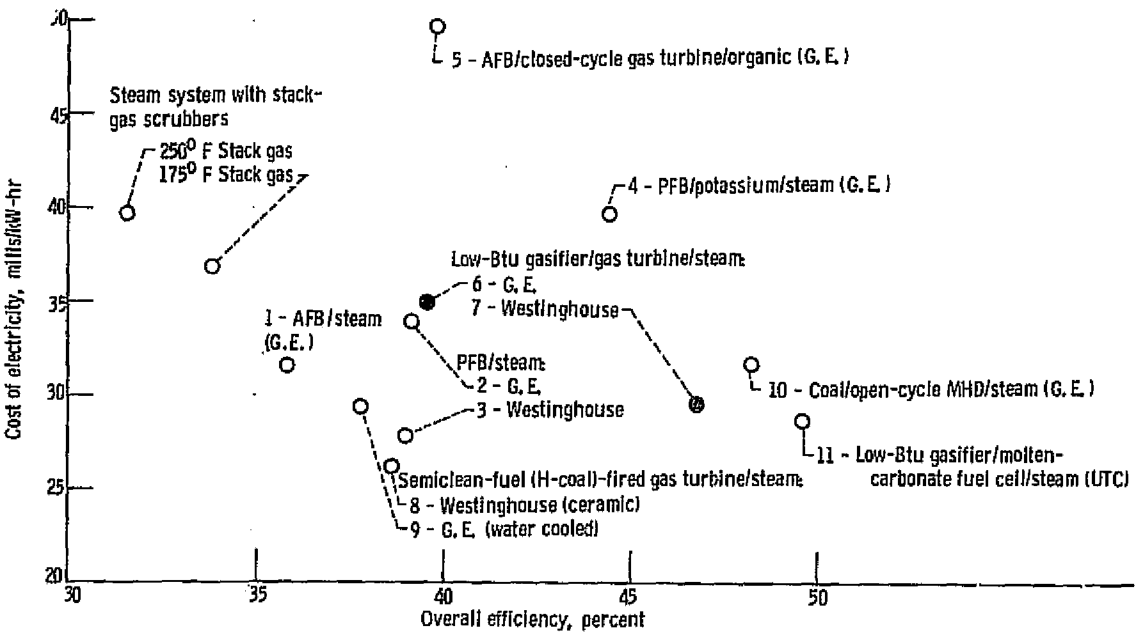
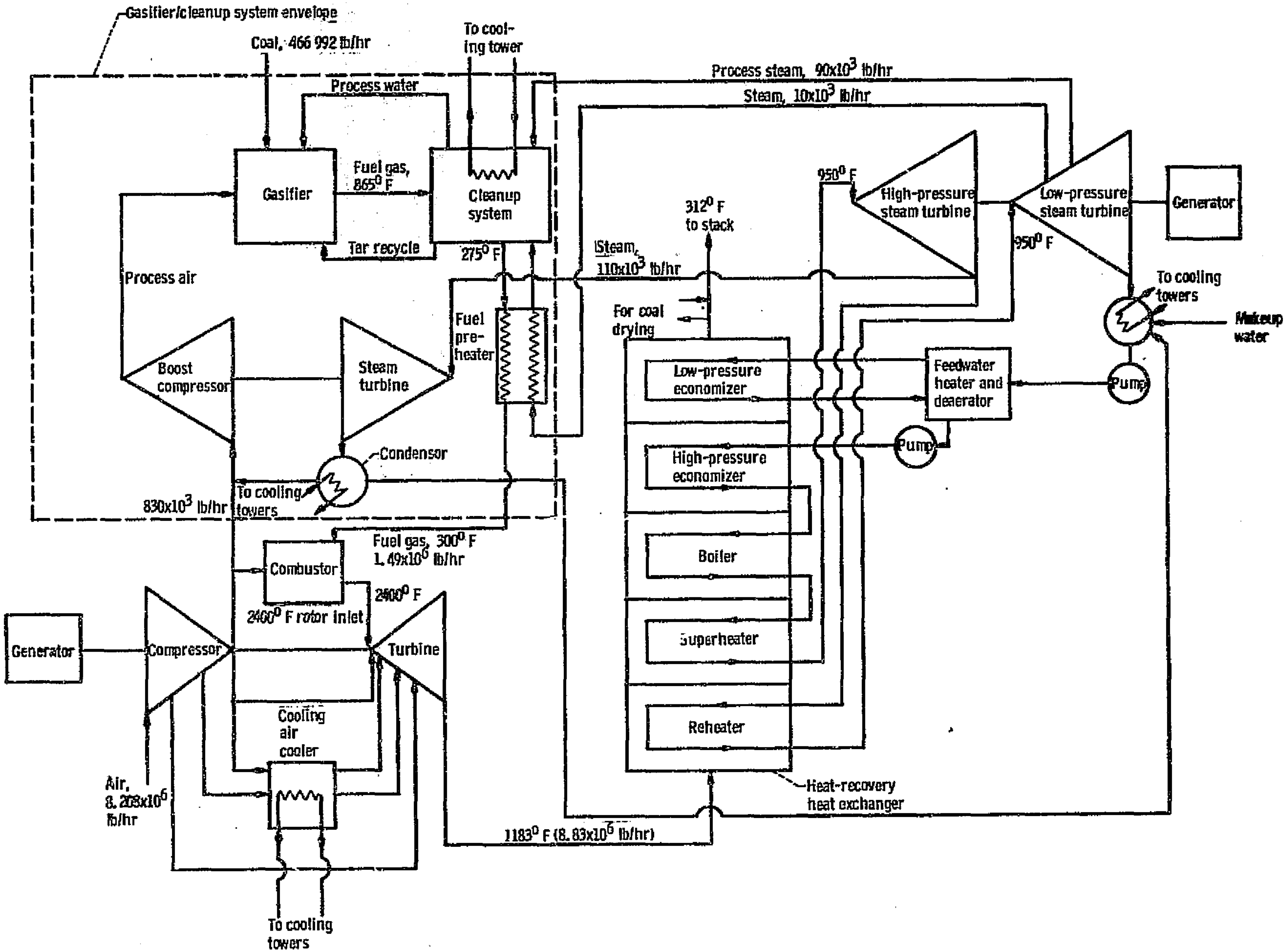
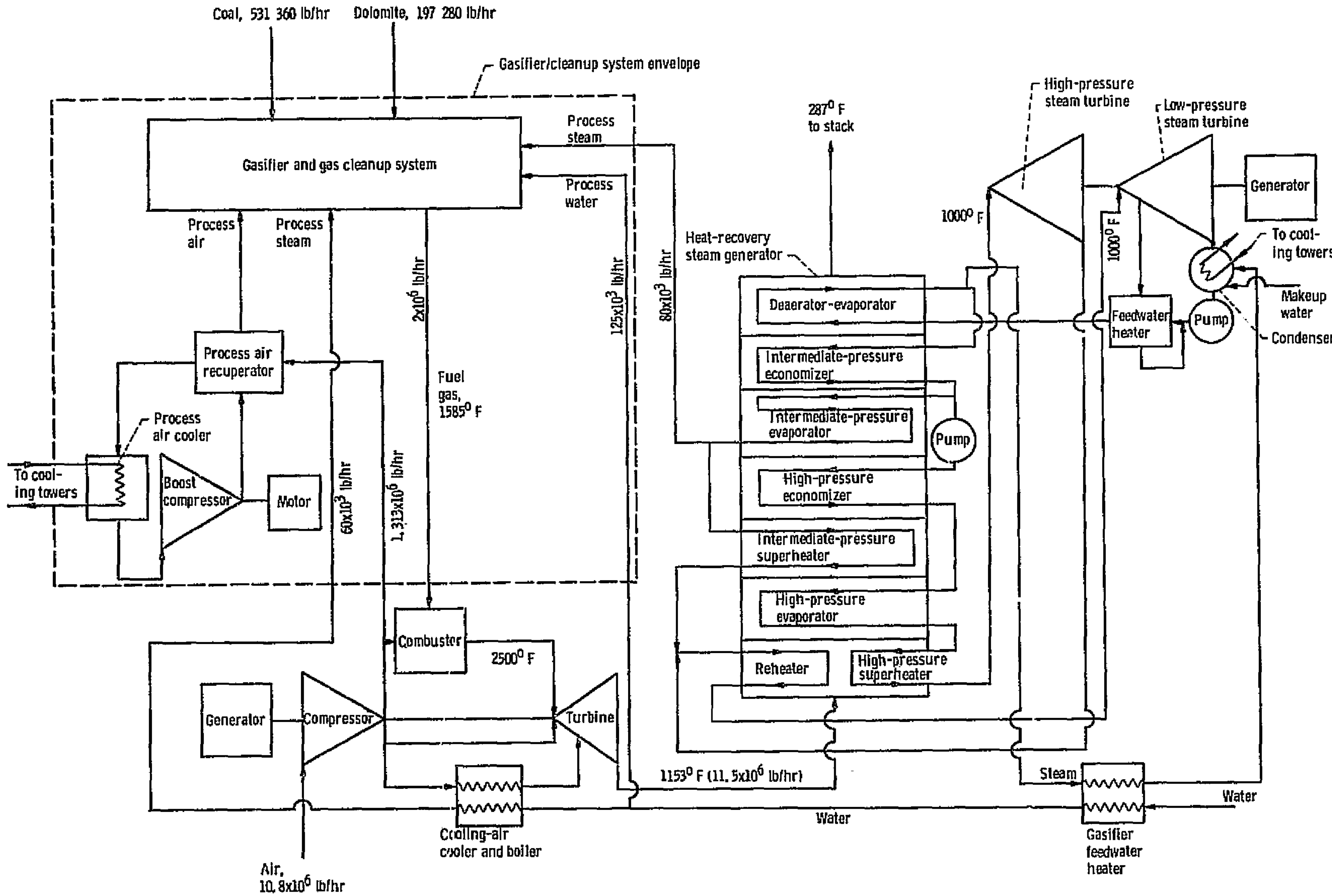


Figure 1. - ECAS Phase 2 results.



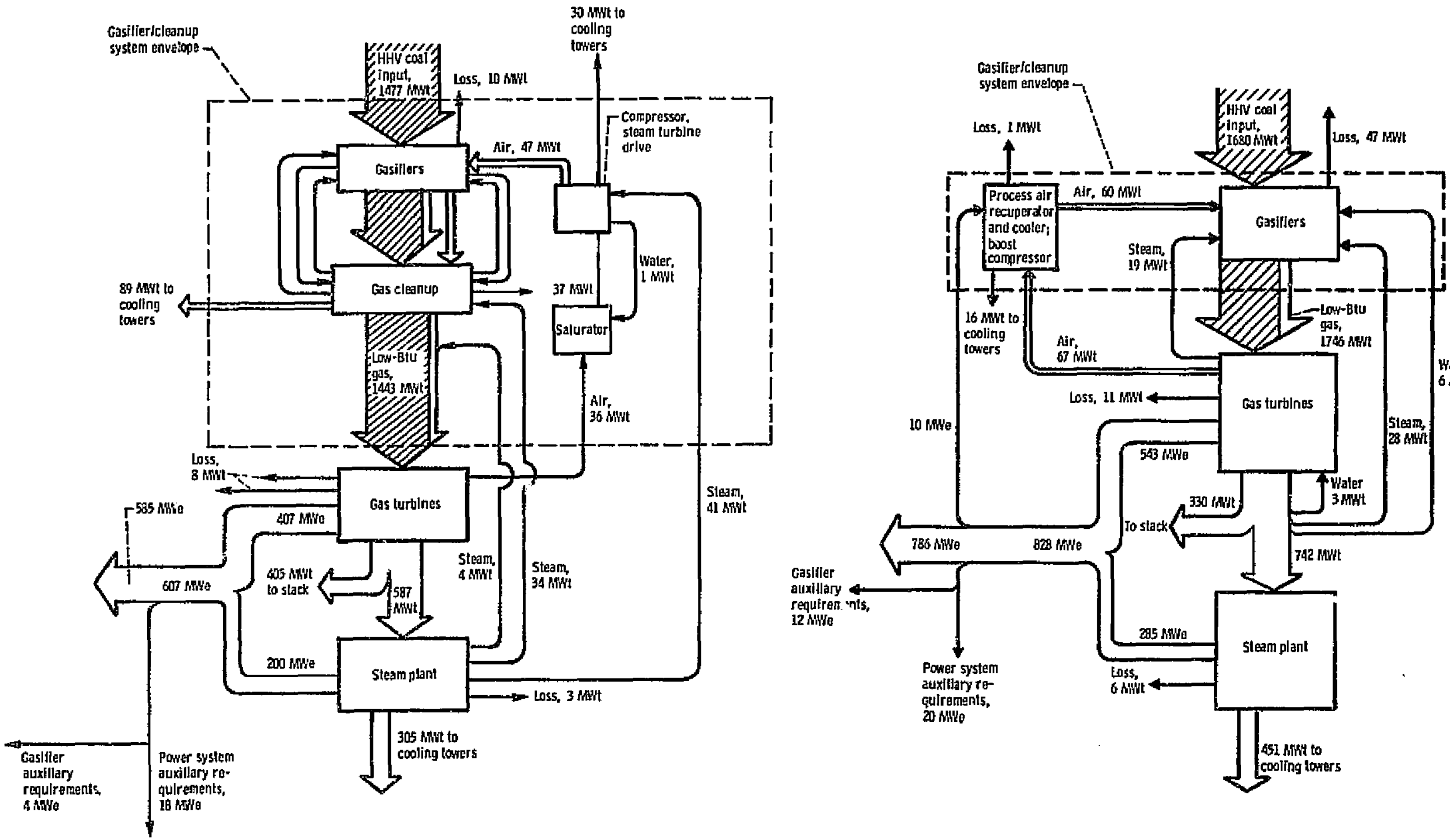
(a) General Electric. (All flow rates are for total of four gas turbines.)

Figure 2. - Schematic for gas turbine/steam combined-cycle systems with integrated low-Btu gasifiers.



(b) Westinghouse. (All flow rates are for total of four gas turbines.)

Figure 2. - Concluded.



(a) General Electric gas turbine/steam combined cycle with gasifier. Net electric power output, 585 MWe; low-Btu gas includes 1338 MWt for higher heating value, 35 MWt for sensible heat, and 70 MWt for latent energy.

(b) Westinghouse gas turbine/steam combined cycle with gasifier. Net electric power, 786 MWe. Low-Btu gas includes 1408 MWt for higher heating value, 300 MWt for sensible heat, and 38 MWt for latent energy.

Figure 3. - Energy flow diagrams.

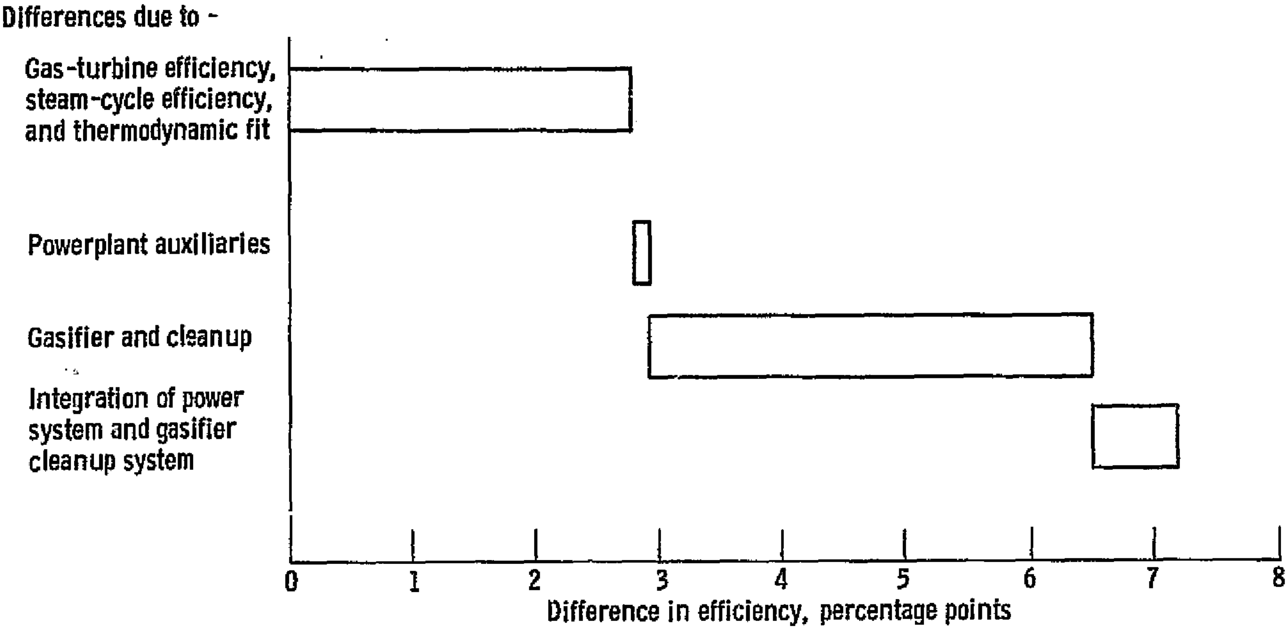


Figure 4. - Major differences between General Electric and Westinghouse integrated-gasifier combined cycles.

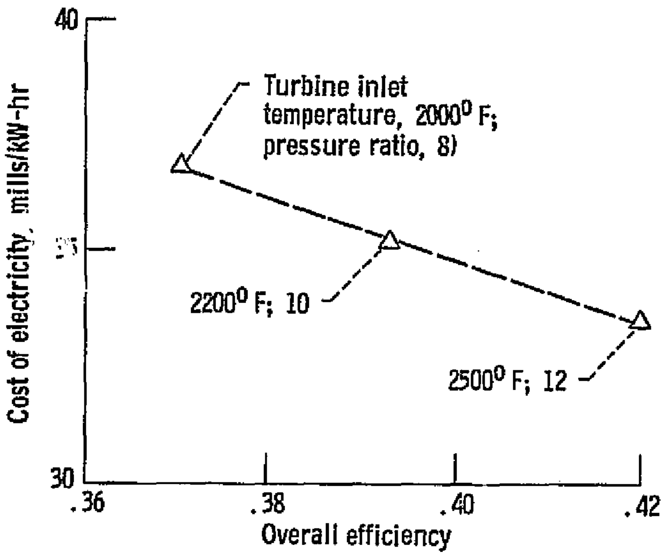
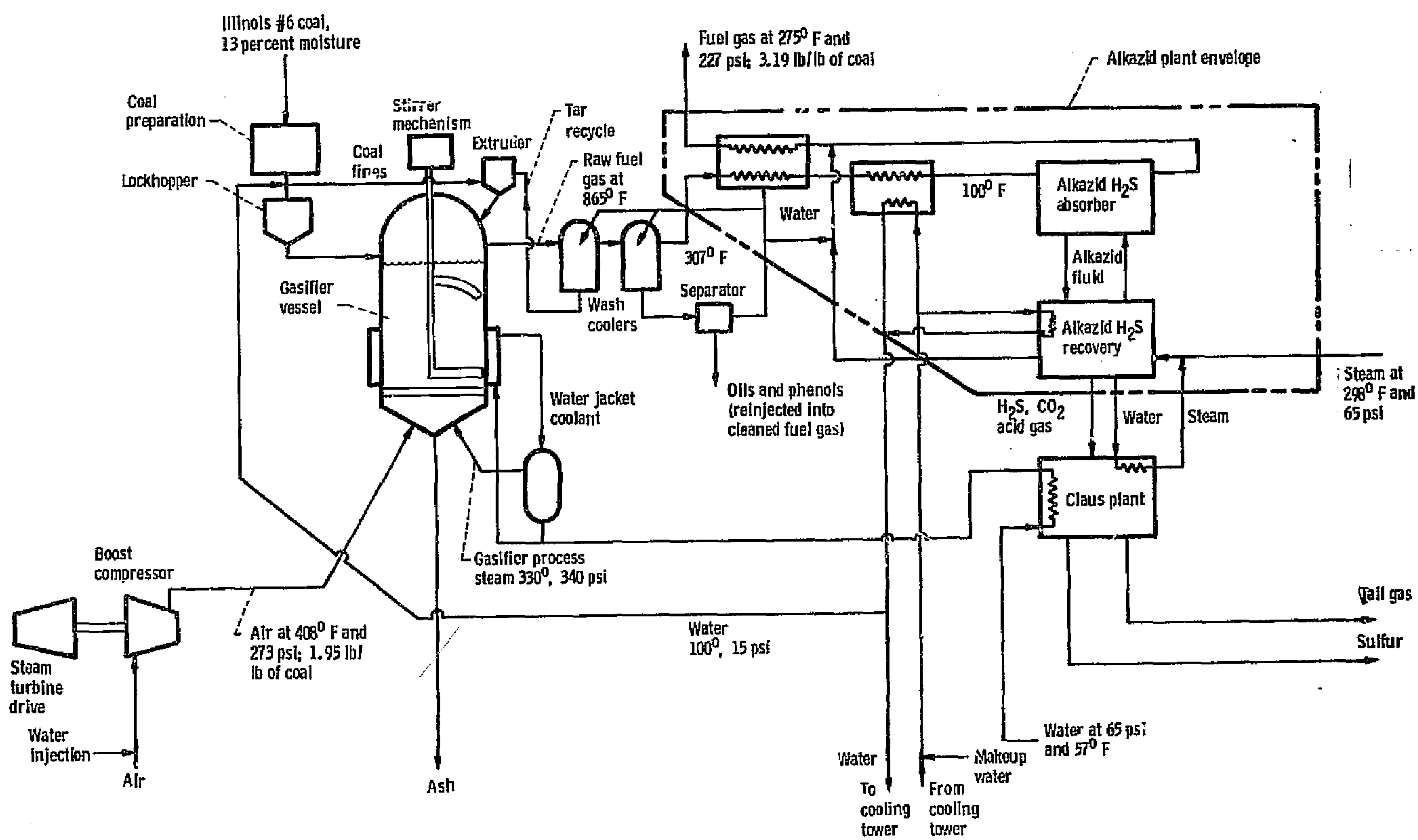
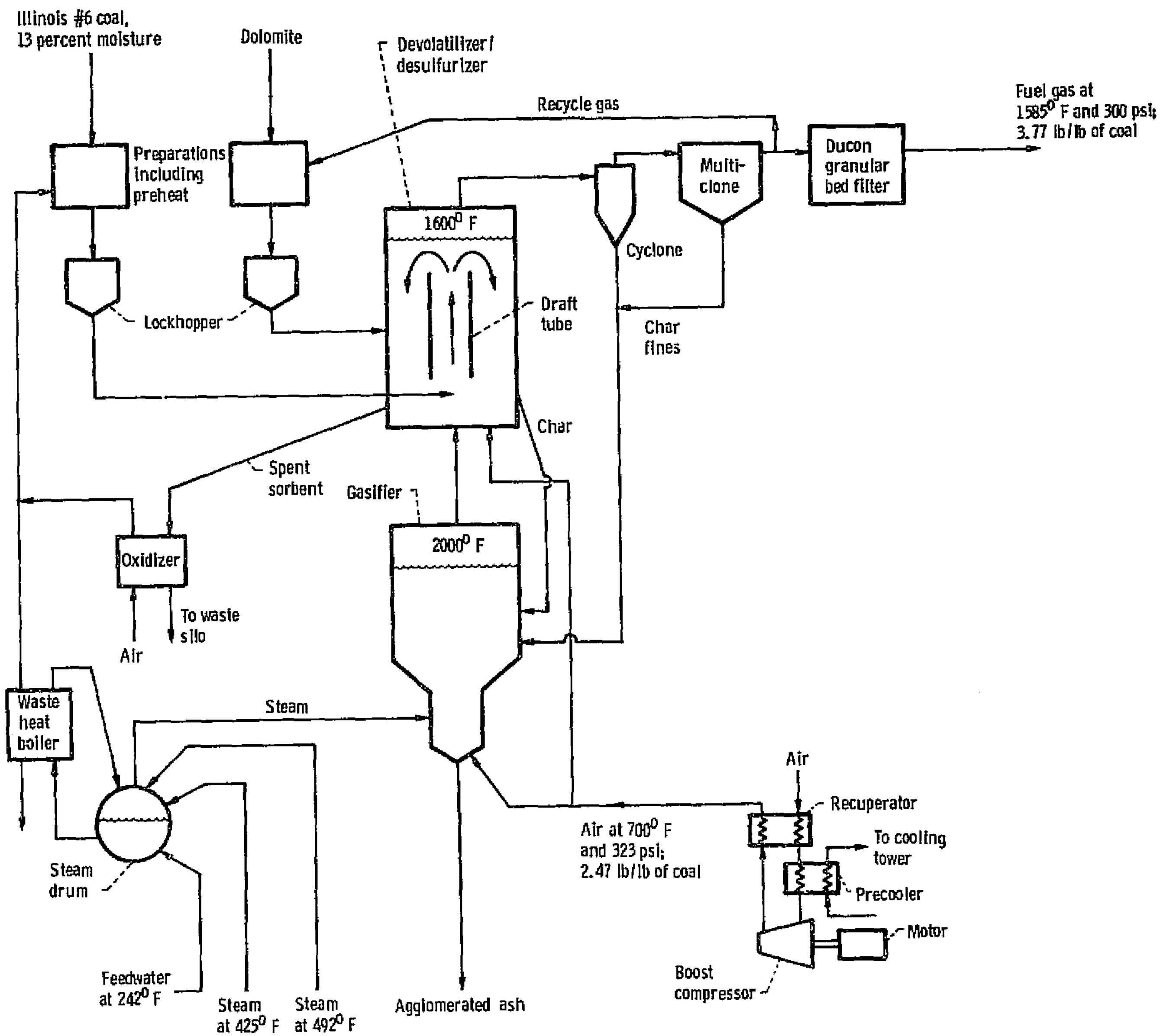


Figure 5. - Effect of turbine inlet temperature and pressure ratio on cost of electricity and overall efficiency of gas turbine/steam combined cycles with G.E. integrated advanced fixed-bed gasifier - NASA modifications.



(a) General Electric.

Figure 6. - Simplified gasifier/cleanup system schematics.



(b) Westinghouse.

Figure 6. - Concluded.