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COMPARATIVE EVALUATION OF PHASE I RESULTS from the ENERGY CONVERSION ALTERNATIVES STUDY (ECAS)

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16. Abstract

Ten advanced energy conversion systems for central-station, base-load electric power generation using coal and coal-derived fuels were studied by NASA at the request of ERDA and NSF. The General Electric Company and the Westinghouse Electric Corporation were selected by competitive bidding to study these systems. Phase I of these contracts was a parametric analysis of each system. The results include performance and economic data, such as plant capital cost and cost of electricity, and emissions and natural resource requirements for selected cases. This report provides a comparative evaluation of the contractor results on both a system-by-system and an overall basis. Ground rules specified by NASA, such as coal specifications, fuel costs, labor costs, method of cost comparison, escalation and interest during construction, fixed charges, emission standards, and environmental conditions, are presented. Each system discussion includes the potential advantages of the system, the scope of each contractor's analysis, typical schematics of systems, comparison of cost of electricity (COE) and efficiency for each contractor, identification and reconciliation of differences, identification of future improvements, and discussion of outside comments. Considerations common to all systems, such as materials and furnaces, are also discussed. Results of selected in-house analyses are presented, in addition to contractor data. The results for all systems are then compared. Maximum efficiency with corresponding COE and capital costs, minimum capital cost with corresponding efficiency and COE, and minimum COE with corresponding efficiency and capital costs are tabulated for each system and contractor. Plots of COE against overall energy efficiency for each system and contractor provide an insight into the effects of fuel, bottoming cycle, or gasifier and permit a ready comparison with the advanced coal-fired steam system. The sensitivity of COE to changes in capital costs, construction time, fuel costs, capacity factor, interest rate, escalation rate, and fixed-charge rate is determined as well as sensitivity to comparisons based on different methods of calculating COE.

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1.0 SUMMARY

The National Aeronautics and Space Administration was requested by the Energy Research and Development Administration and the National Science Foundation to conduct a study of advanced energy conversion systems. The Energy Conversion Alternatives Study (ECAS) is structured into two phases. Phase 1 is a parametric analysis of the conversion systems being investigated. The objective of this parametric analysis was to develop a base of performance and economic data that would define the potential for each system and from which the most promising systems could be selected for Phase 2. The system candidates evaluated were

(1) Advanced steam
(2) Open-cycle gas turbine
(3) Combined-cycle gas turbine/steam turbine
(4) Closed-cycle gas turbine
(5) Supercritical carbon dioxide cycle
(6) Liquid-metal Rankine topping cycle
(7) Open-cycle magnetohydrodynamic (MHD)
(8) Closed-cycle, inert-gas MHD
(9) Liquid-metal MHD
(10) Fuel cells

In Phase 2 conceptual designs of the selected systems will be made. These conceptual designs will provide a more detailed basis for cost and performance determination and sufficient detail of each powerplant to make an implementation assessment.

The major Phase 1 technical effort was accomplished through two parallel contracts, with the support and assistance of an in-house NASA Lewis Research Center project team of technical specialists with expertise and experience in most of the conversion systems being evaluated. The parallel-contract approach was selected to involve major suppliers of electric utility equipment and subcontractors or corporate groups familiar with each system concept, as well as architect-engineer firms. The primary contractors selected by a competitive procurement were the General Electric Company and the Westinghouse Electric Corporation. It was anticipated that each contract team would use somewhat different design approaches, which could lead to real and valid differences in the results. Common ground rules were provided, and each contractor analyzed the systems at a comparable level of powerplant detail. This permitted the differences in design approach, philosophy, and technical assumptions to be isolated for review and comparison.

Emphasis in Phase 1 was on estimating performance, capital cost, and cost of electricity of the various parametric points. This report summarizes the contractors' Phase 1 results, together with comparison and evaluation of results by the NASA Lewis technical review team. The contractor results are described in references 1 and 2. Further, sensitivity of the results to changes in economic ground rules is presented. The ground-rule parameters varied were capital cost, fuel price, method of computing the cost of electricity, construction time, and interest and escalation rates.

2.0 INTRODUCTION
by Robert P. Migra

2.1 BACKGROUND

The Energy Conversion Alternatives Study, more commonly called ECAS, was undertaken by NASA for the National Science Foundation (NSF) and the Energy Research and Development Administration (ERDA). This study has as its primary goal the identification and comparison of national options for the future generation of electricity from coal and coal-derived fuels. It is a unique effort in that it combines the funds of three agencies, NSF, ERDA, and NASA; the cooperation of the Department of the Interior and the Environmental Protection Agency (EPA); and the contracted expertise and experience of the Westinghouse Electric Corporation and the General Electric Company. Parallel studies and overall coordination are provided by NASA's Lewis Research Center.

The objectives of ECAS are to provide information that will enable an impartial evaluation on a comparable basis of a variety of advanced base-load electric utility powerplant concepts that use coal energy and to define the relative potential of these concepts for meeting future electrical generating needs of the Nation with acceptable impact to the environment. For each plant concept the study will provide estimates of the overall efficiency in converting coal and coal-derived fuels to electricity, powerplant capital costs, the cost of electricity, the environmental impact, and the resources and time required to bring the powerplant to commercial service.

The Energy Conversion Alternatives Study arose from the need to place in perspective for the Federal Government planner the many known advanced concepts for the conversion of heat to electricity from the combustion of coal fuels. Those concepts that are being examined in ECAS are the following:

(1) Advanced steam
(2) Open-cycle gas turbine
(3) Closed-cycle gas turbine
(4) Open-cycle magnetohydrodynamic (MHD)
(5) Closed-cycle MHD
(6) Liquid-metal MHD
(7) Supercritical carbon dioxide
(8) Liquid-metal Rankine
(9) Fuel cells
(10) Combined cycle (gas turbine and steam)

Each of these advanced concepts is backed by an industrial proponent who sincerely believes that his option has merit and should be pursued. Obviously, every option cannot be pursued with equal priority. At the same time, it has been difficult, if not impossible, for Federal Government planners to prepare a valid strategy for research and development because these concepts have not been projected on a common basis for comparison and because the concepts are supported by varying degrees of design and technological maturity. ECAS is the first comprehensive Federal undertaking to relate these various approaches to a common frame of reference.

It is important to recognize that ECAS, while a study, is also the first step in a coherent Federal process that will lead to the formulation of a research and development strategy for implementation. NASA's role in this process is limited to providing the base of information and technical expertise from which planners with direct responsibility for implementing research and development can make valid and defensible decisions as to which advanced energy conversion concepts have the greatest potential for the Nation as a function of time.

The emphasis in ECAS is placed on evaluating the potential of the 10 chosen advanced energy conversion concepts by studying them as a part of a complete electrical generating plant. This method assures that all costs and plant auxiliary thermal and electrical loads are included. It necessarily involves including advanced combustion processes and equipment as well, such as atmospheric and pressurized fluidized-bed furnaces, coal gasifiers, and liquified coal combustors. However, the study is not intended to provide a comparison between these various advanced coal-to-heat processes independently of the 10 major concepts.

2.2 ECAS ORGANIZATION

ECAS involves a broad base of both Federal and private sector participation. This is illustrated in figure 2.2-1, which displays the organization for the study. An ECAS Interagency Steering Committee, chaired by NSF with membership drawn from ERDA and NASA, provides to NASA the necessary guidance and direction for study execution. The Steering Committee receives advice and counsel from two supporting panels: the Technical Review Panel headed by an ERDA representative, and a Utility Review Panel with members drawn from the utilities sector, the Electrical Power Research Institute (EPRI), and the Sierra Club. In addition, NASA is receiving direct technical support from ERDA for coal and coal-derived fuel data and from EPA for environmental constraints. The membership for all committees for Phase 1 of ECAS is shown in table 2.2-1.

General Electric and Westinghouse, under separate but essentially parallel contracts to NASA (G.E study - NAS 3-19406; Westinghouse study - NAS 3-19407) are studying the advanced plant concepts. These parallel study contracts should improve the quality of engineering judgement through competition and identify valid differences in the assessment of the potential of particular advanced plant concepts. Such differences should be subsequently addressed by Federal planners.

2.3 CONTRACT SCOPE

The study is being done in two phases:
Phase 1 - parametric analysis
Phase 2 - conceptual design and implementation assessment

The Interagency Steering Committee reviewed the Phase 1 contractor results and decided that the parametric results should be published as soon as possible to permit wide dissemination of the information. The G.E. and Westinghouse reports on the ECAS Phase 1 results are being distributed as NASA CR-134948 and CR-134941, respectively (refs. 1 and 2). The Interagency Steering Committee also requested that NASA prepare a comparative evaluation of the contractor results for Phase 1.

2.4 NASA REPORT - PURPOSE AND APPROACH

This report was written

(1) To summarize and compare the contractor results for Phase 1 of ECAS

(2) To identify major differences and uncertainties and to resolve differences where possible

(3) To identify critical or limiting assumptions used in the study

(4) To define improvements to systems studied and evaluate impact

(5) To define comparability in the various energy conversion systems

The preparation of this report drew on teams of NASA Lewis Research Center experts in the various energy conversion systems. The project office prepared the introduction, summary, and general discussion of approach and scope. Additional information resulted from a public presentation of the contractor Phase 1 results at Lewis on May 27, 1975. The attendees were invited to comment on the results of the study. In addition, Lewis requested comments from the public and industry and each contractor requested comments from each subcontractor or corporate division that developed the information for the various energy conversion systems. Written comments were received from the following organizations:

(1) Actron Industries, Division of McDonnell Douglas
(2) AiResearch
(3) Argonne National Laboratory
(4) ERDA (OCR)
(5) General Electric Co., Direct Energy Conversion Division
(6) General Electric Co., Valley Forge Space Center
(7) General Electric., Steam Turbine Division
(8) NASA Jet Propulsion Laboratory
(9) Hollifield National Laboratory
(10) Westinghouse Research Laboratory
(11) Westinghouse, Gas Turbine Division (2)
(12) United Technologies Research Laboratory
(13) ERDA Pittsburgh Energy Research Center as well as from the public.

In addition, several advocates (AiResearch, General Atomics, General Electric, and Hollifield National Laboratory) visited Lewis to discuss their comments. The comments have been reviewed and evaluated by the Lewis personnel responsible for each energy conversion system. Those comments having substantial impact on the study were incorporated in the sections covering the respective conversion systems.

The report was compiled under the direction of Lloyd I. Shure, ECAS Project Manager at the Lewis Research Center, with substantial contributions from Gerald J. Barna, Raymond K. Burns, Donald C. Guentert, and Robert P. Migra.

2.5 SCOPE OF RESULTS

The information generated by each contractor in Phase 1 of ECAS included performance, economics, natural resource requirements, and the environmental intrusion for the advanced conversion systems studied. The parametric analysis was defined by a matrix of points for each system and contractor. The matrix of points summarized the important parameters for base cases as well as each parametric point. The information required for a base case and a parametric point is summarized in table 2.5-1. The matrices of points covered in the contractors' parametric analyses were proposed by the contractors and approved by the project manager after negotiation of NASA recommended changes.

It was recognized that each of the systems covered by ECAS has been to some extent previously investigated. However, they had not been examined collectively on a consistent and comparable basis. In addition, the emphasis in ECAS was on total powerplant design performance and cost, which, as stated earlier, was a unique feature of this study. On this basis, together with programmatic constraints of time and resources, it was decided to exercise the collective judgement of industry and government to use this base of information and experience from previous studies as a point of departure rather than to perform an optimization study for each of the candidates. Thus, on the basis of this background, a number of base cases were defined that were judged as representative of the potential for each candidate. In addition, a number of parametric variations from these base cases were investigated to define sensitivity of the systems for both cost and performance. These base and parametric cases were covered with, for the most part, differing emphasis in each contract to achieve as broad a coverage as possible and thereby to insure that the potential for each system would be adequately covered. In many cases, further optimization could be expected to make some improvement. As a part of the evaluation described in this report, guidance is provided for the focus of future evaluation to achieve, where appropriate, an enhanced comparison. This parametric approach (Phase 1) did achieve its objective of providing a basis for selection of systems for additional detailed evaluation in Phase 2 of the ECAS study.

The matrix of points for each conversion system is discussed in sections 5.2 to 5.12 of this report. An examination of the parametric points will reveal certain approaches emphasized by the contractors, such as G.E.'s selection of atmospheric furnaces and Westinghouse's selection of pressurized fluidized beds or G.E.'s use of low-temperature gas cleanup and Westinghouse's use of high-temperature gas cleanup for gasifiers. Three efficiencies were calculated for each system: overall energy efficiency, powerplant efficiency, and thermodynamic cycle efficiency. Overall energy efficiency is the ratio of electric power output to the higher heating value of the coal required and is the efficiency commonly referred to as "coal pile to bus bar." Powerplant efficiency is defined as the electric power output divided by the higher heating value of the actual fuel input to the system. In cases where fuel was used as an over-the-fence supply, overall energy efficiency is the product of the conversion efficiency (coal to fuel) for the assumed fuel and powerplant efficiency. For those cases where coal is combusted directly, such as fluidized-bed furnaces or integrated low-Btu gasifiers, the plant and overall energy efficiencies are the same. Thermodynamic efficiency is defined as the gross electrical power output from the prime cycle divided by the heat input to the prime cycle. It does not include auxiliary power requirements for the plant nor allow for thermal or power losses or power outputs from any separate combustion loop. When a topping and bottoming cycle occur in ECAS, they are considered as the prime cycle, and gross electrical power for both is used in determining thermodynamic efficiency.

Economics information generated in this study is based on mid-1974 dollars and includes estimates of the capital cost of energy conversion equipment, the balance-of-plant costs (for coal handling, heat rejection, all installation materials and labor, and cleanup), the operating and maintenance costs, period of construction, escalation during construction, interest during construction, and cost of electricity. The sensitivity of the cost of electricity to important parameters was also investigated.

TABLE 2.2-1. - ENERGY CONVERSION ALTERNATIVES STUDY COMMITTEE

Level of organization	Component	Members
Program	Steering Committee	D. Senich, Chairman (NSF) R. Zahradnik (ERDA) L. Topper (NSF) S. Freedman (ERDA) D. Ginter (NASA Headquarters) M. Ault (NASA Lewis) R. Schoen, Executive secretary (NSF) S. Gage, Observer (EPA/ORD) J. Sullivan, Observer (OMB)
	Technical Advisory Panel	J. Lynch, Chairman (ERDA) W. Crim (ERDA) J. Belding (ERDA) R. English (NASA Lewis)
	Utility Advisory Panel	C. Falcone, Chairman (American Electric Power) H. Phillip (Niagara Mohawk Power) R. Huse (Public Service Gas & Electric) R. Dunham (Tennessee Valley Authority) J. Agosta (Commonwealth Edison of Chicago) V. Cooper (Electric Power Research Institute) A. Rosenberg (Consolidated Edison of New York) R. Curry (Sierra Club Research Office)
	Headquarters Program Manager	R. Miller (NASA)
Project	NASA Lewis Project Managers	L. Shure D. Packe, Lewis Analysis
	Consultants	M. Schlesinger (ERDA/PERC) D. Walters (EPA) S. Grisaffe, Materials Advisory Group (NASA Lewis)

TABLE 2.5-1. - INFORMATION REQUIRED FOR BASE CASES AND PARAMETRIC POINTS

Base case	Parametric point
Powerplant efficiency	Powerplant efficiency
Overall energy efficiency	Overall energy efficiency
Plant capital costs	Plant capital costs
Cost of electricity (including capital, fuel, and maintenance costs)	Cost of electricity (including capital, fuel, and maintenance costs)
Construction materials	
Size, weight, and capital cost of major components	
Cooling tower	
Emission control equipment	
Natural resources required (including coal, water, and land)	
Environmental intrusion (including gaseous and particulate emission, thermal pollution, and wastes)	
Flow rates, state conditions, component efficiencies, etc.	

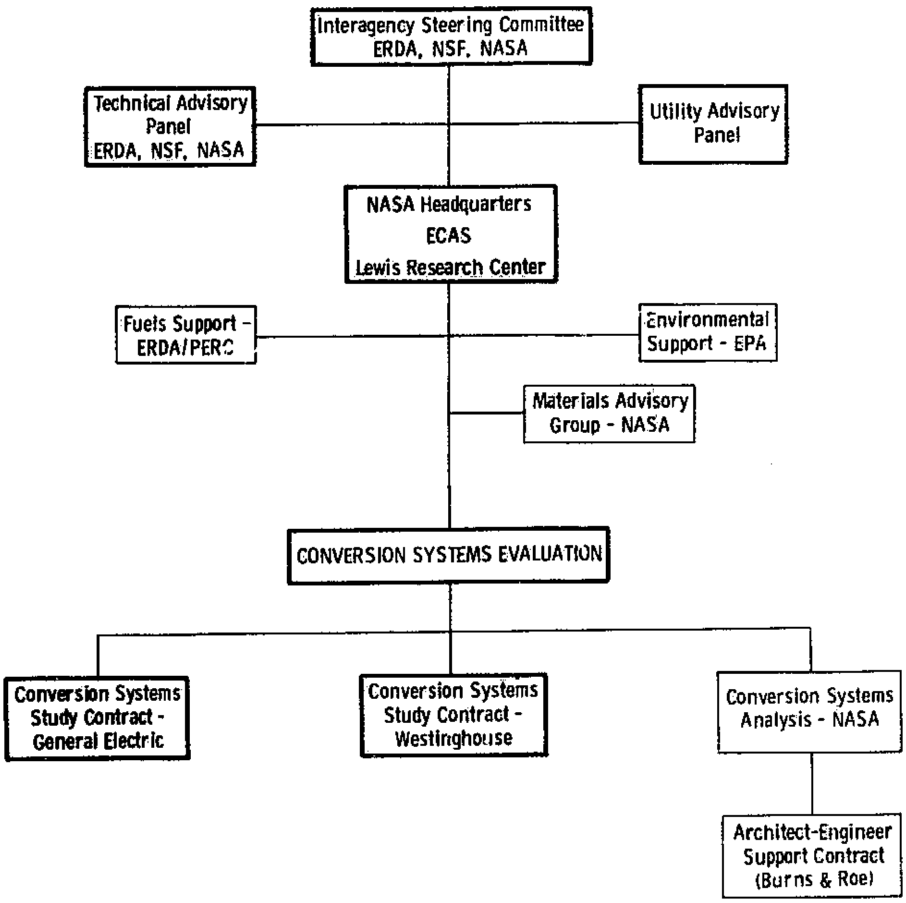

Figure 2.2-1. - Energy Conversion Alternatives Study (ECAS) organization.

3.0 SUMMARY OF PHASE 1 RESULTS

3.1 PERSPECTIVE ON INTERPRETATION OF RESULTS

The purpose of this section is to provide a perspective on the results of the parametric analysis from Phase 1 of ECAS and an insight into those factors that have the most significant effect on the cost and performance of the energy conversion systems studied. A secondary objective is to introduce those factors not evaluated that would have a substantial impact on an overall comparison of fossil-fueled advanced conversion systems. In the following subsections, each of the major factors that influence system comparisons are qualitatively discussed.

3.1.1 Influence of Study Emphasis on Results

The primary emphasis of the ECAS study is an evaluation of the various advanced energy conversion systems on a consistent and comparable basis for base-load electric utility application. A distinguishing feature of the study is the attempt to evaluate these systems in a total powerplant context. Assessing the overall impact of these systems on the energy economy of the nation was an important consideration, explicit in the objective of ECAS. To that end, we considered not simply cycle or powerplant efficiency and the attendant costs, but the overall efficiency from "coal pile to bus bar." This efficiency is more indicative of true performance. For example, many of the powerplants evaluated may display the potential for high plant efficiency with a "clean fuel." If the "overall" efficiency is not considered, coal demand could be greater for this system than for a system of somewhat lower plant efficiency that uses coal directly. Thus, the total coal consumption is important in an overall comparison of cycles. It should be clearly recognized that when the total coal consumption is considered the auxiliary power requirements, losses, and inefficiencies of all the various steps in the handling, processing, combustion, cleaning, and disposal from "coal pile to bus bar" will have a dramatic effect on both efficiency and cost comparison of the various cycles. In fact, in many cases, the balance of plant is a major determinant in system performance and to some extent is almost independent of the cycle itself. Past studies have also considered the balance-of-plant impact, but in most cases as subordinate to the evaluation of the cycle itself. In the first phase of ECAS, emphasis has been given to the balance of plant, but with less detailed analysis than for the conversion system itself.

To guide the reader in interpreting the impact of balance of plant and auxiliary losses and reconciling the results with intuition, it is convenient to arrange the various systems into three classes: systems that

(1) Combust coal directly to fire the primary cycle

(2) Process the coal to a low-Btu gas on site and integrated with the primary cycle(s)

(3) Utilize a processed, clean or semiclean fuel delivered "over the fence" and processed off site

These classes of systems are shown in a highly schematic and simplified way in figure 3.1-1. Each of the blocks in this diagram can be characterized by an efficiency, an auxiliary power requirement, and/or losses from step to step. Except for the components that comprise the energy conversion cycle, there was generally good agreement on these factors between contractors. On the basis of this simplified diagram the overall energy efficiency of any class of system can generally be obtained from the thermodynamic efficiency as follows:

Overall energy efficiency = f (1 - A), (1 - L), (Furnace loop efficiency),
(Coal processing efficiency),(Thermodynamic efficiency)

where A is auxiliary power required expressed as a percentage of gross power and includes fan power (AFB, cooling towers, etc.); coal handling, drying and pulverizing; pump power; waste handling; housekeeping, etc.; and where L is losses as a percentage of gross power and includes transformers, inverters, generators, and miscellaneous thermal and mechanical losses outside the energy conversion system itself. In the sections of this report that follow, the magnitudes of the furnace, processing, and thermodynamic efficiencies are discussed. A review of all the results indicates that it is possible, within broad limits, to generalize these values - with the benefit gained exceeding the hazards of generalizations.

For the first class of systems with AFB, the auxiliary power is 6 to 8 percent (1 - A = 92 to 94 percent), the losses are 2 to 3 percent (1 - L = 97 to 98 percent), and furnace efficiency is 85 to 90 percent. Since this class of system fires coal directly, there is no processing loss. Therefore, overall efficiency is from 76 to 83 percent of thermodynamic efficiency. Similar values for the other classes are 67 to 87 percent for class 2 and 44 to 55 percent for class 3. These low values result primarily from low processing efficiencies for coal conversion. For closed-cycle systems with furnace pressurizing turbocompressors, the factor for class 1 systems will be higher. Therefore, to achieve overall efficiencies of 45 percent would require thermodynamic efficiencies of about 56 percent. Few systems achieved such high levels of performance. Furthermore, it can be concluded that these efficiencies are both real and reasonable and are in large measure independent of either the level of technical sophistication or technology achieved in the prime cycle itself. In addition, total plant design is clearly as important as conversion system design with respect to performance and cost.

In addition to efficiency considerations, figure 3.1-1 also provides a perspective on capital cost. As the complexity and number of components increase between class 3 and classes 1 and 2, it can be inferred that capital costs will also rise for both equipment and balance of plant (BOP) and that construction times will increase. The results, in general, support this inference. It is also generally true that for the simpler systems using clean fuels the capital equipment costs, BOP, and construction times are substantially lower. However, the fuel costs tend to dominate and as a result COE still remains high. This merely reflects a transfer of capitalization from the utility to the fuel processor and reappears as operating expense in the cost for the processed fuel. For the more complex, high-capital-cost systems with longer construction times, in many cases BOP constituted as much as half of the total plant cost. This again reemphasizes the importance of plant design, which can be the most important single factor in plant cost.

Plant arrangement, level of integration, and conversion sytem concept are stong determinants in establishing plant design and hence cost. The impact of these factors is illustrated in figure 3.1-1. As illustrated in this figure, the design concept defines both the components and a part of the BOP. The integration of these components also affects the BOP, which in turn influences the time of construction. The time of construction taken together with interest during construction and escalation now operates on both component costs and BOP. The interest and escalation were 10 and 6.5 percent, respectively. As a consequence those systems with high BOP and long construction times have interest and escalation charges amounting to as much as 50 percent of the total capital costs. Although the values used may be varied, the effect is real and has an important impact on the overall comparison of systems.

3.1.2 Influence of Study Approach on Results

The study was divided into three tasks performed in two phases:

Phase 1 - parametric analysis

Phase 2 - conceptual design and implementation assessment.

The study logic was to evaluate all energy conversion systems on a parametric basis in order to provide an indication of each system's potential. From the resulting data base the most attractive systems could be delineated and selected for more-detailed conceptual design in Phase 2. These conceptual designs would provide the level of detail required to perform a meaningful implementation assessment together with a better basis for estimating powerplant cost and performance.

Within the constraints of time and resources allocated to the overall effort, Phase 1 was structured around a selection of parametric points. These parametric points were selected on the basis of inputs from the agencies sponsoring the study, each of the prime contractors, and the various groups that acted as advocates for each of the cycle concepts. Each of these systems had been previously studied on at least an independent basis but to a different extent. Thus, it was anticipated that each advocate or concept group familiar with each system could select design points (base cases) and variations about these base cases that would indeed represent each system to its maximum potential. However, the design points were picked at the beginning of the study, and hence there was little opportunity for modifying the points chosen. Where such modification could lead to improved performance and/or cost, these are noted in the results discussed for each system in section 5.0 of this report. Therefore, Phase 1 was not an optimization study for each of the concepts but rather was an evaluation based on previous experience or familiarity with the various concepts. In addition, to enhance the value of the study, we emphasized breadth of coverage, with a limited overlap between contractors for comparison. As a result, the parametric points evaluated by each contractor have in most cases substantially different emphases.

In reviewing the results of Phase 1, it is, therefore, important to recognize that limited design detail was generated particularly with respect to plant design because the emphasis was on parametric analytical comparison. It can, consequently, be assumed that further detailed plant layout and integration could in many cases enhance both confidence in cost projections and performance estimates. This is the objective of Phase 2 and forms the basis for the study logic. Further, the data, particularly with respect to cost, are more meaningful on a relative basis than on an absolute basis. The differences in results between the two contractors for a given powerplant, in themselves, provide a great deal of insight into the sensitivity of each system to differences in design approach and integration techniques. For example, the results for combined cycles with integrated, fixed-bed, low-Btu gasifiers and low-temperature gas cleanup (G.E.) are substantially different than for fluidized-bed gasifiers and high-temperature gas cleanup (Westinghouse). The method of bottoming-steam-cycle integration chosen by each contractor also has a significant effect on performance. These comparisons of results are detailed in the remaining sections of this report. A derivative result of this approach was that iteration (zeroing in on "best" designs) was not possible but the breadth of coverage and results was sufficient to provide a basis for evaluating system potential and selecting the most promising concepts. Within these limits, Phase 1 achieved its objectives:

(1) It did provide a clear basis for selection of systems for Phase 2 conceptual design (section 3.5).

(2) It did provide a basis from which to proceed to conceptual design of powerplants that would exploit the potential of the selected systems with more attention to plant design.

(3) It did define those factors in need of more detailed attention to make those systems not selected more attractive or to confirm the basis for their exclusion.

(4) As a result of the display of ground rules, methodology, assumptions, and data format, it did provide a common basis upon which advocates of the various systems and others can make future comparisons.

The sections that follow compare and evaluate the results and examine the impact of changes in ground rules.

3.2 SUMMARY OF OVERALL SYSTEMS COMPARISONS

The ranges of overall energy and powerplant efficiency and cost of electricity obtained for most parametric cases of each system are shown in figures 3.2-1 and 3.2-2, respectively. In each case the General Electric results are plotted in part (a) and the Westinghouse results in part (b). When the results for two different powerplant configurations or two different fuels are substantially different, more than one ellipse is used to define the range of results.

The ellipses approximate the actual ranges of results, which are shown in more detail in figures 6.2-1 to 6.2-5 and 6.2-7 to 6.2-11. The size and location of these ellipses are, of course, a function not only of the procedures and assumptions made in the calculations, but also of the choice of the study ground rules and the system parameters and ranges of parameters examined. For some systems the areas of emphasis, ranges of parameters, or system configurations examined by the contractors differed. These are described in the individual system discussions in section 3.3 (or in more detail in section 5.0).

The data output of each contractor has been reported in sufficient detail to allow recalculation of the cost of electricity (COE) for other than the specified economic ground rules. This has been done to facilitate examining the sensitivity of the results to the ground rules. The effects of changes in the fuel price, the capacity factor (0.65 base), the interest (10 percent base) and escalation (6.5 percent base) rates, and the fixed-charge rate (18 percent base) have been examined. The method of calculating COE has also been varied. The COE values shown in figures 3.2-1 and 3.2-2 and those shown in the contractor reports were calculated as if construction of each type of system were started in mid-1974, and escalation and interest during construction are included. The result is that plants with different construction durations come on line in different years, and construction costs are not in mid-1974 dollars but in different-year dollars depending on construction completion date. The fuel and operation and maintenance (O and M) costs are in mid-1974 dollars, however. NASA has recalculated the COE results by several different methods. These include the COE assuming common on-line date, the COE in terms of constant dollars (deflated back to mid-1974), and the average COE over the lifetime of the plant. These effects are summarized in section 3.4.

An objective of this study is to compare power systems on the basis of their efficiency in the use of coal. Emphasis has therefore been placed on the overall energy efficiency, which includes the efficiency of the conversion of coal into a cleaner fuel for those systems that do not use coal directly. It is not intended, however, to reduce the significance of the powerplant efficiency. One of the initial assumptions made by contractors was the fuel conversion efficiency to obtain a clean or semiclean fuel from coal. In some cases the contractors have used different fuel conversion efficiencies for the same or similarly processed fuels. As a result their overall energy efficiencies for some systems may be substantially different even though their powerplant efficiencies agree. In such cases a more valid comparison of the power system results of the contractors is made on the basis of powerplant efficiency. Both overall energy efficiency and powerplant efficiency have been presented.

The shape and inclination of the ellipses in figures 3.2-1 and 3.2-2 indicate that for some systems the point with maximum efficiency corresponds closely to the point with minimum COE. This is generally true for the lower capital cost systems where the COE is dominated by fuel cost. For some of the higher capital cost systems, the COE of the point with maximum efficiency is considerably above the minimum COE for that system. In such cases a change in system design parameters that results in a decrease in capital cost, even if accompanied by some decrease in efficiency, results in a decrease in COE. The trade-off between cost and efficiency differs from system to system because the relative magnitude of the capital charges, fuel, and operating charges varies considerably among the systems. Also changes in the economic ground rules of the study would affect the capital and fuel portions of the COE differently and hence affect this trade-off. The system design parameters that will result in minimum COE depend on the choice of the economic ground rules. Sufficient data have been reported to allow examination of the effects of any change in ground rules.

Comparing figures 3.2-1 and 3.2-2 shows that a system that uses a clean or semiclean fuel rather than coal directly is at a disadvantage in terms of coal utilization efficiency. Even though the powerplant efficiencies of combined cycles using clean fuels or of low-temperature fuel cells using hydrogen, for example, exceed that of a steam plant, the overall energy efficiency, which includes the fuel conversion efficiency, is lower. Using cleaner fuels can permit an increase in system operating temperature and hence in powerplant efficiency but usually means lower fuel conversion efficiency. For combined-cycle gas turbine/steam turbine systems, the results of both contractors showed that using an integrated low-Btu gasifier resulted in the best trade-off between these two effects and hence in the lowest COE and highest overall energy efficiency.

According to both contractors, the open- and closed-cycle inert-gas MHD systems and the liquid-metal Rankine topping cycle exceeded 40 percent overall energy efficiency. Each contractor also had another system with greater than 40 percent overall efficiency: for G.E., the supercritical carbon dioxide system; for Westinghouse, some high-temperature fuel-cell cases. In all these cases the COE exceeded that for a 3500 psi/1000° F/1000° F steam plant with a conventional coal-fired boiler. However, Westinghouse calculated one parametric case for the combined cycle with overall energy efficiency above 40 percent and COE very near that of the conventional steam plant.

In both contractors results, the steam systems, combined cycles, liquid-metal MHD, closed-cycle gas turbine, and high-temperature fuel cells generally fall in the 30 to 40 percent range of efficiency. The clean-fueled gas turbine systems and the low-temperature fuel cells using clean over-the-fence fuels fall below this range, although in terms of powerplant efficiency some of the parametric cases exceed 40 percent. The efficiency and COE results are discussed more specifically and the results of the two contractors are compared in the next section (and in section 5.0).

3.3 SUMMARY AND COMPARISON OF CONTRACTORS' RESULTS BY SYSTEM

This section summarizes the more comprehensive discussion of each conversion system that is presented in section 5.0 of this report. The reader may refer to the following sections for more detailed information on each system:

5.2 ADVANCED STEAM SYSTEM
5.3 OPEN-CYCLE GAS TURBINE SYSTEM
5.4 COMBINED-CYCLE GAS TURBINE/STEAM TURBINE SYSTEM
5.5 CLOSED-CYCLE GAS TURBINE SYSTEM
5.6 SUPERCRITICAL CARBON DIOXIDE CYCLE
5.7 LIQUID-METAL RANKINE TOPPING CYCLE
5.8 OPEN-CYCLE MHD SYSTEM
5.9 CLOSED-CYCLE INERT-GAS MHD SYSTEM
5.10 LIQUID-METAL MHD SYSTEM
5.11 FUEL-CELL POWERPLANTS

3.3.1 Advanced Steam

Steam powerplants today provide the bulk of this nation's electrical generating output. Because of their widespread use and demonstrated performance and reliability, it is appropriate that the performance and cost of steam systems be used as one yardstick for evaluating the merit of advanced conversion systems. This evaluation of advanced conversion systems must, however, include comparison with both state-of-the-art and advanced steam systems. The emphasis for the advanced steam system in Phase 1 was on investigating those systems using advanced furnace concepts and/or increased steam turbine temperatures (to the 1200° F level or higher).

Both contractors investigated four combustion techniques: conventional furnace (CF), atmospheric-fluidized-bed furnace (AFB), pressurized-fluidized-bed furnace (PFB), and pressurized furnace (PF) burning low-Btu gas from an integrated gasifier. Both contractors also investigated a range of turbine throttle temperatures and pressures, reheat temperatures, number of reheats, powerplant sizes, heat rejection methods, types of coal, and other system parameters. General Electric evaluated a total of 28 parametric points around a base case using an atmospheric-fluidized-bed furnace and steam conditions of 3500 psi/1200° F/1000° F. Westinghouse evaluated a total of 180 parametric points around three base cases using conventional, pressurized-fluidized-bed, and pressurized furnaces, respectively. All Westinghouse base cases had steam conditions of 3500 psig/1000° F/1000° F. The Westinghouse study emphasized the use of PFB's, PF's, and CF's. The different emphases on furnace types thus complemented each other and enabled a broader coverage of parametric variations to be investigated.

As illustrated in table 3.3-1 there was a substantial difference between the two contractors' results in terms of the range of efficiency and absolute level of COE. General Electric results showed overall energy efficiencies from 34 to 40 percent and COE's from 30 to 38 mills/kW-hr. Westinghouse results showed an efficiency range of 34 to 43 percent and a COE range of 21 to 35 mills/kW-hr. NASA investigated the differences between the contractors' ranges of efficiency and COE. The range of steam conditions investigated by Westinghouse, which included higher pressures and higher temperature combinations (throttle and reheat) than General Electric, produced the higher efficiencies. Westinghouse efficiencies also ranged lower than G.E.'s because some of their dry cooling tower cases involved condenser pressures higher than the highest pressures examined by G.E. for such cases.

Differences between the two contractor's on capital cost estimates were the reason for the difference in absolute level of COE. The G.E. capital cost estimates were consistently higher for cases using similar parametric characteristics. As reported in section 5.1, NASA investigated the contractors' costing approaches and made a detailed comparison of conventional technology (base-line) steam plant capital costs. The difference between contractors was primarily in the balance-of-plant (BOP) materials costs estimated by the participating architect-engineer firms. Independent cost estimates, obtained by NASA according to ECAS ground rules, indicated steam plant capital costs lying between the G.E. and Westinghouse ECAS estimates.

Absolute cost differences notwithstanding, certain significant trends were shown in the results from both contractors: (1) the fluidized-bed furnaces (AFB and PFB) produced lower or comparable COE as measured against the conventional furnace with scrubber; and (2) lowest COE's were generally obtained at or near present state-of-the-art steam pressure and temperature conditions. The fuel cost savings (efficiency) from 1200° F-and-higher steam conditions were clearly overshadowed by rapid increases in turbine capital cost. In Phase 2, steam systems using AFB and PFB furnaces will be evaluated further through conceptual designs of each system for steam conditions of 3500 psig/1000° F/1000° F.

3.3.2 <u>Open-Cycle</u> <u>Gas</u> <u>Turbines</u>

Both contractors studied simple-cycle, recuperated-cycle, and organically bottomed gas turbine systems. The influence of major parameters such as turbine-inlet temperature, pressure ratio, turbine cooling method, uncooled ceramic materials, recuperator effectiveness, recuperator pressure drop, and organic working fluid was evaluated. General Electric emphasized HBTU gas and Westinghouse emphasized a coal-derived distillate as clean turbine fuels. A fuel conversion efficiency of 50 percent was selected by G.E. and Westinghouse for their fuel of emphasis and fuel costs specified by NASA were identical (table 4.1-2). Overall efficiencies may therefore be compared directly. For these fuels, powerplant efficiency would be twice the overall energy efficiency.

As shown in table 3.3-1, the COE determined by G.E. ranged from 31 to 39 mills/kW-hr, and overall efficiency (including fuel processing efficiency) ranged from 15 to 22 percent. Minimum COE (efficiency, 17 percent) occurred for the recuperated cycle with an effectiveness of 0.85 and a turbine-inlet temperature of 2200° F. Maximum efficiency occurred for the organically bottomed cycle (COE, 34 mills/kW-hr) with a turbine-inlet temperature of 2200° F (highest temperature considered). A most interesting single point presented by G.E. was for a recuperated cycle using solvent-refined coal (SRC) fuel (fuel conversion efficiency, 78 percent) for which COE was 26 mills/kW-hr and overall energy efficiency was 28 percent. The nitrogen oxide emission standard was not met because of the organically bound nitrogen in the fuel.

Also as shown in table 3.3-1, the COE determined by Westinghouse ranged from 28 to 42 mills/kW-hr, and the overall efficiency (including fuel processing efficiency) ranged from 12 to 24 percent. Minimum COE (efficiency, 19 percent) occurred for the recuperated cycle with an effectiveness of 0.90 and a somewhat higher turbine inlet temperature than G.E.'s. Maximum efficiency (COE, 35 mills/kW-hr) occurred for the organically bottomed system. Using ceramic blades and vanes would reduce COE somewhat more than 1 mill/kW-hr and increase overall efficiency approximately 2 percentage points.

Comparing the G.E. and Westinghouse results for similar systems and operating parameters shows that G.E.'s COE is approximately 3 mills/kW-hr higher than

Westinghouse's and that G.E.'s overall efficiency is approximately 2 percentage points lower than Westinghouse's. Lewis Research Center performance calculations show that the performance difference (2 percentage points) is totally accounted for by the difference in the higher heating value of the fuels, the difference in the contractors' definitions of turbine-inlet temperature (G.E. uses the temperature at the inlet to the first-stage rotor, whereas Westinghouse uses the temperature at the inlet to the first-stage stator), the difference in recuperator performance, and G.E.'s use of water injection to suppress nitrogen oxide. The cost difference was examined in detail but was not resolved. However, the costing approach and methodology used by G.E./Bechtel generally result in higher costs than Westinghouse. Estimated capital costs are \$150/kWe for simple-cycle plants, \$200/kWe for recuperated systems, and of the order of \$400/kWe for organically bottomed systems. The increase in cost for organic bottoming is associated primarily with BOP costs.

Both contractors agree on the major trends in the data. The cost of electricity decreases with increasing turbine-inlet temperature to 2600° F with air cooling and to 3000° F with water cooling. However, efficiency increases with increasing turbine-inlet temperature to 2600° F with air cooling and decreases with water cooling at all temperatures considered. Recuperation reduces COE and increases efficiency for the same operating conditions. Organic bottoming substantially increases efficiency but is not cost effective because COE also increases. Although both contractors show increased COE for organic bottoming, the doubling of capital cost (\$/kWe) for organic bottoming as compared to open-cycle recuperated gas turbine systems requires further investigation. Westinghouse shows that intercooling will increase overall efficiency 1.5 percentage points and reduce COE about 2 mills/kW-hr.

Important additional observations on the results are as follows:

(1) A capability to use low-cost, semiclean fuels in open-cycle recuperated gas turbine systems would impact COE and efficiency in a desirable manner.

(2) Realization of the benefits of high turbine temperatures requires a vigorous gas turbine technology program.

(3) Water cooling reduces COE but also reduces system efficiency through excessive heat removal for the concept considered.

3.3.3 Combined-Cycle Gas Turbine/Steam Turbine Systems

In studying the combined-cycle system, both contractors evaluated LBTU gas, liquid coal derivatives, and HBTU gas fuels; G.E. also evaluated IBTU gas. General Electric emphasized LBTU gas and nonreheat steam systems; Westinghouse emphasized distillate fuel from coal and evaluated both reheat and nonreheat steam systems. General Electric evaluated both air and water cooling; Westinghouse emphasized air cooling. The influences of major gas turbine parameters such as turbine-inlet temperature, compressor pressure ratio, and blade and vane materials were evaluated. Major steam-bottoming-cycle parameters evaluated included throttle pressure and temperature.

As shown in table 3.3-1, the COE determined by G.E. ranged from 23 to 33 mills/kW-hr, and overall efficiency (including fuel processing efficiency) ranged from 21 to 37 percent. The low overall efficiencies occurred for HBTU gas (fuel conversion efficiency, 50 percent); the high overall efficiencies occurred for LBTU gas. The COE of 23 mills/kW-hr was for the LBTU gas fuel, near 2600° F turbine-inlet temperature and near 37 percent overall efficiency. Water cooling resulted in higher COE and lower efficiency than air cooling at corresponding turbine-inlet temperatures.

As shown in table 3.3-1, the COE determined by Westinghouse ranged from 24 to 34 mills/kW-hr, and the overall efficiency (including fuel processing efficiency) ranged from 20 to 42 percent. The low overall efficiency occurred for distillate fuel (fuel conversion efficiency, 50 percent); the high overall efficiency occurred for an LBTU integrated gasifier. The COE of 24 mills/kW-hr was for the LBTU gas fuel, 2200° F turbine-inlet temperature, and 42 percent overall efficiency. These were the lowest COE and highest efficiency reported by Westinghouse. Higher turbine temperatures would lead to higher efficiencies and lower COE. Higher temperatures will be evaluated in Phase 2.

The contractors' COE's for the LBTU gas case are in excellent agreement. Plant capital costs are within 10 percent and COE within 5 percent. However, a substantial difference of 7 percentage points in overall efficiency exists for the LBTU gas case. The difference in overall performance is accounted for by the difference in performance of the gasifier and the steam bottoming cycle and the approach to gas cleanup. General Electric selected a fixed-bed gasifier requiring 1.1 pounds of steam per pound of coal, imposing a significant efficiency penalty on the G.E. steam bottoming cycle. Westinghouse selected an advanced gasifier requiring 0.45 pound of steam per pound of coal. Westinghouse also used induction in the steam bottoming cycle to further improve efficiency. General Electric used cold-gas cleanup for the turbine, resulting in an additional efficiency penalty; Westinghouse used hot-gas cleanup.

The trends resulting from this study are

(1) Using LBTU gas produced in plant-integrated gasifiers results in the highest overall energy efficiency and lowest COE for combined-cycle systems.

(2) The cost of electricity decreases with increasing turbine-inlet temperatures to 2600° F with air cooling and to 3000° F with water cooling.

(3) The efficiency of water-cooled turbines is lower than that of air-cooled turbines operating at the same temperatures.

(4) Reheat steam bottoming cycles are not attractive unless high turbine-inlet temperatures are used.

(5) Ceramic blades and vanes are attractive at all firing temperatures.

(6) Semiclean (minimally processed) liquid fuels provide attractive COE, efficiency, and capital cost for combined-cycle systems.

3.3.4 Closed-Cycle Gas Turbines

Because it is a closed cycle, the working-fluid composition and pressure of the closed-cycle gas turbine are independent design parameters chosen for the benefit of the turbomachinery and heat exchangers. Since the working fluid is independent of the combustion products, clean (and expensive) fuels are not required. Coal can be burned directly without the penalty of a fuel conversion efficiency. These are potential benefits over the open-cycle gas turbine. However, because it is a closed cycle, the heat input is through a furnace/heat exchanger, which imposes an upper limit on operating temperature, introduces a significant cost item, and introduces a loss due to furnace-loop inefficiencies. The system was included in ECAS to examine the balance between these potential advantages and disadvantages.

The closed-cycle gas turbine system is one of those wherein the contractors' areas of emphasis differed considerably. The main differences involved the furnace and fuel type and the integration of bottoming cycles.

General Electric emphasized atmospheric fluidized beds using direct coal firing. Of a total of 46 parametric cases, 35 used an atmospheric fluidized-bed coal-fired furnace, one used a pressurized fluidized-bed coal-fired furnace, and 10 used a clean-fuel pressurized furnace.

Westinghouse emphasized pressurized combustion loops and clean over-the-fence fuels. Of a total of 100 parametric cases, 88 used a pressurized furnace and clean fuel (distillate in 84 cases). Westinghouse studied 11 cases with pressurized fluidized-bed furnaces with direct coal firing. They also did one case with an atmospheric furnace that used distillate fuel.

Both contractors used helium working fluid and varied such helium-loop parameters as pressure ratio, turbine-inlet temperature, recuperator effectiveness, and pressure losses. Many of Westinghouse's parametric variations involved changes in the furnace-pressurizing gas turbine parameters (which they referred to as the "pumpup cycle"). These included turbine-inlet temperature, pressure ratio, recuperator effectiveness, and pressure losses. General Electric did few parametric variations of these furnace-pressurizing gas turbine parameters but focused their attention on the helium cycle.

General Electric considered eight cases with an organic bottoming cycle (using R-22 and Fluorinol 85). A recuperated helium cycle was used in all cases. They also did five cases with a steam bottoming cycle and in all but one case used a recuperator in the helium cycle.

Westinghouse considered 45 parametric cases with a steam bottoming cycle, six with an organic cycle (R-12 and methylamine), and one with a sulfur dioxide bottoming cycle. In contrast with G.E. they configured the system so that the bottoming cycle received heat input from the furnace cycle as well as from the helium cycle. Also in contrast with G.E., none of their bottomed cases included a recuperator in the helium cycle. As a result, the temperature levels of their bottoming cycles were generally higher than G.E.'s.

General Electric's recuperated closed-cycle gas turbine with AFB furnace had overall energy efficiencies from 26 to 33 percent and COE from 34 to 48 mills/kW-hr. The most attractive case was with one stage of intercooling, 1500° F turbine-inlet temperature, and 0.85 recuperator effectiveness. This case had about 32 percent overall efficiency and 34 mills/kW-hr COE. Their steam and organic bottomed cases yielded similar ranges in COE (but higher than unbottomed cases primarily because of higher balance-of-plant costs). The organic-bottomed cases resulted in higher efficiency. The highest efficiency case was 38 percent with a COE of 42 mills/kW-hr.

The Westinghouse results with the highest overall energy efficiency and lowest COE were those with a PFB furnace or integrated gasifier. With a steam bottomer, the PFB furnace cases reached 38 percent overall efficiency with a COE of 31 mills/kW-hr. Those cases with a recuperator and no bottoming cycle had from 31 to 38 mills/kW-hr COE and from 30 to 35 percent overall efficiency.

The Westinghouse cases using clean fuels and pressurized furnaces had lower efficiencies because of the fuel conversion efficiency. In terms of powerplant efficiency, however, the 1500° F inlet cases reached 43 percent with a bottoming cycle and 36 percent without. In spite of this and the lower capital cost, however, COE was higher than for the coal-fired cases because of the higher cost of distillate fuel.

The coal-fired cases resulted in highest overall efficiency and lowest COE. Cleaner fuels allow higher firing temperatures and/or more power extraction from the furnace cycle but result in higher COE because of higher fuel prices.

Both contractors' results show that the use of intercooling in the recuperated, unbottomed cycle both increases overall efficiency and decreases COE.

Both contractors' results also show that using bottoming cycles increases efficiency. However, caution must be exercised in comparing their results because of the different way they integrated the systems. Because of the way Westinghouse configured the system, most of the power output is from the bottom and furnace loops (less than 50 percent from the helium cycle). In G.E.'s case most of the power output is from the helium cycle (approximately 80 percent).

Both contractors' results show that powerplant efficiency increases with increasing turbine-inlet temperature, above 1500° F. However, both used a clean-fueled furnace with high-temperature metallic heat exchangers. As a result the overall energy efficiency was lower than the 1500° F coal-fired cases, and the COE was substantially higher. In Phase 2 a nominally 1900° F helium cycle using a coal-fired AFB furnace with a ceramic heat exchanger will be studied.

3.3.5 Supercritical Carbon Dioxide Cycle

The supercritical carbon dioxide cycle was investigated only by G.E. (with Actron Industries as subcontractor) in the ECAS study. A total of 32 cases were examined, including variations in the fuel, furnace type, and primary-cycle configuration and operating parameters. Emphasis in the study was on the atmospheric fluidized-bed furnace (AFB), with variations to include one case with a pressurized fluidized bed (PFB) and four cases with a pressurized furnace (PF) - three burning low-Btu gas from an integrated gasifier, and the fourth burning a high-Btu gas. The prime-cycle configurations considered were the simple (Feher), recompression, and postheat cycles. The recompression cycle with a pump flow fraction of about 0.7 (ratio of pump flow to total flow) proved to be the most attractive of the three configurations in terms of cost of electricity and overall energy efficiency.

The supercritical carbon dioxide cycle was characterized by fairly good efficiencies but high cost of electricity (between 35 and 41 percent with corresponding COE's of 50 and 68 mills/kW-hr). The two best AFB cases in both efficiency and COE had overall energy efficiencies of 39 and 41 percent and COE's of 66 and 68 mills/kW-hr, respectively. The PFB case resulted in lower COE (about 57 mills/kW-hr) and about the same efficiency (somwhat over 39 percent) as the majority of the AFB cases. The PF cases with integrated low-Btu gasifiers offered the lowest COE (about 50 mills/kW-hr) but at a reduced efficiency (about 35 percent) because of the losses in the gasification process. An examination of the trends shown by the contractors' results indicated that a modified cycle combining favorable variations in the furnace type and cycle parameters examined in the study might have a COE of about 55 mills/kW-hr at an overall energy efficiency of 40 percent.

The high COE of the supercritical carbon dioxide cycle is a result of very high component capital costs, primarily the recuperator and turbine. For good efficiency, the cycle requires a very large recuperator that must accommodate differential pressures resulting from about 3800 psi on one side of the heat exchanger and 1400 psi on the other. The turbine must operate in an environment of both high pressure (3800 psi) and relatively high temperature (1350° F). Innovative design approaches to these components are required to arrive at less costly solutions to the design problems associated with the high pressures at relatively high temperatures that are peculiar to the supercritical carbon dioxide cycle. The scope of Phase 1, however, did not provide an opportunity for the detailed design studies that would be required but did identify the technical areas of focus if additional studies of this system are to be conducted. Because the costs of the recuperator and turbomachinery are such a large proportion of the total plant capital costs (over 50 percent for the base case studied by G.E.), the effect of possible reductions in the costs of these components that might result from detailed design studies was evaluated in a cursory manner. Reduced costs equal to approximately one-third of the original cost estimates were assumed for these components, based on consideration of equipment costs of other closed-cycle dynamic systems examined in the study. Applying these reduced costs to the modified cycle previously mentioned resulted in a plant with a COE of about 38 mills/kW-hr and an overall energy efficiency of about 40 percent.

3.3.6 Liquid-Metal Rankine Topping Cycle

General Electric and Westinghouse conducted performance analyses and made cost estimates of liquid-metal Rankine topping cycles as part of the ECAS Phase 1 studies. These systems comprised a Rankine topping cycle, with either potassium or cesium as the working fluid, rejecting heat to a conventional steam plant as a bottoming cycle. General Electric studied a total of 16 cases and Westinghouse a total of 50. Three types of furnace/boilers were examined, including the atmospheric fluidized bed (AFB), the pressurized furnace (PF), and the pressurized fluidized bed (PFB). The fuel for the PF was either a low-Btu gas produced in a coal-gasifier integrated with the power system or a high-Btu gas or liquid produced in a free-standing gasification or liquefaction plant. General Electric emphasized the use of an AFB in their study; Westinghouse emphasized the PFB.

The best AFB case with potassium as a working fluid that was studied by G.E. had an overall energy efficiency of about 40 percent and a COE of about 48 mills/kW-hr. This represents both the highest efficiency and lowest COE of the AFB cases. The pressurized furnace cases with integrated low-Btu gasifiers had somewhat lower efficiencies (approx 35 percent) and lower COE's (approx 40 to 41 mills/kW-hr). The single PFB case studied had an overall energy efficiency of about 40 percent with a COE of about 40 mills/kW-hr. The Westinghouse results generally indicated higher efficiencies and lower COE's than those of G.E. The best case studied by Westinghouse, for both efficiency and COE, was a PFB case with an overall energy efficiency of about 44 percent and a COE of about 29 mills/kW-hr.

There are several reasons for the lower efficiencies of the G.E. cases, one of which contributes in varying degrees to all the configurations studied by G.E. A high potassium recirculation ratio was assumed in the G.E. furnace/boiler designs on the basis of insuring complete wetting of the horizontal tube walls. This resulted in high recirculating pump power and efficiency penalties of about 2 percentage points for the AFB cases, about 1.5 percentage points for the PFB case, and about 0.3 percentage point for the PF with integrated low-Btu gasifier. Westinghouse, on the other hand, assumed vertical tubes and a recirculation ratio of 2.5, with correspondingly low pump power and negligible effect on efficiency. Although the extent of recirculation that might be required is unknown at the present time, it is likely that recirculation ratios considerably lower than those used in the G.E. study can be used because of the extreme ease with which potassium wets metal surfaces. Recirculation pumping power could then be reduced to the point where it has a very minor impact on the overall system efficiency. In the case of the PFB, the G.E. method of recovering exhaust heat from the pressurizing gas turbine through recuperation to the combustion air resulted in higher stack losses and lower efficiencies than were obtained in the Westinghouse cases that used this heat for feedwater heating in the steam bottoming plant. Lower efficiencies for the G.E. PF cases with integrated low-Btu gasifiers can be attributed to the higher losses associated with the cold-gas cleanup and the higher steam requirements of the G.E. gasifier, as well as to the difference in the ways the two contractors integrated the gasifier into the power system.

The lower COE's of the Westinghouse results are attributable to (1) lower capital costs of all components in terms of $/kWe and reduced fuel costs due simply to the effect of higher plant efficiencies; (2) lower furnace/boiler costs due in part to lower pump costs resulting from lower recirculation pumping requirements; and (3) lower contingency allowances.

Both G.E. and Westinghouse found the PFB potassium topping plant to be highest in efficiency and lowest in COE. However, G.E. favored the AFB because of its more advanced state of technology and the elimination of possible hot corrosion and erosion of the gas turbine blades from particulates and contaminants in the gases from the PFB. Although cesium appeared to offer some advantage in turbomachinery costs and size and a small advantage in efficiency, its higher costs and less advanced state of technology would result in a much more costly development program.

Although the contractors were not able to conduct sufficiently complete parametric studies during Phase 1 to arrive at an "optimized" system, sufficient information was generated to suggest that the best efficiency and lowest COE can be obtained for a PFB case with a potassium cycle operating between a 1400° F boiling temperature and an 1100° F condensing temperature and a pressurizing gas-turbine-inlet temperature near 1800° F. Exhaust heat recovery from the gas turbine would be in the form of feedwater heating to the 3500 psi/1000° F/1000° F steam plant bottoming the potassium cycle. It is estimated that an overall energy efficiency of about 45 percent can be achieved with this configuration burning Illinois #6 coal. The COE would be about 28 mills/kW-hr using Westinghouse cost estimates or about 35 mills/kW-hr using G.E. cost estimates adjusted to reflect reduced pump costs resulting from lower recirculation ratios and the higher efficiency of the proposed configuration. A configuration similar to this will be examined in more detail by G.E. in Phase 2, and better estimates of efficiency and COE should be obtained.

3.3.7 Open-Cycle Magnetohydrodynamic Systems

Magnetohydrodynamic (MHD) power systems are of interest for advanced powerplants primarily because of their high performance potential. This potential is the direct result of their high maximum operating temperature. The MHD working fluid exiting the generator is also at a relatively high temperature, and this heat must be utilized in order to obtain high efficiency. This is accomplished by using the MHD generator exhaust to preheat the oxidizer (and sometimes the fuel) and to produce additional power in a bottoming plant. In addition to a large number of possible MHD operating parameters, there are many different configurations for such an MHD plant. These involve a variety of bottoming cycle types and their integration with the MHD cycle, a variety of methods of preheating the oxidant, and a range of possible fuels and oxidants. A representative sample of such variations has been studied in ECAS.

General Electric studied 30 parametric cases, 23 of which used direct coal firing and seven of which used solvent-refined coal (SRC) as the fuel. All but one case used a steam bottoming cycle; that one used a gas-turbine bottoming cycle. All but two cases used a high-temperature (2000° F and higher) regenerative heat exchanger to preheat the air with MHD generator exhaust gas (i.e., direct air preheat). One used lower temperature (1500° F) direct air preheat with oxygen enrichment, and the other assumed the air to be preheated by a separate clean fuel gas from a coal gasifier (i.e., indirect air preheat).

Westinghouse studied 39 parametric cases, 34 of which were direct coal fired and five of which used a low-Btu fuel gas obtained from an integrated gasifier. Half of their direct-coal-fired cases used direct air preheat to about 2400° F, the others assumed direct air preheat to as high as 2400° F followed by additional heating in an indirect air preheater. The fuel for the indirect air preheater was the volatiles obtained by carbonizing the coal before using it in the main combustor. All the Westinghouse cases used a steam bottoming cycle.

The G.E. coal-fired cases ranged from 44 to 53 percent in overall efficiency and their SRC cases ranged from 40 to 46 percent. The SRC fuel cases suffer from the assumed 78 percent fuel conversion efficiency; their powerplant efficiency, not including this fuel conversion penalty, ranged from 52 to 59 percent. The costs of electricity (COE) ranged from 41 to 48 mills/kW-hr.

The Westinghouse coal-fired, direct-air-preheat cases ranged from 44 to 49 percent in efficiency and 27 to 31 mills/kW-hr in COE. The coal-fired cases with direct and indirect air preheat ranged from 44 to 54 percent in efficiency and 27 to 35 mills/kW-hr in COE. The higher efficiency was obtained by air preheat to about 3500° F. With indirect air preheat to about 3000° F, 50 percent efficiency was obtained. The cases using low-Btu fuel gas ranged from 46 to 54 percent in efficiency and 34 to 42 mills/kW-hr in COE.

For nearly comparable conditions both G.E. and Westinghouse obtained efficiencies of about 49 percent. This is for a direct-coal-fired plant using direct air preheat to 2400° - 2500° F and a 3500 psi/1000° F/1000° F steam bottoming cycle. The results indicate that by using the best features of each, the efficiency could reach 50 percent. The cost estimates, however, are substantially different. The G.E. COE for these conditions is 43.9 mills/kW-hr, and the Westinghouse COE is 27 mills/kW-hr. Most of this difference is due to a difference in plant capital cost estimates. The G.E. and Westinghouse results were $1102/kWe and $642/kWe, respectively. The Westinghouse cost estimates for several of the major components were higher than G.E.'s. General Electric's estimates for balance-of-plant materials and installation costs, however, were higher than Westinghouse's estimates. Differences in the estimates of major component costs can be resolved only after further technology development. The conceptual design being done for this system in Phase 2 should help clarify the balance-of-plant cost estimates.

Both contractors show a loss in efficiency of about 3 percentage points associated with seed reprocessing when high-sulfur coal is used. Alternative reprocessing concepts with lower performance penalties should be investigated. A system with an integrated gasifier and in-bed sulfur removal appears to have the potential to be competitive with direct-coal-fired MHD systems when high-sulfur coal is used.

3.3.8 Closed-Cycle, Inert-Gas Magnetohydrodynamic Systems

This study represents the first serious attempt to mate the closed-cycle, inert-gas MHD system with fossil-fuel-fired heat sources for utilities application. Since there was no data base of results from previous studies, a variety of powerplant configurations were considered, and some of the initially chosen configurations did not result in attractive systems. The contractors differed in both the powerplant configurations considered and in their approach to evaluating the systems performance. The initial configurations chosen in the G.E. study were an MHD topping cycle using an over-the-fence fuel and a direct-coal-fired parallel cycle. The majority of the over-the-fence fuel cases used solvent-refined coal with a conversion efficiency of 78 percent. In the parallel-cycle concept, a fraction of the combustion energy is transferred to a recuperative MHD Brayton cycle through a refractory regenerative heat exchanger, and the remaining combustion energy is transferred directly to the steam boiler. As the study progressed, G.E. added two direct-coal-fired MHD topping cycles.

The MHD topped steam cycle was the only configuration considered by Westinghouse. The fuel used in the majority of cases was a low-Btu gas derived from an on-site gasifier that was closely coupled. Westinghouse evaluated the system performance by doing efficiency calculations for a wide range of generator parameters and then optimizing the thermodynamic efficiency for a given generator inlet temperature. The costs were then calculated for these optimum efficiency points.

Besides the different powerplant configurations considered, variations in coal type, generator inlet temperature (2400° to 3800° F), generator inlet pressure (10 to 20 atm), generator turbine effectiveness (0.6 to 0.8), and power level were also studied.

The G.E. results for the parallel cycle and the clean over-the-fence fuel MHD topping cycle (table 3.3-1) indicate that these are not attractive systems. The overall energy efficiencies for the parallel cycle ranged from 35.2 to 39.1 percent, the capital costs varied from $1654/kWe to $1886/kWe, and the COE from 66 to 73 mills/kW-hr. The powerplant efficiencies for the clean-fuel MHD topping cycles are much higher (35 to 46 percent), but the overall energy efficiencies are from 26.4 to 35.9 percent when the coal-to-clean-fuel conversion efficiency is considered. The capital costs and COE range from $1300/kWe to $1535/kWe and from 58 to 66 mills/kW-hr for this configuration. The COE's for the above systems are 2 to 2.5 times that of the G.E. advanced steam cases. The best G.E. results were obtained for the direct-coal-fired MHD topping systems. Two of these cases were considered. The first case, with an inlet temperature of 3000° F, an MHD generator adiabatic efficiency of 0.7, and magnetic field strength of 3.5 teslas, resulted in an overall energy efficiency of 41.8 percent, a capital cost of $1551/kWe, and a COE of 61.6 mills/kW-hr. The single iteration made on this configuration, in which temperature is 3121° F, MHD generator adiabatic efficiency is 78 percent, magnetic field is 4.5 teslas, and the powerplant layout was considerably modified, improved the efficiency, capital cost, and COE to 46 percent, $1109/kWe, and 45.6 mills/kW-hr, respectively.

The Westinghouse overall energy efficiencies for the LBTU gasifier configuration were 46.1 percent at an inlet temperature of 3800° F and 42.2 percent at 3100° F. This includes an effective efficiency of the gasifier/combustion loop combination of about 78 percent. The capital costs and COE at 3800° F range from $2228/kWe to $2434/kWe and from 77 to 85 mills/kW-hr. At 3100° F, the capital costs were $1912/kWe and the COE was 68 mills/kW-hr.

There are no irreconcilable differences between the G.E. and Westinghouse efficiencies when the different assumptions, operating conditions, and combustion-loop efficiencies are considered. However, the Westinghouse capital costs for a nearly equivalent system were approximately $400/kWe higher than G.E.'s. This difference is mainly due to the differences in the costs of the refractory regenerative heat-exchanger system. The Westinghouse design was quite conservative relative to the G.E. designs and to designs by FluiDyne obtained by NASA through a contract with Burns and Roe. Their COE could probably be reduced to approximately 44 mills/kW-hr by using a more compact heat-exchanger system. The best configuration considered was the direct-coal-fired MHD topping cycle with an efficiency of 46 percent and COE of 45.6 mills/kW-hr. Pressurization of the combustion loop should further reduce the costs of this system. The LBTU gasifier cases have lower efficiencies and generally higher costs than the direct-coal-fired systems at equivalent generator inlet temperatures. More closely integrating the gasifier and optimizing the economics could significantly improve the initial results obtained for this configuration.

3.3.9 Liquid-Metal Magnetohydrodynamic Systems

General Electric and Westinghouse approached the liquid-metal MHD (LMMHD) systems in a similar manner. Both used the two-phase LMMHD power cycle with an inert gas as the primary thermodynamic working fluid and a liquid metal as the electrodynamic fluid in the MHD generator. At the lower temperatures considered (1200° to 1300° F), G.E. used a He/Na working fluid and Westinghouse used Ar/Na. Westinghouse considered the use of both Ar/Na and He/Li at the higher temperatures (1400° to 1500° F), but G.E. only used He/Li. The majority of cases studied by both contractors included the use of a binary LMMHD/steam cycle, the use of a steam cycle with little regenerative feedwater heating, and the use of pumps to recirculate the liquid metal. Cases were included, however, to determine the effect of eliminating the liquid-metal pumps.

Both contractors used modularized MHD generators that are operated hydraulically in parallel and electrically in series. The series connection is required to attain a reasonable voltage level for the inverters.

The contractors approach to the parametric variations differed somewhat. The majority of the Westinghouse cases used a cyclone combustor, Illinois #6 coal, a power level of approximately 1000 MWe, and various liquid-metal-system parameters. The G.E. cases mainly treated variations in combustors, fuels, and power level.

The overall energy efficiencies obtained by both contractors were quite similar (table 3.3-1). At temperatures of 1200° to 1300° F, they ranged from 33.6 to 37.3 percent, and at 1400° to 1500° F from 37 to 39.5 percent. The costs were significantly different, however. For the lower temperature cases, the G.E. costs were in the range $1430/kWe to $2570/kWe and 77 to 93 mills/kW-hr, and Westinghouse's were $790/kWe to $1177/kWe and 33.9 to 46.2 mills/kW-hr. At 1400° to 1500° F the ranges were as follows: G.E., $2500/kWe to $3000/kWe and 92 to 100 mills/kW-hr; Westinghouse, $1165/kWe to $2140/kWe and 45 to 78 mills/kW-hr.

A detailed analysis of the contractors' costs showed major differences in every item. Differences in the costs of such major components as the magnet, MHD generator, and power conditioning equipment have been reconciled by consideration of the different design philosophies used by the contractors. Westinghouse attempted to minimize the MHD generator, magnet, and liquid-metal piping costs in their design approach. Inverter costs differ (G.E., \$200/kWe; Westinghouse, \$39/kWe) because G.E. required dc interrupters in their system and Westinghouse did not. However, for equivalent powerplants, there are still unresolved cost differences of approximately \$300 million between the contractors' results.

The highest overall energy efficiency obtained by the contractors at the temperature limits dictated by the present sodium technology (1200° to 1300° F) was 37.3 percent. Their results indicate that the maximum potential efficiency at these temperatures would be approximately 40 percent. This is assuming a generator isentropic efficiency of 0.80, the development of a highly efficient nozzle/separator/diffuser, and optimistic system component efficiencies. The overall energy efficiency is limited to about 40 percent because at these temperatures the liquid-metal MHD system cannot be effectively coupled to an advanced steam plant. Because of a pinch-point problem in the steam boiler, both contractors found that the highest LMMHD/steam system efficiencies were obtained by using a steam plant with minimal regenerative feedwater heating and with the steam reheat energy being supplied by the combustor. The adverse effect of this coupling is twofold. The thermodynamic efficiency of the steam bottoming plant is limited to approximately 39 percent, and the system does not derive the full benefit of the topping cycle because a portion of the combustion energy is transferred directly to the steam plant.

At the higher temperature considered in this study (1500° F), these problems may be alleviated. Westinghouse has calculated an overall energy efficiency of 43 percent by assuming that the sodium technology can be extended to 1500° F and that the system can be coupled to a 45 percent steam plant. The sodium vapor carryover could be a considerable problem at these temperatures. However, only a few of the higher temperature systems were considered by the contractors in this study, and the potential for improvement from better coupling with an advanced steam plant at higher temperature is indicated. Resolution of the large differences in cost estimates requires more detailed component design and plant integration optimization.

3.3.10 Fuel-Cell Powerplants

In ECAS Phase 1, three types of low-temperature fuel cells and two types of high-temperature fuel cells were studied. Comparison of the G.E. and Westinghouse work was possible in the case of the low-temperature (375° F) phosphoric acid fuel-cell system and in the case of the high-temperature (approx 1832° F) zirconia solid electrolyte (SE) fuel-cell system. Other low-temperature fuel cells studied were the solid polymer electrolyte (SPE) system by G.E. and an aqueous alkaline (KOH) fuel-cell system by Westinghouse. Also included in the Westinghouse study was the relatively high-temperature (approx 1200° F) molten carbonate fuel cell. The G.E. study included 19 parametric cases with primary emphasis given to low-temperature fuel cells; the Westinghouse study included 69 parametric cases approximately evenly distributed among the low- and high-temperature fuel-cell systems. In this parametric study the influences of powerplant size, fuel type, oxidant type, temperature, electrolyte thickness, catalyst loading, and fuel-cell life were evaluated.

3.3.10.1 High-Temperature Fuel-Cell Powerplants

An important part of the high-temperature fuel-cell systems study was the utilization of waste heat either by a steam bottoming cycle, the gasifier, or both. These are referred to as "integrated" cases. Such large powerplants (250 to 1100 MWe) have potential as central-station base-load electric power generators. The Westinghouse overall efficiency results bear this out for both high-temperature fuel-cell systems investigated. For the Westinghouse zirconia SE fuel cell the efficiencies of the integrated cases were between 47.8 and 53.0 percent. (The 53.0 percent efficiency was reported for the well-known Westinghouse "Project Fuel Cell" concept, in which the fuel-cells are actually housed inside the gasifier in order to maximize heat and mass transfer to the gasifier.) The overall efficiency for the molten carbonate fuel cell using a steam bottoming cycle was 46 percent (table 3.3-1).

The principal sources of high efficiency in high-temperature fuel-cell systems are as follows: (1) the increase in reaction rates (reduced polarization) brought about by high temperature, which helps the fuel cell to approach its theoretical potential for high efficiency, and (2) utilization of high-quality fuel-cell waste heat by the gasifier and/or bottoming cycle. The SE fuel-cell concepts of G.E. and Westinghouse are different. The G.E. approach involves thicker solid electrolytes than does the Westinghouse approach. This results in higher resistances (lower voltages) and consequently lower efficiencies.

A comparison of Westinghouse integrated and nonintegrated high-temperature fuel-cell system cases, both molten carbonate and zirconia SE, revealed that the overall efficiency gain due to fuel-cell waste heat utilization is approximately 15 percentage points. There were no corresponding G.E. "nonintegrated" zirconia SE fuel-cell cases to allow the same comparison to be made.

Confidence in the efficiency predictions is much greater than in the estimation of fuel-cell costs. This is especially true for the high-temperature fuel cells, for which costs are based upon limited data for small laboratory-size units. However, the fuel-cell configuration is a very large number of repeating cells arranged in modules and represents only a small extrapolation in size from the laboratory-size unit.

An uncertain factor that, as expected, has a significant influence upon COE is the useful life of the fuel cell. For assumed 10,000-hour lives, Westinghouse estimated costs for a zirconia SE and a molten carbonate fuel cell (each with a steam bottoming cycle) to be 40 and 44 mills/kW-hr, respectively. On the other hand, with 50,000-hour lives the costs would be close to 30 mills/kW-hr for each high-temperature system. The G.E. zirconia cost estimates of 42 to 45 mills/kW-hr are consistent with the Westinghouse cost estimates. The G.E. estimate is based on very long life (100,000 hr), but lower efficiency of the G.E. concept raises the overall COE to more than that of the 50,000-hour Westinghouse case.

Finally, because of the very difficult high-temperature-technology problems, the contractors estimate commercial availability not before 1990 for the molten carbonate system and not before 1998 for the zirconia SE system.

3.3.10.2 Low-Temperature Fuel-Cell Powerplants

Low-temperature fuel cells are less suited for the primary ECAS utility application, that is, base-load power generation from coal-derived fuels. First of all, the requirements for clean fuel are much more stringent for low-temperature fuel cells than for high-temperature fuel cells. Secondly, there is less potential for utilization of waste heat in the powerplant at the low temperatures. Third, the rate processes are slower at low temperatures, and polarization losses are significant at current density levels that result in optimum power levels. All three conditions reduce the efficiency of a low-temperature fuel-cell powerplant. However, greater utilities applications for low-temperature fuel cells are foreseen, outside the context of ECAS, for non-base-load service. (A number of these potential applications are mentioned in section 3.3.10.3.)

In terms of ECAS, both contractors' studies bear out the lower efficiency performance of low-temperature fuel-cell systems compared with high-temperature systems. In both G.E. and Westinghouse studies the highest overall efficiencies (31 percent) for low-temperature fuel-cell powerplants merely approach the lower end of the overall efficiencies of the high-temperature system (table 3.3-1).

Among the low-temperature fuel-cell cases, a direct comparison can be made between the G.E. and Westinghouse phosphoric acid high-Btu-fuel (HBTU/air) results. Both contractors considered a phosphoric acid case very similar to the 26-MWe fuel-cell powerplant being proposed for commercial service (United Technologies Corp. FCG-1). The G. E. estimate of COE for this case was 52 mills/kW-hr and that of Westinghouse was 40 mills/kW-hr (both based on 40,000-hr life). General Electrics' higher COE is attributable primarily to a much higher fuel processing cost ($173/kWe) than estimated by Westinghouse ($38/kWe). The G.E. fuel processing cost estimate appears high and the Westinghouse estimate appears somewhat low.

The powerplant efficiencies estimated by G.E. and Westinghouse for these cases were 30 and 36 percent, respectively. The difference reflects the contractors' estimates of fuel-cell efficiency and the degree of integration of the fuel cell with the fuel processor. Finally, the overall efficiency estimates for these cases were 24 and 15 percent for Westinghouse and G. E., respectively. These reflect the large efficiency penalty to be paid in producing HBTU in a gasifier (50 and 67 percent gasifier efficiencies for the G.E. and Westinghouse concepts, respectively).

Both G.E.'s and Westinghouse's results indicated the significant influence that fuel choice had upon both overall efficiency and COE. Westinghouse reports an overall efficiency of 29 percent (a 5-percentage-point increase) when IBTU is used in place of HBTU, the base-case fuel. (This reflects directly the more efficient gasification process for producing IBTU.) General Electric results for cases using hydrogen show larger improvements over cases using HBTU.

An interesting case in the study of the SPE fuel cell is an SPE operating on over-the-fence hydrogen/oxygen and producing 201 MWe. Hydrogen/oxygen is the most desirable fuel/oxidant combination for maximizing powerplant efficiency. Cost of electricity was reduced because the use of hydrogen eliminates the need for a fuel processor.

This G.E. SPE low-temperature fuel-cell case had the highest reported overall efficiency for a low-temperature fuel cell (31 percent) and the lowest reported COE for any of the G.E. or Westinghouse fuel-cell cases (31 mills/kW-hr). However, if a calculation of the energy required to produce oxygen is made (to take into account the oxygen-plant power drain upon the fuel cell), it would reduce overall efficiency to an estimated 26.5 percent and increase COE to approximately 37 mills/kW-hr. In addition, the basic COE costs probably reflect an optimistic projection of cell costs and polymer life at 300° F.

For the aqueous alkaline fuel-cell systems studied by Westinghouse the results indicated higher costs than those of similar phosphoric acid fuel-cell systems. First, additional reactant processing is required to guard against carbonation of the alkaline electrolyte. Second, lower power densities are obtained with the alkaline fuel cell at 158° F than with the phosphoric acid fuel cell at 375° F. Hence, fuel-cell costs are higher. The COE for 10,000- to 30,000-hour alkaline systems is in the 50- to 61-mill/kW-hr range.

3.3.10.3 Concluding Remarks

In the primary ECAS application of base-load power from coal-derived fuels:

(1) Improved integration could lead to reduced COE without efficiency penalty.

(2) Efficiency increases with fuel-cell temperature, that is, proceeding from low-temperature fuels cells to the high-temperature molten carbonate fuel cell and finally to the very high-temperature zirconia solid electrolyte system.

(3) Scaleup in powerplant size only results in significant reduction in COE when it is accompanied by utilization of waste fuel-cell heat through a steam bottoming cycle and/or integration with the gasifier.

(4) The potential for near-term utilities application of fuel-cell systems may be as dispersed power generators in peaking or intermediate service, taking advantage of the fuel cells' special features (a) to increase overall efficiency of a utility's energy conversion equipment, (b) to reduce transmission costs, (c) to better match capacity to growth requirements, (d) to improve system reliability and availability, (e) to meet the needs of very small utilities, and (f) to provide total energy savings through on-site waste heat utilization.

3.4 SUMMARY OF SENSITIVITY OF RESULTS TO ECONOMIC GROUND RULES

The ECAS contractors, G.E. and Westinghouse, were provided with common ground rules and used common assumptions to achieve comparable treatment in analyzing the different power systems. The cost of electricity numbers associated with the many parametric points studied are functions of both the technical results (e.g., system efficiency, component cost estimates, and installation material and labor estimates) and the specified economic ground rules (e.g., fixed-charge rate, capacity factor, fuel price, and interest and escalation rates). Therefore, the powerplant capital cost and cost of electricity values can be changed by using different economic ground rules without affecting the technical results of the contractors. The power systems comparisons can be made by choosing many different sets of economic ground rules. A number of variations are studied in section 6.2.3. The effect on COE of using ranges of fuel prices, fixed-charge rates, capacity factors, and interest and escalation rates are studied in section 6.2.3. No major changes in the relative rankings based on COE of the different systems occurs when these economic assumptions are varied one at a time over a wide range.

The major-component, labor, balance-of-plant materials and components, and indirect costs and the architect and engineering charges for the powerplants studied in ECAS are in mid-1974 dollars. The COE values presented by the contractors were calculated as if construction of each type of plant were started in mid-1974. All capital costs before interest and escalation are estimated in the same-valued dollars (mid-1974). The interest and escalation charges are calculated by using an S-shaped cash flow curve typical of those in references 3 and 4. Because different powerplants have different construction times, the relative amounts of interest and escalation added on are different. The result is that the total capital costs are in different-year dollars for plants with different construction periods. In any case, the fuel and operating-and-maintenance charges are in mid-1974 dollars. This procedure is referred to here as the "common start-of-construction date" approach.

An alternative to assuming a common start-of-construction date is to assume a common end-of-construction date. In this analysis, 1981 is assumed as the end-of-construction date. Therefore a system with a 2-year construction time has a 1979 start-of-construction date. However, the results of a powerplant with a 7-year construction time would not change relative to the common start-of-construction date results, since its start-of-construction date is still mid-1974.

To calculate the COE's based on a 1981 end-of-construction date, the capital costs, before interest and escalation are applied, are escalated to a start date corresponding to a 1981 end date (e.g., 1979 for a 2-yr-construction-powerplant). Then the appropriate interest and escalation factors are applied by using the cash flow curve. The fuel charges and O and M charges are still in mid-1974 dollars.

The common-start-date and common-end-date analyses are compared in table 3.4-1 for selected points for each system studied. There is relatively little change in the COE's for the various systems, and no new conclusions can be stated from the results shown. The COE's based on a common end date increased for most systems, with the exception of open- and closed-cycle MHD, which have 7 years or longer estimated construction times. A better approach, which insures comparability of costs, is to deescalate all costs to some common base year or, in other words, to express capital cost in constant mid-1974 dollars. A constant-dollar analysis provides a common dollar basis for comparing systems that have different start- or end-of-construction dates. It has an advantage over the previous analyses in that the on-line date of the powerplant is not a factor in the COE values generated but the effect of the period of construction is included.

Since the powerplants studied in ECAS have the costs expressed in dollars based on their on-line years (i.e., 1976 for 2-year construction, etc.), it is necessary to deescalate their costs at the prevailing escalation rate to 1974. As a result, the duration of construction causes the capital cost to increase only by the interest paid in excess of the escalation rate. For a more detailed comparison of constant-dollar and current-dollar costs, refer to section 4.2.

The constant-dollar COE's for selected G.E. and Westinghouse cases are presented in table 3.4-1. There is a large effect on COE for many of the systems of both contractors, with the largest change seen in the high-capital-cost systems. In current dollars, the COE's for these systems decrease because their escalation charges on capital are proportionately larger due to the high capital cost of components and longer construction times. In constant dollars this inflationary increment does not exist. Conversely, the COE's for the lower-capital-cost systems do not change much when constant dollars are used partly because the capital component of COE for these systems is not a large portion of the total COE. Also, these systems are generally characterized by short construction times, and the escalation during construction is not a large contributor to capital cost.

The constant-dollar versus current-dollar analysis presented so far compares the on-line COE's for the various systems. This is a method of evaluating competing concepts often used by utilities as an important criterion for purchase. Generally the higher-efficiency systems suffer from an economic

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viewpoint because of large initial capital costs. In the long run, it might be expected that the higher efficiency systems would become more favorable economically in an inflationary period through their more efficient use of increasingly expensive fuel. Thus an average-powerplant-lifetime COE using constant dollars was also studied.

The Phase 1 powerplants were assumed to have a 30-year lifetime, so average COE's for the total 30-year lifetime of the plants have been calculated by NASA. The 30-year average COE is defined as the total bus-bar cost of producing electricity for 30 years divided by the total amount of power produced during that lifetime. During that 30-year span, two different inflation rates, 3.25 and 6.5 percent, are assumed here. Note that, if the inflation rate were zero over the 30-year plant lifetime, the average lifetime COE would correspond to the constant-dollar analysis just discussed. The capital component of COE is reduced when considering an average plant lifetime and an inflation rate during its lifetime. This is because the capital portion is a fixed charge dependent on the initial capital cost of the plant and the fixed-charge rate, which as for the contractors is assumed to be 18 percent as specified by the study ground rules. With an inflation rate greater than zero, the constant-dollar COE decreases during the plant life because of the decreasing constant-dollar value of the fixed capital charges. Again for a more detailed discussion of average lifetime COE's refer to section 4.2.

Assuming constant dollars, the average COE's for the powerplants studied by the contractors are presented in table 3.4-1 for inflation rates of 3.25 and 6.5 percent. Under this assumption, many of the higher cost systems now have more-favorable COE's. The Westinghouse open-cycle MHD case has the lowest COE of all systems; the other MHD cases, along with supercritical carbon dioxide and liquid-metal Rankine have considerably lower COE's when compared with the current-dollar, common start-of-construction date analysis. This is more graphically illustrated in figure 3.4-1. In parts (a) and (c), the effect of overall efficiency on COE is shown for selected points from the G.E. and Westinghouse studies (solid circles) using current-year dollars and the common start-of-construction date assumption. In parts (b) and (d), the average lifetime COE's are presented for the same points using constant dollars. Here the difference in COE between the two approaches is more clearly seen. The relative positions of the power systems have changed because of the large decrease in the COE's of the high-capital-cost, high-efficiency systems and the relatively much smaller decrease for the lower-cost systems.

Although the variations presented here have not been exhaustive, the economic assumptions are clearly important determinants of the final results. Also, the ECAS results can be used in many ways because the assumptions and data are clearly displayed and readily separable. Different comparisons can be made using different economic assumptions without affecting the performance data while providing additional perspectives on the relative competitiveness of the various systems.

3.5 SELECTION OF SYSTEMS FOR PHASE 2 DESIGN AND ANALYSIS

This section describes the process used to select the Phase 2 systems. Initially, the Interagency Steering Committee obtained recommendations from the Utility Advisory Panel and each of the two contractors (refs. 1 and 2), together with recommendations from the Lewis project team. This was accomplished as a part of the public briefing following the Phase 1 presentation of results in May 1975. On the basis of these inputs and the perspective obtained directly from the data presentation, the Interagency Steering Committee subsequently selected the systems for Phase 2 conceptual design, as shown in table 3.5-1. The selection of systems was not constrained by any given time frame for commercial implementation but rather to the potential for deriving the greatest national benefit from advanced technologies showing the most promise for economical production of electricity with increased efficiency. This table also indicates the assignment of these systems by contractor. The assignment of systems was based on programmatic considerations.

The Utility Advisory Panel in their deliberations established the following set of criteria against which the various systems in Phase 1 were evaluated:

(1) System suitable for commercial availability by 1990
(2) Emphasis on systems that will result in lower capital intensiveness
(3) Minimal technical barriers to assure probability of success
(4) Cost of development against impact on ultimate economics and energy independence
(5) Applicability of cycle to integrated or over-the-fence fuels
(6) Flexibility of combustor to accept multiple choice of fuels
(7) Emphasis on cycles promising low relative cost of electricity
(8) Strong emphasis on environmental intrusion factors that promise minimal waste disposal quantities and qualities besides meeting conventional regulatory standards

On the basis of these criteria the panel made the following recommendations for consideration by the Steering Committee:

(1) Class I - candidates strongly recommended for Phase 2:
   (a) Advanced steam with pressurized- and atmospheric-fluidized-bed furnaces and steam conditions limited to 1200° F and 3500 psig
   (b) Simple and recuperated open-cycle gas turbines with over-the-fence, integrated fuels
   (c) Combined open-cycle gas turbine/steam turbine with blade cooling (air and water) and over-the-fence, integrated fuels
(2) Class II - candidates that do not generally meet the panel's criteria but may show promise upon further detailed examination (in the 1990's)
   (a) Open-cycle MHD/steam, direct coal fired
   (b) Combined closed-cycle gas turbine/steam turbine using inert gas (not metal vapor) and integrated fuels in a conventional furnace
   (c) Simple low-temperature fuel cells with over-the-fence fuels
(3) Class III - It is also recommended that those systems studied in Phase 2 that appear to be suitable for peaking or intermediate operation be reoptimized for such service.

As can be seen, the systems recommended by the Utility Advisory Panel were, for the most part, incorporated by the Steering Committee into Phase 2 of ECAS. The exceptions were class I system b and class II system c. In both cases the Steering Committee judged these systems to be more attractive for other than base-load applications. In addition, the technology advancement for the open-cycle gas turbine systems was judged to be adequately covered by their inclusion in the combined-cycle application of Phase 2. The class III recommendation was not included because of funding and schedule limitations. However, the Steering Committee agreed that evaluation of peaking and intermediate applications is an important consideration that might better be treated in follow-on studies.

The molten carbonate fuel cell is a special case. On the basis of Phase 1 results and review by Lewis, the Steering Committee selected this concept to be included in Phase 2. However, it was recommended that the United Technology Corp. (UTC) - Power Systems Division perform the conceptual design on the basis of their unique background and current effort in this technology. As a result, Burns and Roe, already under contract for A-E support to ECAS, was directed to provide this conceptual design with UTC performing the power systems design under subcontract. This system includes a low-Btu integrated gasifier, the design of which will be provided by the Institute for Gas Technology (IGT).

The fact that a system was not selected does not necessarily imply that no further consideration is warranted. Systems not selected generally fall into two categories:

(1) Those systems for which the technology or design base was insufficient to permit, within given resource constraints, the ability to adequately treat the system at a conceptual design level (In most of these cases, recommendations are made in section 5.0 for the focus of future efforts.)

(2) Those systems that could not be expected to show their maximum potential on a comparative basis for the study emphasis, which is primarily aimed at large, central-station, base-load powerplants

TABLE 3.3-1. - RANGE OF RESULTS

System	General Electric			Westinghouse		
	Cost of electricity, mills/kW-hr	Overall energy efficiency, percent	Powerplant efficiency, percent	Cost of electricity, mills/kW-hr	Overall energy efficiency, percent	Powerplant efficiency, percent
Advanced steam	30 - 38	34 - 40	34 - 40	21 - 35	34 - 43	34 - 43
Open-cycle gas turbine:						
No bottoming	31 - 37	15 - 19	31 - 37	28 - 42	12 - 22	25 - 44
Organic bottoming	33 - 39	20 - 22	42 - 43	33 - 36	22 - 24	42 - 48
Combined cycle	23 - 33	21 - 37	34 - 48	24 - 34	20 - 42	38 - 49
Closed-cycle gas turbine:						
No bottoming	34 - 49	15 - 34	26 - 34	30 - 50	14 - 34	29 - 37
Organic bottoming	38 - 43	35 - 38	35 - 38	35 - 45	17 - 22	35 - 43
Steam bottoming	36 - 45	30 - 34	30 - 33	30 - 43	16 - 38	33 - 44
Supercritical CO_2	50 - 79	35 - 41	35 - 41	-------	------	-------
Liquid-metal Rankine	40 - 61	34 - 41	34 - 41	29 - 37	32 - 43	32 - 43
Open-cycle MHD	41 - 48	40 - 53	44 - 57	27 - 42	44 - 54	44 - 54
Closed-cycle MHD	46 - 73	26 - 46	35 - 46	68 - 80	41 - 46	41 - 50
Liquid-metal MHD	58 - 110	17 - 39	28 - 39	34 - 78	34 - 39	34 - 39
Fuel cells:						
High temperature	42 - 45	24 - 34	24 - 34	35 - 60	27 - 53	32 - 70
Low temperature	31 - 60	13 - 31	25 - 51	42 - 60	24 - 31	30 - 38

TABLE 3.4-1. - SENSITIVITY OF COST OF ELECTRICITY TO DIFFERENT ECONOMIC GROUND RULES

System	Type of combustion (fuel)	General Electric					Westinghouse				
		Contract results	Results based on -				Contract results	Results based on -			
			Common end date	Constant mid-1974 dollars	Average 30-year lifetime for inflation rate of -			Common end date	Constant mid-1974 dollars	Average 30-year lifetime for inflation rate of -	
					3.25 percent	6.5 percent				3.25 percent	6.5 percent
Advanced steam	AFB (coal)	29.8	31.8	24.2	19.3	16.6	----	----	----	----	----
	PFB (coal)	----	----	----	----	----	22.5	24.7	19.2	15.7	13.7
Open-cycle gas turbine:											
Simple	GT combustor (HBTU)	31.2	33.4	30.7	28.9	28	----	----	----	----	----
Recuperated	GT combustor (distillate)	----	----	----	----	----	27.5	29.8	26.6	24.6	23.5
Organic bottoming	GT combustor (HBTU)	33.7	37.2	32.2	28.9	27.2	----	----	----	----	----
	GT combustor (distillate)	----	----	----	----	----	33.9	37.6	31.6	27.8	25.7
Combined cycle	LBTU integrated gasifier (coal)	22.9	26	20.5	16.9	14.9	24.3	28	21.1	16.6	14.2
Closed-cycle gas turbine:											
Recuperated	AFB (coal)	33.7	37.7	28.3	22.3	19	----	----	----	----	----
	PFB (coal)	----	----	----	----	----	35.4	40.4	29.7	22.7	19
Steam bottoming	PFB (coal)	----	----	----	----	----	31.6	35.4	26.1	20.1	16.9
Organic bottoming	AFB (coal)	42.1	45.6	33.2	25.1	20.8	----	----	----	----	----
Supercritical CO_2	PFB (coal)	56.9	62.2	43.3	31.2	24.6	----	----	----	----	----
Liquid-metal Rankine	PFB (coal)	39.6	41	30.2	23.2	19.4	27.8	29.3	21.8	16.9	14.2
Open-cycle MHD	Direct combustor (coal)	41.7	41.4	29.6	22	17.9	27.1	26.9	19.7	15	12.5
Closed-cycle MHD	Direct combustor (coal)	61.6	61	43.7	32.6	26.5	----	----	----	----	----
	LBTU integrated gasifier (coal)	----	----	----	----	----	68.5	68	46.6	32.8	25.4
Liquid-metal MHD	PFB (coal)	70	72.8	50.9	36.9	29.2	----	----	----	----	----
	Direct furnace (coal)	----	----	----	----	----	34	33.7	24.9	19.2	16.1
Low-temperature fuel cells:											
Solid polymer electrolyte	Hydrogen/oxygen	31.3	33.2	29.8	27.6	26.4	----	----	----	----	----
Phosphoric acid	HBTU gas	----	----	----	----	----	41.5	47.5	40.3	35.7	33.1
High-temperature fuel cells (solid electrolyte)	LBTU integrated gasifier (coal)	45	46.5	36	27.6	23.5	----	----	----	----	----
	IBTU gas	----	----	----	----	----	35	41.5	33.7	28.8	26.1

TABLE 3.5-1. - PHASE 2 SYSTEM SELECTION

Contractor	System
General Electric	Advanced steam with AFB (3500 psi/1000° F/1000° F steam conditions) Advanced steam with PFB (3500 psi/1000° F/1000° F steam conditions) Combined cycle with low-Btu integrated gasifier (2500° F; air cooled) Combined cycle with semiclean fuel (3000° F; water cooled) Open-cycle MHD (direct coal fired) Liquid-metal Rankine topping cycle (potassium; PFB) Closed-cycle gas turbine (1900° F; helium)
Westinghouse	Advanced steam with PFB (3500 psi/1000° F/1000° F steam conditions) Combined cycle with low-Btu integrated gasifier (2500° F; air cooled) Combined cycle with semiclean fuel (2500° F; ceramic)
Burns and Roe /UTC	Molten carbonate fuel cell combined cycle with low-Btu integrated gasifier

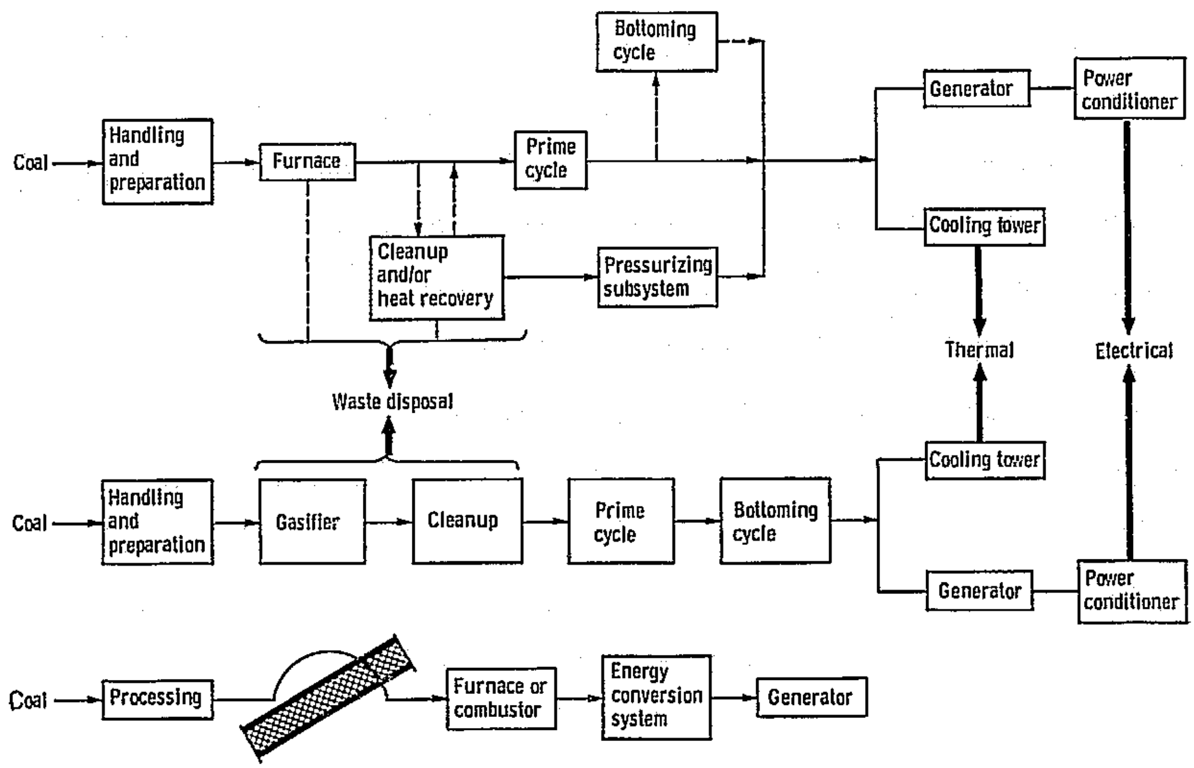


Figure 3. 1-1. - Generalized requirements for various systems.

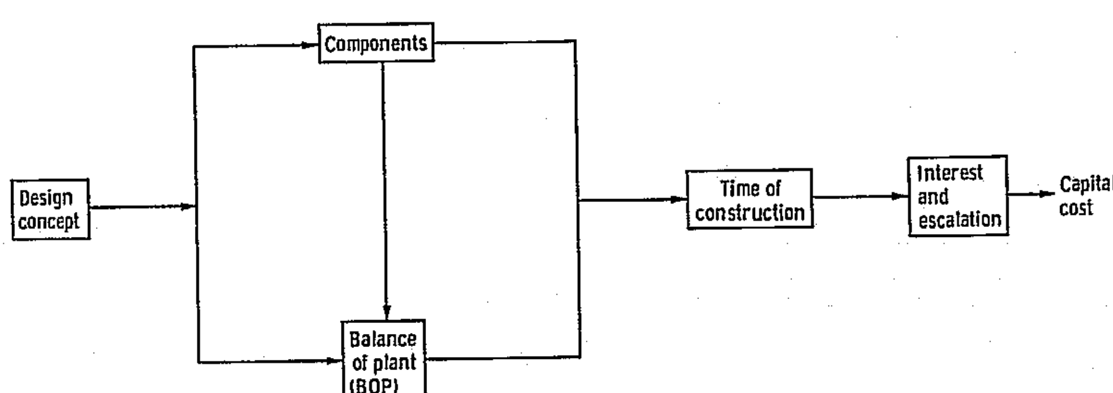
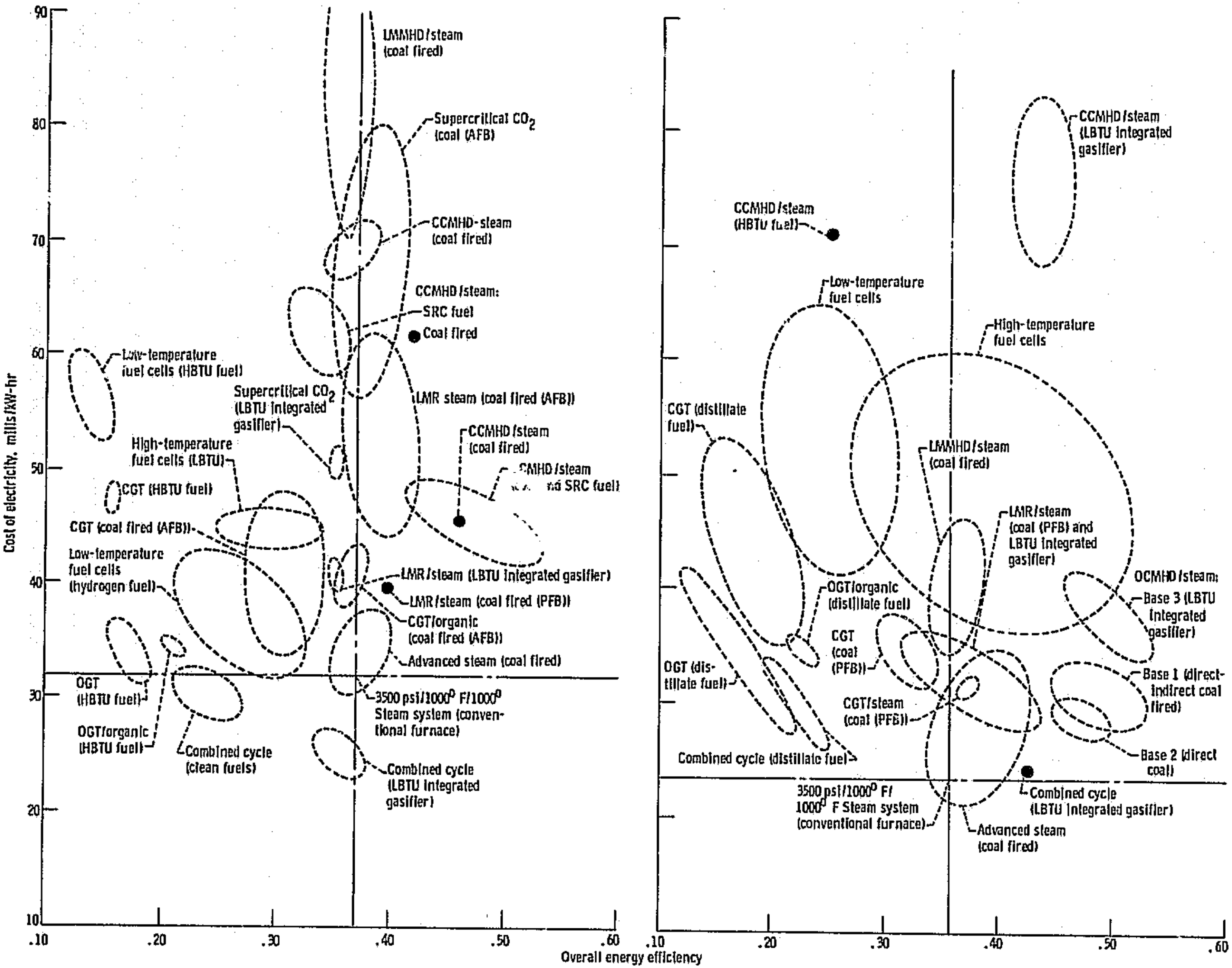


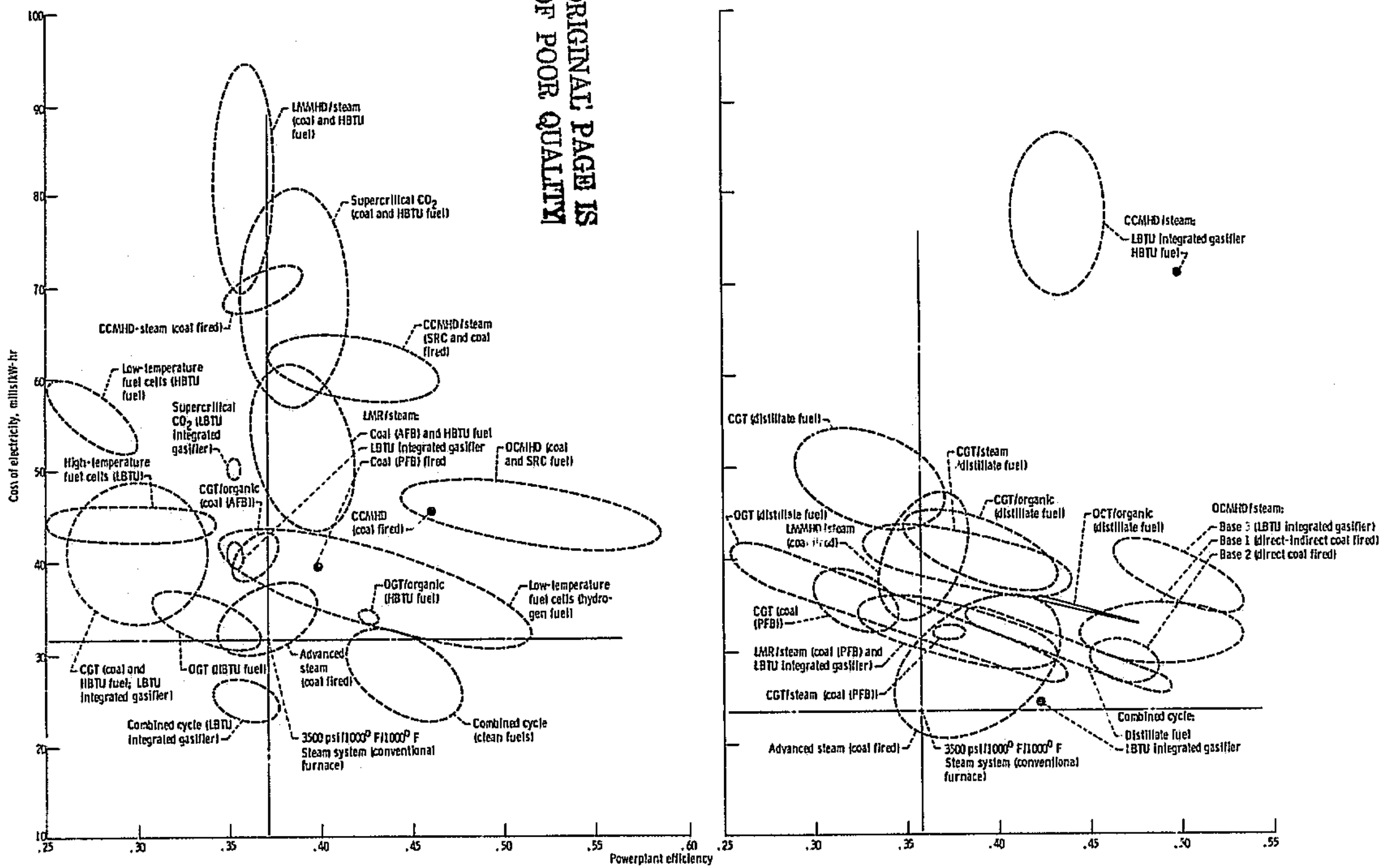
Figure 3. 1-2. - Interaction of components and balance of plant on design concept and cost.



(a) General Electric results.

(b) Westinghouse results.

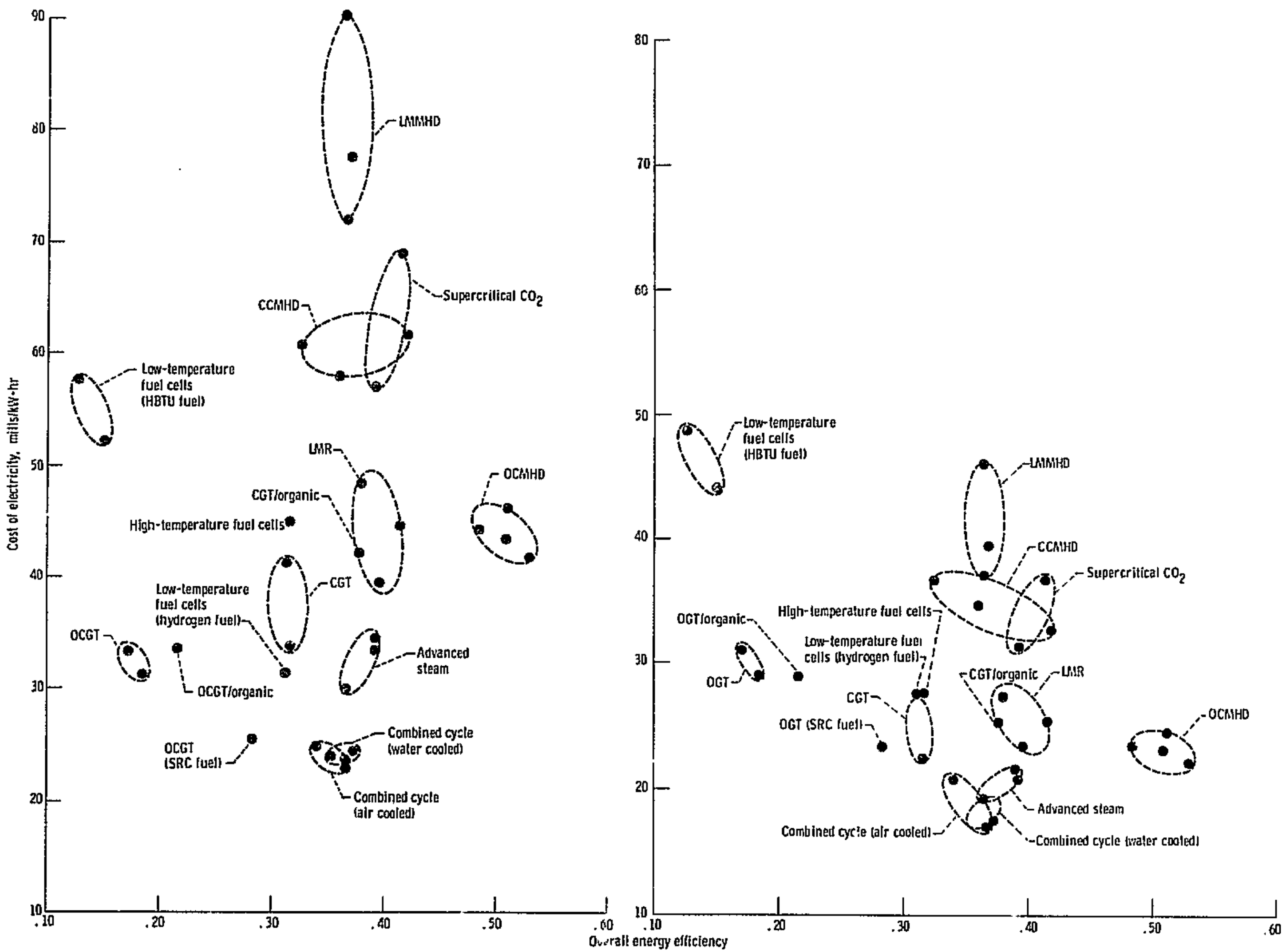
Figure 3.2-1. - Effect of overall energy efficiency on cost of electricity - comparison of systems.



(a) General Electric results.

(b) Westinghouse results.

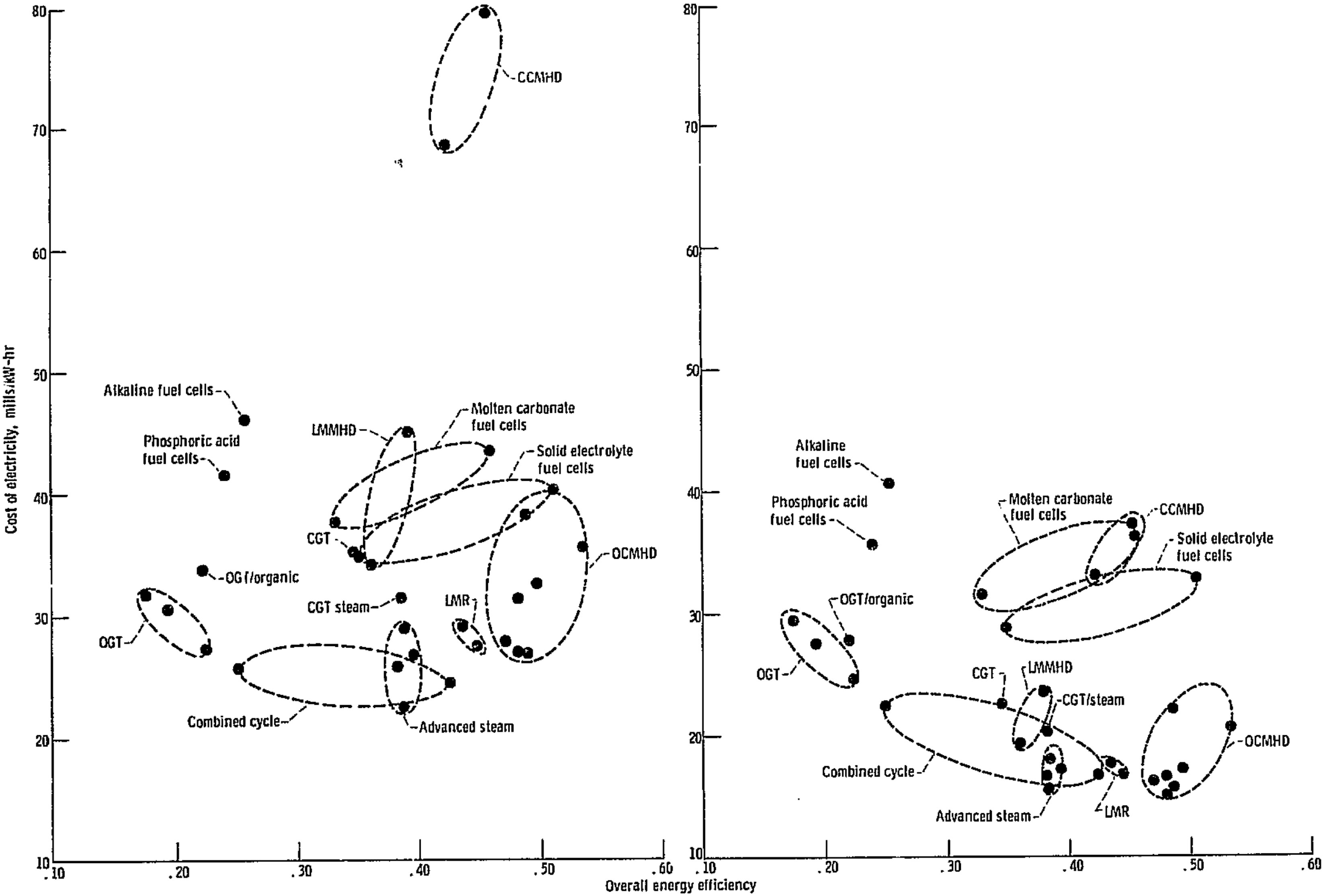
Figure 3.2-2. - Effect of powerplant efficiency on cost of electricity - comparison of results.



(a) Selected General Electric results - current-year dollars and common start-of-construction date.

(b) Average lifetime COE's - General Electric cases; average inflation rate for 30 years, 3.25 percent.

Figure 3.4-1. - Sensitivity of results to different cost-of-electricity (COE) calculation methods.



(c) Selected Westinghouse results - current-year dollars and common start-of construction date.

(d) Average lifetime COE's - Westinghouse cases; average inflation rate for 30 years, 3.25 percent.

Figure 3.4-1. - Concluded.

4.0 GENERAL APPROACH AND SCOPE

The common and consistent treatment of systems in Phase 1 of ECAS was achieved through use of common specifications and ground rules. This section first describes the ground rules specified by NASA and then discusses the impact of the economic ground rules and the sensitivity of the cost of electricity to changes in various ground rules. Alternate economic ground rules are also discussed.

4.1 NASA LEWIS SPECIFIED GROUND RULES
by Robert P. Migra

The Lewis Research Center, with the help of supporting agencies such as ERDA, PERC, and EPA, specified ground rules for the ECAS study in areas such as fuels, fuel costs, labor costs, method of cost comparison, escalation rates, interest rates, fixed charges, emission standards, environmental ambient conditions, transmission voltage and frequency, capacity factor, and availability. The specified ground rules common to both contractors are described in the following sections.

4.1.1 Coal Specifications

Three coals were specified for ECAS: namely, Illinois #6 (Macoupin County), Montana subbituminous (Rosebud County), and North Dakota lignite (Mercer County). The specifications for these coals are shown in table 4.1-1.

4.1.2 Fuel Costs

In addition to the direct combustion of coal, various coal derivatives were defined. These include high-, intermediate-, and low-Btu gas, liquid distillate, semiclean solvent-refined coal (SRC), hydrogen, and methanol. The costs of the three types of coals and derivative fuels are listed in table 4.1-2. In addition to fuel cost, table 4.1-2 gives conversion efficiency (coal to fuel type) associated with each coal fuel derivative as selected by the contractors. It is evident that the contractors differed considerably on fuel conversion efficiency.

Lewis also provided cost information on oxygen. The cost of oxygen to be used in ECAS averaged $9.00/ton delivered, with a range of $5.00/ton to $15.00/ton.

Both contractors were also directed to integrate a gasifier with the total powerplant when using low-Btu gas as it was considered nontransportable for long distances in an economic sense. Therefore, cost and conversion efficiencies for low-Btu gas are not included as a common ground rule for ECAS.

The fuel costs specified for ECAS Phase 1 were arrived at from a consideration of contractor recommendations, consultation with PERC, and data obtained by the Lewis Research Center. The use of different fuel conversion efficiencies by the contractors for the same coal-derived fuel (high- and intermediate-Btu gas, hydrogen, and distillate) was an oversight and should not have occurred. It was recognized that fuel costs are uncertain. A range of fuel cost was specified for which sensitivity analysis would show the importance of fuel cost to COE.

4.1.3 Labor Costs

A composite labor rate of $10.60/hour, representative of a combined civil/mechanical/electrical rate, was used for all construction-site-labor hours in ECAS cost estimates. This was based on a survey of rates applicable to the utilities industry and was selected as a weighted average for a "Middletown, USA," construction site.

4.1.4 Method of Cost Comparison, Escalation, and Interest

All cost estimates developed for ECAS Phase 1 were based on mid-1974 dollars. The effect of construction time on total capital cost was evaluated by applying an escalation factor of 6.5 percent per year on unused funding and an interest rate of 10 percent per year compounded quarterly on committed funding. Fuel costs were maintained constant in mid-1974 dollars regardless of construction time.

The ECAS contractor results compare the various system costs based on a common start-of-construction date throughout. In the common start-of-construction-date method, mid-1974 estimated capital costs are escalated by 6.5 percent per year and for the use of these capital funds an interest rate of 10 percent per year is charged. The actual cost escalation and the interest charges will depend on the cash flow required during the construction period. The cash flow curve that was applied to the various conversion systems in ECAS is shown in figure 4.1-1. It is the typical S-shaped logistics curve used in references 3 and 4. Typical cash flow curves for energy conversion systems requiring various construction times are shown in figure 4.1-2.

4.1.5 Fixed Charges

A fixed charge of 18 percent per year was used in the ECAS study over a depreciation life of 30 years. The 18 percent rate included the following:

Item	Rate (percent/yr)
Cost of money	7.5
Federal income tax	4.1
Depreciation	3.3
Other taxes	2.8
Insurance	.1
Working capital	.2
Total	18.0

The fixed-charge rate was provided by the Utility Review Panel.

4.1.6 Emission Standards

The emission standards specified for Phase 1 of ECAS were established after consultation with EPA. These standards corresponded to existing national emission standards for fossil steam-generating units of more than 250 million Btu per hour heat input. The intrusion in pounds per million Btu heat input allowed for sulfurous oxides (SOX), nitrous oxides (NOX), and particulates is as follows:

Pollutant	Fuel	lb/MBtu
SOX	Solid	1.2
	Liquid	.8
	Gaseous	.2
NOX	Solid	.7
	Liquid	.3
	Gaseous	.2
Particulates	All fuels	.1

4.1.7 Environmental Conditions

A Middletown, USA, site was selected for the powerplants of ECAS. The 5 percent summer environmental conditions were specified for this site for use in sizing and estimating the cost of the heat rejection systems. These conditions are as follows:

(1) Cooling water temperature, 75° F
(2) Air temperature (wet bulb), 77° F
(3) Air temperature (dry bulb), 93° F
(4) Ambient air pressure, 1.00 atm
(5) Performance based on average-day condition of 59° F

4.1.8 Miscellaneous

There are a number of miscellaneous items specified by Lewis that are important to the ECAS study:

(1) Capacity factor: A capacity factor of 0.65 was specified for base-load economic studies. The range recommended for parametric variation was from 0.50 to 0.80.

(2) Availability: A target of 90 percent was specified but did not impact Phase 1 results.

(3) Power: Base-load power delivered by the ECAS powerplants was specified as 500-kilovolt, 60-hertz ac power suitable for transmission. Smaller plants in limited cases were studied at low voltages.

(4) Higher heating values for all fuels were used in determining efficiencies.

4.1.9 Data Format

A common format was provided to the contractors for the Phase 1 results in order to ease the problem of screening and selecting systems for Phase 2 of the study. The format for Phase 1 data is shown in table 4.1-3.

4.2 ECONOMIC GROUND RULES AND SENSITIVITY TO CHANGES
by Richard M. Donovan

The Phase 1 systems analyses performed by General Electric and Westinghouse included estimates of capital cost, construction duration, system efficiency, operations and maintenance (O and M) costs, and the cost of electricity (COE) at the bus bar. Some of the ground rules used in the study during Phase 1 are summarized in table 4.2-1. To examine the sensitivity of system economics to the ground rules, common costing methods are needed. The COE's developed by the contractors in Phase 1, according to the study ground rules, assumed that all systems have a common start-of-construction date (mid-1974). Since different types of systems were estimated to have different construction periods, this resulted in different on-line dates and therefore costs in different-year dollars following the escalation and interest accrual during construction. In computing the COE, the contractors used the interest rate and the escalation rate as specified by the contract. However, the method for computing interest and escalation during construction was not specified and, as a result, slightly different methods were used by the contractors, resulting in slightly different estimates of escalation and interest costs during construction. In accordance with the contract ground rules, capital costs were escalated, while fuel and O and M costs were not escalated. Also, all COE computations by the contractors were based on a common start of construction time of mid-1974. The result is that plants with different construction durations come on line in different years; thus, the construction costs are not in mid-1974 dollars but in different-year dollars, depending on on-line date.

There is another approach to computing the COE's of the advanced powerplants being studied in ECAS that will enable comparisons to be made on a more common basis. The approach includes a methodology for computing and comparing COE's and uses constant mid-1974 dollars. The term constant-year dollars refers to dollars that may be expended over a number of years but that are measured in terms of their equivalent purchasing power in some reference year - in this case mid-1974. Thus, under inflationary conditions, future-year dollars need to be deflated to mid-1974 to express them as constant mid-1974 dollars. The term current-year dollars is also used in the following discussion and refers to the actual dollar cost in the year of the expenditure.

This section then examines the sensitivity of COE to coal price, escalation rate, powerplant efficiency, capacity factor, fixed capital charge factor, and capital cost. These sensitivities are determined for three example systems for illustrative purposes. These three systems, referred to as systems A, B, and C, are described in table 4.2-2. They may be broadly thought of as representing advanced steam, combined cycle with integrated gasifier, and open-cycle MHD systems, respectively. They do not represent actual data from the contractor results. In section 6.2.2 the economics of the actual systems are discussed, and the methods used here are applied.

4.2.1 Interest and Escalation of Capital Costs during Construction

In computing escalation and interest during construction the S-shaped cumulative cash flow curve from reference 3 was used (fig. 4.1-2). The approach in using this curve is similar to that of reference 4. The method involves dividing the total cash flow, as described by the S-curve, into 100 equal increments (100 equal payments). For each at these payments, the time in years, of the midpoint of the increment, was obtained from a continuous curve fit of the cash flow curve. The contribution due to escalation and interest was computed for each increment and the increments appropriately

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summed. The escalation and interest rates were assumed to be constant during the design and construction period. Escalation was assumed to be compounded annually, while interest was compounded quarterly. The resulting escalation and interest factors are shown in figures 4.2-1 and 4.2-2 along with those used by the contractors for Phase 1. The total factor, or effect of escalation and interest on the capital costs, estimated prior to construction may be very closely approximated as the product of the two separate factors. The resulting total capitalization of a plant, then, is the total capital outlay including escalation and interest until the time the plant is on line.

4.2.2 Start-of-Construction Time

The total capitalization costs were computed by the contractors for a common start of construction (design and construction) of mid-1974. As a result, powerplants with different construction periods will be completed at different times. This results in noncomparable capital costs. As an illustration, consider two plants, X and Y, with construction durations of 4 and 7 years, respectively. Assume that the total capitalization (including all escalation and interest) for each plant is $400/kWe and that each plant begins its construction period in mid-1974. Plant X is on line in mid-1978 with $400/kWe liability, and plant Y is on line in mid-1981 with $400/kWe liability. If there were no general inflation, a presumption inconsistent with 6.5 percent escalation and 10 percent interest rates, the plant X and plant Y liabilities might be looked upon as equals. In an inflationary environment consistent with the escalation and interest rates used in the study, the mid-1981 indebtedness is significantly less than the mid-1978 indebtedness since it will be paid in "cheaper" dollars. To avoid this inconsistency, the capital cost for each system may be computed, for a common on-line date. Costs estimated from mid-1974 until the start of construction assume a 6.5 percent escalation charge - the same as during construction.

The variations of COE with time, in current-year dollars, of a powerplant "costed" in mid-1974 with a construction time of 4 years and on line in mid-1981, is illustrated in figure 4.2-3. The costs are for example system B and show equivalent bus-bar COE in current-year dollars (not constant dollars) during the preconstruction time, construction period, and life cycle. A common rate of inflation of 6.5 percent per year was assumed for each component of COE (i.e., capital, fuel, and O and M costs). In mid-1974 the estimated construction cost of $350/kWe is equivalent to a fixed charge of 11.06 mills/kW-hr. Operation and maintenance costs are 2.5 mills/kW-hr, and fuel cost is computed as 7.25 mills/kW-hr for coal at $0.85/MBtu and a 0.40 overall system efficiency.

By the time construction starts in mid-1977, all costs have escalated at 6.5 percent per year. During the following 4-year construction period, the capital costs increase due to escalation and interest charges, with cash flow following the S-shaped curve of figure 4.1-2, while O and M and fuel costs continue to escalate at 6.5 percent per year. By mid-1981, when the plant goes on line, the actual construction costs have escalated from the original estimate of $350/kWe to a mid-1981 value of $580/kWe. The COE's due to capital, fuel, and O and M costs are 18.3, 3.9, and 11.3 mills/kW-hr, respectively - for a total COE of 33.5 mills/kW-hr in mid-1981 dollars. Once the plant goes on line, capital charges are fixed at 18.3 mills/kW-hr, while fuel and O and M costs follow general price escalation. With a 6.5 percent general escalation rate, this has the effect of decreasing the relative significance of the capital component of COE with time. Thus, while the capital component represents 55 percent of the total COE in mid-1981, by mid-life of the plant (mid-1996) it represents only 32 percent of the total cost.

To validly compare the COE's of different plants, they must be quoted in dollars having equivalent purchasing power. The use of constant-year dollars permits comparing the costs of plants with different on-line dates by deescalating costs to a common reference year. In addition, deescalating costs results in more familiar cost values, consistent with today's experience. All COE comparisons in this section are made on the basis of mid-1974 dollars.

To illustrate the differences between escalated current-year dollars and mid-1974 dollars, figure 4.2-3 was reconstructed in terms of mid-1974 dollars (fig. 4.2-4). Each cost component of COE was deflated at the escalation rate back to mid-1974; thus, the relative values of the components remain unchanged. In addition to the 6.5 percent escalation rate used in figure 4.2-3, rates of 3.25 percent and zero during plant lifetime are also shown for comparison purposes. With a general cost escalation rate during the plant life-cycle greater than zero, the constant-dollar COE decreases during the plant life because of the decreasing constant-dollar value of the fixed capital charges. The COE at the on-line date is 21.6 mills/kW-hr, with the rise during construction attributable to interest charges on capital expenditures. The use of constant dollars results in the escalation of capital costs by only the cost of money <u>in excess</u> of the general escalation rate. Thus, for the Phase 1 ground-rule rates of 6.5 percent escalation and 10 percent interest during construction, the effective constant-dollar increase is approximately 3.5 percent per annum on funds expended in accordance with the cash flow curve. The effective incremental rate differs from exactly 3.5 percent because the construction interest charges are compounded quarterly, while escalation and deescalation rates are compounded annually.

4.2.4 COE Sensitivities

A single figure of merit - the average cost of electricity - is used in this section to represent the cost of electricity over a powerplant life-cycle. The average COE is the quotient of the total bus-bar cost of all electricity generated during the life cycle of a plant and the total generation (in kW-hr). The effect of cost escalation during the 30-year life cycle on the average COE is illustrated in figure 4.2-5 for each of the three example systems, with the ground rules of table 4.2-1 observed. Remember that these costs are in mid-1974 dollars and that the use of constant dollars has the effect of making the escalation of capital costs during construction independent of a specific escalation rate and only a function of the difference between escalation and interest. As stated earlier, constant-dollar capital costs escalate during construction by only the cost of money in excess of the general escalation rate (about 3.5 percent for the Phase 1 ground-rule rate of 6.5 percent escalation and 10 percent interest). Thus, a 12 percent escalation rate, for example, would imply an interest rate during construction of 15.5 percent. This is not unreasonable since interest rates should rise along with general escalation. The curves in figure 4.2-5 reflect the decreasing constant-dollar value of the capital cost component of COE as escalation increases. This decrease is more pronounced for the higher capital cost systems. These curves may also be viewed in terms of the increasing influence of fuel prices and O and M costs relative to capital costs as escalation increases. Thus, at a zero cost escalation rate (at which average COE is equivalent to the COE at plant startup), a real-dollar increase in fuel cost and/or O and M costs of some 11 mills/kW-hr would be needed to bring systems C and B to an economic parity. At a 6.5 percent escalation rate, this real-dollar cost increase need be only 5 mills/kW-hr; at 12 percent, only 3 mills/kW-hr.

The effect of coal price on the three example systems is examined in figures 4.2-6, 4.2-7, and 4.2-8 for 0, 3.25, and 6.5 percent general cost escalation during the plant life-cycle. Shown on each abcissa, along with the mid-1974 coal price, is a scale of the equivalent annual incremental fuel-price escalation rate as applied to the $0.85/MBtu coal. This equivalent incremental coal-price escalation rate is over and above the general escalation rate starting in mid-1974 and continuing throughout the entire plant life-cycle that would result in the same average COE as with the indicated constant-dollar fuel price and no incremental escalation.

The three different escalation rates of 0, 3.25, and 6.5 percent were used to illustrate the sensitivity of COE to escalation. However, as a long-term rate, 6.5 percent, while comparable with today's level, is judged to be excessive, and no escalation seems highly improbable. The 3.25 percent rate is judged to be more representative of a long-term escalation rate and is featured in the subsequent comparisons. With this "moderate" inflation rate of 3.25 percent, figure 4.2-7 indicates that constant-dollar fuel prices of $2.50/MBtu and $5.00/MBtu are needed to allow system C to economically compete with systems A and B, respectively. These constant-dollar prices are equivalent to real coal-price escalation rates of 4.7 and 7.5 percent, respectively, for plants on line in 1981.

The effective real coal-price escalation rate that yields the same life-cycle average COE as an unescalating constant-dollar fuel price varies depending on the on-line date of the plant. The later the plant goes on line, the greater will be the period over which the constant-dollar price of fuel escalates. To illustrate this effect, a constant-dollar fuel price of $2.50/MBtu is equivalent to escalating (real escalation) an $0.85/MBtu fuel by 4.7 percent per year for a plant on line in 1981 and by 3.3 percent per year for a plant on line in 1991. In each case, the fuel price escalates from mid-1974 to the end of plant life, 2011 and 2021, respectively. A plot of equivalent incremental or real fuel price escalation against on-line date for several assumed mid-1974 fuel prices is shown in figure 4.2-9.

The sensitivity of average COE, in mid-1974 dollars, to change in system efficiency is illustrated in figure 4.2-10 for a 3.25 percent cost escalation and two coal price levels, $0.85/MBtu and $2.55/MBtu. Average COE proved to be relatively insensitive to efficiency changes (±20 percent) for the lower coal price but noticeably more sensitive at triple the coal price. The competitiveness of systems A and C is again evident at the $2.55/MBtu level.

The sensitivity of average COE to several capital cost parameters was next examined for the three example systems. The parameters investigated were capacity factor, fixed capital charge rate, and changes in the magnitude of capital costs (prior to adding escalation and interest during construction). Since COE is proportional to the last two variables and inversely proportional to the first, the nature of the sensitivities is fairly predictable. Each of the variables was examined for 6.5 and 3.25 percent cost escalation rates, representing rapid and moderate deflation of capital charge influence, respectively. The sensitivity of average life-cycle COE to capacity factor is shown in figures 4.2-11 and 4.2-12 for 6.5 and 3.25 percent cost escalation rates, respectively; to fixed capital charge rate in figures 4.2-13 and 4.2-14; and to changes in capital cost in figures 4.2-15 and 4.2-16.

4.2.5 Concluding Remarks

To examine the sensitivity of system costs to ground rules and to allow cost comparisons within and between systems, common methods of estimating COE are needed. The COE's developed by the contractors in Phase 1, according to the study ground rules, assumed that all systems have a common start-of-construction date (mid-1974). Since different types of systems were estimated to have different construction periods, this resulted in different on-line dates and therefore costs in different-year dollars following the escalation and interest accrual during construction.

This section has presented an approach for computing the COE's of the advanced powerplants that enables comparisons to be made on a more common basis. The approach includes a methodology for computing and comparing COE's and uses constant (mid-1974) dollars for all comparisons to avoid the difficulties inherent in using current-year dollars. The approach incorporates (1) the S-shaped cumulative-cash-flow curve from reference 3 (fit with a continuous curve); (2) annual compounding of escalation and quarterly compounding of interest during construction; (3) a common end-of-construction date, or on-line time instead of a common start-of-construction date; and (4) use of average life-cycle COE rather than the COE at beginning of life.

Using the average life-cycle COE in an inflationary environment has the effect of lending more weight to fuel price, plant efficiency, and O and M costs than does using the beginning-of-life COE. The reason is that the fixed-rate method of charging for capital is used. This method is similar to using constant mortgage payments, which decrease in an inflationary environment. The fixed charge rate of 18 percent per year used in this study is judged to be consistent with the current relatively high cost of money. Given this fixed charge rate, the real or constant-dollar value of the capital charge would decrease over the plant life-cycle depending on the inflationary level of the economy.

Using this approach, the following sensitivities, which are pertinent in comparing COE's, were then investigated for the three example systems (see table 4.2-2):

(1) The effect on COE of including general escalation during the powerplant life

(2) The effect on COE of escalating fuel and O and M costs (not required in contractor's Phase 1 effort)

(3) The sensitivity of COE to coal price, escalation rate, powerplant efficiency, capacity factor, fixed capital charge rate, and capital cost

General escalation during the powerplant's life increases the influence of fuel prices and O and M costs relative to capital costs, with the shift becoming increasingly significant as escalation rate increases.

Escalating fuel price, of course, increases the importance of plant efficiency. The effect of fuel price escalation is dependent on the on-line date, the later the on-line date the greater will be the period over which the constant-dollar price of fuel escalates. For an on-line date of mid-1981, example system C would compete economically with systems A and B, respectively, if real coal-price escalation rates of 4.7 and 7.5 percent per year were experienced. For an on-line date of mid-1991, these escalation rates would be 3.3 and 5.4 percent, respectively. It is problematical whether real coal prices can be expected to escalate at such rates over the long term. Over the short term, real coal-price escalation has exceeded these levels.

For instance, from 1970 to the present the national average coal price approximately doubled in real terms, which translates to a real escalation rate of about 15 percent per year over the short term.

The sensitivity of COE to the cost drivers is illustrated by using the three example systems. The more costly systems show greater correlation to factors affecting the capital cost component of COE, whereas those with lower efficiency are sensitive to increases in fuel costs. For the example systems it is illustrated that only substantial coal-price increases will make a more efficient, but capital intensive, system competitive economically with a less efficient, but lower capital cost, system.

In section 6.2.2, the economics of the actual system results are illustrated by using the ground-ruled contractor methods and those of this section. Comparisons within systems are discussed in that section.

TABLE 4.1-1. - ECAS COAL SPECIFICATIONS

	Coal		
	Illinois #6 (Macoupin County)	Montana subbituminous (Rosebud County)	North Dakota lignite (Mercer County)
Reference material	BOM TP-641	BOM TP-629	BOM RI-7158
Proximate analysis (as received), percent:			
Moisture	13.0	24.3	36.7
Volatile	36.7	28.6	26.6
Fixed carbon	40.7	39.6	30.5
Ash	9.6	7.5	6.2
Ultimate analysis (as received), percent:			
Ash	9.6	7.5	6.2
Sulfur	3.9	0.8	0.7
Hydrogen	5.9	6.1	6.9
Carbon	59.6	52.2	41.1
Nitrogen	1.0	0.8	0.6
Oxygen	20.0	32.6	44.5
Higher heating value (as received), Btu/lb	10 788	8944	6890
Gross heating value (dry), Btu/lb	12 600	11 300	10 400
Average softening temperature, ^{o}F	1979	2224	2280
Initial deformation temperature, ^{o}F	1990 - 2130	2120 - 2410	2190 - 2400
Fluid temperature, ^{o}F	2090 - 2440	2180 - 2520	2330 - 2500
Ash analysis, percent:			
SiO_2	46.6	22.1	17.9
Al_2O_3	19.3	15.5	9.9
FC_2O_3	20.8	6.4	10.2
TiO_2	0.8	1.2	0.3
P_2O_5	0.24	0.11	0.4
CaO	7.7	18.9	23.6
MgO	0.9	6.6	6.7
Na_2O	0.2	1.0	7.4
K_2O	1.7	0.4	0.4
SO_3	2.4	26.2	21.8

	Coal		
	Illinois #6 (Macoupin County)	Montana sub-bituminous (Rosebud County)	North Dakota lignite (Mercer County)
Trace-element analysis, ppm in coal:			
Beryllium	0.6 - 7.6	0.1 - 3.9	0.1 - 3.9
Fluorine	50 - 167	60 - 70	60 - 70
Arsenic	8 - 45	------	------
Selenium	------	------	------
Cadmium	------	------	------
Mercury	0.04 - 0.49	0.07 - 0.09	0.07 - 0.09
Lead	8 - 14	5 - 10	5 - 10
Boron	13 - 198	78 - 201	78 - 201
Vanadium	8.7 - 67	5.3 - 29	5.3 - 29
Chromium	5 - 54	2.6 - 19	2.6 - 19
Cobalt	1.2 - 10	0.7 - 7	0.7 - 7
Nickel	5 - 37	1.5 - 15	1.5 - 15
Copper	3.1 - 25	2.8 - 16	2.8 - 16
Zinc	0 - 53	0 - 23	0 - 23
Gallium	1.5 - 8	1.0 - 13	1.0 - 13
Germanium	0.4 - 27	0 - 7	0 - 7
Molybdenum	0.6 - 8.5	0.1 - 3.4	0.1 - 3.4
Tin	0.1 - 5	0.2 - 4.3	0.2 - 4.3
Yttrium	1 - 13	1 - 27	1 - 27
Lanthanum	0.2 - 24	0 - 22	0 - 22
Uranium	10	50 - 240	50 - 240
Trace-element analysis, wt % in ash:			
Lithium	0.017 - 0.039	0.010 - 0.022	0.010 - 0.022
Scandium	0.007 - 0.008	0.003 - 0.005	0.003 - 0.005
Manganese	0.020 - 0.062	0.030 - 0.046	0.030 - 0.046
Strontium	0.058 - 0.070	0.061 - 0.066	0.061 - 0.066
Barium	0.029 - 0.047	0.265 - 0.300	0.265 - 0.300
Ytterbium	0.0003 - 0.0011	0.0003 - 0.0011	0.0003 - 0.0011
Bismuth	0.0001 - 0.0002	0.0001 - 0.0002	0.0001 - 0.0002
Grindability (HGI):			
Range	52 - 66	49 - 59	36 - 75
Average	55	53	50
Free-swelling index:			
Range	1 - 6.5	------	------
Average	4.5	------	------

TABLE 4.1-2. - ECAS FUEL COST AND EFFICIENCY ASSUMPTIONS

Fuel type	Base fuel cost (delivered), $/MBTU	Minimum range, $/MBTU	Conversion efficiency	
			General Electric	Westinghouse
Coal:				
Illinois #6	0.85	0.50 - 1.50	-----	-----
Montana subbituminous	0.85	0.30 - 1.50	-----	-----
North Dakota lignite	0.85	0.25 - 1.50	-----	-----
High-Btu gas	2.60	1.50 - 4.00	0.50	0.67
Intermediate-Btu gas	2.10	1.20 - 3.10	0.70	0.84
Low-Btu gas	(a)	(a)	(a)	(a)
Hydrogen	2.50	1.45 - 3.80	0.61	0.56
Liquid (distillate)	2.60	1.50 - 4.00	0.56	0.51
Methanol	2.70	1.60 - 4.20	(b)	0.70
Semi-clean (solvent-refined coal)	1.80	1.05 - 2.70	[c]0.78	(b)

[a]Always integrated.
[b]Not used.
[c]Revised downward to 0.74 in final reading by G. E.

TABLE 4.1-3. - OUTPUT DATA FORMAT

(a) System base cases

	Case		
	1 (base)[a]	2	3
Parameters			
Power output, MWe			
Furnace type			
Conversion process			
Coal type			
Additional parameters as used on parametric lists			
Summary of plant results			
Thermodynamic efficiency,[b] percent			
Powerplant efficiency, percent			
Overall energy efficiency, percent			
Capital costs, dollars			
Capital costs, $/kWe			
Cost of electricity,[c] mills/kW-hr:			
Capital			
Fuel			
Operation and maintenance			
Total			
Estimated construction time,[d] yr			
Estimated availability date[e]			
Breakdown of plant results			
Capital costs, $/kWe:			
Each major component[f]			
Total for all major components			
Balance of plant[g]			
Site labor			
Escalation			
Interest during construction			
Cost of electricity, mills/kW-hr, at capacity factor of -			
0.50			
0.65			
0.80			
Change in cost of electricity with 20 percent increase in capital costs, mills/kW-hr			
Change in cost of electricity with 20 percent increase in fuel costs, mills/kW-hr			

[a] Use base delivered fuel cost.
[b] Provide where applicable. Defined as alternating-current output from prime cycle (and bottoming cycle) divided by heat input into prime cycle (i.e., not including furnace or gasifier efficiency or power output from furnace pressurizing subsystem.
[c] For 0.65 capacity factor.
[d] From start of site construction to plant on-line operation.
[e] First plant commercial operation.
[f] Use total alternating-current plant output and component FOB manufacturing plant price.
[g] Does not include site labor.

TABLE 4.1-3. - Continued.

(b) Summary for each base case and each parametric point recommended for ECAS Phase 2

Parameter	Value
Performance and cost	
Powerplant efficiency, percent	
Overall energy efficiency, percent	
Plant capital cost, dollars	
Plant capital cost, $/kWe	
Cost of electricity, mills/kW-hr	
Natural resources	
Coal, lb/kW-hr	
Water, gal/kW-hr:	
Total	
Cooling	
Processing	
Makeup	
NOX suppression	
Stack-gas cleanup	
Land, acres/10^3 MWe	
Environmental intrusion	
Amount of pollutant, lb/MBtu heat input; lb/kW-hr:	
SO_2	
NOX	
HC	
CO	
Particulates	
Heat, Btu/kW-hr:	
To water, where applicable	
Total rejected	
Wastes (type and quantity),[h] lb/kW-hr; lb/day	

Major component[i]	Module size (width, length, or diameter)	Module weight, lb	Cost FOB from manufacturing plant		Number of modules required	Total cost
			Dollars	$/kWe		

[h]Assuming rated output throughout 24 hr.

[i]As a minimum, the components listed in the statement of work and including cooling towers and emission control equipment.

TABLE 4.1-3. - Concluded.

(c) Materials review for all system base cases and each case recommended for ECAS Phase 2

Major component	Subelement	Material	Comment

TABLE 4.2-1. - ECAS PHASE 1 ECONOMIC GROUND RULES[a]

[Base-loaded systems; 30-yr life cycle.]

Capacity factor	0.65
Fixed capitalization charge, percent	18
Interest on construction outlays, percent	10
Escalation of construction costs, percent	6.5
Fuel cost (coal), \$/MBTU	0.85

[a]Contractor output: capital cost estimate; construction duration; on-line date; system efficiency; operations and maintenance costs; cost of electricity.

TABLE 4.2-2. - ECAS PHASE 1 EXAMPLE SYSTEMS

System	Description	Overall efficiency	Construction time, yr	Operation and maintenance costs, mills/kW-hr	Capital costs,[a] \$/kWe	
					Mid-1974 estimate	Actual (mid-1981)
A	Advanced steam	0.38	5	2.5	500	843
B	Combined cycle with gasifier	.40	4	2.5	350	580
C	Open-cycle MHD	.50	7	3.8	650	1137

[a]Includes 6.5 percent escalation and 10 percent interest during construction.

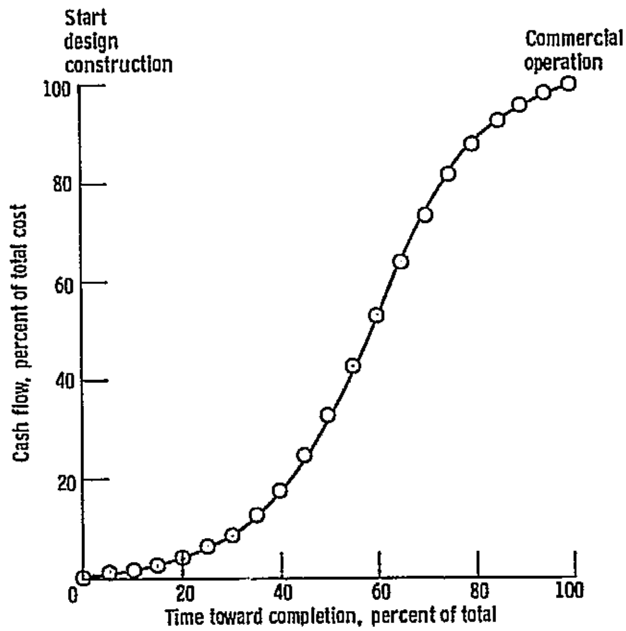

Figure 4.1-1. - Cash flow during powerplant design and construction. (From refs. 3 and 4.)

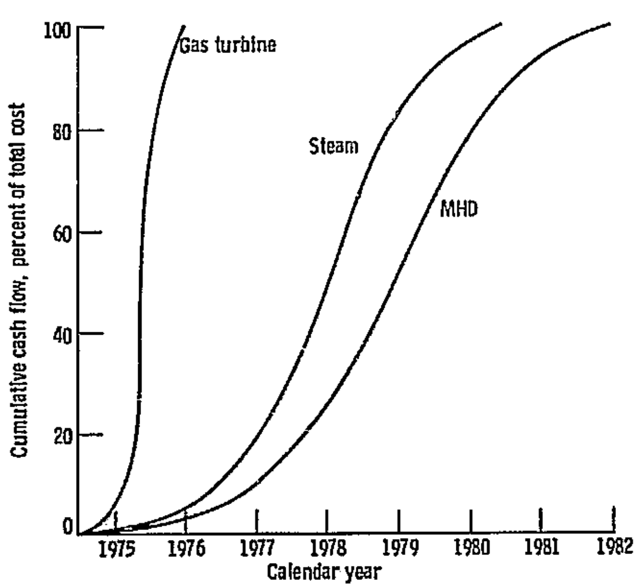

Figure 4.1-2. - Cumulative cash flow during powerplant design and construction. (From ref. 3.)

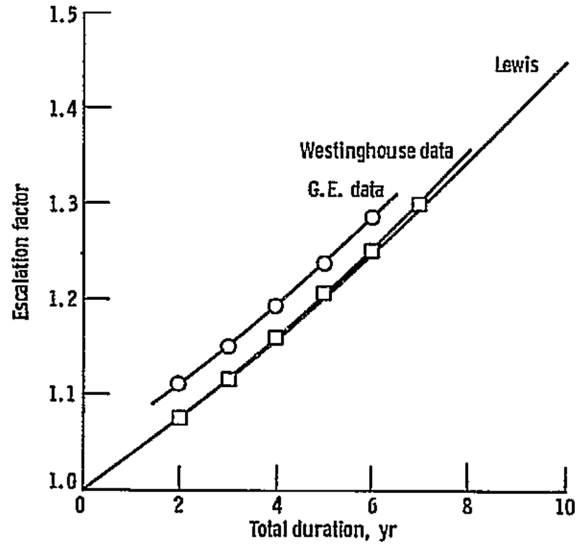

Figure 4.2-1. - Cost escalation rate of 6.5 percent per year.

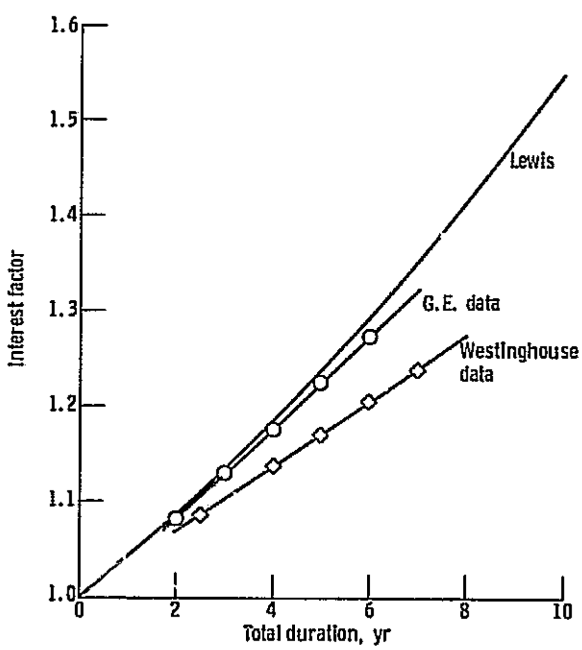

Figure 4.2-2. - Interest rate of 10 percent per year.

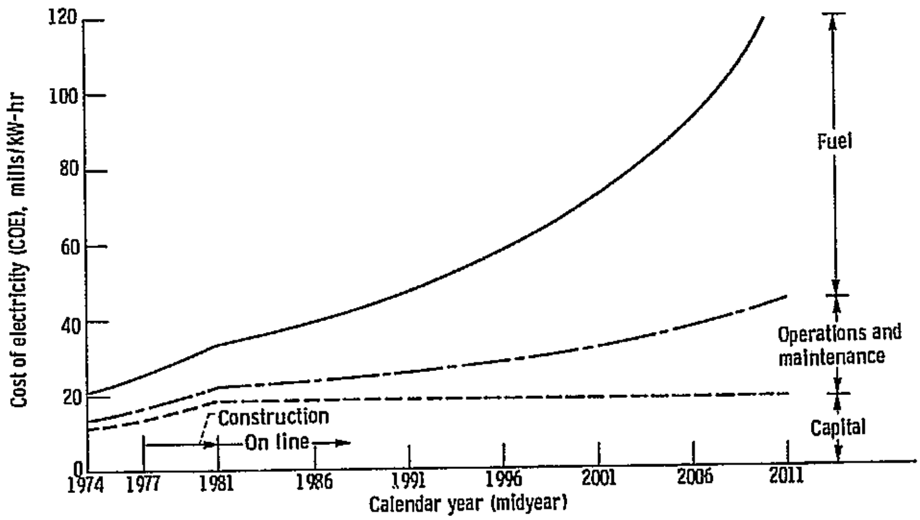

Figure 4.2-3. - Cost of electricity with 6.5 percent general cost escalation rate for years 1974 to 2011 in current-year dollars.

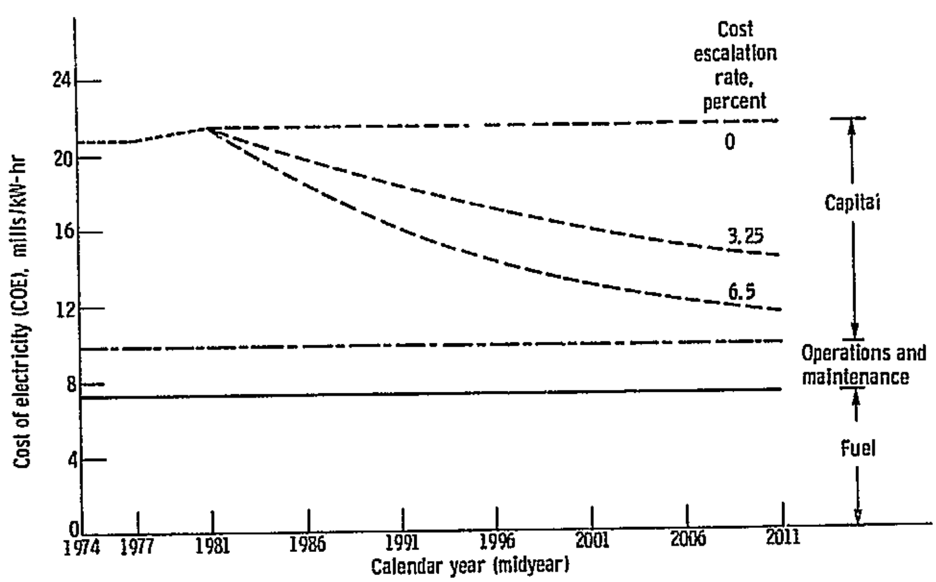

Figure 4.2-4. - Cost of electricity with different rates of general cost escalation for years 1974 to 2011 in constant (mid-1974) dollars.

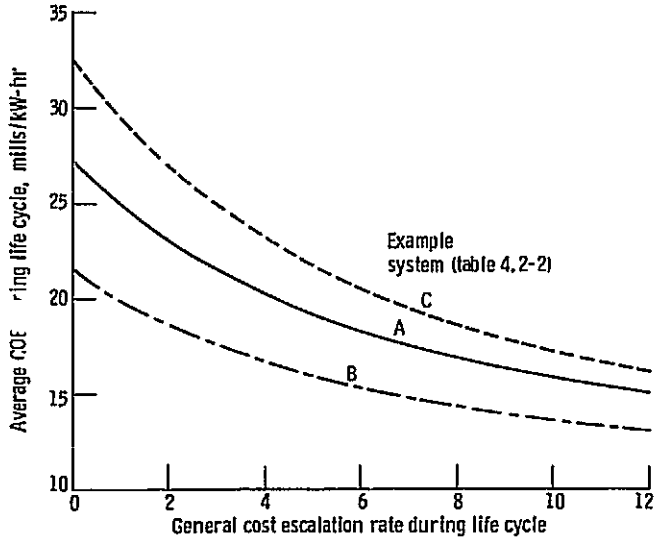

Figure 4.2-5. - Effect of general cost escalation rate on average cost of electricity during life cycle. Fixed capital charge rate, 0.18.

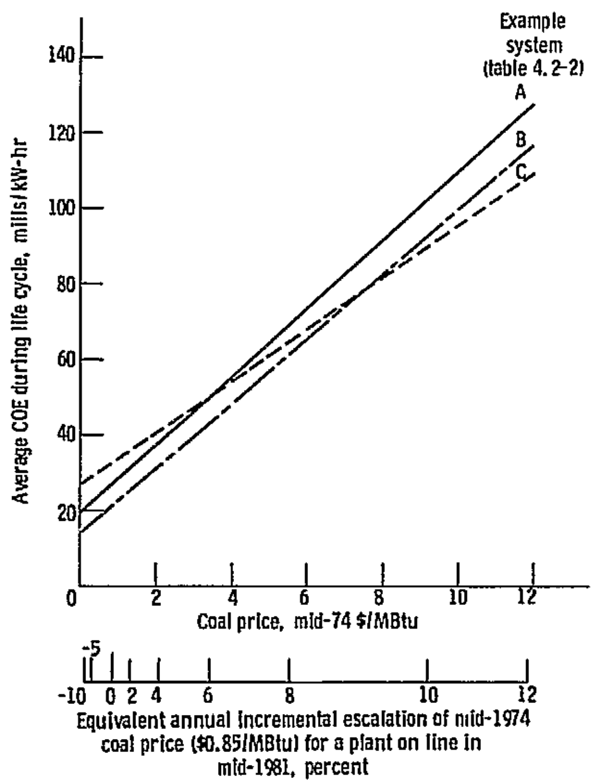

Figure 4.2-6. - Effect of coal price on average cost of electricity during life cycle, in mid-1974 dollars - with no cost escalation during life.

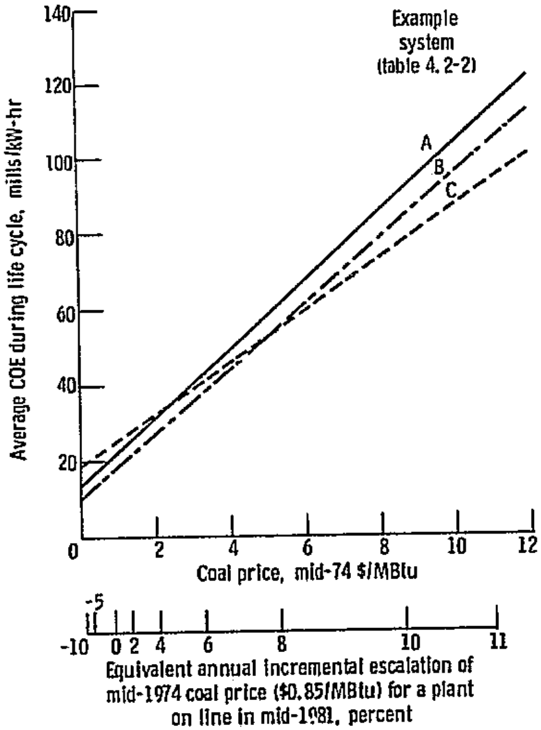

Figure 4.2-7. - Effect of coal price on average cost of electricity during life cycle, in mid-1974 dollars - with 3.25 percent general cost escalation during life.

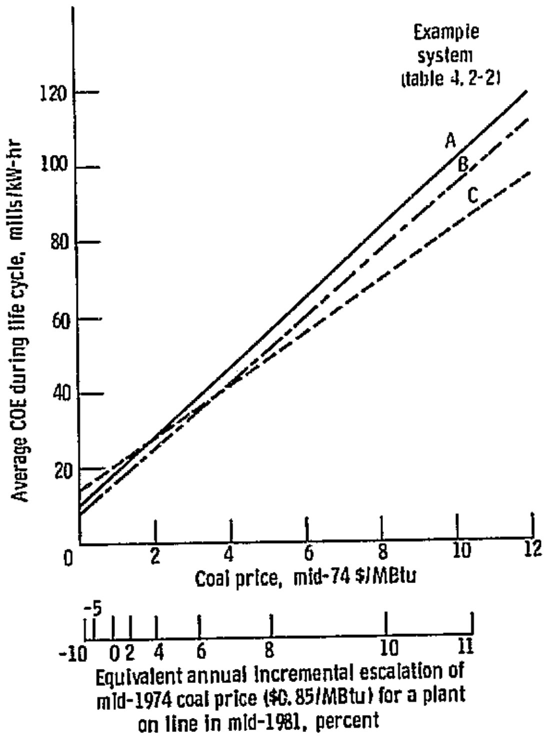

Figure 4.2-8. - Effect of coal price on average cost of electricity during life cycle, in mid-1974 dollars - with 6.5 percent general cost escalation during life.

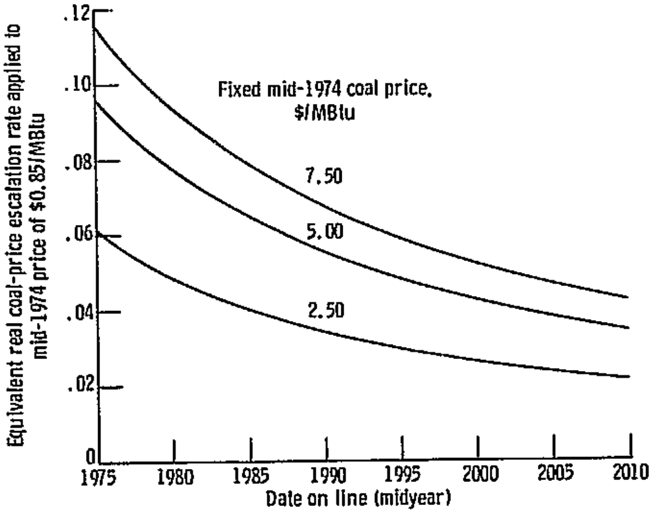

Figure 4.2-9. - Effect of plant on-line date on real coal-price escalation equivalent to fixed coal price. (Escalation from mid-1974 to end of plant life (30 yr).)

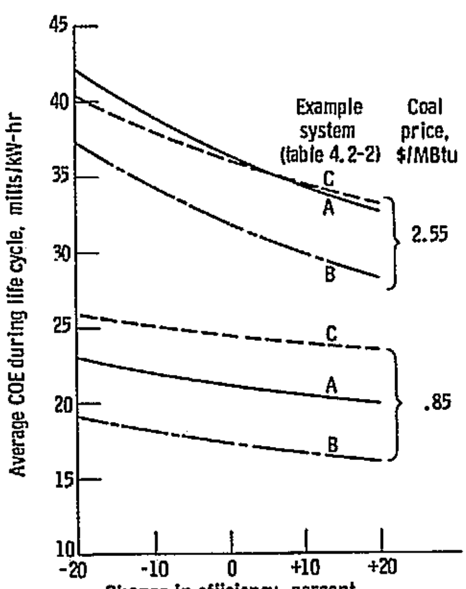

Figure 4.2-10. - Effect of change in efficiency on average cost of electricity during life cycle in mid-1974 dollars - with 3.25 percent general cost escalation during life.

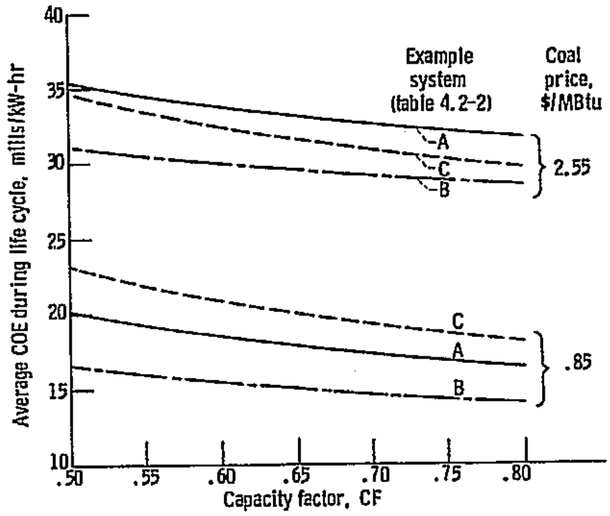

Figure 4.2-11. - Effect of capacity factor on average cost of electricity during life cycle, in mid-1974 dollars - with 6.5 percent general cost escalation during life.

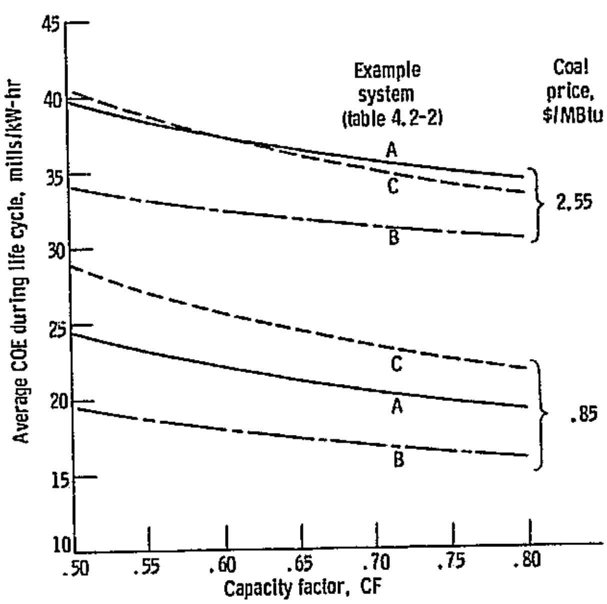

Figure 4.2-12. - Effect of capacity factor on average cost of electricity during life cycle, in mid-1974 dollars - with 3.25 percent general cost escalation during life.

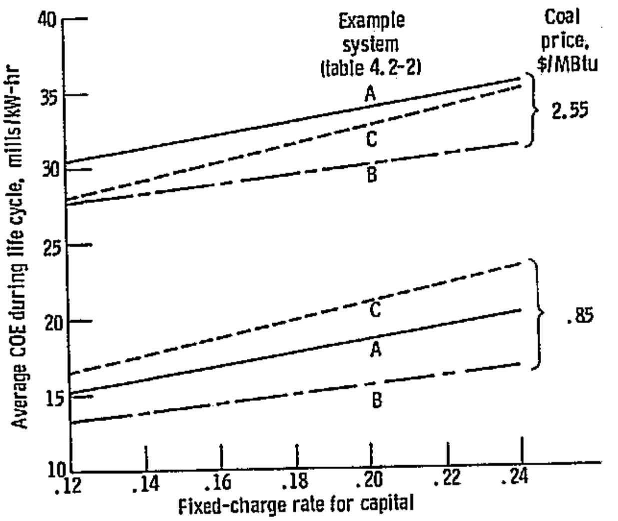

Figure 4.2-13. - Effect of fixed capital charge rate on average cost of electricity during life cycle, in mid-1974 dollars - with 6.5 percent general cost escalation during life.

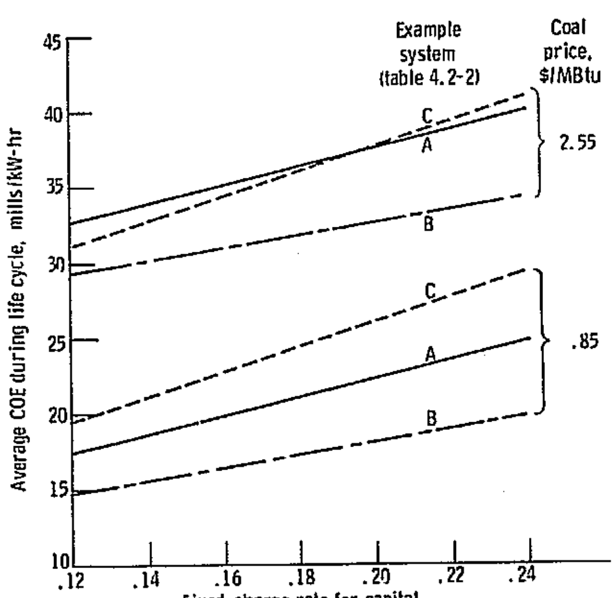

Figure 4.2-14. - Effect of fixed capital charge rate on average cost of electricity during life cycle, in mid-1974 dollars - with 3.25 percent general cost escalation during life.

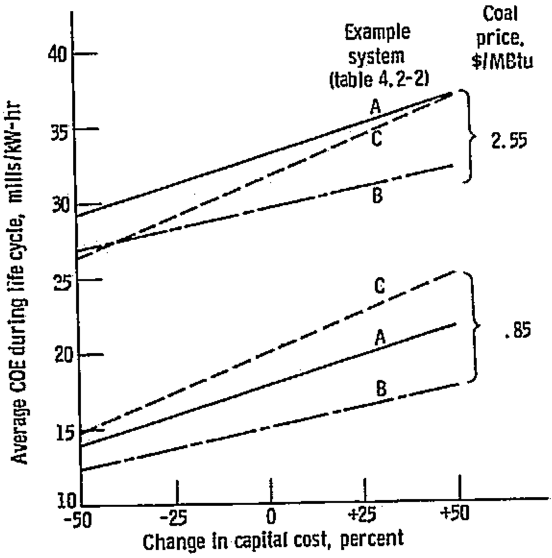

Figure 4.2-15. - Effect of change in capital cost on average cost of electricity during life cycle, in mid-1974 dollars - with 6.5 percent general cost escalation during life.

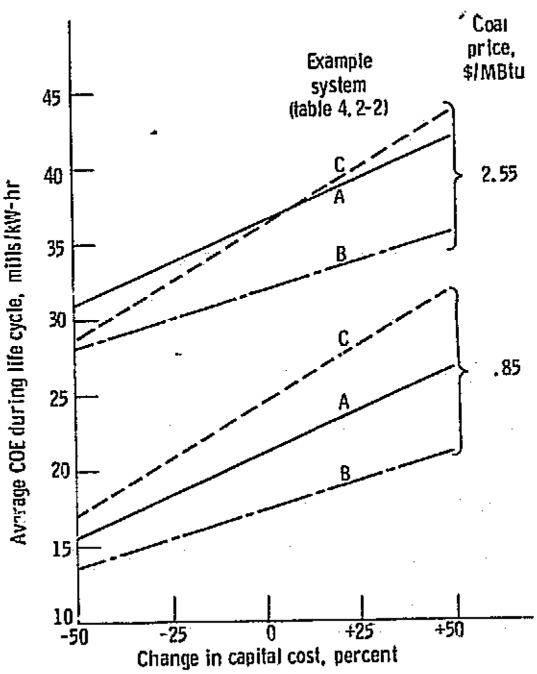

Figure 4.2-16. - Effect of change in capital cost on average cost of electricity during life cycle, in mid-1974 dollars - with 3.25 percent general cost escalation during life.

5.0 DISCUSSION AND EVALUATION OF ECAS PHASE 1 RESULTS

The contractors results for ECAS Phase 1 are compared and evaluated on a system-by-system basis in the following sections. The comparison cites major differences and resolves them wherever possible. Performance and costing results are also evaluated. A materials and furnace evaluation for all systems is also included.

5.1 COSTING APPROACH
by M. Murray Bailey

The objective of ECAS is to provide data on a wide variety of advanced energy conversion systems on a common and consistent basis so that the relative merit of the various systems may be assessed. In Phase 1 the emphasis was on estimating the performance and cost of the various systems over a wide range of parametric conditions and system configurations. Ground rules were specified, as described in section 4.1, for common use by both contractors and for all systems being investigated to help achieve the desired comparability in treatment of the systems. Ground rules were included that directly affect the values of powerplant capital cost estimated, such as fixed-charge rate and interest and escalation rates. These are discussed in detail in section 4.1. Within these ground rules and the overall objective the contractors selected approaches to making their performance and cost estimates that best suited their particular situation while consistent with the ECAS requirements. These approaches were predicated on the makeup of the contractor team, the form of applicable data from previous studies, and the procedures and methodology normally used by the various team members, including the architect-engineer.

This section describes the costing approach used by each contractor, discusses the various factors that were applied to achieve an estimate of the total capital cost of the powerplants, and compares results estimated by the two contractors for a steam plant with a sulfur dioxide scrubber, as an example, using the ECAS ground rules and their particular costing approach. This is being done in an attempt to provide perspective on the approaches taken and the results for the various conversion systems, which are discussed in the following sections.

5.1.1 Estimating Procedures

The basis approach to plant capital cost estimating was the same for General Electric and Westinghouse. They, or a subcontractor, provided estimates of component costs (i.e., factory cost) for the conversion system's major components and used the services of an architect-engineer (A-E) for balance-of-plant (BOP) cost estimating, including installation of the major components. Bechtel Corp. acted as A-E for G.E.; and C. T. Main, Inc., provided the same service for Westinghouse. The role of the A-E was a major one in estimating total plant cost for most conversion systems. The turbine-generator, furnace-boiler, and air preheater for a steam plant with a conventional furnace are examples of the major component (factory) equipment estimated by G.E. and Westinghouse. The BOP estimate for this study then included all remaining equipment and material costs and all site labor costs for component installations and plant construction. Examples of the approximate percentage of cost associated with BOP as compared with plant total cost are the following: open-cycle gas turbine, 20 percent; combined cycle, 50 percent, steam (1200° F), 60 percent; steam (1000° F), 80 percent; and open-cycle MHD, 80 percent. Considering the approximately 900 total parametric points involved in Phase 1, the A-E's estimates of BOP cost had to rely heavily on cost factors derived from recent experience in construction project estimating. The approach generally taken was to compare functional subareas of advanced systems with the most applicable known reference and to use appropriate allowance or factoring to account for differences. Informal engineering calculations and sketches were used as required for definition of equipment and quantities.

Total capital cost estimates were made in the context of a complete utility powerplant. These cost estimates are the dollar summation of a number of discrete cost elements involved in the estimating process. These cost elements, which were common to all the powerplant capital cost estimates in ECAS Phase 1, are discussed below. The basic description of these elements as used in ECAS Phase 1 is as follows:

(1) Direct - This is the basic cost developed as a dollar estimate for each major component or grouping of BOP material or site labor identified for costing (cost account categories) in the powerplant.

(2) Indirect - A percentage factor applied to direct site labor costs, it accounts largely for labor-related costs such as supervision, field engineering, administration, medical services, overhead, payroll taxes, insurance, tools, equipment and supplies, and temporary construction facilities at the construction site.

(3) A-E services - A percentage factor to account for the design, engineering, procurement, and construction management services and the fee of the architect-engineer, it can be applied to all cost categories including major components or as a different percentage applied to only the BOP material and site labor.

(4) Contingency - A percentage factor on all cost categories, it accounts for the money, man-hours, and time that must be added to the estimate to compensate for uncertainties in the details of quantity, pricing, and productivity and the variations in the other cost elements of the estimate. For conventional plants, the contingency is money that experience has shown will be spent. Contingency reflects a selected risk of overun and is generally selected such that the estimate including contingency is the most probable total cost of the proposed powerplant. Contingency does not provide for changes in the defined scope of a project or for unforseen circumstances beyond normal experience or control.

(5) Finance - This is the increase in plant cost due to price escalations (increases in prices of materials or wage rates because of inflationary trends) and interest paid on capital during the final design and construction period. Escalation and interest were applied over an assumed cash-flow curve.

Table 5.1-1 shows the general procedures and numerical percentage values used by G.E./Bechtel and Westinghouse/C. T. Main in developing the cost elements and in obtaining powerplant total capital cost estimates. The table illustrates differences between the contractors' procedures and between the percentage values that they used. The differences shown were investigated by NASA to assess any impact on the comparability of results between contractors, some of which are discussed below.

For direct costs, each contractor had different groupings of BOP materials and site labor (cost account categories) based on the A-E's normal cost estimating methodology. While making direct comparisons of BOP estimates more difficult, allowing different cost account categories facilitated the A-E's job and might provide somewhat greater confidence in the results in an effort like ECAS since the A-E could estimate in the way he customarily employs. For the A-E's portion of the cost estimating, direct costs are not necessarily comparable since different levels of detail may be included in "direct" with different indirect factors, for example, to account for not costing some items as "direct."

The participating A-E's, Bechtel and C. T. Main, used different estimating procedures. Bechtel estimated on the basis of a general contractor with the entire work force on company payroll. C.T. Main estimated on the basis of the engineer/construction manager role, in which portions of the project are on a subcontract basis. On a final "bottom line" basis, estimates prepared according to the two different contractor methods should be comparable. As mentioned, they are not necessarily comparable, however, at the direct-cost level. In the ECAS results this is because C.T. Main's "direct" costs include some subcontractor indirect costs and A-E service charges that are included in the subcontractor's price. Therefore, for the results presented it is generally more appropriate to compare direct-plus-indirect labor costs rather than to compare direct labor costs, for example. Direct comparison of major component or identifiable unit equipment costs can, of course, be made.

Contingency is tailored to each A-E's estimating technique, judgment, and experience, and different percentage values may be justified on that basis. However, the contractors differed in their basic viewpoints of the role contingency had in ECAS Phase 1. C. T. Main applied contingency that they felt would be appropriate for a standard steam plant in the context of an analytical study like ECAS. They considered that the potential value of advanced systems could be compared on a relative basis as though they all had been developed to the same condition of proven technology and commercial use as a standard steam plant. C. T. Main's contingency formula used for all systems and parametric points included a function of the estimated construction time of the plant such that the more complex, longer-construction-time plants received a higher contingency. In addition, Westinghouse in some cases included a design allowance in the direct cost estimates of some of the components for the more advanced systems such as MHD. Bechtel's contingency value was selected with consideration of the conceptual nature of the systems. Bechtel considered that the available level of detail in the ECAS Phase 1 designs increased the risk of underestimating costs. To compensate they applied a contingency that is nearer the high end of the range of values currently used in the construction industry. Bechtel also applied a 10 percent design allowance to the BOP direct cost estimates of the MHD and high-temperature fuel-cell systems because of the uncertainties in plant equipment and design for these systems. Bechtel used a constant contingency percentage for all systems and parametric points.

The difference illustrated in table 5.1-1 for finance (i.e., interest and escalation) is attributable to small differences in the cash-flow "S" curve assumed by the two contractors and/or differences in the specific method of dividing the curve into time increments for the cost calculation. For the second phase of ECAS this difference will be eliminated by NASA specifying the actual percentage factor to be used rather than just the annual rates of escalation and interest.

Differences in plant physical assumptions were also assumed by Westinghouse/C.T. Main and G.E./Bechtel. Westinghouse/C.T. Main estimated on the basis of a semi-outdoor plant with regard to enclosing equipment and with the assumption of a full 30-year requirement for disposal of waste products on site. Westinghouse/C.T. Main also included land costs (a small dollar item) for the basic powerplant site in their cost totals. General Electric/Bechtel in contrast estimated the plant costs for fully enclosed construction, did not include land costs, and included waste-product disposal only to the extent of

15 days holding on site. While the differences in plant physical assumptions tended to cancel out, it was not possible within the level of detail of the Phase 1 scope to quantitatively assess the net result of these differences with absolute precision although this has been factored in some of the results presented in the following section.

5.1.2 Comparison of Steam Plant Cost Estimates

The guidelines specified for ECAS were intended to produce performance and cost estimates of the systems that could be compared on a relative basis in making an assessment of the various concepts. Achieving "correct" costs in an absolute sense is not within the intended scope of ECAS. This was particularly true in Phase 1, where a large number of parametric points were considered and the scope of activity did not permit preparation of detailed plant layouts and the like. However, to compare the results between the contractors for the various conversion systems, it was necessary to make an assessment of the relative costs as estimated by the two contractors for a common system. The best agreement on absolute cost would be expected where more or less conventional technology (base line) systems are compared.

For illustrative purposes, therefore, the G.E. and Westinghouse steam plant capital cost results are compared in this section to determine the degree of agreement on absolute cost for a conventional steam plant with a stack-gas scrubber. To make a proper evaluation, it was necessary that the plants compared be identical. A steam plant configuration with a stack-gas scrubber for sulfur dioxide removal was selected having approximately 750 MWe net output with 3500 psi/1000° F/1000° F steam conditions, and corresponding costs were developed through minor interpolation from each contractor's data. The resulting costs were $675/kWe based on G.E. data and $468/kWe based on Westinghouse data. The difference of $207/kWe for this steam plant estimated to common cost guidelines is substantial. In an attempt to examine the differences at a more detailed level, NASA investigated the contractors' costing approaches and estimating procedures as discussed above and modified the contractors' steam plant capital cost results as described in the following paragraphs.

The net impact of the differences in contractor estimating procedures and approach to plant design on the plant cost estimates was assessed by adjusting the contractor results to a common approach and procedural basis. The adjusted basis chosen for comparison was fully enclosed construction, no land cost or on-site waste disposal, contingency as might be appropriate to a conventional steam plant in the context of a study (i.e., NASA assumed 15 percent on the G.E. estimate rather than 20 percent), and identical finance charges per an NASA-generated factor of 49 percent for a 5-year construction period. The impact of these adjustments was to narrow the $/kWe difference between the contractors' estimates. The adjusted cases are shown in table 5.1-2, together with an independent estimate from the CONCEPT program modified by NASA to the same ground rules. The adjusted values shown in table 5.1-2 amount to a 6 percent reduction in the G.E./Bechtel $/kWe costs due to change in the contingency and finance factors. The Westinghouse/C.T. Main values did not change because the adjustments assumed for the changes in plant physical content tended to cancel out and the NASA finance factor for a 5-year construction period represented no change from the factor Westinghouse had used for a 5.4-year construction period. (Westinghouse had indicated a 5.4-yr construction period for a 800-MWe conventional-furnace steam plant as opposed to the 5 yr estimated by G.E. for the same plant (section 5.2.2).) The NASA approach was to use 5 years for the comparisons. The CONCEPT data shown in table 5.1-2 are thus calculated for a 5-year construction period by using the NASA 49 percent finance factor. The CONCEPT data are from a computer run made specifically for ECAS by Hollifield National Laboratory using mid-1974 dollars and the $10.60/hour composite labor rate. Factory equipment costs were then adjusted by using the Handy-Whitman (ref. 5) index of public utility material and equipment costs to account for inflation above the 5 percent per year built into the CONCEPT program. Site material costs were average U.S.A. values developed from the CONCEPT current library of mid-1974 materials costs in 20 cities.

Table 5.1-2 shows that there is a difference of $167/kWe remaining between the G.E. and Westinghouse totals and that the CONCEPT total estimate falls between the two ECAS estimates. In an attempt to obtain the additional information relative to the cost differences, NASA developed two additional independent estimates according to the common ground rules of table 5.1-2. Burns and Roe, Inc., was requested (under contract NAS3-19586) to adapt a recent plant budget estimate to the ECAS ground rules. This was accomplished by adding the cost of sulfur dioxide scrubbing, for a plant total estimate of $507/kWe. In addition, NASA made an in-house adjustment on the "as built" price of the TVA Bull Run plant. The Bull Run estimate with cooling towers and scrubbers added, adjustment to average U.S.A. values, and escalation from mid-1974 dollars is $520/kWe. The average of the capital cost estimates obtained excluding the G.E. and Westinghouse results (i.e., only the NASA/TVA Bull Run, CONCEPT, and Burns and Roe estimates) is $516/kWe on a conventional steam plant, with scrubber, constructed according to the ECAS ground rules. The G.E./Bechtel estimate is $119/kWe or 23 percent above this average, the Westinghouse/ C.T. Main estimate is $48/kWe or 9 percent lower. If the ECAS contractors are compared according to a common contingency of 15 percent, the Westinghouse/C.T. Main estimate becomes $506/kWe, and the difference between ECAS contractor estimates is reduced to $129/kWe, a 20 to 25 percent difference.

A review of table 5.1-2 allows further insight into the areas of cost difference between G.E. and Westinghouse. The largest difference shown is in the BOP materials costs estimated. Costs for the major (factory) components of the steam plant, the furnace-boiler and turbine-generator, were estimated by price quotes from the manufacturers of this equipment. General Electric and Westinghouse, of course, provided prices for their own turbine-generators. Both contractors obtained estimates for the conventional furnace-boiler from Foster Wheeler, Inc. - thus the agreement on major components costs. In the site labor area, the composite labor rate ($10.60/hr) being fixed by NASA tended to reduce the possibility for uncertainty. The BOP materials include all the remaining factory equipment in the plant as well as all materials for construction. Differences in BOP materials could not be isolated to a few areas, such as cooling towers or coal handling but were generally found through all BOP cost account categories (see section 5.2.2). The ground rule applicable to BOP materials was to use average U.S.A. prices. This allows for the possibility of variations in the unit prices as well as quantities of construction materials. Estimating the cost of materials in mid-1974 dollars was significantly hampered by the severe inflation during 1974. The Handy-Whitman index (ref. 5) of public utility construction costs indicates an average inflation of 7 percent per year from 1970 to 1973 and then inflation of 25 percent in 1974. This made price a "moving target" that was very difficult to specify. Inflation alone, however, cannot explain the large difference between contractors on BOP materials costs.

The detailed investigation of the capital cost estimates made by G.E. and Westinghouse for a steam plant with scrubber indicates that at the level of design done in Phase 1 substantial differences can exist in the absolute value of costs. That this was true in a situation where common ground rules were used by both contractors and for a system where a large data base already existed is indicative of the hazards involved in making comparisons of systems from results of other studies where basic ground rules might be substantially different. Since the assumptions and ground rules in ECAS have been clearly displayed, this can be accounted for in making a more confident and meaningful assessment of the various systems. The differences in absolute level of costs estimated for the steam plant with scrubber are believed to be generally reflected in all the systems studied by both contractors, and comparison of systems should be made in this light. The effect will be more pronounced for systems with high BOP material and labor costs since this was where the biggest differences were found between the contractors' results for a steam plant with scrubber. Further, since detailed plant layouts were not prepared in Phase 1, the cost estimates for these more-complex, capital-intensive systems with high BOP costs are those with the greatest associated uncertainty.

TABLE 5.1-1. - CAPITAL COST ESTIMATING PROCEDURES

AND PERCENTAGE FACTORS

(a) General Electric/Bechtel

	Materials		Site labor
	Major components	Balance of plant	
Direct[a]	$	$	$
Indirect, percent	---	---	×90
Architect-engineer services, percent	---	×15	×15
Contingency, percent	×20	×20	×20
Finance,[b] percent	×52	×52	×52
Total,[c] percent	182	210	399

(b) Westinghouse/C. T. Main

	Major components	Balance of plant	Site labor
Direct[a]	$	$	$
Indirect, percent	---	---	+51
Architect-engineer services, percent	+8	+8	+8
Contingency,[d] percent	+8	+8	+8
Finance,[b] percent	×44	×44	×44
Total,[c] percent	167	167	240

[a]The dollar value that is the basic estimating variable. The content of "direct" is not identical between the two contractors.

[b]Based on a 5-yr design and construction period.

[c]The symbols × and + indicate the contractor's method of applying the percentage factors to a direct base of 1.0. For example, G. E./Bechtel site labor, 1.0×1.9×1.15×1.20×1.52 = 3.99, or 399 percent increase on direct; Westinghouse/C. T. Main site labor, 1.0+0.51+0.08+0.08×1.44 = 2.40, or 240 percent increase on direct.

[d]Based on a 5-yr design and construction period and the formula 3 percent plus 1 percent per year.

TABLE 5.1-2. - CAPITAL COST COMPARISON OF CONVENTIONAL-STEAM PLANTS WITH SULFUR DIOXIDE SCRUBBER

[Gross plant output, 800 MWe; steam conditions, 3500 psi/1000° F/1000° F; condenser pressure, 1.5 in. of Hg; mechanical-draft wet cooling tower; sulfur dioxide scrubber; results developed by NASA by interpolation of General Electric and Westinghouse data and compared to CONCEPT.]

	Based on General Electric data	Based on Westinghouse data	Based on CONCEPT[a]
	Cost,[b] $/kWe		
Major-components materials (turbogenerator and boiler, including air preheater)	120	124	121
Balance-of-plant materials	314	168	184
Site labor	201	176	216
Total	635	468	521

[a]Computer printouts 10/24/75 for NASA Lewis.

[b]Costs are all inclusive, including applicable contingency, interest, and escalation. Cost basis is enclosed construction with land cost excluded and without provision for on-site disposal of wastes. Contingency applied to General Electric-based results is 15 percent. Interest and escalation a·ɜ per the NASA factor of 49 percent for 5-yr construction period. $/kWe based on plant net output.

5.2 ADVANCED STEAM SYSTEMS

by Gerald J. Barna, M. Murray Bailey, and William J. Brown

Steam powerplants today provide the bulk of this nation's electrical generating output. High-performance systems with turbine-inlet pressures of 2400 or 3500 psi are commonly used with turbine throttle and reheat temperatures of approximately 1000° F. Figure 5.2-1 is a simplified schematic diagram of a typical conventional-furnace steam plant. Because of their widespread use and demonstrated performance and reliability, it is appropriate that the performance and cost of steam systems be used as one yardstick for evaluating the merit of advanced energy conversion systems. This evaluation of advanced conversion systems must, however, include comparison with both state-of-the-art and advanced steam systems. Advancements must be considered for the steam systems themselves in order to assess the potential for increasing efficiency and/or reducing steam powerplant costs relative to the current state of the art. In the context of ECAS the impact of substantial departures from state-of-the-art practice, rather than incremental changes in operating conditions, is of primary interest. The ECAS analyses focused on evaluating these departures. Although steam plants have been studied and, indeed, built with substantially higher steam conditions than those now commonly used, such as at Eddystone #1 with 5000-psi, 1200° F throttle conditions, these have not proved to be economical in the past. New economic conditions in terms of the relative cost of fuel and capital could alter this situation. Further, advances in combustion techniques can offer alternative methods for producing environmentally acceptable and economical electric power from advanced steam systems.

5.2.1 Scope of Analysis

Table 5.2-1 summarizes the ranges of some of the major parameters investigated by each contractor. Underlined values indicate emphasis in the individual contractor's analysis. General Electric considered one base case and 28 parametric points. Westinghouse studied three base cases and approximately 180 parametric points. Both contractors emphasized direct burning of coal and use of the 3.9-percent-sulfur Illinois #6 coal. The General Electric base case used an atmospheric-fluidized-bed furnace and steam throttle conditions of 3500 psi and 1200° F with one reheat to 1000° F (designated 3500 psi/1200° F/1000° F). The Westinghouse base cases involved the use of the conventional furnace, a pressurized-fluidized-bed furnace, and a pressurized furnace with an integrated low-Btu gasifier. All of the Westinghouse base cases used steam throttle conditions of 3500 psi and 1000° F with one reheat to 1000° F.

The effects of a great number of variables were investigated by each contractor. Here we discuss and compare contractor results from an overall system viewpoint with respect to two approaches for advancing steam systems from the present state of the art: advanced furnaces, and increasing steam turbine throttle and reheat temperatures substantially above current practice. Advanced furnaces are discussed in more detail in section 5.14 of this report.

5.2.2 Results of Analysis

5.2.2.1 Overall Comparison

Figure 5.2-2 shows the cost-of-electricity (COE) and overall-efficiency ranges of results from both G.E. and Westinghouse. In the Westinghouse results, a small number of points with COE uncharacteristically (i.e., 50 percent) above the group have been omitted from the figure as not being representative. The higher efficiencies shown in the Westinghouse data are the results of their evaluating higher cycle conditions than did G.E. The near 43 percent efficiency shown results from use of 5000 psi/1400° F/1400° F steam conditions in the pressurized boiler and pressurized-fluidized-bed systems.

In general, the G.E. COE results were higher than those of Westinghouse for a similar range of parametric points. The reason for this and the impact on comparability of COE results between contractors' studies were investigated by NASA and are described.

5.2.2.2 Discussion and Assessment

5.2.2.2.1 Comparison of conventional-plant capital cost. - The general level of COE differed substantially between the G.E. and Westinghouse results for similar cases. The largest factor contributing to this overall difference was a difference in the estimates for the capital cost portion of the COE. With the same overall economic ground rules being used by both contractors, this difference is directly attributable to differences in the estimates for plant capital cost. An evaluation of the differences in capital cost was made by NASA by interpolating contractor results to as nearly an identical set of parametric conditions as possible and comparing these interpolated results. A plant with conventional steam conditions was selected in order to minimize any differences resulting from differences in approach toward advancements in technology for the steam systems. A plant design of nominally 800-MWe size and 3500 psi/1000° F/1000° F steam conditions and a conventional furnace was chosen as the common point for comparison. Cost estimates were then developed by NASA through interpolation from the G.E. and Westinghouse data. These estimates were then further adjusted to reflect a common costing approach, as described in section 5.1. The resulting estimates are shown in table 5.2-2(a).

Table 5.2-2(a) shows a difference of $167/kWe between the estimate developed from G.E. data and the one developed from Westinghouse data. As discussed in section 5.1, the bulk of the cost difference is in the balance-of-plant materials estimated by the consulting A-E firms of Bechtel and C.T. Main. In an attempt to gain further insight into this difference, NASA compiled the balance-of-plant materials cost breakdown shown in table 5.2-2(b). The breakdown must be considered as approximate in that it represents a less-than-exact matching of the two contractors' (different) cost categories into a common format. The results show that the G.E./Bechtel-based cost estimates are consistently higher and that a significant percentage of the total difference is contributed by two relatively broad categories, "other mechanical equipment" and "civil and structural work." This is consistent with the observation (5.1) that the difference is general in nature and will likely be reflected through all the other systems studied in ECAS, particularly those with high capital costs. A similar breakdown for site labor costs showed plus and minus differences between the two contractors and a fairly even distribution of the differences among the categories.

Considering the rather wide difference between the level of the two cost estimates for a base-line plant, the NASA evaluation of contractor results for advanced steam systems was conducted with emphasis on identifying trends within an individual contractor's results and then comparing trends between contractors' results.

5.2.2.2.2 COE and efficiency results for plants using various furnace types. - Figure 5.2-3 shows the cost of electricity (COE) and the efficiency for various points calculated for plants using each of the four types of furnace investigated. The open triangles denote G.E. data, and the open circles denote Westinghouse data. Not all the points calculated by the contractors have been included on the figure. Sufficient points are given to be indicative of the results obtained and to allow a general comparison of the results using the different furnaces. The solid triangles and circles denote points that were not calculated by the contractors but that were estimated by NASA, using the G.E. and Westinghouse data, respectively. These estimated points were selected to have nearly identical parametric conditions so that detailed comparisons of results could be made. These points were for systems with a nominal power output of approximately 800 MWe. Since substantially different configurations were used by G.E. and Westinghouse for the pressurized-furnace cases using an integrated low-Btu gasifier (fig. 5.2-3(d)), it was not deemed appropriate to attempt an NASA-developed detailed comparison of comparable points for this case.

The Westinghouse results for the conventional furnace (CF) shown in figure 5.2-3(a) show COE's as low as 23.1 mills/kW-hr and efficiencies as high as 39.7 percent. Figure 5.2-3(a) excludes points with COE's more than 50 percent higher than the lowest COE. The highest efficiency points shown were achieved with steam conditions of 3500 psig/1400° F/1400° F and 5000 psig/1200° F/1200° F/1200° F. The lowest COE points were for systems using temperatures and pressures that are current state of the art for steam plants: namely, 2400- and 3500-psig pressures with 1000° F throttle and reheat temperatures. The G.E. results show COE's as low as 34.4 mills/kW-hr and efficiencies as high as 38.2 percent. The only steam conditions used by G.E. in the CF cases were 3500 psig/1200° F/1000° F. The points estimated by NASA (solid symbols) were for 3500 psig/1000° F/1000° F steam conditions with 1.5-inch-Hg condenser pressure for both contractors. These points turned out to be near the minimum COE estimated by the contractors in their respective studies of the conventional furnace.

The G.E. results for the atmospheric-fluidized-bed (AFB) case shown in figure 5.2-3(b) show COE's as low as 29.8 mills/kW-hr and efficiencies as high as 39.8 percent. The Westinghouse results indicate COE's as low as 24.3 mills/kW-hr and efficiencies as high as 38.6 percent. The highest efficiency points for both contractors were achieved with high throttle and reheat temperatures, 1200° and 1400° F, respectively, and 3500-psig throttle pressure.

The Westinghouse results for the pressurized-fluidized-bed (PFB) cases shown in figure 5.2-3(c) indicate COE's as low as 21.1 mills/kW-hr and efficiencies as high as 42.8 percent. The higher efficiency points were obtained for systems with 5000 psig/1400° F/1400° F steam conditions. The Westinghouse lower COE points were obtained with 3500 psig/1000° F/1000° F conditions and with only a small COE change by increasing the pressurizing gas-turbine-inlet temperature over a base value of 1600° F and varying pressure ratio. The Westinghouse matrix of points did not include any coupling of higher steam conditions with the higher gas turbine (i.e., fluidized bed) temperatures of 1700° and 1800° F. Westinghouse investigated values for excess air of 15, 45, and 90 percent; the lowest COE cases were for the 15-percent excess air. The G.E. cases were all calculated for steam conditions of 3500 psig/1200° F/1000° F, a gas-turbine-inlet temperature of 1600° F, a pressure ratio of 10, and 20-percent excess air. Efficiency as high as 39.2 percent was achieved with a COE of 34.6 mills/kW-hr. The NASA estimated points using the respective contractor results were for 3500 psig/1000° F/1000° F, 1.5-inch-Hg condensing pressure, a gas-turbine-inlet temperature of 1600° F, and a pressure ratio of 10. Excess air values of 15 and 20 percent, respectively, were selected for the Westinghouse and G.E. data.

For the pressurized-furnace (PF) cases shown in figure 5.2-3(d) the Westinghouse results show COE's as low as 25.6 mills/kW-hr and efficiencies as high as 42.6 percent. The highest efficiency points shown were achieved with steam conditions substantially above the state of the art, like those used to obtain high PFB efficiencies, in combination with 2000° F pressurizing gas turbines. The G.E. results are clustered around an efficiency of about 34 percent and a COE of about 35 mills/kW-hr. These G.E. cases are for pressurizing gas turbines with an inlet temperature of 1800° F and a pressure ratio of 10.

We may make two observations from the preceding discussion: First, there is a significant difference in the level of COE between the G.E. and Westinghouse data for each type of furnace. Second, advancing the steam conditions substantially beyond the current state of the art achieves a higher overall energy efficiency, to values exceeding 40 percent, but at higher COE's. In the following sections the differences between the G.E. and Westinghouse results are discussed for each furnace type, using the points interpolated by NASA for comparison purposes. Following this discussion, the trends in performance and COE are examined as steam conditions are advanced.

Table 5.2-3(a) shows performance results for the comparison cases developed by NASA from G.E. and Westinghouse data to illustrate the impact of different furnace types on powerplant performance, capital costs, and COE. These comparison cases are the ones identified in figure 5.2-3 by solid triangles and circles. Each is at approximately the 800-MWe gross output level and uses 3500 psi/1000° F/1000° F steam conditions. For the pressurized-fluidized-bed plants the point developed from G.E. data uses 20-percent excess air, and the point developed from Westinghouse data uses 15-percent excess air.

The performance results in table 5.2-3(a) show consistent trends in that the presurized fluidized bed offers an advantage in plant overall efficiency as compared with the conventional furnace or atmospheric fluidized bed. For the specified conditions selected for the cases shown in the table, the advantage was approximately 1 percentage point in the cases developed from G.E. data and approximately 2 percentage points in the cases developed from Westinghouse data.

The auxiliary power requirements shown in table 5.2-3(a) are approximately the same between contractors, with the exception of the power requirement for the conventional-furnace case. Here the case developed from Westinghouse data had a considerably higher power requirement. The power requirements for the conventional furnace, the cooling towers, and general housekeeping were approximately the same for the two contractors, but the power requirement assigned to stack-gas scrubbers and other balance-of-plant items was higher for the Westinghouse case.

Table 5.2-3(b) shows a capital cost breakdown for the comparison cases interpolated by NASA. The figures shown are based on modification of the contractor data as described in section 5.1.2. In table 5.2-3(b) the costs are broken down to several functional accounts of the plant. For each account the cost listed is an all-inclusive cost; that is, it includes the material and site labor costs and proportional amounts of the indirect costs, contingency costs, escalation, and interest contributing to the plant total cost.

The capital cost results of the cases developed from G.E. and Westinghouse data show similar trends as furnace type is changed. The results indicate that the capital cost of furnace and required gas cleanup equipment, added together, is lower for advanced furnaces than for conventional furnaces. This advantage is reflected in the plant total cost in the form of a 2- to 12-percent-lower capital cost for the plants using advanced furnaces.

There is an additional capital cost factor not fully displayed in table 5.2-3(b) that may impact cost comparisons of the pressurized-fluidized-bed furnace. Table 5.2-3(b) was prepared on the basis of a 5-year construction period for each plant (furnace) type - with escalation and interest during construction that is appropriate to that construction period. Westinghouse estimated that a shorter construction period would be required for a pressurized-fluidized-bed furnace plant than for plants of the same MWe rating using either a conventional furnace or an atmospheric fluidized bed. The time difference, about 0.4 year on an 800-MWe plant, would reduce the estimated pressurized-fluidized-bed plant capital costs by 3 percent by virtue of a reduction in the escalation and interest compilation. A more detailed evaluation is required to determine if the pressurized fluidized bed has modularization characteristics that will permit a reduced construction time relative to a conventional furnace plant of the same MWe size. The G.E. data for ECAS Phase 1 indicate a 5-year construction period for all of the 800-MWe steam plants regardless of furnace type.

Table 5.2-3(c) shows the cost-of-electricity results developed by NASA interpolation of the G.E. and Westinghouse data for plants using the different furnace types. The overall COE developed from Westinghouse data is lower than the corresponding COE based on G.E. results for all furnace types. The difference is 27 percent for the conventional-furnace and atmospheric-fluidized-bed cases and 36 percent (based on the Westinghouse numbers) for the pressurized-fluidized-bed case. The portion of COE's due to fuel cost for the G.E.-based conventional furnace and atmospheric-fluidized-bed cases are lower than the corresponding Westinghouse-based results because of a 1-percentage-point higher overall energy efficiency in the G.E. cases. For the operating-and-maintenance (O and M) part of COE the figures developed from G.E. data are considerably higher than those developed from Westinghouse data for each furnace type. The difference is substantial, approximately 100 percent for the conventional-furnace and pressurized-fluidized-bed cases and approximately 50 percent for the atmospheric-fluidized-bed case.

The major COE difference, in terms of absolute magnitude, is that due to the difference in the contractor's capital cost estimates. Here a 36- to 48-percent difference (based on the Westinghouse numbers) equates to approximately 6 mills/kW-hr in COE. The results developed from G.E. data represent the higher COE due to capital for each furnace type. Both contractors' data show that for comparable plants the overall COE is lower or approximately the same with an advanced furnace as with a conventional furnace. One reason for the G.E.-PFB case being higher than the CF was the higher O and M costs estimated for the PFB system. All differences are small, however, considering the level of detail of Phase 1. More detailed analysis is required to better define the differences in results among furnace types.

5.2.2.2.3 <u>Impact of steam throttle and reheat temperature on COE</u>. - The G.E. and Westinghouse results were reviewed to understand the dependency of the overall energy efficiency and cost of electricity on an increase in steam throttle temperature and reheat temperature. The system results reviewed for advanced steam were the G.E. and Westinghouse atmospheric-fluidized-bed cases and the Westinghouse conventional-furnace cases. There were not sufficient parametric cases for the G.E. conventional furnace to use for this purpose.

Figure 5.2-4 is a plot of COE in mills/kW-hr against overall energy efficiency for the advanced steam powerplant. Results are presented for the G.E. atmospheric-fluidized-bed case, 3500-psig steam conditions, throttle temperatures of 1000° and 1200° F, and reheat temperatures of 1000°, 1200°, and 1400° F. Westinghouse results are presented for the conventional furnace, a throttle temperature of 1000° F, and reheat temperatures of 1000°, 1200°, and 1400° F. According to figure 5.2-4 steam throttle temperature and reheat temperature have a major effect on COE and efficiency. For the G.E.-AFB, as the throttle temperature is increased from 1000° F to 1200° F, there is a COE increase of 3 mills/kW-hr and an overall efficiency increase of 1.2 percentage points. When the reheat temperature is increased by 200° F, such as from 1000° F to 1200° F, the COE increased about 1.8 mills/kW-hr and overall efficiency increased 1 percentage point.

A more pronounced effect is observed if steam conditions are changed from 3500 psi/1000° F/1000° F to 3500 psi/1200° F/1200° F. On figure 5.2-4 this is a change from point A (throttle temperature, 1000° F) to point B (throttle temperature, 1200° F). Observe that COE increases 5 mills/kW-hr and overall efficiency increases 2.2 percentage points. The same effect can be observed for the Westinghouse conventional-furnace-plant results. Figure 5.2-4 shows that a 200° F increase in the reheat temperature raises the COE by 1.9 mills/kW-hr and efficiency by 1 percentage point. This is about the same as shown in the G.E.-AFB cases for a 200° F reheat temperature increase.

A G.E.-AFB 3500 psi/1000° F/1200° F/1200° F (double reheat) case is shown in figure 5.2-4 (point D). If point D is compared to point B (single reheat to 1200° F), the second reheat increases COE by 1.8 mills/kW-hr and raises efficiency by 1.8 percentage points.

The COE increase with increasing steam conditions shown in figure 5.2-4 obviously results from capital cost increases. Since the most costly major components are the steam turbogenerator (turbine-generator) and the furnace, costs in $/kWe net are plotted against steam conditions in figures 5.2-5 and 5.2-6. In figure 5.2-5 if a G.E. 3500 psig/1000° F/1000° F system is compared to a G.E. 3500 psig/1200° F/1200° F system, the direct cost of the steam turbogenerator increases by a factor of approximately 4, from $30/kWe to $128/kWe. The same comparison can be made for a Westinghouse 3500 psig/1000° F/1000° F plant to a 3500 psig/1200° F/1200° F plant. In this case, steam turbogenerator cost in $/kWe increases by a factor of 2.5 ($35/kWe to $88/kWe), which is much less than the G.E. increase but still very large. Westinghouse studied a parametric point for a 3500 psig/1400° F/1400° F plant; figure 5.2-5 shows the steam turbogenerator cost increasing by an additional factor of 1.9 over the 3500 psig/1200° F/1200° F case. The higher costs estimated by both contractors result from the requirement for more-expensive, higher strength materials in the turbine at these higher temperatures.

The effect of increasing reheat temperature only while keeping throttle temperature at 1000° F is also seen in figure 5.2-5. The steam turbogenerator cost increased by a factor of 2 for a reheat temperature increase from 1000° F to 1200° F, which constitutes one-half of the combined throttle and reheat effect previously mentioned.

For the Westinghouse conventional furnace, the same effect of steam condition on turbogenerator cost is shown in figure 5.2-6. Turbogenerator costs increase by factors of 2.5 and 1.9 for the 3500 psig/1200° F/1200° F and 3500 psig/1400° F/1400° F plants, respectively. The effect of reheat temperature increase alone can be seen for the 1000° F throttle temperature.

It can also be observed from figures 5.2-5 and 5.2-6 that a 200° F increase in throttle and reheat temperature has a minor efect on furnace module costs. The furnace module as discussed here includes the boiler and precipitator material cost.

5.2.3 Concluding Remarks

A wide range of parametric conditions were investigated by both contractors. Cost-of-electricity values as low as approximately 30 to 35 mills/kW-hr were obtained by G.E. for the various types of furnace; Westinghouse obtained values of approximately 20 to 25 mills/kW-hr. This substantial difference between the G.E. and Westinghouse COE estimates held true for all furnace types and parametric conditions. The main source of this difference was in the capital cost estimated for the balance of plant. The efficiencies at the low cost-of-electricity points were roughly in the range 34 to 39 percent for both contractors. Conditions producing the lowest cost of electricity were generally those at or near present-state-of-the-art temperature and pressure, again for both contractors.

While the abolute levels of the costs were different, the trends shown by the contractors' results were the same for the major variations discussed in this report: namely, the impact of various furnace types and the impact of substantial increases in steam turbine throttle and reheat temperatures. Both contractors' results when modified by NASA to obtain identical parametric conditions showed lower or comparable cost of electricity for the atmospheric- and pressurized-fluidized-bed furnaces compared with the conventional furnace. Likewise both contractors' results indicated substantially higher efficiencies and cost of electricity when steam throttle and reheat temperature were increased in large steps from the current state of the art. The cost-of-electricity increases were due largely to increases in the cost of the major equipment, primarily the turbine-generator. Westinghouse estimated efficiencies as high as 41 percent with throttle temperatures limited to 1200° F and as high as 43 percent at throttle temperature of 1400° F. (Only Westinghouse investigated 1400° F throttle temperatures.) These high efficiency points would have costs of electricity competitive with those at the more conventional temperatures only if coal costs were assumed to be approximately 7 times those used in obtaining the results reported ($0.85/MBtu was the base cost for delivered coal assumed in Phase 1). General Electric results for 1200° F throttle temperatures and reheat to 1400° F indicated an efficiency of approximately 40 percent and a requirement for a nearly 12:1 increase in assumed fuel cost in order to be competitive with conventional-temperature systems. More attractive in the G.E. results in this regard was the 1000° F/1200° F/1200° F system, which developed over 39 percent efficiency and which would require approximately a 7:1 increase in assumed fuel cost to be competitive with the standard 1000° F/1000° F system. Section 6.2.2 gives more discussion on the impact of fuel cost changes on plant total COE. Formidable technical problems would have to be overcome in order to achieve 1200° F and higher throttle temperatures. In addition, large investments for new forging facilities with increased forging press and furnace capacity would also be required if conventional turbine fabrication approaches were used, as has been assumed by both contractors.

Improvements in performance or reduction in the cost of electricity that might be obtained through more modest changes in temperature or modifications to the plant configurations were not the thrust of this investigation. These changes could indeed offer improvements over plants in service or currently being delivered but were considered outside the scope of this study.

TABLE 5.2-1. - COMPARISON OF RANGES OF MAJOR PARAMETERS INVESTIGATED FOR ADVANCED STEAM SYSTEMS

Parameter	General Electric conditions		Westinghouse conditions	
Power output (nominal), MWe	600, 800, 1200,[a] 1600		500, 900	
Throttle pressure, psig	2400, 3500, 4000		2400, 3500, 4500, 5000, 10 000	
Throttle temperature, ^{o}F	1000, 1200		1000, 1200, 1400	
Reheat temperature, ^{o}F	1000, 1200, 1400		1000, 1200, 1400	
Number of reheats	1, 2		0, 1, 2, 3	
Fuel type[b]	Coal, SRC, LBTU		Coal, LBTU	
Furnace type[c]	CF, AFB, PFB, PF		CF, AFB, PFB, PF	
Furnace pressurizing system	PFB	PF	PFB	PF
Turbine-inlet temperature, ^{o}F	1600	1800	1600 to 1800	1600 to 2500
Pressure ratio	10	10	5 to 15	5 to 15
Amount of excess air, percent of total	20	15	15 to 90	15 to 90
Heat rejection method[d]	WCT, DCT		OTC, WCT, DCT	
Condenser pressure, in. of Hg abs	1.5, 1.9, 3.35		2.0, 3.5, 9.0	

[a]Two 800-MWe units.
[b]SRC = solvent-refined coal; LBTU = low-Btu gas.
[c]CF = conventional furnace; AFB = atmospheric fluidized bed; PFB = pressurized fluidized bed; PF = pressurized furnace.
[d]WCT = wet cooling tower; DCT = dry cooling tower; OCT = once-through cooling.

TABLE 5.2-2. - CAPITAL COST COMPARISON OF CONVENTIONAL-FURNACE STEAM PLANTS

[Gross plant output, 800 MWe; steam conditions, 3500 psi/1000° F/1000° F; condenser pressure, 1.5 in. of Hg; mechanical-draft wet cooling tower; sulfur dioxide scrubber; results developed by NASA from General Electric and Westinghouse data.]

(a) Overall cost comparison

	Cost,[a] $/kWe	
	Based on General Electric data	Based on Westinghouse data
Major-components materials (boiler and turbogenerator)	120	124
Balance-of-plant materials	314	168
Site labor	201	176
Total	635	468

(b) Balance-of-plant materials cost breakdown

Coal handling equipment	13	13
Plant electrical equipment	24	22
Piping and instrumentation	24	17
Cooling tower system	13	9
Precipitators and scrubbers	86	59
Other mechanical equipment	74	25
Civil and structural work	57	17
Miscellaneous and yardwork	23	6
Total	314	168

[a]Costs are all inclusive, including applicable contingency, interest, and escalation. Cost basis is enclosed-type construction with land cost excluded and without provision for on-site disposal of waste. Contingency applied to General Electric-based results is 15 percent. Interest and escalation are per NASA factor of 1.49 for 5-yr construction period. $/kWe based on plant net output.

TABLE 5.2-3. - COMPARISON OF ADVANCED STEAM PLANTS USING

DIFFERENT FURNACE TYPES

[Steam conditions, 3500 psi/1000° F/1000° F; condenser pressure, 1.5 in. of Hg for each; results developed by NASA from General Electric and Westinghouse data.]

(a) Performance comparison

	Based on General Electric data			Based on Westinghouse data		
	CF	AFB	PFB	CF	AFB	PFB
Steam turbogenerator output, MWe	800	800	600	800	800	640
Gas turbogenerator output, MWe	---	---	177	---	---	114
Total gross output, MWe	800	800	777	800	800	754
Auxiliary losses, MWe	40	52	26	62	58	24
Total net output, MWe	760	748	751	738	742	730
Overall efficiency, percent	37	37	38	36	36	38

(b) Capital cost comparison[a]

	CF	AFB	PFB	CF	AFB	PFB
Furnace/steam boiler cost, $/kWe	110	126	192	118	103	140
Stack-gas cleanup cost, $/kWe	139	63	(b)	97	48	(b)
Steam turbogenerator cost, $/kWe	66	66	62	61	61	52
Gas turbogenerator cost, $/kWe	---	---	58	---	---	36
Balance-of-plant costs, $/kWe	320	337	310	192	198	194
Total	635	592	622	468	410	422

(c) Cost of electricity

	CF	AFB	PFB	CF	AFB	PFB
Capital component of COE, mills/kW-hr	20.1	18.7	19.7	14.8	13.0	13.3
Operation-and-maintenance component of COE, mills/kW-hr	2.2	2.5	3.4	1.0	1.7	1.7
Fuel component of COE, mills/kW-hr	7.9	7.9	7.6	8.1	8.1	7.6
Total	30.2	29.1	30.7	23.9	22.8	22.6

[a]Costs for each line item are all inclusive, including applicable contingency, interest, and escalation. Cost basis is enclosed-type construction with land cost excluded and without provision for on-site disposal of waste. Contingency applied to General Electric-based results is 15 percent. Interest and escalation are per NASA factor of 1.49 for 5-yr construction period.

[b]Cost of gas cleanup equipment is included in furnace cost.

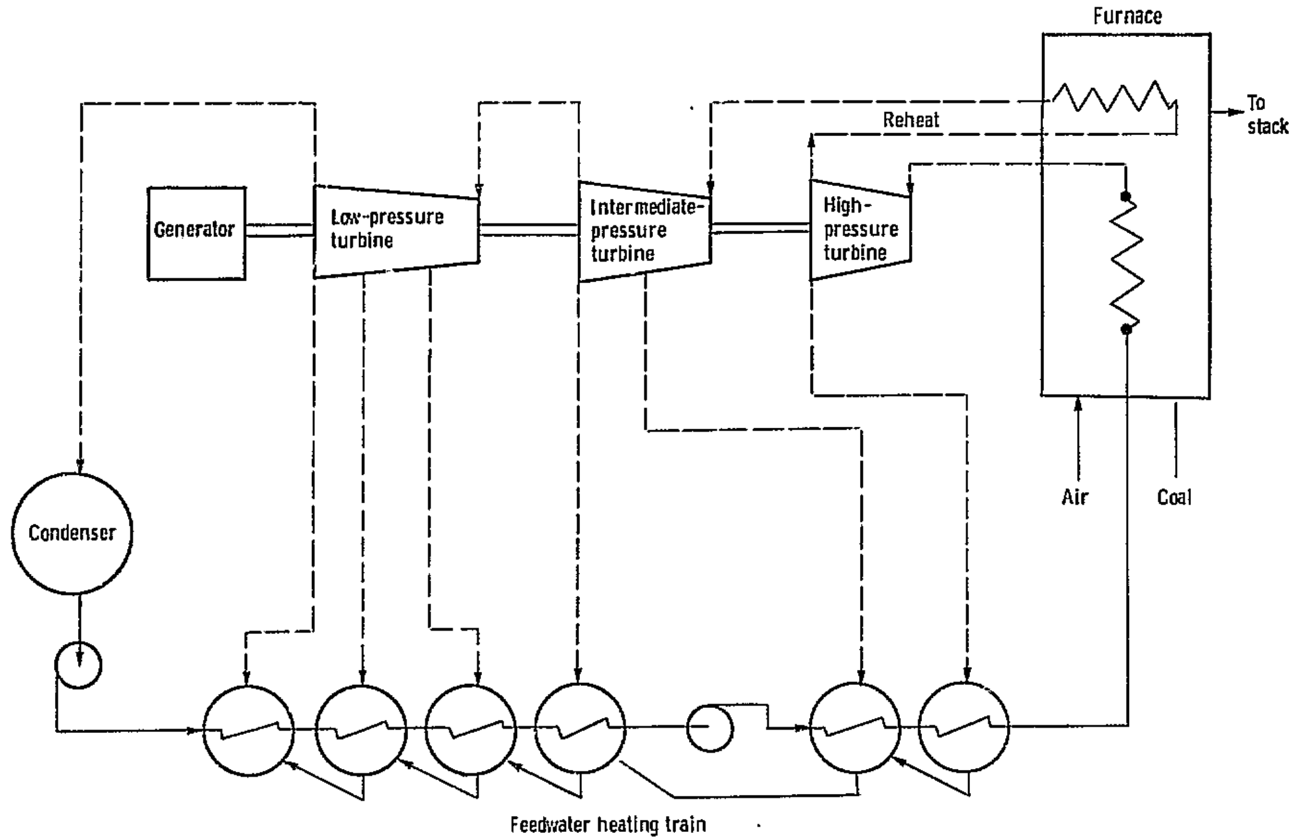

Figure 5.2-1. - Conventional-furnace steam plant.

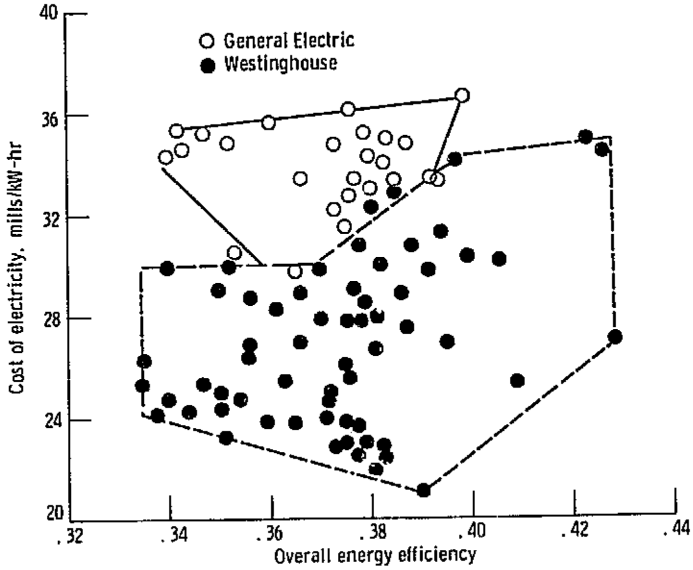

Figure 5.2-2. - Range of General Electric and Westinghouse results for advanced steam systems - both direct coal fired and with integrated gasifiers.

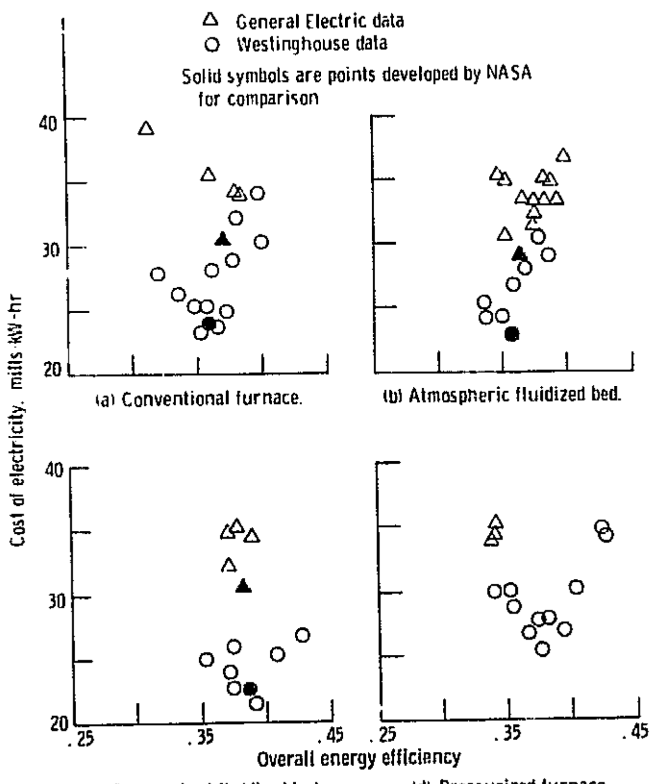

Figure 5.2-3. - Effect of overall energy efficiency on cost of electricity for various furnaces - comparison of General Electric and Westinghouse results.

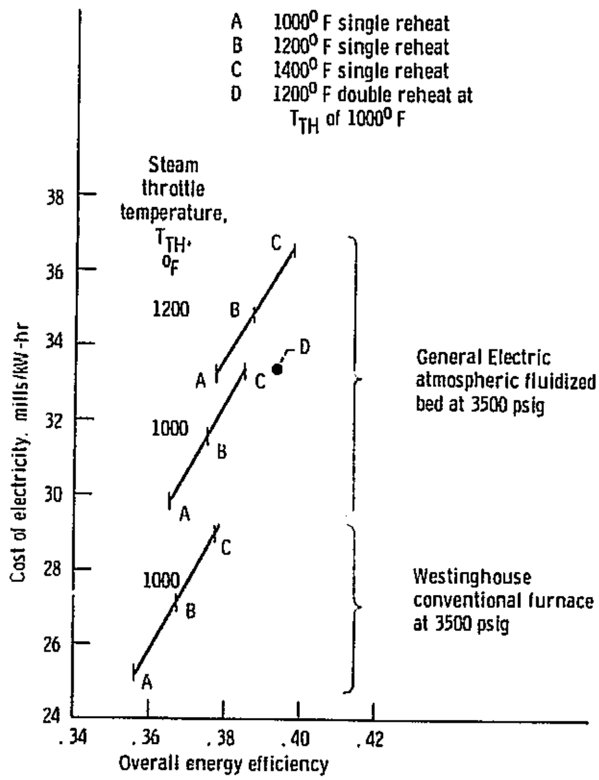

Figure 5.2-4. - Effect of steam throttle and reheat temperatures on cost of electricity for advanced steam plants - comparison of General Electric and Westinghouse results.

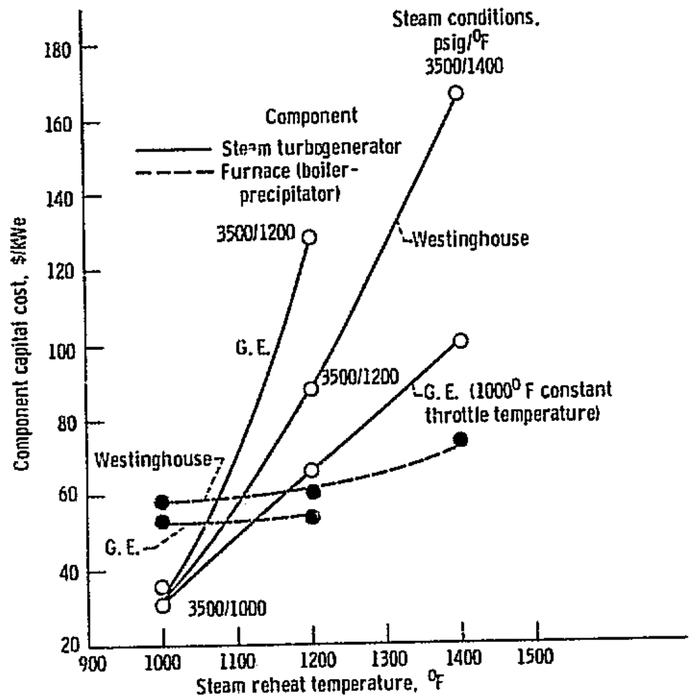

Figure 5. 2-5. - Effect of steam reheat temperature on steam turbogenerator and furnace module costs for atmospheric fluidized bed with 3500-psig single reheat - comparison of Westinghouse and General Electric results. (Westinghouse turbogenerator cost corrected for 1.5-inch-of-Hg condenser pressure.)

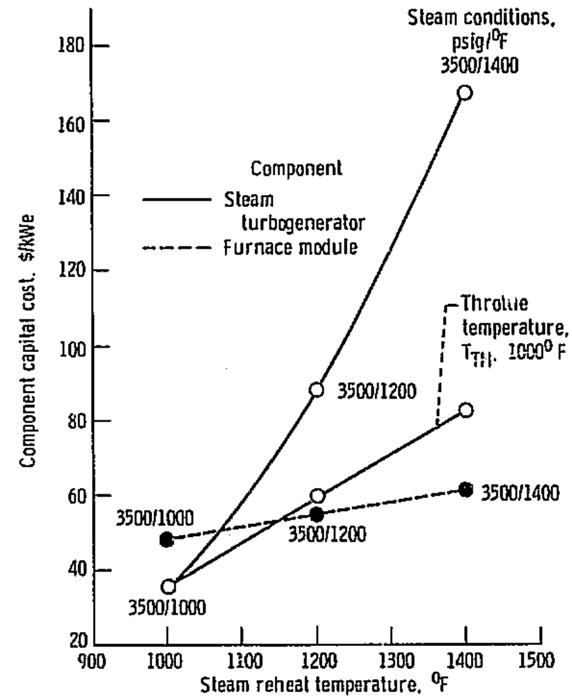

Figure 5. 2-6. - Effect of steam reheat temperature on steam turbogenerator and furnace module costs for conventional furnace with 3500-psig single reheat - Westinghouse results. (Turbogenerator cost corrected for 1. 5-inch-of-Hg condenser pressure.)

5.3 OPEN-CYCLE GAS TURBINES

by John L. Klann, Joseph J. Nainiger, and Paul T. Kerwin

Gas-turbine electric generators are used in the utilities industry mainly for peaking. Most of those in use today are based on the simple gas cycle, that is, without waste heat recovery (recuperation). Their use is attractive because of features such as low capital cost, quick load response, and short construction time. These gas turbines burn either natural gas or petroleum products and operate with temperatures to about 2000° F. However, current gas-turbine powerplants have lower conversion efficiency than steam-cycle powerplants.

In ECAS, gas-turbine powerplants were assessed for base-load power generation with coal-derived fuels. Since these fuels will be expensive, emphasis was placed on improving gas-turbine conversion efficiency. Higher operating temperatures, recuperation, and bottoming cycles were considered by the ECAS contractors in Phase 1. Results for steam-bottomed gas turbines are considered separately in the next section, 5.4 COMBINED-CYCLE GAS TURBINE/STEAM TURBINE SYSTEMS. Overall results for organic-bottomed gas turbines are presented here, with a more detailed discussion in section 5.12 ORGANIC BOTTOMING CYCLES.

5.3.1 Scope of Analysis

Both contractors emphasized the recuperated cycle in their calculations. General Electric calculated a total of 37 cases, of which 26 were for the recuperated cycle, 5 were for the simple cycle, and 6 were for organic-bottomed gas turbines. Westinghouse calculated 97 cases, of which 69 were for recuperated cycles, 25 were for simple cycles, and 3 were for organic bottoming. The schematic in figure 5.3-1 is representative of the recuperative cycle assumed by both contractors. However, there were differences in approach, mainly with regard to (1) the definition of turbine-inlet temperature, (2) recuperator construction, and (3) the suppression of (NOX) in the combustion products. Effects of these differences are discussed in section 5.3.2.

A comparison of the ranges of calculations performed by the contractors is presented in table 5.3-1. Underlined parameters indicate either base-case conditions or emphasis. Both contractors used clean, coal-derived fuels that would be supplied to the powerplant from a remote processing plant rather than produced on the site. General Electric used "high-Btu" gas as a base fuel. Two cases considered coal-derived liquids. Westinghouse used a distillate of coal as a base fuel and included one case with high-Btu gas.

Both contractors assumed a base-case turbine-inlet temperature of 2200° F, a near-term increase over present levels. Bleed air from the compressor was used as the basic method for turbine cooling. Both contractors evaluated performance with uncooled ceramic stator vanes and air-cooled turbine blades. Westinghouse also evaluated the use of both ceramic vanes and blades. In this case, only a small amount of cooling air was needed as a blocking flow to avoid disk and rim overheating. General Electric considered one case with water cooling (simple cycle, table 5.3-1(a)) at a turbine-inlet temperature of 3000° F.

Westinghouse examined most gas-turbine parameter changes over a range in compressor pressure ratio. Ranges in recuperator effectiveness and pressure drop were studied for the base-case turbine-inlet temperature of 2200° F. At other conditions the underlined values of effectiveness and pressure drop(table 5.3-1(b)) were assumed for recuperation. General Electric emphasized slightly higher values for both recuperator effectiveness and pressure drop than did Westinghouse. Westinghouse also examined some effects of intercooling between compressors. Almost all calculations were made for a turbomachinery speed of 3600 rpm.

Both contractors chose to use fixed values of compressor-inlet air mass-flow rate. Westinghouse used 750 lb/sec for all calculations. General Electric used 570 lb/sec for all but three cases: the 3000° F, water-cooled case for the simple cycle, where the flow rate was increased to 700 lb/sec; the 1800-rpm recuperated case, where the rate was 2280 lb/sec; and the 5100-rpm recuperated case, where the rate was 170 lb/sec. The base-case inlet mass-flow rates were chosen mainly because of previous design experience at the resultant frame sizes. Powerplant specific power output, in kW/ (lb/sec), varies with each combination of gas-turbine parameters. Therefore, fixing the values of inlet mass-flow rate results in a variation in gas-turbine unit output. For the simple cycle cases in General Electric's analysis, unit outputs varied from 87 to 212 MW. The corresponding unit outputs for Westinghouse varied from 56 to 122 MW. For the recuperated cycle analyses the unit output ranges were from 25 to 323 MW in the General Electric results and from 60 to 148 MW in the Westinghouse results. General Electric emphasized single gas-turbine units in their analysis. One case for the recuperated cycle (table 5.3-1(b)) considered a powerplant with four units. Westinghouse assumed four gas-turbine units for all but the bottoming-cycle studies (table 5.3-1(c)), where single units were used.

For bottoming cycles, General Electric assumed Fluorinol-85 as the working fluid and studied the bottoming-cycle parameter changes shown in table 5.3-1(c). Westinghouse examined two organic working fluids and sulfur dioxide for the bottoming cycle, mainly to study effects of bottoming-cycle operating temperature level.

5.3.2 Results of Analysis

5.3.2.1 Overall Comparison

Figure 5.3-2 shows the cost of electricity (COE) as a function of overall energy efficiency from both contractors' results. Major parametric variations are shown by circles for the simple cycle, by squares for the recuperated cycle, and by diamonds for the bottomed cycles. Solid symbols are used to indicate the base-case turbine-inlet temperature of 2200° F. Related variations in gas-turbine-inlet temperature and recuperator effectiveness are joined by straight lines. These results are for a 59° F day and a powerplant capacity factor of 0.65.

Although the contractors emphasized different fuels, both the coal distillate (used by Westinghouse) and the high-Btu gas (used by General Electric) were estimated by their respective users to have a conversion efficiency from coal to the fuel form of 0.50. Hence, for most of the data in figure 5.3-2, the powerplant efficiency is twice the energy efficiency. The alternate fuels considered by each contractor were estimated to have coal conversion efficiencies greater than 0.50.

Comparison of similar calculations for the simple and recuperated cycles in figure 5.3-2 shows that, in general, General Electric's COE was about 3 mills/kW-hr higher than Westinghouse's COE; and General Electric's energy efficiency was about 2 percentage points lower than Westinghouse's. The differences in efficiency and COE are considered in more detail in sections

5.3.2.2.1 and 5.3.2.2.2.

Of course, efficiency and total cost of electricity are not the only criteria for evaluation of powerplants. Table 5.3-2 compares some other considerations: namely, capital cost, operation-and-maintenance cost, and estimated time for construction. Ranges in these parameters are presented in the table for both contractors' results as a function of the type of conversion cycle. There are differences between the contractors' results. In general, Westinghouse shows slightly higher capital costs, longer construction times (Westinghouse had 4-unit installations compared with single units for G.E.), and lower operation-and-maintenance charges than does General Electric. These differences are examined in more detail in the section 5.3.2.2.2.

As has been past experience for gas-turbine powerplants, capital costs are projected in these studies to remain low. They appear to be of the order of \$150/kW for simple-cycle plants and of the order of \$200/kW for recuperated-cycle plants. The plants with bottoming cycles have about double the capital costs of the recuperated powerplants without bottoming cycles.

5.3.2.2 Discussion and Assessment

The trends shown in figure 5.3-2 by both contractors are similar. Increasing turbine-inlet temperature to 2600 ° F with air-cooled turbine vanes and blades increases efficiency and decreases the cost of electricity. Because of efficiency penalties in supplying cooling air from the compressor, further increases in temperature offer little or no gains. General Electric's results for the simple cycle show an increased cost and decreased efficiency between 2600° and 3000° F with air cooling.

Both contractors' results show that for similar temperatures the recuperated cycle has a higher efficiency and lower COE.

Although large ceramic vanes are not state of the art, both contractors show reduced cost and increased efficiency for recuperated configurations.

Among the Westinghouse results for the recuperated cycle, the effects of intercooling show a 1.5-percentage-point (or 8 percent) improvement in efficiency and about a 2-mill/kW-hr (or 6 percent) decrease in COE in spite of the added complexity.

In the General Electric results, the data taken with solvent-refined coal (SRC) show the lowest cost of electricity and the highest energy efficiency. However, General Electric estimated that because of high fuel-bound nitrogen, NOX emission standards could not be met with the use of liquid SRC.

General Electric's results show the least COE for a recuperator effectiveness near 0.8. Westinghouse results show that about 0.9 effectiveness yields the least cost. These results are not necessarily in conflict. The value of effectiveness that yields the least cost is strongly dependent on the heat exchanger geometry and the type of construction. Westinghouse assumed a pure plate-fin type of geometry on both the air and gas sides of the recuperator. General Electric used a "strongback" construction with relatively thick spacers on the air side of the recuperator and plate-fin surfaces on the gas side. Hence, the recuperator construction in the Westinghouse approach was lighter than that in the General Electric approach. Because of the lighter construction, there would be a lesser increase in recuperator mass (and cost) with increasing effectiveness. Therefore, the lighter construction should yield the least COE at a higher level of effectiveness. (A more detailed discussion and assessment is presented in section 5.3.2.2.4.)

Results in figure 5.3-2 showed substantial increases in energy efficiency with the addition of organic or sulfur-dioxide bottoming cycles. General Electric results also showed that these higher efficiencies could be obtained at about the same cost of electricity as the recuperated cycle. Westinghouse results showed about a 3- to 4-mill/kW-hr increase over the recuperated-cycle data at similar gas-turbine inlet temperatures.

5.3.2.2.1 Efficiency comparisons. - In general, figure 5.3-2 shows higher efficiencies for the Westinghouse results than for the General Electric results. Figure 5.3-3 further expands on the performance differences for the recuperated-cycle base-case conditions over the calculated range in compressor pressure ratio. The difference between peak thermodynamic efficiencies is 3 percentage points. Also, General Electric's results showed about an 11 percent higher specific output than Westinghouse's results.

Details of the contractors' approaches and cycle parameter assumptions were examined for differences. Table 5.3-3 lists those that were identified by NASA as the major reasons for the performance differences between the contractors. To illustrate this, parallel calculations using each of the contractor's parameters were made at the Lewis Research Center. Because of the proprietary data, such as cooling schedules, the NASA calculations were made to illustrate the trends and effects of differences in approach and not to duplicate the contractor results.

Performance factors used in the NASA calculations are listed in table 5.3-4. Calculation A parallels the Westinghouse conditions (table 5.3-3) and calculation B parallels the General Electric conditions. Each parameter change between A and B was calculated separately, and the results are discussed in the following paragraphs. Effects of each parameter change on efficiency and specific output are listed in table 5.3-5 and the overall results, plotted in figure 5.3-4, show that the Lewis calculations approximate the differences in efficiency and the trends in specific output in the contractor's results.

The fuels that were used by the contractors introduced performance differences mainly because of differences in heating values (section 4.1). The size of the performance difference (table 5.3-5) is also larger than would be expected in practice because of the use of the higher heating value as specified in the common ground rules. Combustion of high-Btu gas forms more water vapor than combustion of coal distillate. And because of the high temperature of the exhaust the water vapor is not condensed and its energy is not recovered. The NASA calculations (table 5.3-4) approximated coal distillate with kerosene, which has similar heating values and composition.

Westinghouse defined turbine-inlet temperature at the inlet to the first-stage nozzle. However, General Electric defined turbine-inlet temperature at the exit plane of the first-stage nozzle vanes (footnotes, table 5.3-3). The temperature is higher at the inlet to the nozzles than at the exit because of the cooling flow introduced in these vanes. According to an NASA cooling schedule, a 2260° F firing temperature yielded a 2200° F temperature at the first-stage nozzle exit.

Differences between the contractors' base-case recuperator parameters are shown in table 5.3-3 and were accounted for in the similar Lewis calculations.

A further difference between contractors occurred because General Electric used water injected into the combustor to control NOX formation and thus meet environmental standards. Westinghouse evaluated the NOX problem and determined that a two-stage dry combustor would be required to control NOX. The Westinghouse results for ECAS Phase 1 do not include performance or cost penalties associated with NOX control. Environmental standards would probably be exceeded for all turbine-inlet temperatures above 1800° F.

One of General Electric's analytical assumptions was that cooling-flow mass was added behind the turbine-stage buckets. This implied that nozzle cooling flow contributed no stage work. Westinghouse did calculate the added stage work. Similar assumptions were made in NASA calculations A and B.

Examination of the incremental effects of these differences (table 5.3-5) showed that the differences in fuel, water injection, and stage-cooling work were dominant. The effects of differences in turbine-inlet temperature and recuperator parameters were small. The NASA calculations duplicated the 3-percentage-point difference in efficiency between the contractors' results. The change in specific output was smaller in the NASA calculations than between the contractors' results, but it did verify the trend.

5.3.2.2.2 <u>Cost comparisons</u>. - In general, it is difficult to make any judgments in comparing contractor capital and O and M cost estimates. There are many factors in the estimating process in which one may be more conservative than the other. Furthermore, in the Phase 1 effort both contractors were faced with scaling existing data over large ranges and into unknown areas. Cost comparisons were made to show where differences exist but not necessarily to resolve them.

Table 5.3-6 presents a comparison of performance factors between the recuperated-cycle base cases. The total cost of electricity between the cases differs by about 10 percent. Most of this difference is in the fuel cost, which is due to the difference in powerplant efficiency. The Westinghouse capital costs are about 20 percent greater than those of General Electric. However, the operation-and-maintenance (O and M) cost estimates are reversed, with General Electric's estimate three times that of Westinghouse. Hence, the sums of capital and O and M costs were about the same.

Although O and M charges are a small part of the estimated cost of electricity, the factor-of-3 difference seems large. Part of this difference in O and M cost may be due to Westinghouse's use of a four-unit, larger-output plant than General Electric's single-unit plant. The O and M charge for General Electric's four-unit case was 1.6 mills/kW-hr. This brings the O and M charges closer, but they still differ by a factor of more than 2. Westinghouse generated an empirical equation for O and M costs that was only a function of capacity factor. Therefore, for a fixed capacity factor, the O and M cost was constant. General Electric's approach was to estimate the O and M cost as a certain number of dollars per year for each powerplant, depending on the fuel and operating temperatures. Therefore, the General Electric O and M cost, within similar parametric variations, was a function of both capacity factor and power level. Adjusting General Electric's four-unit O and M cost to the same power level as Westinghouse's base case yields 1.3 mills/kW-hr. Hence, after adjustments, the O and M costs appear to differ by less than a factor of 2.

From table 5.3-6, it would appear that the capital cost estimates for the recuperated, open-cycle, gas-turbine plants are in reasonable agreement. However, there are some rather large differences in some of the components of capital cost; namely, in direct costs for the balance-of-plant assembly and installation.

Table 5.3-7 presents a breakdown of the capital cost factors in dollars per kilowatt. The levels of breakdown are by direct costs, indirect costs, and escalation and interest costs during construction. The escalation and interest cost factors were 12 percent of the total capital cost for the General Electric case and about 19 percent for the Westinghouse case. The same rates were used by both contractors, and most of the difference here is due to the differences in estimated time of construction (table 5.3-6).

The indirect costs and other charges are mainly a matter of bookkeeping. Individual rates for the indirect costs were different with each contractor. However, the sums of the indirect costs in table 5.3-7 are approximately the same. Most of the actual difference between contractor estimates, then, is in direct costs.

Major component costs as reported by the contractors for their base cases are nearly identical: $101.7/kW for General Electric and $99.5/kW for Westinghouse. This is somewhat misleading in two ways. First, there were differences in recuperator construction and design parameters. (These differences are assessed in section 5.3.2.2.4.) Second, there were differences in major-component cost accounting. General Electric's results were for the cost of the gas turbine delivered to the plant site. Remaining costs of material and labor to install the gas turbine were part of the balance-of-plant costs. Westinghouse major-component costs were for materials only. Labor costs for assembly and installation were part of the balance-of-plant labor cost.

The direct costs shown in table 5.3-7 have been adjusted so that the major-component costs for both contractors include all material and labor costs for installation of the gas turbine. Even after these adjustments were made, major-component costs were very close and did not account for the difference in capital cost estimates between contractors. The difference, then, was mainly because of direct balance-of-plant costs. Westinghouse's balance-of-plant costs were 2.2 times those of General Electric. Comparison of other cases showed similar differences in direct balance-of-plant costs.

No reason could be found that would totally resolve the differences in direct balance-of-plant costs. Westinghouse's use of coal distillate does require a fuel-oil handling system and storage tanks. However, the handling system was only 2.6 percent of the total direct cost, and the storage need would not influence the total by more than 2 or 3 additional percent.

5.3.2.2.3 Alternate considerations. - The following alternatives were considered:

5.3.2.2.3.1 Use of a pressurized fluidized bed combustor: The contractor results and the comparison of data in this report indicate a substantial penalty for the open-cycle gas turbine introduced by the requirement for a processed fuel. The processing efficiency dramatically reduced overall efficiency, although COE remained attractive. There are at least two options for direct firing of an open-cycle gas turbine with coal: a modularized gasifier or a PFB combustor. Neither of these options was included in ECAS. To provide insight into the potential for this class of system, Lewis performed a cursory evaluation of the PFB combustor, stand-alone open-cycle gas turbine. Such a combination would increase capital cost, but it would also improve overall energy efficiency by eliminating the fuel conversion inefficiency. Such configurations have been considered in ECAS, for several systems, as the pressurizing loop for pressurized fluidized-bed combustors; however, they were not considered as a stand-alone powerplant. The staff at Lewis has made some estimates of the performance of such a powerplant, as summarized in table 5.3-8.

A turbine-inlet temperature of 1800° F was assumed along with a recuperator effectiveness of 0.80. The recuperator pressure drop (delta P/P) was 0.04. The pressurized fluidized-bed combustor was assumed to have a heat loss of 5 percent and a pressure drop (delta P/P) of about 0.13. An operating compressor pressure ratio of 8 was chosen and resulted in an overall energy efficiency of 0.32 as shown in table 5.3-8. Four gas turbine units were used, each fed by three fluidized-bed combustors. Total powerplant output was 276 MW. Direct costs were scaled from Westinghouse's Phase 1 results, and Westinghouse's charge rates for indirect costs were used, except for the contingency cost, which was assumed to be 20 percent (rather than 6.5 percent as in the Westinghouse approach) of the total direct cost. The total capital cost was estimated to be $490/kW (or 15.5 mills/kW-hr). This is from 2.5 to 3 times the capital cost of the contractors' recuperated clean-fuel-fired base cases (table 5.3-6).

The fuel cost was 9.0 mills/kW-hr using Illinois #6 coal, which is 60 to 65 percent lower than the base cases in table 5.3-6. Hence, the reduction in fuel charge more than offset the increase in capital charge. The O and M charge was taken as 1.8 mills/kW-hr, such that the total cost of electricity was 26.3 mills/kW-hr. Hence, these estimates show a 13- to 14-percent decrease in the cost of electricity compared with table 5.3-6 and 5 percent lower th- the lowest COE determined.

A majo. uncertainty in such a configuration is the effectiveness of the particulate removal system required for the turbine-inlet gas. However, the requirements are no more severe than those for the pressurized fluidized-bed boilers in steam power systems or for pressurized fluidized-bed gasifiers. Because of the requirement for larger amounts of excess air, the cleanup system flow rate per unit of coal flow is higher for the stand-alone, open-cycle, gas-turbine system. An estimate of the impact on cost has been included in the estimates in table 5.3-8.

The pressurized fluidized-bed and the required particulate removal systems require further investigation. The results in table 5.3-8 indicate that it might be a possible alternative to either the clean-fuel-fired gas turbine or the open-cycle gas-turbine combined with a steam-bottoming cycle and fed by an integrated gasifier. It has a higher overall energy efficiency than clean-fuel-fired turbines, and it has the potential for more operational and/or siting flexibility than an integrated-gasifier turbine system, with competitive cost of electricity.

5.3.2.2.3.2 Performance effects of technology advancements: The effects of several potential technology advancements were not evaluated in ECAS Phase1. The relative cycle performance effects of some selected potential improvements were calculated by the Lewis Research Center and are documented here for an initial assessment of future impact on open-cycle, gas-turbine powerplants. The cost effectiveness of these advancements was not evaluated.

Results of the NASA calculations are presented in figure 5.3-5. The NASA base-case cycle assumptions were somewhat arbitrary: turbine-inlet temperature, 2260° F; recuperator effectiveness, 0.85; relative recuperator pressure drop (delta P/P), 0.03; and turbine and compressor polytropic efficiency, 0.90. Furthermore, the base case assumed the turbine material to be Inconel-738.

Figure 5.3-5(a) shows the relative effects of a change in turbine alloy and the combination of a change in alloy and precooling the compressor bleed flow before using it for turbine cooling. The advanced turbine alloy was Rene-120.

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Because of its higher strength at a turbine-inlet temperature of 2260° F and its correspondingly lower turbine cooling-air requirement, thermodynamic efficiency was increased. For gas turbines operating at a pressure ratio of 10, efficiency would increase by 1.1 percentage points and specific output would increase by about 5 percent. The compressor bleed flow was assumed to be cooled to 200° F before its use in the turbine. Again at a pressure ratio of 10, the gain in efficiency would be 0.4 percentage point and the increase in specific output would be about 2.5 percent.

Figure 5.3-5(b) shows the effects of using a barrier coating on turbine vanes and blades made of Inconel-738. The coating was assumed to be zirconia, 0.015 inch thick. This coating is being investigated at Lewis. At the temperatures assumed here, it has a thermal conductivity of 0.6 Btu/hr/ft/° F. Its use in the NASA calculations at a constant turbine-inlet temperature of 2260° F cut the required turbine cooling flow about 50 percent. The results in the figure show that at a pressure ratio of 10, the efficiency gain was 1 percentage point, while the specific output increase was about 5 percent. At higher firing temperatures, the impact will be larger.

Figure 5.3-5(c) shows the effects of increased turbine and compressor polytropic efficiency. Two step changes are shown from the base-case value of 0.90; an increase in turbine efficiency to 0.92 while holding compressor efficiency at 0.90; and an increase of both efficiencies to 0.92. Each change, at a compressor pressure ratio of 10, showed about a 1-percentage-point increase in efficiency and a 3-percent increase in specific output over the previous case. These curves show the sensitivity of cycle performance with respect to attainable levels of small-stage or polytropic efficiency.

The potential advances shown in the curves of figure 5.3-5 demonstrate that gas-turbine technology is dynamic and that, with development, future improvements in performance may be expected. Successful application of advanced turbine alloys with thermal-barrier coatings might allow two avenues for growth: namely, either higher operating temperatures with relatively clean fuels and without excessive cooling-flow penalties, or operation at conventional temperatures with greater resistance to the corrosive products from a coal-fired, fluidized-bed combustor.

5.3.2.2.4. Recuperator. - The recuperator represents a major cost item in the open-cycle gas-turbine system. For the respective base cases, General Electric shows a cost increase of $41/kWe when adding a recuperator to the simple cycle. The Westinghouse results show a capital cost increase of $24/kWe. However, the base-case effectiveness for Westinghouse is 0.80, compared with 0.85 for General Electric. Although the recuperator adds to the plant cost, its addition increases cycle efficiency sufficiently to reduce the cost of electricity. Both contractors show a reduction of 3 mills/kW-hr for the recuperated cycle compared with the simple cycle.

Westinghouse included recuperator costs as a line item, while General Electric included the recuperator cost with the turbomachinery and generator. However, by subtracting the simple-cycle turbomachinery and generator costs from the recuperated-cycle costs, a rough estimate of recuperator cost can be deduced.

Both contractors used pure counterflow plate-fin construction. Westinghouse used a compact (large heat transfer area per unit volume) surface on both the air and gas sides. However, for G.E. cases, a construction similar to the recuperator for the G.E. 7001R was the basis of cost and size estimates. This new 7001R industrial recuperator is quite similar to the "strongback" construction developed by Harrison Radiator, Inc. The heat transfer surface used by Westinghouse is more dense, that is, it has more area per unit volume than the General Electric surface.

The selection of heat transfer surface has an effect on recuperator cost and size. In general, the denser surface will cost more per unit of volume but will require a smaller volume or weight. As has been discussed earlier, the surface or type of construction selected influenced the system results. For an application, there is an optimum heat-exchanger surface that results in minimum component cost. A recuperator core optimization was beyond the scope of Phase 1. Therefore, the contractors selected configurations that they believed would meet the system requirements at a reasonable cost.

The design parameter having the greatest effect on recuperator size and therefore cost is the recuperator effectiveness. Within the range studied, results of both contractors have shown that pressure drop ratio has only a small effect on recuperator cost. The recuperator heat transfer area is related to effectivenss in a dimensionless parameter called the number of thermal units transferred (NTU) by Kays and London (ref. 6). The NTU's relate effectivness to core heat transfer area; but if a fixed type of surface is used and end sections and manifolds (i.e., wrap-up) are a constant fraction of the core, the total volume or cost is also directly related to effectiveness. The required NTU's are also a function of working-fluid flow rate. Therefore, care was taken to choose cases for comparison that had a constant power-to-flow ratio. Varying effectiveness varies efficiency by reducing required thermal input rather than flow rate.

Recuperator cost as a function of effectiveness is presented in figure 5.3-6 for both contractors. The costs shown for both contractors include the recuperator and associated ducting. The ducting costs should not vary significantly with effectiveness so that the data shown tend to underestimate the variation in cost of the recuperator alone. Data for G.E. costs were deduced from a comparison of recuperated and nonrecuperated systems. As effectiveness increases, recuperator cost also increases, as would be expected. The General Electric cost trend shown is much steeper than the Westinghouse curve. This is the primary reason that the minimum cost of electricity occurs at a lower value of effectiveness for General Electric.

The NTU relation for a counterflow configuration indicates that the recuperator should be approximately twice the size for an effectiveness of 0.90 as for an effectiveness of 0.80. In this same range the General Electric cost increases by a factor of 3.66, but the Westinghouse cost by only 1.68. The General Electric costs increase more rapidly than would be indicated by the NTU relation between 0.80 and 0.90. The Westinghouse costs increase less than would be indicated by the NTU's over the same range. Between effectiveness values of 0.90 and 0.95, the General Electric costs increase less than would be indicated by the NTU relation.

To enlarge the data base on recuperators, study efforts were let to AiResearch Manufacturing Company and Zurn Industries, Incorporated, through an NASA contract with Burns and Roe. AiResearch provided recuperator design and cost information relative to plate-fin units, and Zurn provided similar information for shell-and-tube construction. Since the results of the AiResearch and Zurn studies were intended for general use in the in-house studies, there is not a direct correspondence with the General Electric and Westinghouse cycle points. The data were used as a basis for sizing and costing relations.

5.3.2.2.4.1 Plate fin: The selection of the fin matrix geometry was based on providing passages large enough to pass particulate cleaning agents typically used for industrial gas turbines. The gas-side matrix has a fin height of

C.2

0.55 inch and a pitch of 6 fins per inch. The selected materials of construction were AISI-409 at metal temperatures up to 1000° F and AISI-201 above 1000° F. Design and costing were based on use of a single material within a recuperator. Using bimetallic plates or varying fin material at lower temperatures in a single unit was not considered. Likewise no consideration was given to the use of a high-temperature and a low-temperature recuperator in series. Such a series arrangement would take advantage of lower cost materials as temperature decreases but would require additional manifolds, ducts, and end sections.

5.3.2.2.4.2 Shell and tube: Zurn used a conventional shell-and-tube heat-exchanger construction for the open-cycle recuperator. The overall flow configuration was counterflow, with the exhaust gas in the tubes and the air on the shell side. The tubes were arranged in a single pass through the unit, while the shell side was baffled to form a number of crossflow passes. A core matrix of plain tubes having a 2-inch outer diameter placed on 2.25-inch-square pitch to facilitate cleaning was selected. Finned surfaces were not considered. Since shell diameter was limited to less than 8 feet (fabrication limit based on Zurn plant capacity), a number of parallel units were required. Only a single unit was used in the flow direction.

While a single tube material was used for a particular recuperator, the tube sheet and shell materials were graded according to temperature. For metal temperatures below 1100° F, the selected tube material was 1.25 chromium-0.5 molybdenum. In the range of 1100° to 1300° F, 304 stainless steel tubes were used. The shell material in a particular unit was varied as follows: carbon steel up to 950° F, carbon-0.5 molybdenum between 950° and 1050° F, 1.25 chromium-0.5 molybdenum from 1050° to 1200° F, and 304 stainless steel above 1200° F.

Comparison of the AiResearch and Zurn results indicates that from the standpoint of weight, volume, and cost the plate-fin recuperator is preferred for the open-cycle system.

The plate-fin recuperators range from 2.5 to 6 times more expensive than the shell-and-tube units on a per pound of fabricated heat-exchanger basis, with the greatest difference being at low temperatures. This is due primarily to the higher cost of fabricating the finned surface and assembly. However, because the plate-fin surface has considerably more heat transfer area per unit of weight or volume, the cost per unit of area is less for the plate-fin recuperator. The cost of a plate-fin recuperator ranges from 50 percent of the cost of a shell-and-tube unit, sized for the same conditions, at low temperatures to only about 20 percent when 304 stainless steel tubes are used.

It is therefore apparent that the ECAS contractors were well justified in their selection of plate-fin core geometry.

One set of design conditions given to AiResearch corresponded to the General Electric base case. This was done primarily to determine what improvements could be realized by deviating from the traditional industrial recuperator plate-fin surface. AiResearch used the offset-fin surface described earlier. The General Electric base-case recuperator was estimated by NASA to cost $2.1 million and to weigh 440,000 pounds. AiResearch estimated that with the more compact surface the weight could be reduced to 276,000 pounds at a cost savings of approximately 30 percent.

5.3.3 Concluding Remarks

The dominant portion of the cost of electricity produced by gas turbines in

ECAS was the fuel cost. Hence, the contractors in ECAS Phase 1 emphasized methods for improving gas-turbine conversion efficiency. It was shown that increasing operating temperatures, with air cooling, was economically beneficial up to about 2600° F. Incorporation of ceramic vanes or ceramic vanes and blades would reduce air-cooling needs and would further reduce the cost of electricity and increase gas-turbine efficiency. However, new technology is needed to develop large static and rotating ceramic blades.

Both contractors showed that recuperated gas-turbine powerplants operating at a turbine-inlet temperature of about 2200° F offer attractive COE for near-term use. For clean coal-derived fuels delivered to these powerplants, the cost of electricity was projected to be near 30 mills/kW-hr. The addition of compressor intercooling was shown by Westinghouse to further decrease the cost of electricity by about 6 percent. Projected capital costs for these types of powerplants are in the range of about $150/kW to $200/kW.

With higher operating temperatures the formation of nitrous oxides may become a problem. General Electric chose water injection at the combustor to control NOX formation and meet environmental standards. This is currently the accepted and near-term approach to the problem. However, as was shown by NASA, there are efficiency penalties associated with this approach. Additional research and technology could offer a better solution for conventional combustors through prevaporization and/or premixing of the fuel.

Potentials of incorporating organic bottoming cycles with gas turbines were also addressed here by the ECAS contractors. Both showed substantial increases in conversion efficiency with these techniques. However, capital costs were about doubled with the addition of the bottoming cycle and its related BOP. The resultant effect was no net reduction in the projected cost of electricity.

Some estimates were made by the Lewis staff for a gas-turbine case with pressurized-fluidized-bed combustors in a stand-alone powerplant. Although the capital cost increased by about 2.5 times that of conventional gas-turbine systems, the fuel charge was reduced by about 60 percent. The net result was a projected cost of electricity of about 26 mills/kW-hr.

Some further effects of technology advancements on gas-turbine performance were calculated by the Lewis Research Center. Successful application of advanced turbine alloys, thermal barrier coatings, and improved component efficiencies were shown to offer potential improvements in gas-turbine efficiency and specific power output.

TABLE 5.3-1. - COMPARISON OF RANGES OF MAJOR PARAMETERS INVESTIGATED FOR OPEN-CYCLE GAS TURBINES

[Underlined parameters denote base-case conditions or emphasis.]

(a) Simple cycle

Parameter	General Electric conditions	Westinghouse conditions
Fuel	High-Btu gas	Coal distillate
Turbine-inlet temperature, °F	[a]<u>2200</u>; [a]2600; [a]3000	[b]1800; [b]2000; [b]<u>2200</u>; [b]2500
Pressure ratio	<u>12</u>; 16	6; 8; 10; 12; 16; 20; 24
Cooling method	Air; water; ceramic vanes	Air
Machinery speed, rpm	3600	3600
Inlet mass-flow rate, lbm/sec	<u>570</u>; 700	750
Number of units	1	4

(b) Recuperated cycle

Parameter	General Electric conditions	Westinghouse conditions
Fuel	<u>High-Btu gas</u>; coal liquids	<u>Coal distillate</u>; high-Btu gas
Turbine-inlet temperature, °F	[a]1800; [a]2000; [a]<u>2200</u>; [a]2600	1800; 2000; <u>2200</u>; 2500
Pressure ratio	8; <u>12</u>; 16	6; 8; <u>10</u>; 12; 16; 20; 24
Recuperator effectiveness	0.8; <u>0.85</u>; 0.9; 0.95	0.7; <u>0.8</u>; 0.9
Cooling method	Air; ceramic vanes	<u>Air</u>; ceramic vanes; ceramic vanes and blades
Intercooling temperature, °F	------------------------	92
Machinery speed, rpm	1800; <u>3600</u>; 5100	3600
Recuperator pressure drop, $\Delta P/P$	0.03; <u>0.05</u>; 0.07; 0.09	0.02; <u>0.03</u>; 0.04
Inlet mass-flow rate, lbm/sec	170; <u>570</u>	750
Number of units	<u>1</u>; 4	4

(c) Gas turbines with organic or SO_2 bottoming cycles

Parameter	General Electric conditions	Westinghouse conditions
Bottoming-cycle fluid	Fluorinol-85	R-12; methylamine; SO_2
Bottoming-cycle turbine-inlet temperature, °F	600	[c]400; [c]600; [d]1000
Boiler pinch-point, ΔT, °F	<u>30</u>; 50; 70	[d]55; [c]180 (supercritical, cold-end ΔT)
Boiler hot-end ΔT, °F	[e]113; 227; 230	100
Boiler gas-side pressure drop, $\Delta P/P$	<u>0.02</u>; 0.05	0.05
Cooling-tower type	Dry; wet	Wet

[a]Defined at exit of first-stage nozzles.
[b]Defined at inlet to first-stage nozzles.
[c]Base-case recuperated gas-cycle conditions apply, except turbine-inlet temperature was 2000° F, pressure ratio was 8, and single unit was used.
[d]Base-case recuperated gas-cycle conditions apply, except turbine-inlet temperature was 2500° F, pressure ratio was 16 (simple cycle), and single unit was used.
[e]Base-case recuperated gas-cycle conditions apply, except turbine-inlet temperature was 1800° F.

TABLE 5.3-2. - COMPARISON OF ESTIMATED RANGES IN PERFORMANCE FACTORS FOR OPEN-CYCLE GAS TURBINES

Cycle type	Performance factor	General Electric range	Westinghouse range
Simple	Capital cost, \$/kWe	99 - 138	166 - 189
	Operation-and-maintenance cost, mills/kW-hr	1.5 - 2.0	0.7
	Construction time, yr	1	~2.5
Recuperated	Capital cost, \$/kWe	148 - 216	190 - 224
	Operation-and-maintenance cost, mills/kW-hr	1.6 - 2.9	0.7
	Construction time, yr	1 or 2	~2.5
Bottomed	Capital cost, \$/kWe	334 - 427	432 - 454
	Operation-and-maintenance cost, mills/kW-hr	2.5 - 3.5	0.6
	Construction time, yr	2	3.5 - 4.0

TABLE 5.3-3. - MAJOR PERFORMANCE FACTOR DIFFERENCES BETWEEN CONTRACTORS' RECUPERATED OPEN-CYCLE-GAS-TURBINE BASE CASES

Performance factor	General Electric conditions (case 6)	Westinghouse conditions (case 1)
Fuel	High-Btu gas	Coal distillate
Turbine-inlet temperature, ^{o}F	[a]2200	[b]2200
Recuperator		
Effectiveness	0.85	0.80
Pressure drop, $\Delta P/P$	0.05	0.03
NOX suppression	Water injection	None
Stage work due to its cooling flow	No	Yes

[a]Defined at exit of first-stage nozzles.
[b]Defined at inlet to first-stage nozzles.

TABLE 5.3-4. - NASA RECUPERATED OPEN-CYCLE-GAS-TURBINE CALCULATIONS TO SHOW EFFECTS OF DIFFERENCES IN CONTRACTORS' PERFORMANCE FACTORS

Performance factor	NASA calculation	
	A	B
Fuel	Kerosene	High-Btu gas
Turbine-inlet temperature,[a] °F	2200	2260
Recuperator		
Effectiveness	0.80	0.85
Pressure drop, $\Delta P/P$	0.03	0.05
NOX suppression	None	Water injection
Stage work due to its cooling flow	Yes	No

[a]Defined at inlet to first-stage nozzles.

TABLE 5.3-5. - INCREMENTAL EFFECTS OF PERFORMANCE-FACTOR CHANGE ON EFFICIENCY AND SPECIFIC OUTPUT OF RECUPERATED OPEN-CYCLE GAS TURBINES

[NASA calculations; compressor pressure ratio, 10.]

NASA calculation	Performance factor changed	Thermodynamic efficiency, η_t	Change in η_t caused by change in performance factor, $\Delta\eta_t$	Specific output, P_N/m_c, kW/(lb/sec)	Change in P_N/m_c caused by change in performance factor, $\Delta(P_N/m_c)$
A		0.381		140.6	
	Fuel		-0.013		+3.4
	Turbine-inlet temperature		0		+3.8
	Recuperator		+0.004		-2.5
	Water injection		-0.011		+5.1
	No stage cooling work		-0.011		-4.9
	Total		-0.031		-4.9
B		0.350		145.5	

TABLE 5.3-6. - COMPARISON OF BASE-CASE RESULTS FOR

RECUPERATED OPEN-CYCLE GAS TURBINES

Performance factor	General Electric case 6	Westinghouse case 1
Powerplant efficiency	0.34	0.38
Energy efficiency	.17	.19
Power output, MW/unit	83	99
Number of units	1	4
Capital cost, $/kW	167	201
Cost of electricity, mills/kW-hr:		
Fuel	25.8	23.5
Capital	5.3	6.4
Operation and maintenance	2.1	.7
Totals	33.2	30.6
Estimated time of construction, yr	1	2.5

TABLE 5.3-7. - BREAKDOWN AND COMPARISON OF CAPITAL COSTS FOR RECUPERATED OPEN-CYCLE-GAS-TURBINE BASE CASES

Cost factor	General Electric		Westinghouse	
	Cost, $/kWe			
Direct costs:				
Major components[a]	104.7		109.6	
Balance of plant:				
Materials		12.0		22.3
Labor		1.6		7.7
Subtotal	13.6		30.0	
Total	118.3		140.6	
Indirect costs:				
Indirect labor		3.1		9.1
A-E services		3.0		11.2
Contingency		24.7		7.7
Subtotal	30.8		28.0	
Total	149.1		168.6	
Escalation and interest costs	18		33	
Grand total	167.1		201.6	

[a]Major-component costs shown here include the material and labor costs for installation.

TABLE 5.3.8. - LEWIS ESTIMATE OF RECUPERATED OPEN-CYCLE-GAS-TURBINE POWERPLANT USING A PRESSURIZED-FLUIDIZED-BED COMBUSTOR

Powerplant efficiency	0.32
Energy efficiency	0.32
Power output, MW/unit	69
Number of units	4
Capital cost, $/kWe	490
Cost of electricity, mills/kW-hr:	
Fuel	9.0
Capital	15.5
Operation and maintenance	1.8
	26.3
Estimated time of construction, yr	2.5

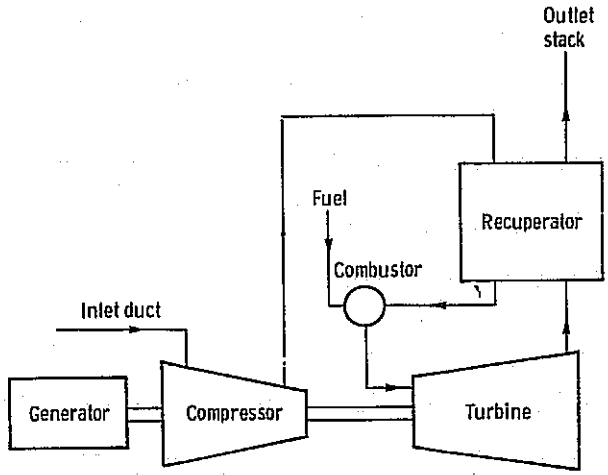


Figure 5.3-1. - Schematic diagram of recuperated gas turbine.

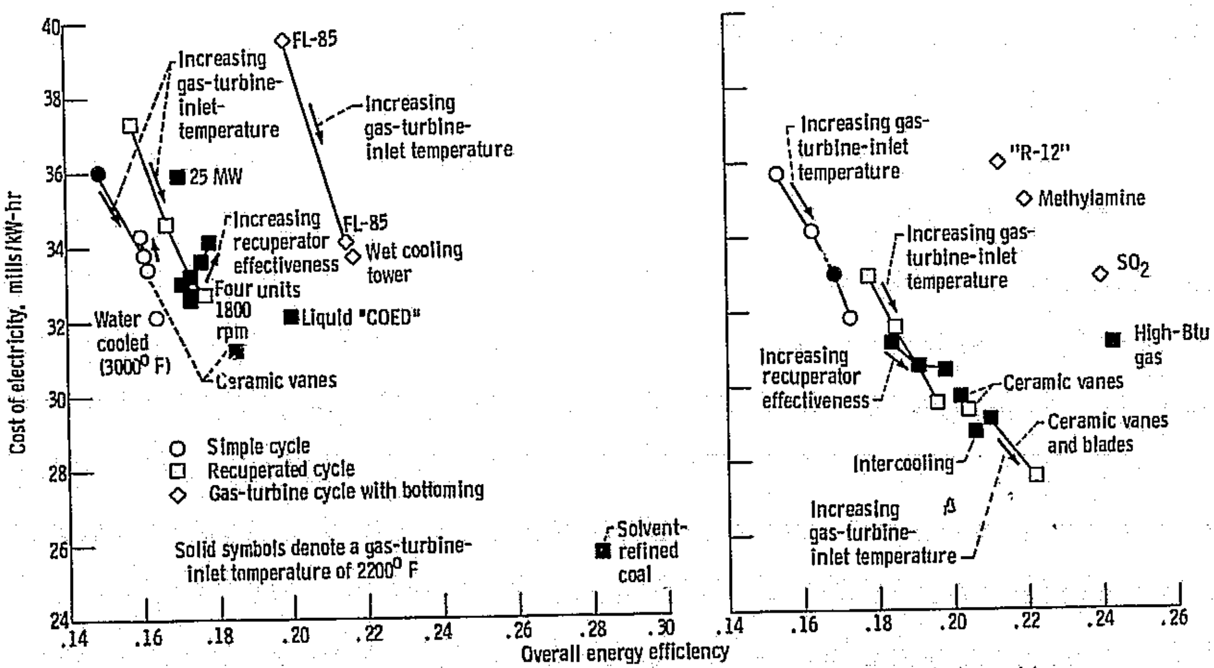


Figure 5.3-2. - Overall results - cost of electricity as function of energy efficiency.

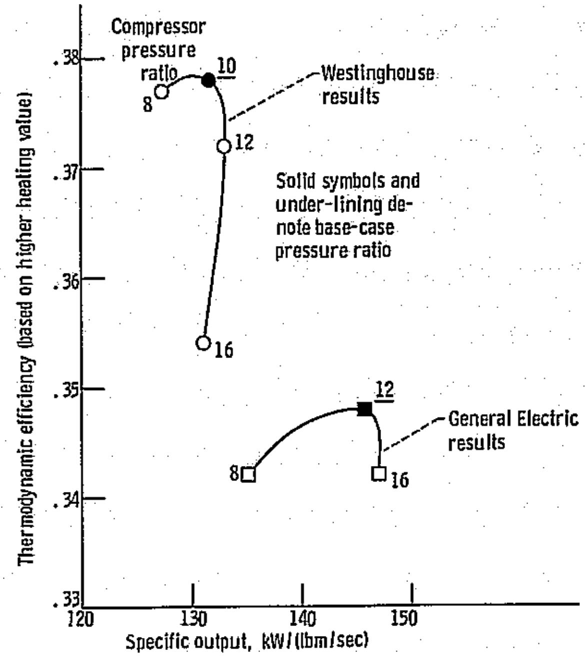


Figure 5.3-3. - Cycle performance for contractors' recuperated base cases (table 4.2-3).

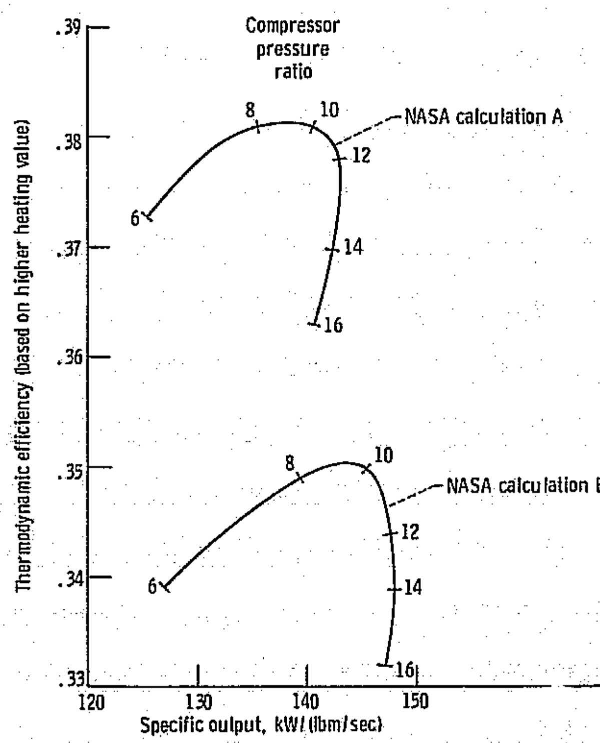


Figure 5.3-4. - Comparison of NASA cycle calculations (table 5.3-3).

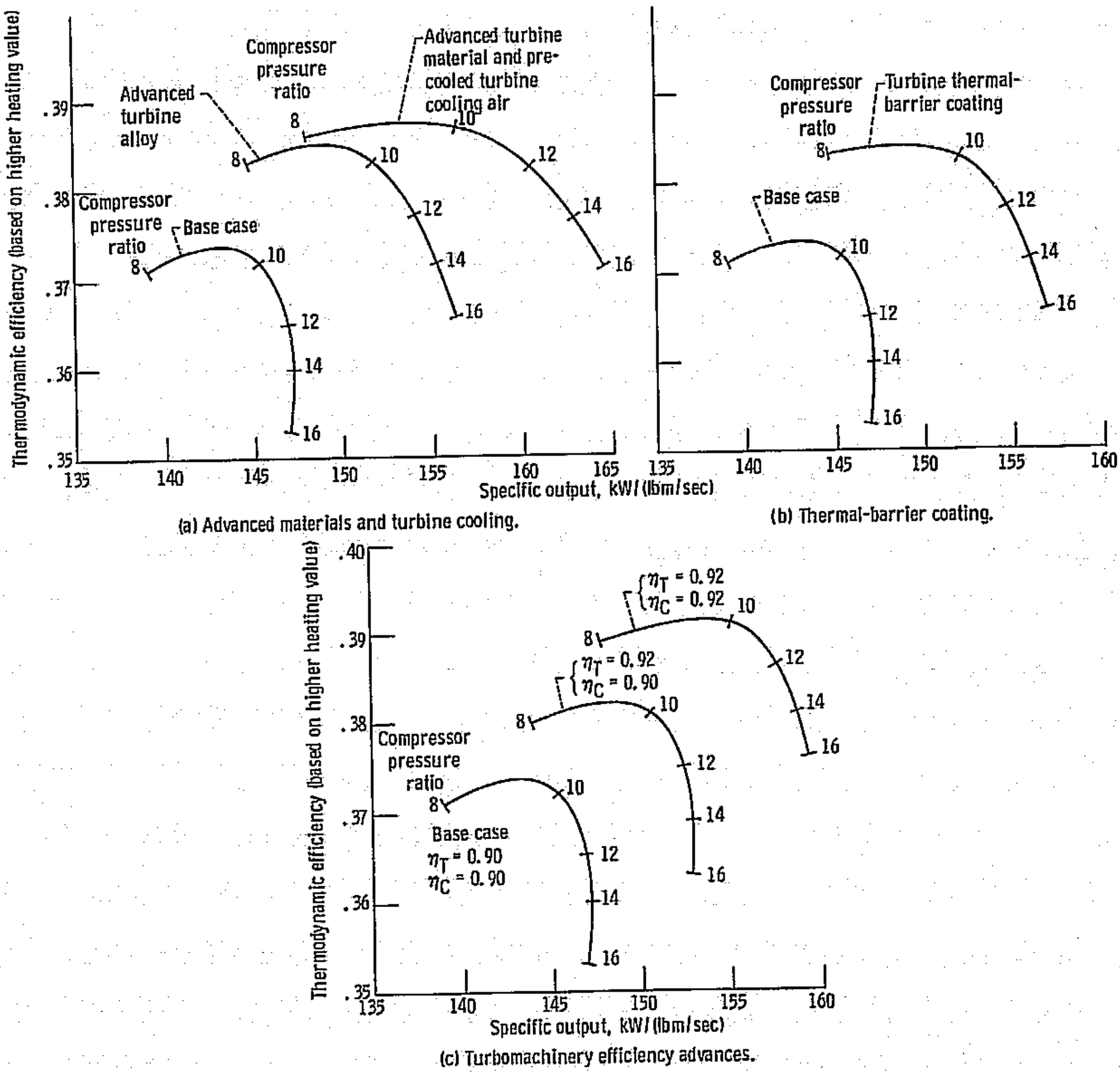


Figure 5.3-5. - Relative cycle performance effects of selected technology advancements (NASA calculations). Firing temperature, 2260° F; recuperator effectiveness, 0.85; recuperator pressure drop, 0.03.

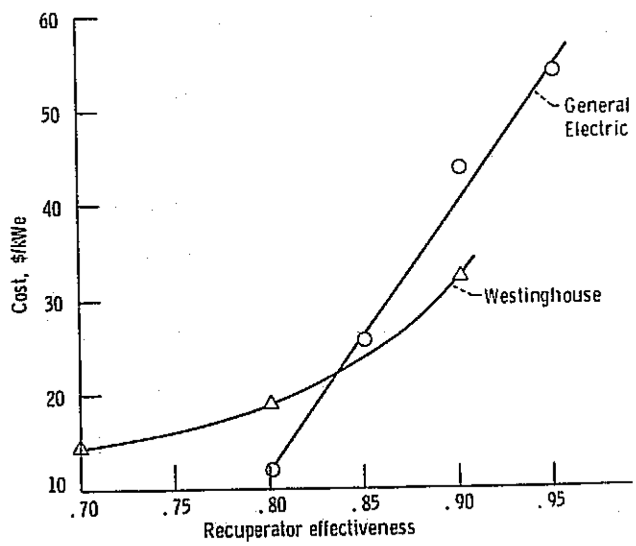


Figure 5.3-6. - Effect of recuperator effectiveness on cost of open-cycle recuperator (including associated ducting) - comparison of General Electric and Westinghouse results. Turbine-inlet temperature, 2200° F; compressor pressure ratio, 12; pressure loss ratio, $(\Delta P/P)_{recup}$, 3 percent.

5.4 COMBINED-CYCLE GAS TURBINE/STEAM TURBINE SYSTEMS
by Harold H. Valentine

Open-cycle, combined gas/steam powerplants burning natural gas or petroleum fuels are presently used by utilities in intermediate-load service. The potential of such plants for base-load service with a coal-derived fuel appears quite attractive based on previous studies. This cycle offers the potential for base-load systems characterized by high thermal efficiency, moderate capital requirements, flexibility of operation, modest siting requirements, and relatively short construction times.

Incorporating combined gas/steam systems in the ECAS study provides a comparative assessment of their desirability as base-load plants and will provide focus for the specific technology advances necessary to bring about their implementation.

5.4.1 Scope of Analysis

The scope of each contractor's study of combined-cycle, gas/steam systems is summarized in table 5.4-1 by fuel type. The parameters underlined in this table depict base cases or emphasis in the study. As can be seen, the emphases of the contractors' efforts differed considerably. Westinghouse reported on a total of 84 parametric points, concentrating on air-cooled gas turbines burning distillate fuel from coal. Two base cases were established - one with reheat steam and one with nonreheat steam; and the parametric points were run as variations from the base cases. Figure 5.4-1 is a simplified schematic of the Westinghouse reheat base case. Compressed air from the gas-turbine compressor is mixed with fuel in the gas-turbine combustor. The hot combustion gases expand through the gas turbine producing power to drive the compressor and the generator unit. The gas-turbine exhaust gases are ducted to the unfired heat-recovery steam generator to produce steam. The resultant steam at 2400 psi/1000° F is routed through the steam turbine to produce additional electric power. Steam is reheated to 1000° F to effect further economies. To improve powerplant efficiency, Westinghouse incorporated low-pressure steam induction into the steam system. The use of steam induction improves the thermodynamic fit between the gas-turbine heat rejection line and the steam-cycle heat acceptance line. By using a multiple-admission steam turbine in the steam system, the additional energy extracted from the exhaust gases can thus be used to produce more power with no increase in fuel consumption. Hence, cycle efficiency is improved. In the parametric study, Westinghouse evaluated several induction steam pressure levels. For the base case the induction steam is produced at 30 psi in the deaerator feedwater heater loop.

General Electric reported on a total of 59 points, concentrating on the use of low-Btu (LBTU) gas and emphasizing nonreheat steam systems. The G.E. parametric points were also run off two base cases: one using air-cooled gas turbines and one incorporating water cooling. About 40 percent of the G.E. parametric effort covered water-cooled gas turbines. A simplified cycle schematic for the G.E. air-cooled base case is presented in figure 5.4-2. In this LBTU-fueled plant, the gasifier is integrated with the heat-recovery steam generator (HRSG), the steam turbine, and the gas turbine. About 10 percent of the total compressed airflow from the gas turbines flows to the booster compressor and then to the gasifier. Steam from the low-pressure section of the HRSG and from the gasifier water jacket feeds to the gasifier. The gasified fuel after cold cleanup is reheated in an air/fuel-gas heat exchanger prior to combustion in the as turbine. The turbine exhaust gas produces steam in the HRSG. About ? percent of the steam flow is extracted from the high-pressure turbine an. used to drive the booster compressor turbine and supply the gasifier. Additional steam for the gasifier is raised in the low-pressure section of the HRSG.

General Electric used four gas-turbine generator units each with its own HRSG for most plants incorporating air-cooled gas turbines. The output of the four steam generators supplied a single steam turbogenerator unit. The design airflow rate for the G.E. air-cooled units was 570 lb/sec. For plants using water-cooled gas turbines, G.E. used three gas turbine units, each with a design airflow rate of 700 lb/sec.

For distillate fuel cases Westinghouse used two gas-turbine units, each with its own HRSG, for plants with nonreheat steam and four gas-turbine units for plants with reheat steam. The use of four gas turbines was selected by Westinghouse for the LBTU plant design. The design airflow rate for all Westinghouse gas-turbine units was 970 lb/sec.

In addition to the major parameters indicated in table 5.4-1, each contractor evaluated variations in gas-path delta P, pinch-point delta T, condenser pressure, feedwater temperature, heat rejection mode, plant size, and the effect of supplemental boiler firing. General Electric also evaluated the effects of using bituminous, subbituminous, and lignite coal in their LBTU and intermediate-Btu (IBTU) plant concepts.

5.4.2 Results of Analysis

5.4.2.1 Overall Comparison

All contractors' results are summarized by fuel type in figures 5.4-3 and 5.4-4. Cost of electricity in mills/kW-hr is plotted against both overall efficiency and powerplant efficiency. Each contractor's ranges of results for gaseous fuels are summarized in figure 5.4-3; similar information for the liquid-fueled cases is presented in figure 5.4-4. Considering the results in total, the cost of electricity (COE) ranges from 23 mills/kW-hr to 35 mills/kW-hr while overall efficiency varies from 19 percent to 42 percent. Powerplant efficiencies ranged from 33 percent to 49 percent.

Westinghouse results show 2 mills/kW-hr lower COE and 2 percentage points higher powerplant efficiency than G.E. for a high-Btu (HBTU) air-cooled case at similar conditions. Because of different fuel conversion efficiency assumptions, the corresponding spread in overall efficiency increases to 9 percentage points. For their LBTU case, Westinghouse reports an overall efficiency about 7 percentage points higher than G.E. and a COE that is comparable to G.E.'s.

The G.E. results for clean liquid fuel, assuming the COED process, are quite similar to the Westinghouse results for distillate from the H-coal process. For the semiclean solvent-refined-coal (SRC) cases, however, G.E. reports a 50 percent improvement in overall efficiency and a COE reduction of about 5 mills/kW-hr compared with the other liquid-fuel cases. As shown in section 4.1 and below, these results for SRC follow from the higher fuel conversion efficiency and lower over-the-fence price specified for this fuel.

5.4.2.2 Discussion and Assessment

Both contractors' parametric results pertaining to variations in gas-turbine-inlet temperature and/or compressor pressure ratio are presented in figure 5.4-5. Cost of electricity is plotted against compressor pressure ratio for values of turbine-inlet temperature. Both contractors' results show that gas-turbine-inlet temperature and/or pressure ratio selection exerted a stronger influence on COE than did steam pressure selection. In addition, both contractors found that lowest COE was obtained with compressor pressure ratios of 8 to 10 at the lower firing temperatures (1800° to 2200° F) and 12 to 14 at the higher firing temperature (2600° to 3000° F). When burning other than LBTU gas, which because of the large amount of water vapor in the product fuel inherently controls NOX by limiting the flame temperature, G.E. used steam injection as necessary to limit NOX production. Westinghouse evaluated the NOX problem and determined that a two-stage dry combustor would be required to control NOX. No performance penalty associated with NOX control has been included by Westinghouse for gas-turbine systems.

As shown in figure 5.4-5(a), Westinghouse found that the reheat steam cycle was not economical at the low gas-turbine firing temperatures and only marginally economical at the higher firing temperatures evaluated. In general, the limited results from G.E. pertaining to reheat cycles support this viewpoint.

With respect to supplemental boiler firing, however, the contractors' results differ. Westinghouse results for distillate fuel showed no benefit in supplemental boiler firing for either nonreheat or reheat steam cycles. General Electric results indicated that, for the LBTU integrated plant at 2200° F, supplemental boiler firing to support an 1800 psi/1000° F/1000° F reheat steam system resulted in a COE reduction of 0.7 mill/kW-hr from the base-case value of 25.5 mills/kW-hr. This apparent contradiction is resolved by a reconsideration of the cycles. Westinghouse incorporated steam induction in the steam system of their plants. The use of induction enhances the utilization of the stack gas energy and hence the overall powerplant efficiency while increasing plant output. The use of supplemental boiler firing increases output power through increased fuel consumption, but only at the efficiency level of the steam system. Westinghouse found no benefit in supplemental firing. General Electric, however, required high-pressure extraction steam to power the booster compressor turbine and to supply the gasifier. Additional low-pressure steam was generated in the low-pressure drum of the HRSG and supplied to the gasifier. Going to supplemental firing of the boiler to attain an 1800 psi/1000° F reheat system gave them two benefits. First, it allowed the elimination of the low-pressure drum in the HRSG, which reduced capital costs. Second, it permitted increased plant output. As a result, overall efficiency dropped (1 percentage point). However, the capital cost reduction and increased specific power were large enough to reduce COE in spite of the reduced efficiency.

The Westinghouse results demonstrating the effect of gas-turbine firing temperature on COE and overall efficiency are presented in figure 5.4-6. The results show that, with air-cooled gas turbines, progressive increases in turbine-inlet temperature to 2600° F (highest temperature considered) reduce COE and improve efficiency. Also presented on this figure are the results obtained by Westinghouse using ceramic gas-turbine components. At 2200° F, replacing the air-cooled stator vanes with ceramic vanes reduced the COE by 0.5 mill/kW-hr and increased overall efficiency by about 1 percentage point. Adding ceramic turbine blades had no impact on COE but further improved efficiency somewhat. The G.E. results pertaining to the influence of gas-turbine firing temperature on COE and overall efficiency are presented in figure 5.4-7. As with Westinghouse, the G.E. results show firing temperatures to 2600° F (highest temperature considered) to be both cost effective and energy efficient for combined gas/steam plants using air-cooled gas turbines. For water-cooled gas turbines, firing temperatures to at least 3000° F appear cost effective. Although the overall efficiency of the 3000° F water-cooled case is slightly less than that at 2800° F, the higher specific power of the plant reduced capital charges and hence lowered COE.

The G.E. results presented here also indicate that at any given turbine-inlet temperature higher performance was obtained with air-cooled turbines than with water cooling. Even though water cooling minimizes or eliminates compressor bleed, the heat loss to the water exceeds the savings associated with cooling air. Water is such an effective coolant that, when used, it is difficult to prevent overcooling of the surfaces involved. Therefore, energy is removed from the gas stream at high temperature, where its thermodynamic utility is high. It is subsequently returned to the system through the feedwater heaters, but at a greatly reduced temperature and hence with a much-reduced thermodynamic utility. However, the low material temperatures associated with water-cooled gas turbines offer an opportunity for exploitation of low-cost, minimally processed fuels or low-cost materials. Viewed from that standpoint, an observation that may be drawn from the results is that water cooling offers the potential of low-cost fuels for gas turbines at little or no performance penalty.

Also presented in figure 5.4-7 are the G. E. results for the use of ceramic gas-turbine stationary parts. For the 2600° F, air-cooled, pressure-ratio-of-16 case, using ceramics for the combustor, transition piece, and first-stage nozzle vanes had very little impact on either COE or efficiency. At first glance one might expect the effect at this higher firing temperature to be greater than that reported by Westinghouse for 2200° F. That this is not so is explained by the following, which was inferred from NASA Lewis calculations. In an air-cooled turbine, the vane coolant mixing with the gas stream reduces the blade coolant requirements. Removing the stator vane coolant by incorporating ceramics therefore increases the blade cooling burden. At 2200° F, where the total cooling requirements are modest, removing the vane coolant has little or no impact on the blade requirement, and hence a positive gain is realized. However, at 2600° F the cooling requirements are large, and removing the vane coolant flow has a marked effect on the blade requirements. Hence, little if any overall gain is realized.

We now turn our attention to the G.E. results for ceramic vanes in a water-cooled turbine (fig. 5.4-7). For a 2800° F water-cooled turbine (in which the stationary-component coolant flows in a closed circuit and does not enter the gas stream), replacing all the water-cooled stationary components with ceramics resulted in significant COE and overall efficiency improvements. Since in an all-water-cooled gas turbine the cooled surfaces have a cooling effect on the gas stream, it is reasonable to expect that incorporating ceramic stator vanes at high firing temperatures would have results similar to those first discussed for the air-cooled turbine at high firing temperature. However, this is not so, because, as was discussed previously, it is difficult to water cool without overcooling. In the water-cooled machines, the cooled surfaces ran about 900° F. The increased blade cooling burden imposed by incorporating ceramic stationary parts merely results in less overcooling of the blades for water cooling. Overall, both contractors' results for ceramics indicate that high firing temperatures (2600° F and higher) are required for cost effectiveness and that both the stator vanes and turbine blades should be ceramic or the blades should be water cooled.

Westinghouse in their Phase 1 parametrics investigated the effects on performance of incorporating multiple steam inductions in a reheat cycle. They also evaluated, for a single induction, the effect on performance of varying the induction point. The results indicate that the bulk of the performance gain comes with the first induction and that additional inductions provide progressively less gain. For a 2400 psi/1000° F/1000° F steam cycle, powerplant efficiency was about 2 percentage points higher with a single steam induction than without it. Westinghouse found the most effective point of induction to be at the reheat point. The potential problem of system control associated with the use of steam induction was beyond the scope of Phase 1.

5.4.2.2.1 <u>Specific comparisons by fuel type</u>. - From the data presented and the accompanying discussion, it is evident that in general the contractors' results for combined gas/steam systems are in good agreement. In this section a somewhat more specific comparison of a few selected cases is made. The comparisons examine COE, COE distribution, powerplant and overall coal-pile-to-bus-bar efficiencies, and plant construction times.

Because of the differences in emphasis and scope of the two contractors' studies, there are no directly comparable one-on-one cases. Therefore, the approach taken in making the following comparisons has been to present the most comparable cases for each common fuel type considered. The contractors' results for these cases are presented in table 5.4-2, and the associated major-cycle conditions are enumerated in table 5.4-3. Only air-cooled cases are considered here. Westinghouse did not have any water-cooled cases, and the ceramic points were discussed in the preceding section. Notice that in every case, the cycle conditions reflect the contractors' base-case conditions.

We begin the comparison with a general observation: Both contractors' results show that using LBTU gas produced in a gasifier integrated into the powerplant results in the lowest COE and the highest overall efficiency for combined-cycle systems at the same firing temperatures. Also, both contractors' results show that using HBTU gas from coal resulted in the highest COE for combined-cycle systems.

Efficiencies are presented near the top of table 5.4-2. For the systems with integrated LBTU gasifiers, powerplant efficiency and overall efficiency are identical. The Westinghouse results using LBTU gas reflect an efficiency level 7 percentage points higher than G.E.'s. The main reason for this difference is the gasifier cleanup method chosen. The G.E. results are based on a near-term, fixed-bed gasifier and cold-gas cleanup.

The gasifier concept selected by G.E. required large quantities of steam - roughly 1.1 pounds per pound of coal. In the G.E. plant concept about 55 percent of this steam was obtained by extraction from the high-pressure turbine of the steam system. (Of the remaining steam required, about two-thirds was generated in the low-pressure drum of the HRSG and about one-third in the gasifier cooling jacket.) Additional steam was extracted from the high-pressure turbine to drive the gasifier air booster compressor. Extracting 30 percent of the total steam flow from the high-pressure turbine imposed a significant penalty on the steam bottoming cycle efficiency and hence on the powerplant efficiency.

The Westinghouse concept assumed an advanced-design, fluidized-bed gasifier incorporating hot-gas cleanup. The steam required by the Westinghouse selected gasifier was about 0.45 pound per pound of coal, and this steam was obtained by extraction from the intermediate-pressure turbine of the steam bottoming cycle. As a result, the penalty on the steam system efficiency was much less for Westinghouse than for G.E. In addition, as pointed out earlier, Westinghouse incorporated induction into the steam cycle. Additional steam - amounting to about 40 percent of the flow into the low-pressure turbine - was generated in the low-pressure drum of the HRSG and inducted into the low-pressure turbine at 30 psi. This use of induction increased powerplant efficiency by about 2 percentage points above that obtained with the same steam conditions and no induction.

The bulk of the difference in powerplant efficiency for the HBTU cases is, again, associated with the use of steam induction by Westinghouse. This notwithstanding, there is a large difference in overall efficiency for these two cases. This is directly attributable to a coal-to-gas energy conversion efficiency of 67 percent used by Westinghouse as compared with the 50 percent used by G.E. Since this fuel was over the fence at the NASA specified price for both contractors, their differing fuel conversion efficiency assumptions have no impact on COE.

The Westinghouse liquid fuel considered was distillate from the H-coal process, with a fuel conversion efficiency of 50 percent. For its clean-liquid-fuel case, G. E. chose COED with a fuel conversion efficiency of 56 percent. Again, since these were over-the-fence fuels with prespecified prices, the different fuel conversion efficiencies had no separate impact on COE. Although there are some small differences in the gas-turbine cycles for these two cases, the higher powerplant efficiency reported by Westinghouse is mainly due to a better utilization of gas-turbine exhaust heat. General Electric used a single-pressure steam system and a boiler pinch-point delta T of 30° F. Their stack-gas temperature was about 400° F. Westinghouse used a two-pressure steam system and the same pinch-point delta T. Their stack-gas temperature was about 290° F. The Westinghouse approach offers higher efficiency with greater complexity. Westinghouse used the additional energy extracted from the exhaust gas to raise more steam in the deaerator - feedwater heater. This additional 30-psi steam was inducted into the low-pressure steam turbine to produce additional power.

Turning now to the three major elements affecting the cost of electricity, a noticeable difference appears in the operations-and-maintenance (O and M) account. The Westinghouse O and M charges appear consistently lower than those of G.E. A review of the Westinghouse draft report on Phase 1 leads to the conclusion that only operations costs were reported. Evidently, no allowance for maintenance was factored into the Westinghouse O and M account for combined-cycle, gas/steam plants.

The plant capital costs are directly related to the major component costs, balance-of-plant costs, and site labor charges. In addition to these direct costs, indirect costs, contingency allowance, and interest and escalation charges over the time of construction are added to arrive at total capital cost. The approach used and the factors established by each contractor in determining direct and indirect costs, contingency, etc., are discussed in sections 4.1 and 5.1 of this report and will not be repeated here. Suffice it to say that a review of the cost information supplied by the contractors leads to the following observation: The major component costs estimates of the two contractors generally are within 10 percent; however, total costs differ by as much as 25 percent.

General Electric assumed a 3-year construction time for all plants with air-cooled gas turbines except those fired with LBTU or HBTU gas. The construction time was shortened to 2 years for these plants. Westinghouse assumed a 3-year construction period for the base-case distillate-fueled plant and 4 years for the HBTU and LBTU plants. For other liquid-fueled plants, Westinghouse varied construction time by the ratio of the plant size to the base-case plant size, with the ratio raised to the 0.175 power. General Electric assumed a 4-year construction time for plants incorporating water-cooled gas turbines, for all fuel types.

For equal times of construction for plants with common fuels, the capital costs for the cases presented in table 5.4-2 agree within 10 percent for the HBTU and LBTU plants and within 20 percent for the liquid-fueled plants.

Considering the preliminary nature of the Phase 1 effort and the advanced nature of the plants being studied, these differences are considered small.

5.4.2.2.2 Semiclean fuels. - General Electric included the use of solvent-refined coal in its Phase 1 parametric analysis. The semiclean SRC had an assumed fuel conversion efficiency of 78 percent as compared with the typical 50 to 55 percent for distillate fuel from coal. The semiclean fuel also has a price advantage over the distillate fuels - $1.80/MBtu for SRC versus $2.60/MBtu for the distillate. However, the SRC has a high fuel-bound nitrogen level (2 percent), and G.E. indicates that ECAS-specified emission levels could not be met.

To properly assess SRC or any other semiclean fuel, a data base of information is needed such that economic trade-offs among fuel conditioning, combustion advancements, turbine materials, coatings, cooling techniques, and stack-gas cleaning can be made.

5.4.2.2.3 Public and advocate comments. - United Technologies Research Center expressed concern about the ability to meet either NOX or particulate emissions with the LBTU hot-gas cleanup proposed by Westinghouse. Westinghouse Gas Turbine Division expressed similar concerns and was also concerned about the deposition of solidified ash on the gas-turbine blades and the resultant effects on turbine performance and life. In Phase 2, Westinghouse will examine the hot-gas cleanup approach in greater detail.

5.4.3 Concluding Remarks

The results of the ECAS Phase 1 studies of both contractors indicate that using coal-derived fuels in base-load, combined-cycle gas/steam powerplants would result in low cost of electricity (20 to 28 mills/kW-hr) and good overall energy efficiency (25 to 42 percent). In addition, such plants would require moderate capital investments and entail comparatively short lead times. Specific significant results of the studies are as follows: (1) Burning LBTU gas produced in plant-integrated gasifiers resulted in the highest overall energy efficiency and lowest cost of electricity. (2) Gas-turbine firing temperatures to 2600° F with air cooling and to 3000° F with water cooling appear to be cost effective. (3) COE minimized at a steam pressure of about 1400 psi for nonreheat steam systems and about 1800 psi for reheat steam systems. (4) Reheat steam systems were only cost effective at firing temperatures of 2450° F or above. (5) The use of ceramic gas-turbine components offers greater benefits at higher firing temperatures. (6) Semiclean liquid fuels appear to be potentially attractive from the multiple standpoints of low cost of electricity, relatively high overall efficiency, and low capital cost; however, additional effort is required to establish whether acceptable emissions levels can be met with such fuels.

Projection to high firing temperatures (2600° to 3000° F) is a very substantial extension of the present state of the art.

TABLE 5.4-1. - TASK I RANGE OF PARAMETERS FOR COMBINED GAS-STEAM SYSTEMS

(a) Fuel, low-Btu gas from coal

Major parameter	General Electric		Westinghouse
Gas turbine:			
Airflow rate, lb/sec	570	700	970
Cooling mode	Air	Water	Air
Inlet temperature, °F	2000, 2200, 2400, 2600	2600, 2800, 3000	2200
Compressor pressure ratio	8, 12, 16, 20	12, 16, 20	12
First-row vane material	Metal, ceramic	Metal, ceramic	Metal
First-row blade material	Metal	Metal	Metal
Steam bottoming cycle:			
Throttle pressure, psig			
Nonreheat	1000, 1250, 1450, 1500	1450, 1800	----
Reheat	1800	2400	2400
Throttle temperature, °F			
Nonreheat	900, 950, 1000	950, 1000	----
Reheat	950	1000	1000
Induction pressure, psig			
Nonreheat	---	----	----
Reheat	---	----	30

(b) Fuel, liquid from coal

Major parameter	General Electric		Westinghouse
Gas turbine:			
Airflow rate, lb/sec	570	700	970
Liquid fuel	SRC, COED	SRC, COED	Distillate
Cooling mode	Air	Water	Air
Inlet temperature, °F	2200	2800	1800, 2000, 2200, 2400, 2600
Compressor pressure ratio	12	16	8, 12, 16, 20
First-row vane material	Metal	Metal	Metal, ceramic
First-row blade material	Metal	Metal	Metal, ceramic
Steam bottoming cycle:			
Throttle pressure, psig			
Nonreheat	1250	1450	1250, 1450
Reheat	----	----	1450, 1800, 2400
Throttle temperature, °F			
Nonreheat	950	1000	950, 1000
Reheat	---	----	1000
Induction pressure, psig			
Nonreheat	---	----	--, 30
Reheat	---	----	--, 30, 150, 500

(c) Fuel, high-Btu gas from coal

Major parameter	General Electric		Westinghouse
Gas turbine:			
Airflow rate, lb/sec	570	700	970
Cooling mode	Air	Water	Air
Inlet temperature, °F	2200	2800	2200
Compressor pressure ratio	12	16	12
First-row vane material	Metal	Metal	Metal
First-row blade material	Metal	Metal	Metal
Steam bottoming cycle:			
Throttle pressure, psig			
Nonreheat	1250	1450	----
Reheat	----	----	2400
Throttle temperature, °F			
Nonreheat	950	1000	----
Reheat	---	----	1000
Induction pressure, psig			
Nonreheat	---	---	--
Reheat	---	---	30

(d) Fuel, intermediate-Btu gas from coal

Major parameter	General Electric
Gas turbine:	
Airflow rate, lb/sec	570
Cooling mode	Air
Inlet temperature, °F	2200
Compressor pressure ratio	12
First-row vane material	Metal
First-row blade material	Metal
Steam bottoming cycle (nonreheat):	
Throttle pressure, psig	1250
Throttle temperature, °F	950

TABLE 5.4-2. - COMPARISON OF CONTRACTORS' RESULTS BY FUEL TYPE FOR AIR-COOLED COMBINED GAS-STEAM SYSTEMS

Parameter	Fuel					
	Low-Btu gas		Liquid		High-Btu gas	
			COED	Distillate		
	General Electric (case 1)	Westing-house (case 1)	General Electric (case 10)	Westing-house (case 2)	General Electric (case 8)	Westing-house (case 84)
Efficiency, percent:						
Powerplant	35.6	42.3	43.1	45.9	41.4	44.2
Overall	35.6	42.3	24.1	23.1	20.9	29.7
Plant capital cost, $/kWe	450	495	276	233	225	245
Construction time, yr	3	4	3	3	2	4
Cost of electricity,[a] mills/kW-hr:						
Capital	14.2	15.7	8.7	7.4	7.1	7.7
Fuel	8.2	6.8	19.4	19.3	21.4	20.1
Operation and maintenance	3.1	1.7	2.0	0.6	1.8	0.6
Total	25.5	24.2	30.2	27.3	30.4	28.4

[a]Includes baseline capacity factor, fixed-charge rate, fuel costs, etc.

TABLE 5.4-3. - MAJOR CYCLE CONDITIONS ASSOCIATED WITH CASES PRESENTED IN TABLE 5.4-2

Parameter	Fuel					
	Low-Btu gas		Liquid		High-Btu gas	
			COED	Distillate		
	General Electric (case 1)	Westing-house (case 1)	General Electric (case 10)	Westing-house (case 2)	General Electric (case 8)	Westing-house (case 84)
Gas turbine:						
Inlet temperature, °F	2200	2200	2200	2200	2200	2200
Compressor pressure ratio	12	12	12	12	12	12
Steam bottoming cycle:						
Throttle pressure, psig	1250	2400	1250	1250	1250	2400
Throttle temperature, °F	950	1000	950	950	950	1000
Reheat temperature, °F	----	1000	----	----	----	1000

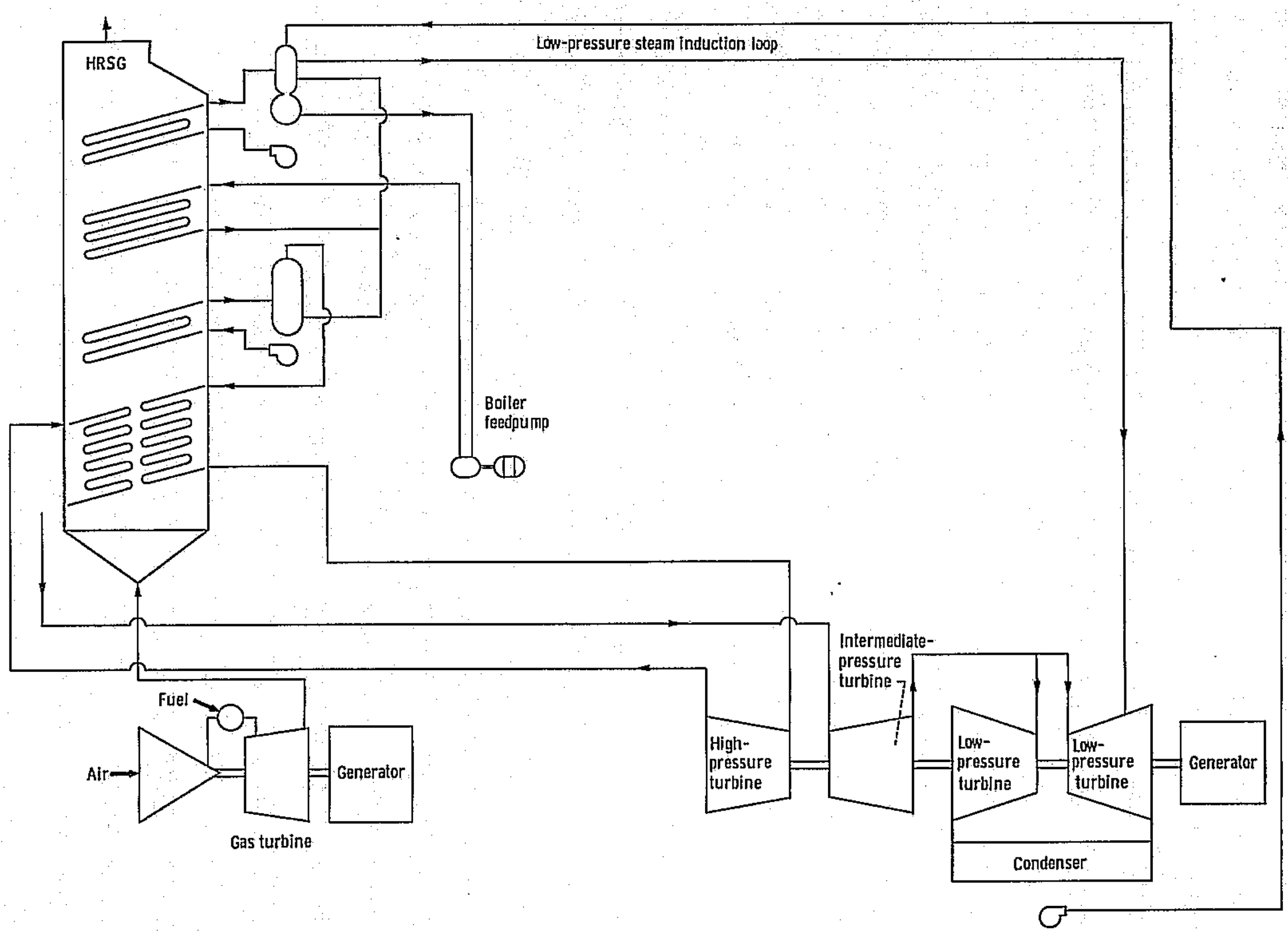


Figure 5.4-1. - Simplified schematic of combined gas-steam system for Westinghouse reheat base case. Fuel, distillate from coal.

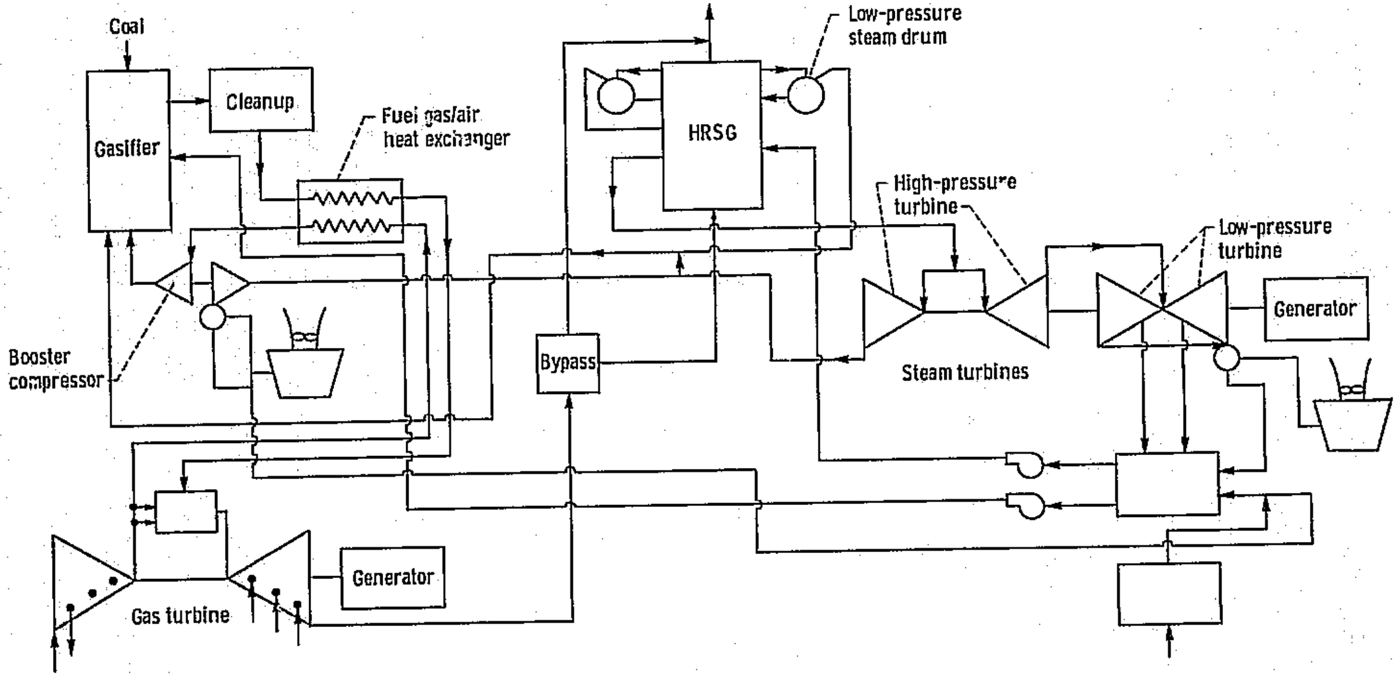


Figure 5.4-2. - Schematic of combined gas-steam system for General Electric air-cooled (nonreheat) base case. Fuel, low-Btu gas.

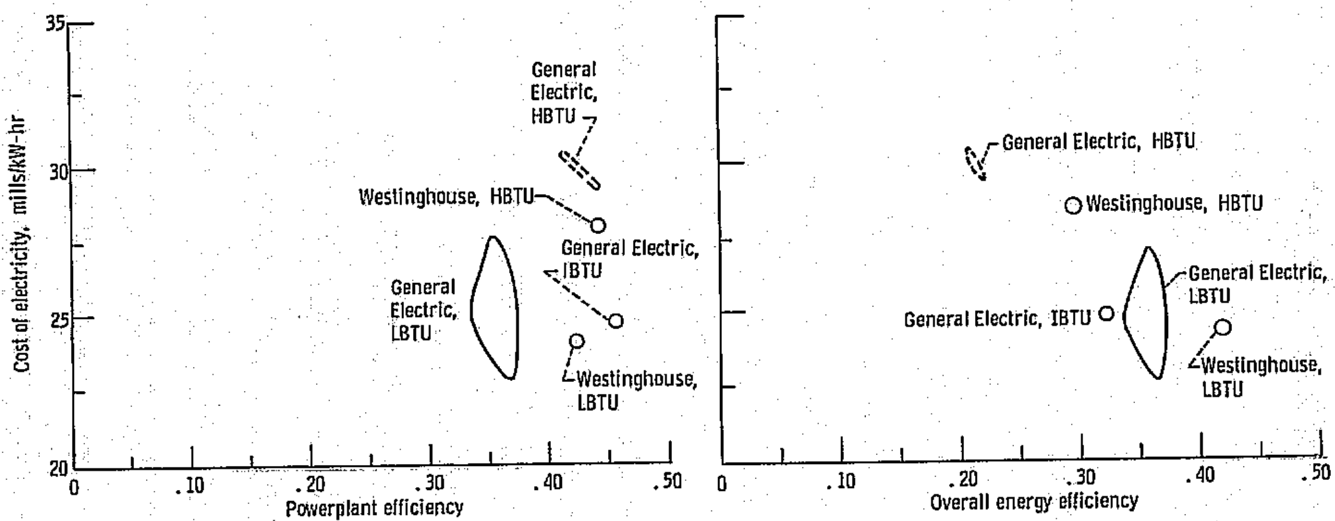


Figure 5.4-3. - Overall range of contractors' results for combined gas-steam systems - gaseous fuels from coal.

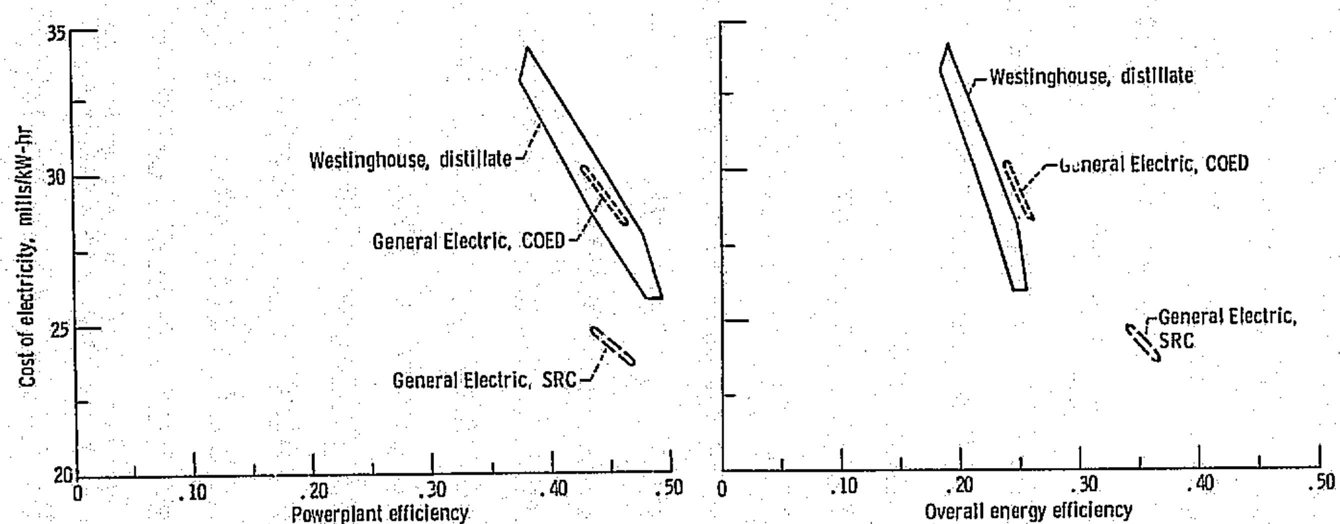
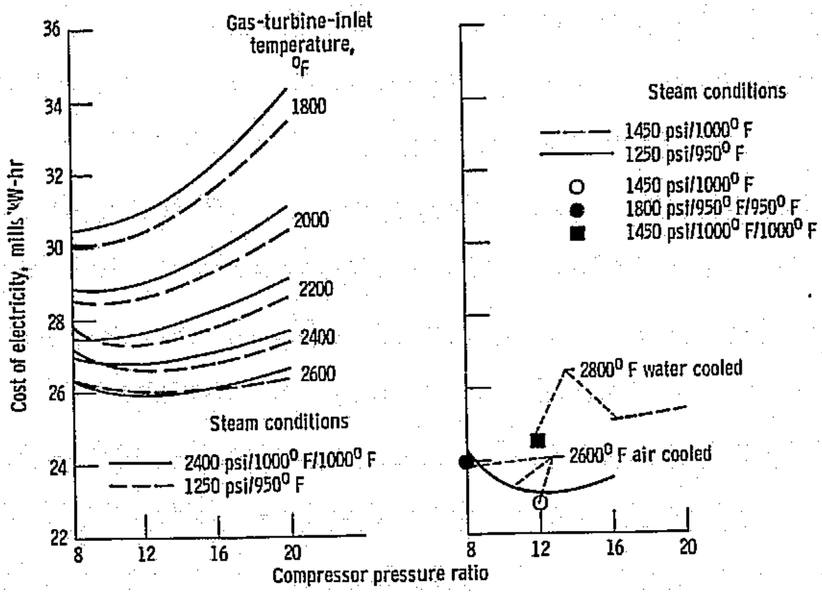


Figure 5.4-4. - Overall range of contractors' results for combined gas-steam systems - liquid fuels from coal.



(a) Westinghouse; distillate fuel.

(b) General Electric, LBTU fuel.

Figure 5.4-5. - Contractors' parametric results related to gas-turbine parameters - combined gas-steam systems.

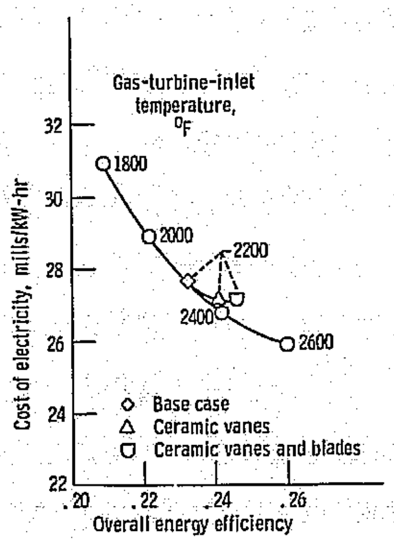


Figure 5.4-6. - Westinghouse results demonstrating effect of turbine-inlet temperature on cost of electricity and overall efficiency. Combined gas-steam systems; distillate fuel; air-cooled, reheat-base-case pressure ratio and steam conditions.

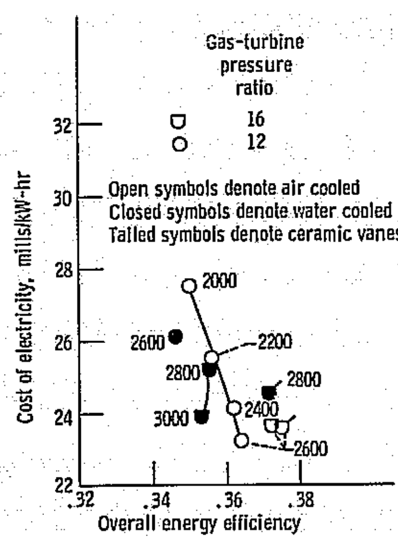


Figure 5.4-7. - General Electric results addressing effects of turbine-inlet temperature, cooling approach, and ceramics utilization on cost of electricity and overall efficiency. Combined gas-steam systems; LBTU fuel; base-case steam conditions.

5.5 CLOSED-CYCLE GAS TURBINES

by Raymond K. Burns, Donald C. Guentert, and Donald G. Beremand

Closed-cycle gas turbines have a number of potential advantages that result from its being a closed thermodynamic cycle. The working-gas composition and pressure level are independent design parameters that can be chosen for the benefit of the turbomachinery and heat exchangers. Operation of the system at high pressure levels would allow higher power density systems than attainable with open-cycle gas turbines. Also a working gas with a high thermal conductivity and hence a high heat transfer coefficient can be used that, together with a higher pressure level, could result in smaller heat exchangers than for a recuperated open-cycle gas turbine. Since the working gas is independent of the combustion products, clean and expensive fuels are not required. Coal can be burned directly in the closed-cycle gas turbine furnace without the penalty of a fuel conversion efficiency.

These potential advantages must be weighed against some potential disadvantages that also follow from its being a closed-cycle system. Because it is a closed system, the heat is input to the working gas through a furnace/heat exchanger. This imposes an upper limit on system maximum operating temperature and introduces a significant cost item. The furnace loop of a closed system also introduces a loss, consisting predominantly of sensible and latent heat in the stack gases. This results in 10 to 15 percent of the fuel heating value not being transferred to the primary power system. In contrast, open-cycle systems have essentially all of the fuel heating value available to the primary power system.

The closed-cycle gas turbine system was included in ECAS to examine the balance between these potential advantages and disadvantages. Closed-cycle gas turbines also have several positive attributes that were not displayed in ECAS Phase 1. The heat rejection from the cycle (when a bottoming cycle is not used) occurs over a range of temperatures from near ambient to several hundred degrees. Thus, the system is more compatible with dry cooling towers than are Rankine systems, where most of the heat is rejected at a constant near-ambient temperature. The closed-cycle gas turbine system may therefore be more competitive in applications where dry cooling towers must be used because of a limitation in available cooling water. The Middletown site specified as a study ground rule does not, however, fit this situation. Also since the heat rejection temperatures range to 400° or 500° F, the system can produce hot pressurized water or steam for use in industrial processes or for industrial/commercial heating applications, without penalizing the power system performance. Use of waste heat for other than the production of electricity in bottoming cycles was, however, beyond the scope of ECAS. Also beyond the scope of ECAS is the consideration of power system performance at power levels other than the design point. The power level of a closed-cycle gas turbine can be controlled by changing system inventory and hence pressure level without changing system temperatures or volume flow rate. As a result, component and system performance at design-point power level can be maintained over a wide range of power levels.

5.5.1 Scope of Analysis

Tables 5.5-1 and 5.5-2 summarize all parametric cases considered by G.E. and Westinghouse. The major input parameters and the number of cases are categorized by furnace and fuel type used. The unbottomed configurations are summarized in table 5.5-1, and those with organic or steam bottoming cycles are summarized in table 5.5-2. The parameters of the base cases used by the contractors are listed in table 5.5-3. Both contractors used helium as the closed-cycle gas turbine working fluid for all cases.

The closed-cycle gas turbine system is one of those wherein the contractors' areas of emphasis differed considerably. The main differences involved the furnace and fuel type and the integration of bottoming cycles. General Electric emphasized atmospheric, direct coal firing. Of a total of 46 parametric cases, 35 used an atmospheric-fluidized-bed (AFB) coal-fired furnace, one used a pressurized-fluidized-bed (PFB) coal-fired furnace, and 10 used a clean-fuel pressurized furnace (PF). Westinghouse emphasized pressurized combustion loops and clean over-the-fence fuels. Of a total of 100 parametric cases, 88 used a pressurized furnace and clean fuel (distillate in 84 cases). Westinghouse studied 11 cases with pressurized-fluidized-bed furnaces and direct coal firing. They also did one case with an atmospheric furnace that used distillate fuel.

Both contractors varied such helium-loop parameters as pressure ratio, turbine-inlet temperature, recuperator effectiveness, and pressure losses. Many of Westinghouse's parametric variations involved changes in the furnace-pressurizing gas turbine parameters (which they referred to as the "pump-up cycle"). These included turbine-inlet temperature, pressure ratio, recuperator effectiveness, and pressure losses. General Electric did few parametric variations of these furnace-pressurizing gas turbine parameters but focused their attention on the helium cycle.

General Electric considered eight cases with an organic bottoming cycle (using R-22 and Flucrinol-85). A recuperated helium cycle was used in all cases. They also did five cases with a steam bottoming cycle and used a helium recuperator in all but one case. Westinghouse considered 45 parametric cases with a steam bottoming cycle, six with an organic cycle (R-12 and methylamine), and one with a sulfur dioxide bottoming cycle. In contrast with G.E. they configured the system so that the bottoming cycle received heat input from the furnace cycle as well as from the helium cycle. Also in contrast with G.E. none of their bottomed cases included a recuperator in the helium cycle. As a result the temperature levels of their bottoming cycles were generally higher than G.E.'s. Organic bottoming cycles are discussed in section 5.12.

A simplified schematic of the closed-cycle gas turbine is given in figure 5.5-1. Each contractor considered a number of cases that included one stage of compressor intercooling, which is not shown in the figure. When a bottoming cycle was used, the G.E. configuration included a helium-to-bottoming-cycle fluid boiler between the recuperator and the precooler. In the Westinghouse configurations the recuperator was not used, and the helium at turbine exhaust was input to the bottoming-cycle fluid boiler. In most Westinghouse cases the precooler was also eliminated so that the helium exiting the bottoming-cycle fluid boiler was input directly to the compressor.

Figures 5.5-2 and 5.5-3 are simplified schematics of an atmospheric and pressurized furnace loop. The atmospheric-furnace exit gases are reduced to a desirably low stack-gas temperature by transferring the heat to the incoming air. The air preheater is labeled "recuperator" in figure 5.5-2. The pressurized furnace exit gases are expanded in a turbine that drives the air compressor and generator. The pressurizing turbocompressor produces additional electrical power and is essentially an open-cycle gas turbine thermodynamically in parallel with the closed cycle. In about half of the parametric cases for the unbottomed configuration, Westinghouse included the recuperator shown in figure 5.5-3. When a bottoming cycle was used, Westinghouse did not include this recuperator but instead transferred the heat of the turbine exhaust to the bottoming cycle. General Electric used a combustion-loop recuperator only in their PFB case.

In those cases that include an integrated low-Btu (LBTU) gasifier the contractors' approaches differed considerably. Westinghouse used an 1100° F pressurizing-gas-turbine inlet temperature and no combustion-loop recuperator. General Electric used an 1800° F pressurizing-gas-turbine inlet temperature and used the turbine exhaust to raise steam. Part of the steam was used as gasifier process steam, and the remainder was used to generate electrical power in a steam turbine. The furnace loop in the G.E. configuration was actually a gas turbine/steam turbine combined cycle with integrated gasifier; it produced more than half of the total plant power output.

5.5.2 Results of Analyses

5.5.2.1 Overall Comparison

The ranges of COE and overall energy efficiency results for all parametric cases of both contractors are shown in figure 5.5-4. The most attractive cases in both contractors' results are those that use coal directly (AFB, PFB, or integrated LBTU gasifier). The clean, over-the-fence-fuel-fired cases have much lower overall energy efficiency because of the fuel conversion efficiency from coal, and they have higher COE because of the higher price of the clean fuels. The fuel conversion efficiencies and fuel prices used are shown in table 4.1-2. General Electric assumed a fuel conversion efficiency of 0.50 for high-Btu (HBTU) gas, and Westinghouse assumed 0.67. This accounts for the difference in efficiency in the G.E. and Westinghouse results in figure 5.5-4. Westinghouse assumed a 0.50 fuel conversion efficiency for distillate fuel. As shown in later tables, the COE of the direct-coal-fired cases is dominated by plant capital costs, but the COE of the clean-fuel-fired cases is dominated by the fuel cost.

One of the most attractive cases in the G.E. results is their case 20, which uses an AFB furnace, a helium turbine-inlet temperature of 1500° F, a compressor ratio of 4 with one stage of intercooling, and a recuperator effectiveness of 0.85. This case has an overall energy efficiency of 31.6 percent and a COE of 33.7 mills/kW-hr. Their PFB case has a slightly higher overall energy efficiency of 31.8 percent and a COE of 35.9 mills/kW-hr. As seen in figure 5.5-4 the G.E.-PFB point falls into the range of results obtained by Westinghouse for the system with a PFB furnace. The Westinghouse PFB case with highest efficiency is case R21, which has an overall energy efficiency of 34.6 percent and a COE of 35.4 mills/kW-hr. This case has a 1500° F helium-turbine-inlet temperature, a pressure ratio of 2.5, and a recuperator effectiveness of 0.90. The PFB furnace is at 5 atmospheres; the pressurizing gas turbine has a 1700° F inlet temperature; and a recuperator with 0.90 effectiveness is included in the furnace cycle. Westinghouse case R27 is the PFB case with lowest COE. Its helium cycle is the same as case R21. However, its PFB furnace is at 10 atmospheres, has a pressurizing-turbine-inlet temperature of 1100° F, and has no recuperator. The COE of case R27 is 31.3 mills/kW-hr with an overall energy efficiency of 32.9 percent.

The configurations with highest efficiency in both contractors' cases are those with bottoming cycles. In the G.E. results, the recuperated closed cycles with organic bottoming have higher efficiency and about the same range of COE as the recuperated closed cycles with steam bottoming. Also the results indicate that the addition of a bottoming cycle results in about the same range or slightly higher COE (see section 5.12). However, the Westinghouse results show the steam-bottomed and organic-bottomed cases with similar ranges of efficiency as well as COE. Also the Westinghouse bottomed cases have lower COE than the recuperated, unbottomed configurations. This difference in the contractors' results follows from a difference in the power system configurations they assumed. As stated previously, the Westinghouse cases with bottoming cycles use unrecuperated closed gas turbine cycles and the heat input to the bottoming cycle is from both the helium cycle and the pressurized furnace cycle. Since neither a helium-cycle nor a furnace-cycle recuperator is used, the gas temperatures input to the bottoming-cycle fluid boiler are higher than for the G.E. configurations. As a result, the bottoming-cycle temperatures and pressures (particularly for the steam cycles) are higher than those employed by G.E. Consequently, most of the power output in the Westinghouse cases is from the bottoming cycle and the pressurized furnace cycle. For the G.E. configurations, most of the power output is from the helium cycle (about 80 percent).

The G.E. point with highest efficiency is case 41, which has an R-22 organic bottoming cycle and a 0.90 effectiveness recuperator in the helium cycle. This is the highest recuperator effectiveness considered for the bottoming-cycle cases. The COE for this case is 42.1 mills/kW-hr. The lowest COE case with an organic bottomer among the G.E. results is case 40 with 37.8 mills/kW-hr and 35.3 percent overall energy efficiency. This case includes a Fluorinol-85 bottoming cycle and a 0.60 effectiveness recuperator in the helium cycle. (See section 5.12 for a discussion of organic bottoming cycles.)

The Westinghouse case with highest overall energy efficiency is case C41 with 38.2 percent and a COE of 31.5 mills/kW-hr. The case has a 3500 psi/900° F/950° F steam bottoming cycle and a 1700° F, 10-atmosphere PFB furnace cycle. All the organic-bottomed cases considered by Westinghouse use distillate fuel with a pressurized furnace and hence have lower overall energy efficiency. The highest efficiency point is case C48 with a methylamine bottoming cycle. The overall energy efficiency is 21.8 percent (43.6 percent powerplant efficiency) with 38.4 mills/kW-hr COE. This case includes a 1500° F unrecuperated helium cycle and a furnace at 10 atmospheres with 2200° F pressurizing-turbine inlet temperature. Forty-eight percent of the power output is from the helium cycle for this case. (See section 5.12 for a further description.)

This last Westinghouse case discussed is representative of many of the clean-fuel-fired cases. The use of a clean fuel allowed the consideration of higher temperatures in the furnace pressurizing cycle. This increased the powerplant efficiency to values above 40 percent (considerably higher than obtained in any of the coal-fired cases considered). However, the fuel conversion efficiency and price of the clean fuels results in much lower overall energy efficiencies and higher COE's than obtained with direct coal firing.

5.5.2.2 Discussion and Assessment

5.5.2.2.1 Cost comparisons. - Table 5.5-4 presents cost information from selected cases studied by the contractors. Four furnace types are represented for G.E., including an AFB (case 1), PFB (case 8), PF with integrated LBTU gasifier (case 4), and a PF burning "over-the-fence" HBTU gas (case 7). All cases are recuperated without bottoming cycles. Costs of closed-cycle gas turbines with bottoming cycles are discussed in section 5.12. Total capital costs range from $814/kWe for the AFB (case 1) to $455/kWe for the PF burning HBTU fuel (case 7). The same helium cycle was used in all these cases, with a gross power output of 300 MWe. Specific cost of the major helium-loop components in terms of dollars per kWe of gross helium-loop output was constant at above $107/kWe. For the cases with pressurized furnaces, additional power was generated in the furnace loop, and the specific cost of the helium components in terms of dollars per net kWe of total output decreased accordingly. Case 4, a pressurized furnace with integrated LBTU gasifier, produced the majority of its power in the furnace loop (441 MWe out of 741 MWe gross output). In this case, the furnace loop was essentially a combined gas turbine/steam turbine cycle, with the steam cycle providing steam for the gasifier. Case 7 used a low-temperature open-cycle gas turbine for furnace pressurization and produced only a small amount of power in the furnace loop.

Furnace-loop major components include the furnace modules and the pressurizing turbomachinery and heat-recovery equipment (recuperator or steam plant). Balance-of-plant costs include all other equipment and material costs, and all site labor costs for component installation and construction. The gasifier cost (case 4) is included in the balance-of-plant costs in this table. As would be expected, the combined furnace-loop and balance-of-plant costs are substantially higher for those cases with coal as a fuel (AFB, PFB, and PF with integrated LBTU gasifier) than for the case with a PF burning "over-the-fence" HBTU gas produced from coal. For the latter case, the capital costs required for coal handling and processing to produce a clean fuel appear in the form of a higher fuel cost. This can be seen by comparing the 14.4 mills/kW-hr capital component and the 30.4 mills/kW-hr fuel component of cost of electricity for case 7 with the 23.8 mills/kW-hr and 9.1 mills/kW-hr, respectively, for case 8. The two coal-burning furnace cases (AFB and PFB) have higher furnace-loop component costs than the two pressurized furnace cases burning LBTU and HBTU gas. As noted previously, the LBTU gasifier costs appear in the balance of plant. The furnace-loop major component cost is lower for case 4, a PF with LBTU gasifier, than for case 7, a PF with HBTU gas, apparently because of the large quantity of power generated in the furnace loop of case 7 by the combined gas turbine/steam turbine system.

Contingency and escalation are applied as percentages of these costs and therefore reflect the differences described. Interest during construction also reflects these costs but in addition is a function of the construction time, which G.E. estimated at 4 years for the three coal-burning plants and 3 years for a pressurized furnace system burning HBTU gas.

Table 5.5-4 presents similar cost information for three cases selected from the recuperated unbottomed cases studied by Westinghouse. They include a PFB (case R22), a PF with integrated LBTU gasifier (case R30), and a PF burning "over-the-fence" HBTU gas (case R24). Westinghouse did not study an AFB case. The same trends can be seen in the Westinghouse cases that were described for the G.E. cases, with the exception of the case using a pressurized furnace with an integrated LBTU gasifier. As with G.E.'s case 4, the gasifier cost is included in the balance-of-plant in this table. Westinghouse estimated capital cost and cost of electricity for this case to be substantially higher than for the PFB case, while G.E.'s estimates were lower than for their PFB case. This difference is apparently due to G.E.'s use of a combined gas turbine/steam turbine cycle in the furnace loop that produced almost 60 percent of the total power output in addition to supplying compressed air and steam for the gasifier. Westinghouse used a low-temperature gas turbine with a heat-recovery steam generator for gasifier steam requirements only. With this configuration the furnace loop produced only 10 percent of the total power. It may also be noted that the balance-of-plant costs estimated by Westinghouse are substantially higher than those estimated by G.E., but contingency is lower.

Although it is difficult to compare component costs between the two contractors, because no two cases had all parameters alike, table 5.5-5 presents a cost breakdown for the roughly similar PFB cases of table 5.5-4 (G.E. case 6 and Westinghouse case R22). Costs of the helium-loop major components and the pressurizing gas turbine and recuperator in the furnace loop are expressed in terms of dollars per kilowatt of gross loop power (in parentheses) as well as dollars per kilowatt of total net power.

The cost of the turbomachinery for the helium cycle was estimated by G.E. at \$49/kWe of helium-loop gross power output. The corresponding Westinghouse estimate was about \$60/kWe. General Electric assumed a single-shaft machine incorporating a small percentage of compressor bleed flow for turbine disk cooling, while Westinghouse assumed a two-shaft machine with no provisions for turbine disk cooling. The somewhat higher cost estimate for the two-shaft machine seems reasonable.

The recuperator cost estimates for the two cases in table 5.5-4 are not directly comparable because of a difference in the design effectiveness, 0.85 for G.E. and 0.90 for Westinghouse. If the G.E. recuperator cost were adjusted to a 0.90 effectiveness by scaling in proportion to NTU requirements, the cost in \$/kWe of helium-loop gross power would increase from \$50/kWe to about \$79/kWe, or almost twice the cost estimated by Westinghouse. Westinghouse also assumed a lower value of pressure loss ratio (delta P/P) for their recuperator than did G.E., but this difference would have only a small effect on recuperator costs in the range of pressure loss ratios considered. Both contractors assumed conventional tube-and-shell construction, with a single material throughout. In addition to a higher level of recuperator cost, cases studied by G.E. to investigate the effect of recuperator effectiveness on costs showed recuperator costs increasing faster than would be expected from a simple NTU relation. The Westinghouse results seemed to follow more closely the NTU requirements. Both factors would tend to make the G.E. cost of electricity minimize at lower recuperator effectiveness than that of Westinghouse. The G.E. results indicated that minimum COE occurs at an effectiveness below 0.85. Although the Westinghouse results show a minimum at around 0.90, it is difficult to draw any definite conclusions because the recuperator effectiveness in both the pump-up loop and the helium loop were varied simultaneously. A further discussion of recuperator performance trade-offs is presented in section 5.5.2.2.2.

Westinghouse's precooler cost estimate is about 30 percent higher than G.E.'s, but the precooler is a relatively low-cost component and does not have a large impact on the COE.

Although the total-cost estimates for the furnace-loop major components are within about 10 percent, there are significant differences in each of the components. General Electric's cost estimate of the pressurizing gas turbine and recuperator is about double that of Westinghouse, while the estimated furnace cost is about 20 percent less. Costs of all the furnace types are discussed and compared in section 5.14. The cost of the G.E. pressurizing gas turbine and recuperator (\$334/kWe based on gross furnace-loop power) appears to be inconsistent with the cost estimates made by G.E. for similar equipment used in other systems studied in Phase 1. Estimated costs of the pressurizing equipment for the PFB case for the liquid-metal topping cycle and supercritical carbon dioxide cycle, for example, were only \$167 per kilowatt of furnace-loop power. This is half that estimated for the closed-cycle gas turbine system and is in reasonable agreement with the Westinghouse estimate.

As indicated previously, Westinghouse's balance-of-plant cost estimate is substantially higher than G.E.'s, while the contingency is lower. A large part of the difference in balance-of-plant cost estimates can be attributed to site labor. Westinghouse's estimate of installation costs amounted to about \$96 per kilowatt of net power for case R22, while G.E.'s site labor costs for case 8 were estimated at about \$41/kWe. Escalation and interest charge rates were specified by NASA, and the differences between the two contractors reflect essentially the differences in capital costs discussed and the difference between the G.E. estimated construction time of 4 years and the Westinghouse estimate of 4.55 years.

5.5.2.2.2 <u>Influence of recuperator effectiveness and pressure losses.</u> - Brayton cycles have a relatively high ratio of compressor power to turbine power. Since the useful output is proportional to the difference between these two, the system performance is very sensitive to parameters or requirements that affect the ratio of turbine power to compressor power. Such parameters or requirements include turbine and compressor aerodynamic performance, system pressure losses, and turbine cooling requirements. The efficiency of Brayton cycles is also very sensitive to recuperation, which essentially reduces the temperature range over which heat is added to and rejected from the cycle. In the case of closed-cycle gas turbines these sensitivities are especially significant because they result in a strong trade-off between capital cost and system efficiency. The closed-cycle gas turbines considered in ECAS have more heat exchangers than the open-cycle gas turbines considered. In addition to the recuperator, they have heat input through a furnace/heat exchanger, they reject heat through a precooler and/or a bottoming-cycle heat-recovery boiler, and sometimes they include a compressor intercooling heat exchanger.

Pressure loss is a primary consideration in the design and layout of all these heat exchangers and the ducting between them. When high-effectiveness heat exchangers (particularly the recuperator) are considered for the sake of performance, the physical size of the heat exchangers becomes large, which makes low-pressure-loss ducting of the working gas between components a more difficult problem.

The curves in figure 5.5-5 show the sensitivity of the closed-cycle gas turbine thermodynamic efficiency to recuperator effectiveness and pressure losses. The pressure losses are indicated in the figure by the loss pressure ratio L, which is the turbine pressure ratio divided by the compressor pressure ratio. The thermodynamic efficiencies range from the mid-30's with recuperator effectiveness and loss pressure ratio similar to the G.E. base case to the mid-40's with recuperator effectiveness and loss pressure ratio near the extremes of the range of parametric variations considered. The G.E. base case (which has 0.85 recuperator effectiveness and 0.913 loss pressure ratio) is plotted near curve A. It is slightly lower mainly because G.E. included almost 4 percent compressor bleed flow for the turbine cooling, while none is included in the NASA calculated curves in figure 5.5-5. The turbine coolant is used for blocking the hotter working gas from the wheel space at the roots of the rotor blades, but not for cooling the blades in either stator or rotor rows. General Electric base case 1 has a furnace-loop efficiency of about 88 percent and auxiliary power requirements of about 7.5 percent so that the powerplant efficiency is 29.5 percent, reduced from the 36.4 percent thermodynamic efficiency shown in the figure.

Most of the Westinghouse cases used a 0.90 effectiveness recuperator and smaller pressure losses. Also most cases had a higher compressor-inlet temperature than the 80° F assumed by G.E. Only one case, R39 with once-through cooling, had an 80° F compressor-inlet temperature. All Westinghouse cases with cooling towers had higher compressor-inlet temperature (which reduces cycle efficiency). Since figure 5.5-5 is a comparison of thermodynamic cycle efficiency (helium cycle only), Westinghouse case R38 was plotted, it being the Westinghouse case with the closest helium-cycle parameters to those of curve B. Westinghouse calculations, like those of the curves of figure 5.5-5, did not include compressor bleed for turbine cooling. The pressure losses for case R38 are slightly lower than those assumed in curve B. However, the Westinghouse mechanical losses assumed were higher, and the two effects cancel each other.

Curve F has the same recuperator effectiveness and pressure losses as curve A but includes one stage of compressor intercooling. General Electric case 20 is such a case except that it includes an additional pressure loss for the intercooler. This additional pressure loss plus the turbine cooling that G.E. included is apparently the reason case 20 is below curve F.

As shown by comparison of curves A to E, the thermodynamic efficiency increases considerably as the recuperator effectiveness is increased and pressure losses are reduced. However, the recuperator cost would also increase considerably. As the recuperator effectiveness is increased from 0.85 to 0.90 the recuperator heat transfer area per unit of helium flow increases by about a factor of 1.6. Increasing the effectiveness from 0.85 to 0.94 increases the area per unit flow about 2.7 times. However, as shown in figure 5.5-5 as the recuperator effectiveness is increased the pressure ratio that yields maximum efficiency decreases. This reduces the power output per unit of helium flow rate, so that the increase in recuperator heat transfer area per unit of power output is actually higher than the factors just stated. For example, the recuperator area per unit of power output for the point in figure 5.5-5 with 0.94 recuperator effectiveness and 2.0 pressure ratio on curve E would be 3.2 times that for the point on curve A with 0.85 effectiveness and 2.5 pressure ratio. If the recuperator configuration and materials were similar for these two cases, this 3.2 factor would be roughly indicative of the ratio of recuperator costs. Since these are large heat exchangers for the system power levels examined in ECAS, they are constructed in modules, with module size influenced by manufacturing and shipping constraints. An increase in recuperator size of the order of a factor of 3 would significantly affect the number of modules, which would in turn significantly affect the cost of gas ducting to and from the modules. Both of these factors would affect the installation costs.

The choice of recuperator effectiveness and system pressure loss is a trade-off between these capital cost and performance considerations. This trade-off is highly influenced by the recuperator design approach and the percentage of total system cost that is due to the recuperator and its associated ducting and installation costs. Both contractors used tube-and-shell recuperator designs (see section 5.5.2.2.4). The G.E. results show the lowest COE for a recuperator effectiveness of 0.85, the lowest value considered. In the Westinghouse results the lower values of recuperator effectiveness also yield the lower COE results. However, in this case the furnace loop is pressurized and the furnace-loop recuperator effectiveness is varied simultaneously with the helium recuperator effectiveness. If a more compact and less expensive recuperator design approach were considered, the trade-off would favor higher effectivenesses. This would result not only in an increase in system efficiency, but also in some cost reductions (in terms of \$/kWe) of some other components and balance-of-plant items. Such items as the furnace, coal handling systems, and cooling towers have costs in dollars more directly proportional to heat input or heat rejection and hence costs in dollars per kilowatt inversely proportional to efficiency.

AiResearch, Division of Garrett Corp., advocates the use of plate-fin heat exchangers in the closed-cycle gas turbine system in order to achieve higher performance by forcing the capital cost - system efficiency tradeoff toward the selection of higher recuperator effectiveness and lower pressure loss. After the Phase 1 public briefing in May 1975 by the contractors, AiResearch sent comments to NASA concerning this approach. They would contain the plate-fin recuperator core within a pressure vessel that was pressurized to the minimum pressure in the loop. The thermodynamic efficiency plotted near curve G was calculated by AiResearch using parameters similar to those assumed by curve G. It falls slightly below curve G because it assumes slightly higher pressure losses and slightly lower compressor efficiency and includes a 1 percent compressor bleed for turbine cooling. For the same furnace-loop efficiency and auxiliary losses as calculated by G.E., this AiResearch point would have an overall energy efficiency of 36.5 percent compared with the G.E. intercooled case 20 with a overall efficiency of 31.6 percent. AiResearch predicts a much lighter heat-exchanger core for this case than calculated by G.E. for a tube-and-shell recuperator. Although such plate-fin heat exchangers would be expected to cost more per unit weight than tube-and-shell heat exchangers, their compactness and reduced weight have the potential for lower cost at higher effectiveness. Recuperators are further discussed in section 5.5.2.2.4.

5.5.2.2.3 Performance potential at higher temperatures. - Both G.E. and Westinghouse considered parametric cases with helium-turbine-inlet temperatures above 1500° F. Both used high-temperature-alloy tubular heat exchangers in the furnace. Clean fuels were used in all cases. Because of the fuel conversion efficiencies, however, the overall energy efficiencies were much lower than for the direct-coal-fired cases. In Phase 2 a nominally 1900° F helium cycle using a coal-fired AFB furnace with a ceramic heat-exchanger section will be studied.

Figure 5.5-6 shows performance calculations for a 1900° F turbine-inlet-temperature, closed-cycle gas turbine with intercooling. The range of recuperator effectivenesses is the same as considered in figure 5.5-5, and the pressure losses are assumed to be the intermediate values considered in figure 5.5-5. The ordinate showing the overall energy efficiency assumes a furnace-loop efficiency of 88 percent and plant auxiliary requirements of 7.5 percent. These assumptions approximate the G.E. values for a closed-cycle plant with a coal-fired AFB furnace.

Turbine cooling would be required with a turbine-inlet temperature of 1900° F and state-of-the-art materials. The curves in figure 5.5-6 show the influence of turbine cooling on system performance. The turbine cooling schedule used was calculated by using a simplified cooling effectiveness curve based on data published in reference 7. Since the data are for open-cycle gas turbines using air coolant at lower pressures than of interest here, use of this effectiveness curve should be considered as an approximation. However, it is judged to be a reasonable approximation. The performance of the helium turbine was calculated by considering each row of blades individually, assuming that the coolant from each row enters and mixes with the main gas stream before inlet to the next blade row. One-half percent of the compressor flow was assumed to be used in each turbine stage for wheel space blockage flow. The number of turbine stages was assumed to vary from 6 at a pressure ratio of 2.5 to 10 at a pressure ratio of 4.5.

The temperature reduction in each stage of a helium turbine (because of the higher specific heat of helium) is much smaller than in an open-cycle gas turbine. This necessitates the cooling of many more stages. (Only the first stage of a 1900° F open-cycle gas turbine would require cooling.) As a result the total amount of cooling is larger for the helium turbine (10 percent or more for the range of conditions in fig. 5.5-6). And consequently, the effect of turbine cooling on performance shown in figure 5.5-6 is larger than would be expected in an open-cycle gas turbine at 1900° F.

Also shown in the figure is a single point for a closed-cycle gas turbine with an organic bottoming cycle. In this case the closed gas turbine cycle includes turbine cooling, has a 0.85 recuperator effectiveness, and does not include compressor intercooling. The organic bottoming cycle is a 460° F turbine-inlet-temperature Fluorinol-85 cycle with a 90° F condensing temperature. The organic-bottomed case including turbine cooling exceeds the performance of the unbottomed intercooled configuration with the same recuperator effectiveness, even when turbine cooling is not included in the intercooled case. In addition, although not shown in the figure, the penalty of turbine cooling when an organic bottoming cycle is used is much less (about half) than in the unbottomed configuration. With turbine cooling the flow rate on the hot side of the recuperator exceeds that on the cold side. As a result the recuperator hot-side exit temperature (the organic boiler helium inlet temperature) is higher when turbine cooling in included. The heat input to the organic bottoming cycle is therefore increased. In effect, the loss in power output from the helium turbine due to turbine cooling is in part compensated for by an increase in the organic bottoming cycle output.

A significant point to be made from figure 5.5-6 is that major performance gains could be made by reducing the amount of turbine cooling required. The performance with turbine cooling at 1900° F in the figure is not significantly higher than that obtained at 1500° F without turbine cooling. The power output per unit of flow is higher for the 1900° F case, however, and this would reduce the specific cost of some of the components. The cooling requirements used in these calculations are, as explained, an approximation. Further experimental data and analysis would be needed to determine whether these requirements are actually necessary. However, several approaches to reducing turbine cooling requirements are obvious. The development of advanced turbine materials and/or thermal barrier coatings would reduce cooling requirements. Also in the case of the closed-cycle gas turbine, the working fluid is a design variable that could be chosen so as to reduce the number of turbine stages and hence cooling needs. A mixture of helium and a heavier inert gas could result in fewer turbine stages while still maintaining a relatively high heat transfer coefficient, which is desirable from the standpoint of the heat exchangers.

5.5.2.2.4 <u>Other important factors</u>. - The following factors were also considered.

5.5.2.2.4.1 Working fluid: Both G.E. and Westinghouse used helium as the working fluid for all parametric cases. Helium has a very good heat transfer coefficient, which is desirable from the standpoint of the heat exchangers. But because of its low molecular weight it results in a large number of compressor and turbine stages and consequently in increased turbomachinery complexity and cost. This is particularly true of the higher pressure ratios, which are of interest for the intercooled configuration or for higher turbine-inlet temperatures.

By using a mixture of helium and a heavier inert gas, the working fluid could be tailored to provide a more optimum combination of molecular weight and heat transfer characteristics. Selection of a desirable mixture requires more study to examine the trade-off between heat-exchanger cost, turbomachinery cost, and the cost and availability of the gas. In cases where the initial turbine stages require cooling, a reduction in total number of stages through the use of a higher-molecular-weight gas mixture would also reduce the amount of cooling required. As discussed in the previous section this could significantly improve performance.

5.5.2.2.4.2 Pressure level: The effect of system pressure levels on cost was examined by Westinghouse on the basis of a constant output power. This required turbomachinery, heat-exchanger, and duct sizes to vary and cost estimates had to include both size and pressure effects. It would also be desirable to evaluate pressure level effects with constant turbomachinery size, wherein output power is proportional to pressure level. Cost increases in the closed cycle would arise primarily from increasing the pressure containment capability. It would also seem likely that a minimum cost per unit output would be achieved by using the largest turbomachinery sizes practical, consistent with fabrication and handling capabilities, to minimize turbomachinery loss effects, such as from seals and tip losses. Pressure levels would then be set to the point where costs due to higher pressures increase as rapidly as the increases in output power with higher pressure.

5.5.2.2.4.3 Recuperators: Both contractors used tube-and-shell construction with a single material throughout. Typically, G.E. assumed the use of 304 stainless steel, and Westinghouse assumed 316 stainless steel. The sizing techniques used by the contractors compare closely based on an estimate of their heat transfer coefficients. The G.E. cost estimates however, were about twice as high per unit of surface area as the Westinghouse cost estimates.

Additional cost estimates for closed-cycle gas turbine recuperators were obtained from Zurn Industries, Inc., through an NASA contract with Burns and Roe. Zurn selected lower cost materials and used two tube-and-shell units in series. A 0.5 chromium - 1.25 molybdenum alloy was assumed for the hot end; and below 650° F, carbon steel was used. The Zurn cost estimates were about half those of Westinghouse. The use of lower cost materials is the primary reason for the lower Zurn cost estimates.

A reduction in the recuperator cost through the use of different materials at different temperature levels could have a significant effect on overall system cost and performance. As discussed in section 5.5.2.2.2 this could shift the capital cost - performance trade-off toward the use of higher recuperator effectiveness. The increased system efficiency could then result in reduced capital costs in other parts of the system from reduced heat input and reduced heat rejection per unit of power produced.

Another alternative with potential for lowering recuperator cost is the use of plate-fin heat exchangers. However, development of this technology constitutes a substantial advance over the current state of the art. The application of plate-fin heat exchangers has been limited to open-cycle systems at pressure levels of approximately 8 to 10 atmospheres and temperatures near 900° F. The closed-cycle conditions would impose requirements for substantially higher pressures (500 to 1000 psia) and higher temperatures while still meeting the requirements for high reliability and availability, ease of maintenance, factory assembly, and field erection at low cost. The use of a vessel pressurized to the minimum system pressure to contain the plate-fin core would considerably reduce the pressure difference experienced by the core, but the pressure difference across the two sides would still be higher than current experience.

5.5.3 Concluding Remarks

The coal-fired cases of both contractors resulted in the highest overall efficiency and lowest COE. Cleaner fuels allow higher firing temperatures and/or more power extraction from the furnace cycle but result in higher COE because of the higher fuel prices. The results show the COE of coal-fired cases to be dominated by capital charges and the COE of clean-fuel cases to be dominated by fuel charges. Consideration of the COE over the lifetime of the plant, in a period of rising fuel prices, would therefore further favor the coal-fired configurations.

The coal-fired cases, with 1500° F helium-turbine-inlet temperature ranged from the low to mid-30's in overall efficiency, with COE also in the low to mid-30's in mills/kW-hr. With bottoming cycles, the results show a substantial increase in efficiency, to about 38 percent. The G.E. cases with bottoming cycles had higher COE because of the increased capital cost. Westinghouse configured the bottomed cases differently, using an unrecuperated helium cycle with the bottoming cycle receiving heat from both the helium cycle and the pressurized furnace cycle. These cases had a lower COE but generally less than half of the power output from the helium cycle (in contrast tc about 80 percent for G.E. cases).

Both contractors' results show that the use of intercooling in the recuperated, unbottomed cycle both increases overall efficiency and decreases COE. Few parametric cases with intercooling were considered; hence, it is likely that better cases could be found through further analysis. Cost reductions in recuperators through use of less-expensive materials at the lower temperature end of the heat exchanger or through the development of plate-fin heat exchangers could have a significant effect on this system configuration. Lower cost and/or more compact recuperators would favor the use of higher effectiveness recuperators, which could result in higher performance and lower cost of electricity.

Considerations of helium-turbine-inlet temperatures above 1500° F would result in turbine cooling requirements having a significant effect on system performance. Development of advanced turbine material and/or thermal barrier coatings, or the use of a heavier working gas to reduce the number of turbine stages could significantly reduce the turbine cooling performance penalty.

Closed-cycle gas turbines may be more competitive in applications where cooling water is severely limited. Because they reject heat over a range of temperatures from near ambient to several hundred degrees, they are more compatible with dry cooling towers than are Rankine cycle systems. This heat rejection at temperatures to 400° or 500° F also presents the opportunity to use waste heat tc produce pressurized hot water or steam for industrial or commercial applications. Utilization of this waste heat in other than a bottoming cycle for electricity production was, however, beyond the scope of ECAS.

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TABLE 5.5-1. - PARAMETERS FOR RECUPERATED (NONBOTTOMED) CLOSED-CYCLE GAS TURBINES

Parameter	Furnace								
	Atmospheric fluidized bed	Conventional atmospheric	Pressurized fluidized bed		Pressurized				
	Fuel								
	Coal	Distillate	Coal		HBTU gas		LBTU gas		Distillate
	Contractor								
	General Electric	Westinghouse	General Electric	Westinghouse	General Electric	Westinghouse	General Electric	Westinghouse	
	Number of parametric points								
	22	1	1	8	7	1	3	1	37
Primary loop:									
Compressor discharge pressure, psia	1000	1000	1000	1000	1000	1000	1000	1000	500, 1000, 2000
Turbine-inlet temperature, °F	1350, 1500	1500	1500	1500	1500, 1700	1500	1500	1500	1200, 1500, 1800
Compressor pressure ratio	2, 2.5, 3	2.5	2.5	2.5	2, 2.5, 3	2.5	2.5	2.5	2, 2.5, 3, 4
Recuperator pressure drop, ΔP/P	0.03, 0.05, 0.07	0.02	0.03	0.02	0.03	0.02	0.03	0.02	0.02, 0.04, 0.06
Recuperator effectiveness	0.85, 0.90, 0.95	0.9	0.85	0.9	0.85, 0.9	0.9	0.85	0.9	0.8, 0.9, 0.95
Compressor inlet temperature, °F	60, 80, 88, 116	96.5	80	96.5	80	96.5	80	96.5	79, 96.5, 120
Number of units	1, 2, 4	1	1	1	1	1	1	1	1
Cooling tower type	Wet, dry	Wet	Wet	Wet	Wet	Wet	Wet	Wet	Wet, dry, once through
Intercooling pressure ratio	2.5, 4, 6.25	----	----	----	----	----	----	----	4, 5, 7
Pressurizing loop:									
Turbine-inlet temperature, °F	----------	----------	1600	1100, 1700	1200	1100	[a]1800	1100	1100, 2200
Pressure ratio	----------	----------	10	5, 10, 15	8	10	10	10	5, 10, 15
Combustor pressure drop, ΔP/P	----------	----------	N.S.	0.09	N.S.	0.06	N.S.	0.06	0.06, 0.09, 0.012
Recuperator effectiveness	----------	----------	0.85	0, 0.9	----	----	----	----	0, 0.85, 0.9, 0.95
Recuperator pressure drop, ΔP/P	----------	----------	N.S.	0, 0.03	----	----	----	----	0.03, 0
Coal type	Illinois #6 North Dakota Montana	Illinois #6	Illinois #6	Illinois #6 North Dakota Montana	Illinois #6	Illinois #6	Illinois #6 North Dakota Montana	Illinois #6	Illinois #6

[a]Integrated with gasifier and steam turbine.

TABLE 5.5-2. - PARAMETERS FOR

Parameter	General Electric		
	Furnace		
	Atmospheric fluidized bed		
	Fuel		
	Coal		
	Bottoming-cycle fluid		
	R-22	FL-85	Steam
	Number of parametric points		
	7	1	5
Primary loop:			
Compressor discharge pressure, psia	1000	1000	1000
Helium turbine-inlet temperature, °F	1500	1500	1500
Compressor pressure ratio	2.5	2.5	2.5
Recuperator pressure drop, ΔP/P	0.03	0.03	0.03
Recuperator effectiveness	0.85, 0.9	0.6	0, 0.5, 0.85, 0.9
Compressor inlet temperature, °F	80	80	80
Helium heater pressure change, ΔP/P	0.015	0.015	0.015
Precooler	With	With	With
Vapor generator pressure drop, ΔP/P	0.01	0.01	0.01
Pressurizing loop:			
Turbine-inlet temperature, °[illegible]	----------------	--------	----------------
Pressure ratio	----------------	--------	----------------
Combustor pressure dr[illegible] ΔP/P	----------------	--------	----------------
Vapor generator pressure drop, ΔP/P	----------------	--------	----------------
Bottoming loop:			
Turbine-inlet pressure, psia	1500, 1600, 1700	650	125, 100, 400, 800
Turbine-inlet temperature, °F	390, 400, 410, 430	460	384, 413, 561, 900
Helium pinch-point ΔT	30, 50, 70	50	30
Turbine reheat pressure, psia	----------------	--------	----------------
Turbine reheat temperature, °F	----------------	--------	----------------
Desuperheating recuperator	None	None	None
Cooling tower type	Wet, dry	Wet	Wet, dry
Coal type	Illinois #6	Illinois #6	Illinois #6

[a]No recuperator.

Westinghouse						
Furnace						
Pressurized furnace						Pressurized fluidized bed
Fuel						
Distillate				HBTU gas	LBTU gas	Coal
Bottoming-cycle fluid						
R-12	Methyl-amine	SO_2	Steam			
Number of parametric points						
2	4	1	40	1	1	3
1000	1000	1000	500, 1000, 2000	1000	1000	1000
1500	1500	1500	1200, 1500, 1800	1500	1500	1500
2.5	2.5	2.5	1.5, 2, 2.5, 3, 4	2.5	2.5	2.5
(a)	(a)	(a)	(a)	(a)	(a)	(a)
(a)	(a)	(a)	(a)	(a)	(a)	(a)
200	200	200	96.5, 150, 200, 250, 300, 320	200	200	200
0.02	0.02	0.02	0.02, 0.04, 0.06	0.02	0.02	0.02
None	None	None	With, without	With	With	With
0.02	0.02	0.02	0.02, 0.04, 0.06	0.02	0.02	0.02
2200	1100, 2200	2200	1100, 1700, 2200	2200	2200	1700
10	10	10	5, 10, 15	10	10	10
0.06	0.06	0.06	0.03, 0.06, 0.09, 0.12	0.06	0.06	0.09
0.04	0.04	0.04	0, 0.02, 0.04, 0.06	0.04	0.04	0.04
2500	2000	1800	1250, 1600, 2000, 2500, 3500	3500	3500	3500
700	550	950	800, 850, 900, 1000	900	900	900
40	40	40	40, 60, 80	40	40	40
----------	----------	----------	250, 350, 500 None	500	500	500
----------	----------	----------	800, 850, 900, 1000, None	950	950	950
With, without	None	None	None	None	None	None
Wet	Wet, dry, direct condensing	Wet	Wet, dry, once through	Wet	Wet	Wet
Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6	Illinois #6 North Dakota Montana

TABLE 5.5-3. - CONTRACTORS' BASE-CASE PARAMETERS FOR CLOSED-CYCLE GAS TURBINES

	General Electric case 1	Westinghouse		
		Case 25R	Case 48R	Case 5C
Furnace	AFB	PFB	Conventional atmospheric	Pressurized
Fuel	Illinois #6	Illinois #6	Distillate	Distillate
Compressor discharge pressure, psia	1000	1000	1000	1000
Helium loop:				
Turbine-inlet temperature, ^{o}F	1500	1500	1500	1500
Compressor pressure ratio	2.5	2.5	2.5	2.5
Recuperator effectiveness	0.85	0.9	0.9	-----
Recuperator pressure drop, $\Delta P/P$	0.03	0.02	0.02	-----
Loop pressure drop,[a] $\Delta P/P$	0.08733	0.059	0.059	0.040
Compressor inlet temperature, ^{o}F	80	96.5	96.5	200
Cooling tower type	Wet	Wet	Wet	Wet
Pressurizing loop:				
Turbine-inlet temperature, ^{o}F	--------	1700	-----	2200
Pressure ratio	--------	10	-----	10
Bottoming loop:				
Turbine-inlet pressure, psia	--------	----	-----	10
Turbine-inlet temperature, ^{o}F	--------	----	-----	3500
Working fluid	--------	----	-----	Steam

[a]Calculated as 1 - (Turbine pressure ratio)/(Compressor pressure ratio).

TABLE 5.5-4. - COSTS FOR RECUPERATED CLOSED-CYCLE GAS TURBINE

	General Electric				Westinghouse		
	AFB case 1	PFB case 8	PF-LBTU case 4	PF-HBTU case 7	PFB case R22	PF-LBTU case R30	PF-HBTU case R29
System parameters:							
Helium loop:							
Turbine-inlet temperature, $^{\circ}F$	1500	1500	1500	1500	1500	1500	1500
Compressor-inlet temperature, $^{\circ}F$	80	80	80	80	96.5	96.5	96.5
Compressor pressure ratio	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Recuperator effectiveness	0.85	0.85	0.85	0.85	0.90	0.90	0.90
Recuperator pressure loss, $\Delta P/P$	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Loop pressure loss, $\Delta P/P$	0.08733	0.08733	0.08733	0.08733	0.059	0.059	0.059
Furnace pressurizing loop:							
Turbine-inlet temperature, $^{\circ}F$	--------	1600	1800	1200	1700	1100	1100
Pressure ratio	--------	10	10	8	10	10	10
Recuperator effectiveness	--------	0.85	Steam	--------	0.90	-----	-----
Power output, MWe:							
Furnace loop	--------	110	441	41	84	35	46
Helium loop	300	300	300	300	253	332	345
Net	276	398	732	335	330	345	387
Capital cost, $/kW net:	814	754	692	455	766	1080	706
Major components - helium loop	115.9	80.4	43.7	95.5	86.1	105.4	97.7
Major components - furnace loop	178.6	202.3	96.5	109.6	181.9	155.8	167.7
Balance of plant	188.4	165.1	270.2	86.5	249.1	463.7	203.0
Contingency	96.7	89.4	82.1	58.3	32.7	45.5	30.6
Escalation	112.3	104.0	95.5	52.9	101.6	144.7	96.6
Interest during construction	122.1	113.0	103.8	52.3	115.2	164.5	110.4
Time for construction, yr	4	4	4	3	4.55	4.62	4.75
Cost of electricity, mills/kW-hr:	38.8	35.9	34.5	46.7	34.6	47.1	50.4
Capital	25.7	23.8	21.9	14.4	24.2	34.1	22.3
Fuel	9.8	9.1	9.4	30.4	8.5	9.4	27.6
Operating and maintenance	3.2	3.0	3.3	1.9	1.9	3.6	0.5
Powerplant efficiency, percent	29.5	31.8	31.0	29.2	34.0	32.2	32.2

TABLE 5.5-5. - COST COMPARISON OF RECUPERATED CLOSED-CYCLE GAS TURBINE SYSTEMS

WITH PRESSURIZED FLUIDIZED BEDS

	General Electric case 8		Westinghouse case R22	
Major component costs:				
Helium loop, $/kW net ($/kW He):	80.4 (106.7)		86.1 (112.3)	
Turbine/generator/compressor		36.9 (49.0)		46.1 (60.1)
Recuperator		37.7 (50.0)		32.0 (41.8)
Precooler		5.8 (7.7)		8.0 (10.4)
Furnace loop, $/kW net ($/kW furnace loop):	202.3		181.9	
Pressurizing gas turbine and recuperator		92.5 (334.5)		46.0 (180.4)
Furnace		109.8		135.9
Balance of plant, $/kW net	165.1		249.1	
Contingency, $/kW net	89.4		32.7	
Escalation, $/kW net	104.0		101.6	
Interest during construction, $/kW net	113.8		115.2	
Total capitalization, $/kW net	754		766	

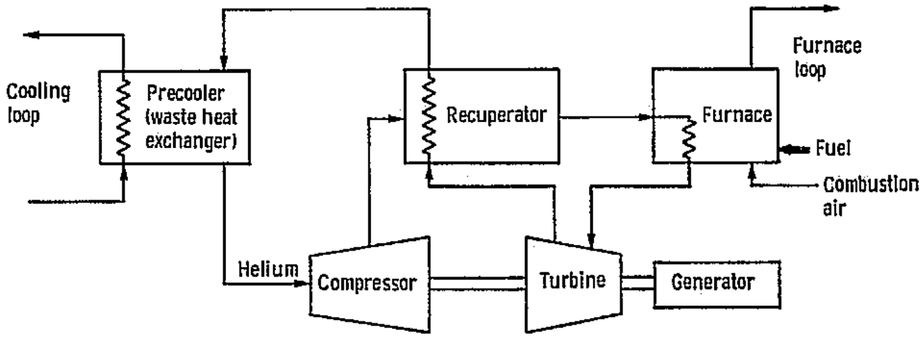


Figure 5.5-1 - Helium loop for closed-cycle gas turbine system.

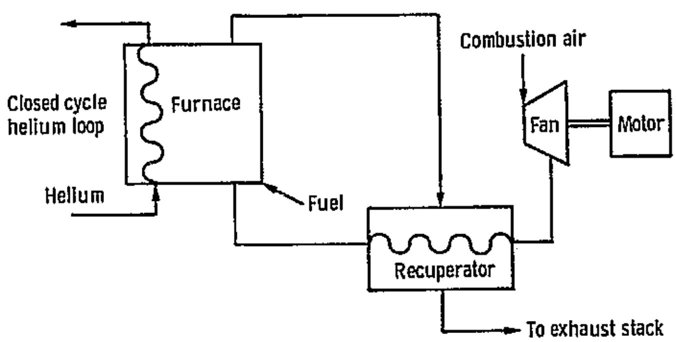


Figure 5.5-2. - Atmospheric furnace loop for closed-cycle gas turbine system.

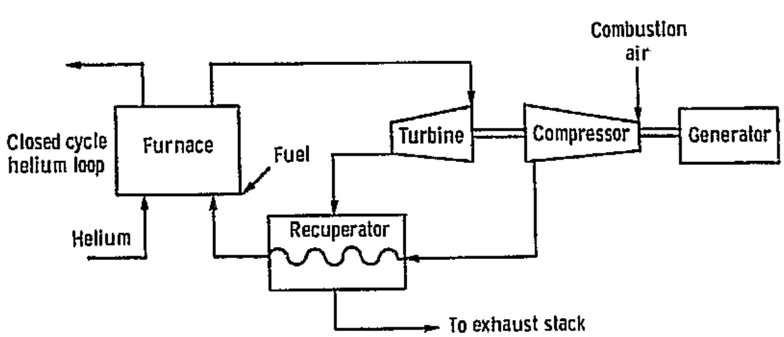


Figure 5.5-3. - Pressurized furnace loop for closed-cycle gas turbine system.

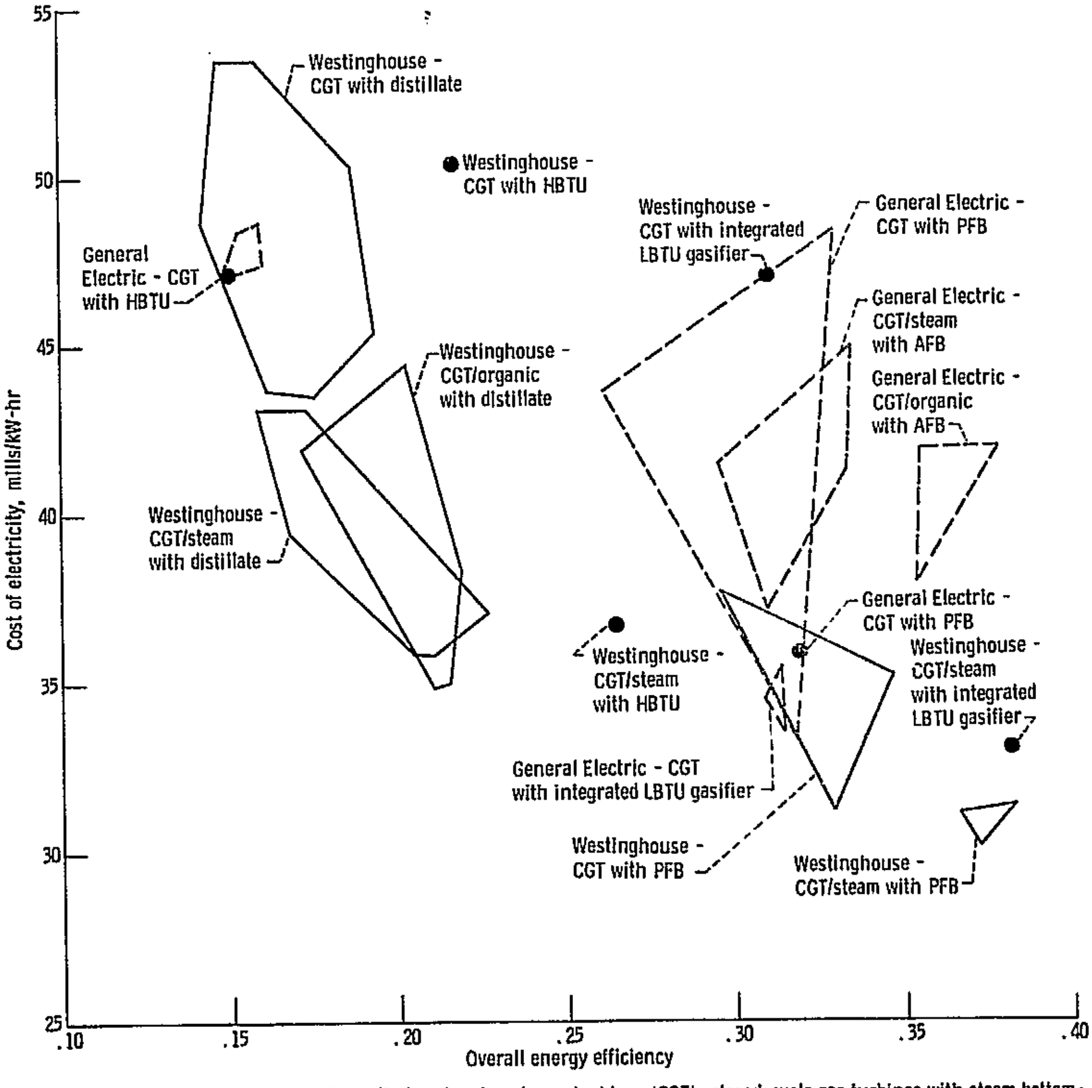


Figure 5.5-4. - Overall range of results for closed-cycle gas turbines (CGT), closed-cycle gas turbines with steam bottoming cycles (CGT/steam), and closed-cycle gas turbines with organic bottoming cycles (CGT/organic), with coal-fired atmospheric (AFB) and pressurized (PFB) fluidized beds.

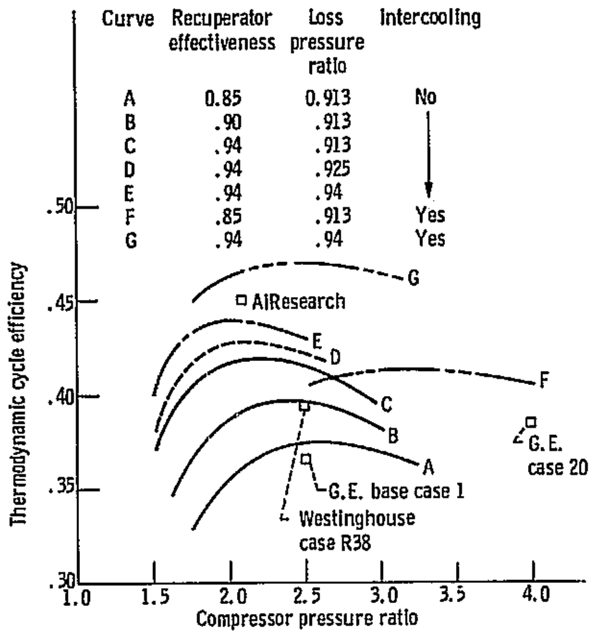


Figure 5.5-5. - Performance of closed-cycle gas turbine with turbine-inlet temperature of 1500° F, compressor inlet temperature of 80° F, turbine and compressor polytropic efficiencies of 0.90, and helium working fluid.

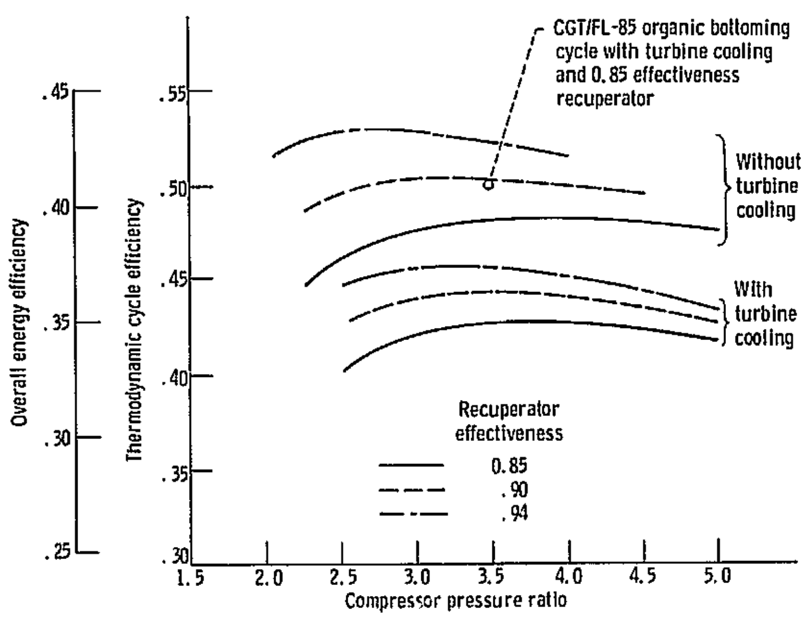


Figure 5.5-6. - Performance of closed-cycle gas turbine with single-stage intercooling; turbine-inlet temperature of 1900° F, turbine and compressor polytropic efficiencies of 0.90, loss pressure ratio of 0.925, and helium working fluid.

5.6 SUPERCRITICAL CARBON DIOXIDE CYCLE
by Donald C. Guentert

The supercritical carbon dioxide cycle is a closed cycle employing carbon dioxide gas at supercritical pressures. It offers advantages in efficiency over the inert-gas, closed Brayton cycle because real-gas effects near the critical point reduce pump or compressor power to about 20 percent of the total turbine power, as compared with about 50 to 55 percent for the inert-gas, closed Brayton cycle. Compactness of turbomachinery is also a characteristic of the supercritical carbon dioxide cycle. However, it is a highly recuperated cycle, with thermal loads in the recuperator equal to about 2.5 times the cycle input, and the recuperator cost is a significant part of the plant cost. Cycle conditions combining very high pressures at relatively high temperatures result in difficult component design problems.

5.6.1 Scope of Analysis

The supercritical carbon dioxide cycle was studied only by General Electric in the ECAS study. The cycle calculations were performed by Actron Industries, the leading exponent of the supercritical carbon dioxide cycle in this country, who have available existing carbon dioxide property data and computer programs for calculating performance. Costs were estimated by G.E. for the turbomachinery and recuperators, by Foster Wheeler for the furnace components, and by Bechtel for balance-of-plant components and installation.

Table 5.6-1 lists the cycle variations considered in the study and the range of the operating parameters. General Electric assumed a base case based on recommendations of the system advocate (Actron Industries) and studied the effect of parametric variations from this base case. The base-case configuration and parameters are underlined. A total of 32 cases were studied, including variations in the fuel, the furnace type, the primary cycle configuration, and the operating parameters.

Emphasis in the study was on the atmospheric-fluidized-bed furnace. Variations included one case with a pressurized fluidized bed and four cases with a pressurized furnace(three burning low-Btu gas from an integrated, pressurized, fixed-bed gasifier with each of the three coal types; and the fourth burning a high-Btu gas).

The primary cycle configurations considered included the simple cycle (Feher cycle), the recompression cycle, and the postheat cycle. A schematic diagram of the recompression cycle, the base-case configuration, is shown in figure 5.6-1. Cycle operating parameters included turbine-inlet temperature, pump-inlet temperature, pressure ratio, pump flow fraction (fraction of total flow passing through the pump), recuperator minimum temperature difference, and component pressure drops.

The temperature-entropy diagrams for the three cycle configurations are shown in figure 5.6-2. The simple cycle (fig. 5.6-2(a)) suffers from a large irreversible heat transfer loss from the high-temperature side to the low-temperature side of the recuperator due to property differences on the two sides. This loss appears as a reduced average temperature of heat addition to the cycle with consequent reduced cycle efficiency. This situation can be improved in the recompression cycle (fig 5.6-2(b)) by splitting the flow at the exit of the low-pressure side of the low-temperature recuperator and compressing one portion of it in a separate compressor to later mix with the pump flow at the exit of the high-pressure side of the low-temperature recuperator. The effect is to raise the average temperature in the high-pressure side of the recuperator and to raise the average temperature at which heat is added to the cycle, with a consequent improvement in cycle efficiency. However, the recuperator size and cost increase as a result of the reduced log mean temperature difference. Increasing the flow fraction passing through the pump (expressed as pump flow fraction) to a value of 1.0 results in the simple cycle. The postheat cycle is shown in figure 5.6-2(c). This cycle variation attempts to alleviate the problems in the heater resulting from high pressure at high temperature. The flow at the high-temperature recuperator exit on the high-pressure side is first expanded through the pump and compressor drive turbine before entering the heater. Although the pressure is reduced in the heater, a penalty is paid in efficiency because of the reduced average temperature at which heat is added to the cycle.

5.6.2 <u>Results of Analysis</u>

5.6.2.1 Overall Comparison

An overview of the results of the study is presented in figure 5.6-3. The large block bounds the atmospheric-fluidized-bed cases, which were emphasized in the study. These cases are characterized by fairly good efficiency (between 36 and 41 percent) but high COE's (between 56 and 78 mills/kW-hr). The base case is shown at an efficiency of 40 percent and a COE of 69.3 mills/kW-hr. The single pressurized-fluidized-bed case resulted in a reduced COE (about 57 mills/kW-hr) at about the same efficiency (slightly over 39 percent). The use of a pressurized furnace with an integrated low-Btu gasifier further reduced the COE to about 50 mills/kW-hr but at a reduced efficiency (about 35 percent). The use of a pressurized furnace with high-Btu gas resulted in both high COE (about 70 mills/kW-hr) and low efficiency (about 20 percent).

In general, the supercritical carbon dioxide cycle was characterized by good efficiency but surprisingly high COE considering views previously expressed in the literature, which generally assumed that cost benefits would result from reduced component size associated with the use of a high-density working fluid. Most of the high COE was due to very high capital costs ($1896/kWe for the base case, including contingency costs, escalation, and interest during construction). The major components of the prime cycle (turbogenerator, turbine-pump-compressor, recuperator, and precooler) were by far the major contributors to the high capital cost. They represented 62 percent of the total direct capital cost of the base case, compared to 13 percent for the furnace loop components and 25 percent for the balance of plant. These costs are considered in more detail in a later section.

5.6.2.2 Discussion and Assessment

5.6.2.2.1 <u>Effect of primary-cycle variations</u>. - Contrary to expectations, the single postheat-cycle case studied did not result in reduced capital costs. The purpose of the postheat-cycle configuration is to reduce the pressure in the heater by first expanding through the power turbine, thereby alleviating design problems of high pressures at high temperature and reducing furnace costs. In actuality, the furnace costs increased slightly, apparently as a result of the greater heat input required at the lower efficiency. Also contributing to higher capital costs was an increase in power turbine costs due to higher inlet temperature. The total effect was an increase in the COE of about 4 mills/kW-hr and a reduction in overall efficiency of 0.7 percentage point.

The recompression cycle and the simple cycle are compared in figure 5.6-4, in which the COE is plotted as a function of overall energy efficiency for four pump flow fractions. The simple cycle is represented by a pump flow fraction of 1.0. As the pump flow fraction is reduced from 1.0, the overall energy efficiency is increased. This increased efficiency is the advantage of the recompression cycle over the simple cycle. However, in spite of the increase in efficiency, COE increases as pump flow fraction is reduced. This is due to the large increase in recuperator costs resulting from the lower log mean temperature difference.

Of the cycle operating parameters that were studied, the effect of cycle pressure ratio, recuperator loss pressure ratio, and recuperator minimum temperature difference are of major interest and are presented in figures 5.6-5 and 5.6-6. Figure 5.6-5 indicates that an increase of almost 1.5 percentage points in efficiency can be achieved by increasing the cycle pressure ratio from the base-case value of 2.7 to 3.14, with a decrease of about 1.5 mills/kW-hr in the COE. Figure 5.6-6(a) indicates the sensitivity of COE to variations in the pressure drop (loss pressure ratio) allotted to the recuperator, a major cost item. It is apparent that a large decrease in COE can be achieved with little penalty in efficiency by increasing the recuperator pressure drop. The efficiency of the supercritical carbon dioxide cycle is relatively insensitive to component pressure drops because compression work is only about 20 percent of the total turbine work. Variations in pressure drop allotted to other components generally showed little effect on either efficiency or COE, primarily because they were lower cost components. Figure 5.6-6(b) shows the sensitivity of COE and overall energy efficiency to variations in the recuperator minimum temperature difference (pinch-point temperature difference). The COE is substantially reduced as the minimum temperature difference is increased but at a somewhat greater penalty in efficiency than occurred with increases in recuperator pressure drop.

One case was studied in which the turbine-inlet temperature was increased to 1600° F. A pressurized furnace burning high-Btu gas was used, and the resulting overall energy efficiency was accordingly very low because of the 50-percent fuel conversion efficiency. Whether it is desirable to go to much higher temperatures than the base-case value of 1350° F is problematical. As evaluated in the study, turbine costs were very sensitive to inlet temperature. With fluidized-bed furnaces, furnace costs would also rise as the result of decreases in mean temperature difference between the bed temperature and the working fluid temperature.

5.6.2.2.2 Effect of furnace variations. - Furnace types were compared using Illinois #6 bituminous coal. The atmospheric fluidized bed was most efficient, 40 percent, for the conditions used in the comparison but had the highest COE, 69.4 mills/kW-hr. The use of a pressurized fluidized bed reduced the COE to 57.3 mills/kW-hr as a result of the additional power provided by the low-capital-cost pressurizing gas turbine. However, efficiency decreased to 39.2 percent, reflecting the lower efficiency of the gas turbine loop. Stack losses were rather high because there was no bottoming cycle in which the energy of the gases exhausting from the regenerator of the pressurizing gas turbine could be used. Only one case was studied with a pressurized fluidized bed, and it is possible that selection of a different set of furnace loop parameters (e.g., pressure ratio and regenerator effectiveness) to reduce the stack losses might have resulted in a more attractive system. The lowest cost of electricity, about 50 mills/kW-hr, was obtained for the case with a pressurized furnace and an integrated low-Btu gasifier. In this configuration, more power was produced by the lower-cost and lower-efficiency combined cycle used for pressurization and steam for the gasifier than was produced by the supercritical carbon dioxide cycle. The result was lower COE but an efficiency reduced to about 35 percent.

5.6.2.2.3 Cycle modifications. - As previously mentioned, the capital costs of the supercritical carbon dioxide system are very high. Therefore, it is of interest to consider a combination of the cases studied that might reduce capital cost without substantially reducing the efficiency of the base case and therefore result in a lower cost of electricity. Examination of the results indicates that changes from the base case (case 1) to incorporate a pressurized fluidized bed instead of an atmospheric fluidized bed (case 5), to increase cycle pressure ratio from 2.7 to 3.14 (case 14), and to increase the recuperator pressure loss ratio from 0.05 to 0.08 (case 17) would offer a significant reduction in COE without penalty to efficiency. Table 5.6-2 lists the significant parameters of each case and the parameters of the resulting modified case. Estimates, based on an examination of the contractor's results, were made of the costs and performance of the modified case. These estimates indicate that the COE can be reduced from 69.4 mills/kW-hr for the base case to 54.9 mills/kW-hr while maintaining an overall efficiency at about 40 percent. A breakdown of the costs and performance for both the base case and the modified case is presented in table 5.6-3. The 750-MWe total plant power of the modified case includes 169 MWe from the pressurizing gas turbine in the furnace loop.

5.6.2.2.4 Costs. - The high capital costs of the supercritical carbon dioxide cycle are very high and warrant further examination. Approximately 86 percent of the COE of the base case is attributable to capital costs. Of the direct capital costs, about 75 percent lies in the major components (turbogenerator, turbine-compressor-pump, recuperator, precooler, furnace, and air preheaters), and 25 percent in the balance of plant. About 46 percent of the cost of the major components is attributable to the recuperator, and about 30 percent to the turbogenerator. The other major contributor is the furnace at about 15 percent.

Because the supercritical carbon dioxide cycle was not included in the Westinghouse contract, component cost comparisons between the two contractors cannot be made. It is informative, however, to make comparisons, where appropriate, to similar equipment in the other closed-cycle systems studied by G. E.

A comparison of base-case turbogenerator cost and weight is presented in table 5.6-4 for the carbon dioxide, potassium topping, steam, and helium closed cycles. Cost and weight are presented as $/kWe, lb/kWe, and $/lb, with kWe being the net electrical power. The very high cost of the carbon dioxide turbogenerator relative to the others is readily apparent. The cost in $/lb of the carbon dioxide turbogenerator, in particular, is very high. The carbon dioxide power turbine cost was estimated by G.E. on the basis of the cost of the high-pressure section of the advanced steam turbine, which was quite similar except that the considerably higher volume flow of the carbon dioxide turbine required a double flow design. They found that the cost of the high-pressure section of the advanced steam turbine increased very rapidly with increases in turbine-inlet temperature. This effect can be seen in the increase in estimated cost of the steam turbogenerator from $32.1/kWe for a 1000° F unit to $93.1/kWe for a 1200° F unit. Most of this cost is attributable to the high-pressure section, which produces only a relatively small portion of the total turbine output in a steam powerplant. However, these costs include the cost of the control valves at the turbine inlet and these valves represent a significant portion of the cost of the high-pressure section of the steam turbine. The carbon dioxide turbomachinery considered in this study was a two-shaft design recommended by Actron. This permits the pump and compressor to operate at a higher speed than the generator. Like the steam turbine, this two-shaft configuration would require control valves at the turbine inlet to protect against loss of load. In contrast, the helium gas turbine, a single-shaft design, provides compressor load on the power turbine shaft. This permits use of low-temperature bypass valves for loss-of-load protection, instead of expensive high-temperature valves at the turbine inlet. It might be possible to consider a similar arrangement for carbon dioxide systems to reduce the costs of the carbon dioxide turbogenerator. However, the much lower power required by the carbon dioxide pump and compressor compared with the helium compressor, as well as the lower inertia of the carbon dioxide rotating components, would pose a more difficult problem. The feasibility of such a control scheme would require a detailed investigation.

The recuperator is the most costly single component in the system. For the base case it transfers a quantity of heat equal to about 2.5 times the heat input into the cycle. For the same electrical power output, the heat transfer area requirement for the base case was almost four times that of the closed Brayton cycle recuperator. The recuperator design used in the study was a conventional shell-and-tube multipass cross-counterflow design. The high pressure differential across the tube sheet and a limitation of 12 inches placed upon the tube sheet thickness limited shell diameter to 30 inches. As a result, 160 modules were required for the high-temperature recuperator and 32 for the low-temperature recuperator. The large number of modules resulted in high costs because of large shell and wrapup costs. The recuperator was estimated at about \$115/square foot for the high-temperature recuperator, \$30/square foot for the low-temperature recuperator, and \$76/square foot averaged over the entire recuperator. The \$115/square foot for the high-temperature recuperator was an average value based on the use of a less-expensive carbon steel at the low-temperature end, with stainless steel used only in the high-temperature regions. For comparison, the G.E. design for the closed Brayton cycle recuperator came to \$46/square foot, using stainless steel throughout. Zurn Industries, Inc., did an independent design for NASA for a closed Brayton recuperator, using multiple materials to minimize costs. They estimated costs at only \$10/square foot to \$17/square foot for inlet temperatures between 1000° F and 1100° F.

It is clear that the use of a conventional shell-and-tube design for the supercritical carbon dioxide recuperator results in a very large number of modules and high costs. If a nonconventional recuperator design could be developed to accommodate the requirements peculiar to the supercritical carbon dioxide cycle with a greatly reduced number of modules, a considerable reduction in capital costs could be realized. Not only might the recuperator costs be reduced, but a reduction in balance-of-plant costs such as for piping and site labor might be achieved as a result of the reduced number of modules.

5.6.2.2.5 <u>Effect of possible cost reductions</u>. - The Phase 1 results have provided information on approaches to optimizing the supercritical carbon dioxide cycle and have indicated critical cost areas that must be addressed for the cycle to be competitive with other cycles. The scope of the Phase 1 effort, however, did not permit the development of innovative approaches to the design problems resulting from the combined high pressures and temperatures and high recuperation requirements of the cycle. A design study providing an opportunity to devise such innovative design approaches might permit substantial reductions in the costs of the supercritical carbon dioxide cycle components.

It is of interest to estimate the effect on capital cost and COE that might result from possible reductions in the cost of the two major cost components of the supercritical carbon dioxide cycle, the turbomachinery and recuperator. Reduced cost estimates for these components were applied to the modified cycle presented in tables 5.6-2 and 5.6-3, and the effect on the capital cost and COE were determined.

In considering the turbomachinery, it was assumed that the carbon dioxide turbomachinery can be configured in a single-shaft arrangement and that loss of load can be handled by low-temperature bypass valves rather than high-temperature valves at the turbine inlet. The carbon dioxide turbomachinery operates at a much higher pressure than does the closed Brayton cycle, but at a lower temperature. Diameters and number of compressor and turbine stages should be considerably less for the carbon dioxide cycle than for helium in the closed Brayton cycle. Under these conditions, a specific cost of $70/kWe does not seem an unreasonable assumption for the supercritical carbon dioxide turbomachinery. This cost is applied to the supercritical carbon dioxide portion of the total plant output of 750 mWe. The effect of this assumed reduction in turbomachinery costs is a 19 percent reduction in capital cost to $1170/kWe and a 16 percent reduction in COE to 46.3 mills/kW-hr.

The conventional shell-and-tube construction of the recuperator resulted in a substantial penalty from a cost standpoint. For the high pressures characteristic of the supercritical carbon dioxide cycle, problems related to tube sheet thickness and resultant shell diameter limitations led to a large number of modules and high cost. If it is assumed that an innovative approach to the recuperator design could reduce the cost of the conventional shell-and-tube recuperator from $76/square foot of heat transfer area to $25/square foot, capital costs of the modified cycle (table 5.6-3) could be reduced 23 percent, to $1110/kWe. A corresponding reduction in COE of 19 percent to 44.4 mills/kW-hr could be obtained. Further reduction in capital cost and COE could result from balance-of-plant (piping and site labor) cost reductions associated with the reduction in the number of recuperator modules. These possible cost savings were not considered, however.

If it were possible to achieve cost reductions in both the turbomachinery and recuperator, as discussed, the capital cost of the supercritical carbon dioxide cycle could be reduced by 38 percent to about $900/kWe, and the COE could be reduced by 31 percent to 37.7 mills/kW-hr.

5.6.3 Concluding Remarks

The results of the study show that the supercritical carbon dioxide cycle has a good efficiency but very high capital cost and cost of electricity. A cycle modified to incorporate favorable variations in the furnace type and cycle parameters examined in the study indicated that the COE might be reduced to about 55 mills/kW-hr at an overall efficiency of 40 percent, using G.E.'s figures. The high COE is a result of very high capital cost components, primarily in the recuperator and turbine. A contributing factor to the high cost of these components is probably the conventional design approach used for the unconventional requirements associated with the supercritical carbon dioxide cycle. The cycle is characterized by very high pressures at fairly high temperatures. For good efficiency, the cycle requires a very large recuperator that must accommodate differential pressures resulting from about

3800 psi on one side of the heat exchanger and 1400 psi on the other.

The scope of Phase 1 of the ECAS study did not provide for the development of innovative approaches that might overcome the design problems peculiar to the supercritical carbon dioxide cycle. It is possible that the high capital cost and COE could be substantially reduced if a more detailed design study effort were devoted to the cycle. Areas for study would include

(1) Recuperator design study to overcome the high costs of recuperator and piping associated with the large number of modules resulting from tube sheet thickness and shell diameter limitations of a conventional shell-and-tube heat exchanger operating at high temperatures and high pressure differentials

(2) Turbine design study to minimize the effects on cost of the high pressure and temperature and to address the problems of very high blade loadings resulting from extracting large amounts of power from a small turbine with few stages

(3) Turbomachinery and control study to determine if a single-shaft configuration can be used with low-temperature bypass valves for loss-of-load protection to eliminate the high-temperature valves at the turbine inlet required in a split-shaft arrangement

(4) Plant and equipment layout study to minimize costly high-temperature and high-pressure piping

The capital cost and COE of the supercritical carbon dioxide plant are very sensitive to the costs of the cycle turbomachinery and recuperator because these components make up a large proportion of the total plant capital costs (over 50 percent for the base case studied by G.E.). The effects of possible reductions in cost of these components that might result from the design efforts mentioned here were evaluated in a cursory manner. The reduced costs assumed for these components considered equipment costs of other closed-cycle dynamic systems included in the study and were approximately one-third of the original costs. With these assumptions, the supercritical carbon dioxide plant could have a COE of about 38 mills/kW-hr with an overall energy efficiency of about 40 percent.

Growth possibilities in the cycle may exist in increases in turbine-inlet temperatures beyond 1350° F. However, the effect of carbon dioxide on material corrosion and physical properties at high temperatures are unknown and would require investigation. There is little possibility for improvement in efficiency through the introduction of a bottoming cycle, in contrast to the closed Brayton cycle, however, because of the low temperature of the gas leaving the recuperator and entering the precooler.

TABLE 5.6-1. - PARAMETRIC VARIATIONS USED WITH SUPERCRITICAL CARBON DIOXIDE SYSTEMS

[Underlined parameters denote base-case conditions or emphasis.]

Coal type	Illinois #6 bituminous; Montana subbituminous; North Dakota lignite
Furnace type	Atmospheric fluidized bed; regenerative pressurized fluidized bed; pressurized furnace with integrated low-Btu gasifier; pressurized furnace with high-Btu gasifier
Prime cycle:	
Turbine-inlet temperature, °F	1200; 1350; 1600
Compressor pressure ratio	2.0; 2.7; 3.14
Recuperator pressure loss ratio, $\Delta P/P$	0.03; 0.05; 0.08
Primary-heat-exchanger pressure difference, ΔP, psi	20; 30; 60; 140
Precooler pressure difference, ΔP, psi	8; 12; 24
Pump flow fraction	0.6; 0.7; 0.8; 0.9; 1.0 (simple cycle)
Compressor-inlet temperature, °F	40; 80; 115
Cycle variation	Simple; recompression; postheat
Heat rejection method	Wet cooling tower; dry cooling tower
Recuperator minimum temperature difference, ΔT, °F	10; 20; 30
Turbine efficiency	0.80; 0.85; 0.90
Furnace pressurizing air supply:	
Excess air, percent of stoichiometric	10; 15; 20
Pressure ratio	8; 10
Turbine-inlet temperature, °F	1200; 1600; 1750; 1800
Regenerator effectiveness	0.85

TABLE 5.6-2. - MODIFICATIONS TO SUPERCRITICAL-CARBON-DIOXIDE-SYSTEM BASE CASE

Parameter	General Electric case				NASA modified case
	1 (base)	5	14	17	
Furnace type	[a]AFB	[b](PFB)R	[a]AFB	[a]AFB	[b](PFB)R
Prime cycle:					
Turbine-inlet temperature, °F	1350	1350	1350	1350	1350
Compressor pressure ratio	2.7	2.7	3.14	2.7	3.14
Pump flow fraction	0.7	0.7	0.7	0.7	0.7
Recuperator pressure loss ratio, ΔP/P	0.05	0.05	0.05	0.08	0.08
Recuperator minimum temperature difference, ΔT, °F	20	20	20	20	20
Furnace pressurizing air supply:					
Excess air, percent	-----	20	-----	-----	20
Pressure ratio	-----	10	-----	-----	10
Turbine-inlet temperature, °F	-----	1600	-----	-----	1600
Regenerator effectiveness	-----	0.85	-----	-----	0.85
Overall energy efficiency	0.40	0.392	0.414	0.398	0.40
Cost of electricity, mills/kW-hr	69.4	57.3	67.9	67.6	54.9

[a]Atmospheric fluidized bed.
[b]Regenerative pressurized fluidized bed.

TABLE 5.6-3. - COST BREAKDOWN FOR SUPERCRITICAL CARBON DIOXIDE CYCLE

Component	General Electric case 1 (base)		NASA modified case	
	Total plant net power, MWe			
	566		750	
	Cost, millions of dollars			
Prime cycle:		363.0		330.9
CO_2 turbogenerator	130.0		127.0	
CO_2 turbine-pump-compressor	20.6		24.0	
Recuperator	202.4		168.0	
Precooler	10.0		11.9	
Primary heat input and fuel system:		76.2		107.4
Furnace modules	67.0		79.3	
High-temperature air preheater	7.1		-----	
Low-temperature air preheater	2.1		-----	
Pressurizing gas turbine system (compressor-generator-heat exchanger)	-----		28.1	
Total costs for major components		439.2		438.3
Balance of plant:		150.3		155.4
Cooling tower	1.9		1.9	
All other	115.9		117.3	
Site labor	32.5		36.2	
Total direct costs		589.4		593.7
Total capital costs		1073.0		1080.9
Capital cost, \$/kWe		1896		1441
Overall energy efficiency		0.40		0.40
Cost of electricity, mills/kW-hr:		69.4		54.9
Capital	60.0		45.6	
Fuel	7.3		7.3	
Operation and maintenance	2.2		2.0	

TABLE 5.6-4. - TURBOGENERATOR COST COMPARISONS

	Cost		
	\$/kWe	lb/kWe	\$/lb
CO_2 turbogenerator (1350° F)	228	2.8	81.5
Potassium turbogenerator (1400° F)	145	8.8	16.5
Steam turbogenerator (3500 psi/1200° F/1000° F)	93	8.7	10.7
Steam turbogenerator (3500 psi/1000° F/1000° F)	32	6.7	4.8
Helium turbine-compressor-generator (1500° F)	53	4.9	10.8

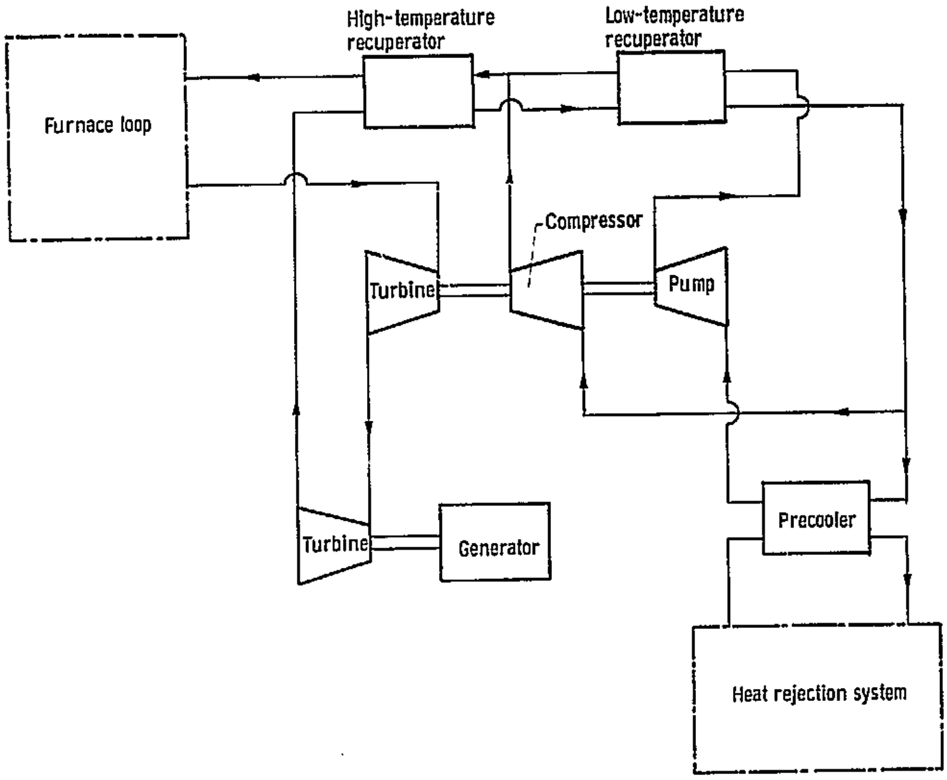
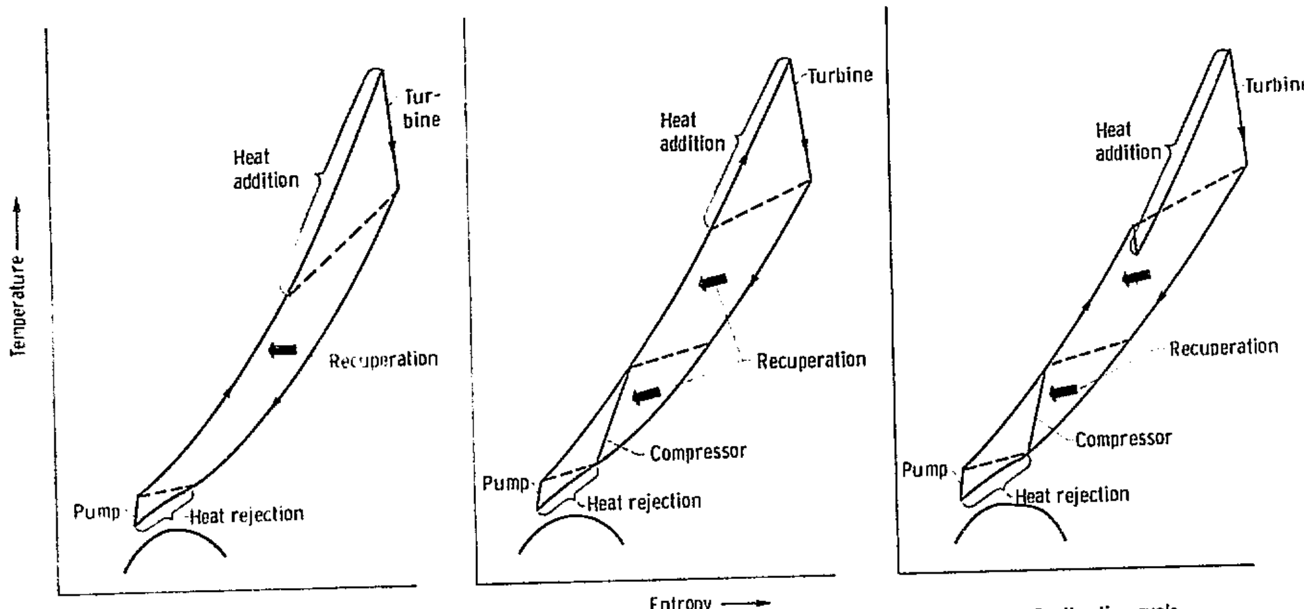


Figure 5.6-1. - Schematic diagram of supercritical carbon dioxide cycle (recompression cycle).



(a) Simple cycle.

(b) Recompression cycle.

(c) Postheating cycle.

Figure 5.6-2. - Variations in supercritical carbon dioxide cycle.

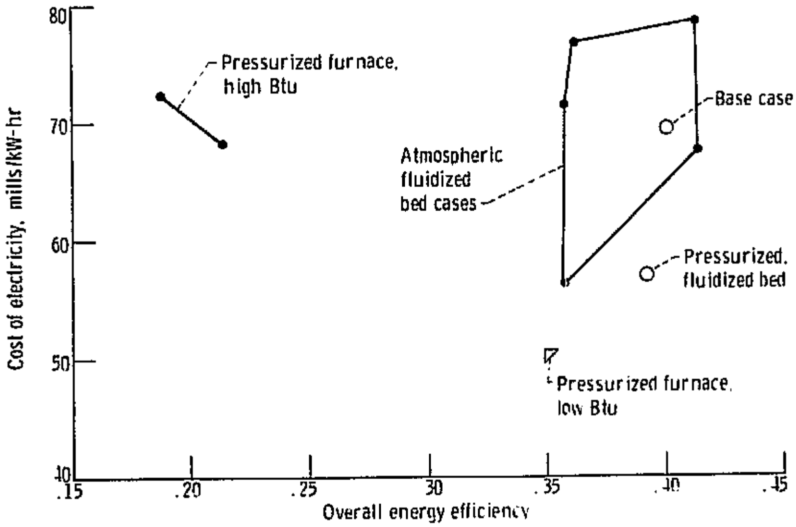


Figure 5.6-3. - Overview of study results for supercritical carbon dioxide cycle.

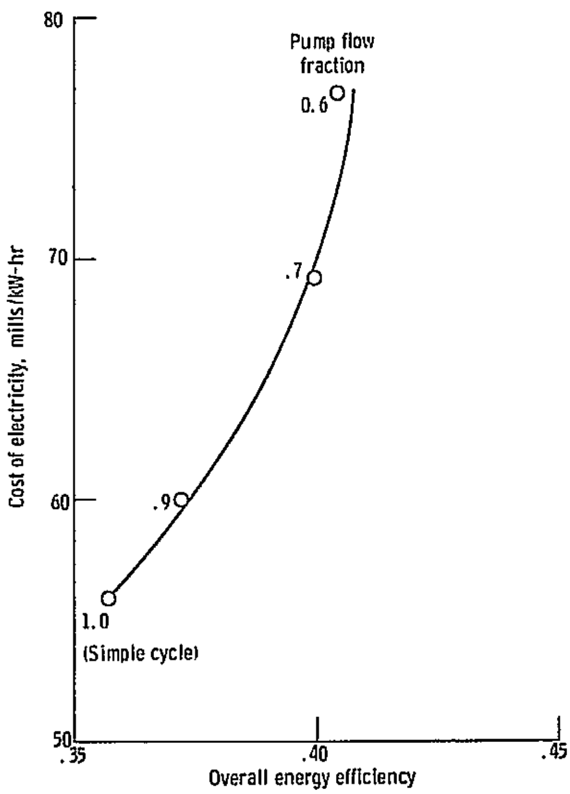


Figure 5.6-4. - Effect of pump flow fraction.

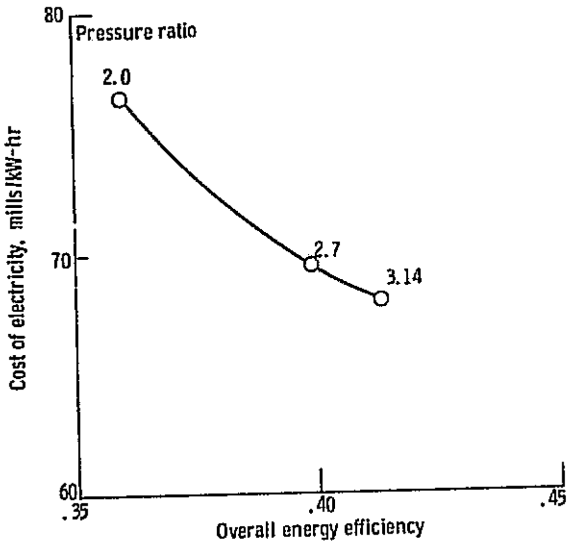
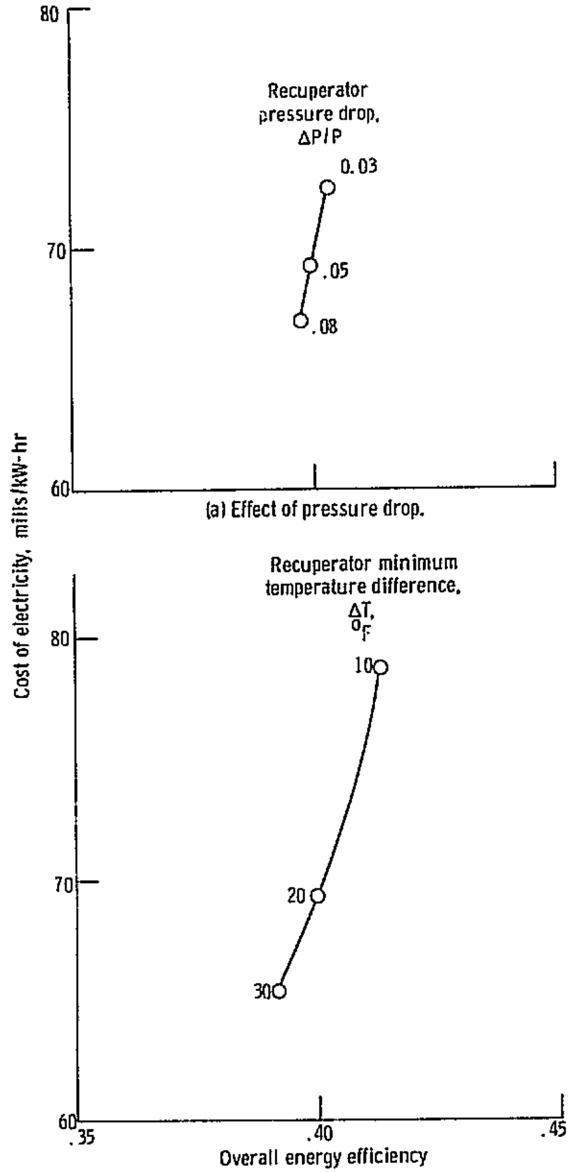


Figure 5.6-5. - Effect of cycle pressure ratio.



(a) Effect of pressure drop.

(b) Effect of minimum temperature difference.

Figure 5.6-6. - Effect of recuperator parameters on cost of electricity and overall energy efficiency.

5.7 LIQUID-METAL RANKINE CYCLE
by Donald C. Guentert

Liquid-metal Rankine cycle powerplants have been considered as topping cycles for steam plants, because liquid metal has more favorable pressure-temperature characteristics and thermodynamic efficiency potential at elevated temperatures than steam. Previous studies of potassium topping plants rejecting heat to a steam bottoming plant (refs. 8 to 10) have indicated a potential for high efficiency at competitive costs of electricity. The liquid-metal Rankine topping cycle (also termed metal vapor Rankine) was therefore included as one of the systems for study in ECAS Phase 1.

5.7.1 Scope of Analysis

Under ECAS Phase 1, both the General Electric Company and Westinghouse conducted performance analyses and cost estimates of liquid-metal topping cycles. General Electric studied a total of 16 cases and Westinghouse a total of 50. Three types of furnace/boilers were explored. They included the atmospheric fluidized bed (AFB), the pressurized furnace (PF), and the pressurized fluidized bed (PFB). The fuel for the pressurized furnace was either low-Btu gas produced in a coal gasifier integrated with the power system or a high-Btu gas or liquid produced in a free-standing gasification or liquefaction plant. A simplified schematic diagram of the potassium topping plant with an AFB is shown in figure 5.7-1. Figures 5.7-2 and 5.7-3 are schematic diagrams of the pressurized furnace systems with integrated low-Btu gasifiers that were used by G.E. and Westinghouse, respectively. Figure 5.7-4 presents a simplified schematic diagram of the PFB system, with two methods of turbine exhaust heat recovery indicated with dashed lines.

Table 5.7-1 presents a listing of the number of cases analyzed by the two contractors for each furnace/boiler concept. General Electric emphasized the use of the AFB in their study, whereas Westinghouse emphasized the PFB. Table 5.7-2 displays the ranges of conditions and other variations that were investigated by each company. Base case values for each contractor are underlined. Westinghouse studied two base cases, case 1 for the PFB and case 4 for the PF with an integrated low-Btu gasifier. The cycle conditions shown in table 5.7-2 were in many cases not independently varied. Westinghouse, for example, in exploring the effect of an increase in potassium turbine-inlet temperature, simultaneously increased the potassium condenser temperature by the same temperature increment. The larger number of points covered by Westinghouse permitted them to explore a greater range of cycle conditions than G.E.

5.7.2 Results of Analysis

5.7.2.1 Overall Comparison

Figures 5.7-5 and 5.7-6 present the overall efficiencies and costs of electricity (COE) obtained by G.E. and Westinghouse, respectively. Figure 5.7-5 indicates overall efficiencies for the majority of the cases studied by G.E. of between 34 and 41 percent, with costs of electricity between 40 and 53 mills/kW-hr. Two pressurized-furnace cases with high-Btu gas had much lower efficiencies (between 20 and 22 percent) because of the 50 percent efficiency of the high-Btu gasification process. The Westinghouse results generally indicated higher efficiencies and lower costs of electricity than those of G.E. Figure 5.7-6 shows overall efficiencies ranging between 35 and 45 percent, with costs of electricity between 29 and 37 mills/kW-hr.

Table 5.7-3 presents the overall efficiencies and costs of electricity of representative potassium and cesium powerplants, as obtained by G.E. and Westinghouse. The operating conditions, power levels, etc., of the system of table 5.7-3 are approximately, though not exactly, comparable: for example, all the cases shown in the table have liquid-metal turbine-inlet and liquid-metal condensing temperatures of 1400° and 1100° F, respectively. A discussion and comparison of the representative results of table 5.7-3 follows.

5.7.2.2 Discussion and Assessment

5.7.2.2.1 Overall energy efficiency. - In general, the efficiencies estimated by G.E. were lower than those reported by Westinghouse. Although it is difficult to make direct comparisons between the two contractors' results because no two cases are identical, there are several causes for lower efficiencies in the G.E. study. One of these affects all the potassium cases studied in varying degrees and is a result of a high recirculation ratio used by G.E. in the potassium boiler.

The G.E. furnace design was done by Foster Wheeler and consisted of multiple fluidized beds stacked vertically into modules. Horizontal tubes were used in the beds to foster lateral mixing of the bed material (coal and dolomite). A high potassium recirculation ratio was specified, based on correlations of two-phase flow regimes, to insure complete wetting of the tube wall. For the AFB and PFB topping plants, the boiler exit quality was of the order of 1.5 percent and the boiler flow recirculation ratio was 67. (Higher temperature systems required smaller recirculation ratios, as low as 18.) The vertical stacking of the beds with recirculation pumps located at ground level required the use of orificing in the lower beds for uniform flow. The combination of high pressure heads and high recirculation flow resulted in high pump power and high pump costs (57 MWe and \$36.4x10⁶, respectively, for the AFB of case 1). The effect on efficiency was about 2 percentage points for the AFB cases, about 1.5 percentage points for the PFB cases, and about 0.3 percentage point for the PF cases with integrated low-Btu gasifiers. Westinghouse, on the other hand, considered a recirculation ratio of 2.5 to be adequate, with correspondingly low pump power and negligible effect on efficiency.

The Westinghouse PFB furnace/boiler was based on a design proposed by A. Fraas (ref. 9). In this design, the boiler tubes are mounted vertically, rather than horizontally. Westinghouse modified the Fraas design to use pumped recirculation, instead of natural convection, and allowed for a boiler tube exit quality of 40 percent, based on their estimate of dry wall occurring at 50 percent quality (the so-called "critical" quality). As a result, their recirculation ratio was 2.5, with consequent very low pumping power and minimum impact on plant efficiency.

There are few data on the relation between critical quality and critical heat flux for potassium flowing in horizontal tubes, but any problems are ameliorated by the extreme ease with which potassium wets metal surfaces. References 11 and 12 cite experimental data and a relation between critical quality and critical heat flux for potassium in bare, vertical tubes. For the heat flux of the Foster Wheeler PFB boiler (12 000 Btu/(hr)(sq ft)(°F)), the critical quality for dry wall obtained from this relation is about 97 percent. On this basis, very little recirculation flow would be required. A different reason for requiring some recirculation within the potassium boiler is to limit corrosion in the subcooled and low-quality regions of the boiler (see discussion in ref. 8). The extent of recirculation that might be required is unknown at this time, but it is likely that recirculation ratios substantially lower than those used in the G.E. study can be used. Recirculation pumping power would then have only a minor impact on the overall system efficiency.

The G.E. study emphasized analysis of the potassium topping cycle's performance with an AFB. The G.E. analysis indicated an overall energy efficiency of 38.9 percent for this system. As noted, this efficiency includes a penalty of about 2 percentage points for the recirculating pump power.

For the PF cases with low-Btu gasifiers in table 5.7-3, G.E. calculated an overall efficiency for the potassium system of 35.1 percent. Westinghouse calculations indicated an efficiency of 40.9 percent. A small part of this difference (about 0.3 percentage point) can be attributed to the greater recirculation pump power of the G.E. cases. The remainder can be attributed to two factors. The first relates to the difference in the gasifiers used by the two contractors. The G.E. gasifier is a fixed-bed gasifier with cold-gas cleanup with its resulting losses and requires twice the amount of steam required by the Westinghouse gasifier, which is a fluidized-bed gasifier with hot-gas cleanup. The second is the difference in approach used by the two contractors in integrating the low-Btu gasifier into the power generation system. General Electric used all of the available energy in the gas turbine exhaust to raise steam, only a part of which was used for the gasifier, the remainder being used for generating electric power (see fig. 5.7-2). In effect, G.E.'s PF cases can be viewed as comprising two parallel combined or topping cycles, a gas turbine/steam turbine cycle and a potassium turbine/steam turbine cycle. This arrangement resulted in about half of the total plant output (about 1200 MWe of the 2400 MWe) being generated by the steam- and gas-turbine-driven generators in the furnace pressurizing loop for the low-Btu PF cases studied by G.E. Westinghouse, on the other hand, used only enough of the gas turbine exhaust to raise the steam required for the gasifier and used the remainder for feedwater heating in the steam plant bottoming the liquid-metal topping plant (see fig. 5.7-3). Thus, the Westinghouse approach used as much of the available gas turbine exhaust energy as possible in the higher efficiency steam cycle bottoming the liquid-metal topping cycle. In the G.E. approach, a large portion of the gas turbine exhaust energy went into the lower efficiency steam cycle bottoming the gas turbine.

General Electric calculated the efficiency of the PFB case that it analyzed as 39.6 percent (case 9). For this case, G.E. recuperated the compressor discharge and turbine exhaust steam (see fig. 5.7-4). The compressor exit temperature of over 600° F (resulting from a pressure ratio of 10), however, limits the amount of turbine exhaust energy that can be recovered in this manner. Stack-gas temperatures of perhaps 650° F result with correspondingly high stack-gas losses. Westinghouse analyzed many PFB cases, including cases with no heat recovery from the gas turbine exhaust, recuperation in the gas turbine exhaust, and the use of gas economizing or gas feedwater heating for energy recovery from the gas turbine exhaust. The latter approach used gas turbine exhaust energy to heat feedwater in the steam plant bottoming the liquid-metal turbine. With a lower sink temperature in this case, stack-gas temperature could be reduced to the normal 250° to 300° F temperature range, with consequent improved efficiency. For case 49, using gas feedwater heating, Westinghouse calculated an efficiency of 42.4 percent as compared with the value of 39.6 percent calculated by G.E. for their recuperated case. This difference is due to higher recirculation pump power and higher stack losses in the G.E. configurations. For the PFB cases in general, the pressurizing gas turbine in the furnace loop produced about 20 percent of the total plant power. The steam turbine contributed the major portion of the total power (about 65 percent), while the potassium turbine produced about

15 percent.

Only small differences in efficiency resulted from the use of cesium as a working fluid in place of potassium. General Electric showed a 1.9-percentage-point increase in efficiency with cesium at the same cycle temperatures as potassium. However, this difference was due almost entirely to reduced recirculation pumping power with the cesium and would essentially disappear with a decrease in potassium recirculation ratio discussed previously. General Electric did show, however, a small increase in efficiency (about 0.7 point) when advantage was taken of cesium properties by reducing the condensing temperature of the topping cycle from 1100° F to 1000° F with a corresponding reduction in the steam bottoming plant throttle and reheat temperatures from 1000° F to 950° F.

Westinghouse examined considerably more parametric points than did G.E. However, even here, parameters were varied from the base cases, and combined effects were generally not examined. Westinghouse considered variations in compressor pressure ratio and gas-turbine-inlet temperature for the PFB, but these variations were made on the base case, which did not incorporate any heat recovery in the gas turbine exhaust. Under these conditions, with stack-gas temperatures increasing with the turbine-inlet temperature, efficiency decreased with increasing turbine-inlet temperature. However, comparison of two cases (cases 13 and 49) in which gas feedwater heating was used to recover energy in the gas turbine exhaust shows an increasing efficiency with increase in gas-turbine-inlet temperature. In a similar manner, the effect of gas turbine pressure ratio was examined with no gas turbine exhaust heat recovery. The effect of recuperator effectiveness was examined only at a pressure ratio of 15 in those cases using a recuperator for exhaust heat recovery. Very little recuperation is possible at a pressure ratio of 15 because of the high compressor discharge temperatures. Pressure ratios for best efficiency will be considerably less than 15 when using recuperation for exhaust heat recovery.

The points mentioned here are made to indicate only that the contractors were not able to conduct sufficiently complete parametric studies within the scope of Phase 1 so as to arrive at an "optimized" system. However, sufficient information was generated to suggest that the best efficiency will be obtained for a PFB case with gas turbine exhaust heat recovery to the feedwater heating system of the steam plant. It was shown that increased efficiency and reduced COE could be obtained with an increase in gas-turbine-inlet temperature from 1600° F to 1800° F, although the effect of the higher temperature on gas turbine corrosion and the sulfur removal capability of the bed would have to be considered. With potassium recirculation ratios at values resulting in small recirculation pump power and cycle parameters more completely optimized than could be done in the Phase 1 study, overall energy efficiencies approaching 45 percent might be obtained. A configuration similar to this will be examined by G.E. in more detail in Phase 2.

5.7.2.2.2 <u>Cost of electricity</u>. - The costs of electricity for the representative cases of table 5.7-3 varied from a low of 29.6 mills/kW-hr for a Westinghouse case with a PFB to a high of 48.3 mills/kW-hr for a G.E. case with an AFB. The Westinghouse estimates are substantially lower than those reported by G.E. Both contractors found the PFB potassium topping plant to be highest in efficiency and lowest in cost of electricity. For this reason, the discussion and comparisons of cost of electricity will be limited to this system concept.

Table 5.7-4 presents a detailed comparison of the capital costs and COE for a PFB case studied by each contractor. The G.E. PFB case is case 9. It has a potassium topping cycle operating at 1400° F boiling temperature and 1100° F condensing temperature. The steam bottoming cycle is a 3500 psi/1000° F/1000° F cycle with a condensing pressure of 1.5 inches of Hg. The furnace pressurizing system operates at a turbine-inlet temperature of 1600° F and a pressure ratio of 10 and uses a 0.85 effectiveness recuperator to recover turbine exhaust heat for air preheat. The Westinghouse case is case 49. The potassium cycle is the same as that of G.E. The steam bottoming cycle is also a 3500 psi/1000° F/1000° F cycle, but it has a condensing pressure of 3.5 inches of Hg. The furnace pressurizing system operates at a turbine-inlet temperature of 1600° F and a pressure ratio of 15. Gas turbine exhaust energy, however, is used in steam plant feedwater heating as opposed to recuperation in G.E.'s case.

The first two columns in table 5.7-4 present the actual costs obtained by the two contractors. As discussed previously, the G.E. case has an efficiency that is almost 3 percentage points lower than that of Westinghouse. This difference can be attributed to the higher recirculation pump power and the higher stack losses resulting from the use of recuperation for gas turbine exhaust heat recovery in the case of G.E. The third column attempts to approximately adjust the G.E. values to show what their costs would be for a configuration similar to that of Westinghouse, and with the same efficiency. To do this, the furnace/boiler pump costs were first reduced to account for the reduction in recirculation pump requirements. All component, balance-of-plant, and site labor costs in dollar/kWe were then decreased by the ratio 0.396/0.424 to reflect the higher power output resulting from the higher efficiency. (The G.E. recuperator would be replaced by a gas feedwater heater, which is assumed to be approximately equal in cost.) Cost of electricity was also adjusted to reflect reduced capital charges and fuel costs resulting from the higher efficiency.

The adjusted value of COE is 35.8 mills/kW-hr. The difference between this value and the Westinghouse estimate of 29.6 mills/kW-hr is due primarily to lower estimates by Westinghouse of furnace/boiler, balance-of-plant, contingency, and operating-and-maintenance costs as compared with G.E. The difference in escalation and interest costs primarily reflects the differences in major component and other direct costs, as the escalation and interest rates were specified by NASA to both contractors. A discussion of the procedures and factors used by each contractor in arriving at capital costs from the direct costs is presented in section 5.1 of this report.

The balance-of-plant and site labor costs reflect the costs associated with installing the major components and purchasing and installing the remaining portions of the plant. Although the sums of these two accounts are similar ($211.6/kWe for G.E. and $220.1/kWe for Westinghouse), Westinghouse estimates for site labor costs are higher ($83.0/kWe against $46.0/kWe for G.E.), while G.E.'s balance-of-plant estimates are higher. Westinghouse may have estimated more field construction of their furnace/boiler and liquid-metal condenser/steam generator. General Electric, on the other hand, included much of the liquid-metal-piping costs in balance-of-plant costs, but Westinghouse included these costs in the major components category.

The difference in major component costs between the two contractors (about $60/kWe) is attributable primarily to the furnace/boiler. This difference in furnace/boiler costs apparently results from the use of a less expensive material by Westinghouse (Incoloy 800 as compared with Hastelloy X used by G.E.) and from the different design approach noted previously. The difference in the other direct costs is due to the inclusion of liquid-metal piping in this category by Westinghouse; G.E. accounted for the costs of this piping in their balance-of-plant costs.

Table 5.7-5 presents cost estimates for a comparable PFB plant analyzed in the NASA-OCR study reported in reference 8. The first column lists the original costs presented in that report, except that the fuel costs have been increased to reflect the subsequent revision by the author of reference 8 of his efficiency calculations to account for higher heat losses than originally estimated. The revised efficiency is 45 percent. The second column, labeled "ECAS equivalent costs," presents the estimates of costs and COE of reference 8 but revised to put them on a comparable basis with the ECAS study. Thus, the costs in the first column were increased by 20 percent to account for inflation from mid-1972, the basis for the estimates of reference 8, to mid-1974, the basis used in ECAS. In addition, a contingency rate of 20 percent of the major components, balance-of-plant, and site labor costs was added, a rate equal to that used by G.E. in ECAS. Escalation and interest costs were computed by the same formulas specified by NASA and used by the two ECAS contractors. A fuel cost of $0.85 per million Btu and a capacity factor of 0.65 were used to derive the total COE, instead of the values of $0.40 and 0.80, respectively, that were originally assumed. An additional adjustment was made to the furnace/boiler cost to reflect the replacement of the 304 stainless steel heat transfer bundle with one made of a high-temperature superalloy, such as HA-188. In the study of reference 8, it was reported that 304 stainless steel was substituted for HA-188 at a savings of about $50 million for a PFB with a potassium boiling temperature of 1400° F. However, it is questionable whether 304 stainless steel would be adequate for this application. Neither contractor considered it in the ECAS study. As noted previously, Westinghouse used Incoloy 800, while G.E. used Hastelloy X, an alloy only a little less expensive than HA-188. A sum of $50 million, or $42.7/kWe, was accordingly added to the furnace/boiler cost. Finally, the costs were adjusted to the same efficiency value of 42.4 percent that was used in table 5.7-4. These adjusted costs are listed in the third column of table 5.7-5 and are close to the G.E. adjusted cost of the ECAS study listed in table 5.7-4.

Westinghouse case 49 has been used in the preceding cost comparison with G.E.'s case 9 because of their comparable cycle conditions. The gas-turbine-inlet temperature was 1600° F for this case. However, the best performance in both overall efficiency and cost of electricity was obtained by Westinghouse for a gas-turbine-inlet temperature of 1800° F by using gas feedwater heating for turbine exhaust heat recovery (case 13). The efficiency and cost of electricity for this case were found to be 43.4 percent and 28.6 mills/kW-hr, respectively. Case 13 incorporated a 3500 psi/1000° F steam bottoming plant with no reheat. A similar case with a reheat steam bottoming plant was not examined, but such a case would probably have an efficiency somewhat over 44 percent and a COE of perhaps 28 mills/kW-hr.

The Westinghouse estimate of operating-and-maintenance costs is considerably lower than G.E.'s estimate. On the other hand, this is counterbalanced by a higher cost for interest and escalation because of the Westinghouse estimate of 6.5 years for the construction time, 6 months longer than estimated by G.E. Recognizing the differences in the cost estimates of the two contractors, the cost of electricity for a 45-percent-efficient potassium vapor topping cycle may be between 28 and 35 mills/kW-hr.

5.7.2.2.3 Working fluid. - The G.E. results show that the thermodynamic efficiency of a cesium topping plant operating between a turbine-inlet temperature of 1400° F and a condensing temperature of 1100° F is the same as that of a corresponding potassium plant (51.4 percent). However, the overall plant efficiency of the cesium system exceeds that of the potassium system by about 2 percentage points (40.8 against 38.9). This difference is attributable primarily to the much lower recirculation pumping power estimated by G.E. for the cesium boiler. Westinghouse found little difference in plant efficiencies between systems using the two working fluids. Cesium can be expanded to lower temperatures than potassium while still maintaining reasonable duct and turbine exhaust sizes. General Electric analyzed the case of a cesium plant operating with a 1400° F turbine-inlet temperature and a 1000° F condensing temperature (case 17). The resulting overall plant efficiency was 41.5 percent, only 0.7 percentage point higher than the same plant condensing at 1100° F (case 18). The G.E. results suggest that a cesium AFB system would have a COE about 10 percent lower than the equivalent potassium cycle. This reduction in COE is due to the lower recirculating pump power, the lower costs of recirculating pumps, and the lower cost of the liquid-metal turbine. The major cost difference, however, is associated with the reduced pumping power and pump costs. Consequently, if the recirculation requirement for the potassium system were reduced, little cost savings could accrue to the cesium plant. As shown in table 5.7-3, Westinghouse estimated a higher COE for cesium systems than for potassium plants.

Research and development costs for a cesium topping plant would be considerably higher than for a potassium plant, because substantially less technology exists for cesium (e.g., ref. 13). In addition, cesium today is substantially more costly than potassium, by a factor of 10 or more. This cost differential, however, would probably shrink with increase in demand and could be small by the time cesium topping plants would come into significant commercial use. Nevertheless, during the early phases of a research and development program, the higher cesium costs would represent an important penalty.

Cesium, however, offers the benefit of smaller and lower cost turbomachinery. Fraas of ORNL has called attention to other, more subtle benefits of cesium. These relate to a reduction of the potential for creep buckling within the pressurized-fluidized-bed boiler and to an easing of operating and maintenance problems. The impact of these benefits is difficult to quantify.

In light of the preceding discussion, potassium is considered the preferred working fluid for study of the liquid-metal topping cycles in Phase 2.

5.7.3 Concluding Remarks

The results of the parametric studies performed by the two contractors in Phase 1 indicate that the most promising configuration, in terms of overall energy efficiency and cost of electricity, is the pressurized-fluidized-bed system. It is estimated that an overall energy efficiency approaching 45 percent can be achieved with this configuration burning Illinois #6 coal, assuming a potassium cycle operating between a 1400° F boiling temperature and an 1100° F condensing temperature and a pressurizing gas-turbine-inlet temperature near 1800° F. Exhaust heat recovery from the pressurizing gas turbine would be in the form of feedwater heating to the 3500 psi/1000° F/1000° F steam bottoming cycle. The cost of electricity for such a plant is estimated at about 28 mills/kW-hr using Westinghouse cost estimates or about 35 mills/kW-hr using G.E. cost estimates adjusted to reflect the higher efficiency of the proposed configuration. A configuration similar to this will be examined in more detail by G.E. in Phase 2, and better estimates of efficiency and COE will be obtained.

A potential problem for the pressurized-fluidized-bed furnace concept, common to all plants using a pressurized-fluidized bed, lies in the possible corrosion and erosion of the pressurizing gas turbine blades because of particulates and contaminants in the hot gases from the pressurized-fluidized-bed furnace. It is not known at this time how severe this problem will be. In the event that it proves to be very serious, a pressurized furnace with an integrated gasifier can be used. However, efficiency would be reduced because of losses in the gasification process and COE would increase. It is estimated that the reduction in efficiency would be about 3 percentage points and the increase in COE about 3 mills/kW-hr. Another possibility, not examined in this study, is proposed in reference 14. In this concept, the pressurizing gas turbine operates at a reduced temperature (about 1000° F) on the furnace gases that have been previously regenerated to the combustion air and provides only enough power for pressurizing the fluidized-bed furnace to about 2 atmospheres. The use of a pressurized furnace burning a clean high-Btu fuel obtained from a free-standing liquefaction or gasification plant is not attractive because of the low fuel conversion efficiency and high fuel costs.

Cesium does not appear to offer a sufficient performance advantage over potassium to compensate for the much more advanced state of potassium technology. This, coupled with much higher cesium costs, would result in much higher costs for the development of a cesium plant.

Improvements in performance of the potassium topping cycle with a pressurized-fluidized-bed furnace could be achieved by increasing potassium turbine-inlet temperatures while maintaining an 1100° F condensing temperature. Using higher potassium-turbine-inlet temperatures would require (1) tube materials that are resistant at metal temperatures of 1500° F or higher to the fire-side corrosion of a fluidized bed on one side and hot potassium on the other, (2) higher strength potassium turbine materials and development of fabrication techniques for large turbine disks of these materials, and (3) development of materials for the pressurizing gas turbine that are resistant at the higher temperatures to the corrosive and erosive effects of the particulates and contaminants in the gas from the pressurized fluidized bed.

TABLE 5.7-1. - FURNACE/BOILER VARIATIONS FOR LIQUID-METAL RANKINE TOPPING CYCLE

	General Electric		Westinghouse	
	Potassium	Cesium	Potassium	Cesium
	Number of cases analyzed			
Atmospheric fluidized bed	8	2	--	--
Pressurized furnace:				
Low-Btu fuel[a]	3	--	13	--
High-Btu fuel	2	--	--	--
Pressurized fluidized bed	1	--	34	3

[a]Integrated gasifier.

TABLE 5.7-2. - RANGE OF CONDITIONS INVESTIGATED

[Underlined values denote base-case conditions.]

	General Electric	Westinghouse
Furnace type	AFB, PFB, PF	PFB, PF
Liquid-metal cycle:		
Fluids	Potassium, cesium	Potassium, cesium
Turbine-inlet temperature, °F	1400, 1500, 1700	1400, 1500, 1600
Condensing temperature, °F	1000, 1100	1100, 1200, 1300
Boiler recirculation ratio	18 to 67	1, 2.5
Gas-turbine cycle:		
Pressure ratio	8, 10	5, 10, 15
Air equivalence ratio	1.10, 1.15, 1.20	1.2, 2.0, 3.0
Turbine-inlet temperature, °F	1600, 1750, 1800	1600, 1700, 1800
Steam cycle:		
Turbine-inlet temperature, °F	950, 1000	1000, 1100, 1200
Turbine-inlet pressure, psia	3500	2400, 3500
Condensing pressure, in. of Hg	1.5, 1.9	2, 3.5, 9
Reheat temperature, °F	950, 1000	1000, 1100, 1200
Cooling tower	Wet, dry	Wet, dry
Other variations:		
Gas-heated economizer	No	Yes[a]
Gas feedwater heating	No	Yes[a]
Gas-turbine recuperator	Yes[a]	Yes[a]
Power level, MWe	1000 to 2500	600, 900, 1200, 1500, 1600

[a]None used for base cases.

TABLE 5.7-3. - REPRESENTATIVE RESULTS FOR LIQUID-METAL RANKINE TOPPING CYCLES

[Liquid-metal turbine-inlet temperature, 1400° F; liquid-metal condensing temperature, 1100° F. Numbers in parentheses are contractor case numbers.]

	General Electric		Westinghouse	
	Potassium	Cesium	Potassium	Cesium
Overall energy efficiency, percent				
Atmospheric fluidized bed	38.9 (1)	40.8 (18)	--------	--------
Pressurized furnace:				
Low-Btu fuel[a]	35.1 (4)	--------	40.9 (14)	--------
High-Btu fuel	20.5 (7)	--------	--------	--------
Pressurized fluidized bed	39.6 (9)	--------	42.4 (49)	42.9 (46)
Cost of electricity, mills/kW-hr				
Atmospheric fluidized bed	48.3 (1)	44.4 (18)	--------	--------
Pressurized furnace:				
Low-Btu fuel[a]	39.9 (4)	--------	32.9 (14)	--------
High-Btu fuel	45.3 (7)	--------	--------	--------
Pressurized fluidized bed	39.6 (9)	--------	29.6 (49)	30.5 (46)

[a]Integrated gasifier.

TABLE 5.7-4. - COST COMPARISONS OF PRESSURIZED-FLUIDIZED-BED POTASSIUM TOPPING CYCLE

	General Electric case 9 (η = 0.396)		Westinghouse case 49 (η = 0.424)		General Electric case 9 (adjusted to η = 0.424)	
Capital cost, $/kWe						
Major components:		240.7		158.4		202.3
Furnace/boiler	144.4		53.2		[a]112.4	
Potassium turbogenerator	29.9		21.1		27.9	
Condenser/steam generator	2.2		9.2		2.1	
Steam turbogenerator	20.8		22.4		19.4	
Gas turbine/compressor/generator	37.3		26.7		34.8	
Other (pumps, dump tank, etc.)	6.1		25.8		5.7	
Other direct costs:		319.9		256.2		294.4
Balance of plant	177.3		137.1		165.6	
Site labor	49.2		83.0		46.0	
Contingency	93.4		29.1		82.8	
Escalation and interest		357.9		252.4		317.1
Total		918.5		667.0		813.8
Cost of electricity, mills/kW-hr						
Capital costs		29.0		21.1		25.7
Operating and maintenance costs		3.3		1.7		3.3
Fuel costs		7.3		6.8		6.8
Total		39.6		29.6		35.8

[a]Includes reduction in recirculation pump costs.

TABLE 5.7-5. - RESULTS OF NASA/OCR TOPPING CYCLE STUDY (REF. 8)

	Original estimates (η = 0.45)		ECAS equivalent costs		ECAS equivalent costs adjusted to η = 0.424	
Capital costs, \$/kWe						
Major components:		138.6		217.6		230.9
Furnace/boiler	[a]48.6		109.6		116.3	
Potassium turbogenerator	20.2		24.2		25.7	
Condenser/steam generator	4.5		5.4		5.7	
Steam turbogenerator	32.2		38.6		41.0	
Gas turbine/compressor/ generator	28.8		34.6		36.7	
Other (pumps, dump tank, etc.)	4.3		5.2		5.5	
Other direct costs:		166.5		273.0		289.7
Balance of plant Site labor	166.5		199.8		212.0	
Contingency	0		73.2		77.7	
Escalation and interest		24.1		313.2		332.4
Total		329.2		803.8		853.0
Cost of electricity, mills/kW-hr						
Capital costs		[b]5.1		25.4		27.0
Operation and maintenance costs		1.2		1.4		1.4
Fuel costs		[c]3.0		6.4		6.8
Total		9.3		33.2		35.2

[a]Type 304 stainless-steel heat transfer bundle.
[b]Capacity factor, 0.8.
[c]Fuel cost, \$0.40/MBtu.

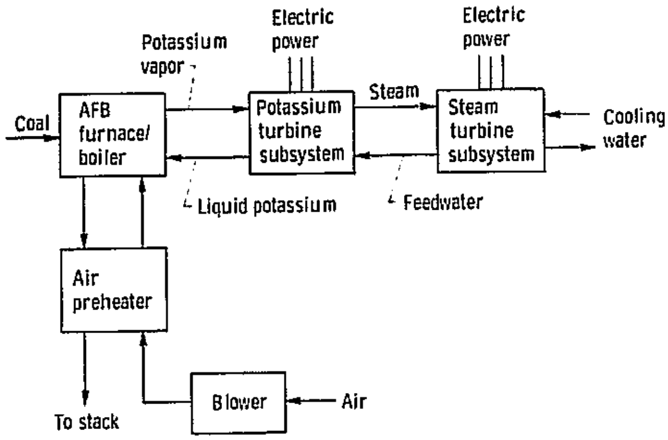


Figure 5.7-1. - Simplified schematic diagram of potassium atmospheric fluidized-bed boiler powerplant.

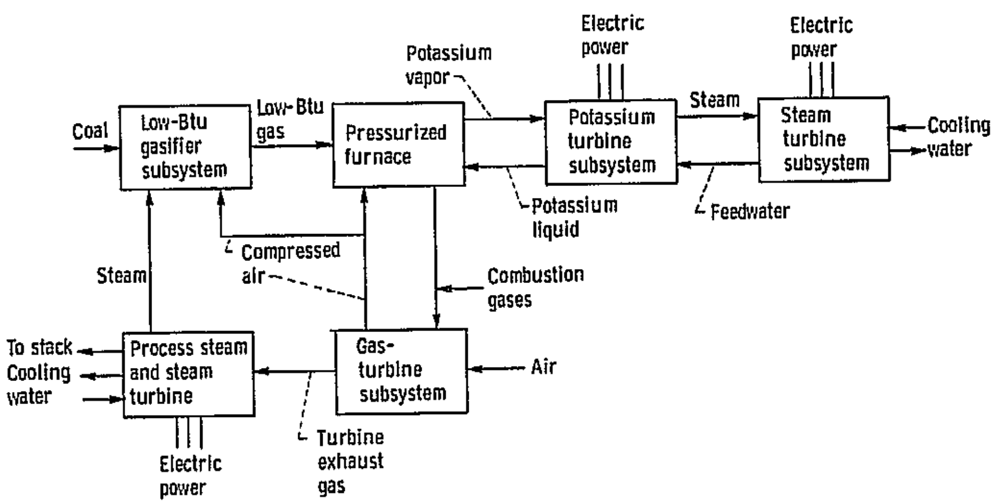


Figure 5.7-2. - Simplified schematic diagram of General Electric potassium topping cycle with pressurized furnace and integrated low-Btu gasifier.

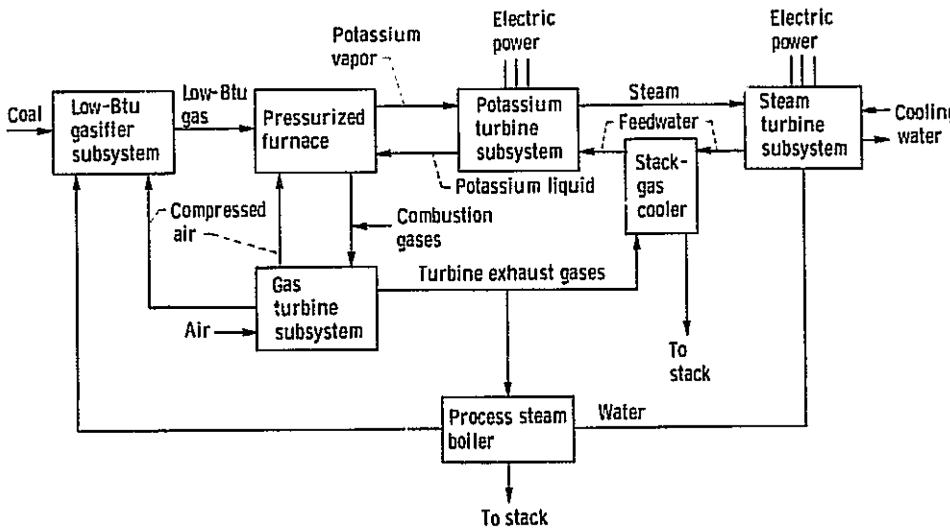


Figure 5.7-3. - Simplified schematic diagram of Westinghouse potassium topping cycle with pressurized furnace and low-Btu gasifier.

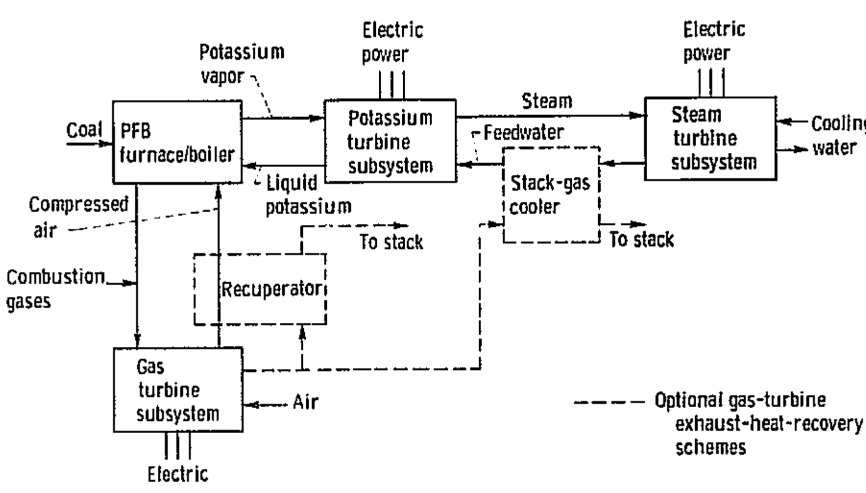


Figure 5.7-4. - Simplified schematic diagram of potassium pressurized fluidized-bed boiler powerplant.

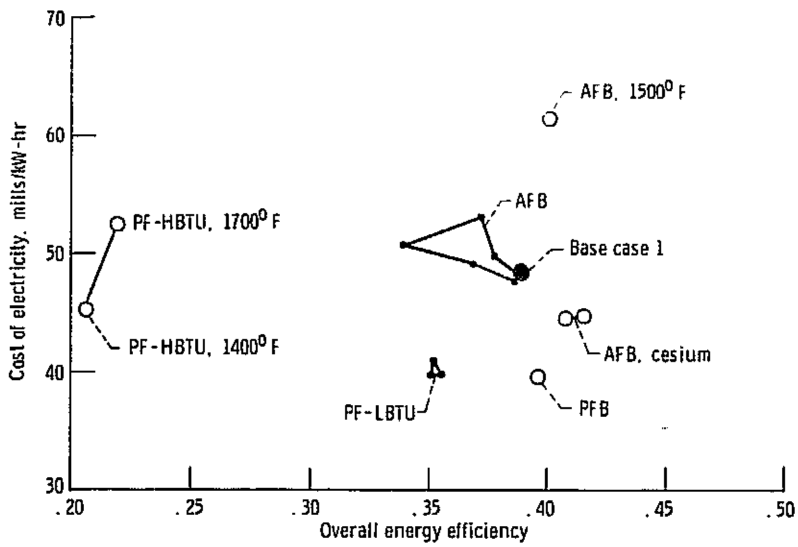


Figure 5.7-5. - General electric liquid-metal topping cycle results.

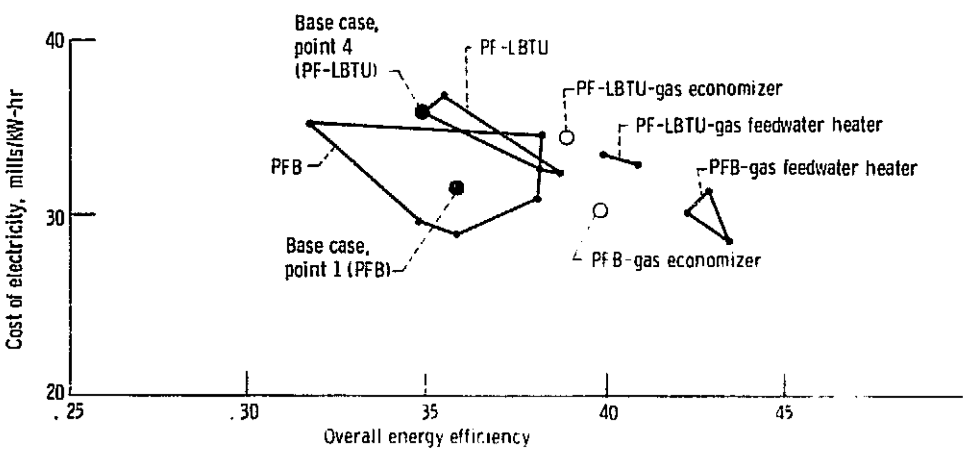


Figure 5.7-6. - Westinghouse liquid-metal topping cycle results.

5.8 OPEN-CYCLE MAGNETOHYDRODYNAMIC SYSTEMS

by George R. Seikel, James A. Burkhart, and Raymond K. Burns

This section and the following two sections, 5.9 and 5.10, summarize the ECAS results for open-cycle, closed-cycle, and liquid-metal magnetohydrodynamic (MHD) systems, respectively. This open-cycle MHD section also contains a subsection, 5.8.5 Common MHD Components, which discusses components that are common to more than one type of MHD system: inverters, magnets, and high-temperature refractory heat exchangers. Other aspects of the MHD systems are treated in the materials section of this report and various other general sections. The following discussion provides an introduction and background for the ECAS study of the various types of MHD powerplants.

5.8.1 MHD Powerplants

Magnetohydrodynamic generators produce electric power by passing a high-velocity conducting fluid through a strong magnetic field. The conducting fluid may be either a conducting gas, a plasma, or a liquid metal. Two types of plasma MHD systems have been studied as part of ECAS. The simplest of these in concept is the open-cycle MHD system. In it an alkali-metal compound is added directly to very high-temperature combustion products and used as the MHD generator fluid. The other plasma MHD generator system is closed-cycle MHD, in which a very pure inert gas is raised to high temperature in a heat-exchanger system and seeded with a pure alkali-metal to produce the MHD generator fluid. The interest in closed-cycle systems stems from the fact that, if the working fluid can be kept sufficiently pure, equivalent conductivities of the working fluids can be obtained at only 3000° F compared with approximately 4500° F for the open-cycle systems.

Two types of liquid-metal MHD (LMMHD) systems have also been proposed. In both, a mixture of a liquid metal and a gas is raised to a high temperature and expanded to high velocity in a nozzle as a foamlike substance. In one type of liquid-metal system, this foamlike mixture is used directly as an MHD working fluid. After exiting the MHD generator, the gas and liquid metal are then separated. In the alternative scheme, the gas and liquid metal are separated at a high velocity after leaving the nozzle and only the liquid metal is passed through the MHD generator. In ECAS only the foamlike MHD generator system was investigated. The alternative concept, which had been previously studied in some detail (ref. 14) by the Jet Propulsion Laboratory (JPL), was not included. This decision was based upon consultations with the leading U.S. experts in liquid-metal MHD, including JPL. It was unanimously agreed that the foamlike MHD generator systems had a higher probability than the alternative LMMHD concept of being competitive within the ECAS ground rules in terms of both cost of electricity and performance.

The MHD power systems are of interest for advanced powerplants primarily because of their high performance potentials. Their performance potential is directly related to their maximum temperatures. Since open-cycle systems operate with the highest temperatures, they have the highest level of performance potential. Closed-cycle systems have the next highest performance potential, and liquid-metal systems have the most limited potential.

In all types of MHD generator systems, the MHD working fluid exits the generator at a relatively high temperature. To obtain high-performance powerplants, the sensible heat in the MHD exhaust must be utilized. This is accomplished both by transferring it to a bottoming cycle, generally a steam plant, and by utilizing it in recuperative and/or regenerative heat exchangers. From the standpoint of mating the MHD topping cycles with steam bottoming cycles, it is generally not advantageous to use steam bottoming plants that are as efficient as the best free-standing steam plants. Specifically, the best combined plants will use less regenerative feedwater preheating than is used in a conventional steam plant. As a result the MHD systems generally cannot take advantage of the higher performance bottoming plant. This is particularly significant in the coal-fired liquid-metal-type systems.

The MHD systems have a number of general features that pose economic penalties on them. Because they are more complex than steam plants, construction times for MHD systems are estimated to be longer than for steam plants. This results in large escalation and interest costs during construction for the MHD systems, as discussed in section 4.2. Because the MHD systems produce direct-current power, they require costly inverter systems to convert this power for alternating-current transmission. In addition, the MHD systems are one of the least developed concepts considered in ECAS. Because of the additional unknowns concerning components and plant design, design allowances in either major components or balance-of-plant costs were included in some cases. General Electric added a 10 percent design allowance in balance of plant, and Westinghouse added an additional contingency to some specific components such as magnets. Equivalent additional costs were not charged to the systems that use lower temperatures and less exotic working fluids and have a higher state of development.

Clearly, there are major uncertainties in estimating cost and performance for system components that have never been built and tested or for which only small-scale experimental results exist. Thus in order to practically carry out the MHD portion of ECAS, a number of fairly pragmatic assumptions were required. Some of these may seem quite optimistic in terms of performance and cost; others may be conservative from the standpoint of underestimating future development.

On the conservative side, a conscious effort was made to favor system concepts and to limit component temperatures to those that could be best defined and costed and for which there was the least stretch of existing technology. Thus for a system such as MHD, which is in its early stages of development and more than a decade away from being a commercial powerplant, possible technology developments may be underestimated. Specifically, some potentially attractive concepts were not included, not because of their lack of potential, but because they could not be sufficiently well defined for adequate performance and cost estimating.

Because of the time limits on the study, performance and cost estimates were done in parallel except for a few points. As a result, most points selected were based on the collective judgement at the start of the study as to which points would be most attractive. This limitation led to the choice of better points for those systems for which more prior parametric studies had been performed. Among the three types of MHD systems studied, this tended to favor the open-cycle systems, but in general this restriction penalized the more advanced systems for which extensive studies had not been previously conducted.

On the optimistic side, it was assumed that there are no unsolvable MHD development barriers despite the lack of any real operating life data on critical components. Performance assumptions have been made based on theory and extrapolation from relatively small-scale experiments. Questions associated with powerplant life and maintenance were addressed only in very crude economic ways and in terms of the materials problems they posed. Open-cycle MHD has been included in Phase 2 of ECAS, and a somewhat more detailed examination of these problems will be made.

The attractiveness of the MHD systems relative to alternative advanced conversion systems is affected by the basic economic ground rules used in comparing the systems. The impact of using various methods of calculating COE, various fuel costs, etc., is discussed in detail in section 6.2.2 of this report.

The following sections briefly summarize the most important results obtained in the ECAS Phase 1 studies from three different and independent sources: the G.E. team, the Westinghouse team, and the supporting in-house Lewis Research Center team; included are studies conducted for NASA by the engineering firm of Burns and Roe and subcontractors to them. The ECAS project office had the assistance and advice of the in-house Lewis Research Center staff in managing these studies. An advisory panel of government MHD experts served as consultants to the Lewis MHD staff.

5.8.2 Scope of Analysis

5.8.2.1 Base Cases and Variations

There are various types of open-cycle MHD systems. Because of limitations in both time and effort, only a representative sample of the possible open-cycle systems could be addressed within the framework of ECAS. The G.E. team examined two base cases and a total of 30 points. The Westinghouse team examined three base cases and a total of 39 points. Table 5.8-1 summarizes the cases and parameter ranges examined.

The emphasis of the study was to burn coal directly in the primary MHD combustor; this was the case in 57 out of the 69 cases studied. In the 12 other cases, either a semiclean solvent-refined coal (SRC; G.E.'s cases 24 to 30) or a low-Btu (LBTU) gas (Westinghouse's five points in base case 3) was used to fire the MHD combustor.

A second emphasis of the study was to use the heat in the MHD exhaust to preheat the combustion air to high temperatures, in what are termed direct-fired preheaters. Generally, the preheat temperatures were assumed to be 2400° to 2500° F for cases in which seed and slag would be present in the heat exchanger. This range was chosen on the basis that it is within a few hundred degrees of present blast furnace heat-exchanger practice with fairly dirty gases. A few points were examined at higher and lower temperatures to indicate the sensitivity of this assumption. For cases in which there was a relatively clean slag-free MHD exhaust (SRC- or LBTU-fired systems), direct-fired-preheat to the 3100° F level was generally assumed.

In only two cases was high-temperature direct preheat not considered, G.E. cases 9 and 10. In G.E. case 9, oxygen enrichment of 1500° F preheated air was assumed. In the other case, G.E. 10, 1500° F preheated air was further preheated in a separately fired heat exchanger to 3100° F. The clean fuel to fire the separately fired preheater was obtained from a gasifier. For the point studied, an advanced gasifier concept that used chemical regeneration of a fraction of the MHD exhaust was assumed. A more conservative assumption of using a state-of-the-art free-standing gasifier was not considered and would, of course, yield lower performance and higher cost of electricity.

An alternative technique of obtaining very high-temperature preheat was, however, considered in the study by the Westinghouse team, base case 1. They considered a number of cases in which air was directly preheated to as high as 2400° F and then further preheated in a separately fired heat exchanger. The fuel for the separately fired preheater was obtained from the volatiles in the coal. The volatiles in the coal were driven off in a carbonizer, and the remaining char was then used to fire the primary MHD combustor.

A third emphasis of the study was to use supercritical steam bottoming plants with wet cooling towers and 3500 psi/1000° F throttle points, with one reheat to 1000° F (3500 psi/1000° F/1000° F). The parametric variations, however, did examine using dry cooling towers, 2400 psi/1000° F/1000° F steam plants, and an open-cycle gas-turbine bottoming plant. Trinary cycles could lead to higher efficiency MHD plants; but because of their complexity, these were not considered in this open-cycle MHD study.

The remaining emphasis of this study is that most plants were nominally 2000 MWe and used Illinois #6 coal. Nominally 1200-MWe and 600-MWe plants were considered in the parametric variations as was the use of Montana subbituminous coal and North Dakota lignite.

5.8.2.2 MHD Cycle

Figure 5.8-1 shows a representative MHD cycle. After proper preparation, the primary coal is supplied to the MHD combustor along with compressed air that has been preheated to a high temperature. Generally, a large fraction, 80 to 90 percent of the coal slag is assumed to be rejected directly from the MHD combustor system. The combustor is assumed to operate fuel rich to reduce NOX production. The alkali-metal seed, a potassium compound, is added to the nominally 4500° F exhaust of the combustor.

The flow is expanded at a high subsonic Mach number through the MHD generator with its superconducting magnet. Since the MHD generator electrical output is direct current, this power is taken through an inverter system to be converted to alternating current for transmission. After the MHD flow is diffused, it is taken into a radiant heat exchanger. Heat losses in the combustor system, the MHD generator, and the diffuser are used in the steam bottoming plant to increase the enthalpy of either feed water or steam.

In the radiant heat exchanger, the flow is further cooled and additional slag is removed. Secondary air is also added to complete the combustion. Residence time in the radiant heat exchanger must be sufficiently long for the nitrogen oxides (NOX) concentration to approach its acceptable equilibrium level. Typically, seconds of residence time are required at approximately 3000° F. The addition of the secondary cooling air to complete combustion actually causes a cooling of the flow at these conditions.

After leaving the radiant heat exchanger, the flow is conventionally assumed to enter a periodic refractory cored-brick regenerative heat-exchanger system that is used to provide the high-temperature air preheat. The G.E./Avco team assumed such a configuration and made use of a water-walled radiant heat exchanger designed by Foster Wheeler to provide heat to the steam bottoming plant. The Westinghouse team, on the other hand, assumed that a radiant high-temperature recuperative air-preheat heat exchanger could be constructed using superalloy tubes at its lower temperatures and silicon carbide tubes at the higher temperatures. Although interesting in concept, caution must be taken because of the lack of any data on such a device.

General Electric splits the exhaust gases after they leave the high-temperature air preheaters, as illustrated in figure 5.8-1, to provide input into the low-temperature air preheater and the steam plant superheater and reheater. This is necessary in order to avoid a pinch-point problem. The low-temperature air preheater heats air to 1400° F. Westinghouse chose an alternative location for the low-temperature air preheater and placed it upstream of the steam heat exchangers.

The combustion products are taken through an electrostatic precipitator before being taken through the economizer and exhausted via a stack. Additional alkali seed compounds will also be collected by soot-blowing techniques from the various low-temperature heat exchangers. A small fraction of the exhaust of the precipitator may typically be diverted to the coal dryer. The remainder of the flow is taken to the steam plant economizer.

Since potassium can readily combine with any sulfur in the combustion products, it is predicted that such an MHD plant could meet sulfur oxides (SOX) emission standards even using high-sulfur coals as long as adequate seed is injected as either potassium carbonate or potassium hydroxide. To meet this requirement, a larger fraction of the seed that is collected as potassium sulfate must be processed in a seed-reprocessing plant to remove the sulfur. Although the concept described is an attractive method of eliminating SOX emission from such powerplants, operation of the seed reprocessing plant does pose a significant performance penalty for high-sulfur coals, reducing overall efficiency by approximately 3 percentage points. Seed reprocessing is discussed in more detail later in this section.

Some of the components that are unique to MHD cycles are estimated to be particularly costly. The three most costly are, in order of cost, the high-temperature air preheaters, the inverter system, and the superconducting magnet system. All three of these components are discussed in subsection 5.8.5 <u>Common MHD Components</u>.

For typical cases, approximately two-thirds of the net electrical output of an MHD plant is from the MHD generator. The steam bottoming plant is sized to have a gross output approximately one-half of the net cycle power. Part of the steam turbine power is used to drive the air compressors for the MHD topping cycle.

5.8.3 Results of Analysis

5.8.3.1 Overall Comparison

Figure 5.8-2 summarizes the overall efficiency and cost of electricity results for 2000-MWe open-cycle MHD plants with steam bottoming cycles. Only plants that use direct high-temperature air preheaters and either Illinois #6 coal or SRC are shown in this figure. Other cases are discussed as parametric variations.

On the top of the figure, at high cost of electricity, are the G.E. base case 1 coal-fired plants. At the bottom of the figure at relatively low cost are the Westinghouse base case 2 direct-coal-fired plants. Clearly there are significant differences in terms of cost of electricity between the two sets of results. The cause of these differences is discussed later in terms of how the cost breaks down for representative points.

The agreement between the contractors in terms of efficiency is far better. Both teams show that direct-coal-fired MHD plant efficiencies in the neighborhood of 50 percent (coal pile to bus bar) can be obtained. Even closer agreement than is apparent in figure 5.8-2 was obtained by the contractors. This is also discussed later in terms of representative points.

Other types of plants shown in figure 5.8-2 are the G.E. base case 2 solvent-refined-coal-fired plants, the Westinghouse base case 1 direct-plus-indirect-preheat coal-fired plants, and the Westinghouse base case

3 plants fired by the gas from an integrated LBTU fluidized-bed gasifier.

5.8.3.2 Discussion and Assessment

Figure 5.8-3 shows the specific cases that were summarized in figure 5.8-2. Three general categories of points are shown. These categories are based upon the relative heat-exchanger technology required. The four points that are solid are judged to be well within present heat-exchanger technology: 2000° F for slag- and seed-laden flows and 2500° to 2600° F for relatively clean flows. The four points that are half-solid form a second category. These are judged to require heat exchangers that significantly exceed present technology: 3100° F for dirty flows and 3500° to 3600° F for relatively clean flows. The remaining points are judged to be within or at least only slightly exceeding present heat-exchanger technology.

As indicated in figure 5.8-3, for different systems and contractors, different parameters were varied. The only type of plant studied in common by both contractors was the direct-coal-fired type. Westinghouse varied the coal moisture and pressure at a preheat temperature of 2400° F. Their results show the desirability of drying the coal from the 13 percent as-received moisture level (Illinois #6) to 3 percent and demonstrate that there is a pressure level that minimizes cost of electricity. There is also a pressure level that would maximize efficiency, but the range of parametric variations was not sufficient to define the value.

The G.E. direct-coal-fired cases examined the effect of generator electrical loading for a 9-atmosphere combustion pressure and a preheat temperature of 2500° F. They also examined the effect of varying preheat temperatures at pressure levels that were judged reasonable. All the G.E. cases were for coal dried to 2 percent moisture.

The results show that the efficiency is very sensitive to the generator loading, the ratio of the generator voltage to its open-circuit value. A load parameter of 0.8 to 0.85 appears desirable for the case studied. In the Westinghouse study, a variable rather than a constant loading parameter was used; they assumed a loading parameter at the MHD channel inlet of 0.82, which varied down to a value of 0.7 at the channel exit.

The G.E. data also show that efficiency is a strong function of preheat temperature. The 2000° F and 3100° F cases are all for a generator loading parameter of 0.8. Also indicated in the data is the desirability of raising combustor pressure with the preheat temperature.

A large range of efficiency and cost is shown for Westinghouse's direct-plus-indirect-preheat coal-fired cases. Generally, the data show that the direct-plus-indirect-preheat concept may offer potential for small performance improvements over the direct-preheat coal-fired case. The economic penalties associated with this more complex system having two series high-temperature heat-exchanger trains would, however, reduce interest in further consideration of this direct-plus-indirect-preheat concept. Of particular interest is the curve of various pressures for which the combustor temperature was maintained at 4400° F by diluting the combustor air with stack gases before it was compressed and preheated to 2933° F. This curve is of particular interest to Westinghouse since they feel that the use of their ceramic-line cyclone combustor design philosophy is uncertain when the combustor temperature exceeds the 4400° to 4500° F range. For the lower pressure levels and lower preheat temperatures of the direct-preheat coal-fired Westinghouse cases, this is not felt to be a problem since combustor temperatures are in the 4400° to 4500° F range.

The G.E./Avco team assumed a significantly different combustor design philosophy. The Avco concept is more advanced. Their approach utilizes concepts more familiar to rocket technology than present coal-burning technology. The G.E. coal-fired systems had combustion temperatures in the 4600° to 4700° F range.

As indicated in figure 5.8-2, the Westinghouse LBTU-fired plants appeared to offer the highest efficiency potential. These plants remove the sulfur from the Illinois #6 coal in their integrated fluidized-bed gasifier. As a result, they are not forced to pay the approximately 3 percentage points in efficiency that the direct-coal-fired plants must pay to remove the sulfur in a seed reprocessing plant. The only type of seed reprocessing that has been considered are plants that produce elemental sulfur. Future studies should consider alternative configurations that would not produce elemental sulfur and would have a much lower penalty for seed reprocessing.

Although Westinghouse does estimate that the cost of electricity for the LBTU-fired cases will be above the cost for the direct-coal fired cases, caution should be exercised. As shown in the common MHD components section 5.8.5, Westinghouse tends to be significantly higher in its cost estimates for both magnets and high-temperature heat exchangers than either G.E. or Burns and Roe's subcontractors. The capital cost of the Westinghouse LBTU-fired cases is dominated by the combined cost of the high-temperature heat exchangers and the magnets, which comprises approximately 60 percent of the major component cost.

Parametric studies for LBTU-fired plants consisted of only three cases and some power level variations. The parameters selected for study may not be near optimum values.

The Westinghouse studies did, however, indicate that LBTU gas may be a marginal MHD fuel because of its low heating value. Any additional studies should consider the possiblity of using oxygen enrichment of the air for either the gasifier or the MHD combustor or both. The effect of oxygen enrichment would be (1) to cut the mass flow of the gas to be preheated and thus reduce the preheater cost; (2) to increase the combustor temperature, which in turn would increase the average MHD channel power density and lower the magnet cost; and (3) to slightly lower the required preheat temperatures.

The G.E. studies of solvent-refined-coal-fired plants showed that, because of its high-Btu content, SRC is an excellent MHD fuel. The powerplant efficiencies for the SRC-fired cases range from 52 to 59 percent, but because of the energy losses associated with producing the fuel from coal, the overall energy efficiencies range from only 40 to 46 percent. The cost of electricity for the SRC-fired plants is, however, estimated by G.E. to be competitive with the coal-fired plants. The SRC-fired plants have higher fuel cost but lower capital cost than the coal-fired plants; therefore, in any future studies, particularly of peaking MHD systems, fuels such as SRC deserve further consideration.

Before discussing other specific results, a few general observations are warranted. Detailed analysis of the MHD generator is important for two reasons: first, to determine what level of isentropic efficiency can be obtained when the heat losses and friction are included; second, to determine the size of superconducting magnet required for the MHD generator.

The Westinghouse channel calculation and the core flow portion of the Avco channel calculation were checked with NASA's own channel program. In both cases the agreement was within 5 percent. Avco considered all of the important channel loss mechanisms, that is, boundary layers, voltage drops, heat transfer, and friction. They found that approximately 8 percent of the power generated was lost due to these factors. Westinghouse did not calculate these losses, but on the basis of their prior experience assumed them to be 10 percent. NASA therefore concludes that the two calculations are consistent to within 5 percent and realistically predict channel sizes within limitations of ones ability to extrapolate the presently available "small" channel experiments to large-scale powerplant designs.

Considerations having to do with the MHD combustor system primarily deal with the question of how much slag can or should be rejected directly from this system. This in turn is connected with questions having to do with seed-slag solubility and how well the seed and slag can be separated by the differences they have in temperatures of condensation and solidification. Many believe that some slag will be required in the MHD generator to replenish the electrodes in order that long-operating-life channels can be obtained. It is uniformly recognized that recuperative and regenerative heat exchangers will not be tolerant of large slag carryovers. Therefore, a high fraction of slag must be removed before the flow enters these components.

If the combustion gases are to be cooled to a low temperature before entering the stack, this must be accomplished in the economizer since it is the lowest-possible-temperature heat exchanger in the system. As a result, there is a trade-off between regenerative feedwater preheating in the steam bottoming plant and the economizer exit temperature. In Phase 2 of the ECAS study, use of multiple economizer sections with additional regenerative feedwater heating between the economizer sections will be examined.

Since a plasma MHD generator produces its electrical output from a large number of electrically isolated electrode pairs, this poses some special consideraton on the inverter system. Of particular note is the necessity of protecting the inverter system from potentially large short-circuit currents, even though it is designed to operate near open-circuit voltage. This is discussed in more detail in section 5.8.5.

5.8.3.2.1 Comparison of representative direct-preheat coal-fired systems. - These systems are compared on the basis of performance, capital cost, and cost of electricity.

5.8.3.2.1.1 Performance: In general the performance results of the two contractors for the direct-coal-fired cases are quite close. A comparison is displayed in table 5.8-2 for General Electric base case 1 and for Westinghouse base case 2, point 17. These two cases are shown because they are closest in terms of power level, preheat temperature, MHD generator inlet pressure, and fuel. Both use Illinois #6 coal dried by exhaust gases prior to combustion. Westinghouse assumed coal dried to 3 percent moisture, and General Electric assumed coal dried to 2 percent moisture. Westinghouse used 95 percent of stoichimetric air input to the combustor, and General Electric used 93 percent of stoichiometric air. In both cases the secondary air to complete combustion was injected into the gas stream in the component downstream of the diffuser.

The thermodynamic efficiencies obtained by the contractors, shown near the bottom of the table, are nearly the same. Ordinarily it would be expected that the General Electric result, with slightly higher MHD inlet temperature and pressure, would have a higher efficiency than the Westinghouse result. As shown, the efficiency of the MHD part of the cycle (defined here as inverter output minus compressor power requirement divided by combustor thermal input) is higher for the General Electric case. However, Westinghouse used a higher steam-cycle efficiency, which in this case compensates for their lower topping-cycle efficiency. This is also reflected in the power split between the MHD topping cycle and the steam bottoming cycle. With a lower MHD topping cycle efficiency, more heat is available to the steam bottoming cycle in the Westinghouse case. This together with the higher steam-cycle efficiency results in more steam turbine-generator power output for the Westinghouse case. As shown in the table, 53 percent of the total output power is attributable to the MHD topping cycle for the General Electric case; for the Westinghouse conditions, only 45 percent of the total power is due to the MHD topping cycle.

As mentioned earlier, both contractors used a 3500 psi/1000° F/1000° F steam cycle. Westinghouse analyzed the system assuming all exhaust-gas-to-steam-heat exchangers are downstream of the combustion air preheaters. They used a steam cycle with 42 percent efficiency and reported no further details concerning the feedwater heater arrangement. General Electric analyzed a configuration that included a radiant steam boiler section downstream of the diffuser, followed by the high-temperature air heater, then the steam superheater/reheater section and the low-temperature air preheater, and finally an exhaust-gas-to-feedwater economizer. They used a steam cycle with regenerative feedwater heating to 232° F, which results in a 40 percent cycle efficiency. In analyzing the system in the second phase of ECAS, General Electric will consider a steam cycle with more regenerative feedwater heating but with a section of the exhaust-gas-to-feedwater economizer included between the low-pressure and the higher-pressure regenerative feedwater heaters. In this way a 1 to 2 percent higher steam-cycle efficiency will be attained while the exhaust gases can still be reduced to the desirable stack inlet temperature of about 300° F.

The difference between the thermodynamic efficiency and the overall energy efficiency shown in the table is due to the effects of plant auxiliary power and seed processing requirements. The thermal inputs for seed processing are shown in the table in terms of coal thermal input required to produce the carbon monoxide and hydrogen used in processing the seed. Westinghouse used an on-site intermediate-Btu (IBTU) gasifier, but General Electric assumed the use of over-the-fence LBTU gas. As shown in the table, the Westinghouse approach required a little over 5 percent of the total thermal input for seed processing, but in the General Electric approach, almost 6 percent was required. This difference is in part due to the difference in gasifier efficiencies associated with the different approaches. The difference in gasifiers for seed processing also affects the comparison of plant auxiliary power requirements. Of the 63 MWe shown for the Westinghouse case, 14 is required for the oxygen production for the IBTU gasifier. Without this power the Westinghouse auxiliary power requirements would have been 2.4 percent of the gross plant output (rather than the 3.1 percent shown in the table) and would have been slightly lower rather than slightly higher than the 2.8 percent required in the General Electric case.

The ratio of auxiliary power required to gross plant power (or the ratio of coal seed processing coal to total coal) is equal to the percentage loss in efficiency due to the auxiliary requirement. The product of this ratio and the thermodynamic efficiency is then equal to the loss in percentage points due to this requirement. The auxiliary power requirements account for about 1.6 and 1.5 percentage points loss in efficiency for Westinghouse and General Electric. The losses due to seed processing are about twice as high, about 2.8 and 3.1 percentage points, respectively, for the Westinghouse and General Electric cases.

5.8.3.2.1.2 Captial cost: Table 5.8-3 shows a comparison of the capital cost distributions for the two representative direct-preheat coal-fired open-cycle MHD plants. The total direct materials costs (the sum of the cost of the major components and other materials) is slightly higher for G.E. than for Westinghouse. This results in spite of the fact that Westinghouse has higher costs for two of the three most expensive major components: the high-temperature preheater system and the magnet system (section 5.8.5). General Electric, on the other hand, does have higher inverter costs even though both contractors base their estimates on essentially the same technology bases. The Westinghouse study used some external diagonal connections to minimize their inverter costs.

In some of the other less expensive components, including the coal-handling system, the MHD combustor, and the MHD generator, G.E. also has higher costs. The overall G.E. materials and labor costs are higher, primarily because G.E.'s architectural engineer, Bechtel, has estimated substantially larger costs for balance of plant. This balance of plant includes all material and labor for plant construction after the major components have been delivered to the site.

Although both contractors give reasonable detail in their breakdown of cost, each uses their own system of breaking down and categorizing cost, as discussed in section 5.1. It was, therefore, not possible to make a detailed item-by-item cost comparison between the contractors. For the level of detail examined in this initial phase of ECAS, the total direct cost comparison for the two contractors is reasonably good. In calculating total capital cost from the total direct cost, the two contractors have major differences in procedure (see section 5.1). To calculate escalation and interest, both contractors estimated the construction time of these plants to be 7 years.

5.8.3.2.1.3 Cost of electricity: Table 5.8-4 shows a comparison of the cost of electricity for the two direct-preheat coal-fired open-cycle MHD plants. The capital charges are higher for G.E. because of their higher capital cost. The total fuel charges are also higher for G.E. because they used an over-the-fence higher-cost LBTU gas to operate their seed-processing plant, and this was included in the fuel charges. The operating and maintenance (O and M) charges were also higher for G.E. since they included additional costs above the normal steam plant maintenance charges for portions of the MHD plant. The increase to O and M cost used by G.E. was equal to 20 percent per year of the initial capital costs of the MHD generator, diffuser, combustor, slagging boiler, and high-temperature air preheaters. These additions, however, did not significantly raise the O and M. Westinghouse's O and M charges were essentially equivalent to those for their steam plants. As indicated in the table, the total effect of the difference in costing between G.E. and Westinghouse causes G.E.'s estimated cost of electricity to exceed Westinghouse's by approximately 50 percent.

5.8.3.2.2 Summary of parametric variations. - Within the framework of the initial ECAS phase, a number of cases were studied in order to assess sensitivity to various parameters and to probe alternative powerplant concepts. Five such effects or alternatives are summarized in this section. These include variation of performance with powerplant power level, with slag carryover percentage, and with use of alternative coals. In addition, results of the cases looking at other than direct-fired high-temperature preheaters and alternative bottoming plants are presented. Two other parametric variations that were addressed in the study were varying the strength of the average magnetic field in the MHD channel and varying the potassium seed fraction. Increasing the average magnetic field strength from 5 to 6 to 7 teslas had no effect on efficiency but did show a very small reduction in cost of electricity. Seed fraction variations of 1.5, 1, and 0.5 percent were examined. Minimizing the seed fraction showed small improvement in both efficiency and cost of electricity in this range, but 0.5 percent seed fraction would be marginal for SOX control for a high-sulfur coal like Illinois #6.

Because of the large costing difference between the two contractors, the results in this section are presented in a normalized form. In each case, the results of the respective contractors are normalized by the appropriate plant of that contractor.

5.8.3.2.2.1 Effect of plant size: Figure 5.8-4 illustrates how the efficiency and cost of electricity vary as a function of powerplant size. The data for the nominally 2000-, 1200-, and 600-MWe plants have been normalized by the cost and efficiency of the 2000-MWe plant for each type of plant. The figure includes data for both G.E.'s and Westinghouse's direct-preheat coal-fired plants, Westinghouse's direct-plus-indirect-preheat coal-fired plants, and Westinghouse's LBTU-fired plants. The reduction in cost in going from 2000 MWe to 1200 MWe for the G.E. data results from lower escalation and interest costs associated with reducing the construction time from 7 to 6 years, which more than compensates for other cost increases. The assumed reduction in construction time by Westinghouse is more gradual. Figure 5.8-4 illustrates that open-cycle MHD plants need to be big and that plants of 1200 MWe or larger are desirable.

5.8.3.2.2.2 Effect of slag carryover in coal-fired plants: Table 5.8-5 summarizes the points studied as a function of slag carryover by both contractors. Both indicate that, within their ability to analyze such systems, there is essentially no effect on either overall efficiency or cost of electricity from slag carryovers up to and including at least 20 percent. Within the assumptions they used for the study, the G.E./Avco team feels that even 100 percent slag carryover into the MHD channel will essentially have no effect. Westinghouse, on the other hand, feels that for the 100 percent slag carryover case, a completely different scheme for seed recovery will be required, efficiency will be significantly affected, and cost will be affected only slightly. A 5 percent reduction in efficiency (approx 2.5 percentage points) is essentially equivalent to giving up 25 percent of the efficiency advantage that the MHD/steam plant combination has over a steam plant.

The question of how to analyze slag carryover into the MHD channel is far from technically resolved. Both contracting teams in this study have taken what could be termed an optimistic viewpoint. Some other teams, such as the Bureau of Standards and ERDA/Pittsburgh Energy Research Center, feel that the concept of zero slag rejection at the combustor will cause excessive losses of seed to the slag. They further state that even with a large percentage of slag rejection, capture of seed by a slag layer protecting the electrode and insulator structure may be a serious problem. Avco and the University of Tennessee Space Institute, on the other hand, state that they have seen no such evidence in their small-scale experiments, which are the largest operating to date.

5.8.3.2.2.3 Performance with alternative coals: Table 5.8-6 summarizes the results obtained for plants using Montana subbituminous coal or North Dakota lignite. Performance has been normalized by the representative powerplants that were fired by Illinois #6 coal. In all cases the plant was designed for operation only on its own coal. All the data shown are for direct-preheated, nominally 2000-MWe, coal-fired plants using well-dried coal. Westinghouse also examined the use of wetter coal (as received), but this only lowered performance. For the alternative coals, each contractor chose only one set of cycle parameters that he felt would be representative for each of the types of coal. Therefore, these alternative coal plants may be further from optimum than the Illinois #6 plant, which has been examined with at least limited parametric variations.

The results shown in table 5.8-6 indicate there may be very little penalty associated with using the Montana coal rather than the Illinois #6 coal in an open-cycle MHD plant. This was a somewhat surprising result in view of the large differences in heating values of the two coals. The significant factor is that the low-sulfur Montana coal requires far less power in the seed reprocessing plant. For lignite, the cases studied indicate that because of its very low heating value there may be significant efficiency and/or cost of electricity penalties associated with its use.

5.8.3.2.2.4 Alternatives to direct-fired high-temperature air preheat: Table 5.8-7 shows the results obtained for systems using either only low-temperature air preheat and oxygen enrichment or an indirect preheat cycle fired by fuel from an advanced regenerative gasifier. These results are compared to a direct high-temperature preheat system. As indicated in the table, G.E. estimated that both of these alternatives could yield costs of electricity that are competitive with the direct-high-temperature-preheated plant.

For the oxygen-enriched case, G.E. used the specified over-the-fence oxygen cost of $9.00/ton. They did not include in their overall efficiency the electric power that would be consumed to produce the gaseous oxygen. Its inclusion would lower the overall efficiency 2.8 points. As a check on the oxygen cost that had been specified, NASA also has estimated the cost of electricity if an on-site oxygen plant was used. The NASA estimates are based upon vendor quotes to Burns and Roe by two major air-separation companies. Quotes were on the basis of turn-key operation. These quotes support the specified mid-1974 $9.00/ton price, but for consistency in table 5.8-7 NASA has used G.E.'s factors for contingency, fees, escalation, and interest.

In the G.E. costing, large balance-of-plant charges were estimated by Bechtel. Within the scope of ECAS only base cases could be examined in detail. Caution must, therefore, be exercised in interpreting the cost for cases such as those in table 5.8-7, which deviate substantially from the base case. In particular, much larger cost reductions than have been shown might be expected for the oxygen-enriched case, since this causes a significant simplification of the total plant and its piping. For the indirect-preheated case, changes in balance-of-plant cost would be expected, but since it was not a base case these costs were estimated in Phase 1 to be equal to the direct-preheat case.

The results for the oxygen-enriched plant with only low-temperature preheat indicate that this may be a simple method of obtaining competitive cost of electricity by using open-cycle MHD. Use of only low-temperature preheat poses a thermodynamic penalty that, however, limits the overall efficiency. This type of plant has a lower capital cost and may be better suited for nonbaseload applications.

The indirect-preheated case offers both relatively low cost of electricity and potentially high overall efficiency. The high efficiency results both from the high preheat temperature, 3100° F, and the assumption of an advanced gasifier using chemical regeneration. In the system envisioned, a fraction of the MHD exhaust is diverted into the gasifier vessel. It supplies both thermal energy, carbon dioxide, and water to gasify coal. Any remaining char has been assumed to be utilized in the MHD combustor. The specific concept assumed is based upon very limited Avco data. These results do indicate that this, as well as other alternative schemes of using chemical regeneration in conjunction with open-cycle MHD, is deserving of further study.

5.8.3.2.2.5 Alternative bottoming plants: A few cases were examined in this study that made use of bottoming plants other than the supercritical steam plant with a 3500 psi/1000° F/1000° F and heat rejection to a wet cooling tower. Westinghouse examined two cases using 2400 psi/1000° F/1000° F plants with a wet cooling tower. Substitution of this lower performance plant decreased the overall cycle efficiency by 0.7 percentage point and increased the cost of electricity by a small fraction of a mill per kilowatt hour, approximately 1/10. General Electric examined the effect of replacing the wet cooling tower with a dry cooling tower. This decreased the efficiency by only 0.2 percentage point but increased the cost of electricity by 1.2 mills/kW-hr.

General Electric also examined one advanced bottoming plant concept. This case assumed an open-cycle air turbine. It used one high-temperature turbine operating at 2400° F with air heated in the high-temperature air preheater. A second lower temperature turbine was operated with air from the low-temperature preheater. The exhaust gas of the high-temperature air turbine was added to the MHD exhaust gas upstream of the low-temperature air heater so that its thermal energy can be utilized in the low-temperature turbine.

This air turbine cycle leads to a very high overall efficiency, 50.9 percent, with a maximum preheat temperature of only 2500° F. Cost of electricity for the case was quite competitive at 45.6 mills/kW-hr. The slight increase in cost of electricity results from a 5 percent higher capital cost for this plant. One-half of this cost increase is associated with the air-cleaning system for the high-temperature turbine. The other half of the capital cost increase is approximately equally shared between the higher cost for the air turbine/compressor/generator than for the alternative steam turbine/compressor/generator and the higher cost for the larger high- and low-temperature air heat exchangers than for the alternative steam heaters. Again caution is in order; balance-of-plant costs for this air turbine plant were not considered in any detail but were merely taken as being equal to those for the steam bottoming plant case. This result does indicate that gas-turbine bottoming plants could be attractive compared with MHD/steam plants if practical hot-gas cleanup systems could be developed.

5.8.4 Conclusions

1. The open-cycle MHD systems appear to have the potential of approaching a 50 percent coal-pile-to-bus-bar efficiency with a competitive cost of electricity: for G.E., approximately 44 mills/kW-hr; for Westinghouse approximately 27 mills/kW-hr.

2. Both contractors indicate approximately 49 percent overall energy efficiency for 2400° F to 2500° F direct-preheat coal-fired systems. Combining the desirable features of the contractors' approaches could raise the efficiency potential to over 50 percent.

3. There are significant cost differences and/or uncertainties concerning a number of major components. Only further technology development can effectively resolve many of these uncertainties.

4. There is also a significant difference between the contractors concerning the balance-of-plant costs. The conceptual design of a direct-preheat coal-fired plant selected for ECAS Phase 2 should help to clarify this issue.

5. There can be a significant performance penalty associated with removal of sulfur from seed in the seed reprocessing plant. Approximately 3 percentage points in efficiency is lost for high-sulfur Illinois #6 coal for plants producing elemental sulfur. Alternative reprocessing concepts with

lower performance penalties should be considered in future studies.

6. The systems studied that use fluidized-bed integrated gasifiers with in-bed sulfur removal appear to have the potential to be competitive with the direct-coal-fired systems, at least for high-sulfur coals. Further study would be required both to optimize these systems and to define their performance and cost potential.

7. The performance and cost of all types of open-cycle MHD systems are sensitive to how well the waste heat in the exhaust is utilized. Using this heat to preheat combustion air to the highest practical temperature is desirable; however, materials problems pose limits to this approach. Extension of present technology by a few hundred degrees Fahrenheit limits preheat temperatures to 2500° F for slag-laden flows or to 3100° F for relatively clean flows. Use of chemical regeneration or advanced bottoming plants may pose attractive alternative uses of the MHD exhaust heat. Both these alternatives are deserving of additional study.

8. Using semiclean fuels, such as SRC, and/or oxygen enrichment (to eliminate the need for high-temperature air preheat) lowers MHD plant capital cost. Even though these techniques reduce efficiency, they appear to result in a competitive cost of electricity. They deserve further examination at least in any future peaking or intermediate-load powerplant studies.

5.8.5 Common MHD Components

5.8.5.1 Direct-Current to Alternating-Current Inverter Systems (Power Conditioning) for MHD Generators

Costing data were estimated for dc to ac inverter systems (also referred to as "power conditioning") by both General Electric and Westinghouse as a part of their prime contracts. Also ASEA, Ltd., estimated costs for Burns and Roe, Inc., who were under contract to NASA Lewis to support ECAS studies through Lewis in-house efforts.

Table 5.8-8 gives the direct costs of the inverter system components as delivered to the powerplant site in normalized units of $/kWe of inverted power. The differences that appear in table 5.8-8 can largely be explained by examining the curves presented in figure 5.8-5. These curves were developed by G.E. The Westinghouse and ASEA data have also been plotted on figure 5.8-5. The module power handling size is determined (1) by the maximum current that the dc interrupters can handle, and (2) by the voltage level of the dc to be inverted. If a very conservative estimate is made of interrupter current capability, more interrupters and hence more (and smaller) inverter modules (one per interrupter set) must be used to achieve the total power level. The larger number of interrupters needed when using the smaller modules drives the system price up, as reflected by the higher costs on the left side of figure 5.8-5.

As can be seen from figure 5.8-5, G.E. uses 28-MWe modules (5000 A per interrupter) for both the open- and closed-cycle MHD, contrasted to the 50- or 60-MWe modules (5000 A per interrupter) used by Westinghouse. Westinghouse proposed the larger module size by assuming larger input voltages as a result of assuming sets of two MHD electrodes connected in series per dc interrupter, rather than one set of electrodes per interrupter as assumed by G.E. Since ASEA also proposed using 50-MWe modules, their price is also below G.E.'s. While the ASEA price is for an entire installed "turn-key" system, it is probable that, for such a complex electronic system, only a small fraction of this price (7 to 13 percent) is for foundations and installation. Hence, the ASEA data are in reasonable agreement with the G.E. and Westinghouse data.

The largest difference is the $165 to $200 per kilowatt price quoted by G.E.

for liquid-metal MHD. Direct-current interrupters are again responsible for this difference. General Electric postulates using dc interrupters between the MHD ducts and the actual inverter circuitry; Westinghouse feels they are unnecessary. Because the liquid-metal MHD is a low-voltage high-current device and uses many generators in parallel, it is necessary to go to smaller power-handling modules when dc interrupters are used because of the current limit placed on each interrupter. Using smaller power modules increases inverter costs (left side of fig. 5.8-5).

If the "state of the art" of dc interrupters is advanced to higher current levels (greater than 5000 A), it will be possible to move more to the right on the curves of figure 5.8-5. Inverter costs can also be lowered by optimizing circuit interconnection to increase input voltage. For example, extending the Westinghouse concept of placing a number of electrode sets in series through a single dc interrupter would obviously reduce cost.

5.8.5.2 Superconducting Magnet Designs for MHD Generators

Costing data were estimated for superconducting magnet designs by both G.E. (with the Avco-Everett Research Laboratory as subcontractor) and Westinghouse as a part of their prime contracts. The Magnetic Corporation of America (MCA) also developed costs for Burns and Roe, Inc., as part of the NASA in-house effort.

Table 5.8-9 presents data for the various magnet design cases studied. Each case was studied in only enough detail to obtain costing information. Magnet costs are normalized in terms of $/kJ of stored energy and in terms of $/lb of magnet weight. To aid in correlating these costs, lb/kJ are also given. The magnet costs for the liquid-metal MHD systems are not included here but are given in section 5.10. Liquid-metal MHD magnets are lower field magnets of a design much different than that used in open- and-closed cycle MHD systems.

The first three cases shown in table 5.8-9 are for an open-cycle MHD direct-coal-fired system with a nominal output power of 2000 MWe. General Electric/Avco assumes the use of an aluminum alloy for most structures and hence their very low price. The $/kJ of stored energy agree quite closely for MCA and G.E./Avco, with the Westinghouse cost being more than double. As can be seen from the last column, the lb/kJ are not too much different in each of the three cases, indicating that Westinghouse assumes much higher costs per pound for materials and labor. Table 5.8-10 compares the price/lb values used by MCA, G.E./Avco, and Westinghouse. Indeed, table 5.8-10 shows that Westinghouse uses much higher pricing numbers than either of the other two companies.

The Westinghouse design (table 5.8-9) shows a much lower stored energy than either MCA or G.E./Avco. In their documentation, Westinghouse indicates that a current density of 1.4×10^8 A/m^2 was assumed for the superconducting wire. General Electric/Avco assumes 0.2×10^8 A/m^2, and MCA assumes 0.4×10^8 A/m^2, factors of 3 to 7 smaller. Hence, for the same number of ampere-turns, the wire bundles in the Westinghouse case are much smaller and can be located much closer to the channel centerline because the average wire cross section is reduced in proportion to the higher current density used. By locating the turns closer to the channel centerline, the stored energy of the Westinghouse magnet is reduced since the energy stored in this type of magnet is proportional to the average value of the conductor distance from the channel centerline squared.

Throughout table 5.8-9 the Westinghouse prices are consistently higher in comparison to the other design cases shown. Likewise their stored energy values are based on the assumption of 1.4×10^8 A/m² current density used throughout the study.

Table 5.8-9 points to the directions that should be taken in advanced MHD magnet design. The highest current density possible should be used to reduce total stored energy. Since the system weight appears to be directly proportional to stored energy, this reduction in stored energy reduces overall system weight. Optimization of the fabrication techniques for both superconductor and structures should be emphasized to reduce these costs on a per pound basis. Advanced NbTi conductor fabrication techniques (or possible substitution of niobium tin for NbTi) could conceivably reduce the costs of the superconducting wire. Additional substitution of aluminum for stainless steel in various parts of the system might further reduce structural material cost. MCA cost estimates for the cases studied indicated that a possible 10 to 13 percent cost reduction can be achieved by operating the superconducting magnet at a reduced temperature of 1.8 K.

5.8.5.3 High-Temperature Refractory Heat-Exchanger Systems

Costing data were developed by both G.E. (with Avco as subcontractor for open cycle systems) and Westinghouse as a part of their prime contracts. FluiDyne Engineering Corp. under contract to Burns and Roe also developed costs for NASA.

The tables given include the cost of both labor and materials required to install heater pressure vessels, refractory matrices, high-temperature valving, and air (or argon) inlet and outlet piping (including manifolds). For direct-fired MHD generators, exhaust gas ducting to and out of the refractory system is also included.

5.8.5.3.1 Direct fired - open cycle. - All three companies estimated the cost of a high-temperature refractory heat exchanger for direct-coal-fired combustion with a 2000-MWe nominal total output power. The combustion air for all three studies was preheated to approximately 2500° F, and the heat transferred to the air was nominally 950 MW. Data for the FluiDyne and G.E./Avco cases are presented in table 5.8-11.

There is obviously a large difference in the total refractory-heat-exchanger system costs shown in table 5.8-11. FluiDyne assumes that high-quality, fused-grain, 99-percent-pure aluminum oxide and magnesium oxide has to be used for much of the refractory matrix in their regenerative heat-exchanger design, at a materials cost of $1.15 per pound. General Electric/Avco on the other hand, assumes that a lower grade of aluminum oxide can be used for their heat-exchanger matrix, at a cost of $0.25 per pound. When this price difference is taken into account, the balance of the system agrees within 10 percent in cost. Some of the remaining difference can be explained by the fact that FluiDyne requires more insulating and pressure vessel materials since they subdivide their system into 34 heat exchangers, contrasted to 6 for G.E. Also the design conditions were different. FluiDyne designed their system for a logarithmic mean temperature difference of 406° F, compared with 610° F for G.E./Avco.

Westinghouse took a much different approach to this heat-exchanger system by assuming that a tube-and-shell recuperative heat exchanger could be built using a combination of silicon carbide and high-nickel alloy tubing. Data for this are presented in table 5.8-12.

It might be expected that a recuperative version of the open-cycle MHD heat exchanger would be less expensive than regenerative heat exchangers with their associated high-temperature valving and extensive high-temperature manifolding. But as can be seen from the data in tables 5.8-11 and 5.8-12, the high materials and labor cost (much of this for tube joining) make the Westinghouse system the most expensive of the three systems. However, there is a very large degree of uncertainty in all of these costs. With a slight change in either materials processing or fabrication techniques, the cost estimate could change considerably.

General Electric/Avco scaled their open-cycle MHD refractory heat exchangers from the base case shown in table 5.8-11 by using the following scaling relation, provided by Avco: that cost in millions of dollars is proportional to the thermal power transferred to the 0.7 power. The FluiDyne base cases appear to scale in a like manner, with the exponent being closer to 0.93 than 0.7. This holds when only the heat-exchanger beds are considered. When all interconnecting high-temperature piping is included, the scaling exponent becomes 1.17. But this is not surprising since FluiDyne assumes a very large subdivision of the system into 34 vessels, and this dictates a very large amount of interconnecting piping.

5.8.5.3.2 <u>Separately fired</u> - <u>open cycle</u>. - Table 5.8-13 gives costing data on a FluiDyne design originally done for clean-fuel (intermediate-Btu gas) MHD firing with the seeded hot MHD exhaust passing directly into the refractory heat-exchanger system. This conceptually is nearly equivalent to a separately fired system with an intermediate-Btu-fired combustor in each vessel, except that in the separately fired system the problems due to seeding are not present. The G.E./Avco point is for a clean fuel gas generated by passing one-third of the MHD exhaust directly into a coal gasifier and using the clean fuel generated by rapid devolatilization of the coal to fire the combustor in each vessel of the separately fired system. In both cases the air is nominally preheated from 1450° F to 3100° F. Two Westinghouse points are shown, one in which the gas being preheated is air only, and one in which a mixture of air and fuel gas is preheated. The amount of heat transferred is different, so the data are normalized to reflect cost per kilowatt of heat transferred. In both cases the preheated fluid is heated to 2934° F. In the air/fuel gas case (base case 1, point 1) the inlet temperature is 2385° F. In the air-only preheat (base case 1, point 12), the inlet temperature is 2129° F. The average temperature of the Westinghouse system is higher than that for the G.E. and FluiDyne systems and can be expected to result in higher costs.

The FluiDyne and G.E./Avco costs are close in $/kWt. However, the FluiDyne cost of refractory brick is higher than G.E./Avco's because the FluiDyne design was originally for a seed-laden environment and requires denser material and hence more expensive pricing in many portions of the refractory matrix. General Electric/Avco assumes brick costs in the lower bed at $0.25 per pound and FluiDyne assumes $0.85 per pound.

The FluiDyne's piping layout is more compact than G.E./Avco's, thus explaining much of the difference in piping costs. The costs per kilowatt transferred for the FluiDyne systems shown in tables 5.8-11 and 5.8-13 differ by almost a factor of 2. The direct-coal-fired case assumes 1.5-inch-diameter holes in the cored brick to avoid blockage by seed and slag. The clean-fuel-fluid (separately heated) case shown in table 5.8-13 assumes a hole diameter of only 0.75 inch, and hence the regenerative heaters are more compact and hence less costly.

The Westinghouse costs shown in table 5.8-13 are twice as high as G.E/Avco's and FluiDyne's on a per unit basis. It is estimated that the Westinghouse system is at least 20 percent more expensive than the G.E./Avco and FluiDyne systems because the average heat-exchanger temperature is higher. The

Westinghouse system appears more conservatively designed and priced to allow for unknown factors and contingencies.

5.8.5.3.3 Main heat exchanger - closed cycle. - Table 5.8-14 gives costing data for three different ceramic heat-exchanger systems used to heat argon to 3100° F. Heat transfer varies from 1765 MWt to 2500 MWt. Costs are normalized in terms of $/kWt. FluiDyne's refractory heat exchanger is much costlier than G.E.'s primarily because G.E. used a smaller hole diameter (1/4 in.) than FluiDyne (3/4 in.).

The Westinghouse system for the main heat exchanger of the closed cycle is extremely high in price when compared to G.E. and FluiDyne costing. Westinghouse heat-exchanger engineering design assumptions are very conservative. Westinghouse used 152 million pounds of ceramic checker brick material for a heat transfer of 1820 MWt. This averages out to 83,500 lb/MWt, compared with 49,800 lb/MWt for the FluiDyne system shown in table 5.8-14. This larger quantity of checker brick is partially necessitated by the assumption of thicker webs between checker holes than assumed by either G.E. or FluiDyne. The stress analysis used to determine web thickness is not documented by Westinghouse in their appendixes on heat exchangers (ref. 2).

Westinghouse also assumes use of a 2.5-inch-square hole in their ceramic checker bricks compared with the 1/4-inch-diameter hole of G.E. and the 3/4-inch-diameter hole of FluiDyne. Westinghouse acknowledges that this also forces the system weight (and cost) to be greater than for the smaller-hole systems. However, Westinghouse feels that the larger holes are needed to lower the system dust loading.

Westinghouse also uses a more stringent value (496° F) of the log mean temperature difference in their heat exchanger system than the other two companies (e.g., FluiDyne uses 588° F). This also accounts for some of the additional weight and hence cost of the Westinghouse system.

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TABLE 5.8-1. - SUMMARY OF KEY PARAMETERS FOR OPEN-CYCLE MHD ECAS PHASE 1 BASE CASES AND VARIATIONS STUDIED IN PARAMETRIC POINTS

Parameter	General Electric				Westinghouse					
	Base case									
	Direct coal fired		Solvent-refined coal fired		1: direct-plus-indirect preheat, coal fired		2: direct preheat, direct coal fired		3: Integrated low-Btu fluidized-bed gasifier	
	Parametric points									
	1 to 23		24 to 30		1 to 17		1 to 17		1 to 5	
	Base case	Variations	Base case	Variations	Base case	Variations	Base case	Variations	Base case	Variations
Power output, MWe	1895	2017 to 599	1932	1754 to 2005	1966	596 to 1977	1989	584 to 1987	1900	577 to 1912
Coal	Illinois #6	Montana, North Dakota	SRC	----	Illinois #6	Montana, North Dakota	Illinois #6	Montana, North Dakota	LBTU/ Illinois #6	----
Moisture content	Dried	----	----	----	Dried	As received	As received	Dried	Gasified	----
Oxidizer	Air	Air plus oxygen	Air	----	Air	----	Air	----	Air	----
Combustor:										
Number of stages	1	----	1	----	2	1; 3	1	2; 3	1	----
Slag rejection (if coal), percent	90	0, 80	----	----	90	0, 80; 95	80	90; 95	(a)	----
Pressure, atm	9	6 to 16	15	9 to 20	6	8, 10, 12	6	7, 8, 10	10	15
Temperature, °F	4684	4490 to 4886	4958	4688 to 5210	4400	4357 to 4855	4415	4220 to 4503	4400	4400 to 4724
Diluent if used	----	----	----	----	Exhaust gas	----	None	Exhaust gas	----	----
Preheater:										
Firing method	Direct	Indirect	Direct	----	Direct plus indirect	----	Direct	----	Direct	----
Temperature, °F	2500	1500, 2000, 3100	3100	2500, 3600	2993	2357 to 3532	2400	2398 to 2402	2587	2587 to 3180
MHD generator:										
Type	Faraday	Diagonal	Faraday	----	Faraday	----	Faraday	----	Faraday	----
Magnetic field, T	6 max., 5 avg.	6 avg., 7 avg.	6 avg.	5 avg., 7 avg.	6 max.	----	6 max.	----	6 max.	----
Potassium seed content, percent	1.0	0.5, 1.5	1.0	0.5, 1.5	1.0	----	1.0	----	1.0	----
Electrical load parameter	0.8	0.6, 0.7, 0.85	0.8	----	0.82 max. (tapered)	----	0.82 max. (tapered)	----	0.82 max. (tapered)	----
Bottoming cycle:										
Type	Steam	Air turbine	Steam	----	Steam	----	Steam	----	Steam	----
Pressure	3500 psi	10 atm	3500 psi	----	3500 psi	2400 psi	3500 psi	2400 psi	3500 psi	----
Temperature, °F	1000/1000	2100	1000/1000	----	1000/1000	1000/1000	1000/1000	1000/1000	1000/1000	----
Cooling tower type	Wet	Dry, none	Wet	----	Wet	----	Wet	----	Wet	----

[a]On gasifier output.

TABLE 5.8-2. - PERFORMANCE RESULTS FOR ILLINOIS #6 -

BITUMINOUS-COAL-FIRED, OPEN-CYCLE

MHD POWERPLANTS

[Nominal plant output power, 2000 MWe; air preheated by direct firing.]

	General Electric base case 1	Westinghouse base case 2, point 17
Net output power, MWe	1895	1988
Coal thermal input to combustor, MWt	3700	3870
Air preheat temperature, ^{o}F	2500	2400
MHD inlet temperature, ^{o}F	4634	4503
MHD diffuser exit temperature, ^{o}F	3625	3655
MHD inlet pressure, atm	9.0	7.0
Compressor exit pressure, atm	10.5	7.6
Airflow, lb/sec:		
Primary	2486	2653
Secondary	187	279
MHD inverter output power, MWe	1399	1230
Compressor power required,[a] MWe	361	307
Steam turbine-generator output, MWe	555	821
Plant gross power output, MWe	1954	2051
(MHD power - Compressor power)/ Plant gross power	0.53	0.45
Auxiliary power required, MWe	55.6	63
Auxiliary power/Plant gross power	0.028	0.031
Coal thermal input to seed processing, MWt	231	213
Coal for seed processing/Total coal	0.059	0.052
MHD efficiency = (MHD power - Compressor power)/Coal to combustor	0.281	0.238
Steam-cycle efficiency (including generator)	0.400	0.420
Thermodynamic efficiency = (Gross power/Coal to combustor)	0.528	0.530
Overall efficiency = (Net power/ Total coal)	0.483	0.487

[a]Given in electric power even if shaft driven.

TABLE 5.8-3. - CAPITAL COST DISTRIBUTIONS FOR OPEN-CYCLE MHD POWERPLANTS USING ILLINOIS #6 BITUMINOUS COAL AND DIRECT-FIRED AIR PREHEATERS

[Nominal plant output power, 2000 MWe.]

Component of capital cost	General Electric base case 1	Westinghouse base case 2, point 17
	Capital cost, $/kWe	
Direct cost:		
Major components and balance-of-plant materials	292	214
Direct site labor	94	78
Indirect site labor cost	84	40
Architect and engineering services	50	23
Subtotal	520	355
Contingency cost	104	29
Escalation cost	209	115
Interest during construction	271	142
Total	1103	642

TABLE 5.8-4. - COST OF ELECTRICITY FOR OPEN-CYCLE MHD POWERPLANTS USING ILLINOIS #6 BITUMINOUS COAL AND DIRECT-FIRED AIR PREHEATERS

[Nominal plant output power, 2000 MWe.]

Component of cost of electricity	General Electric base case 1	Westinghouse base case 2, point 17
	Cost of electricity, mills/kW-hr	
Capital cost	34.9	20.3
Operating and maintenance cost	2.8	.8
Fuel cost for MHD generator	5.6	5.7
Fuel cost for seed reprocessing	.6	.3
Total	43.9	27.1

0,3

TABLE 5.8-5. - EFFECT OF SLAG CARRYOVER IN COAL-FIRED MHD POWERPLANTS USING ILLINOIS #6 BITUMINOUS COAL

[Nominal plant output power, 2000 MWe; air preheated by direct firing 2400° to 2500° F.]

Percentage of slag carryover (from combustor to MHD channel)	General Electric, direct high-temperature preheat only	Westinghouse		General Electric, direct high-temperature preheat only	Westinghouse	
		Direct high-temperature preheat only	Indirect and direct preheats		Direct high-temperature preheat only	Indirect and direct preheats
	Performance relative to a 10-percent-slag carryover system					
	Ratio of overall energy efficiency			Ratio of cost of electricity		
5	-----	1.000	1.000	-----	0.995	0.998
10	1.000	1.000	1.000	1.000	1.000	1.000
20	.996	1.001	1.001	1.003	1.012	1.005
100	.996	.950	.959	1.003	1.026	1.024

TABLE 5.8-6. - EFFECT OF COAL TYPE ON OPEN-CYCLE MHD PERFORMANCE

[Nominal plant output power, 2000 MWe; air preheated by direct firing.]

Type of coal	General Electric	Westinghouse[a]	General Electric	Westinghouse[a]
	Performance relative to Illinois #6 bituminous coal			
	Ratio of overall energy efficiency		Ratio of cost of electricity	
Montana subbituminous	[b]0.971	0.995	0.998	1.005
North Dakota lignite	[b].949	.987	1.023	1.058

[a]Data are shown only for maximum-dried coal (16 to 18 percent moisture after drying) since subbituminous and lignite coals perform better in both overall energy efficiency and cost of electricity if maximum dried.

[b]Data reflect corrections mentioned in ref. 1 (vol. II, part 3, pp. 34 and 35) for Montana subbituminous and North Dakota lignite.

TABLE 5.8-7. - COMPARISON OF ALTERNATE OPEN-CYCLE MHD SYSTEMS TO A DIRECT HIGH-TEMPERATURE PREHEATED SYSTEM

	Direct air preheat (G. E. base case 1)	Air enriched to 33 percent oxygen (mass basis)		Indirect air preheat[a] (G. E. base case 10)
		With over-the-fence oxygen (G. E. base case 9)	With on-site oxygen plant (NASA estimate)	
Direct preheat temperature, °F	2500	1500	1500	1400
Total preheat temperature, °F	2500	1500	1500	3100
Combustor pressure, atm	9	10.2	10.2	13
Overall energy efficiency, percent	48.3	[b]46.1	43.3	50.8
Cost of electricity, mills/kW-hr	43.9	43.1	47.9	43.1

[a]Indirectly preheated fuel is obtained from an advanced concept gasifier (a chemical regenerator) heated by a fraction of the MHD exhaust.

[b]General Electric did not include energy charge for off-site oxygen plant. If included, energy efficiency would reduce to 43.3 percent.

TABLE 5.8-8. - COST OF INVERTER SYSTEM COMPONENTS IN TERMS OF INVERTED POWER

Contractor	MHD system		
	Open cycle	Closed cycle	Liquid metal
	Inverted power cost, $/kWe		
General Electric	60 - 70	70 - 90	165 - 200
Westinghouse	49	51	38
Burns and Roe (ASEA, Ltd.)	[a]40 - 50	[a]40 - 50	----------

[a]"Turn-key" price of system.

TABLE 5.8-9. - COSTING DATA ON SUPERCONDUCTING MAGNET SYSTEMS STUDIED

[Costs include labor but not foundations.]

Point	Contractor	Magnet use	Total system cost, million dollars	Stored energy, MJ	Weight, tons	Cost		Weight/energy ratio, lb/kJ
						\$/kJ	\$/lb	
1	G.E./Avco	Open cycle (2000 MWe)	43.0	15 200	4110	2.83	5.23	0.542
2	Westinghouse[a]		45.9	7 467	1840	6.13	12.47	0.493
3	MCA		32.3	11 790	2287	2.72	7.07	0.388
4	MCA	73 Percent of length used in point 3	25.9	9 300	1815	2.78	7.13	0.389
5		Smaller inlet aperture than point 3	27.2	9 270	1900	2.94	7.16	0.411
6		Smaller-bore tube than point 3	14.7	4 160	988	3.55	7.43	0.478
7	Westinghouse[a]	Comparable bore to point 6	15.8	2 014	487	7.85	16.22	0.483
8	MCA	Inert-gas generator, 4.5-tesla peak	18.9	6 030	1361	3.13	6.94	0.452
9	Westinghouse[a]	Inert-gas generator, 5.0 tesla peak	12.9	1 526	477	8.45	13.53	0.623

[a]Total costs listed are without engineering fees, construction allowances, and design allowances shown in ref. 2 (appendixes A9.9 and A10.2).

TABLE 5.8-10. - COST-PER-POUND ASSUMPTIONS FOR SUPERCONDUCTING MAGNETS USED IN MHD GENERATORS

Item	Contractor		
	MCA	G. E./Avco[a]	Westinghouse
	Cost, $/lb		
Superconducting material (Cu-NbTi)	9.42	6.22	25.00
Coil fabrication	2.97	6.03	16.00
Support-structure material	2.98	[b]0.80	1.60
Support-structure fabrication	2.00	[b]2.20	5.40

[a]Data obtained from Avco on 10-15-75 (private communication).
[b]Aluminum alloy.

TABLE 5.8-11. - COMPONENT COSTS (INCLUDING LABOR) FOR DIRECT-FIRED REFRACTORY-HEAT-EXCHANGER SYSTEMS USED IN OPEN-CYCLE MHD POWERPLANTS

Component	FluiDyne case 1	G. E./Avco case 1
	Cost, million dollars	
Materials for pressure vessel and refractory bed (also includes vessel fabrication)	50.60	12.40
Refractory installation	4.02	[a]4.65
High-temperature valves	14.75	[a]5.77
High-temperature piping	26.51	[a]30.22
Total system	95.88	53.04
Cost, $/kWt	101	56

[a]Data supplied by Bechtel Corp. on 9-15-75 (private communication).

TABLE 5.8-12. - COSTS FOR WESTINGHOUSE TUBE-AND SHELL HIGH-TEMPERATURE HEAT EXCHANGER

[Base case 2, point 1.]

Cost, million dollars:	
Materials	76.71
Installation	39.69
Total	116.40
Cost, $/kWt	123

TABLE 5.8-13. - COMPONENT COSTS (INCLUDING LABOR) FOR SEPARATELY FIRED REFRACTORY HEAT-EXCHANGER SYSTEMS USED IN OPEN-CYCLE MHD POWERPLANTS

Component	FluiDyne case 4	G. E./Avco case 10	Westinghouse	
			Base case 1, point 1	Base case 1, point 12
	Cost, million dollars			
Refractory materials and pressure vessel (materials and labor)	25.36	14.70	27.99	12.12
Refractory installation	1.37	[a]4.90	6.85	3.04
High-temperature values	8.10	[a]6.07	5.76	3.45
High-temperature piping	8.36	[a]31.86	15.79	13.08
Total	43.19	57.53	56.39	31.69
Heat transferred, MWt	792	1036	548	245
Cost, $/kWt	55	55	103	129

[a]Data supplied by Bechtel Corp. on 9-15-75 (private communication).

TABLE 5.8-14. - COMPONENT COSTS (INCLUDING LABOR) FOR

REFRACTORY HEAT-EXCHANGER SYSTEMS USED IN

CLOSED-CYCLE MHD POWERPLANTS

	FluiDyne case 3	General Electric case 2	Westinghouse case 6
	Cost, million dollars		
Pressure vessel and heater	61.45	22.00	225.84
High-temperature valves	12.30	[a]10.02	140.90
Piping	16.03	[a]48.10	
Refractory installation	3.82	[a]7.04	-------
Low-temperature tube-and-shell argon preheater	------	-------	50.30
Total	93.60	87.16	417.04
Heat transferred, MWt	1765	2500	1820
Cost, $/kWt	53	35	229

[a]Data supplied by Bechtel Corp. on 9-15-75 (private communication).

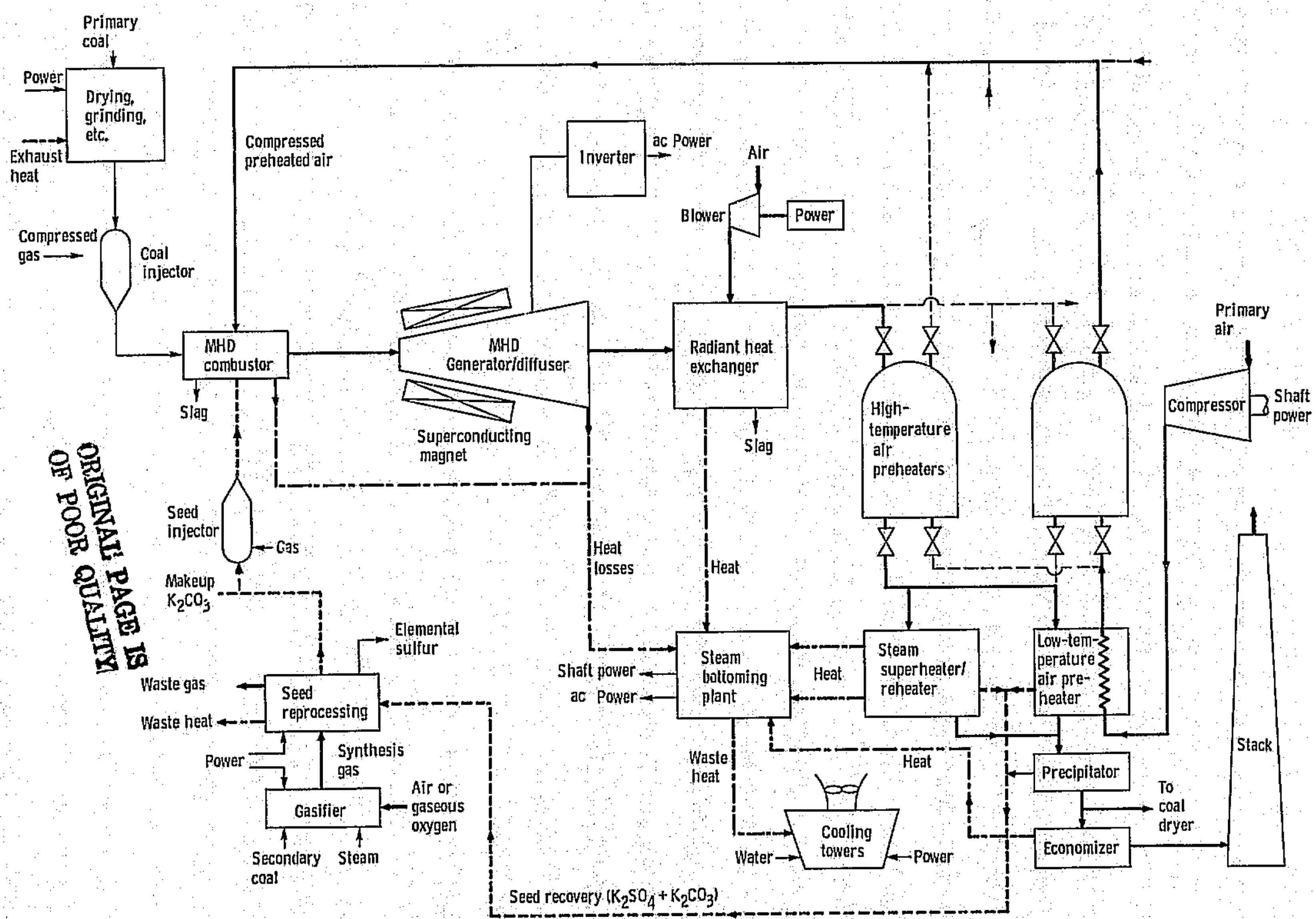

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Figure 5.8-1. - Schematic diagram of open-cycle coal-fired MHD powerplant.

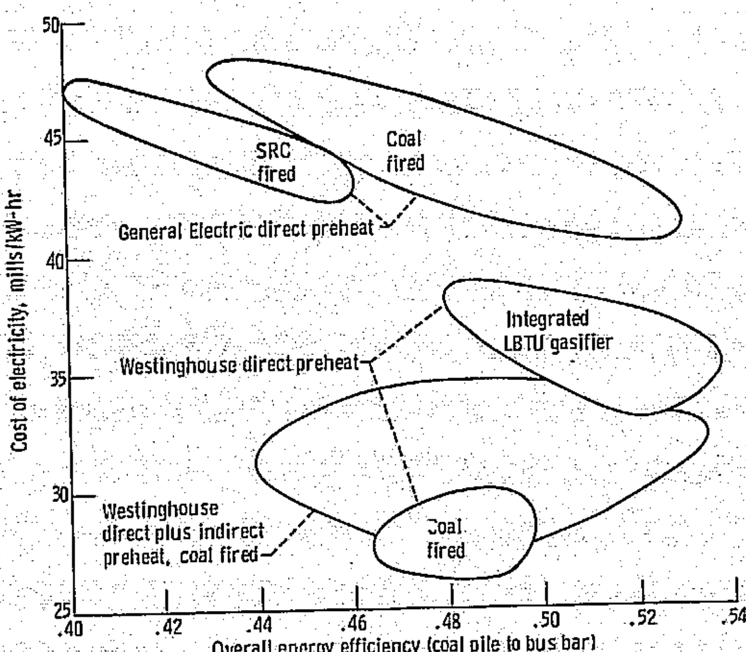

Figure 5.8-2. - Summary of open-cycle MHD powerplant performance.

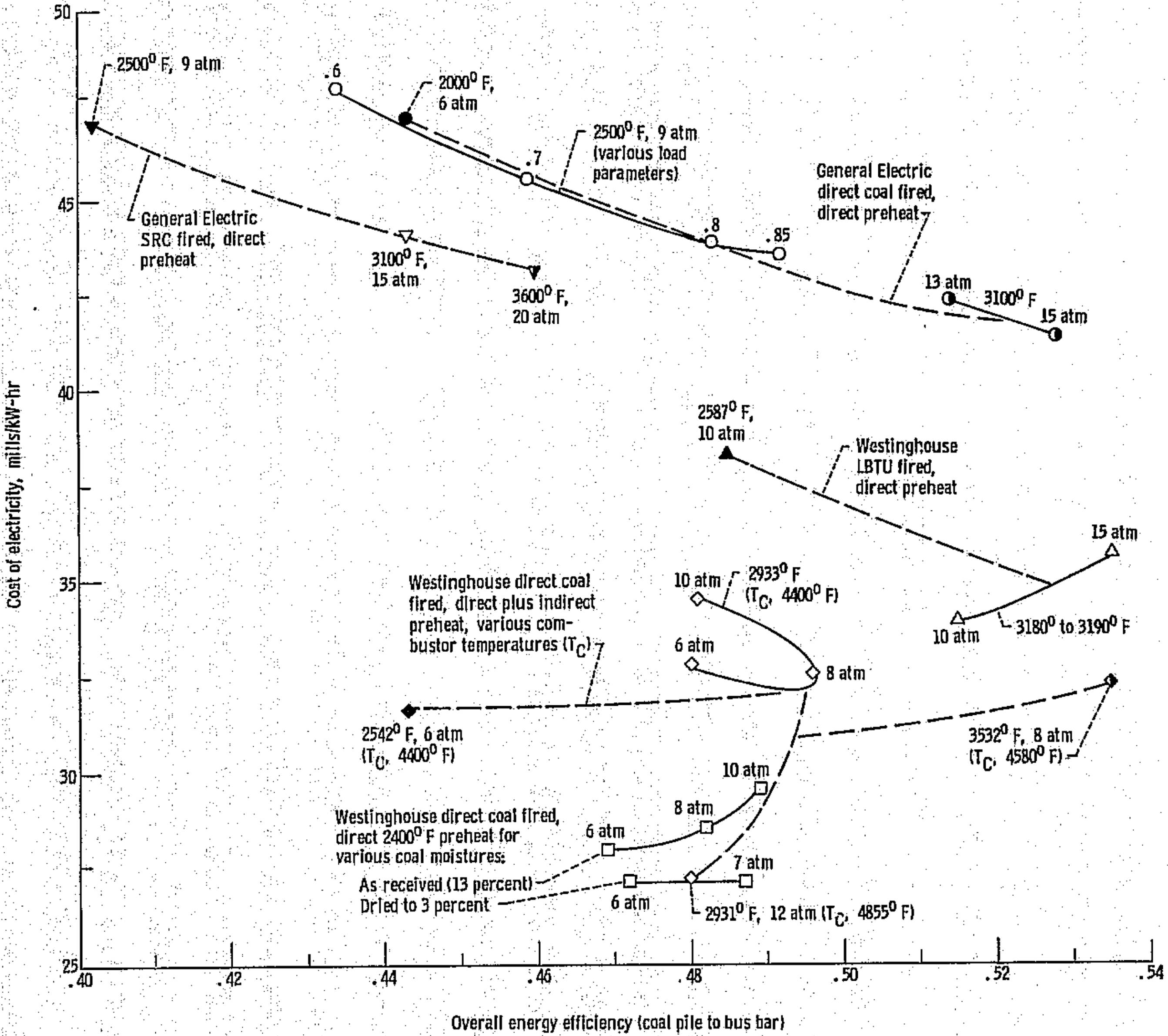

Figure 5.8-3. - Comparison of direct-preheated 2000-MWe open-cycle MHD powerplants. Preheat temperature and combustor pressure are indicated.

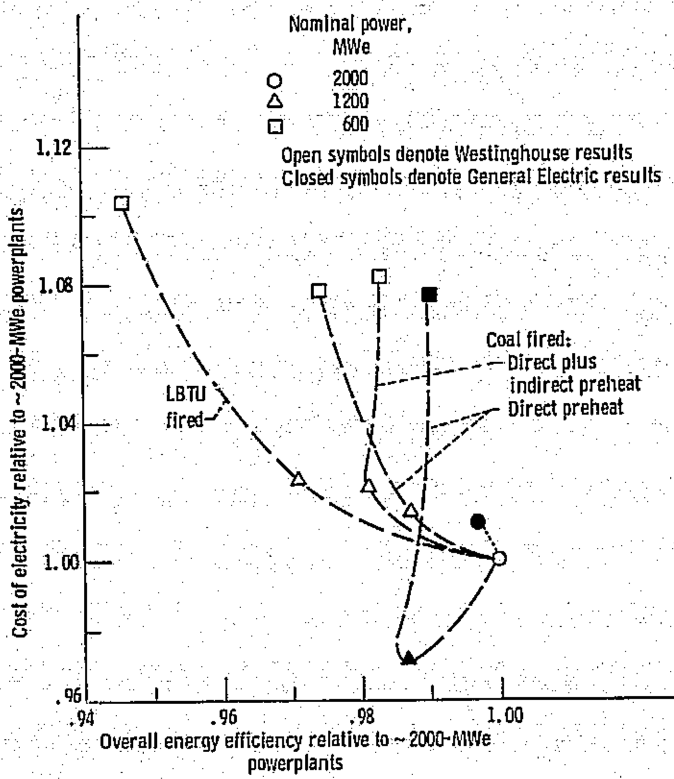

Figure 5.8-4. - Effect of MHD powerplant size on performance and cost of electricity.

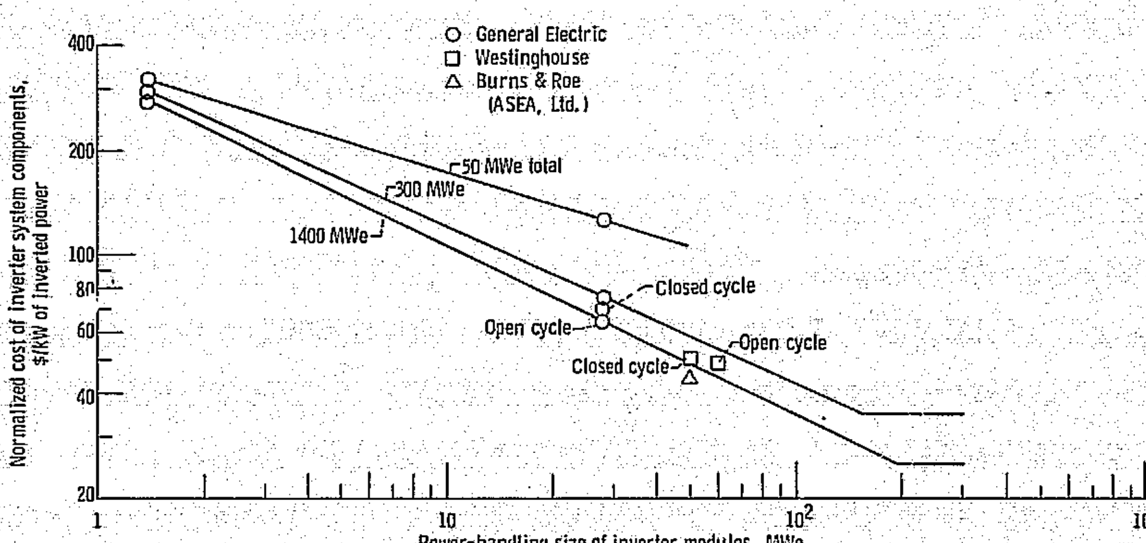

Figure 5.8-5. - Effect of power-handling size of inverter modules on normalized cost of inverter system components.

5.9 CLOSED-CYCLE, INERT-GAS MAGNETOHYDRODYNAMIC SYSTEMS
by Ronald J. Sovie and Raymond K. Burns

In the closed-cycle plasma magnetohydrodynamic (MHD) system an inert gas is raised to a high temperature in a regenerative heat-exchanger array and is seeded with a pure alkali metal to produce the MHD generator working fluid. The working fluid must be essentially free of molecular contaminants with their low-lying rotational and vibrational energy levels. Consequently, as the generated voltages drive the current through the load and the plasma, the plasma electrons are heated to temperatures substantially above the equilibrium gas temperature. This nonequilibrium effect greatly enhances the electrical conductivity of the plasma. Closed-cycle, inert-gas MHD systems can attain electrical conductivities at 3000° F that are comparable to the open-cycle MHD conductivities at 4500° F. Thus the problems associated with operation at very high peak temperatures are somewhat reduced. The high values of the nonequilibrium electrical conductivity also lead to high power densities and allow for smaller MHD generator and magnet systems for equivalent MHD power outputs. Another advantage of the alkali-metal-seeded, inert-gas working fluid is that it allows the use of refractory-metal electrodes, which could greatly simplify the problems associated with obtaining long-lived MHD channels.

Among the problems associated with the advancement of closed-cycle, inert-gas MHD systems are the development of high-temperature regenerative heat exchangers that can be operated with the low-impurity carryover required for nonequilibrium ionization. It must also be shown that the excellent results obtained to date in high-temperature shock tube experiments can be obtained at a realistic temperature (approx 3100° F) in a steady-state configuration.

5.9.1 Scope of Analysis

There were fundamental differences in each contractor's approach to the inert-gas MHD systems. The contractors differed significantly in powerplant configurations and approach to evaluating the system's performance. Summaries of the key parameters considered are given in tables 5.9-1 and 5.9-2. A typical closed-cycle, inert-gas MHD powerplant is schematically shown in figure 5.9-1.

General Electric considered essentially three powerplant configurations. An MHD topped-steam system using relatively clean fuels (cases 1-15 with the exception of case 3, which is an all-MHD recuperative Brayton cycle), a direct-coal-fired MHD-steam parallel-cycle system (cases 16-22), and two direct-coal-fired MHD topped-steam systems (cases 101 and 102). The clean fuels used are solvent-refined coal (SRC, fuel conversion efficiency = 0.78) or intermediate-Btu gas (IBTU, fuel conversion efficiency = 0.70). Both were considered to be over-the-fence fuels. In the parallel-cycle concept, a fraction of the combustion energy is transferred to a recuperative MHD cycle through a refractory heat exchanger and the remaining combustion energy is transferred directly to the steam boiler.

The MHD topped-steam system was the only configuration considered by Westinghouse. Westinghouse considered one case (case 4) in which the fuel was an over-the-fence, high-Btu (HBTU) gas. In the remainder of the cases, the fuel was a low-Btu (LBTU) gas derived from an on-site gasifier. The gasifier is essentially a stand-alone gasifier from the standpoint of the rest of the power system. It provides its own pressurized air and process steam and delivers hot, nearly atmospheric fuel gas to the power system. The gasifier was considered to be an advanced gasifier incorporating a pressurized fluidized bed and hot gas cleanup.

The Westinghouse approach to evaluating the system performance was to calculate the efficiency for a wide range of generator conditions and to optimize the system efficiency for a given generator inlet temperature and type of ionization (i.e., nonequilibrium, cases 1-6; or equilibrium, case 7). The costs were then calculated for these "efficiency optimized" cases The MHD generator adiabatic efficiency and pressure ratio were outputs of Westinghouse's procedure. In contrast, General Electric parametrically assumed these values and then designed the generator to achieve them.

The specific values of parameters considered by the contractors for the costed points are listed in tables 5.9-1 and 5.9-2. Other quantities not listed in the tables but common to both contractors for most cases are an argon inert gas with cesium seed as the working fluid, nonequilibrium ionization, a plasma turbulence factor of 0.5, and no set limit on the interaction parameter as long as the channel was not allowed to choke. The exceptions are Westinghouse case 5 (turbulence factor of 1.0 and interaction parameter limited to 0.5), Westinghouse case 7 (thermal ionization), and General Electric cases 13 and 102 (turbulence factor = 0.2).

Both contractors used a 3500 psi/1000° F/1000° F steam bottoming plant. General Electric used a 40 percent steam-cycle efficiency, which corresponds to a regenerative feedwater heating temperature of 232° F. Westinghouse assumed an optimistic 45 percent steam-cycle efficiency but did not disclose the level of regenerative feedwater heating. (High levels of regenerative feedwater heating cannot be used in this application.)

5.9.2 <u>Results of Analysis</u>

5.9.2.1 Overall Comparison

The results obtained for the capital costs, the cost of electricity, and the thermodynamic, powerplant, and overall energy efficiencies are presented in tables 5.9-3 and 5.9-4. The cost of electricity is plotted against the overall energy efficiency in figure 5.9-2. The areas identified on the figure delineate the results for the different system configurations. The figure shows that the highest efficiencies were obtained for the Westinghouse LBTU-gas cases and the General Electric direct-coal-fired MHD topping cases. The General Electric SRC cases yield the lowest cost of electricity for the coal-derived clean-fuel cases, but the overall energy efficiencies are quite low because of the 0.78 coal-to-SRC conversion efficiency. The figure also shows that there are no benefits to be gained by using over-the-fence LBTU or HBTU gases or an all-MHD cycle (G.E. case 3) and that there is a strong incentive in terms of coal utilization to use coal directly or in a close-coupled or integrated gasifier. Although the Westinghouse gasifier is not closely integrated, it is close coupled so that the power system benefits from the sensible heat of the fuel gas. The fuel conversion efficiency is therefore much higher than those for the SRC, LBTU, or HBTU over-the-fence fuels.

The ranges of the efficiencies, capital costs, and cost of electricity are given in table 5.9-5 for the remaining system configurations. A detailed breakdown of efficiencies, capital costs, and cost of electricity for some representative points is given in figure 5.9-3.

According to the data in table 5.9-5 and figure 5.9-3, the Westinghouse results generally yield the higher efficiencies and capital costs on a $/kWe basis. Figure 5.9-3 shows that Westinghouse's higher capital costs are due to the fact that Westinghouse's major component costs are about a factor of 2 higher than General Electric's for a nearly equivalent powerplant. The items included in the major component cost are the furnace and all auxiliary furnace equipment, MHD generator, magnet, refractory heat exchangers, compressors and steam drive turbines, steam generator, inverters, and heat rejection system. Tables 5.9-3 and 5.9-4 and figure 5.9-3 also show that the Westinghouse operation-and-maintenance cost estimates were much lower than General Electric's.

To illustrate the effect of the parametric data variations on the thermodynamic efficiency, it is plotted against MHD generator inlet temperature and generator adiabatic efficiency in figure 5.9-4. All the data presented were taken from the General Electric SRC cases. The figure shows that for a given powerplant configuration, increases in thermodynamic efficiency are realizable at constant temperature if adiabatic efficiency can be increased or at constant adiabatic efficiency if it is possible to operate at higher temperatures. General Electric cases 9 (thermodynamic efficiency = 50.2 percent) and 10 (thermodynamic efficiency = 52.4 percent) indicate that increasing the enthalpy extraction can also yield higher thermodynamic efficiencies. The Westinghouse points indicate a 4.2-percentage-point increase as inlet temperature is increased from 3100° to 3800° F, which is slightly higher than the change indicated by the General Electric results.

5.9.2.2 Discussion and Assessment

The results summarized in the previous section show that there were differences in thermodynamic efficiency, overall energy efficiency, major component costs, steam bottoming plant efficiency, and operation-and-maintenance costs in the contractors' results. These differences are discussed in detail in this section by analysis of General Electric case 2 and Westinghouse case 6. These cases were chosen because of their similar power levels (approximately 1000 MWe) and generator inlet temperatures (3000° to 3100° F).

5.9.2.2.1 Comparison of performance results. - In terms of overall energy efficiency, the Westinghouse results are generally higher than General Electric's results, as shown in figure 5.9-2. This is in part due to the use of different fuels, or different methods of utilizing coal, and consequently the different fuel conversion efficiences involved. Comparison on the basis of thermodynamic efficiency eliminates this difference due to type of fuel firing. However, even on this basis there is a large difference in the results, with Westinghouse's being higher. There are several reasons for the higher Westinghouse efficiency, the most important of which are the use of higher MHD generator inlet temperatures and lower pressure losses by Westinghouse and the different efficiencies of the steam cycle and the way it was interfaced with the MHD cycle.

NASA examined these differences quantitatively by making independent calculations and changing the parameters one at a time from those used by one contractor to those used by the other. The effects of these differences in input parameters on the results are illustrated by comparing Westinghouse case 6 and General Electric case 2. The thermodynamic efficiency of the MHD/steam cycle is plotted against the MHD exit temperature in figure 5.9-5. Curve A corresponds to the General Electric parameters and curve E to the Westinghouse results. The actual contractor points are located on the figure and show excellent agreement with the calculated curves. Parameters held constant for each of the curves in figure 5.9-5 are tabulated on the figure. Each is discussed in the following paragraphs. The loss pressure ratio is defined as the ratio of the pressure ratio across the MHD generator-diffuser combination to that across the compressor.

As the diffuser exit temperature is decreased, the cycle pressure ratio (and MHD enthalpy extraction) increases. As is the case with all Brayton cycles, there is a pressure ratio for which the efficiency is maximum on each curve. As shown in the figure, the MHD exit temperature used by General Electric is not at the peak efficiency point but was chosen in order to balance the steam-bottoming-cycle power output and the argon-compressor power requirement. A lower exit temperature would have resulted in too little steam-cycle power to drive the compressor and the need for some motor drives on the compressor.

Curve B shows the increase in efficiency that would have been obtained by using 3100° F inlet temperature. Curve C shows the further increase in efficiency achieved by assuming the value of pressure loss and compressor adiabatic efficiency used by Westinghouse.

The General Electric procedure was to parametrically assume the value of the adiabatic efficiency of the MHD generator-diffuser combination and then, after calculating the system performance, to size the generator to meet the assumed performance. Westinghouse, on the other hand, included the "design" of the MHD generator as an integral part of their system performance calculations. The adiabatic efficiency was an output rather than an input to their procedure. For Westinghouse case 6, the adiabatic efficiency of the generator-diffuser combinations was calculated from Westinghouse data to be 0.68, slightly lower than the 0.70 assumed in General Electric case 2. This adiabatic efficiency of 0.68 does not correspond to the value quoted by Westinghouse, which is labeled generator "isentropic efficiency." The Westinghouse quoted value does not include the diffuser; also their parameter is proportional to the actual temperature change across the generator, which includes the effect of heat losses as well as power extraction. The 0.68 value used here corresponds to the temperature change that would occur in an adiabatic generator and is more correctly an indication of the performance of the generator in producing power. Curve D shows the efficiency obtained for a 0.68 generator-diffuser adiabatic efficiency. Curves B and D are within 1/2 percentage point in efficiency; the lower value of generator-diffuser efficiency of curve D almost counteracts the effect of the lower pressure losses and higher compressor efficiency of curve C compared with curve B.

All the curves discussed to this point (A to D) were calculated by NASA assuming the bottoming cycle performance and interface used by General Electric. They used a 3500 psi/1000° F/1000° F steam cycle with regenerative feedwater heating to 232° F. The steam-cycle efficiency was 40 percent, and the cycle was interfaced so as to recover the argon waste heat from the diffuser exit down to 262° F. The argon was further cooled to 80° F at the compressor inlet with this heat being rejected. Westinghouse, on the other hand, assumed a 3500 psi/1000° F/1000° F steam cycle with 45 percent efficiency. They further assumed an argon compressor inlet temperature of 301° F with one stage of intercooling down to 301° F. The steam cycle was assumed to recover the argon waste heat from diffuser exit to compressor inlet, the waste heat from the intercooler, and the heat losses from the generator and inverter. The cycle performance obtained with these assumptions is shown in figure 5.9-5 by curve E. Figure 5.9-5 shows that this was the most important difference in assumptions as far as the effect on thermodynamic efficiency was concerned. Westinghouse also chose a value of generator exit temperature to obtain maximum efficiency for the assumed parameters. In this case, with the use of intercooling and the Westinghouse assumptions concerning steam cycle, the steam power output exceeds the argon compressor requirement at the maximum efficiency point. Since generator efficiency was an output of the Westinghouse calculations, Westinghouse would not have obtained the same generator efficiency at other generator exit temperatures. For this reason, it appears that the Westinghouse point is not quite at the maximum of curve E, which assumes a constant generator efficiency.

Since Westinghouse used one stage of compressor intercooling while General Electric did not consider intercooling for this case, the pressure ratio of individual compressor sections was smaller for the Westinghouse results. The higher adiabatic compressor efficiency assumed by Westinghouse actually represents nearly the same aerodynamic performance (polytropic efficiency) as that assumed by General Electric when this difference in pressure ratio is taken into account.

The conclusion is that for those cases with similar MHD generator inlet temperature, the major reason for the difference between thermodynamic efficiency results of the contractors is the cycle efficiency of the steam bottoming cycle configuration used and the way it was interfaced with the MHD cycle. The General Electric approach was to use minimal regenerative feedwater heating in the steam cycle in order to recover the argon waste heat to as low a temperature as possible. Westinghouse, on the other hand, assumed a higher steam-cycle efficiency, 45 percent. The Westinghouse results of the advanced steam system indicate a level of regenerative feedwater heating of about 500° F to obtain a cycle efficiency of about 45 percent. It has not been disclosed by Westinghouse exactly how such a steam cycle would be interfaced with the MHD cycle in order to recover all the waste heat that was assumed to be recovered. To recover all the waste heat, it would be necessary to use a lower level of regenerative feedwater heating and consequently a lower steam-cycle efficiency. Taking their results and merely replacing the 45 percent steam-cycle efficiency with 40 percent would reduce the overall energy efficiency of cases 1 and 6 by 3.0 and 3.3 percentage points, respectively. This, however, is only an approximation of the effect. Had they actually used the 40 percent efficiency in their calculations, the system probably would have optimized differently, so the decrease might not be quite as large.

5.9.2.2.2 <u>Comparison of major component costs</u>. - The major component cost difference can be compared by considering the data in table 5.9-6. The data in this table represent a breakdown of the costs for Westinghouse case 6 and General Electric case 2. The General Electric costs are broken down into the major component supplier cost and Bechtel's estimate of the materials and labor cost for the component installation. The table shows that the major difference is in the refractory heat-exchanger costs. The Westinghouse cost for materials and labor is $417 million, whereas the G.E. cost is $87.1 million. The heat-exchanger costs are discussed in more detail in the common MHD components section (section 5.8). There are also differences in the inverter, steam generator, and furnace costs. The furnace costs should be different since the Westinghouse gasifier and coal-handling equipment are included in this item. The SRC furnace cost used by General Electric does represent a substantial difference in design approach between the closed-cycle, inert-gas MHD and the open-cycle MHD systems. The SRC combustor for the open-cycle MHD system costs a factor of 40 less on a $/MWth basis. The main reason for this difference is that the SRC combustor of the closed-cycle MHD system was designed as a conventional furnace, whereas the open-cycle MHD SRC combustor was designed as an advanced rocket-type combustor. The differences between contractors for the items "piping and instrumentation" through "other" in table 5.9-6 represent a difference between the contractors' approaches that is common to most of the energy conversion systems. It is not discussed in this section.

At the time this report was written, the only information received concerning the Westinghouse case 6 heat-exchanger system was that there were 56 heat exchangers and that the matrix size was 2.5 inches by 2.5 inches. The use of such a large matrix for the clean fuel used in this case results in very high heat-exchanger costs. In contrast to this approach, General Electric uses 1/4-inch-diameter holes. In addition, a refractory regenerative heat exchanger was designed for a 1000-MWe, inert-gas MHD system as part of the NASA in-house ECAS program. This system was designed by Fluidyne under NASA contract with Burns and Roe. The system consisted of 24 units and was designed with a 3/4-inch hole size for an argon outlet temperature of 3100° F. Estimated costs were $93.5 million, or $53,000/MWt transferred to the argon. The General Electric and Westinghouse heat-exchanger systems were $36,000/MWt and $230,000/MWt, respectively. The costs estimated by Westinghouse were thus more than four to six times as high on a per-MWt basis as the two other estimates made for heat-exchanger systems with similar conditions.

Calculations made to determine the effect of using the Fluidyne heat-exchanger system in Westinghouse case 6 show that the capital costs and cost of electricity would be reduced to $1109.5million and 44.5 mills/kW-hr, respectively. This represents a 35 percent reduction in the cost of electricity.

The operation-and-maintenance costs used by Westinghouse seem unduly low, however, considering the powerplant complexity. The costs are about the same or even lower than those for an advanced steam plant. The detailed Westinghouse data indicate that operation-and-maintenance costs were included only for such items as the gasifier, the coal and waste handling systems, and the heat rejection system, with no estimate included for the components unique to MHD. General Electric, on the other hand, did include a factor for the MHD generator diffuser and the refractory input heat exchangers. This seems to be an omission on the part of Westinghouse.

5.9.2.2.3 <u>Discussion of contractors' results - better configurations.</u> - Although there have been many studies of nuclear-heated, inert-gas MHD systems, the ECAS study represents the first attempt to mate such a system with fossil-fuel-fired heat sources. Consequently, there was no data base of previous performance and economic studies, and in retrospect it was unlikely that the optimum system configuration would have been initially selected in the original matrix of points.

Consideration of early Phase 1 results led to the identification of various approaches to improving performance and/or lowering the system cost. Let us first consider General Electric case 101 with an overall energy efficiency of 41.8 percent. It is quite unlikely that a direct-coal-fired refractory heat exchanger can be operated at temperatures above the 3000° to 3100° F used in this case. Consequently, further improvements in cycle performance must be derived from improved generator performance or a more optimum cycle arrangement. Changing the generator adiabatic efficiency from 0.7 to 0.8 as General Electric has done for cases 1 and 13 would increase the overall energy efficiency of case 101 to 45.3 percent. A generator adiabatic efficiency of 0.8 is very optimistic. The attainment of a generator adiabatic efficiency of 0.8 would require operation of the MHD generator at conditions where the plasma turbulence is suppressed.

General Electric has also considered a case with a higher adiabatic efficiency and a different cycle arrangement as a part of Phase 1. The additional case (case 102) has been calculated at a base-case level of detail. The input parameters and results are shown in tables 5.9-1 and 5.9-3. Compared to case 101 the inlet temperature was increased to 3100° F, the MHD adiabatic generator efficiency was increased to 0.78, and the pressure losses decreased to 7.5 percent. Also the steam bottoming cycle regenerative feedwater heating level was reduced to 117° F. Although this reduced the steam-cycle efficiency about 2 percentage points, the efficiency of the MHD/steam combination was increased by this change since the argon waste heat was recovered to a lower temperature.

The results of calculations made by NASA for variations of the MHD generator adiabatic efficiency and diffuser exit temperature about the values used by G.E. for this additional case are shown in figure 5.9-6. The overall energy efficiency was calculated by assuming a combustion loop efficiency and auxiliary power requirements equal to those of case 101. The Phase 1 (case 102) point is called out in the figure. It was chosen at the generator pressure ratio for which the steam bottoming cycle power just matched the compressor power requirements. As shown by the figure, this constraint results in a system efficiency about three-quarters of a percentage point below the peak value.

A minimum temperature difference between the argon and the steam of 30° F was assumed in figure 5.9-6. For a diffuser exit temperature above about 1750° F, this temperature pinch point occurs at the cold end of the heat-recovery heat exchanger - so that the argon is cooled to 147° F. Below this diffuser exit temperature the pinch point is located upstream in the heat exchanger - so that the argon cannot be cooled down to 147° F. The dashed lines in figure 5.9-6 show the system performance if it is assumed that the argon is still cooled to 147° F and the pinch point limitation is violated. (At a diffuser exit temperature of approximately 1550° F this solution is physically impossible since the minimum temperature difference is zero.)

In addition to the higher efficiency obtained by varying the operating parameters of case 101, significant cost reductions were also obtained for case 102 by modifying the plant layout. The more important modifications were

(1) To reduce the plant size by shortening the MHD generator and diffuser by a factor of about 3. This allowed <u>vertical</u> mounting of these components instead of horizontal mounting.

(2) To reduce the number of large (greater than 10-ft-diam) ducts by rearranging the overall plant layout

(3) To redesign the heat exchangers and to compute the cost of the bricks separately for each operating condition

(4) To increase the magnetic field from 4 teslas to 6 teslas

(5) To remove all feedwater heating from the steam plant

With these changes the cost of the plant was reduced from approximately \$1500/kWe to approximately \$1100/kWe.

Another variation that may be considered is a pressurized combustor loop. By using a heat exchanger to transfer heat from the combustion gases at the exit of the refractory heat exchanger to the compressed combustion air, and a combustion loop pressure of about 4 atmospheres, the temperature and pressure of the gas would be such that sufficient power could be produced in a turbine to drive the air compressor. The higher pressure level might significantly reduce the size and cost of the refractory heat exchangers and high-temperature piping in the system. Further cost reductions could result from using cyclone combustors mounted in each heat exchanger. General Electric evaluated the cost reductions that may be achieved by such pressurization. Using these initial results an overall energy efficiency of 47.7 percent and a capital cost of \$1017/kWe can be estimated. Areas of concern for this particular configuration are (1) operating the gas turbine on coal combustion gases and (2) the effectiveness of the stack-gas cleanup required to remove sulfur dioxide and particulates. However, these problems are not unique to this particular cycle configuration as far as what has been considered in the whole of ECAS Phase 1 for other systems. As long as no net power is obtained from the pressurized combustion loop, the overall system performance would be similar to the case with atmospheric combustion.

To take advantage of the higher efficiencies attainable by increasing the generator inlet temperature, a coal-to-clean-fuel conversion system would have to be incorporated in the system. The Westinghouse results represent the optimum system efficiencies for the plant configuration considered and the assumptions made concerning plasma turbulence factor, generator length, etc. The results of a previous section have shown that the Westinghouse estimates for the refractory heat-exchanger system costs were very high compared with other estimates made as part of ECAS. As a result a reduction in cost of electricity of the order of 35 percent might be possible. Further potential reductions could result from pressurization of the combustion loop heat-exchanger system. It is also possible that integration of the gasifier with the powerplant could be used advantageously in obtaining high overall energy efficiency, particularly if a pressurized combustion loop is considered. This configuration should be examined in future analyses of closed-cycle MHD systems.

5.9.3 Concluding Remarks

This study represents the first attempt to mate the closed-cycle, inert-gas MHD system with fossil-fuel-fired heat sources. The best initial General Electric case indicated a rather low overall energy efficiency (41.8 percent) for a high-temperature advanced system and a high cost of electricity (61.6 mills/kW-hr). However, review of the contractors' results indicated that their results could be significantly improved. Indeed in the Phase 1 study the powerplant layout was subsequently modified and the operating parameters changed, and the best General Electric efficiency was increased to 46 percent. The costs were reduced to 45.6 mills/kW-hr. An initial investigation of using a pressurized combustion loop for this system was made by General Electric. Using these results an overall energy efficiency of 47.4 percent and a cost of electricity of approximately 41 mills/kW-hr can be estimated. A 35 percent reduction in the Westinghouse costs may also be estimated. In addition, better cycle configurations can be suggested that might be considered in future studies. It should be determined if the direct-coal-fired system could benefit from pressurization of the combustion loop, optimization of the MHD generator performance, and steam plant integration. A system with a fully integrated advanced gasifier might also show benefit.

A major issue that must be addressed, particularly for the coal-fired MHD topped-steam system, is the level of contamination in the argon working fluid that can be tolerated and still achieve nonequilibrium ionization of the gases. Future research in the areas of increasing the MHD generator efficiency by suppressing plasma turbulence, increasing the outlet temperature of direct-coal-fired refractory heat exchangers, and advanced gasification systems would be required in order to obtain the performance levels indicated for the highest efficiency cases calculated.

TABLE 5.9-1. - SUMMARY OF KEY PARAMETERS FOR GENERAL ELECTRIC CLOSED-CYCLE MHD CASES

[For all cases: inlet Mach number, 1.5; no set limit on interaction parameter.]

Parameter	Clean-fuel MHD topping cycle															Direct-coal-fired parallel cycle							Direct-coal-fired topping cycle	
	Case																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	101	102
Power output, MWe	583	1168	88	586	587	587	582	560	576	520	508	670	582	578	582	934	948	960	894	931	940	923	600	930
Coal	Illinois #6				Mon-tana	North Dakota	Illinois #6										Mon-tana	North Dakota	Illinois #6					
Coal conversion process[a]	SRC			IBTU			SRC									Direct								
Inlet pressure, atm	10	10	10	10	10	10	20	10	10	20	10	10	10	10	10	10	10	10	10	20	10	10	10	10
Inlet temperature, °F	3000	3000	3000	3000	3000	3000	3000	2400	3500	3800	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3100
Magnetic field strength, T	3	3	3	3	3	3	6	3	3	6	3	3	3	3	3	3	3	3	3	6	3	3	3	4.5
Turbine effectiveness	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.8	0.75	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0.78
Cesium seed content, percent	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.30	0.30
Heat rejection method (cooling tower)	Wet		Dry	Wet											Dry	Wet						Dry	Wet	

[a]SRC = solvent-refined coal; IBTU = intermediate-Btu gas.

TABLE 5.9-2. - SUMMARY OF KEY PARAMETERS FOR WESTINGHOUSE

CLOSED-CYCLE MHD CASES

[Clean-fuel MHD topping cycle; heat rejection method, wet cooling tower.]

Parameter	Case						
	1	2	3	4	5	6	7
Power output, MWe	964	977	976	988	959	962	958
Coal	Illinois #6	Montana	North Dakota	Illinois #6			
Coal conversion process[a]	LBTU			HBTU	LBTU		
Inlet pressure, atm	9.27	9.27	9.27	9.27	10.26	10.82	7.33
Inlet temperature, ^{o}F	3800	3800	3800	3800	3800	3100	3800
Inlet Mach number	0.9	0.9	0.9	0.9	1.2	0.9	0.5
Magnetic field strength, T	5	5	5	5	5	6	6
Turbine effectiveness	0.724	0.724	0.724	0.724	0.65	0.68	0.78
Interaction parameter	(b)	(b)	(b)	(b)	≤0.5	(b)	(b)
Cesium seed content, percent	0.10	0.10	0.10	0.10	0.15	0.05	0.50

[a]LBTU = low-Btu gas; HBTU = high-Btu gas.
[b]No set limit.

TABLE 5.9-3. - SUMMARY OF GENERAL ELECTRIC CLOSED-CYCLE MHD RESULTS

Parameter	Clean-fuel MHD topping cycle															Direct-coal-fired parallel cycle							Direct-coal-fired topping cycle	
	Case																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	101	102
Power level, MWe	583	1168	88	586	587	587	582	560	576	520	508	670	582	578	582	934	948	960	894	931	940	923	600	930
Thermodynamic efficiency, η_t, percent	50.1	50.2	42.4	50.1	50.1	50.1	50.1	47.0	50.2	52.4	53.3	45.8	53.6	52.3	51.6	46.0	45.9	46.0	43.9	45.8	48.3	45.2	49.8	55.9
Powerplant efficiency, η_{pp}, percent	41.5	41.6	35.6	37.8	37.8	37.9	41.5	38.9	41.3	44.9	45.3	37.0	46.0	43.5	42.4	37.1	36.5	35.3	35.2	37.0	39.1	36.4	41.8	46.0
Overall energy efficiency, η_{oa}, percent	32.4	32.5	27.8	26.4	26.9	26.9	32.3	30.4	32.2	35.0	35.4	28.8	35.9	33.9	33.1	37.1	36.5	35.3	35.2	37.0	39.1	36.4	41.8	46.0
Capital cost, million dollars	787	1641	162	767	768	768	779	778	873	799	775	865	762	774	794	1726	1738	1754	1479	1714	1709	1742	931	1033
Capital cost, $/kWe	1349	1404	1825	1307	1307	1307	1337	1390	1516	1535	1525	1290	1310	1337	1364	1849	1832	1827	1654	1841	1816	1886	1551	1109
Cost of electricity, mills/kW-hr:																								
Capital	42.7	44.4	57.7	41,3	41.3	41.3	42.3	44.0	47.9	48.5	48.2	40.8	41.4	42.3	43.1	58.5	57.9	57.8	52.3	58.2	57.4	59.6	49.0	35.1
Fuel	14.8	14.8	17.2	18.1	18.0	18.0	14.8	15.8	14.9	13.7	13.6	16.6	13.4	14.1	14.5	7.8	7.9	8.2	8.2	7.8	7.4	8.0	6.9	6.3
Operation and maintenance	3.2	2.8	5.6	4.3	4.3	4.3	3.2	3.4	3.2	3.5	3.6	2.9	3.2	3.2	3.2	5.4	5.3	5.3	5.7	5.4	5.4	5.5	5.6	4.2
Total	60.7	62.0	80.5	63.7	63.7	63.6	60.3	63.1	66.1	65.7	65.4	60.3	58.0	59.6	60.8	71.7	71.2	71.3	66.2	71.4	70.2	73.0	61.6	45.6
Time to construct plant, yr	6	7	4	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7	7	6

TABLE 5.9-4. - SUMMARY OF WESTINGHOUSE CLOSED-CYCLE MHD RESULTS

[Clean-fuel MHD topping cycle; time to construct plant, 8 yr.]

Parameter	Case						
	1	2	3	4	5	6	7
Power level, MWe	964	977	976	988	959	962	958
Thermodynamic efficiency, η_t, percent	59.3	59.3	59.3	59.3	54.1	55.1	54.2
Powerplant efficiency, η_{pp}, percent	45.5	46.1	46.1	50.0	41.4	42.2	41.3
Overall energy efficiency, η_{oa}, percent	45.5	46.1	46.1	33.5	41.4	42.2	41.3
Capital cost, million dollars	2207	2178	2202	1667	2336	1839	2093
Capital cost, $/kWe	2287	2228	2256	1687	2434	1912	2147
Cost of electricity, mills/kW-hr:							
Capital	72.3	70.4	71.3	53.3	77	60.5	67.8
Fuel	6.4	6.3	6.3	17.0	7.0	6.9	7.0
Operation and maintenance	1.1	0.34	0.40	0.1	1.2	1.2	1.2
Total	79.8	77.1	78	71.1	85.2	68.5	76.0

TABLE 5.9-5. - RANGE OF RESULTS FOR CLOSED-CYCLE MHD SYSTEM CONFIGURATIONS

Result	General Electric			Westinghouse low-Btu gas cycle
	Parallel cycle	Direct-coal-fired MHD topping cycle	SRC MHD topping cycle	
Thermodynamic efficiency, η_t, percent	43.9 - 48.3	49.8 - 55.9	45.8 - 53.6	54.1 - 59.3
Overall energy efficiency, η_{oa}, percent	35.2 - 39.1	41.8 - 46	28.8 - 35.9	41.3 - 46.1
Capital cost, $/kWe	1816 - 1886	1109 - 1551	1290 - 1535	1686 - 2287
Cost of electricity, mills/kW-hr	70.2 - 73	45.6 - 61.6	58 - 65.7	68 - 85

TABLE 5.9-6. - COST COMPARISON FOR INERT-GAS MHD SYSTEMS - BETWEEN WESTINGHOUSE CASE 6 AND GENERAL ELECTRIC CASE 2

Component	Westinghouse case 6		General Electric case 2		
	Power, MWe				
	962		1168		
	Materials	Direct labor	Major component	Bechtel	
				Materials	Direct labor
	Cost, million dollars				
Furnace	79.1	45.4	46.5	9.3	9.44
MHD generator:					
Nozzle/diffuser	1.02	.84	5.3	8.4	5.9
Magnet	36.0	-------	32.0		
Compressor drive turbine	31.44	1.39	27.6	1.8	1.9
Refractory heat exchanger	361.6	55.4	22	41.4	23.7
Steam generator	47.0	-------	17.8	1.2	2.3
Steam turbogenerator	.46	.1	------	------	-------
Heat rejection system	4.7	2.6	8.0	-----	6.15
Precooler	-------	-------	7.2	------	-------
Inverter system	50.1	6.05	98.1	-----	-------
Piping and instrumentation	7.5	4.19	------	46.6	17.98
Civil and structural	18.8	18.4	------	35.8	23.3
Auxiliary electric	9.9	8.3	------	25.0	14.8
Auxiliary mechanical	6.62	1.68	------	27.0	4.2
Other	-------	-------	-----	24.2	7.2
Total	654.24	144.3	264.5	220.7	116.9
Indirect labor cost	73.6		105.1		
Architectural and engineering services	63.9		66.06		
Contingency	87.8		154.6		
Escalation	358.6		310.7		
Interest	457.0		402.9		
Total capital cost	1839.4		1641.5		
Total capital cost, \$/kWe	1912		1405		

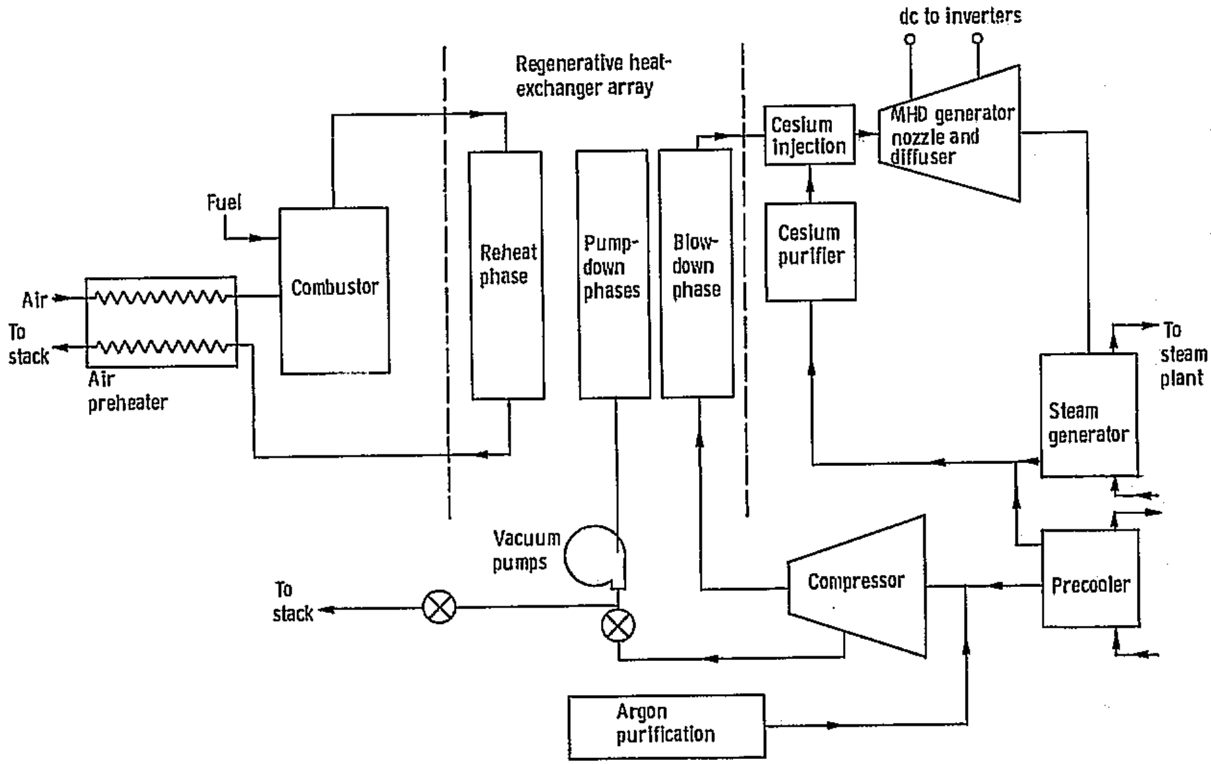

Figure 5.9-1. - Schematic of typical closed-cycle, inert-gas MHD powerplant.

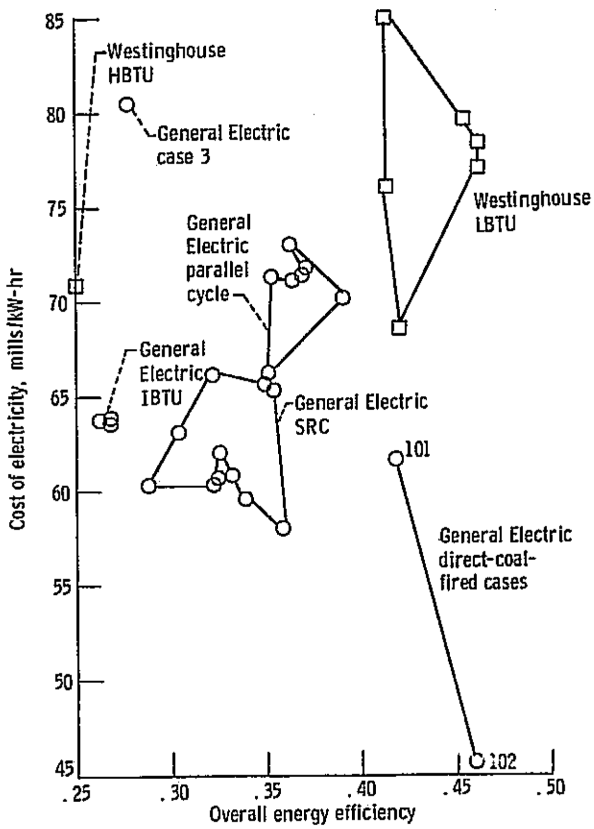

Figure 5.9-2. - Effect of overall energy efficiency on cost of electricity for closed-cycle, inert-gas MHD systems.

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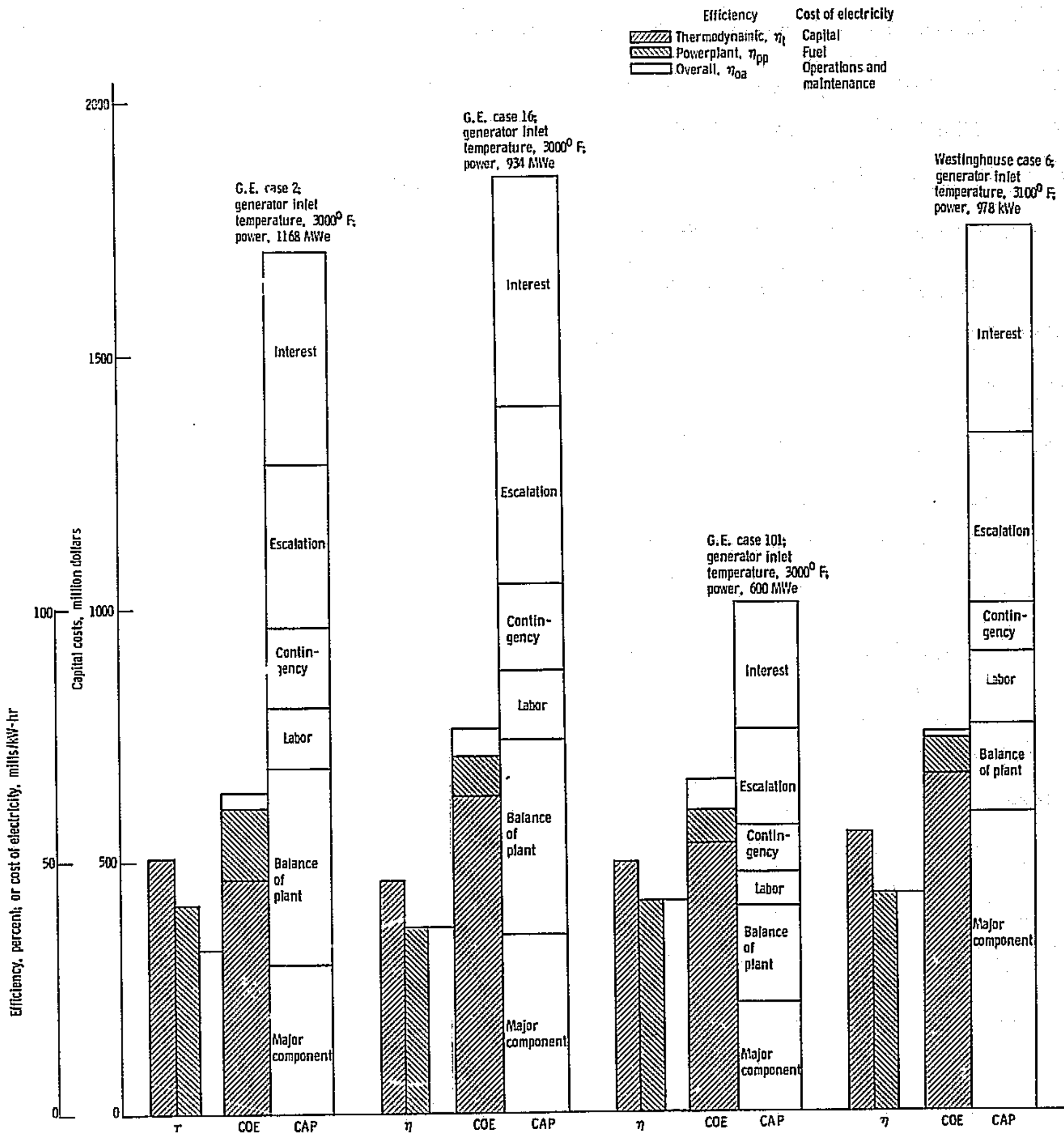

Figure 5.9-3. - Cost and efficiency distributions for typical cases.

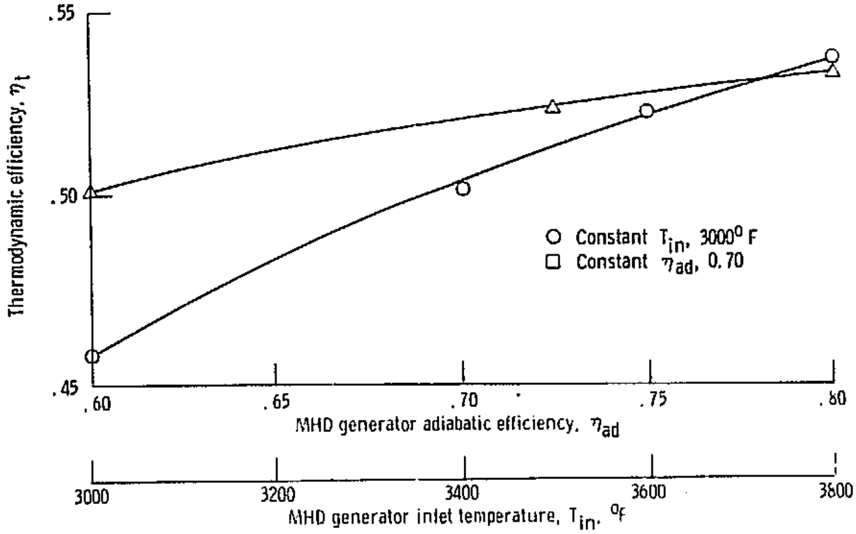

Figure 5.9-4. - Effect of MHD generator inlet temperature and adiabatic efficiency on thermodynamic efficiency - General Electric data.

Curve	Generator inlet temperature, °F	Compressor adiabatic efficiency	Argon loop loss pressure ratio	Generator diffuser adiabatic efficiency	Steam bottoming cycle efficiency	Intercooling	Compressor inlet temperature, °F	Heat recovered
A	3000	0.88	0.845	0.70	0.40	None	80	From diffuser exit to 262° F
B	3100	.88	.845	.70	↓	↓	↓	
C	↓	.90	.932	.70				
D		.90	.932	.68				
E		.90	.932	.68	.45	One stage	300	All waste heat

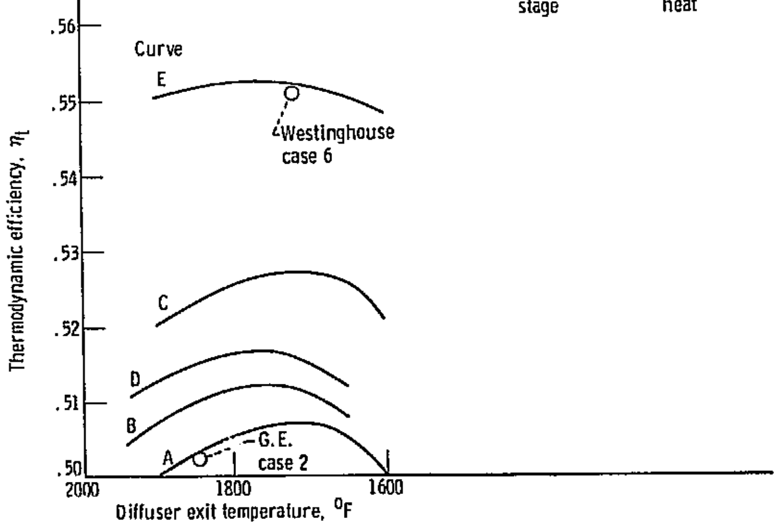

Figure 5.9-5. - Comparison of thermodynamic efficiency data.

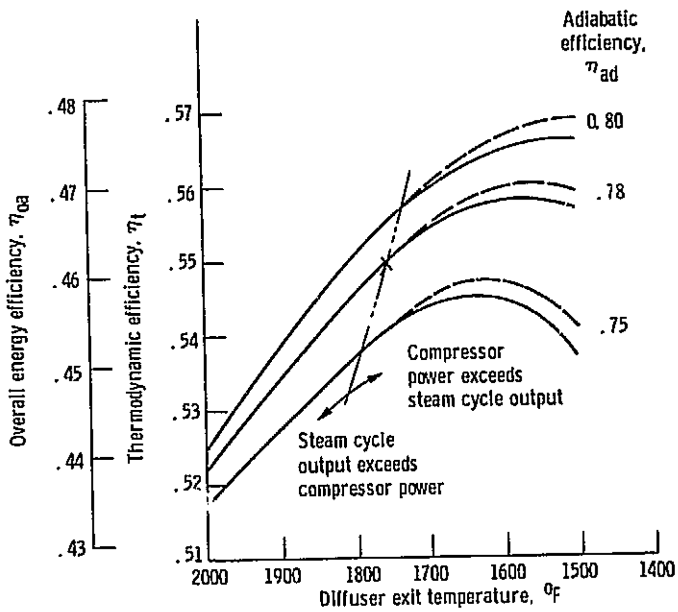

Figure 5.9-6. - Performance of closed-cycle MHD/steam system. MHD cycle conditions: inlet temperature, 3100° F; compressor inlet temperature, 80° F; pressure loss, 7.5 percent. Steam bottoming cycle conditions: 3500 psi/1000° F/1000° F; feed-water temperature, 117° F.

5.10 LIQUID-METAL MAGNETOHYDRODYNAMIC SYSTEMS
by Ronald J. Sovie

The alternate types of liquid-metal magnetohydrodynamic (MHD) systems are discussed in the introduction to the open-cycle section (section 5.8.5). The only type considered in this study was the two-phase-flow, liquid-metal MHD power cycle using an inert gas as the primary thermodynamic working fluid and a liquid metal as the electrodynamic fluid in the MHD generator. A typical schematic diagram of the binary liquid-metal/steam cycle is shown in figure 5.10-1.

In the two-phase-flow system, the gas and the liquid metal are mixed and the mixture enters the MHD generator as a foam-like substance. The expansion of the gas drives the liquid metal across the magnetic field, and electric power is generated. The two phases are then separated, and the liquid metal passes through the combustor and back to the mixer. The liquid-metal drive is supplied either by the nozzle/diffuser combination or a liquid-metal pump. The inert gas flows through the steam boiler and inert-gas cooler and is then compressed, heated, and returned to the mixer.

The unique feature of the liquid-metal MHD system is that the gas expansion in the MHD generator is nearly isothermal. This occurs because of the relatively high mass flow rate of liquid metal to gas and the fact that heat is transferred from the liquid metal to the gas during the expansion. The liquid-metal MHD systems operate at relatively low temperatures (1200° to 1500° F) and, consequently, many of the high-temperature materials problems associated with the open-cycle and inert-gas MHD systems are avoided.

Some of the disadvantages associated with this system are the large amount of compressor power required and the low-voltage, high-current output from the MHD generators.

5.10.1 Scope of Analysis

General Electric and Westinghouse approached the liquid-metal MHD systems in a similar manner. Both contractors considered a two-phase, liquid-metal MHD (LMMHD) power cycle that used an inert gas as the primary thermodynamic working fluid and a liquid metal as the electrodynamic fluid in the MHD generator. General Electric used helium/sodium (He/Na) in the majority of cases, and Westinghouse used argon/sodium (Ar/Na). Summaries of the key parameters considered are given in tables 5.10-1 and 5.10-2.

The basic powerplant configuration considered by both contractors was the binary LMMHD/steam cycle. However, both contractors did consider configurations with no steam bottoming plant. General Electric case 17 is a dual cycle using a gas turbine to drive the compressor. Westinghouse case 13 is an all-LMMHD system with an electric motor compressor drive, and their case 4 is an open-cycle MHD system topping a LMMHD system. Both contractors also used a steam bottoming plant with little regenerative feedwater heating and having efficiencies in the range 37.5 to 39.5 percent. Liquid-metal pumps were used to circulate the electrodynamic working fluid in all cases except G.E. case 101 and Westinghouse cases 11 and 12. General Electric case 101 and Westinghouse case 12 used the nozzle/separator/diffuser combination to recirculate the liquid metal, and an electromagnetic pump was used in Westinghouse case 11.

Both contractors used modularized MHD generators that were operated hydraulically in parallel and electrically in series. The series connection is necessary to attain a reasonable voltage level for the inverters. General

Electric used 13 MHD modules in the majority of their cases. The power per module was 47.3 MWe, and the terminal voltage was 390 V. Westinghouse used 10 modules with a power per module of 62 MWe, and the terminal voltage was approximately 500 V.

The data in tables 5.10-1 and 5.10-2 show that the contractors' approaches to the parametric variations were somewhat different. Westinghouse treated only one combustor-fuel combination and power level, whereas a majority of the General Electric cases treated variations in combustor, fuel, or power level and not variations of the basic liquid-metal system.

5.10.2 Results of Analysis

5.10.2.1 Overall Comparison

The results obtained for the capital costs, cost of electricity, and the thermodynamic, powerplant, and overall energy efficiencies are presented in tables 5.10-3 and 5.10-4. The cost of electricity is plotted against the overall energy efficiency in figure 5.10-2. The figure shows that the overall energy efficiencies range from 17.3 to 39.4 percent, with most of the points being in the range 33 to 39.4 percent. The figure also shows that, while the contractors' efficiencies are comparable, the costs differ significantly. The data in tables 5.10-3 and 5.10-4 show that there are differences in both the capital costs and operation-and-maintenance costs. These differences are discussed in detail in the next section (5.10.2.2).

According to the results given in tables 5.10-2 and 5.10-3 and figure 5.10-2 the use of a low-Btu fuel with a pressurized integrated gasifier yields the lowest cost of electricity in the General Electric study. However, in these cases more than half the total power output is generated by gas and steam turbines in the gasifier-combustor combination, and these results do not give a true indication of the LMMHD system performance. General Electric cases 1 and 101 and Westinghouse cases 12 and 16 suggest that improvements in the system performance and economics are realizable if an efficient nozzle/separator/diffuser can be developed and the need for a liquid-metal pump is eliminated. Figure 5.10-2 indicates that for a given contractor's results, there are no benefits to be derived by using an all-MHD system or an over-the-fence high-Btu gas. The results also show that the higher system efficiencies obtained in the high-temperature helium/lithium (He/Li) cases are accompanied by higher costs of electricity.

5.10.2.2 Discussion and Assessment

5.10.2.2.1 Comparison of contractors' results. - The results presented in the previous section showed that the contractors' efficiencies were comparable but that there was a significant difference in the capital and operation-and-maintenance (O and M) costs between contractors. The slight differences in the efficiencies are a result of the different temperatures and system component efficiencies considered and are not discussed further. The cost differences are treated in this section by considering a detailed breakdown of the costs for General Electric case 3 and Westinghouse case 9. The power outputs for these cases are 972 and 950 MWe, respectively.

The cost comparison between Westinghouse case 9 and General Electric case 3 is given in table 5.10-5. The General Electric costs are divided into the major component supplier costs and Bechtel's estimate of the materials and labor costs for the component installation. Table 5.10-5 shows a difference of approximately $300 million between the contractors' major component costs (items "furnace" through "power conditioning"), a difference of approximately

$315 million in their balance-of-plant costs (items "primary piping" through "miscellaneous"), and a difference of about $1.1 billion in the "indirect cost" through "interest" items. The $1.1 billion difference in the latter items results from the different methods used by the contractors for calculating these costs and the differences in total direct costs. The costing methods used by the contractors are discussed in another section (5.1) of this report and will not be discussed here.

The primary differences in the major component costs are in the furnace, the MHD generator and magnet combination, and the power conditioning. The General Electric furnace costs appear consistent among the different energy conversion systems. However, there are not sufficient data available to make a detailed cost comparison of the contractors' LMMHD furnaces.

The cost differences for the MHD generator and magnet combinations are mainly due to the different design concepts used by the contractors for these components. In the General Electric approach, each MHD generator has its own superconducting magnet. A conceptual design for each generator-magnet module was arrived at and costed. The total cost for the system was obtained by multiplying by the number of modules required. In the General Electric plant layout used for case 3, fourteen separate modules are sited parallel to each other.

Westinghouse approached the MHD generator-magnet design in a manner that minimized the major component cost and the amount of liquid-metal and high-temperature piping. The MHD generators are arranged in pods concentric to the steam generators. Each pod consists of four MHD power modules in a superconducting magnet. The magnetic field uniformity required for each MHD generator is obtained by using iron pole pieces to shape the magnetic fields. The pole pieces are intimately connected to the MHD duct insulating walls and also serve as part of the pressure containment structure. Westinghouse also used a reinforced (ribbed) plate construction for the structured housing of all pressurized components in order to obtain minimum weight designs. Because of the different materials used for the MHD generator structure, the different magnetic fields considered, and the design approaches used, the costs of the MHD generator-magnet combinations are understandably different. For an equivalent magnetic field strength, the Westinghouse magnet configuration would cost about half as much as the General Electric magnet configuration.

Inverter costs were $39/kWe for Westinghouse and $200/kWe for General Electric. These costs are discussed in detail in the common MHD components section (section 5.8) of the open-cycle MHD section. The main difference between the contractors' inverter costs is that General Electric required the inclusion of direct-current circuit breakers as a protection against short-circuit currents that might accidentally occur. The Westinghouse design did include alternating-current circuit breakers but did not require the costly direct-current circuit breakers. The use of direct-current breakers or alternating-current breakers requires further investigation and selection of proper approach. It is possible that they may not be required for the LMMHD systems because a short-circuit current could cause the MHD generator to "choke" and hence turn itself off until the problem is rectified. If inverter costs of $200/kWe are truly required for LMMHD systems, they would be at a severe cost disadvantage when compared with other systems in the same efficiency and temperature range.

The differences in the balance-of-plant items cannot be reconciled. These numbers are the architectural-and-engineering companies cost estimates from a single powerplant layout. The Westinghouse approach of minimizing the component sizes and the amount of high temperature and liquid-metal piping should result in lower powerplant costs. The General Electric approach, with the 14-parallel-MHD-modules arrangement, would require large amounts of liquid-metal piping and manifolding. However, since the Phase 1 effort was not intended to yield an extensive delineation of balance-of-plant items, the balance-of-plant cost differences for the LMMHD systems cannot be reconciled. Optimization of the powerplant arrangement and component designs might substantially reduce the General Electric costs. Westinghouse costs appear quite optimistic considering the number of working fluids used and the overall complexity of the LMMHD powerplants.

The data in tables 5.10-3 and 5.10-4 show that Westinghouse's O and M costs are significantly lower than General Electric's. In the Westinghouse calculation of O and M costs, operating costs are included for the heat rejection, fuel handling and storage, and water treatment systems only. Consequently, the Westinghouse O and M costs are probably underestimated for a powerplant as complex as the LMMHD systems considered in this study. Indeed, the O and M costs listed in table 5.10-4 are the same as those for the Westinghouse advanced steam systems.

5.10.2.2.2 <u>Discussion of contractors' results</u>. - The results presented in the previous sections indicate that the overall energy efficiencies for the LMMHD systems are relatively low for an advanced energy conversion system. The costs of electricity varied considerably between contractors. General Electric estimated COE's about three times that of the advanced steam system. Westinghouse's estimates were about 1.5 times that of the advanced steam system. The General Electric costs can be reduced by optimizing the design and arrangement of the system components and even eliminating some of the components. For instance the helium precooler and recuperator could be eliminated from the General Electric system with little effect on the overall system efficiency. The net effect of the economic optimization cannot be ascertained at this time. However, it is reasonable to assume that this plant will not be cheaper than a steam plant. Consequently, it must be shown that higher overall energy efficiencies can be obtained if this system is to warrant further consideration for base-load, coal-fired applications. Indeed, even with the low Westinghouse costs, Westinghouse did not recommend a further detailed study of this system.

At the temperature limits dictated by present sodium technology (1200° to 1300° F) the highest overall energy efficiency presented by the contractors was 37.3 percent. An inspection of the contractors' results indicates that the maximum potential efficiency at these temperatures would be approximately 40 percent. This is assuming a generator isentropic efficiency of 0.80, the development of a highly efficient nozzle/separator/diffuser, and optimistic system component efficiencies. The overall energy efficiency is limited to this value at these temperatures because the liquid-metal MHD system cannot be effectively coupled to an advanced steam plant, due to a pinch-point problem in the steam boiler. Both contractors found that the highest LMMHD/steam system efficiencies were obtained by using a steam plant with minimal regenerative feedwater heating and with the steam reheat energy being supplied by the combustor. The adverse effect of this coupling is twofold. The thermodynamic efficiency of the steam bottoming plant is limited to the range 37 to 39 percent, and the system does not derive the full benefit of the topping cycle because a portion of the combustion energy is transferred directly to the steam plant.

At the higher temperature considered in this study (1500° F), these problems may be alleviated. Westinghouse has calculated an overall energy efficiency of 43 percent by assuming that the sodium technology was extended to 1500° F and that the system could be coupled to a 45-percent-efficient steam plant.

However, the sodium vapor carryover could be a considerable problem at these temperatures. Only a few of the higher temperature systems were considered by the contractors in this study. The possibility of a better coupling with an advanced steam plant at the higher temperature and resolution of the large differences in cost estimates between the contractors require more-detailed component design and plant integration optimization.

5.10.3 Concluding Remarks

This study represents an initial attempt to couple the liquid-metal MHD cycle to fossil-fuel-fired heat sources. Consequently, it was not likely that the study would yield the optimum system. However, it is not expected that the overall energy efficiencies obtained at the 1200° to 1300° F temperatures dictated by present sodium technology can be changed significantly. The best overall energy efficiencies obtained for the cases considered by the contractors at these temperatures were in the range 34 to 37.3 percent. The development of a highly efficient nozzle/separator/diffuser, an MHD generator with a 0.80 isentropic efficiency, and efficient system components could result in overall energy efficiencies near 40 percent. The overall energy efficiency appears to be limited to this value because the liquid-metal MHD topping cycle cannot be effectively coupled to an advanced steam plant at these temperatures because of a pinch-point problem in the steam boiler. Westinghouse has shown that a 43 percent overall energy efficiency can be obtained if the sodium technology can be extended to 1500° F and an effective coupling can be made with the steam bottoming cycle.

There was a significant difference in the cost of electricity between the contractors' results. The General Electric costs ranged from 58 to 110.3 mills/kW-hr. The Westinghouse costs ranged from 33.9 to 66.2 mills/kW-hr. In both cases the higher costs were associated with the higher temperature systems. These cost differences could not be totally reconciled from the contractors' data. The Westinghouse costs are probably somewhat optimistic, and the General Electric costs might be substantially reduced by optimizing the major component integration and powerplant layout as Westinghouse has done.

Because of the large unreconciled cost differences and the possibility that the steam plant interface problem can be alleviated at higher temperatures, further studies of these high-temperature systems should focus on these areas in any further assessment.

TABLE 5.10-1. - SUMMARY OF KEY PARAMETERS FOR GENERAL ELECTRIC LIQUID-METAL MHD CASES

[Maximum void fraction, 0.85; compressor efficiency, 88 percent.]

Parameter	Case																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	101
Power output, MWe	486	243	972	485	488	1148	1203	1230	571	662	485	486	489	479	486	477	509	559
Coal	Illinois #6			Mon-tana	North Dakota	Illinois #6	Mon-tana	North Dakota	Illinois #6									
Coal conversion process[a]	AFB - direct					PF - LBTU			PF - HBTU	PFB - direct	AFB - direct							
Working fluid	Helium/sodium										Helium/lithium		Helium/sodium					
Inlet temperature, °F	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1400	1500	1300	1300	1300	1300	1200	1300
Inlet pressure, atm	50	50	50	50	50	50	50	50	50	50	50	50	100	50	50	50	50	50
Magnetic field strength, T	1.13	1.13	0.97	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.15	1.18	1.95	1.13	1.13	1.13	0.92	1.13
Isentropic efficiency, percent	80	80	80	80	80	80	80	80	80	80	80	80	80	78	80	80	80	80
Liquid-metal drive	Liquid-metal pump																	Nozzle/diffuser
Heat rejection method (cooling tower)	Wet															Dry	Wet	

TABLE 5.10-2. - SUMMARY OF KEY PARAMETERS FOR WESTINGHOUSE LIQUID-METAL

MHD CASES

[Maximum void fraction, 0.85; inlet pressure, 82.8 atm.]

Parameter	Case								
	4	6	8	9	11	12	13	14	16
Power output, MWe	947	951	950	950	948	951	954	949	949
Coal	Illinois #6								
Coal combustion process	Open-cycle MHD	Fluidized bed - cyclone							
Working fluid	Argon/sodium	Helium/lithium	Argon/sodium						
Inlet temperature, °F	1200	1500	1500	1200	1200	1200	1500	1500	1200
Magnetic field strength, T	0.55	1.2	1.45	0.55	0.55	0.55	1.2	0.55	0.55
Isentropic efficiency, percent	75	75	75	85	75	75	80	80	75
Liquid-metal drive	Liquid-metal pump				EM pump	Nozzle/diffuser	Liquid-metal pump		
Compressor efficiency, percent	85	85	85	87.5	85	85	86	87.5	85
Heat rejection method (cooling tower)	Dry	Wet					Once through	Wet	

TABLE 5.10-3. - SUMMARY OF GENERAL ELECTRIC LIQUID-METAL MHD RESULTS

Result	Case																	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	101
Power output, MWe	486	243	972	485	488	1148	1203	1230	571	662	485	486	489	479	486	477	509	554
Thermodynamic efficiency, η_t, percent	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	43.8	45.2	46.6	43.6	43.1	43.8	43.8	34.9	44.2
Powerplant efficiency, η_{pp}, percent	36.2	36.1	36.2	35.1	33.9	33.6	33.9	33.8	34,2	36.4	37.3	38.5	35.9	35.6	36.1	35.5	28,4	36.7
Overall energy efficiency, η_{oa}, percent	36.2	36.1	36.2	35.1	33.9	33.6	33.9	33.8	17.3	36.4	37.3	38.5	35.9	35.6	36.1	35.5	28.4	36.7
Capital cost, million dollars	1182	582	2505	1184	1187	1658	1773	1826	1017	1208	1232	1477	1151	1162	1182	1189	1245	1182
Capital cost, \$/kWe	2432	2396	2577	2441	2430	1445	1473	1484	1780	1824	2539	3039	2353	2426	2433	2493	2449	2114
Cost of electricity, mills/kW-hr:																		
Capital	76.9	75.8	81.5	77.2	76.8	45.7	46.6	46.9	56.3	57.7	80.3	96.1	74.4	76.7	76.9	78.3	77.4	66.8
Fuel	8.0	8.0	8.0	8.3	8.6	8.6	8.6	8.6	25.9	8.0	7.8	7.5	8.1	8,2	8.0	8.2	10.2	7.9
Operation and maintenance	4.2	5.6	3.8	4.2	4.2	3.7	3.7	3.4	3.1	3.5	4.8	6.7	4.1	4.1	4.2	4.3	4.1	2.8
Total	89.2	89.4	93.3	89.6	89.6	58.0	58.9	59.0	85.3	69.1	92.9	110.3	86.5	89.0	89.2	91.3	91.7	77.6
Time to construct plant, yr	6	5	7	6	6	6	6	6	5	6	6	6	6	6	6	6	6	6

TABLE 5.10-4. - SUMMARY OF WESTINGHOUSE LIQUID-METAL MHD RESULTS

Result	Case								
	4	6	8	9	11	12	13	14	16
Power output, MWe	947	951	950	950	948	951	954	949	949
Thermodynamic efficiency, η_t, percent	(a)	43.4	42.0	43.9	40.6	42.9	36.4	45.7	40.0
Powerplant efficiency, η_{pp}, percent	29.6	37.5	36.2	37.3	34.5	36.4	31.0	39.4	34.3
Overall energy efficiency, η_{oa}, percent	29.6	37.5	36.2	37.3	34.5	36.4	31.0	39.4	34.3
Capital cost, million dollars	1318	1728	1118	809	854	751	2042	1106	894
Capital cost, $/kWe	1392	1817	1177	852	901	790	2140	1165	942
Cost of electricity, mills/kW-hr:									
Capital	44.0	57.4	37.2	26.9	28.5	25.0	67.6	36.8	29.8
Fuel	9.9	7.8	8.1	7.8	8.5	8.0	9.5	7.5	8.6
Operation and maintenance	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	54.8	66.2	46.2	35.6	37.8	33.9	78.0	45.2	39.3
Time to construct plant, yr	8	8	8	8	8	8	8	8	8

[a]Not applicable.

TABLE 5.10-5 - COST COMPARISON FOR LIQUID-METAL MHD SYSTEMS - BETWEEN WESTINGHOUSE CASE 9 AND GENERAL ELECTRIC CASE 3

Component	Westinghouse case 9		General Electric case 3		
	Materials	Direct labor	Major-component cost	Bechtel estimate	
				Materials	Direct labor
	Cost, million dollars				
Furnace	65.0	29.8	110	41.6	25.4
MHD generator:					
Nozzle/diffuser	4.3	1.7	24.8	14.3	9.1
Magnet	.9	.3	11.7		
Waste heat boiler	23.9	9.5	25.2	1.3	2.8
Liquid-metal pump drive	49.2	5.4	45.9	.9	.2
Low-temperature-air heater	5.0	.7	4.1	-----	-----
Compressor/turbine drive	9.0	0.9	25.4	-----	-----
Steam turbogenerator	5.2	.5	-----	-----	-----
Cooling tower system	6.2	3.7	8.6	-----	6.6
Power conditioner	44.4	8.6	214.5	-----	-----
Primary piping	1.2	.5	-----	54.1	18.2
Piping and instrumentation	12.0	6.8	-----	71.7	24.2
Auxiliary electric	7.0	6.2	-----	38.4	18.7
Auxiliary mechanical	5.1	1.4	-----	29.6	5.1
Civil and structural	12.6	12.8	-----	64.7	26.6
Miscellaneous	-----	-----	-----	22.0	7.2
Total	251	88.8	470.2	340.6	146.2
Indirect labor costs	45.3		131.6		
Architectural and engineering services	27.2		92.7		
Contingency	37.3		236.0		
Escalation	157.2		474.1		
Interest	199.8		614.7		
Total capital cost	809.1		2506.1		

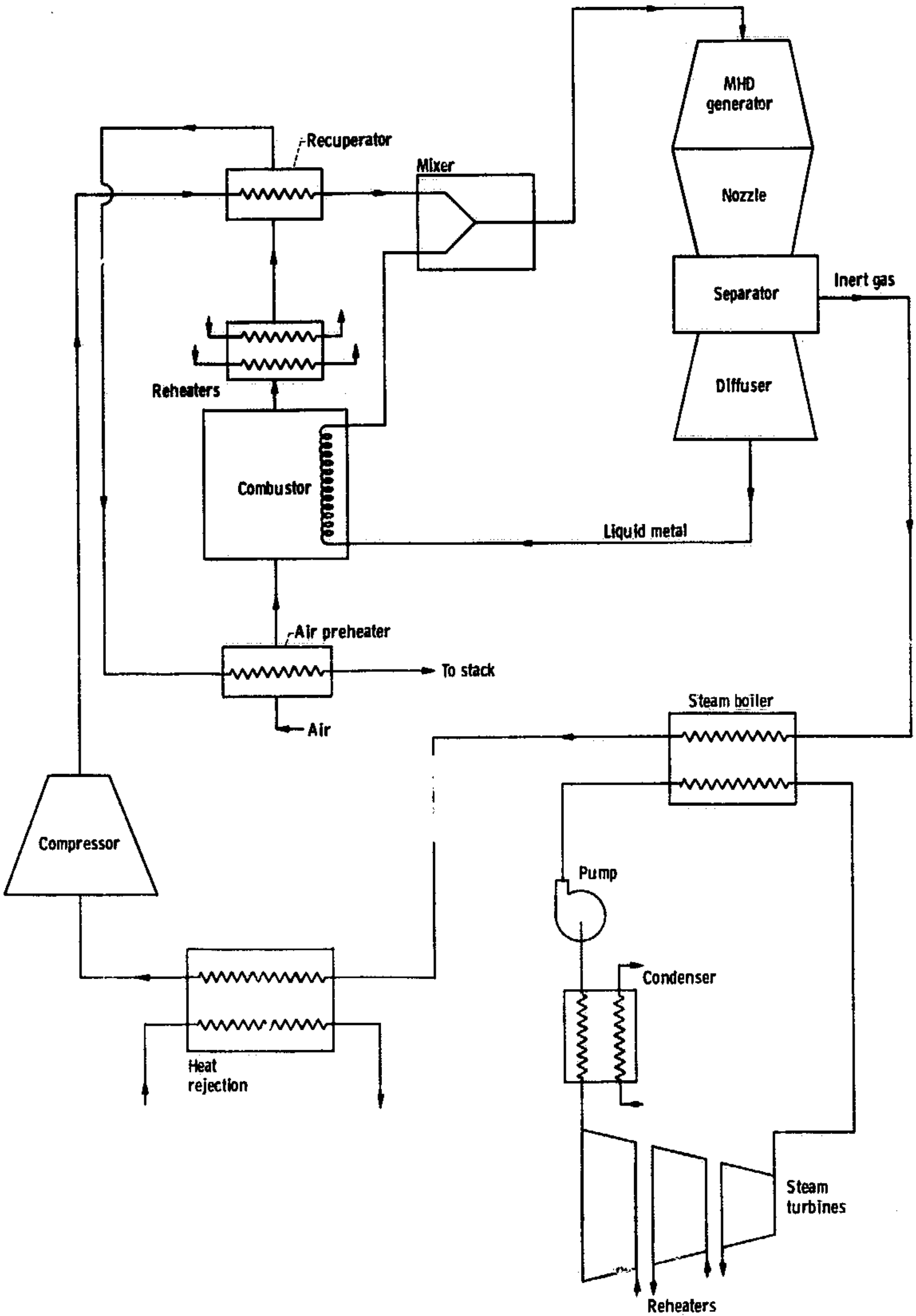

Figure 5.10-1. - Typical schematic diagram of liquid-metal MHD/steam power cycle.

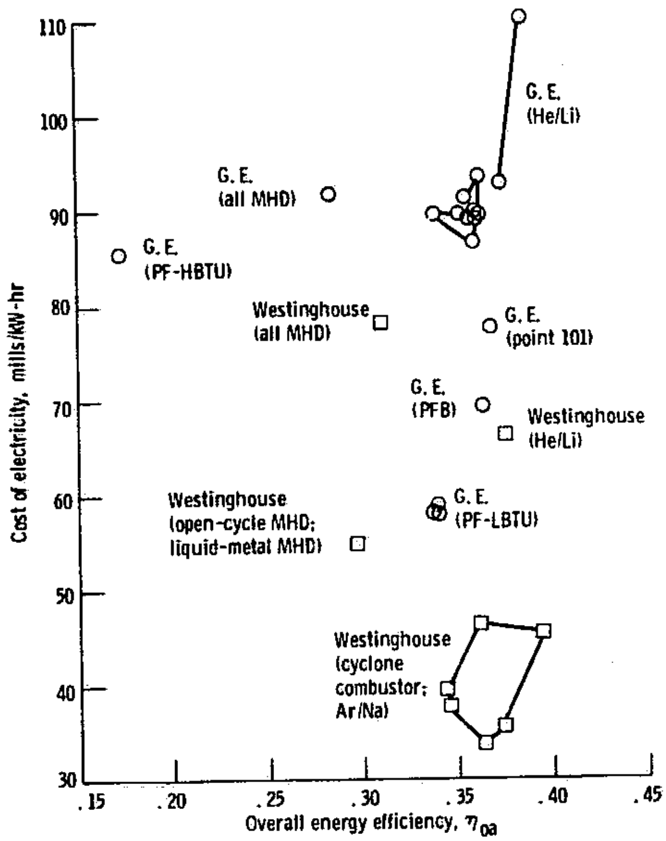

Figure 5.10-2. - Effect of overall energy efficiency on cost of electricity for liquid-metal MHD systems.

5.11 FUEL-CELL POWERPLANTS
by Marvin Warshay

Fuel cells offer the potential for high-efficiency generation of electricity. These electrochemical devices are not Carnot-cycle limited as are conventional thermodynamic cycles.

In particular, fuel cells that operate at high temperatures (1200° to 1800° F) fit well into the ECAS study framework. They are quite suitable as large base-load utility powerplants. In fact, their high-quality waste heat is best utilized in large systems. Waste heat can be used either by a bottoming cycle or by a coal gasifier, or in some cases by both. Further, close integration can effectively improve the energy efficiency of the coal conversion process.

All fuel cells require clean fuels. However, high-temperature fuel cells do not require fuels to be clean within extremely narrow tolerances. Consequently, their fuel processing requirements are not very stringent. Finally, the increase in the reaction rates brought about by high temperatures helps the fuel cell to approach its potential for high efficiency.

All these aspects of the high-temperature fuel-cell systems lead to energy conversion systems with very high overall efficiencies.

Low-temperature fuel cells are less suited for the primary ECAS utility application, that is, base-load power generation from coal-derived fuels. First of all, the requirements for clean fuel are much more stringent for low-temperature fuel cells than for high-temperature fuel cells. Secondly, there is less potential for utilization of waste heat in the powerplant at the low temperatures. Third, the rate processes are slower at low temperatures; polarization losses are significant when operating at desirable current density levels. All three of these conditions reduce the efficiency of a low-temperature fuel-cell powerplant system.

However, greater potential for low-temperature fuel-cell utility applications is foreseen for non-base-load service. Outside the context of ECAS, low-temperature fuel cells are associated with dispersed power generation, peaking or intermediate service, load following, efficient use of natural gas or petroleum products, transmission savings, total energy savings through on-site waste heat utilization, modularity advantages, high efficiency at wide load variation, the hydrogen economy, etc. These potential fuel-cell applications are discussed briefly in section 5.11.2.2.4.

Previous reports on fuel-cell powerplants have indicated their potential for high efficiency. The present ECAS study not only further documents this, but also adds cost dimensions to the description.

5.11.1 Scope of Analysis

5.11.1.1 Low-Temperature Fuel Cells

5.11.1.1.1 General Electric treatment. - Two low-temperature fuel-cell systems were treated by G.E., the solid polymer electrolyte (SPE) system and the phosphoric acid system. The SPE fuel cell received the major emphasis, being chosen as the base case (table 5.11-1) and treated in 10 out of 14 parametric variations. In the base case, high-Btu (HBTU) gas was used as the fuel, but hydrogen was used in over half of the parametric variations. The oxidizer was air in all but one case, in which oxygen was used.

The choice of HBTU fuel was dictated by the selection of the 48-MWe (substation size) powerplant. This small powerplant would, in most cases, be used at a dispersed site rather than as a central-station powerplant. Undoubtedly the first gasified fuel to be transported through gas pipelines will be substitute natural gas, that is, HBTU, rather than a hydrogen-rich fuel, which fuel cells prefer. However, the HBTU gas presents fuel processing problems, especially for the SPE system. (See fig. 5.11-1 for a typical low-temperature fuel-cell schematic.)

The base-case SPE fuel cell was operated at 250 A/ft² and 170° F; the phosphoric acid fuel-cell operating temperature was 375° F. The range of current density variation in the study was 100 to 350 A/ft².

A single central-station-sized powerplant case (201 MWe; SPE; on-site hydrogen; oxygen) was included in the G.E. study.

5.11.1.1.2 Westinghouse treatment. - Two low-temperature fuel-cell systems were treated by Westinghouse, the aqueous alkaline (KOH) and the aqueous phosphoric acid systems. (See fig. 5.11-2 for schematics of the systems.) An appropriate base case for each of the fuel-cell systems was selected (table 5.11-2). One characteristic that all base cases had, including the ones for high-temperature fuel cells, was the nominal 25-MWe powerplant size. This size selection is in keeping with the first fuel-cell electric utility powerplant, the FCG-1.

The assumed fuel-cell useful life for both low-temperature base cases was 10,000 hours. Parametric variations covered fuel-cell life up to 100,000 hours. HBTU fuel and air oxidizer were used in the majority of the 32 low-temperature cases. Methanol and intermediate-Btu gas (designated medium Btu (MBTU) by Westinghouse but termed IBTU in the ECAS study) were other fuels investigated; oxygen was used as the oxidizer in three cases.

The operating temperatures were 158° F (70° C) for the KOH fuel-cell system and 375° F (190° C) for the acid system. The KOH base-case current density was 100 mA/cm², with parametric variations up to 250 mA/cm² investigated. (Current densities are commonly reported in either A/ft² or mA/cm². The latter is 7 percent lower than the former.) The phosphoric acid system base-case current density was 200 mA/cm² with parametric variations up to 400 mA/cm² investigated.

These current densities were a direct reflection of the operating temperatures of the two fuel-cell systems.

Finally, to determine the effects of scale-up, several large powerplants at a nominal 900-MWe size were investigated.

5.11.1.2. High-Temperature Fuel Cells

5.11.1.2.1 General Electric treatment. - The G.E. ECAS contract had the major emphasis on low-temperature fuel cells with only a small study of high-temperature fuel-cell systems.

General Electric treated the high-temperature (1832° F) zirconia solid electrolyte (SE) fuel cell in four cases, all of which included steam bottoming cycles. The fuel was low-Btu (LBTU) gas. (See table 5.11-3 for details of the base case.) However, there was no integration of the LBTU gasifier with the powerplant although the capital cost of the gasifier is included in the plant cost. (See fig. 5.11-3 for a schematic of the system.) Air was the oxidizer in all cases. Two current densities were investigated, 200 and 700 A/ft^2. The electrolyte thickness was 0.020 inch in three out of four cases; for one case the effect of a fourfold reduction in electrolyte thickness (0.005 in.) was explored. The powerplant outputs varied from 632 to 1112 MWe.

5.11.1.2.2 Westinghouse treatment. - Westinghouse examined two high-temperature fuel-cell systems, the molten carbonate (MC) system (1200° to 1381° F; or 650° to 750° C) and the zirconia solid electrolyte (SE) system (1652° to 2012° F; or 900° to 1100° C). (See fig. 5.11-4 for schematics of the two systems.) An appropriate base case was chosen for each system. (See table 5.11-4 for details.) HBTU was the predominant fuel used for the 16 MC cases, while IBTU fuel predominated in the 20 SE cases. Additionally, IBTU gas and methanol were investigated in the MC systems. The zirconia SE investigation also covered HBTU and LBTU cases. Air was the oxidizer in all but two cases.

In 13 out of 16 MC cases the current density was $200 mA/cm^2$. It ranged from 150 to 300 mA/cm^2 in the remaining parametric variations. In the SE cases, 400 mA/cm^2 was the most common current density; the range covered 800 mA/cm^2.

Thinner cell electrolytes were investigated in the Westinghouse zirconia SE study (0.002 and 0.004 cm) than were investigated by G.E.

The MC powerplant sizes ranged to 1255 MWe, a case that included a steam bottoming cycle. The SE cases, which covered sizes up to 1164 MWe, included three integrated powerplant cases. In one case the fuel cell and steam bottoming cycle were integrated, in another case the fuel cell and gasifier were integrated, and in the last case all three were integrated. The gasifier/fuel-cell integration represented a version of Westinghouse's previously studied "Project Fuel Cell" concept. In this concept, the fuel cell is inside the gasifier to maximize heat and mass transfer from the fuel cell.

5.11.2 Results of Analysis

5.11.2.1 Overall Comparison

With the aid of figure 5.11-5 an overall comparison of the results of the fuel-cell portion of the parametric study can be made. The G.E. low-temperature fuel-cell system points are divided into two groups to indicate the significant effect of hydrogen fuel. Likewise, the Westinghouse high-temperature points are divided into two groups to indicate the significant effect of using a steam bottoming cycle and/or integration with the gasifier.

The general conclusions that can be drawn from inspection of figure 5.11-5 are as follows:

(1) With low-temperature fuel-cell power systems the use of hydrogen fuel in place of HBTU gas improves efficiency and lowers the cost of electricity (COE).

(2) The Westinghouse estimates of low-temperature fuel-cell efficiencies (with no hydrogen-fuel cases) were all higher than the G.E. overall efficiency estimates for HBTU/air. The Westinghouse estimates of COE for these same cases were either higher or lower than those of G.E.

(3) The results indicate that, in general, high-temperature fuel-cell

systems are more efficient than low-temperature fuel-cell systems.

(4) Using a steam bottoming cycle and/or integration with the gasifier results in the highest efficiencies obtained with a high-temperature fuel cell.

(5) The estimates by Westinghouse of the high-temperature fuel-cell efficiencies for systems with a steam bottoming cycle are significantly higher than G.E.'s estimates.

Additional conclusions based on a closer examination of the results are discussed in the following section. In addition, the present general conclusions are more precisely stated and discussed. Finally, it is important to state that optimization was not a goal of Phase 1 of ECAS. Optimization could result in points with reduced COE.

5.11.2.2 Discussion and Assessment

5.11.2.2.1 General. - The general results obtained by both General Electric and Westinghouse in their studies of fuel-cell systems are as follows:

5.11.2.2.1.1 Low-temperature fuel cells - G.E. solid-polymer-electrolyte systems: In G.E.'s treatment of low-temperature fuel cells, major emphasis was placed on the SPE fuel-cell system. The overall efficiency of the SPE system operating with HBTU/air at 170° F is only 12.7 percent. The fact that the fuel-cell powerplant efficiency is double that illustrates the heavy penalty the fuel cell pays for coal conversion to HBTU fuel. Significant performance jumps to 23 to 25 percent occur when the SPE operates with hydrogen/air. This is no surprise because fuel cells operate best on hydrogen. Also the conversion efficiency to hydrogen is somewhat better than to HBTU gas. Nor is it surprising that the best efficiency, 31.1 percent, was registered by the 201-MWe system operating with hydrogen/oxygen at 300° F. The cost data for the SPE systems follow the same pattern as the performance efficiencies. The highest-cost electricity (55 to 60 mills/kW-hr) would be produced by HBTU/air systems, the lowest (31 mills/kW-hr) by the most efficient hydrogen/oxygen system. In all cases, the fuel cost, which reflects powerplant efficiency, is the major component of the COE. For the hydrogen cases, both fuel and capital components of COE costs are lower than for the HBTU cases. In fact, capital costs for the hydrogen cases are sharply lower. The hydrogen-fueled converters do not require costly fuel processing to convert the fuel to hydrogen-rich gas, as in the case of HBTU. Operating and maintenance costs were not high for any of the SPE cases. The cell life was assumed to be 100,000 hours for all fuel cells. This assumption is considered very optimistic for the 300° F case.

5.11.2.2.1.2 Low-temperature fuel cells - G.E. phosphoric acid systems: The results for the G.E. phosphoric acid fuel cell followed exactly the pattern of the SPE results in COE, efficiency, and response to hydrogen or HBTU fuel. However, a surprising G.E. result is the mere 4.7-percentage-point powerplant efficiency advantage for the higher temperature (375° F) phosphoric acid HBTU/air system compared with the SPE system (170° F). Furthermore, the results indicate no advantage in efficiency for the phosphoric acid system over an SPE system using hydrogen fuel.

5.11.2.2.1.3 Low-temperature fuel cells - Westinghouse phosphoric acid systems: For the phosphoric acid cases, comparisons can be made between the G.E. and Westinghouse results. Westinghouse included a very broad parametric study almost exclusively devoted to HBTU/air, with no hydrogen cases considered. Several similarities as well as differences in the results of the two contractor studies stand out. The Westinghouse results indicate, as did G.E.'s results, that the fuel COE component is highest. However, the powerplant efficiencies upon which fuel costs hinge are significantly higher for Westinghouse than for G.E. The Westinghouse powerplant efficiencies for HBTU/air cases are approximately 36 percent, compared with 29.8 percent for G.E. Also the Westinghouse overall efficiencies, at approximately 24 percent, are about 50 percent greater than G.E.'s (15.6 percent). This is reflective of both the higher powerplant efficiency and the higher gasifier conversion efficiency estimated by Westinghouse.

However, since both contractors used the NASA-specified cost for over-the-fence HBTU gas, a lower or higher conversion efficiency is not reflected in the fuel COE in this parametric study. In actual detailed designs and in the ECAS system cases integrated with LBTU or IBTU gasifiers, the efficiency of the coal conversion process does affect the fuel costs.

Another significant difference between the G.E. and Westinghouse HBTU/air results is in capital cost. The Westinghouse capital cost estimates ($339/kWe to $463/kWe) are all lower than for the G.E. HBTU/air base case ($570/kWe). The difference is largely a reflection of the much higher fuel processing costs for HBTU estimated by G.E.

Finally, a contrast exists between the G.E. oxygen case (hydrogen/oxygen SPE, case 8) results and the Westinghouse low-temperature fuel-cell case results (HBTU/oxygen phosphoric acid, cases 5 and 16). The Westinghouse HBTU/oxygen systems were more costly and less efficient than the Westinghouse HBTU/air systems. However, the G.E. hydrogen/oxygen system was more efficient and has a lower COE than any of the G.E. hydrogen/air systems. Part of the explanation lies in the two contractor's treatments of oxygen production. Westinghouse elected to estimate the costs of producing oxygen on site; G.E. used over-the-fence oxygen at an NASA-specified cost of $9/ton. Doing the calculation the first way not only resulted in a higher oxygen price, but in a significant (from 36 to 29.6 percent) lowering of powerplant efficiency. This accounts for the parasitic power required to run the oxygen plant. For further discussion of this point see section 5.11.2.2.3.1, a detailed discussion of G.E. hydrogen/oxygen SPE case 8.

5.11.2.2.1.4 Low-temperature fuel cells - Westinghouse alkaline (KOH) systems: In the Westinghouse treatment of the alkaline fuel cell, the more-conventional reactant scrubbing technique of handling the electrolyte carbonation problem was selected. Neither the carbon dioxide rejecting buffered-base technique nor the cyclic decarbonation technique was examined in the Westinghouse study. The Westinghouse parametric treatment of the alkaline (KOH) fuel-cell systems was also almost exclusively devoted to HBTU/air cases. (The only other case treated was an IBTU/air case.) Comparing these results with Westinghouse's phosphoric acid results indicates the following: Despite higher powerplant efficiency the KOH system COE's are higher. This means capital costs are higher for the KOH cases. High capital costs result from (1) higher reactant processing costs to handle the carbonation problem and (2) the higher fuel-cell stack costs resulting from the lower power density operation (due to the lower current density) of this lowest temperature fuel cell (158° F).

5.11.2.2.1.5 High-temperature fuel cells - G.E. zirconia solid electrolyte system: The overall efficiencies for the G.E. zirconia SE fuel cells (27.9 to 34.3 percent) are surprisingly low for this highest temperature (1832° F) fuel-cell system. As discussed in the next section, this is primarily attributable to zirconia fuel-cell performance, not to lower-than-expected steam-bottoming-cycle performance.

In G.E.'s treatment of fuel cells, their projection of long life (40,000 to 100,000 hr) kept the operation and maintenance (O and M) COE to approximately 5 mills/kW-hr. By contrast, the Westinghouse O and M COE for fuel cells varies from 2 to over 30 mills/kW-hr. The reason is that in the Westinghouse treatment, fuel-cell useful life (which is 10,000 hr for all four base cases) is allowed to vary up to 100,000 hours in the parametric variations.

5.11.2.2.1.6 High-temperature fuel cells - Westinghouse zirconia solid electrolyte systems: The Westinghouse results indicate a much greater zirconia fuel-cell efficiency in all cases than is estimated by G.E. Apparently, Westinghouse's thinner-cell concept results in much higher energy densities than the G.E. zirconia concept. The Westinghouse system with a steam bottoming cycle (case SE 19) has an overall efficiency of 47.8 percent compared with 31.5 to 34.3 percent for G.E. systems. The Westinghouse system operates at twice the current density (400 mA/cm²) of the G.E. systems while generating approximately equal voltage (0.56 V compared with 0.58 V for G.E.). Both the capital and fuel costs are lower for the Westinghouse cases. However, because of the long life assumption by G.E. (10 yr compared with 10,000 hr by Westinghouse), the O and M estimate by G.E. (5 mills/kW-hr) is much less than that estimated by Westinghouse (23 mills/kW-hr). This causes the total COE estimate made by Westinghouse to exceed by a small amount the COE for the G.E. case.

The majority of the Westinghouse parametric cases use IBTU fuel because Westinghouse had greater confidence in it than in HBTU gas. Also, there are more technical data available on the effects of using IBTU gas in the zirconia fuel cell.

5.11.2.2.1.7 High-temperature fuel cells - Westinghouse molten carbonate systems: The most interesting Westinghouse molten-carbonate system for base-load application is the IBTU/air system (1200° F), which produces 1255 MWe with the aid of a steam bottoming cycle (case MC 4). The powerplant and overall efficiencies for this case are very attractive at 54.4 and 45.7 percent, respectively. For a similar zirconia SE system, powerplant and overall efficiencies were 60.2 and 50.6 percent, respectively (case SE 4). For these two cases, the capital, fuel, and O and M costs were very close to one another, with the O and M cost being the largest. This produced a COE of 40 to 45 mills/kW-hr. To what extent the fuel and O and M COE's can be reduced by a reasonable life projection beyond 10,000 hours is discussed later (section 5.11.2.2.3).

5.11.2.2.2 <u>Significant trends in General Electric and Westinghouse results</u> - The Westinghouse results show most clearly (table 5.11-5) that efficiency increases with fuel-cell temperature. In going from the low-temperature phosphoric acid fuel cell to the high-temperature molten carbonate system and finally to the very high-temperature zirconia solid electrolyte system, the overall efficiency almost doubles. These results are for HBTU fuel. Table 5.11-6 illustrates the enhanced overall efficiencies that result from using IBTU fuel instead of HBTU fuel and from using a steam bottoming cycle, in the case of the two high-temperature fuel cells. Only the high-temperature fuel cells have the quality of waste heat that can be used by a steam bottoming cycle, and then only with large (900-MWe) fuel-cell powerplants. (The increased size affects the phosphoric acid low-temperature fuel-cell powerplant very little.) That most of the increased efficiency for the high-temperature fuel-cell systems comes from integration can be seen in table 5.11-7. This table indicates that each of the high-temperature systems gains approximately 15 percentage points in overall efficiency through using a steam bottoming cycle. (Not shown in this table but included in the Westinghouse results are data for both high-temperature systems that indicate no efficiency improvements due to simple scale-up from 25 to 250 MWe.)

Looking at these tables from the standpoint of COE, the results indicate great benefit for the high-temperature fuel cells from using a steam bottoming cycle. There is no clear COE trend related to fuel-cell temperature (tables 5.11-5 and 5.11-6). The benefits of integration are again most clearly shown in table 5.11-7. Cost of electricity is lowered more than 13 mills/kW-hr in both high-temperature fuel-cell systems. (The lower COE for phosphoric acid indicated in table 5.11-6 stems principally from the lower price of IBTU fuel compared with HBTU fuel.)

Table 5.11-8, the last in this set of Westinghouse results, provides some results for various modes of high-temperature-solid-electrolyte system integration. The use of a steam bottoming cycle compared with integration with the gasifier seems to be an efficiency/COE trade-off; higher efficiency but also higher COE result from integration with the gasifier. In the third case, which has both integration with the gasifier and use of a steam bottoming cycle, it is not surprising that the LBTU fuel results in the lowest efficiency. What is surprising is that it does not also result in the lowest COE since LBTU should be the cheaper fuel. (However, there is no assurance that the contractor's estimate (which is not explicitly stated) of LBTU cost is consistent with the NASA-specified costs for HBTU and IBTU fuels.)

The G.E. results (table 5.11-9) also show the efficiency increase in going from the low-temperature fuel cells to the high-temperature fuel cells; the overall efficiency increases almost 18 percentage points. This efficiency increase with temperature results from a comparison that is not entirely valid; the high-temperature case uses a steam bottoming cycle and uses LBTU fuel from a free-standing gasifier instead of HBTU fuel. However, closer examination of the complete set of G.E. data indicates that the trend is very substantially correct.

While the trend of the G.E. efficiency data in table 5.11-9 is in agreement with the Westinghouse results, the absolute values indicate several differences between the two contractors' results. These differences are as follows: (1) Westinghouse used a higher conversion efficiency for HBTU production from coal than G.E. (67 percent against 50 percent). (2) Westinghouse calculated a higher phosphoric acid powerplant efficiency than G.E. (36.0 percent against 29.8 percent). (3) Westinghouse calculated a higher overall efficiency for the high-temperature solid electrolyte fuel-cell system (47.7 percent against 31.5 percent).

From an analysis of G.E.'s and Westinghouse's treatments of the phosphoric acid system it appears that the powerplant efficiency difference stems principally from G.E.'s lower fuel-cell efficiency plus a lower degree of fuel cell - fuel processor integration. Close integration of the fuel cell with the fuel processor can increase the conversion efficiency substantially.

The explanation for the lower efficiencies obtained with the G.E. high-temperature solid electrolyte concept lies in the use of much thicker cells (0.020-in. electrolyte) than in the Westinghouse concept (0.00158 in. (0.004 cm) electrolyte). For this concept G.E. voltages varied between 0.18 and 0.58 volt compared with a 0.51 to 0.84 voltage range for Westinghouse.

To complete the discussion of the G.E. results in table 5.11-9, the lower COE value for the zirconia SE system merely reflects a savings due to the use of a steam bottoming cycle and is not possible with the low-temperature fuel cells. This would be consistent with the conclusion based upon the Westinghouse results.

Comparing the COE values of G.E. and Westinghouse in tables 5.11-5, 5.11-8, and 5.11-9 might lead to the specious conclusion that the values are close for both the phosphoric acid and zirconia cases. This is because the G.E. life assumptions were much longer than the 10,000-hour Westinghouse life assumptions. A closer look at the G.E. and Westinghouse data reveals higher capital costs in both G.E. cases but lower O and M costs. These data are examined in greater detail in the next section.

Table 5.11-10 illustrates the dual benefit of using hydrogen instead of HBTU fuel. Using hydrogen fuel results in higher efficiencies and in lower COE's for both the SPE and phosphoric acid low-temperature fuel-cell systems. Higher overall efficiency is attributable to the absence of a fuel processor and to the higher conversion efficiency for producing hydrogen from coal. The lower COE's are the result of the elimination of the fuel processor cost.

5.11.2.2.3 Detailed evaluation of "points of interest". - The specific results obtained by General Electric and Westinghouse in their studies of fuel-cell systems are evaluated in detail here.

5.11.2.2.3.1 Solid polymer electrolyte - hydrogen/oxygen - 300° F - 201 MWe (G.E. case 8): The detailed results for this interesting case are listed in table 5.11-11. The use of hydrogen fuel has obvious benefits. Using hydrogen/oxygen at the elevated temperature of 300° F (up from 170° F) results in the highest low-temperature fuel-cell powerplant efficiency of 51.1 percent (31.1 percent overall) in the G.E. results. At 31 mills/kW-hr the electricity produced by this 201-MWe powerplant is also the lowest in cost of all the fuel cells reported in the G.E. study. The capital cost is $242/kWe. The potential also exists, as G.E. points out, for further cost reduction through sale of steam, which can be produced from waste heat. The fuel cell operates at a moderate pressure of 115 psi.

However, the preceding results are probably optimistic in three areas. First, the performance penalty to account for the equivalent fuel required to manufacture oxygen will lower overall efficiency. (Efficiency is lowered by approximately 4.6 percentage points according to an NASA estimate based upon information obtained from oxygen manufacturers. NASA also estimated that the effect upon COE would be to increase it from 31 mills/kW-hr to approximately 37 mills/kW-hr. In their writeup, G.E. mentions the fact that the use of the NASA-specified $9/ton oxygen cost overlooks the impact upon efficiency.) Second, it is considered highly optimistic that an SPE polymer can be developed to last 100,000 hours at 300° F. General Electric has extrapolated to 100,000-hour life on the basis of an 800-hour test. If the SPE polymer life at 170° F is 100,000 hours, there is G.E. evidence which indicates that at 300° F the life must be much shorter. Below a 30,000-hour life, the O and M costs rise steeply. Finally, the projected reduction of current SPE fuel-cell costs from approximately $70 or $80/ft² to $16/ft² is believed optimistic. Achievement of this large a cost reduction while maintaining cell performance would require complete success in three major materials areas: the SPE polymer, the metallic screens, and the electrode catalyst.

5.11.2.2.3.2 Phosphoric acid electrolyte - high-Btu gas/air - 375° F (G.E. case 12, 48 MWe; and Westinghouse case AC 12, 23 MWe): In terms of commercial interest, the phosphoric acid fuel-cell systems operating on HBTU/air are of greatest current interest. Most similar to the United Technologies Corp. FCG-1 fuel-cell powerplant that is proposed for intermediate-peaking service are G.E. case 12 and Westinghouse case AC 12. Data for these cases are shown in tables 5.11-11 and 5.11-12. As was discussed earlier, the higher overall efficiency of the Westinghouse treatment (23.9 percent for Westinghouse case 12 compared with 15.0 percent for G.E. case 12) is attributed primarily to the higher fuel-cell powerplant efficiency estimate by Westinghouse coupled with their more efficient gasifier concept. The second important item is the capital cost. The G.E. estimate of $570/kWe is much higher than Westinghouse's capitalization estimate of $371/kWe. Before the contingency, escalation, indirect, and interest-during-construction costs are added, the total direct costs (including site labor) are estimated at $395/kWe by G.E. and $276/kWe by Westinghouse.

The capital cost difference between the two contractors' estimates is attributable to the fuel processing cost difference. The G.E. estimate for fuel processing is $173/kWe; the Westinghouse estimate for their phosphoric acid system is only $38/kWe (both before contingency, escalation, and other costs). The added cost of a carbon dioxide scrubber (about $14/kWe) in the G.E. concept and differences in cost accounting between G.E. and Westinghouse cannot account for this large a difference. Based upon information from manufacturers and upon engineering design data, it is believed that actual costs may be somewhere between the G.E. and Westinghouse estimates.

The major item in the COE in both treatments is the fuel-cost portion, 29 mills/kW-hr for G.E. and 25 mills/kW-hr for Westinghouse. It is likely that the fuel-cost portion of COE will remain high. The O and M portion of COE for Westinghouse could be reduced by increased fuel-cell life. Westinghouse case AC 12 uses a 10,000-hour life, while G.E. case 12 assumes 40,000 hours - a reasonable projection of the current state of the art. Making the 40,000-hour life assumption for Westinghouse case 12 would reduce their COE to approximately 40 mills/kW-hr.

5.11.2.2.3.3 Molten carbonate electrolyte - 1200° F - integrated steam bottoming cycle - 1255 MWe total - (Westinghouse case 4): The overall efficiency of 45.7 percent (powerplant efficiency, 54.4 percent) reduces the fuel cost (table 5.11-13). At 13 mills/kW-hr the reduction is no more than half the fuel COE cost of low-temperature fuel cells. It is further believed, that a complete integration of the molten carbonate (MC) system with the gasifier will yield further increases in efficiency. The total capital cost estimate for the MC system is $482/kWe. (The total direct cost is only $276/kWe.) The capital cost influences the O and M portion, as well as the capital cost portion, of the 44-mills/kW-hr COE. In the Westinghouse calculation for this case it is the primary influence. NASA feels that a significant improvement in the current state-of-the-art life of 10,000 hours (demonstrated in small-scale fuel cells) is achievable. Applying correction to the O and M cost for a projected MC life of 30,000 to 50,000 hours reduces the COE to 34 to 32 mills/kW-hr. Because MC work is still in the small-scale stage, conclusions (principally those involving cost) must be regarded as uncertain. For all fuel-cell systems, the uncertainty in predicted efficiency is much less than the uncertainty in predicted costs.

5.11.2.2.3.4 Zirconia solid electrolyte - intermediate-Btu gas/air - 1832° F - (Westinghouse case SE 4): Much of what was just said about the high-temperature MC system applies to the higher temperature zirconia SE system (table 5.11-14). For this case, the total direct costs and capitalization costs are $264/kWe and $466/kWe, respectively. The COE is 40 mills/kW-hr, and the overall efficiency is 50.6 percent. For this system one could also calculate a reduction in O and M costs based on a 30,000- to 50,000-hour life, bringing the COE down to 34 to 32 mills/kW-hr. However, for this 1832° F system, no more than 1000-hour life has been demonstrated on small-scale cells. Therefore, a projection to 40,000-hour life is premature and the COE of 40 mills/kW-hr already represents a projection.

5.11.2.2.3.5 Zirconia solid electrolyte - intermediate-Btu gas/air - 1832° F - integrated into gasifier - 219 MWe (Westinghouse case SE 18): This treatment constitutes the Westinghouse "Project Fuel Cell" concept of zirconia SE fuel-cell integration with the gasifier. By locating the fuel cell inside the gasifier, heat and mass transfer are maximized. This most intimate contact requires expensive alloy steel housings for the fuel cells to make them resistant to the corrosive gasifier environment. This results in high direct costs (including the highest site labor costs) of $607/kWe and a total capitalization cost of $948/kWe.

This system produces the highest overall efficiency of any fuel-cell powerplant system, 53.0 percent. This of course is reflected in the low-fuel-cost portion of COE. In comparing fuel components of COE it is important to realize that the 5 mills/kW-hr for this case (integrated with a gasifier) is based on coal. In the previous case the fuel component of COE was based upon an over-the-fence IBTU cost. However, it is instructive to compare the sum of the capital and fuel components of COE for each case. For case 4 this equals 26 mills/kW-hr, while for the present case, SE 18, it is 34 mills/kW-hr. The question is whether this difference is attributable to the expensive alloy steel costs in the present case or merely a difference between NASA-specified IBTU costs and the contractor's cost estimate of producing IBTU gas from coal in an advanced gasifier. Further light is shed on this by looking ahead to the next case in table 5.11-14. These results are for an integrated gasifier - SE fuel cell - steam bottoming cycle (Westinghouse case SE 19). The fuel cell is not installed inside the gasifier. Therefore, expensive alloys are not required for the housing. The power output of 1064 MWe is close to the 1164 MWe of case SE 4. The fuel is LBTU gas, which probably accounts for a slightly lower overall efficiency, 47.8 percent, compared with case 4, 50.6 percent. The two cases are very close. Yet, the total capital and fuel COE components for case 19 equal 33 mills/kW-hr compared with the 26 mills/kW-hr for case 4. This lends weight to the suspicion that the difference between cases 18 and 19 on one hand and case 4 on the other is associated with the NASA-specified fuel costs versus the contractor's cost estimate of manufacturing clean gaseous fuels from coal.

For case 18 (table 5.11-14), the total COE is 48 mills/kW-hr. As was mentioned in the previous case SE 4 discussion, realistic projections of life (bringing COE down below 40 mills/kW-hr) beyond 10,000 hours must await further research-and-development work on this system.

5.11.2.2.3.6 Zirconia solid electrolyte - low-Btu gas/air - 1832° F - bottoming cycle - 1064 MWe (Westinghouse case SE 19): To complete the discussion of this case begun in the previous section, its total direct and capitalization costs are $454/kWe and $859/kWe, respectively. These are lower than those of the previous case. However, due to higher O and M costs attributable to the 10,000-hour-life fuel cell, the COE is 52 mills/kW-hr. The overall efficiency is 47.8 percent. The fuel manufacturing cost question and ultimate fuel-cell life uncertainty, previously discussed, of course apply to this system as well.

5.11.2.2.4 <u>Estimation of time of construction and date of commercial availability</u>. - As expected, the order of estimated dates of commercial availability follows the order of increasing fuel-cell temperature, that is, the higher the fuel-cell temperature the later the estimated availability date. This holds for both the General Electric and Westinghouse estimates. (See the individual data tables for these estimates.)

5.11.2.2.5 Special features of fuel-cell powerplants. - Fuel cells have a number of features, many of them unique, that have potentially important applications in the utilities industry. Many of these features can be translated into cost credits by utilities cost analysts. Only some of these features are discussed in this section since many of them are outside the scope of the ECAS study.

Fuel cells, especially low-temperature systems, are very suitable for utility peaking and intermediate service. Advantage can be taken of the fuel cell's constant, or actually increased, efficiency at part load. (Characteristically, the fuel-cell efficiency itself increases as the load decreases. However, where a fuel processor is part of the powerplant, the net powerplant efficiency increase at part load may be smaller.) By using fuel cells to follow the changing load requirements, that is, bringing the fuel-cell unit (or units) on at full rated load at times and at part load at other times, other utility energy convertors can be kept at their most efficient rated loads a higher percentage of the time.

Substation-sized fuel-cell powerplants dispersed throughout the utility service area can result in significant savings in transmission costs. The transmission costs are quite utility specific. However, one report (ref. 15) estimates that the transmission savings would range between $60/kWe and $200/kWe. In addition, another report (ref. 16) points out that the cost of underground transmission is 9 to 15 times that of overhead transmission.

Modularity is a feature that has several potential benefits. First of all, it provides flexibility. Substation fuel cells could be provided in various multiples of the basic module without sacrificing cost or efficiency. In fact a single module, probably considerably smaller than the 25-MW minimum size considered by the ECAS study, could be effectively utilized by a small municipal or rural power company.

Modularity also enables a utility to better match capacity growth requirements from year to year than with conventional powerplants that have to be added in large units. To keep the $/kWe cost down, powerplants have been growing in size in recent years. This ties up utility capital in unused capacity for a number of years until the growing power requirement matches the new capacity. In addition, utilities must be able to predict their growth rates perhaps 10 years in advance. Utilities reduce the impact of these difficulties by pooling power. Fuel-cell powerplant modularity provides them with another option.

A final important advantage of modularity is related to system reliability and availability. When one module out of a series of modules making up the fuel-cell powerplant is out of service, either because of scheduled maintenance or an unscheduled mishap, the other modules can continue to provide power. In fact the remaining fuel-cell modules are usually capable of picking up some of the slack by providing significantly more than their rated capacities. There will be some loss in efficiency of course while the fuel cells are overloaded.

The final feature of fuel cells is their potential for total energy savings through on-site waste heat utilization. The present ECAS study illustrated, for high-temperature fuel-cell systems, the advantage of using waste heat in a steam bottoming cycle or in a gasifier. Also, for low-temperature fuel-cell systems some of the fuel-cell stack waste heat can be used by the powerplant fuel processor. But there is quite a lot of unused fuel-cell stack waste heat. In their treatment of the SPE hydrogen/oxygen fuel cell (case 8) G.E. showed that a substantial credit could be realized by using steam generated from fuel-cell stack waste heat. This total energy savings concept is not limited to large powerplants. Much smaller fuel-cell powerplants could be used to supply not only electric power, but also steam or hot water from fuel-cell waste heat. This total energy concept could be suitable for industrial factories or even apartment complexes.

Finally, with respect to fuels, it will take a number of years before gasified or liquefied coal-derived fuels become available. In the mean time, those energy convertors that do not use coal directly will have to use natural gas or petroleum-derived fuels. Although both fuels are not in unlimited supply, they will be around for quite some time. In many cases, fuel cells make more efficient use of these fuels than many of the other energy convertors using or planning to use them.

5.11.3 Concluding Remarks

5.11.3.1 General Trends

The results of this study of fuel-cell powerplants indicate several general trends.

(1) Efficiency increases with fuel-cell temperature, that is, proceeding from low-temperature fuel cells, to the high-temperature molten carbonate fuel cell, and finally to the very high-temperature zirconia solid electrolyte system.

(2) Scale-up in powerplant size only results in significant reduction in COE when it is accompanied by utilization of waste fuel-cell heat through a steam bottoming cycle and/or integration with the gasifier.

5.11.3.2 Low-Temperature Fuel-Cell Systems

For the low-temperature fuel-cell systems, the following results were obtained:

(1) The inefficiency and cost of producing the required clean fuels are considerable.

(2) The use of hydrogen fuel results in the highest efficiency and lowest COE.

(3) Operating SPE fuel cells on HBTU/air at 170° F results in the lowest fuel-cell powerplant efficiency, 25.2 percent, and an overall efficiency of 12.7 percent as well as quite high COE (58 to 60 mills/kW-hr).

(4) On the other hand, operating SPE fuel cells at 300° F with hydrogen/oxygen results in considerable efficiency improvement, to 31.1 percent overall, and the lowest reported COE for any fuel-cell system, 31 mills/kW-hr. However, accounting for the equivalent fuel requirement to manufacture oxygen would reduce overall efficiency to an estimated 26.5 percent and raise COE to approximately 37 mills/kW-hr. In addition, the basic COE costs probably reflect an optimistic projection of cell costs and SPE polymer life at 300° F.

(5) The phosphoric acid fuel-cell system, which is closest to commercialization for intermediate-peaking service, was treated by both G.E. and Westinghouse. Their results differed chiefly in gasifier and fuel-cell power system efficiencies and in fuel processor costs. For a phosphoric acid, 40,000-hour-fuel-cell-life system, the COE based upon Westinghouse estimates is approximately 40 mills/kW-hr compared with 52 mills/kW-hr estimated by G.E.

(6) Alkaline fuel-cell costs are higher than those for phosphoric acid fuel-cell systems, for two reasons. First, additional reactant processing is required to guard against carbonation of the alkaline electrolyte. Second, because lower power densities are obtained with the alkaline fuel cell at 158° F than with the phosphoric acid fuel cell at 375° F, alkaline fuel cell costs are higher. For the alkaline system in the 10,000- to 30,000-hour-life range the COE was 50 to 61 mills/kW-hr.

5.11.3.3 High-Temperature Fuel-Cell Systems

For the high-temperature fuel-cell systems, the following results were obtained::

(1) The most promising molten carbonate case, utilizing a steam bottoming cycle, offered high overall efficiency, 45.7 percent. A reasonable projection of life from the present 10,000 hours to the 30,000- to 50,000-hour range results in a projected total COE for this molten carbonate system of 32 to 34 mills/kW-hr.

(2) The zirconia solid electrolyte system offers the potential for highest overall efficiency of any fuel-cell system, 53.0 percent.

(3) For the zirconia systems, large fuel-cell powerplants utilizing a steam bottoming cycle and/or integrated with the gasifier produce electricity at high overall efficiency, 47.8 to 53 percent for the cases studied. The fuel-cell - steam bottoming cycle powerplant offered the best combination of efficiency (50.6 percent overall) and COE (40 mills/kW-hr) of the zirconia systems. A projection of life beyond 10,000 hours (as was suggested in the case of the molten carbonate fuel cell) accompanied by a lower COE is not warranted for the zirconia fuel cell at this time since it already represents a substantial life projection.

For fuel-cell powerplant systems, confidence in predicted efficiencies is greater than confidence in predicted costs. In many cases, projections are based upon small laboratory-sized units. While there is a high degree of confidence in the estimates of fuel-cell system efficiency, the uncertainty in costs of coal-derived fuels makes the fuel portion of COE uncertain. However, with the upward trend in fuel costs, the emphasis that has been placed upon powerplant efficiency in the ECAS study would seem to be quite reasonable.

Finally, it appears that the potential for low-temperature fuel-cell utilities application lies in dispersed sites to provide peaking or intermediate service, where advantage of fuel cells' special features can be taken. Fuel cells' special features are (1) to increase the overall efficiency of a utility's energy conversion equipment; (2) to reduce transmission costs; (3) to provide, through modularity, a means of better matching capacity with growth requirements; (4) to provide improved system reliability and availability; (5) to provide the fuel-cell features in units small enough to meet the needs of very small utilities; and (6) to provide total energy savings through on-site waste heat utilization.

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TABLE 5.11-1. - GENERAL ELECTRIC BASE-CASE PARAMETERS FOR LOW-TEMPERATURE FUEL-CELL POWERPLANT (CASE 1)

Power output, MWe	48
Coal	Illinois #6
Conversion process	HBTU
Oxidizer	Air
Fuel-cell type	SPE
Current density, A/ft^2	250
Operating temperature (maximum), ^oF	170
Electrolyte thickness, in. (cm)	0.005 (0.0127)
Actual powerplant output, MWe	48

TABLE 5.11-2. - WESTINGHOUSE BASE-CASE PARAMETERS FOR LOW-TEMPERATURE FUEL-CELL POWERPLANTS (CASES 1)

	Aqueous acid (H_3PO_4) systems	Aqueous alkaline (KOH) systems
Power output, MWe	23.4	22
Fuel-cell rating, MW	25	25
Fuel	HBTU	HBTU
Oxidizer	Air	Air
Fuel-cell life, hr	10 000	10 000
Voltage degradation, percent	5	5
Temperature, ^oC	190	70
Electrolyte type	85 wt % H_3PO_4	30 wt % KOH
Electrolyte thickness, cm (in.)	0.05 (0.02)	0.05 (0.02)
Anode type	Pt/C	Pt/C
Anode catalyst loading, mg Pt/cm^2	1.0	1.0
Cathode type	Pt/C	Ag/C
Cathode catalyst loading, mg Pt (or Ag)/cm^2	1.0	5.0
Current density, mA/cm^2	200	100
Average cell voltage, V	0.7	0.8

TABLE 5.11-3. - GENERAL ELECTRIC BASE-CASE PARAMETERS FOR HIGH-TEMPERATURE FUEL-CELL POWERPLANT (CASE 1)

Power output, MWe	1112
Coal	Illinois #6
Conversion process	LBTU
Oxidizer	Air
Current density, A/ft^2	200
Electrolyte thickness, in. (cm)	0.02 (0.05)
Steam bottoming cycle:	
Turbine-inlet temperature, ^{o}F	1000
Turbine-inlet pressure, psig	3500
Reheat temperature, ^{o}F	1000
Maximum feedwater temperature, ^{o}F	510
Heat rejection method	[a]WCT
Condenser pressure, in. of Hg	1.5
Actual powerplant output, MWe	1112

[a]Wet cooling tower.

TABLE 5.11-4. - WESTINGHOUSE BASE-CASE PARAMETERS FOR HIGH-TEMPERATURE FUEL-CELL POWERPLANT (CASES I)

	Molten carbonate systems	Solid electrolyte (SPE) systems
Power output, MWe	22.6	22.9
Fuel-cell rating, MW dc	25	25
Fuel	HBTU	HBTU
Oxidizer	Air	Air
Fuel-cell life, hr	10 000	10 000
Voltage degradation, percent	5	5
Temperature, °C	650	1000
Electrolyte type	Paste of Li, Na, K, carbonates, and alkali aluminates	$(ZrO_2)_{1-x}(Y_2O_3)_x$
Electrolyte thickness, cm (in.)	0.1 (0.04)	0.004 (0.0015)
Anode type	Ni	$NiZrO_2$-cermet
Cathode type	Lithiated NiO	$In_2O_3/PrCoO_{3-x}$
Interconnection type	------------	Cr_2O_3
Interconnection thickness, cm (in.)	------------	0.002 (0.0008)
Current density, mA/cm^2	200	400
Average cell voltage, V	7	0.84

TABLE 5.11-5. - EFFECT OF FUEL-CELL TEMPERATURE (TYPE) ON EFFICIENCY AND COST OF ELECTRICITY FOR 25-MWe POWERPLANTS - WESTINGHOUSE RESULTS

Fuel-cell temperature, °F	Fuel-cell type[a]	Efficiency, percent		Cost of electricity,[b] COE, mills/kW-hr
		Powerplant	Overall	
375	H_3PO_4	35.5	23.9	50
1200	Molten carbonate	48.8	32.9	58
1832	ZrO_2 SE	69.7	46.9	42

[a]HBTU/air.
[b]Assumed 10 000-hr life for all fuel cells.

TABLE 5.11-6. - EFFECT OF FUEL-CELL TEMPERATURE (TYPE) ON EFFICIENCY AND COST OF ELECTRICITY FOR 900-MWe POWERPLANTS - WESTINGHOUSE RESULTS

Fuel-cell temperature, °F	Fuel-cell type[a]	Efficiency, percent		Cost of electricity,[b] COE, mills/kW-hr
		Powerplant	Overall	
375	H_3PO_4	34.8	29.3	44
1200	Molten carbonate[c]	54.4	45.7	44
1832	ZrO_2 SE[d]	60.2	50.6	40

[a]IBTU/air.
[b]Assumed 10 000-hr life for all fuel cells.
[c]Fuel cell with steam bottoming cycle; 1255 MWe total.
[d]Fuel cell with steam bottoming cycle; 1164 MWe total.

TABLE 5.11-7. - EFFECT OF STEAM BOTTOMING CYCLE ON HIGH-TEMPERATURE FUEL-CELL PERFORMANCE - WESTINGHOUSE RESULTS

Fuel-cell temperature, °F	Fuel-cell type[a]	Overall efficiency, percent		Cost of electricity,[b] COE, mills/kW-hr	
		25-MWe systems	Nominal 900-MWe systems	25-MWe systems	Nominal 900-MWe systems
1200	Molten carbonate[c]	30.6	45.7	60	44
1832	ZrO_2 SE[d]	35.0	50.6	52	40

[a]IBTU/air.
[b]Assumed 10 000-hr life for all fuel cells.
[c]1255 MWe total.
[d]1164 MWe total.

FIGURE 5.11-8. - EFFICIENCY AND COST OF ELECTRICITY FOR THREE TYPES OF INTEGRATED, HIGH-TEMPERATURE, SOLID-ELECTROLYTE FUEL-CELL POWERPLANTS - WESTINGHOUSE RESULTS

Size (total MWe)	Fuel	Extent of integration	Efficiency, percent		Cost of electricity,[a] COE, mills/kW-hr
			Powerplant	Overall	
1164	IBTU	With steam bottoming cycle	60.2	50.6	40
219	IBTU	With gasifier[b]	53.2	53.2	48
1064	LBTU	With gasifier and steam bottoming cycle	47.8	47.8	52

[a]Assumed 10 000-hr life fuel cell.
[b]This is the most intimate integration, and is the "Project Fuel Cell" concept of Westinghouse.

TEMPERATURE 5.11-9. - EFFECT OF FUEL-CELL TEMPERATURE (TYPE) ON POWERPLANT EFFICIENCY AND COST OF ELECTRICITY - GENERAL ELECTRIC RESULTS

Fuel-cell temperature, °F	Fuel-cell type	Efficiency, percent		Cost of electricity,[a] COE, mills/kW-hr
		Powerplant	Overall	
170	SPE[b]	25.2	12.7	58
375	H_3PO_4[b]	29.8	15.0	52
1832	ZrO_2 SE[c]	31.5[d]	31.5	45

[a]Assumed 100 000-hr life for SPE system, 40 000-hr life for H_3PO_4 system, and 10-yr life with 10-percent/yr replacement for ZrO_2 SE system.
[b]HBTU/air; 48 MWe.
[c]LBTU/air; with steam bottoming cycle; 1112 MWe total.
[d]Fuel cost based upon coal rate to gasifier. Gasifier cost included in capital cost. However, powerplant not integrated with gasifier in terms of heat and mass conservation.

TABLE 5.11-10. - EFFECT OF FUEL TYPE ON EFFICIENCY AND COST OF ELECTRICITY FOR LOW-TEMPERATURE FUEL-CELL POWERPLANTS - GENERAL ELECTRIC RESULTS

Fuel[a]	Fuel-cell type	Efficiency, percent		Cost of electricity,[b] COE, mills/kW-hr
		Powerplant	Overall	
HBTU	SPE	25.2	12.7	58
Hydrogen[c]	SPE	38.3	23.3	36
HBTU	H_3PO_4	29.8	15.0	52
Hydrogen[c]	H_3PO_4	37.9	23.1	37

[a]Air oxidizer.
[b]Assumed 100 000-hr life for SPE system, and 40 000-hr life for H_3PO_4 system.
[c]Hydrogen obtained from gasified coal.

TABLE 5.11-11. - GENERAL ELECTRIC VALUES OF ALL RELEVANT PARAMETERS FOR LOW-TEMPERATURE FUEL-CELL POWERPLANTS

Parameter	Case	
	8	12
Power output, MWe	201	47
Coal	Illinois #6	Illinois #6
Conversion process	Hydrogen (on site)	HBTU
Oxidizer	Oxygen	Air
Fuel-cell type	SPE	H_3PO_4
Current density, A/ft^2	300	250
Operating temperature (maximum), $^{\circ}F$	300	375
Electrolyte thickness, in. (cm)	0.005(0.0127)	9.020(0.05)
Actual powerplant output, MWe	201	47
Thermodynamic efficiency, percent	0	0
Powerplant efficiency, percent	51.1	29.8
Overall energy efficiency, percent	31.1	15.0
Coal consumption, lb/kW-hr	1.02	2.10
Plant capital cost, million dollars	49	27
Total direct costs, $/kWe	155	395
Plant capital cost, $/kWe	242	570
Cost of electricity (capacity factor =0.65):		
Capital, mills/kW-hr	7.7	18.0
Fuel, mills/kW-hr	19.6	28.6
Maintenance and operating, mills/kW-hr	4.1	5.5
Total, mills/kW-hr	31.3	52.1
Sensitivity:		
Capacity factor = 0.50 (total mills/kW-hr)	34.8	58.8
Capacity factor = 0.80 (total mills/kW-hr)	29.2	48.0
Capital Δ = 20 percent (Δmills/kW-hr)	1.5	3.6
Fuel Δ = 20 percent (Δmills/kW-hr)	3.2	5.7
Estimated time for construction, yr	3	2
Estimated date of commercial availability	1992	1982

TABLE 5.11-12. - WESTINGHOUSE VALUES OF ALL RELEVANT PARAMETERS FOR LOW- AND HIGH-TEMPERATURE FUEL-CELL POWERPLANTS

Parameter	Aqueous acid system (case 12)	Molten carbonate system (case 4)	Solid electrolyte system		
			Case 4	Case 18	Case 19
Power output, MWe	23.4	1255	1164	219	1064
Fuel-cell rating, MW dc	25	900	900	250	900
Fuel	HBTU	IBTU	IBTU	IBTU	LBTU
Oxidizer	Air	Air	Air	Air	Air
Fuel-cell life, hr	10 000	10 000	10 000	10 000	10 000
Voltage degradation, percent	5	5	5	5	5
Temperature, °C	190	650	1000	1000	1000
Electrolyte type	85 wt % H_3PO_4	Paste of Li, Na, K, carbonates, and alkali aluminates	$(ZrO_2)_{1-x}(Y_2O_3)_x$	$(ZrO_2)_{1-x}(CaO)_x$	$(ZrO_2)_{1-x}(Y_2O_3)_x$
Electrolyte thickness, cm	0.05	0.1	0.004	0.002	0.004
Anode type	Pt/C	Ni	Ni-ZrO_2 - cermet	Ni-ZrO_2 - cermet	Ni-ZrO_2 - cermet
Anode catalyst loading, mg Pt/cm^2	0.3	----------	----------	----------	----------
Cathode type	Pt/C	Lithiated NiO	$In_2O_3/PrCoO_{3-x}$	$In_2O_3/PrCoO_{3-x}$	$In_2O_3/PrCoO_{3-x}$
Cathode catalyst loading, mg Pt/cm^2	0.3	----------	----------	----------	----------
Interconnection type	---	----------	Cr_2O_3	Cr_2O_3	Cr_2O_3
Interconnection thickness, cm	---	----------	0.002	0.002	0.002
Current density, mA/cm^2	200	200	400	800	400
Average cell voltage, V	0.7	0.7	0.66	0.68	0.56
Powerplant efficiency, percent	36.0	54.4	60.2	53.2	45.6
Overall energy efficiency, percent	24.2	45.7	50.6	53.2	47.7
Total plant capital cost, million dollars:	9.64	569.90	539.05	205.46	893.28
Fuel processing equipment	0.645	2.30	2.41	52.36	75.37
Fuel-cell system	2.4	171.00	142.00	18.80	167.00
Steam turbine generator	0	11.72	11.52	0	0
Oxygen plant	0	0	0	0	0
Heat-recovery steam generator	0.086	20.20	15.62	0.211	11.80
Recuperator	0	4.84	18.4	4.20	28.00
Power conditioning	1.38	59.00	59.00	17.50	59.00
Capital cost, $/kWe					
Result breakdown:					
Total major-component cost, million dollars	4.51	269.06	248.95	93.87	341.17
Total major-component cost, $/kWe	193.74	227.74	215.40	429.58	327.96
Balance-of-plant cost, $/kWe	39.93	18.38	15.57	39.59	36.98
Site labor cost, $/kWe	42.70	29.47	33.35	137.54	89.08
Total direct cost, $/kWe	276.37	275.58	264.32	606.71	45[illegible].03
Indirect costs, $/kWe	21.78	15.03	17.01	70.14	45.43
Profit and owner costs, $/kWe	22.11	22.05	21.15	48.54	36.32
Contingency cost, $/kWe	12.44	22.05	21.15	36.40	38.59
Escalation cost, $/kWe	19.00	68.62	66.35	89.81	130.94
Interest during construction, $/kWe	19.46	79.04	76.43	96.71	153.38
Total capitalization, $/kWe	371.16	482.370	456.40	948.31	858.70
Cost of electricity, mills/kW-hr:					
Capital component	11.73	15.25	14.74	29.98	27.15
Fuel component	25.01	12.55	11.34	5.47	6.35
Operating-and-maintenance component	9.85	16.05	14.16	12.25	18.40
Total	46.68	43.85	40.24	47.70	51.89
Estimated time for construction, yr	1.5	5	5.0	3.0	5.5
Estimated date of commercial availability	1990	1990+	2000+	2000+	2000+

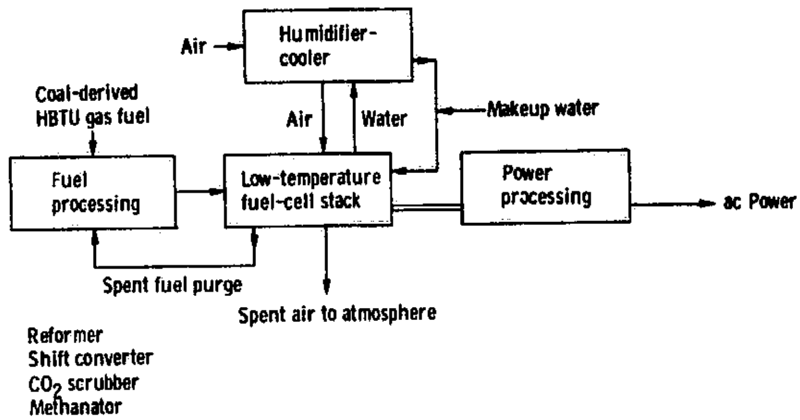


Figure 5.11-1. - Simplified schematic of General Electric low-temperature solid-polymer-electrolyte fuel-cell powerplant base case.

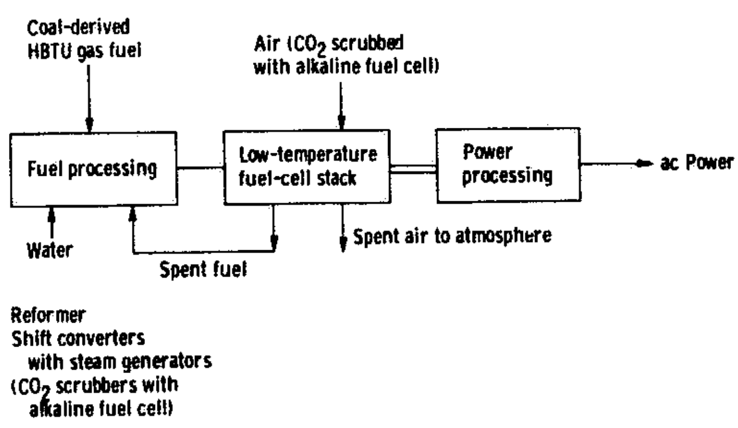


Figure 5.11-2. - Simplified schematic of Westinghouse low-temperature acid (H_3PO_4) and alkaline (KOH) fuel-cell powerplant base cases.

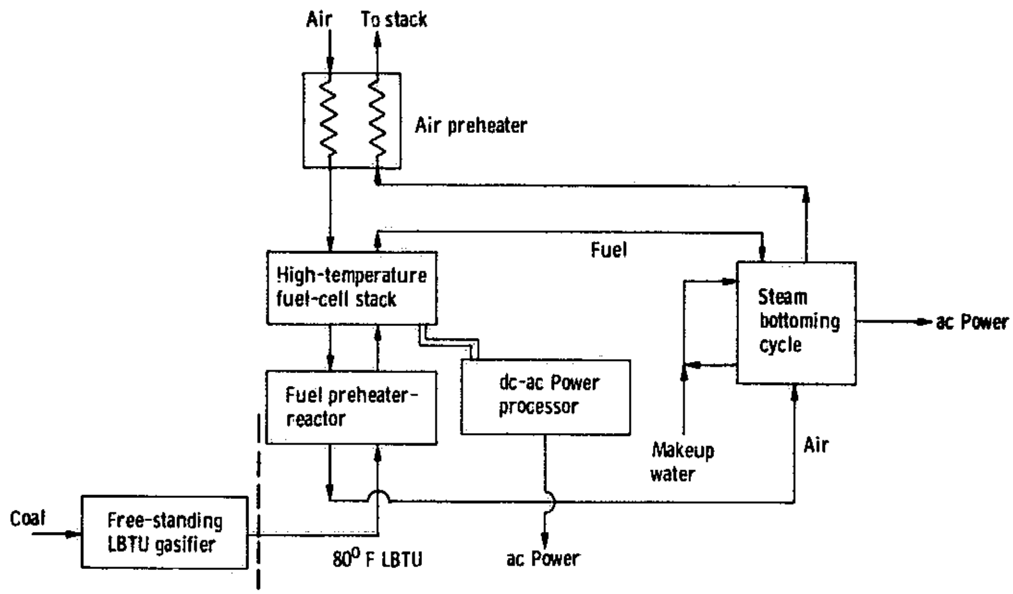


Figure 5.11-3. - Simplified schematic of General Electric high-temperature zirconia fuel-cell powerplant base case.

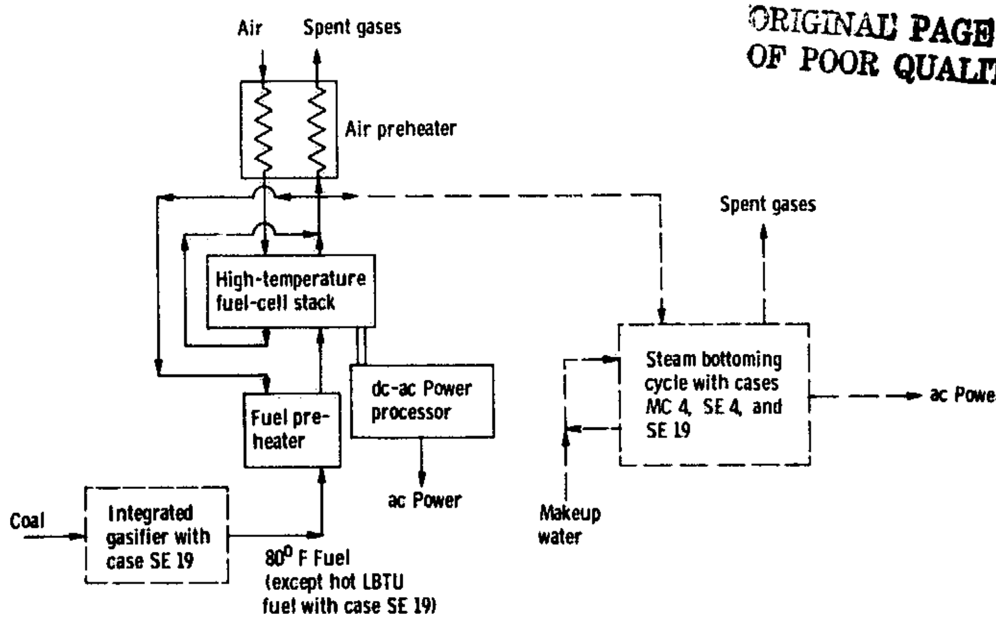


Figure 5.11-4. - Simplified schematic of Westinghouse high-temperature molten carbonate and zirconia fuel-cell powerplant base cases.

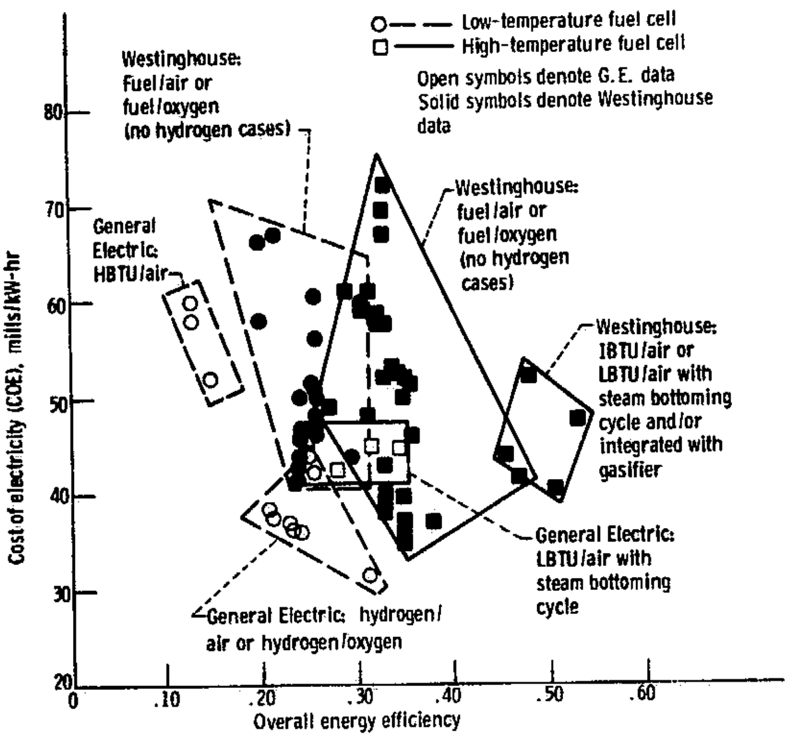


Figure 5.11-5. - Energy efficiency - cost of electricity map for various types of fuel-cell powerplants.

5.12 ORGANIC BOTTOMING CYCLES
by Robert J. Stochl

The use of an organic Rankine cycle as a bottoming plant to a gas turbine offers the potential for the economical utilization of energy that would otherwise be wasted. Organic fluids are considered because they are well suited for the medium temperature levels available and offer a good compromise between bottoming-cycle efficiency and efficient recovery of the gas turbine's waste heat. Additional electric power is generated by the bottoming cycle with no additional fuel consumption. Whether the use of a bottoming cycle is economically advantageous depends on the value of the additional power generated compared with the additional capital cost expenditure. In Phase 1 of ECAS both General Electric and Westinghouse evaluated the use of an organic Rankine cycle to bottom both recuperated open-cycle gas-turbine systems and closed-cycle gas-turbine systems. This section discusses these results and where appropriate compares them with those obtained for the unbottomed prime cycle.

5.12.1 Scope of Analysis

5.12.1.1 Recuperated Open-Cycle Gas Turbine/Organic Rankine Systems

A comparison of the contractors' parametric points for combined recuperated open-cycle gas turbine/organic Rankine systems is presented in table 5.12-1. Schematics of General Electric's and Westinghouse's bottoming-cycle configurations are shown in figures 5.12-1 and 5.12-2, respectively. The gas-turbine recuperator exit temperature (gas temperature input to the organic boiler) for the General Electric prime cycles was 828° F (except case 31, which used 808° F; fig. 5.12-1). For this temperature range, General Electric, with Thermo Electron Corporation (TECO) as subcontractor, selected Fluorinol-85 (FL-85) as the organic working fluid in regenerative subcritical bottoming cycles. The organic turbine-inlet conditions used were 600° F and 700 psia in all cases. The only variation in the bottoming-cycle state points was for case 36, where a wet cooling tower was assumed. Dry cooling tower cases used a 99.1° F organic condensing temperature; a 92° F condensing temperature is used for the wet cooling tower case. Organic boiler pinch-point temperatures of 30°, 50,° and 70 ° F were evaluated. Pinch point is defined as the minimum local temperature difference between the prime-cycle fluid and the bottoming-cycle fluid occurring anywhere in the heat exchanger.

The gas-turbine recuperator exit temperatures for Westinghouse's prime cycles were 708° F for the cases using 2000° F gas-turbine-inlet temperature and 1090° F for the 2500° F gas-turbine-inlet temperature case(fig. 5.12-2). For the 708° F gas temperature to the organic boiler, Westinghouse selected cases with R-12 or methylamine in a supercritical Rankine cycle. The organic turbine-inlet conditions were 600° F and 2500 psia. The use of R-12 at 600° F is questionable from the standpoint of thermal stability. This point will be discussed later. For the 1090° F gas temperature to the organic boiler, Westinghouse selected sulfur dioxide as the working fluid (also in a supercritical Rankine cycle) with turbine-inlet conditions of 1000° F and 2500 psia. While not an organic fluid, sulfur dioxide was used because of its thermal stability at the higher temperatures.

5.12.1.2 Closed-Cycle Gas Turbine/Organic Rankine Systems

A comparison of the contractors' parametric points for the combined closed-cycle gas turbine/organic Rankine systems is presented in table 5.12-2.

Schematics of General Electric's and Westinghouse's bottoming-cycle configurations are shown in figures 5.12-3 and 5.12-4, respectively.

For General Electric's 0.85 recuperator effectiveness the primary fluid temperature out of the recuperator was 463° F, for the 0.90 recuperator effectiveness it was 434° F, and for the 0.60 recuperator effectiveness it was 611° F. The 463° and 434° F primary fluid temperatures are considerably below the optimum temperature capability of FL-85. Therefore General Electric selected R-22 as the organic fluid in a supercritical bottoming cycle. The R-22 bottoming cycle has parametric variations in turbine-inlet temperature and pressure and also variations in organic boiler pinch point. FL-85 was used as the bottoming fluid for the 611° F primary fluid temperature at the exit of the recuperator.

In the Westinghouse scheme, heat is added to the bottoming cycle by the helium gas-turbine exhaust and a "pump up" turbine exhaust (fig. 5.12-4). The Westinghouse pump-up cycle is used for furnace pressurization; it consists essentially of an open-cycle gas-turbine system driven by the exhaust gases of a pressurized furnace. This scheme provides an additional heat source that is not available in General Electric's systems using atmospheric fluidized beds. The helium gas temperature at the helium-cycle organic vapor generator was 979° F. The exhaust gas from the pump-up portion of the cycle to the organic vapor generator was at 1193° F. Westinghouse selected the same three bottoming fluids here as they used to bottom the open-cycle cases. Two cases (46 and 47) used R-12 with turbine-inlet conditions of 700° F and 2500 psia. The bottoming cycle in case 46 used a desuperheating recuperator (not shown in the figure); case 47 did not. Four cases used methylamine with variations and heat rejection methods in turbine-inlet conditions as shown in table 5.12-2. One case used sulfur dioxide at turbine-inlet conditions of 950° F and 1800 psia.

5.12.2 Results of Analysis

5.12.2.1 Overall Comparisons

5.12.2.1.1 Open-cycle gas turbine/organic Rankine systems. - Figure 5.12-5 presents the cost of electricity (COE) as a function of powerplant effectiveness as determined by both General Electric and Westinghouse for the open-cycle gas turbine/organic systems. Powerplant efficiency is used in these comparisons in order to eliminate the effect of the different fuels (and their conversion efficiencies from coal) that were used by each contractor. Cost of electricity as a function of overall efficiency is presented in figure 5.3-2 as part of the open-cycle gas-turbine system results. The numbers shown with each point represent the contractors' parametric point designations and correspond to those shown in table 5.12-1. Also shown, for comparison purposes, are the results for the unbottomed prime cycles. These two points are shown as solid symbols. Comparing these two points with their respective bottomed results indicates a substantial increase in powerplant efficiency for the bottomed cases. However, in spite of the increased efficiency, the higher capital costs of the bottomed cases result in slightly higher COE. In general, General Electric's and Westinghouse's organic bottomed cycles had approximately the same range of powerplant efficiencies, with General Electric showing slightly lower COE.

With one exception, all General Electric's results are centered around a powerplant efficiency of approximately 42 percent and a COE of approximately 34.2 mills/kW-hr. There is a 0.7-percentage-point decrease in powerplant efficiency and a slight increase in COE for an increase in boiler pinch-point temperature (from 30° to 70° F). This decrease in efficiency is expected; the increase in COE is the result of the increased cost of fuel (caused by the lower efficiency) offsetting the reduction in organic boiler cost. The only variation in the bottoming-cycle parameters was the use of a wet cooling tower for point 36(G.E.). Comparing this point with point 30 (dry cooling tower) shows the penalty in both efficiency and COE in using dry cooling towers.

The Westinghouse results indicate that for the 2000° F primary turbine-inlet temperature, using a methylamine bottoming cycle results in higher efficiency and lower COE than were obtained using R-12. The prime cycle (2500° F turbine-inlet temperature) bottomed with sulfur dioxide working fluid gave the highest efficiency and lower COE than the organic-bottomed cycles.

5.12.2.1.2 Closed-cycle gas turbine/organic Rankine systems. - Figure 5.12-6 presents the COE and powerplant efficiency determined by both contractors for the organic-bottomed, closed-cycle gas-turbine systems. Here again the numbers shown with each point correspond to the respective contractor's parametric points shown in table 5.12-2. Also shown for comparison purposes are the unbottomed prime-cycle base cases. Direct comparison between contractors is difficult because they used substantially different configurations (see section 5.5 for a complete description).

With R-22 as the organic fluid, General Electric's results show a powerplant efficiency range between 35.5 and 37.8 percent at a COE between 40.8 and 42.1 mills/kW-hr. The one case using FL-85 as the organic fluid had a powerplant efficiency of 35.3 percent at a COE of 37.8 mills/kW-hr. This COE is approximately 3.0 mills/kW-hr less than that obtained using R-22; it is also 1.0 mill/kW-hr less than the prime-cycle base case as a result of the lower cost of the 0.60 effectiveness recuperator that was used in the top part of this cycle. (An 0.85 effectiveness recuperator was used in the base case.)

Westinghouse has a slightly greater spread (between 3 and 4 percentage points) on powerplant efficiency for both organic working fluids, accompanied by a larger spread in COE. The effect of adding a desuperheater to the R-12 organic cycle (case 46) is to increase combined-cycle efficiency and to decrease COE. The effects of various heat rejection methods are compared, with methylamine as the organic fluid, in cases 48, 50, and 51. Case 48 rejects heat through a water circuit to a wet cooling tower, case 50 rejects heat through a water circuit to a dry cooling tower, and case 51 rejects heat directly to a dry cooling tower. As indicated in the figure the wet cooling tower results in the highest efficiency and lowest COE. Case 49 is bottomed to a cycle with a 1100° F pump-up turbine-inlet temperature and shows the lowest efficiency and largest COE of the four methylamine cycles. The one sulfur dioxide cycle considered resulted in an efficiency of 42.5 percent (comparable to the best methylamine cycle) at the lowest COE of any of the bottoming cycles.

5.12.2.2 Discussion and Assessment

5.12.2.2.1 Open-cycle gas turbine/organic Rankine systems. - As shown in figure 5.12-5 the addition of an organic bottoming cycle appreciably increases the powerplant efficiency, but the results of both contractors indicate that the COE also increased. The increase in capital cost more than offset the effect of increased efficiency. Figure 5.12-7 shows both the COE and the total capital cost in $/kWe for both contractors. Although the COE's for the bottomed cycles are approximately the same for both contractors, Westinghouse has the higher capital cost (by approximately $100/kWe). The reason for this is as follows: the total COE consists of charges for capital, fuel, and operating and maintenance (O and M). The fuel cost portions of COE for both contractors are approximately the same as a result of the closeness of their efficiency values. Westinghouse is higher on the capital cost portion (the $100/kWe value), but General Electric is higher on the O and M costs. The net result is approximately the same total COE.

Shown for comparison purposes are both contractors' unbottomed prime-cycle points. A comparison of these points with their respective bottomed cycles indicates that, under the ground rules used in this study, it is not cost effective (in terms of either COE or capital cost) to use organic bottoming on open-cycle gas turbines.

A breakdown of the total capital cost ($/kWe) for both contractors is shown in table 5.12-3. The values shown for the General Electric organic bottomed point (case 30) are representative of all the 2200° F prime-cycle turbine-inlet temperature cases. Although, as stated previously, there is reasonably good agreement between the contractors' values for the COE (mills/kW-hr), there are some rather large differences in some of the categories in the breakdown of the total capital cost ($/kWe) in table 5.12-3.

Major component costs as reported by the contractors are nearly the same, especially for the bottoming cycle. However, balance-of-plant (BOP) costs for Westinghouse were almost twice those of General Electric. (This difference is also true for the two prime cycles.) General Electric's contingency costs, on the other hand, are at least 2.6 times those of Westinghouse. But the Westinghouse escalation and interest costs were higher than General Electric's because of the difference in the estimated time of construction between the two contractors.

As stated previously, the estimated increase in capital cost, by adding an organic bottoming cycle, more than outweighs the effects of increased efficiency and results in a higher COE than the unbottomed prime cycle. As shown in table 5.12-3 the capital costs (in $/kWe) of the bottomed cycles are substantially greater than those of the unbottomed cycles for both contractors. Also shown in table 5.12-3 are the incremental costs for General Electric's case 30 and Westinghouse's case 95. The incremental cost is defined here as the difference in capital cost between the combined gas-turbine/organic cycle plant and the unbottomed gas turbine divided by the power output of the organic bottoming cycle. If this difference in capital cost between the bottomed and unbottomed cycles is attributed entirely to the organic cycle, the incremental cost is merely the bottoming-cycle cost in dollars divided by the bottoming-cycle power in kilowatts. As shown in the table the costs of the organic-cycle major components in terms of the organic-cycle power output are $166/kWe and $250/kWe for General Electric (case 30) and Westinghouse (case 95), respectively; and the total incremental costs for these two bottoming-cycle cases are $878.5/kWe and $2053/kWe, respectively. These total values include substantially larger BOP costs and large incremental increases in the interest and escalation charges. Both contractors estimated that the bottomed-cycle plants would take longer to build. As a result the incremental bottoming-cycle cost includes the effect of larger escalation and interest charges for the entire plant over the longer construction period. From these values it is apparent that the increased capital cost lies in the high balance-of-plant (BOP) costs assigned to the organic bottoming plant by both contractors' architect-engineers. Further study of the BOP for such plants is required before any conclusion is reached about the cost effectiveness of organic bottoming cycles.

5.12.2.2.2 <u>Closed-cycle gas turbine/organic Rankine systems</u>. - As in the case of the open-cycle gas-turbine systems, the contractors' results indicated that the increased capital cost of a system with organic bottoming more than offset the effect of the increased efficiency and that the resulting COE increased over the unbottomed case. Figure 5.12-8 shows the COE and the capital cost for both contractors. The General Electric results using R-22 show that the COE is around 41.5 mills/kW-hr with a capital cost of $960/kWe (which is slightly greater than that obtained with steam bottoming and approximatlely 20 percent more costly than the unbottomed base case). The General Electric case using FL-85 (with 0.6 effectiveness recuperator) has a 3- to 4-mill/kW-hr decrease in COE compared with the R-22 cases and 1 mill/kW-hr less than the unbottomed base case. The capital cost using FL-85 was between $85/kWe and $125/kWe less than that using R-22 but about $50/kWe more than the unbottomed base case.

The Westinghouse results show a larger spread in both COE and capital cost using R-12 and methylamine. Both fluids have approximately the same range of values for COE with the methylamine cycles having the larger capital cost. The sulfur dioxide cycle has the lowest capital cost of the Westinghouse fluids. Comparisons should not be made in this figure between the costs of the two contractors because of the large differences in topping-cycle configurations, including the fact that the Westinghouse cases are clean-fuel fired as compared with General Electric's coal-fired AFB cases.

A breakdown of the total capital cost ($/kWe) for both contractors is shown in table 5.12-4. The cases shown in this table are representative of each organic fluid that was selected by each contractor. Also shown for comparison is General Electric's unbottomed base case (case 1). Westinghouse did not evaluate the particular unbottomed prime cycle used with the organics.

Comparing General Electric's bottomed cycle using R-22 (case 35) with the unbottomed base case indicates that even though the cost of the major components decreased (on a $/kWe basis) for the bottomed case, the total capital cost increased by $139.8/kWe because of increased BOP, contingency, escalation, and interest charges. The additional year of estimated construction time adds about $71/kWe to interest and escalation charges, which results in an additional 2.2 mills/kW-hr to the COE. Therefore, if the construction time could be reduced to 4 years (instead of the 5 yr estimated), the total COE for case 35 would be the same as for the base case. The even larger reduction in major component cost using FL-85 is primarily due to the decrease in prime-cycle component cost as the result of using a 0.6 effectiveness recuperator instead of the 0.85 value used in the base case. The increased BOP, escalation, and interest charges more than offset this major component reduction and resulted in a net increase in capital cost of $48.5/kWe for the FL-85 case compared with the base case. The additional year of construction time for the FL-85 case added approximately $64/kWe to the interest and escalation charges and resulted in a 2.0-mill/kW-hr increase in the COE. If the construction time for this case could be reduced to 4 years the resulting COE would be approximately 3.0 mills/kW-hr less than for the base case.

Also shown in table 5.12-4 is the incremental cost of General Electric's case 35. The cost of the organic-cycle major components in terms of organic power output is $239.4/kWe. The total incremental cost is $1537.9/kWe, which again includes substantially larger BOP cost and large increases in interest and escalation charges.

A breakdown of the major component cost into those associated with the prime and bottoming cycles could not be accomplished from the Westinghouse results. As mentioned previously, Westinghouse did not evaluate the unbottomed prime cycle, so the direct effect on capital cost for a bottoming plant could not be determined.

Direct comparison between contractors for these cases should not be used to draw conclusions concerning the organic bottoming cycles because of the substantial differences in configuration (i.e., the additional pump-up cycle). At approximately the same power levels, the Westinghouse total capital costs are about one-half those of General Electric. The reasons for this are in part that approximately 30 percent of the total cycle power is provided by the cheaper open-cycle gas turbine of the pump-up cycle and that the Westinghouse cases are clean-fired while the G.E. cases are coal-fired AFB's.

As mentioned earlier, General Electric performed parametric variations on bottoming-cycle turbine-inlet temperature and pressure and also variations in organic boiler pinch-point temperature differential for the R-22 fluid. The effects of these variations on efficiency and COE are shown in figure 5.12-9. As indicated in part (a) of this figure, as turbine-inlet temperature is increased, efficiency increases and total COE decreases (primarily due to the increased power produced from the bottoming cycle). Figure 5.12-10 presents a set of NASA Lewis calculations that show the effect of an extended range of turbine-inlet temperatures on the combined-cycle efficiency for three turbine efficiencies. Also shown in this figure are the thermodynamic efficiencies for the cases shown in figure 5.12-9(a). The NASA Lewis results are in agreement with General Electric's and indicate that the thermodynamic efficiency reaches a maximum at approximately 470° F. The 430° F General Electric point is within 0.3 percentage point of this maximum efficiency and is the maximum temperature consistent with their topping-cycle parameters. Figure 5.12-9(b) indicates decreased efficiency and increased COE for increased boiler pinch-point temperature differential. The decrease in the organic boiler cost resulting from the increased log mean temperature difference was not sufficient to compensate for the higher fuel costs due to the reduced efficiency. Figure 5.12-9 (c) shows that the use of a dry cooling tower decreases the efficiency and increases the COE.

5.12.3 Concluding Remarks

Potentials of bottoming both open and closed gas-turbine cycles were considered by both contractors. Their results indicate that bottomed open-cycle gas-turbine systems substantially increased powerplant efficiency compared with an unbottomed system. However, the capital cost estimates doubled, resulting in no net reduction in the cost of electricity. The same general statement can be made of bottoming a closed-cycle gas-turbine system, with two exceptions. Both contractors had one parametric variation (G. E. case 40, Westinghouse case 52) that increased powerplant efficiency and reduced the projected COE compared with the unbottomed base case. These results might be different under other ground rules (see section 4.2). For example, considering the average plant lifetime COE would increase the relative importance of fuel costs and make organic bottoming more attractive. It was also shown earlier that both contractors estimated substantially larger incremental BOP charges for these bottoming cycles, as well as longer construction periods. Since capital cost and construction time estimates were made without detailed BOP designs, a general conclusion that organic bottoming is not cost-effective cannot be made without further investigation.

Westinghouse use of R-12 at temperatures much above 400° F is contrary to information available from Dupont. These data indicate that R-12 decomposes rapidly at temperatures exceeding 400° F. In order to possibly use it to 700° F, it must be completely free from air, oil, and water, which is highly improbable in a practical system.

TABLE 5.12-1. - PARAMETRIC VARIATIONS FOR COMBINED OPEN-CYCLE GAS TURBINE/ORGANIC RANKINE SYSTEMS

Parameter	General Electric						Westinghouse		
	Case								
	30	31	34	35	36	37	95	96	97
Gas-turbine-inlet temperature, °F	2200	2200	2200	2200	2200	1800	2000	2000	2500
Gas-turbine pressure ratio	12	12	12	12	12	12	8	8	16
Recuperator effectiveness	0.85	0.85	0.85	0.85	0.85	0.85	0.80	0.80	0
Recuperator pressure drop, $\Delta P/P$	0.05	0.05	0.05	0.05	0.05	0.05	0.03	0.03	0
Bottoming-cycle fluid	FL-85	FL-85	FL-85	FL-85	FL-85	FL-85	R-12	Methyl-amine	SO_2
Bottoming-cycle turbine-inlet temperature, °F	600	600	600	600	600	600	600	600	1000
Heat rejection method (cooling tower type)	Dry	Dry	Dry	Dry	Wet	Dry	Wet	Wet	Wet
Boiler pinch-point ΔT, °F	30	30	50	70	30	30	----	----	----
Bottoming-cycle power, MW	23.5	23.6	22.7	21.9	24.3	19.1	16	20	78
Total power, MW	102	101	102	101	103	76	97	101	233

TABLE 5.12-2. - PARAMETRIC VARIATIONS FOR COMBINED CLOSED-CYCLE GAS TURBINE/ORGANIC RANKINE SYSTEMS

Parameter	General Electric								Westinghouse						
	Case														
	34	35	36	37	38	39	40	41	46	47	48	49	50	51	52
Prime-cycle turbine-inlet temperature, ^{o}F	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
Prime-cycle pressure ratio	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Recuperator effectiveness	0.85	0.85	0.85	0.85	0.85	0.85	0.60	0.90	0	0	0	0	0	0	0
Recuperator pressure drop, $\Delta P/P$	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	---	---	---	---	---	---	---
Heat rejection method (cooling tower type)	Wet	Wet	Wet	Wet	Wet	Dry	Wet	Wet	Wet	Wet	Wet	Wet	Dry	(c)	Wet
Pump-up cycle turbine-inlet temperature, ^{o}F	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	2200	2200	2200	1100	2200	2200	2200
Pump-up cycle pressure ratio	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	10	10	10	10	10	10	10
Bottoming-cycle turbine-inlet temperature, ^{o}F	430	410	390	410	390	430	460	400	700	700	500	450	500	500	950
Bottoming-cycle turbine-inlet pressure, psia	1700	1700	1700	1600	1500	1700	650	1500	2500	2500	2500	2000	2500	2500	1800
Bottoming-cycle working fluid	R-22	R-22	R-22	R-22	R-22	R-22	FL-85	R-22	R-12	R-12	(b)	(b)	(b)	(b)	SO_2
Boiler pinch-point ΔT, ^{o}F	30	30	30	50	70	30	50	30	40	40	40	40	40	40	40
Bottoming-cycle power, MW	69	66	64	63	57	65	144	60	165	128	105	111	100	105	209
Total power, MW	344	342	340	338	333	340	408	337	364	327	413	450	400	413	408

[a] Not applicable.
[b] Methylamine.
[c] Direct condensing.

TABLE 5.12-3. - CAPITAL COST BREAKDOWN FOR OPEN-CYCLE GAS TURBINE/ORGANIC RANKINE SYSTEMS

	General Electric			Westinghouse			
	Case		Incremental cost of bottom cycle for case 30	Case			Incremental cost of bottom cycle for case 95
	30	6		95	97	31	
	Cost, \$/kWe						
Major components:							
Prime cycle	82.0	101.7	-----	73.1	53.6	104.6	------
Bottoming cycle	39.0	0	-----	40.6	67.5	0	------
Total	121.0	101.7	166.0	113.7	121.1	104.6	250.8
Balance of plant	113.3	22.8	411.2	219.9	181.6	65.2	1187.8
Contingency	46.9	24.9	115.6	18.0	17.8	8.1	82.9
Escalation	31.4	9.7	102.0	48.9	52.6	16.8	252.4
Interest	25.8	8.0	83.7	53.5	58.7	17.7	279.9
Total capital cost	338.4	167.0	878.5	454.0	431.8	212.4	2053.0
Bottoming-cycle working fluid	FL-85	---	-----	R-12	SO_2	---	------
Estimated time of construction, yr	2	1	-----	3.5	4.0	2.5	------

TABLE 5.12-4. - CAPITAL COST BREAKDOWN FOR CLOSED-CYCLE GAS TURBINE/ ORGANIC RANKINE SYSTEMS

	General Electric				Westinghouse		
	Case			Incremental cost of bottom cycle for case 35	Case		
	30	40	1		46	48	52
	Cost, \$/kWe						
Major components:							
Prime cycle	239.2	189.6	294.5		-----	-----	-----
Bottoming cycle	44.7	35.3	0		-----	-----	-----
Total	283.9	224.9	294.5	239.4	136.5	144.0	130.2
Balance of plant	240.2	249.0	188.4	456.1	170.9	208.3	149.4
Contingency	104.8	94.8	96.6	137.9	20.4	23.9	18.8
Escalation	150.3	135.9	112.5	309.1	66.3	78.0	61.7
Interest	174.9	158.1	122.2	395.5	76.2	90.0	71.2
Total capital cost	954.0	862.7	814.2	1537.9	470.3	544.2	431.3
Bottoming-cycle working fluid	R-22	FL-85	-----		R-12	(a)	SO_2
Estimated time of construction, yr	5	5	4		5	5	5

[a]Methylamine.

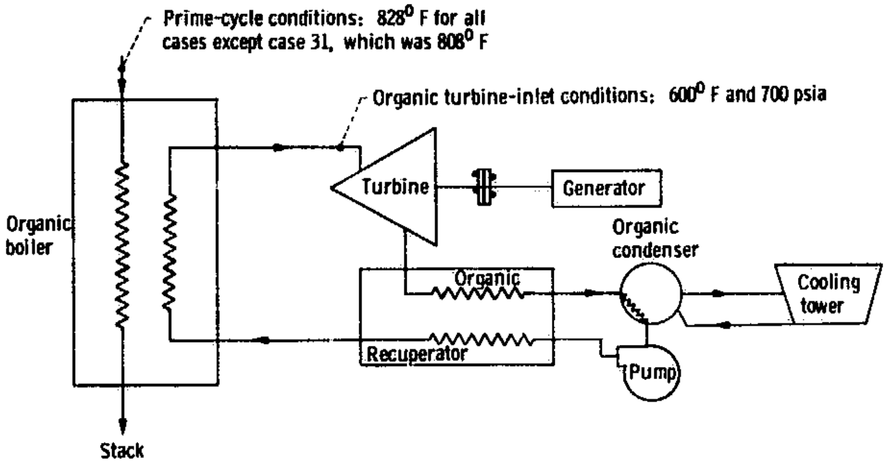


Figure 5.12-1. - Schematic of General Electric organic Rankine bottoming cycle to open gas turbine.

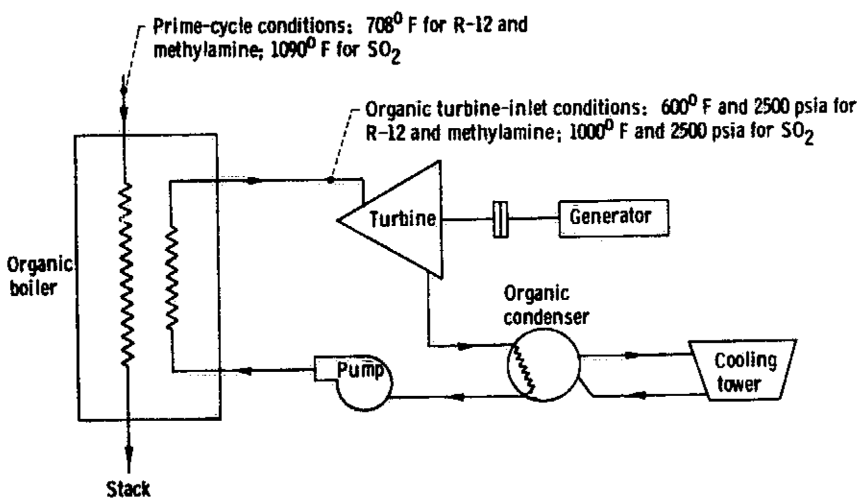


Figure 5.12-2. - Schematic of Westinghouse organic Rankine bottoming cycle to open gas turbine.

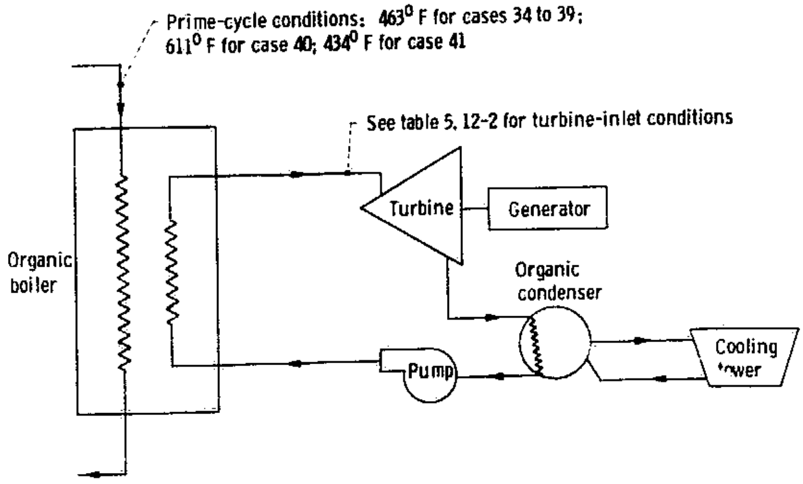


Figure 5.12-3. - Schematic of General Electric organic Rankine bottoming cycle to closed gas turbine.

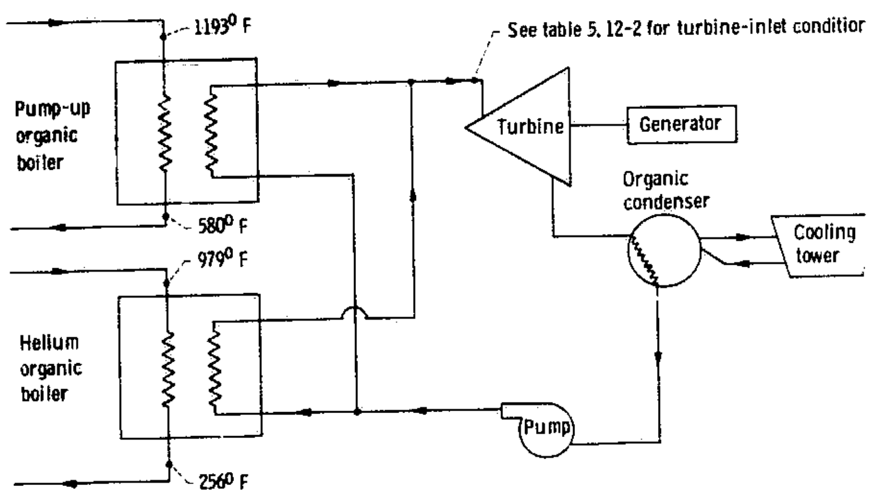


Figure 5.12-4. - Schematic of Westinghouse organic Rankine bottoming cycle to closed gas turbine.

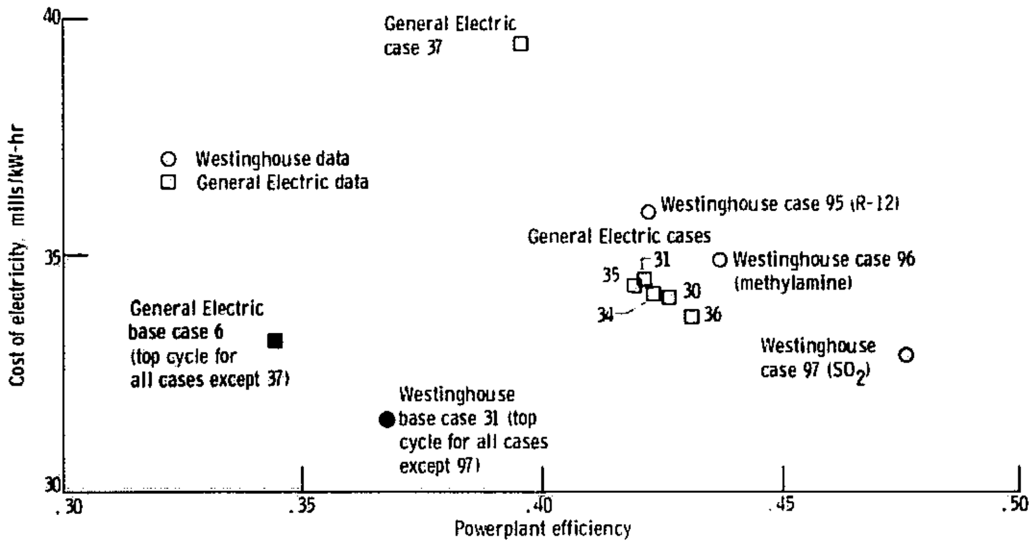


Figure 5.12-5. - Effect of powerplant efficiency on cost of electricity for open-cycle gas turbine/organic Rankine systems.

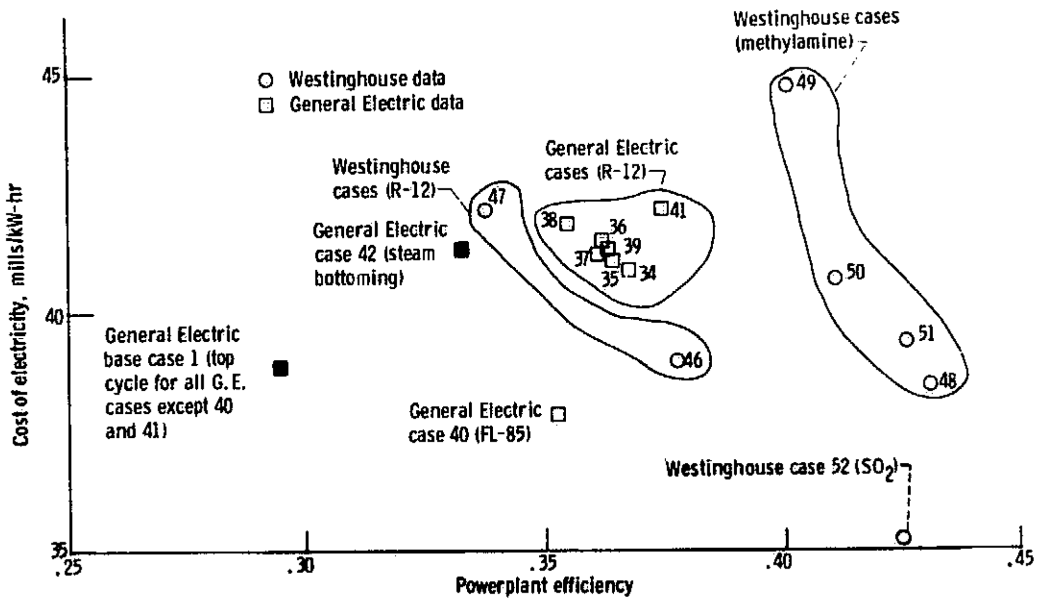


Figure 5.12-6. - Effect of powerplant efficiency on cost of electricity for closed-cycle gas turbine/organic Rankine systems.

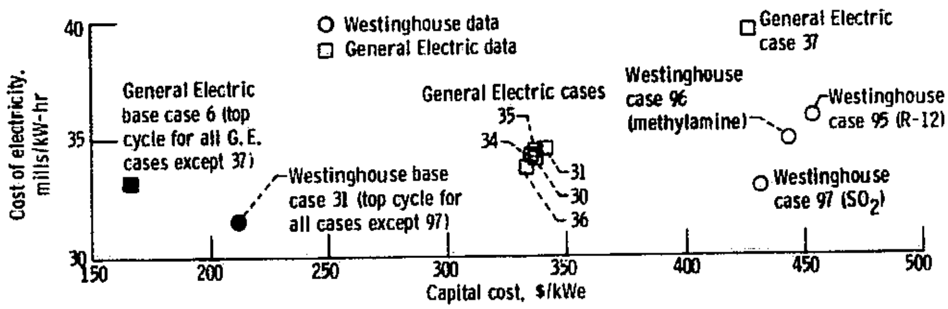


Figure 5.12-7. - Effect of capital cost on cost of electricity for open-cycle gas turbine/organic Rankine systems.

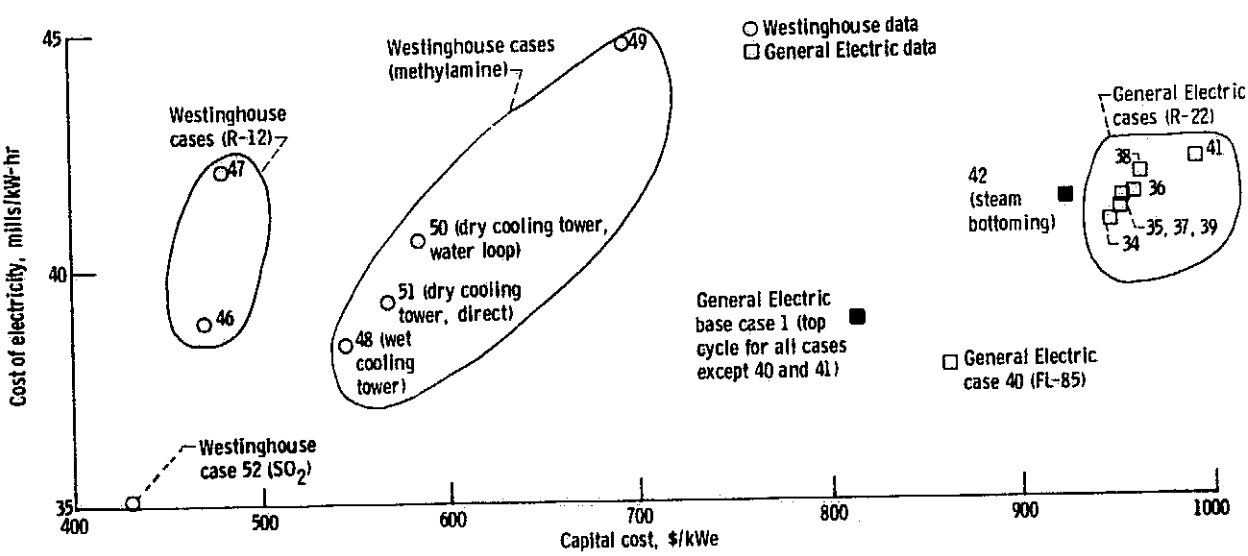
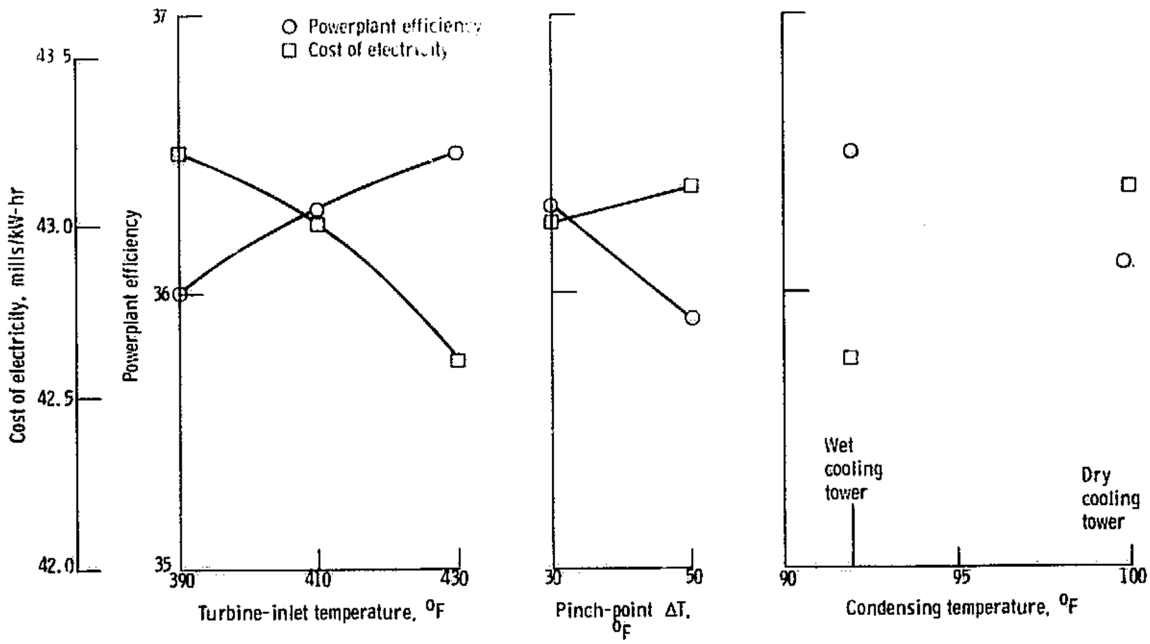


Figure 5.12-8. - Effect of capital cost on cost of electricity for closed-cycle gas turbine/organic Rankine systems.



(a) Variation in turbine-inlet temperature; pinch-point ΔT, 30° F; condensing temperature, 92° F.

(b) Variation in pinch-point ΔT; turbine-inlet temperature, 410° F; condensing temperature, 92° F.

(c) Variation in condensing temperature; turbine-inlet temperature, 430° F; pinch-point ΔT, 30° F.

Figure 5.12-9. - Effect of General Electric bottoming-cycle variations on powerplant efficiency and cost of electricity. Topping cycle is G.E.'s closed gas turbine case 1; organic fluid is R-22.

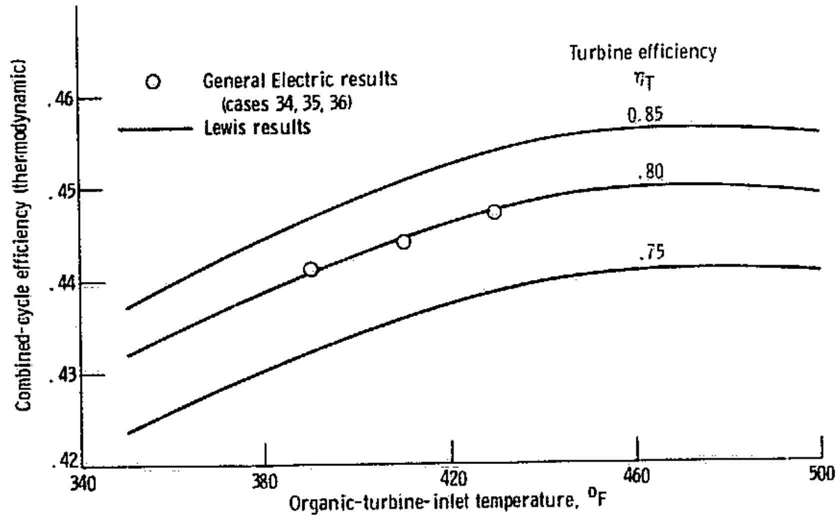


Figure 5.12-10. - Effect of organic-turbine-inlet temperature on combined-cycle efficiency for three bottoming-cycle turbine efficiencies. Topping cycle, closed gas turbine; efficiency, 0.356. Bottoming cycle: fluid, R-22; turbine-inlet pressure, 1700 psi (supercritical); condensing temperature, 94.1° F.

5.13 MATERIALS

by Salvatore J. Grisaffe, Robert L. Davies, Robert L. Dreshfield, and Marvin Warshay

The Materials Advisory Group (MAG) reviewed, evaluated, summarized, compared, and commented on the materials requirements as well as on the materials selected for both the General Electric and Westinghouse systems analyzed in ECAS Phase 1. This review involved all base-case materials needs, as well as those for any other significantly different systems, and included consideration of the following:

(1) Contractors' estimates of the date of commerical readiness and the plant construction time to provide an indication of the time frame in which materials must be developed and demonstrated

(2) Contractors' proposed system operating conditions to provide for the reader a capsule view of the system requirements in relation to MAG-identified critical components and materials needs

(3) A summary of MAG-identified critical components including only those components MAG identified to be materials, life, or fabrication critical

(4) Materials the contractors selected for these critical components

(5) Contractors' assumptions and a short summary of the stated basis for materials selection, if given

(6) Contractors' estimates of the maturity or state of the art of the materials selected as related to the specific application and system

(7) MAG view of the key materials-related uncertainties in each system

(8) MAG view of the technology advances required to ensure that cost-effective materials would be available for the critical components when the construction is scheduled to begin

(9) MAG estimate of the probability that adequate materials could be developed and demonstrated by the time they would be needed for plant construction (This estimate reflects the MAG judgement of the difficulty of the major problems as well as the time frame available for their solution.)

Caution is necessary since this review is based on very preliminary Phase 1 designs. More detailed designs and cost information, trade-offs between critical component life and initial component and materials costs, the development of realistic data bases for some of the unusual environments and system requirements, etc., have yet to be established. Thus, at this time the MAG comments mainly reflect their view of how reasonable the materials selections were, based on the information available. For example, MAG did not attempt to judge the relative merits of one contractor's proposed cast nickel superalloy over the other's for similar open-cycle gas turbine service.

In addition, it must also be recognized that for the mature conversion systems, the materials state of the art is also mature, and extrapolations to longer times or somewhat more severe conditions are on a sounder basis. Furthermore, for mature systems at least first-approximation analytical techniques have been developed for design and life estimation as well as for estimation of maintenance costs. The less mature a system is, the less well founded are the materials selection criteria, and the less accurate are the MAG judgements as well. This applies to both higher performance (temperature, life, etc.) versions of mature systems as well as to systems that still require demonstration of commercial feasibility.

The results of this review are summarized in table 5.13-1, are detailed in tables 5.13-2 to 5.13-12, and are briefly discussed in the following paragraphs.

5.13.1 Open-Cycle Gas Turbines

Materials required for air-cooled, open-cycle gas turbines, alone or combined with a steam bottoming cycle, were evaluated by MAG (table 5.13-2). The major concerns are the lack of experience with such cooled machinery over the projected lifetimes - 50,000 to 100,000 hours for hot-gas-path components - and the lack of knowledge on the extent of the probable corrosion from impurities in the low-Btu (LBTU) gas or other coal-derived fuels. Within the time frame proposed - materials ready by about 1979 - MAG judges the probability of reaching such long lives as moderately high. However, the proposed low metal temperatures (approx 1650° F) must be achieved, fuels must be clean, and true base-load operating conditions (few shutdowns and startups and little load-following) must be followed. Although 2200° F-turbine-inlet-temperature machines could be built and operated today on "semi-clean" fuels, replacement or hot-gas-path components would probably be much more frequent than anticipated, possibly in the 5000- to 10,000-hour range at best. The long-time utilities operation of even more advanced machines, with 2400° to 2500° F turbine-inlet temperatures, is beyond the current state of the art. Here, in particular, long-lived combustor materials technology is lacking.

For even higher temperature machines, with water-cooled static and/or rotating components (table 5.13-3) or with ceramic airfoils, the problems of reasonable life demonstration and fabrication of the more complex, large, utilities-sized hardware have yet to be solved. With a somewhat longer time available for development of these machines (materials must be ready about 1982), there is a moderate probability of having the materials ready if a major technology effort is made. Again, replacement frequencies close to current technology are anticipated. If such components must have lives in the 50,000- to 100,000-hour range, the probability of having materials developed and demonstrated by 1982 is low for water-cooled airfoils and very low for large ceramic rotating airfoils.

5.13.2 Closed-Cycle Gas Turbines

The closed-cycle gas turbine and supercritical carbon dioxide system base cases (tables 5.13-4 and 5.13-5) are proposed for operation with helium at 1500° F(1000 psi) and with carbon dioxide at 1350° F (3800 psi), respectively. There is a real need for demonstrated, long-lived, heat-source heat-exchanger tubes that are combustion gas resistant since these temperatures are 300° to 500° F beyond the current state of the art for the most advanced steam system boiler tubes. Similarly, it should be proved that the turbine hot-section materials will be compatible with the working fluids/gases over very long times. The carbon dioxide system operates at lower temperatures than the helium systems (but has a higher pressure), and the contractor estimates that the materials must be demonstrated by 1990. Therefore, there is a moderately high probability that suitable materials can be available. For the helium system operating at 1500° F (1000 psi) but with materials requiring demonstration by about 1983, the probability of readiness is considered only moderate. This probability would improve to moderately high if significant evaluation and development work were directed toward appropriate gas-cooled reactor materials in the next several years. For helium systems operating in the 1700° to 1800° F range, MAG has serious concerns about the ultimate availability of long-life, heat-source heat-exchanger tubing. Thus, in all these cases, there is a recurrent need for higher temperature, higher strength, and more-corrosion-resistant heat-source heat-exchanger tubing material to be developed and demonstrated as suitable for long-life, closed-cycle system service.

5.13.3 Organic Bottoming Cycle

For the organic bottoming cycle, the contractors' materials assessments were rather limited. For this reason no separate table was developed. However, from studies of other low-temperature organic cycles, there are no key materials uncertainties from the standpoint of containment or operating component life. The major uncertainties are associated with the fluid-containment materials interactions with the Freon-type working fluid and with the selection of operating temperatures to ensure stability of the working fluid. Above approximately 400° F, degradation of the working fluid can be catalyzed by some materials or can result from leakage of air or oil into the working system.

The MAG assessment of the probability of success for this system is high, provided adequate material-fluid interaction data are available, suitable materials are selected, and temperatures are held to near 400° F so as to insure thermal stability of the working fluid.

5.13.4 Liquid-Metal Rankine Topping Cycle

The liquid-metal topping cycle is based on prior, space-electric-power-related, potassium Rankine studies. It benefits from the extensive work on the liquid metal fast breeder reactor (LMFBR). For the 1400° F potassium (K) case (table 5.13-6), the fire-side corrosion/potassium corrosion data base is not sufficiently well developed to estimate boiler tube life reliably, even though at this temperature K corrosion alone should not be a major barrier. At 1400° F, the K turbine could be built of superalloys. but to design for a 30-year turbine life, long-time corrosion data are needed as well as mechanical property stability data in a K environment. Assuming materials with adequate corrosion resistance are identified, MAG sees no major materials barrier and estimates a moderate probability of success as long as adequate support is provided within the development time available (estimated to be until approx. 1986).

5.13.5 Advanced Steam Systems

For advanced steam systems (table 5.13-7), boiler tube problems should be minimal at 3500 psi/1000° F steam conditions if the following hold true: (1) the fluidized beds adequately remove the sulfur in the coal combustion gases, (2) the low combustion temperatures help minimize hot corrosion/erosion attack due to sulfur and other coal impurities, and (3) higher temperature (more difficult to fabricate) tube materials are not needed (i.e., stainless steel can be used). The MAG then expects the major concerns to center around the turbines used to drive the bed's air compressor since the turbine components will be exposed to the bed's combustion gases with little, if any, hot-gas cleanup. However, for increases in steam temperature to 1200° F and beyond, major improvements in boiler tube materials would be required. Also, since forging large steam turbine rotors from the required higher strength alloys is beyond the state of the art, the aircraft engine concept of separately forged disks and shafts should be given careful attention if 1200° F (and above) steam is ever found to be needed. Therefore, for the state-of-the-art steam conditions, materials for both the atmospheric and the pressurized fluidized beds appear to have very high and moderately high (respectively) probabilities of being ready when needed. In the latter case, pressurizing turbine materials will require considerable development and thus there is a moderately low probability of long-lived materials being ready within the short development time estimated (approx 1979).

5.13.6 Magnetohydrodynamic Systems

Because of the lack of any significant MHD operating experience under full utilities load conditions, MAG generally estimates low probabilities of materials being ready when needed for most variations of the MHD power systems. For very high-temperature, open-cycle systems with approximately 3000° F or greater air preheater temperatures (table 5.13-8), the basis for an unfavorable estimate is more specific: seed/ slag attack and the potential for degradation of the electrodes' electrical properties from seed/slag/electrode interdiffusion or from changes in the slag (input coal) composition. Little real-time data have been obtained in clean or coal-fired systems. Thus, the open-cycle MHD materials development problem appears to be very difficult, and MAG is very uncertain as to the probability of suitable materials being available when needed. Due to such uncertainties, both contractors estimated long times before start of plant construction. A large national MHD materials development and demonstration effort could improve this situation.

The closed-cycle MHD (table 5.13-9) operates at similar or higher heat-exchanger temperatures. Here some of the same considerations apply but, instead of slag, the potential corrodent is cesium seed. A major MAG concern rests with the long-time integrity of the primary heat exchanger and the prevention of combustion gas leakage into the cesium-seeded argon system. If such leaks occur, the refractory-metal electrodes would fail rapidly as a result of oxidation.

The liquid-metal MHD system (table 5.13-10) could draw on the materials technology developed for the liquid-metal fast breeder reactor. Since the materials must only operate in the 1200° to 1400° F range, the problems are potentially less severe. Again, however, the lack of real operating experience gives little basis for estimation. If plant construction is to begin in 1975 (as Westinghouse estimates), the probability of the materials being ready is extremely low. If however, a 1985 date is considered (as by G.E.), there is a moderate probability that the materials could be ready.

5.13.7 Fuel Cells

The technology of low-temperature fuel cells (table 5.13-11) appears to hinge more on the cost of components than on any one major material inadequacy. For the solid polymer electrolyte (SPE) cell, it is the costs of the polymer, the electrode current collectors, and the platinum electrode catalyst that are crucial. At 170° F, current-state-of-the-art SPE cell materials could have useful lives to 100,000 hours. At 300° F, lives less than 10,000 hours are expected. The chances are moderately high for the phosphoric acid cell to reach 40,000-hour lives. The potassium hydroxide system requires advances in carbon dioxide control if lives are to be extended beyond 10,000 hours. And, for all three systems, additional effort will be needed before the fuel processor catalyst life can be confidently predicted or the desired lives achieved.

For higher temperature cells (table 5.13-12), MAG has greater concerns. Corrosion, nickel electrode sintering, and electrolyte loss at 1200° F are three problems that lead to only a moderate probability of having materials ready by about 1988 (Westinghouse estimated date). The very high-temperature

(1832° F) zirconium dioxide cell has a moderately low probability of materials readiness because high-temperature stability has not been proved and because brittle ceramic interconnects are needed.

5.13.8 Concluding Remarks

In the Phase 1 effort, both contractors proposed state-of-the-art materials for all major systems. And, in general, both contractors extrapolated mechanical property data to very long times and assumed no microstructural instabilities. The Materials Advisory Group reviewed these proposals. They concluded that most of the systems could probably be built with the materials proposed but that such materials have not been qualified for lengthy service, especially in many of the new environments. Thus, operating lives are expected to be far less than those estimated or desired. A sound data base is urgently needed to help establish concept viability and to assist designers of pilot/demonstration plants in achieving realistic lifetimes for critical components. Such information would also help in calculating component replacement costs.

TABLE 5.13-1. - MATERIALS ADVISORY GROUP (MAG)

System	Table	Approximate maximum temperature (gas, liquid, turbine inlet, etc.), °F		Critical-component life, hr; or plant life, yr		Estimated year of plant commercial availability		Time to construct plant, yr	
		General Electric	Westinghouse	General Electric	Westinghouse	General Electric	Westinghouse	General Electric	Westinghouse
Open-cycle gas turbine	5.13-2	2200	2200	50 000	100 000	1980	(a)	1	2.5
Air-cooled combined cycle	5.13-2	2200	2200	50 000	100 000	1982		3	4
Water-cooled combined cycle	5.13-3	2800	----	50 000	-------	1986		4	---
Closed helium cycle	5.13-4	1500	1500	100 000	100 000	1987		4	5
Supercritical carbon dioxide cycle	5.13-5	1350	----	100 000	-------	1995		5	---
Liquid-metal topping cycle (metal vapor Rankine)	5.13-6	1550	1800	100 000	100 000	1992		6	6.5
Advanced steam systems	5.13-7	1200	1000	30 yr	100 000	1987		5	5-6
Open-cycle MHD	5.13-8	2950	2990		-------	1997	1990	7	8
Closed-cycle MHD	5.13-9	>3000	3800		-------	2000	1990	6	8
Liquid-metal MHD	5.13-10	1300	1200		30 yr	1991	1983	6	8
Solid-polymer-electrolyte fuel cell	5.13-11	170	----	100 000	-------	1986	----	2	---
Phosphoric acid fuel cell	5.13-11	375	375	40 000	10 000	1982	1985	2	1.5
Potassium hydroxide fuel cell	5.13-11	----	158	-------		----	1985	---	
Molten carbonate fuel cell	5.13-12	----	1200	-------		----	1990	---	
Zirconium dioxide fuel cell	5.13-12	1832	1832	-------		----	2000	---	

[a]Not estimated.
[b]M = mature; MM = moderately mature; MI = moderately immature; I = immature; VI = very immature.
[c]Cannot estimate without knowing plant availability date to estimate when material must be ready.

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REVIEW OF ECAS PHASE 1 BASE CASES

Year that materials must be ready		Current estimate of materials maturity[b]			MAG estimate of probability that materials could be developed and demonstrated when needed	
General Electric	Westinghouse	General Electric	Westinghouse	MAG	General Electric	Westinghouse
1979	(a)	M	M	MM	Moderately high	(c)
1979		M	M		Moderately high	
1982		MM	----		Moderate	
1983		MM	M		Moderate	
1990		MM	----	MM	Moderately high	
1986		MM	MM	MM	Moderate	
1982		I	M	I(G. E.)-M(W)	Moderately low	High
1990	1982		I	VI	Very low	Very low
1994	1982		MM	I	Low	Low
1985	1975		M	MI	Low	Extremely low
1984	----	MM	----	MM	Moderate	(c)
1980	1983	M	MM	M	Moderate	Moderately high
----	1983	----		MM	(c)	Moderate
----	1988	----		MM	(c)	Moderate
----	1998	I		MI	(c)	Less than moderate

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TABLE 5.13-2. - AIR-COOLED OPEN-CYCLE GAS TURBINES

(a) Base cases for Phase 1

Critical component	General Electric (Turbine-inlet temperature, 2200° F; pressure ratio, 12; air-cooled hot section; fuels: simple cycle, high-Btu gas; recuperated cycle, high-Btu gas; combined cycle, low-Btu gas; estimated date of commercial availability, 1980)	Westinghouse (Turbine inlet temperature, 2200° F; pressure ratio, 10; air-cooled hot section; fuels: recuperated cycle, coal distillate; combined cycle (PR = 12), low-Btu gas; combined cycle (PR = 12), coal distillate; commercial availability date not provided)	MAG comment (G. E. defines all fuels as clean, but Westinghouse considers low-Btu gas as dirty)
Turbine nozzle	Cast Ni or Co alloy (X-40) cooled to 1975 state of the art	Cast Co alloy (MAR M-509), with CoCrAlY coating for low-Btu gas, cooled to 1975 state of the art	Such materials are now in commercial aircraft and peaking power turbine use; in these cases, CoCrAlY coatings provide adequate hot corrosion protection for the shorter times to refurbishment
Turbine blade	Cast Ni alloy (Inconel-738 or René 80) cooled to 1975 state of the art	Cast Ni alloy (Udimet-500), with CoCrAlY coating for low-Btu gas, cooled to 1975 state of the art	
Turbine disk	Wrought Ni alloy (Inconel-706) cooled to 1975 state of the art	--	
Combustor	Sheet Ni alloy (Hastelloy-X) cooled to 1975 state of the art	--	Combustor materials and designs are questionable for the long lives desired

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selection	50 000-Hour life for hot-gas-path components; 30-year life for remainder of components	100 000-Hour hot-gas-path life; life in "clean" fuels is oxidation limited; life in low-Btu gas is hot-corrosion limited	Both contractors acknowledged that the ability of the proposed alloys to survive 50 000 to 100 000 hours in highly cooled machines has not been demonstrated. Such lives are difficult to predict. The long-time severity of coal-derived-fuel combustion products is not known, and there seems to be a disagreement on their environmental severity.
Estimated state of the art for materials	Mature at 2200° F turbine-inlet temperature	Mature at 2200° F turbine-inlet temperature	Relatively mature for clean-fueled aircraft and peaking power turbines, with 10 000- to 20 000-hour life at turbine-inlet temperatures of ≤2200° F
MAG-listed key uncertainty	The long lives that were assumed and upon which maintenance costs were estimated - Both mechanical property and environmental resistance effects on life need better definition.		
Technology advance required	Extension of materials life data to longer times - No major advances are required for 2200° F cases, but the 2400° to 2500° F cases require improved materials for combustors and other hot-section components.		
MAG estimate of the probability that materials will be ready when needed	Moderately high for 2200° F service if initial part-replacement frequencies are close to current state of the art. For 50 000- to 100 000-hour life at 2200° F and above and/or in low-Btu gas, the probability of success by 1979 is low, especially if rotating ceramic blades are required (Westinghouse, Phase 2).		

TABLE 5.13-3. - WATER-COOLED OPEN-CYCLE GAS TURBINES

(a) Base cases for Phase 1

Critical component	General Electric (Turbine-inlet temperature, 2800° F; pressure ratio, 16; water-cooled hot section; low-Btu gas; bottomed with steam at 3500 psi/ 1000° F/1000° F; estimated date of commercial availability, 1986)	MAG comment
Turbine nozzle and turbine blade	Ternary composite - Hastelloy-X clad on cast Udimet-500 with internal Cu clad - cooled to 1975 state of the art	All constituents are state-of-the-art materials, but fabrication and quality control development, proof-of-concept demonstration on airfoils, and cost effectiveness have not been established.
Turbine disk	Wrought Fe-Ni alloy (A-286) cooled to 1975 state of the art	State-of-the-art alloy
Combustor	Ni-base sheet (Hastelloy-X)	Alloy is state of the art, but operation at 2800° F is not. Improved materials are needed.

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	MAG comment
Assumptions for Phase 1 materials selections	50 000-Hour life for hot-gas-path components; ~30-year life for remainder of components	There is no state of the art on which to base these assumptions.
Estimated state of the art for materials	Moderately mature	--
MAG-listed key uncertainties	The long anticipated lives, the low maintenance cost estimates, the design philosophy, and the influence of external and/or internal deposits and erosion on cooling efficiency require much more consideration.	
Technical advances required	The design, materials, and fabrication process, as well as the nondestructive evaluation (NDE) for ternary composite airfoils, must be optimized and a long-life demonstration made. An improved combustor material is needed.	
MAG estimate of the probability that materials will be ready when needed	Moderate for 5000- to 10 000-hour life of critical turbine components; low for lives of 50 000 hours and beyond, within reasonable maintenance costs, by 1982.	

TABLE 5.13-4. - CLOSED-CYCLE GAS TURBINES

(a) Base cases for Phase 1

Critical component	General Electric (Helium turbine-inlet temperature, 1500° F; pressure ratio, 2.5; helium pressure, 1000 psia; atmospheric fluidized bed with Illinois #6 coal; no steam bottoming cycle; estimated date of commercial availability, 1987)	Westinghouse (Helium turbine-inlet temperature, 1500° F, pressure ratio, 2.5; helium at 1000 psia; combustion: (1) pressurized fluidized bed; Illinois #6 coal, with 1700° F pump-up turbine and pressure ratio of 10; (2) atmospheric fluidized bed with distillate fuel; commercial availability date not provided)	MAG comment
Heater tubes	Fe-Ni alloy (Mo-Re 2)	For coal, Ni-50 Cr coating on Haynes-188; for distillate, Haynes-188	Tube protection from corrosion needed at these temperatures; tubing development needed
Turbine airfoils	Cast Ni superalloys (M21LC or René 100)	First vane: 1500° F; cast Co alloy (Mar M-509) First blade: Cast Ni alloy (TRW-NASA VIA) for pressurizing turbine	Both contractors propose Mo-TZM for growth to 1700° to 1800° F and the use of state-of-the-art alloys in the turbine at base-case conditions
Disks	Ni-Fe based forgings (Inconel-706)	------------------------------------	------------------------------------
Hot-gas ducts	Wrought Ni alloy (Hastelloy-X)	------------------------------------	------------------------------------

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selections	40-Year (~280 000-hr) life	100 000-Hour life; selective impure-He oxidation of alloys containing Al, Ti, or Si	G. E.'s assumed life (280 000 hr) is at least twice that of analogous current machinery. In both designs, fire-side corrosion will occur on external tube surfaces.
Estimated state of the art for materials	Moderately mature	Mature	Maturity of materials in He service is only moderate.
MAG-listed key uncertainties	The impure helium environment is not well defined and is new for this type of system. Thus, the effects on maturity are not well understood. The small existing data base was generated for a graphite-core nuclear reactor, where higher carbon levels exist in the helium. Thus, metal tubes for 1500° F primary heat exchangers are not well backed by operational data. Heater tube and turbine materials for 1700° and 1800° F service are well beyond the state of the art.		
Technical advances required	A data base for design is needed, and the suitability of state-of-the-art materials for high-temperature service must be verified. For temperatures of 1700° to 1800° F and beyond, the development of ceramic heater components and large TZM components is beyond the state of the art.		
MAG estimate of the probability that materials will be ready when needed	Moderate for 1500° F service; moderately low for higher temperatures, where ceramic heater tubes will be needed.		

TABLE 5.13-5. - SUPERCRITICAL CARBON DIOXIDE SYSTEM

(a) Base cases for Phase 1

Critical component	General Electric (Turbine-inlet temperature, 1350° F; pressure ratio, 2.7; CO_2 pressure, 3800 psi; atmospheric fluidized bed with Illinois #6 coal; estimated date of commercial availability, 1995)	MAG comment
Turbine blade	Ni alloys (Inconel-718 or Inconel-617); temperature, 1310° F; helium environment; stress, 6700 psi	Only critical for higher temperatures
Heater tubes	Inconel-601	Fire-side and CO_2 corrosion data will be required.
Special ducting	Refractory-lined Inconel duct 47 inches in diameter; temperature, 1350° F; flow rate, 10 700 lb CO_2/sec; stress, 3780 psi	State of the art is not well defined

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	MAG comment
Assumptions for Phase 1 materials selections	30-Year life, based on Larson-Miller curve, to keep stresses below those producing rupture	Fatigue and CO_2 corrosion should be considered, and a more realistic design approach is needed. Most turbine preliminary designs include creep considerations.
Estimated state of the art for materials	Intermediate maturity	Agree
MAG-listed key uncertainties	The materials data base for CO_2 environmental effects on the corrosion and mechanical properties of materials needs extension to support design.	
Technology advances required	Need data base to use in predicting required technology advances; may require some protection against mildly oxidizing/carburizing environment over 30-year life.	
MAG estimate of the probability that materials will be ready when needed	Moderately high due to large lead time	

TABLE 5.13-6. - LIQUID-METAL TOPPING CYCLE

(a) Base cases for Phase 1

Critical component	General Electric (Turbine-inlet temperature, 1400° F; condensing temperature, 1100° F; atmospheric fluidized bed at 1550° F; Illinois#6 coal; 3500 psi/1000° F/1000° F steam bottoming cycle; estimated date of commercial availability, 1992)	Westinghouse (Pressurized fluidized bed at 1800° F: turbine-inlet temperature, 1800° F; pressure ratio, 15; Illinois #6 coal. Potassium turbine inlet temperature, 1400° F; condensing temperature, 1100° F; 3500 psi/1000° F steam bottoming cycle; commercial availability date not provided)	MAG comment
Potassium boiler tube	Wrought Ni or Co alloys (Hastelloy-X) 1/4 inch in diameter and 0.2-inch wall thickness. Tube temperature, 1400° F to 1550° F maximum; coal combustion gases on fire side; potassium with 20 ppm O_2 inside	Incoloy-800, perhaps with Ni-50Cr cladding on fire side. Tube temperature, 1400° F; pressure, 200 to 300 psia; potassium with 1 to 2 ppm O_2	Combined resistance to both potassium (inside) and fire-side corrosion (outside) is not adequately known for potential tubing materials.
First potassium vane	Wrought Ni or Co alloys (Inconel-617, Haynes-188); temperature, 1400° F	Not specified	Ability to survive 40 years is not known. Also if large disks (>40 in. diam) are needed, forging technology must be advanced.
First potassium turbine blade	René 77; temperature, 1335° F; stress, 27 600 psi	Udimet-700; design stress not specified in Sept. 1975 study draft	
First potassium turbine disk	Astroloy; temperature, 1335° F; stress, 22 260 psi	Inconel-901	
Steam boiler	304 Stainless steel	2¼Cr-1Mo steel; minimum thickness, ~0.35 inch; temperature, 1100° F	Additional data and design studies are needed to clarify the uncertainties regarding the extent of intergranular corrosion due to oxygen contamination of potassium and the need for separating the potassium and steam in case potassium leaks develop.

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selections	40-Year life at 80 percent utilization (i.e., 32 yr); designed for 0.2 percent creep in 32 years; no potassium corrosion or fatigue effects accounted for	Rotating part life of 100 000 hours based on Larson-Miller plots: shaft, disk, and blades are not cooled	Assumption of creep-rupture-controlled life is extremely optimistic. Boiler thermal fatigue, as well as liquid-metal and fire-side corrosion could lower estimates markedly.
Estimated state of the art for materials	Intermediate maturity	Intermediate maturity	--
MAG-listed key uncertainties	No verification of combined long-time potassium/fire-side corrosion resistance exists, and thus design approaches are not well developed - especially for critical tube joints, where potassium or air leakage could be very detrimental. If large disks are mandatory for cost-effective designs, the technology is not now in existence. No cost/life trade-off studies have been made to determine how long critical components must survive for economic viability.		
Technology advances required	An adequate potassium/fire-side corrosion data base must be developed to assess if long boiler and turbine component lives are really possible. If Cs is to be considered, a similar data base will be needed.		
MAG estimate of the probability that materials will be ready when needed	Only moderate until a data base exists upon which to estimate life. There is no problem in building the unit within the state of the art, but cost-effective lifetimes must be demonstrated and a realistic critical-component replacement schedule developed.		

TABLE 5.15-7. - ADVANCED STEAM SYSTEMS

(a) Base cases for Phase 1

Critical components	General Electric (Steam conditions: 3500 psi/1200° F/1000° F; atmospheric fluidized bed at 1550° F; Illinois #6 coal; steam turbine inlet temperature, 1200° F; estimated date of commercial availability, 1987)	Westinghouse (Steam conditions: 3500 psi/1000° F/1000° F; Illinois #6 coal; combustion process: (1) conventional furnace; (2) pressurized boiler - turbine-inlet temperature, 1700° F; pressure ratio, 18; pressurizing turbine; (3) pressurized fluidized bed - turbine-inlet temperature, 1600° F; pressure ratio, 10; pressurizing turbine; commercial availability date not provided)	MAG comments (The Westinghouse conventional-furnace case is the current state of the art at 3500 psi/1000° F/1000° F. Atmospheric fluidized beds are just approaching commercial feasibility. Pressurized boilers are used in naval service but usually with cleaner fuels. PFB state of the art is not well developed.)
Boiler tubes	Stainless steels (347) or wrought Ni alloys (Inconel-601); maximum temperature, not stated; fire-side corrosion-producing environment	304 Stainless steel; maximum temperature not stated	State-of-the-art technology is only to 1050° F. Beyond this temperature, fire-side corrosion increases and tube life is short when stainless steel is used. No data base on Ni or Co alloy boiler tubing over long-time, high-temperature service.
Main steam valves	Wrought Fe-Ni alloys (Inconel-102 for body, Inconel-901 for stem); large-size valves, temperature, 1200° F	2¼ Cr-1Mo steel	State-of-the-art technology is for 2¼ Cr-1Mo steel. Large wrought Fe-Ni alloy tubing and castings are far beyond the 1975 state of the art and would require large fabrication development efforts, as General Electric points out.
Main steam piping	Inconel-102; inside diameter, 26 inches; temperature, 1200° F	2¼ Cr-1Mo steel	
Turbine shell	Cast Fe-Ni alloy (Inconel-102); large-size component; temperature, 1100° to 1200° F	2¼ Cr-1Mo steel	
High-pressure rotor	Inconel-901 or A286 (if cooled); 25 feet long and 40 inches in diameter; temperature, 1200° F	Cr-V-Mo steel with 403 or 422 stainless-steel blades	Large, forged rotors are far beyond the state of the art when Fe-Ni alloys are required for high-temperature use. Disk/shaft designs are mandatory in such cases.

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selections	30-Year steady operation	**ASME boiler code**	Boiler (conventional) design is well developed. Translation to AFB and then to PFB boiler design has yet to be substantiated.
Estimated state of the art for materials	Immature for 1200° F; mature for 1000° F	Current state of the art very mature for 1000° F	Major difference in maturity rests with boiler tubes and forged rotors for 1200° F service.
MAG-listed key uncertainties	Boiler tube hot corrosion at 1200° F service and the design philosophy that requires integral rotors of Ni alloys for 1200° F instead of shaft/disk designs as used in aircraft turbines. It is much easier to forge the latter piece by piece than one huge rotor.		
Technology advances required	No major boiler-tube material advances are needed if AFB and PFB boilers produce environments similar to (or less aggressive than) those of conventional boilers. However, pressurizing turbines will require major system/component materials development even to achieve reasonable operating lives.		
MAG estimate of the probability that materials will be ready when needed	Very high for AFB; moderately high for PFB if low-cost, easy-to-replace pressurizing turbines can be developed, otherwise moderately low.		

TABLE 5.13-8. - OPEN-CYCLE MHD SYSTEMS

(a) Base cases for Phase 1

Critical component	General Electric (Direct fired; Illinois #6 coal; 2950° F air preheat; estimated date of commercial availability, 1997)	Westinghouse ((1) Separately fired air preheater, Illinois #6 coal, 10 percent ash carryover; (2) direct-fired preheater, 20 percent ash carryover; (3) low-Btu gas-fired preheater; estimated date of commercial availability, 1990)	MAG comment (With plant construction time of 7 years, it would take a major national effort to be on line by 1990. The state of the art is not yet advanced enough to show commercial feasibility.)
Air preheater	Al_2O_3 or MgO for <3100° F areas; stabilized ZrO_2 for >3100° F areas; 3100° to 3600° F gases containing seed and ash	(1) Separately fired air preheater: Al_2O_3; 3000° F (2) Direct-fired preheater: SiC; 2400° F (3) Low-Btu gas-fired preheater: SiC; 2950° F ~10 000-Hour life assumed	Separately fired and low-Btu gas-fired preheaters should have less slagging and slag/seed corrosion than direct-fired preheaters. The hot valves needed are beyond the state of the art.
MHD generator	5-Tesla magnet; 1 percent K; pressure, 9 atmospheres; gas flow rate, 1500 to 2000 ft/sec	6-Tesla magnet; pressure, ~6 atmospheres	--
MHD conductor	Ni alloy (Inconel-601); cooled to 1520° F and coated with coal slag	SiC for direct and separately fired; $LaSr_2CrO_3$ for low-Btu gas fired	
MHD generator insulator	Al_2O_3, MgO, or ZrO_2; coated with 2600° F coal/slag seed	Si_3N_4 for direct and separately fired; MgO for low-Btu gas fired	
MHD generator magnet	Nb-Ti in a Cu matrix; 5 teslas; superconducting	Nb-Ti; 6 teslas; superconducting	Magnet weights are estimated to be as much as 2×10^6 lb.
Combustor	Carbon steel, 90 percent slag rejection; water cooled; temperature, ~440° F	Calcia-stabilized ZrO_2 for all cases; temperature, 4400° F	The water-cooled approach should lead to longer lives, but slag could deposit and alter combustor performance.
Steam boiler tubes	<800° F	------------------------------------	--

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selections	30-Year plant life; a yearly charge of 20 percent of plant capital cost for maintenance	--	There is no basis for estimating the lives of most components. The materials were selected primarily on temperature limits. Seed/slag corrosion effect on life not considered
Estimated state of the art for materials	Immature	Immature	While oxides, SIC, Si_3N_4, etc., are in use in other applications, no long-time use in MHD-type environments has occurred. Embryonic maturity.
MAG-listed key uncertainties	The ability of the system to operate with a range of coals; the resistance of proposed preheater, duct, and steam bottoming cycle materials to seed/slag corrosion and thus the life of such components; also, the operating stability and interdiffusional effects on electrode performance.		
Technology advances required	First, materials must be identified, by reasonable tests, that have the desired thermal, electrical, environmental stability properties; etc. Improvement and optimization efforts, as well as long-time demonstration under full-power conditions, will then confirm their suitability for MHD service. Maintenance costs could be much higher than 20 percent per year. If duct life is only ~1000 hours, maintenance costs could be 500 to 700 percent of capital costs, which would markedly impact the feasibility of this approach.		
MAG estimate of the probability that materials will be ready when needed	MAG is not convinced that coal slag (whose composition varies with coal source) will form a protective, yet properly conducting, and invariant coating on the MHD electrodes. Until much more data are developed, MAG estimates the direct-coal-burning case to have a very low probability of success. The indirect-fired and low-Btu gas-fired cases have a slightly greater probability of success.		

TABLE 5.13-9. - CLOSED-CYCLE INERT-GAS MHD SYSTEMS

(a) Base cases for Phase 1

Critical component	General Electric (3000° F, 10-atmosphere duct inlet; 1800° F outlet; 0.5 percent cesium in argon; Illinois #6 coal or solvent-refined coal; steam bottoming at 3500 psi/ 1000° F/1000° F; estimated date of commercial availability, 2000)	Westinghouse (3800° F, 9-atmosphere duct inlet; Mach 0.9; all three coals in a fluidized-bed furnace or HBTU gas - direct fired; cesium in argon; steam bottoming at 3500 psi/1000° F/ 1000° F; estimated date of commercial availability, 1990)	MAG comment (With 8-year construction time, a 1990 date appears very optimistic.)
Argon/combustion gas heat exchanger	Al_2O_3 brick to 3000° F and then ZrO_2 brick (1-in. squares) ~3000° F	Y_2O_3-stabilized ZrO_2; 3600° to 3800° F	3600° F values are beyond the state of the art. Problems are expected in sealing against combustion gas/argon-cesium mixture in heat exchanger.
MHD generator	100-Square-foot inlet; 473-square-foot exit; 243-foot length; 1.4 million pounds	Approximately 60 feet by 830 feet	Impurities (or leaks) into argon system mean rapid (almost instantaneous) failure.
MHD generator electrode	W-plated Ta; 2900° F	TZM or W; 3400° F	
MHD generator insulator	Al_2O_3; 2900° F	Al_2O_3; 2400° F	
MHD generator magnet	3 Teslas; 14-inch diameter; 73-foot length; 2 million pounds	5 to 6 Teslas, NbTi	
Boiler tubes	Not specifically mentioned	Not specifically mentioned	Materials compatibility with argon-cesium system have not been established.

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selection	30-Year plant life; a yearly charge of 10 percent of capital cost for generator/diffuser maintenance and 15 percent for heat-exchanger maintenance; ~6 to 7-year brick life	------------------------------------	There is no basis for these long-life assumptions (i.e., no materials studies).
Estimated state of the art for materials	Immature	Immature	Long-term demonstration of materials is not near; their development is in immature stage.
MAG-listed key uncertainties	No basis exists for life estimation. No data base exists for long-time argon-cesium compatibility with system materials. Thus, repair frequency cannot be adequately estimated. Leaks in argon-cesium/combustion gas heat exchanger could be disasterous to life of refractory-metal electrode. No information on the probability of such leaks was presented.		
MAG estimate of the probability that materials will be ready when needed	Probability of success is slightly greater than for open-cycle MHD systems - but still low.		

TABLE 5.13-10. - LIQUID-METAL MHD SYSTEMS

(a) Base cases for Phase 1

Critical component	General Electric (Na/He at 1300° F; He at 50 atmospheres; atmospheric fluidized bed with Illinois #6 coal; steam bottoming at 3500 psi/ 1000° F/1000° F; estimated date of commercial availability, 1991)	Westinghouse (Na at 1200° F; Ar at 82 atmospheres; 1-atmosphere fluidized bed cyclone with Illinois #6 coal; Na flow rate, 119 500 lb/sec; steam bottoming at 3500 psi/ 1000° F/1000° F; estimated date of commercial availability, 1983)	MAG comment (With 8-yr construction time, a 1983 availability data means the plant should be started now. MAG disagrees strongly that this is feasible. Westinghouse's use of 100° F lower Na temperature lowers Na corrosion potential.)
Heat exchanger	Not specified	316 Stainless steel	30 000-Hour Na corrosion data exist for stainless steel.
MHD generator	Not specified	316 Stainless steel; pressure, ~1200 psia	
MHD generator conductor	Pyrolytic graphite with 0.1-inch W coating; 1280° F Na and He	316 Stainless steel	
MHD generator insulator	Al_2O_3	High-purity and high-density Al_2O_3	--
MHD generator magnet	1.3 Teslas	0.55 Tesla	
Steam boiler	Not specified	$2\frac{1}{4}$ Cr-1Mo steel	

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selection	30-Year plant life; a yearly maintenance charge of 10 percent of the generator/ diffuser capital cost	Design based on liquid-metal, fast-breeder reactor technology; 30-year life	There is no real data base to support this life assumption.
Estimated state of the art for materials	Immature	Mature	While Na technology in the LMFBR is moderate in maturity, liquid-metal MHD technology is immature. There is no real assurance that materials that are mature in normal service will be mature here. Immature.
MAG-listed key uncertainties	There is no data base on materials behavior under liquid-metal operating conditions. The system offers the possibility of corrosion and erosion attack.		
Technology advances required	Difficult to identify without a good data base.		
MAG estimate of probability that materials will be ready when needed	Probability of success may be moderate, but this is an unsupported estimate. Without access to a good data base, we must rate low.		

TABLE 5.13-11. - LOW-TEMPERATURE FUEL CELLS

(a) Base cases for Phase 1

Critical component	General Electric		Westinghouse		MAG comment
	Solid polymer electrolyte; HBTU gas/air at 170° F maximum; atmospheric pressure; current density, 250 A/ft^2; estimated date of commercial availability, 1986	H_3PO_4 electrolyte; Illinois #6 coal; estimated date of commercial availability, 1982	H_3PO_4 electrolyte; HBTU/air at 375° F; atmospheric pressure; current density, 200 A/ft^2; estimated date of commercial availability, 1985	KOH electrolyte; HBTU/air at 158° F; atmospheric pressure; current density, 100 A/ft^2; estimated date of commercial availability, 1985	
Electrolyte	Solid polymer 0.005 inch thick 170° F; humidified reactants; 100 000-hour life	----------------	85-wt % H_3PO_4 paste 0.005 cm thick in an inert matrix; 10 000-hour life	30-wt % KOH paste 0.05 cm thick in an inert matrix; 10 000-hour life	Grafted polymer is in early stage of development, and cost projections are based on current SPE state of the art. H_3PO_4 cell should last ~40 000 hours based on state of the art. KOH cell life should be >10 000 hours if good CO_2 scrubbing is used for both fuel and air.
Electrodes	Ti/Pd screens with 0.2-g/ft^2 Pt catalyst		Porous carbon with 1-g/ft^2 Pt catalyst; 10 000-hour life	Anode: porous carbon with 1-g/ft^2 Pt catalyst; cathode: porous carbon with 5-g/ft^2 Ag catalyst; 10 000-hour life	With 0.2-g/ft^2 catalyst loading, SPE's performance at 170° F is questionable.
Fuel processor	For 1400° to 1600° F, steam reformer with NiO catalyst; for 300° to 800° F, shift converter(s) of iron oxide, Zn-Cu, etc.		For 1400° to 1600° F, NiO catalyst with steam reformer; for 600° to 800° F, shift converger with iron oxide catalyst; 10 000-hour life		Fuel processing catalysts might last 15 000 to 25 000 hours. Effect of transient operation on catalyst life and performance is not known.

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selection	100 000-Hour life; cost of $\$16/ft^2$; that SPE and Pt state of the art could be improved to desired levels	10 000-Hour life for both systems; excellent S and CO_2 scrubbing for KOH cell	---
Estimated state of the art for materials	For SPE, intermediate maturity; for H_3PO_4, intermediate maturity	Intermediate maturity for both systems	Maturity downgraded primarily because of catalyst loading and life requirements
MAG-listed key uncertainties	For SPE cell, attainment of both 0.2-g/ft^2 Pt loading level and grafted polymer SPE, as well as cell performance at 0.2 g/ft^2; also 100 000-hour life for fuel processor catalysts For H_3PO_4 cells, optimization of system for cost by low Pt loading, cell life beyond 10 000 hours, and extent of carbon electrode and frame oxidation at 375° F For KOH cell, ability to remove CO_2 effectively at low cost		
Technology advances required	For SPE cell, advances are needed in grafted polymer electrolyte and 0.2-g/ft^2 Pt loading, as well as 100 000-hour polymer life - although the latter two advances may not greatly affect cost. Considerable overall effort will be needed to operated cells at 300° F. For H_3PO_4 cells, the major advances are minimizing carbon electrode and frame oxidation at 375° F and lowering costs. For KOH cell, cell life must be increased by 3 or 4 times to lower cost, and CO_2 removal needs to be improved.		
MAG estimate of the probability that materials will be ready when needed	For SPE cell, at cost of $\$16/ft^2$, moderately low; above $\$16/ft^2$, moderately high For H_3PO_4 cells, moderately high For KOH cell, moderate		

TABLE 5.13-12. - HIGH-TEMPERATURE FUEL CELLS

(a) Base cases for Phase 1

Critical component	General Electric (ZrO_2 electrolyte; LBTU/air at 1832° F; current density, 200 A/ft^2; steam bottoming at 3500 psi/1000° F/1000° F, commercial availability date not provided)	Westinghouse		MAG comment
		ZrO_2 electrolyte; HBTU/air at 1832° F; current density, 400 A/ft^2; no bottoming cycle; estimated date of commercial availability, 2000+	Molten carbonate electrolyte; HBTU/air at 1200° F; current density, 200 A/ft^2; estimated date of commercial availability, 1990	
Electrolyte	CaO-stabilized ZrO_2 0.020 inch thick	Y_2O_3-stabilized ZrO_2 0.0015 inch thick	Li, Na, K carbonate paste plus alkali aluminates ~0.5 inch thick	Thick cell components lower performance.
Anode	Ni with ZrO_2	Ni-ZrO_2 cermet	Porous Ni	Tends to sinter and performance changes.
Cathode	Sn-doped In_2O_3	In /$PrCoO_{3-x}$	Lithiated NiO	An alternate to lithiated NiO would be to let an Ni anode oxidize.
Interconnections	$CoCr_2O_4$	Cr_2O_3 0.001 inch thick	Ni	These materials have lives of ~1000 hours at present.
Tube support	ZrO_2	ZrO_2	------------------------	--

(b) Assumptions, estimates, uncertainties, and probabilities for Phase 1

	General Electric	Westinghouse	MAG comment
Assumptions for Phase 1 materials selection	No life assumption was made; bottoming cycle is the same as for other steam systems	10 000-Hour life was assumed for both cell types	For ZrO_2, 10 000-hour lives may be achievable - but may not be good enough. For molten carbonate, present state of the art is 10 000 hours, and 30 000 hours might be a reasonable goal.
Estimated state of the art for materials	Low maturity	Moderate maturity	These estimates conflict with contractor's high operating-and-maintenance cost estimates.
MAG-listed key uncertainties	For ZrO_2 cells: can thin components perform adequately; can thermal expansion mismatches between brittle oxide interconnections and other components be overcome; how degrading are solid-state interdiffusional effects on all high-temperature components and the electrolyte, and what is a realistic cell life? For molten carbonate cells: can an "invariant" Ni anode be made, and how will the cell tolerate impurities? The main uncertainty is cell life.		
Technology advances required	For ZrO_2 cells, finding low-cost materials with the necessary mechanical/chemical properties for lives >>10 000 hours, especially cell interconnection materials. For molten carbonate cells, minimum corrosion and electrolyte loss must be achieved, a porous NiO cathode developed, and sintering during service reduced.		
MAG estimate of the probability that materials will be ready when needed	For ZrO_2, less than moderate probability For molten carbonate, moderate probability		

5.14 FURNACES AND GASIFIERS

by Lester D. Nichols and Raymond K. Burns

The primary emphasis of ECAS is on the evaluation of the various energy conversion systems. An important element of the systems is the furnace or combustor and the associated combustion equipment. For each system, parametric variations were included for a number of fuel types and combustion systems. In some cases coal was used directly; in others a clean or semiclean fuel derived from coal was assumed. Some of the parametric variations involved the integration of a coal gasifier with the power system. Only limited consideration was given to variations in gasifier type, configuration, operating parameters, or method of integration with the power system. Each contractor selected one type of gasifier and generally one approach to integrating it with each type of power system. In the summary of results for each system in section 5.0, the effects of all these parametric variations and/or contractor areas of emphasis on the systems results are discussed. The purpose of this section is to describe the contractor areas of emphasis concerning fuels, furnaces, and gasifiers and to summarize the results from that standpoint. Comparisons are made of different furnace types and of the same furnace types between the two contractors. A comparison of the furnace performance and the costs is made. Combustors are not included in the discussion but are discussed as necessary in the individual system sections.

5.14.1 Scope of Analysis

Each contractor considered various coal and coal-derived fuels for the energy conversion systems. Table 5.14-1 lists the number of parametric cases for each type of coal, or the type of coal-derived fuel and the coal from which it was derived, the energy conversion system, and the contractor. The number of parametric cases considered for each energy conversion system for each type of furnace, combustor, or gasifier is shown in table 5.14-2.

Some of the energy conversion systems considered are open thermodynamic cycles in that the combustion products are used directly in the conversion system. The others are closed cycles, which require the transfer of heat from the combustion products to the working fluid of the conversion system. For some open cycles, such as MHD, the parametric variations included direct coal firing. For others, such as gas turbines, the coal ash is less tolerable and cleaner fuels derived from coal were used. In either case, the component that burns the fuel is listed in the combustor column in table 5.14-2. Other than being listed in the table, combustors are not considered in this section.

The closed-cycle energy conversion systems have not only components that burn the fuel (combustors), but also components that transfer the heat (heat exchangers) to a working fluid. If both processes take place in one component, that component is listed as a furnace in table 5.14-2. All closed cycles considered, except closed-cycle MHD, use a furnace. In closed-cycle MHD the heat is transferred from the hot combustion products to the closed-cycle inert gas by means of a regenerative heat exchanger located downstream of the combustor. Consideration of this particular system is included in section 5.9.

If the combustion process starts in one component and finishes in another, the first component is called a gasifier (or a partial combustion burner) and the second is called a combustor. (If it also includes the heat exchanger, the second component is called a furnace.)

The gasifiers can also be divided into two broad groups depending upon their relation to the energy conversion system. If heat, steam, or pressurized air from the energy conversion system is transferred to the gasifier, it is referred to as an integrated gasifier. If not, it is called free standing. Also, the gasifiers can be used to provide low-, intermediate-, or high-Btu gas. When free-standing gasifiers were assumed, the conversion system analysis was performed using an "over-the-fence" fuel supply with fuel prices shown in table 4.1-2. This was the case for intermediate- and high-Btu gas with one exception. Westinghouse included one parametric case for high-temperature fuel cells with an integrated intermediate-Btu gasifier. With one exception, low-Btu gasifiers were assumed to be integrated with the power system. In the General Electric analysis of open-cycle MHD, a relatively small amount of the conversion system fuel was assumed to be "over-the-fence" low-Btu gas for seed processing. Only integrated gasifiers are listed in table 5.14-2.

The method of integrating the low-Btu gasifier differed between the two contractors and from one type of system to another. In all cases G.E. cooled the product gas (cold-gas cleanup) prior to sending it to the furnace; Westinghouse used hot-gas cleanup and sent the product gas to the furnace much hotter. For some of the Westinghouse systems (such as MHD) it might be argued that the gasifiers are not integrated since they receive no compressed air, steam, or waste heat from the powerplant. They are called integrated because they are located sufficiently close to the powerplant that it is assumed that the sensible heat of the hot fuel gas is not lost and is available to the energy conversion system and because the gasifier capital cost is included in the total system cost. The situation is similar for the General Electric analysis of high-temperature fuel cells. These cases are listed as integrated LBTU gasifiers here since the capital cost of the gasifiers has been included in the total system cost, even though G.E. refers to these cases as nonintegrated.

The furnaces can be divided into two broad groups. One group is fluidized beds for burning coal. When air is forced through a bed of solid particles with sufficient velocity, the bed will take on many of the properties of a fluid - in particular, the convective heat transfer properties. If some of the particles are coal, the coal can be burned; and if the rest of the particles are limestone, the sulfur in the coal will react with the limestone and stay in the bed. Finally, if heat transfer surface is included in the bed to heat the conversion system working -as, the unit can be considered a furnace. The other group of furnaces are those that do not involve a fluidized bed. This group is divided into two categories depending on the type of fuel and the pressure. For coal at atmospheric pressure, a conventional pulverized coal furnace is used. For coal-derived fuels a pressurized furnace is used.

All these components can operate at any pressure level. However, the gasifier and furnace combinations for the energy conversion systems considered in this study were pressurized. The furnaces burning coal directly were either atmospheric or pressurized fluidized beds or atmospheric pulverized coal furnaces; the furnaces burning clean fuel were all pressurized.

Whenever combustion takes -lace at elevated pressures, the combustion gases at the exit of the furnace can be expanded to produce power. If the pressure level is high enough, the power produced exceeds the combustion-air compressor power requirement and there is a net power output. The furnace pressurizing loop then is actually an open-cycle power system. The combination with the prime cycle can be made in "parallel" or in "series."

Choice of such parameters as furnace pressure level and exit temperature, excess air, prime-cycle inlet and exit working-fluid temperatures, or the specific way the furnace loop and prime cycle are integrated have a strong influence on the amount of energy that is input to each system. Generally, one would favor putting the most energy into the highest efficiency system - but cost may be a mitigating factor. The waste heat from one cycle can also be used as heat input to the other. When all heat input to the closed cycle is from the waste heat of the open system, it can be thought of as a "series" flow of heat from the open to the closed. In the case of an open-cycle gas turbine and a closed steam cycle, the system is referred to as a combined cycle. Usually only combustors are used in the "series" system. But the other combined systems all have furnaces.

Typical schematics of atmospheric and pressurized fluidized beds for burning coal are shown in figure 5.14-1. The conventional furnace is schematically similar to the atmospheric fluidized bed.

It may be advantageous to separate the gas cleaning function of the fluidized-bed furnace from the heat transfer function because the conditions optimum for one process may not be the most desirable for the other. In this case, the gasifier/pressurized-furnace concept is used and is shown schematically in figure 5.14-2. Integrating this gasifier-furnace system with the energy conversion system makes it possible to take advantage of the waste heat from that system. The manner in which this is done can have a significant effect on the total performance of the energy conversion system.

5.14.2 <u>Results of Anlaysis</u>

Certain cases considered in table 5.14-2 were chosen for discussion. These parametric points are listed in table 5.14-3. The points were chosen to provide as comparable furnace and gasifier conditions as possible. Consideration was given to the remainder of the system only to choose comparable conditions, and in some cases the parametric point chosen for discussion here is not the most attractive parametric variation and/or does not correspond to a case discussed in section 5.0. Where blanks occur in the table, either the contractor did not consider that particular furnace configuration for that system or the parametric conditions were not close enough to make a comparison meaningful. Only cases involving bituminous coal are included.

5.14.2.1 Furnace Performance

The furnace is designed to burn the fuel completely and with a minimum of losses. Table 5.14-4 shows the furnace percentage losses used by Westinghouse when burning bituminous coal or low-Btu gas. Sensible heat in the stack gas is not included in the table. The sulfur reaction loss for the fluidized-bed cases occurs because it takes energy to form the products of the reaction between the limestone (or dolomite) and the sulfur. The effect of fuel type on the losses is negligible except for the desulfurization losses in the fluidized beds. For subbituminous coal this loss is 1.5 percent and for lignite the loss is 0.6 percent. For the conventional furnace there would also be a loss associated with sulfur removal, but these losses or energy requirements for stack-gas cleaning are included elsewhere as auxiliary power requirements. In the case of the pressurized furnace, it is assumed that a clean fuel gas is used.

The losses listed in the table are not recoverable and depend only upon the fuel and the furnace operating conditions. The loss of energy in the stack gas due to sensible heat is also not recoverable, but its amount depends upon the temperature of the stack gas. This temperature is usually set by systems considerations. All these losses, including the stack losses, are added together to determine the heat-exchanger efficiency for the atmospheric furnace. They are shown in table 5.14-5 for the chosen cases for both contractors.

The efficiencies for Westinghouse's advanced steam system cases are slightly lower than those for comparable G.E. cases. This appears to be the result of a lower estimate by G.E. for one or more of the items in table 5.14-4. General Electric provided less detail in their loss breakdown and the items where the difference occurs have not been identified.

All the G.E. efficiencies listed in table 5.14-5 are similar except for the liquid-metal Rankine topping cycle. This particular efficiency is lower because the stack temperature used was 362° F compared with 300° F for the other systems. There is no apparent reason why this temperature could not be reduced to 300° F without significant effect on cost. The fact that it was not reduces the performance estimate for this case.

Even for furnaces operating at high pressure, the maximum amount of energy available to the thermodynamic cycle is determined by considering the losses just described. When the furnace is pressurized, there are more components of the system involved in extracting this energy. The additional components can be seen in figure 5.14-1(b). A compressor is required for the combustion air. A turbine is used to extract energy from the gases after they leave the furnace - but there is still energy in the exhaust gases from the turbine. This heat is recovered in a low-temperature heat exchanger (either an air preheater as shown in the sketch or a feedwater heater if a steam cycle is used), and the gases finally leave the stack with a temperature about the same as for systems with atmospheric furnaces. Part of the heat of combustion is transferred to the main thermodynamic system, while the rest is recovered by the furnace pressurizing gas turbine and the low-temperature heat exchangers. The fraction of the higher heating value of the fuel that is transferred to the primary closed thermodynamic cycle is given in table 5.14-6 for pressurized furnaces burning high-Btu gas and pressurized fluidized beds burning coal. The amount of energy varies from system to system, for each contractor, and from contractor to contractor for those systems chosen in common.

The numbers in table 5.14-6 cannot be interpreted as furnace loop efficiencies since there is a net power output from the furnace pressurizing gas turbine. The fraction of the entering chemical energy that does not go to the prime cycle is either lost or used in the open system. The amount lost is approximately the amount lost in the atmospheric furnace case, typically about 12 percent if the stack-gas temperature is the same. If the prime cycle and the furnace pressurizing system were purely in parallel thermodynamically, the overall power system efficiency would be a weighted average of their efficiencies. Thus, the numbers in the table would be the weighting factor, in which case higher values are desirable. However, in some situations the prime cycle is itself a combined cycle, with perhaps a steam bottoming cycle. In such a case if the combustion gases are reduced to a desirable low temperature by adding heat to the feedwater of the bottoming cycle, the prime cycle and the furnace pressurizing cycle are not purely in parallel. And in such a case this physical interpretation of the numbers in table 5.14-6 does not apply.

Consider first the pressurized fluidized beds in table 5.14-6. General Electric systems transfer about 65 percent to the primary cycle when the heat in the turbine exhaust gas is used to preheat the combustion air, about 71 percent when an economizer is used, and 79 percent when boiler feedwater heating is used. All these systems used 20 percent excess air, a pressure ratio of 10, and a pressurizing turbine-inlet temperature of 1600° F. Westinghouse calculated their cost for the advanced steam case with the same pressure ratio and turbine-inlet temperature, but with various amounts of excess air from 10 percent to 80 percent. Parametric point 7 (excess air, 10 percent) is comparable with the G.E. value. Westinghouse's conditions for the closed-cycle gas turbine are the same as G.E.'s except the turbine-inlet temperature is 1700° F. Their fraction of heat transferred to the prime cycle is slightly higher than G.E.'s. Westinghouse's conditions for the liquid-metal Rankine topping cycle are the same as G.E.'s except the pressure ratio is 15. The fraction of heat transferred to the prime cycle is slightly lower. The slight differences are probably the result of different choices made in selecting the system configuration.

5.14.2.2 Furnace Cost

Each type of energy conversion system puts different requirements on the combustor, heat exchanger, and associated equipment. The costs of these components are sensitive to these requirements and taken together make up the furnace cost. The requirements that are most important in determining the cost are size and operating temperature. The size is determined by the fuel flow and airflow rates, the heat transfer requirements, the heat transfer coefficient, and the average logarithmic mean temperature difference between the working fluid and the combustion gases. The temperature of the heat transfer materials is also determined from the heat transfer requirements. The operating temperatures then dictate the type, and, ultimately, cost, of materials.

Since the heat exchanger is the most expensive component in the atmospheric furnace and its size is determined by the amount of heat that must be transferred, the cost of the furnace is presented in terms of the cost per kilowatt of thermal energy transferred to the prime cycle. The atmospheric furnaces costs are shown in table 5.14-7. The furnace components are listed, along with any additional heat exchangers that make up the furnace loop. This loop can be defined as the equipment between the air inlet and the stack. All furnace components are approximately the same cost (table 5.14-7(b)), with the exception of the heat exchanger, not only for all the systems calculated by G.E., but also for the advanced steam systems proposed by both G.E. and Westinghouse.

The liquid-metal MHD system furnace costs about twice as much as the advanced steam system furnace primarily because the log mean temperature difference is smaller and the material is more expensive (table 5.14-7(a)). The closed-cycle gas-turbine furnace is nearly four times as expensive as the advanced steam system furnace, mainly because of more expensive materials. This is in some measure the result of the higher working fluid temperature of 1507° F. Finally, the liquid-metal Rankine and supercritical carbon dioxide cycles are about five times as expensive as the advanced steam system. The surface area is also about 25 percent larger, but the material cost is much greater. The supercritical carbon dioxide heat exchanger is made of Hastelloy X and Inconel; the liquid-metal Rankine heat exchanger is entirely made of Hastelloy X. The working fluid temperature for the supercritical carbon dioxide cycle is not as high as for the closed-cycle gas turbine, but the difference in working fluid pressure makes it necessary to use the stronger and more expensive material. The more expensive material is used with the liquid-metal Rankine system in order to withstand corrosion.

The costs of the pressurized furnaces are given in table 5.14-8. In table 5.14-8(a) the costs for the pressurized fluidized-bed components and additional heat exchangers in the furnace loop are shown. The furnace components are approximately the same cost with the exception of the heat exchanger. The slight differences in costs of these components between the systems are greater than in the atmospheric case. This is due to the difference in the fraction of coal energy that is transferred in the heat exchanger because the costs of these particular components depend upon the fuel flow rate.

The heat-exchanger costs calculated by G.E. follow a pattern similar to those for the atmospheric heat exchangers. The liquid-metal MHD system is about 50 percent higher in cost than the advanced steam system, primarily because of a lower log mean temperature difference. The closed-cycle gas turbine is about twice as expensive as the advanced steam system because of the more expensive material (Hastelloy X) and a smaller log mean temperature difference. The supercritical carbon dioxide cycle is about 3.5 times as expensive as the advanced steam system even though there is only a 50 percent smaller temperature difference. The material is more expensive (Hastelloy X and Inconel 601) and there is more of it because of the pressure of the working fluid. Finally, the liquid-metal Rankine system is about 4.5 times more expensive than the advanced steam system because of the expensive corrosion-resistant material.

The Westinghouse calculations are different. While their advanced steam system cost is similar to G.E.'s, their closed-cycle gas turbine cost is 50 percent higher than G.E.'s and the liquid-metal Rankine system cost is 50 percent lower than G.E.'s. In the latter case, G.E. chose Hastelloy X and Westinghouse chose Incoloy 800. However, G.E. chose a larger tube wall thickness (greater than 0.15 in.) than did Westinghouse (0.1 in.). Because of the cost of the material involved, this difference can account for a large part, if not all, of the difference in the heat-exchanger costs for the liquid-metal Rankine system. The furnace in the Westinghouse case selected operated at a pressure ratio of 15 but at the same air equivalence ratio and turbine-inlet temperature. This should also contribute to a lower cost.

The closed-cycle gas-turbine furnace costs for the two contractors are calculated for the same pressure ratio (10) and air equivalence ratio (1.2) but Westinghouse uses a 1700° F open-cycle gas-turbine-inlet temperature and G.E. uses 1600° F. This changes both the logarithmic mean temperature difference and the average tube wall temperature. The larger mean temperature difference of the Westinghouse case would tend to make the heat transfer surface area smaller and hence less expensive, but the higher tube wall temperature would tend to make the heat exchanger more expensive. The level of design detail in Phase 1 is insufficient to reconcile this 50 percent difference in cost.

The costs for the pressurized furnace components burning high-Btu gas are shown in table 5.14-8(b). The G.E. systems have air equivalence ratios of 1.1 and pressure ratios of 8. However, the maximum working fluid temperature in the closed cycle increases from the liquid-metal MHD (1300° F) to the liquid-metal Rankine (1400° F) to the closed-cycle gas turbine (1500° F) to the supercritical carbon dioxide (1600° F). The heat-exchanger costs are ordered the same way. Not only does the material get more expensive at the higher temperatures, but in the supercritical carbon dioxide case the amount also increases because of the increase in working fluid pressure.

The closed-cycle gas-turbine furnace cost was also calculated by Westinghouse. Their costs are about twice as high as those calculated by G.E. Again, the level of detail is insufficient to explain the difference.

5.14.2.3 Gasifier and Furnace Performance

The gas cleanup process can be separated from the heat transfer process by partially burning the coal in the gasifier. The process of gasification requires energy addition, as well as water and steam. In a free-standing plant, this energy comes from burning the fuel; but in an integrated plant some can come from heat-recovery heat exchangers in the energy conversion system in the form of steam or hot pressurized air. The power to drive the gasifier air compressors can also come from the energy conversion system in an integrated plant. A schematic of an integrated gasifier is shown in figure 5.14-2. If the gasifier is integrated with the energy conversion system, the product gas need not be cooled before being sent to the furnace. However, before the combustion gases from the furnace can be passed through a turbine, the gas must be cleaned. This could be done with the gas at a high temperature (e.g., 1600° F), as shown in figure 5.14-2(b).

The efficiency of a gasifier can be characterized by the amount of energy in the coal that ultimately is found in the product gas. There are some losses that are unavoidable; these are listed in table 5.14-9 for the Westinghouse case. There is the possibility of oxidizing the calcium sulfide formed in the desulfurization of the coal and reducing the losses by 4.2 percent of the lower heating value of coal. This would involve making use of the heat that is shown being withdrawn from the spent sorbent oxidizer in figure 5.14-2(b).

If the product gases are cooled, the efficiency of the gasifier depends upon how much of that heat is recovered. If none were recovered, the losses would be about an additional 18 percentage points. However, G.E. used a practical efficiency when the product gas is cooled to 315° F that is only about 6 percentage points lower. The efficiency of the configuration used by Westinghouse is 0.93, and the efficiency of that used by G.E. is 0.87.

But, for an integrated system, the gasifier, furnace, and conversion system should be considered together. Since the energy from the fuel is recovered in different ways, the most useful measure of efficiency is the overall energy conversion system efficiency. This efficiency depends not only upon the losses, but also upon how the integration is accomplished. If the product gas is cooled, cleaned, and then reheated (as G.E. does), there will be a loss in availability of the product gas if its temperature is lowered. On the other hand, if the gas is cleaned at a high temperature (as Westinghouse does), this loss in availability is avoided.

Another factor in the integration is the amount of heat transferred from the furnace to the prime cycle. This affects the system performance because the prime cycle is more efficient than the furnace pressurizing cycle. In table 5.14-10 the fraction of the heat transferred to the prime cycle for both contractors is shown. General Electric uses about 35 percent in all cases; Westinghouse uses 50 percent in the liquid-metal Rankine system and around 70 percent in the closed-cycle gas turbine and advanced steam systems.

These numbers reflect the integration approach taken by each contractor for the closed-cycle systems. General Electric used the furnace-pressurizing gas turbine exhaust to raise steam for the gasifier and to produce power in an additional steam turbine, as indicated in figure 5.14-2(a).

Westinghouse, on the other hand, tended in most cases to transfer this heat to the prime cycle and then extract steam from the prime-cycle steam bottoming cycle for the gasifier.

5.14.2.4 Gasifier and Furnace Costs

The cost of the gasifier based upon the flow rate of coal and the higher heating value (in MWt) is shown in table 5.14-11. The G.E. costs are the same for all systems (except for the combined cycle, where the gasifier pressure is 351 psi compared with 185 psi for the others). The Westinghouse costs are the same for all systems.

Two columns are shown for the Westinghouse cases: one gives the material costs, the other includes material costs plus all direct and indirect labor costs involved in the gasifier installation. General Electric provided only the total number. The Westinghouse gasifier is a fluidized-bed design with sulfur removal in the bed and particulate removal from the hot gas. The gasifier used by General Electric is a fixed-bed, Lurgi-type gasifier with cold-gas cleanup. The cost agreement in the table is quite close, even though the designs are quite different.

The pressurized furnace loop component costs are given in table 5.14-12 for both contractors. The heat-exchanger costs calculated by General Electric vary considerably from system to system. The advanced steam system is the lower cost system because of a large logarithmic mean temperature difference and a low tube wall temperature. Also the tubes are 1.25 and 1.75 inches in outside diameter for this heat exchanger. The next cheapest system is the liquid-metal MHD. The logarithmic mean temperature difference is lower and the tube size for this and all other systems is near approximately 2.5 inches. The liquid-metal Rankine and closed-cycle gas turbine systems are about 5 times as costly as the advanced steam system because the logarithmic mean temperature difference is lower (by about 1/3) but mainly because the material is Hastelloy X and more expensive. Finally, the supercritical carbon dioxide cycle is much more expensive than the advanced steam system (about 8 times) because material costs are higher (Hastelloy X and Mo-Re 2) and more material is required at the higher pressures.

Westinghouse's costs are comparable to G.E.'s for both the advanced steam and liquid-metal Rankine systems. However, their costs are much higher for the closed-cycle gas turbine.

TABLE 5.14-1. - NUMBER OF PARAMETRIC POINTS CALCULATED FOR EACH ENERGY CONVERSION SYSTEM AND EACH FUEL

Energy conversion system	Contractor	Type of fuel															Total for ECAS
		Coal			Low-Btu gas			Intermediate-Btu gas			High-Btu gas	COED	Solvent-refined coal	Distillate	Hydrogen	Methanol	
		Type of coal[a]															
		B	SB	L	B	SB	L	B	SB	L	(b)						
		Number of parametric points															
Advanced steam	General Electric	18	3	3	1	1	1						1				28
	Westinghouse	116	5	5	48	3	3										180
Closed-cycle gas turbine	General Electric	34	1	1	1	1	1				7						46
	Westinghouse:																
	Combined	1	1	1	1						1			47			52
	Recuperated	6	1	1	1						1			38			48
Liquid-metal Rankine topping cycle	General Electric	12	1	1	1	1	1				1						18
	Westinghouse	35	1	1	11	1	1										50
Liquid-metal MHD	General Electric	11	1	1	1	1	1				1						17
	Westinghouse	9															9
Supercritical CO_2	General Electric	25	1	1	1	1	1				2						32
	Westinghouse																--
Combined cycle	General Electric:																
	Water-cooled turbines				19	1	1				1	1	1				24
	Air-cooled turbines				27	1	1	1	1	1	1	1	1				35
	Westinghouse				1						1			78			80
Open-cycle MHD	General Electric	21	1	1									7				30
	Westinghouse	26	4	4							5						39
Closed-cycle MHD	General Electric	6	1	1				1	1	1			12				23
	Westinghouse				4	1	1				1						7
Fuel cells	General Electric							3	1		5				9		18
	Westinghouse				1			21			43					3	68
Open-cycle gas turbine	General Electric										33	1	1				35
	Westinghouse										1			96			97

[a]B = bituminous; SB = subbituminous; L = lignite.
[b]Not applicable.

TABLE 5-14-2. - NUMBER OF PARAMETRIC POINTS CALCULATED FOR EACH ENERGY CONVERSION SYSTEM AND SELECTED CHEMICAL- TO THERMAL-ENERGY CONVERSION PROCESS

Energy conversion system	Contractor	Furnace				Combustors		Gasifier-integrated LBTU (except as noted)
		Conventional (CF)	Atmospheric fluidized bed (AFB)	Pressurized (PF)	Pressurized fluidized bed (PFB)	Coal fired	Clean- or semiclean-fuel fired	
		Number of parametric points						
Advanced steam	General Electric	4	17	3	4			3
	Westinghouse	59	13	54	54			54
Closed-cycle gas turbine	General Electric		35	10	1			3
	Westinghouse:							
	Combined			49	3			1
	Recuperated	1		39	8			1
Liquid-metal Rankine topping cycle	General Electric		10	5	1			3
	Westinghouse			13	37			13
Liquid-metal MHD	General Electric		12	4	1			3
	Westinghouse	9						
Supercritical CO_2	General Electric		26	5	1			3
Combined cycle	General Electric:							
	Water-cooled turbines						24	21
	Air-cooled turbines						35	29
	Westinghouse						80	1
Open-cycle MHD	General Electric					23	7	
	Westinghouse					34	5	5
Closed-cycle MHD	General Electric					8	15	
	Westinghouse						7	6
Fuel cells	General Electric							4
	Westinghouse							[a]2
Open-cycle gas turbine	General Electric						35	
	Westinghouse						97	

[a]One IBTU gasifier; one LBTU gasifier.

TABLE 5.14-3. - PARAMETRIC POINT (CASE) SELECTED FOR FURNACE AND GASIFIER DISCUSSION

Energy conversion system	Contractor	Furnace: Conventional (CF)	Furnace: Pressurized (PF)	Furnace: Fluidized beds: Atmospheric (AFB)	Furnace: Fluidized beds: Pressurized (PFB)	Gasifier-integrated
		Parametric point (case) selected				
Advanced steam	General Electric	17	21	1	24	21
	Westinghouse	23	7, 16	24	7	7, 16
Closed-cycle gas turbine	General Electric	--	4, 7	1	8	4
	Westinghouse	--	30, 29	--	22	30
Liquid-metal Rankine topping cycle	General Electric	--	4, 7	1	9	4
	Westinghouse	--	44	--	21	44
Liquid-metal MHD	General Electric	--	6, 9	17	10	6
	Westinghouse	9	----	--	--	--
Supercritical CO_2	General Electric	--	6, 9	11	5	6
	Westinghouse	--	----	--	--	--
Combined cycle	General Electric	--	----	--	--	25
	Westinghouse	--	----	--	--	1

TABLE 5.14-4. - LOSSES FOR VARIOUS FURNACES AND TYPES OF FUEL - WESTINGHOUSE RESULTS

Type of loss	Furnace			
	Conventional (CF)[a]	Pressurized (PF)[b]	Atmospheric fluidized bed (AFB)[a]	Pressurized fluidized bed (PFB)[a]
	Amount of loss, percentage of HHV			
Incomplete combustion	0.5	0	2.4	1.5
Radiation	.1	0	.18	.15
Solids sensible heat	0	0	.1	.1
Desulfurization reactions	0	0	2.1	2.1
Latent heat (steam)	5.14	7.04	5.14	5.14

[a]Uses Illinois #6 bituminous coal with HHV of 10 778 Btu/lb.
[b]Uses HBTU gas with HHV of 22 674 Btu/lb.

TABLE 5.14-5. - FURNACE EFFICIENCIES

[Atmospheric pressure furnace with bituminous coal.]

Energy conversion system	Furnace type	Westinghouse	General Electric
		Furnace efficiency[a, b]	
Advanced steam	CF AFB	0.864(23) .856(24)	0.879(17) .888(1)
Closed-cycle gas turbine	AFB	(c)	0.876(1)
Liquid-metal Rankine topping cycle	AFB	(c)	0.859(1)
Liquid-metal MHD	AFB CF	(c) 0.88(9)	0.888(17) .888(17)
Supercritical CO_2	AFB	(c)	0.888(11)

[a] Furnace efficiency $= \left(\dfrac{\text{Heat input to prime cycle}}{\text{Coal flow rate} \times \text{Coal HHV}}\right) = Q_{hex}/W_f(\text{HHV})$,

where HHV = 10 778 Btu/lb.

[b] Numbers in parentheses denote contractors' parametric points (cases).

[c] Not applicable.

TABLE 5.14-6. - FRACTION OF FUEL ENERGY TRANSFERRED TO PRIME CYCLE

[Pressurized furnaces with high-Btu gas and pressurized fluidized beds with bituminous coal; higher heating value, HHV, 22 674 Btu/lb for HBTU and 10 788 Btu/lb for bituminous coal.]

Energy conversion system	Furnace type	Westinghouse	General Electric
		Fraction of fuel energy transferred to prime cycle,[a] Q_{hex}/W_f(HHV)	
Advanced steam	PFB	0.753(7)	[b]0.786(24)
Closed-cycle gas turbine	PF	0.750(29)	[c]0.713(7)
	PFB	.682(22)	.654(8)
Liquid-metal Rankine topping cycle	PF	--------	0.647(7)
	PFB	0.597(21)	.656(9)
Liquid-metal MHD	PF	--------	[c]0.712(9)
	PFB	--------	.653(10)
Supercritical CO_2	PF	--------	0.646(9)
	PFB	--------	.653(5)

[a]Numbers in parentheses denote contractors' parametric points (cases).

[b]Q_{hex} includes feedwater heat.

[c]Q_{hex} includes heat from stack-gas cooler.

TABLE 5.14-7. - ATMOSPHERIC FURNACE CAPITAL COST

(a) Summary (atmospheric-pressure furnace with bituminous coal)

Energy conversion system	Furnace type	Westinghouse	General Electric
		Cost[a] = Furnace cost/Q_{hex}, \$/kWth	
Advanced steam	CF AFB	21.2(23) 26.9(24)	18.5(17) 24.4(1)
Closed-cycle gas turbine	AFB	--------	60.1(1)
Liquid-metal Rankine topping cycle	AFB	--------	84.7(1)
Liquid-metal MHD	AFB CF	-------- 54.6(9)	39.2(17) --------
Supercritical CO_2	AFB	--------	76.2(11)

(b) Atmospheric-fluidized-bed component cost

	Energy conversion system					
	Advanced steam		Closed-cycle gas turbine	Liquid-metal Rankine topping cycle	Liquid-metal MHD	Super-critical dioxide
	Heat input to prime cycle, MWth					
	1085	1755	819	2400	1587	1330
	Westing-house (case 24)	General Electric (case 1)	General Electric			
			Case 1	Case 1	Case 17	Case 11
	Cost, Furnace cost/Q_{hex}, \$/kWth					
Furnace components:						
Heat exchanger	12.0	12.4	45.0	61.3	26.4	57.8
Input solids handling	4.4	3.4	3.5	3.6	3.5	3.5
Waste solids handling	1.4	1.0	1.0	1.0	1.0	1.0
Combustion gas treatment	4.0	3.2	3.2	3.4	3.2	3.2
Draft fans	1.0	1.5	1.6	1.7	1.6	1.6
Miscellaneous	.6	1.3	1.8	1.9	1.8	1.8
Subtotal	23.4	22.8	56.1	72.9	37.5	68.9
Additional heat exchangers:						
Low-temperature air heater	3.5	1.6	1.6	1.5	1.7	1.6
High-temperature air heater	----	----	2.4	10.3	----	5.7
Total	26.9	24.4	60.1	84.7	29.2	76.2
Prime-cycle maximum temperature, °F	1200	1200	1500	1400	1200	1200
Prime-cycle pressure, psia	3500	3500	967	33	735	3810

[a]Numbers in parentheses denote contractors' parametric points (cases).

TABLE 5.14-8. - PRESSURIZED-FURNACE CAPITAL COST

(a) Pressurized-fluidized-bed component cost

	Energy conversion system							
	Advanced steam		Closed-cycle gas turbine		Liquid-metal Rankine topping cycle		Liquid-metal MHD	Super-critical carbon dioxide
	Heat input to prime cycle, MWth							
	1422	1492	662	819	1775	2400	1186	1250
	Westing-house (case 7)[a]	General Electric (case 24)	Westing-house (case 22)	General Electric (case 8)	Westing-house (case 21)	General Electric (case 9)	General Electric	
							Case 10	Case 5
	Cost, Furnace cost/Q_{hex}, $/kWth							
Furnace components:								
Heat exchanger	4.5	7.5	25.2	17.2	15.6	33.2	10.7	25.1
Input solids handling	5.2	7.5	6.7	9.0	11.5	9.7	10.0	8.2
Waste solids handling	1.77	2.9	2.1	3.5	3.6	3.7	3.8	3.2
Combustion gas treatment	14.8	16.9	15.3	20.4	17.4	21.9	22.5	18.8
Miscellaneous	3.4	1.5	2.9	1.8	----	2.0	2.1	1.7
Subtotal	29.6	36.3	52.2	51.9	48.1	70.5	49.1	57.0
Additional heat exchangers:								
Low-temperature air heater	3.3	----	1.7	----	----	.6	----	----
Recuperator	----	----	10.3	2.8	----	----	----	3.2
Total	32.9	36.3	64.2	54.7	48.1	71.1	49.1	60.2
Air equivalence ratio	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pressure ratio	10	10	10	10	15	10	10	10
Open-cycle turbine-inlet temperature, °F	1600	1600	1700	1600	1600	1600	1600	1600
Prime-cycle maximum temperature, °F	1000	1200	1500	1500	1400	1400	1300	1350
Prime-cycle pressure, psia	3500	3500	1000	967	30	33	735	3810

(b) Pressurized-furnace total cost

	Energy conversion system				
	Closed-cycle gas turbine		Liquid-metal Rankine topping cycle	Liquid-metal MHD	Super-critical carbon dioxide
	Heat input to prime cycle, MWth				
	904	819	2400	1187	1154
	Westinghouse (case 29)	General Electric (case 7)	General Electric		
			Case 7	Case 9	Case 9
Total capital cost, Furnace cost/Q_{hex}, \$/kWth	64.3	31.2	25.7	18.9	80.0
Air equivalence ratio	1.15	1.1	1.1	1.1	1.1
Pressure ratio	10	8	8	8	8
Open-cycle turbine-inlet temperature, ^{o}F	1100	1200	1750	1200	1750
Prime-cycle maximum temperature, ^{o}F	1500	1500	1400	1300	1600
Prime-cycle pressure, psia	1000	967	33	750	3810

[a]Cost numbers quoted are for air equivalence ratio of 1.15, and hence are slightly different from actual case 7 values.

TABLE 5.14-9. - GASIFIER LOSSES - WESTINGHOUSE RESULTS

[Bituminous coal (3 percent moisture; product gas temperature, 1600° F.]

Type of loss	Amount of loss, percent of LHV[a]
Desulfurization reactions	2.6
Carbon loss (in ash, etc.)	1.0
Ash sensible heat	.3
Sorbent sensible heat	1.7
Radiation	1.0
Recycle gas loss	.3

[a]10 230 Btu/lb.

TABLE 5.14-10. - FRACTION OF COAL INPUT ENERGY TRANSFERRED TO PRIME CYCLE

[Pressurized furnace with low-Btu gas from bituminous coal.]

Energy conversion system	Westinghouse	General Electric
	Heat input to prime cycle[a,b]	
Advanced steam	0.715(7) 0.686(16)	0.347(21)
Closed-cycle gas turbine	0.755(30)	0.347(4)
Liquid-metal Rankine topping cycle	0.726(44)	0.347(4)
Liquid-metal MHD	--------	0.348(6)
Supercritical CO_2	--------	0.344(6)

[a]Furnace efficiency = $\left(\frac{\text{Heat input to prime cycle}}{\text{Coal flow rate} \times \text{Coal HHV}}\right)$

$= Q_{hex}/W_f(HHV)$, where HHV = 10 788 Btu/lb.

[b]Numbers in parentheses denote contractors' parametric points (cases).

TABLE 5.14-11. - INTEGRATED-GASIFIER CAPITAL COST[a]

[Bituminous coal.]

Energy conversion system	Westinghouse			General Electric	
	Parametric point	Material cost, $/kWth	Cost including direct and indirect installation labor, $/kWth	Parametric point	Cost including direct and indirect installation labor, $/kWth
Advanced steam	7	26.4	48.8	21	58.3
	16	26.4	48.8		
Closed-cycle gas turbine:					
Recuperated	30	27.8	51.3	4	58.3
Combined	40	27.9	51.6		
Liquid-metal Rankine topping cycle	44	27.6	51.0	4	58.3
Liquid-metal MHD	(b)	----	----	6	58.3
Supercritical CO_2	(b)	----	----	6	58.3
Combined cycle	1	27.5	50.8	25 (Air cooled)	43.9

[a]Capital cost = Gasifier cost/(Coal flow rate)(Coal HHV) = Gasifier cost/W_f(HHV). where HHV = 10 788 Btu/lb.

[b]Not applicable.

TABLE 5.14-12. - PRESSURIZED-FURNACE-LOOP COMPONENT COST

	Energy conversion system								
	Advanced steam			Closed-cycle gas turbine		Liquid-metal Rankine topping cycle		Liquid-metal MHD	Super-critical carbon dioxide
	Heat input to prime cycle, MWth								
	1353	1329	1755	868	819	1418	2400	1186	1250
	Westinghouse		General Electric (case 21)	Westing-house (case 30)	General Electric (case 4)	Westing-house (case 44)	General Electric (case 4)	General Electric (case 6)	
	Case 7	Case 16							
	Cost, Furnace cost/Q_{hex}, \$/kWth								
Furnace components:									
Heat exchanger	---	---	5.4	----	31.5	---	33.8	10.2	51.5
Auxiliary equipment	---	---	1.0	----	1.0	---	.9	9	.9
Subtotal	5.6	6.2	6.4	54.2	32.5	9.3	34.7	11.1	52.4
High-temperature heat exchangers	---	---	---	----	----	---	4.6	----	2.1
Total	5.6	6.2	6.4	54.2	32.5	9.3	39.3	11.1	54.5
Air equivalence ratio	1.1	1.1	1.15	1.1	1.15	1.2	1.15	1.15	1.15
Pressure ratio	10	8	10	10	10	10	10	10	10
Open-cycle turbine-inlet temperature, ^{o}F	1000	1700	1800	1100	1800	1800	1800	1800	1800
Prime-cycle maximum temperature, ^{o}F	1000	1000	1200	1500	1500	1400	1400	1300	1350
Prime-cycle pressure, psia	3500	3500	3500	1000	967	33	33	740	3810

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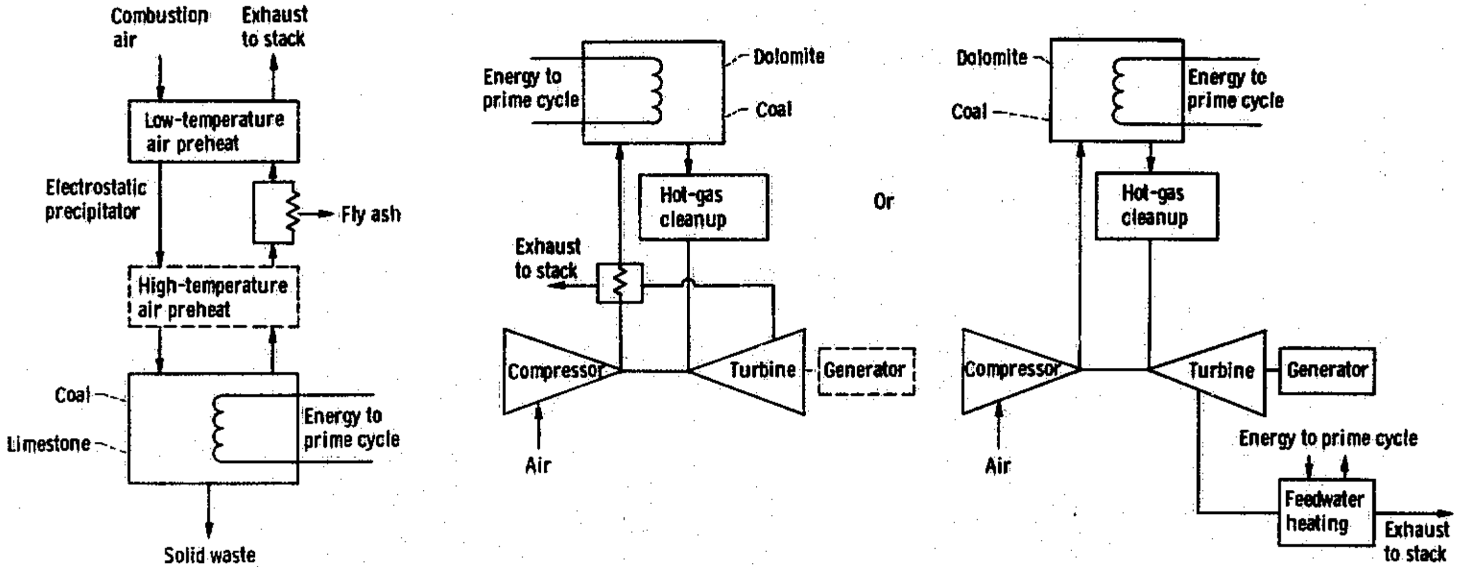
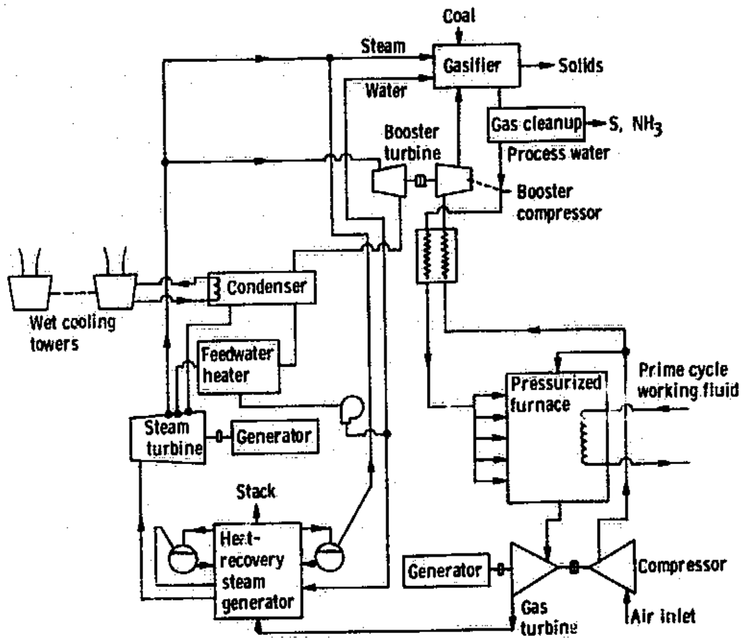


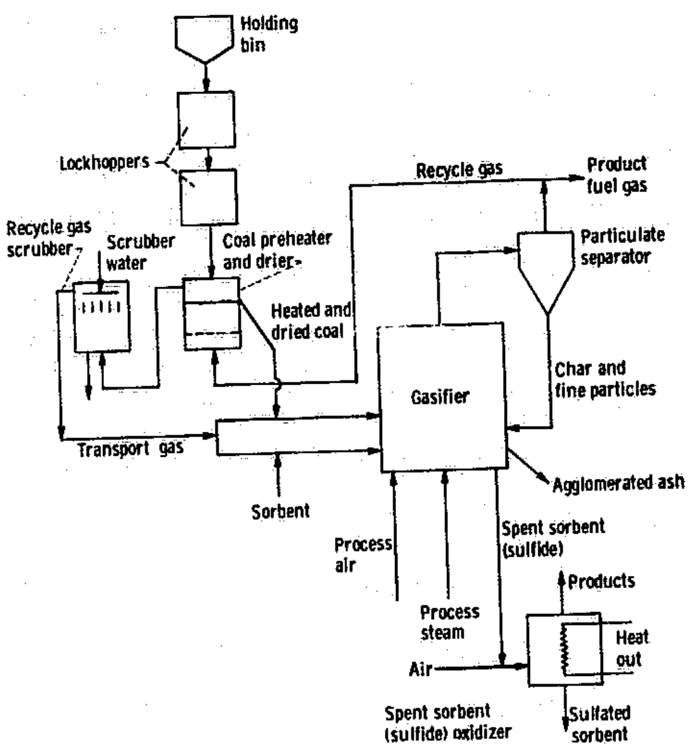
(a) Direct-coal-combustion atmospheric fluidized bed.

(b) Direct-coal-combustion pressurized fluidized bed.

Figure 5.14-1. - Furnace configuration.



(a) Pressurized furnace with integrated LBTU gasifier - General Electric.



(b) Fluidized-bed gasification process with high-temperature sulfur and particulate removal - Westinghouse.

Figure 5.14-2. - Gasifier configuration.

6.0 COMPARISON OF ENERGY CONVERSION SYSTEMS

by Raymond K. Burns, Joseph J. Nainiger, Robert J. Stochl, and Robert F. Migra

6.1 COMPARABILITY OF TREATMENT

A primary objective of ECAS is to assist in developing a technical and economic data base for a variety of advanced energy conversion systems on a common and consistent basis. In Phase 1, emphasis was placed on estimating the performance and cost of the 10 conversion systems studied over a wide range of parametric conditions and configurations. A number of approaches are employed in Phase 1 in an attempt to insure comparability of treatment of the systems studied. Among these were the specification by NASA of common study ground rules to be used by both contractors for all systems studied. (These are discussed in section 4.1.) Another was the use by each contractor of common groups to provide estimates of the performance and cost of components and subsystems common to more than one system - such as furnaces, heat exchangers, and balance-of-plant equipment. Further, all systems were studied in the same context of a complete utility powerplant with emphasis on base-load service.

A great deal of attention was placed on achieving comparability of treatment in the analyses of the various systems in Phase 1. Overall, comparability of treatment of the systems was successfully achieved, and relative comparisons of the systems and selections for Phase 2 study could be made. However, a number of factors should be kept in mind when evaluating the results of Phase 1. One important factor is that the conversion systems studied vary widely in the state of their technology. On the one hand are systems such as steam, open-cycle gas turbine, and combined gas turbine/steam turbine cycles for which an extensive and relatively mature technical and economic data base exists. A substantial extension of the technology would be required to reach the temperatures and/or other conditions associated with many of the parametric points studied for these systems. However, the total plant is relatively well known and cost information is well documented or within grasp. In contrast, the state of the art for systems such as high-temperature fuel cells and the MHD systems is not well developed, the total plant not well known, and a much less certain basis exists for estimating capital costs of components or balance-of-plant equipment. The other systems generally fall between these extremes. These considerations give rise to a number of additional factors affecting a complete system comparison.

First, performance and life assumptions will, of necessity, be more optimistic, that is, farther from demonstrated current state of the art, for systems with less-mature technologies than for the more mature, well-developed technologies. Second, the uncertainties associated with the cost estimates will be greater for the less-mature systems than for the mature systems both in terms of cost of components and balance-of-plant equipment. For those concepts selected for further study in Phase 2, these issues will be addressed in much greater detail than was possible in Phase 1, where approximately 900 parametric points were studied.

In Phase 2 the uncertainties in cost should be reduced through layout and conceptual design of the overall plant and major components. In Phase 2 the plant characteristics and the research and development required to bring the technology to the assumed levels of performance will be assessed. Also the time and resources needed to bring the plants to commercial fruition will be estimated. Although these factors are required for a complete evaluation and comparison to be made, no attempt is made here to do so.

With these points in mind, a comparison of systems is presented in section 6.2. Because the various systems might be affected by changes in the basic ground rules in different ways and to a different extent, the sensitivity of the systems to changes in the ground rules is also presented in section 6.2.

6.2 COMPARISON OF SYSTEM RESULTS

The General Electric and Westinghouse results are compared on a system-by-system basis in sections 5.2 to 5.14. In each case the range of system parameters and the areas of emphasis considered by each contractor are described. Parametric cases with nearly comparable conditions were chosen in section 5.0 so as to make a detailed comparison of system efficiency and cost estimates between General Electric and Westinghouse results. In this section all the system results are presented so as to allow a comparison of systems.

The ranges of efficiencies and cost of electricity calculated for all parametric points for all systems are summarized and compared. The results for the parametric cases with maximum efficiency, minimum cost of electricity, and minimum capital cost are tabulated for each system.

In section 6.2.1 the results as calculated by the contractors are examined. The effects on these results of changes in the study economic ground rules are displayed and discussed in section 6.2.2. For selected cases of each system, the effects of changing fuel price, fixed-charge rate, capacity factor, and interest and escalation rate are shown. Also, the costs of electricity for selected points are recalculated with common end-of-construction dates instead of common start-of-construction dates as described in section 4.2. The cost of electricity is also calculated on the basis of the average over the lifetime of the plant, also as described in section 4.2.

6.2.1 <u>Contractor Results</u>

6.2.1.1 Overall Results

In figures 6.2-1 to 6.2-6 the range of cost of electricity against the range of overall energy efficiency is given for all the parametric results for each system. In each figure the G.E. results are given in part (a) and the Westinghouse results in part (b). In section 5.0 the G.E. and Westinghouse results are compared for each individual system. The primary emphasis of this section is to compare the results for different systems. The details of comparisons discussed in section 5.0 will not be repeated here.

In each of figures 6.2-1 to 6.2-5 the results for a small group of systems are shown. The advanced steam system results are included in every case for a consistent reference. For each system, the results of all parametric points were plotted and a polygon was drawn around the points to define the range of results. In most cases the results for a system are described by more than one polygon, depending on the power system or combustion system configuration or type of fuel used. Some configurations or fuels are represented by a single point. In some cases a parametric point with clearly unattractive or uninteresting results was not included.

The size, shape, and location of these polygons are, of course, a function not only of the results of the calculations, but of the choice of study ground rules or the choice of system parameters. It was expected that the results of the two contractors' analyses would differ because of different approaches, procedures, assumptions, cost estimates, opinions, etc. These have been considered in the individual system discussions in section 5.0. Also described in section 5.0 was the range of system parameters considered in each contract, which in some cases varied considerably between the two contractors. As a result, the range of results would be expected to differ. In many cases, the results of the two contractors were meant to complement one another rather than to serve as a one-for-one comparison.

The effects on the results of changes in study ground rules are discussed in section 6.2.2 and shown in figures 6.2-17 to 6.2-26. The effect of one initial assumption, however, should be brought to attention here. That is, that the overall energy efficiencies of the contractors' results for cases using coal derived over-the-fence fuels sometimes differed predominantly because they assumed different fuel conversion efficiencies (see table 4.1-2). This is also discussed in section 6.2.2.

In each of figures 6.2-1 to 6.2-5, ellipses were drawn around the range of results for each system. These were then reproduced in figure 6.2-6, where the results for all the power systems are compared. When the results for two different configurations or two different fuels were sufficiently close, a single ellipse was used. In some cases when a particular configuration or fuel was of less interest than others considered, no attempt was made to include its results within the ellipses. Also more attention was given to reflecting the results accurately on the high-efficiency, low-cost side than on the less attractive side of the range. In this way the comparison of results in figure 6.2-6 was somewhat simplified. The grouping of power systems in figures 6.2-1 to 6.2-5 was arbitrary, chosen only to show more detail than was possible in figure 6.2-6.

An objective of this study is to compare power systems on the basis of their efficiency in the utilization of coal. Emphasis has therefore been placed on the overall energy efficiency, which includes the efficiency of the conversion of coal into a cleaner fuel for those systems that do not use coal directly. The power systems considered in ECAS have wide ranges of characteristics concerning fuel requirements. For each type of power system a range of fuel types has been considered, with a corresponding range of fuel conversion efficiencies. In some cases the powerplant efficiency is not substantially different for one clean fuel than for another, but the overall energy efficiency is substantially different because of a difference in fuel conversion efficiency. In other cases the powerplant efficiency might be increased by the use of a cleaner fuel that would allow an increase in maximum temperature. In such a case the cleaner fuel probably would have a lower fuel conversion efficiency. The overall energy efficiency may then increase or decrease depending on the relative changes in powerplant and fuel conversion efficiencies. Therefore, it is also of interest to display the system results on the basis of powerplant efficiency.

There are several other reasons for comparing the results in terms of powerplant efficiency. One is that, as shown in table 4.1-2, G.E. and Westinghouse have, in some cases, used different fuel conversion efficiencies for similar (or the same) fuels. In such cases a comparison of their results would be misleading without having considered this. The fuel conversion efficiencies were assumptions, as were the fuel prices. The assumed fuel conversion efficiency affects only the overall energy efficiency, and the assumed fuel price affects only the fuel cost portion of the COE. The absolute and relative positions of the polygons or ellipses in figures 6.2-1 to 6.2-6 are strongly dependent on these initial assumptions. The results of the analyses to determine the powerplant efficiency and capital costs, however, were not affected. Also sufficient information has been published so that the results of any parametric point could easily be modified to reflect different fuel price and/or fuel conversion efficiency values. In fact, in some later figures the sensitivity of certain selected results to some study ground rules or assumptions is displayed.

Still further, there may be situations where there are products from the coal conversion process, in addition to the powerplant fuel, that may be of value. In such a case the overall energy efficiency, which does not include these other possible useful byproducts, is not a complete measure of the efficiency of coal utilization. Quantitative consideration of such situations, however, was beyond the scope of this study.

Recognizing these factors, the results shown in figures 6.2-1 to 6.2-6 are also shown in terms of powerplant efficiency in figures 6.2-7 to 6.2-12. The format used is similar, groups of systems are compared in figures 6.2-7 to 6.2-11, and all systems are compared in figure 6.2-12. To show more detail than is possible in such figures as 6.2-1 to 6.2-12, some of the parametric results were tabulated. The maximum efficiency cases are listed in table 6.2-1. Also included are the powerplant and thermodynamic efficiencies, the cost of electricity, and the capital cost. Some of the major parameters were included to identify the powerplant operating conditions. For some systems, additional cases were included to represent some of the different plant configurations or fuels that were analyzed.

It should be emphasized that these are the maximum efficiency points chosen from the range of parametric cases considered by each contractor. Since in some cases the parametric ranges considered by the two contractors differed, the ranges of results obviously also differ. See the individual systems sections (section 5.0) for a discussion and comparison of the contractors' results. Also in comparing systems on the basis of the results shown in table 6.2-1, it should be noted that these points are not intended to represent the same degree of technological advancement for each system.

The results in figures 6.2-1 to 6.2-12 indicate that for some systems the maximum efficiency points are not the most attractive ones from the standpoint of cost of electricity (COE). It would be expected that the COE for low-capital-cost systems would be dominated by the fuel costs so that the maximum efficiency cases would correspond closely to the minimum COE cases. For high-capital-cost systems, on the other hand, it might be expected that anything done to reduce capital cost would decrease COE even if a decrease in efficiency (increased fuel costs) were also involved. For such systems there would likely be a correspondence between minimum capital cost cases and minimum COE cases. In tables 6.2-2 and 6.2-3 the results for the parametric cases with minimum COE and minimum capital cost are listed for each system. Table 6.2-4 is a listing of the parametric cases with maximum overall energy efficiency, minimum capital cost, and minimum COE for each system. The case numbers correspond to those listed in tables 6.2-1 to 6.2-3. As already discussed, the case with maximum efficiency is often also the case with minimum COE for the lower capital cost systems, such as gas turbines. However, for the higher capital cost systems, such as MHD or supercritical carbon dioxide, the case with minimum COE usually is also the case with minimum capital cost.

6.2.1.2 Efficiency Breakdown

The powerplant and thermodynamic efficiencies, as well as the overall energy efficiency, are listed in table 6.2-1. As explained in section 4.0, the thermodynamic efficiency is defined as the prime-cycle electrical output divided by the prime-cycle heat input. When a bottoming cycle is used, the prime cycle is defined to include both the top and bottom cycles. For an open-cycle system the heat input is the fuel flow rate times the higher heating value of the fuel. For closed-cycle systems, only part of the fuel energy content is transferred to the prime cycle. The remainder is either lost or, in the case of pressurized furnace systems, is used to produce power in the pressurizing gas turbine. The losses are in terms of latent and sensible heat of the stack gases, losses in cleaning combustion gas, and other losses from the furnace associated with such things as heat losses and solids removal. This is discussed in section 5.14. Table 5.14-5 gives the furnace efficiencies for several systems with atmospheric furnace loops. The atmospheric furnace-loop efficiency, defined as heat input to the prime cycle divided by the fuel input energy, varies from about 86 percent to 89 percent. When the furnace is pressurized, a smaller fraction of the fuel energy is transferred to the prime cycle.

The furnace pressurizing system is actually an open-cycle gas turbine operating in parallel to the prime cycle. The powerplant efficiency is a function of both the prime-cycle efficiency (referred to here as the thermodynamic efficiency) and the furnace-loop efficiency. It is defined as the net powerplant power output divided by the fuel energy input. The net powerplant output is the prime-cycle electrical output plus any net power output from the furnace pressurizing system minus all plant auxiliary power requirements.

The differences between powerplant and overall energy efficiencies shown in table 6.2-1 are the result of the type of fuel used and its conversion efficiency. The differences are largest for the open-cycle gas-turbine systems that use distillate or high-Btu gas and the G.E. low-temperature fuel cells that use hydrogen and oxygen. Comparative ranking of the systems on a powerplant efficiency basis indicates that open-cycle MHD, fuel cells, closed-cycle MHD, and liquid-metal Rankine are the most efficient systems from both contractors results.

As previously mentioned, the furnace pressurizing system is actually an open-cycle gas turbine operating in parallel with the prime cycle. Generally, the prime cycle has higher efficiency than the furnace pressurizing cycle. For a given prime cycle, the powerplant efficiency is therefore generally highest when the fraction of the power obtained from the prime cycle is highest. This power split between the prime cycle and the furnace cycle depends on how the cycles are integrated. Table 6.2-5 is a comparison of the power splits for each contractor for systems that use three types of pressurized furnace systems: (1) a pressurized furnace with an integrated gasifier, (2) a pressurized furnace burning an over-the-fence clean fuel, and (3) a pressurized fluidized bed. The three sources of power are the furnace loop, the primary topping cycle, and the primary bottoming cycle (where applicable). Also shown in table 6.2-5 is the ratio of furnace-loop power to total power. The similarity in methods of integration results in reasonable agreement in this ratio between contractors for comparative systems that use either the pressurized furnace burning clean fuel or the pressurized fluidized bed. However, there is a large difference in the ratio of furnace power to total power for comparative systems that use a pressurized furnace with an integrated gasifier. General Electric's method of integration was in all cases to bottom the open-cycle gas turbine in the furnace loop with a steam cycle, which provided additional power and steam for the gasifier. This resulted in the high ratio of furnace power to total power. Westinghouse, on the other hand, used two methods of integration. For the particular closed-cycle gas turbine case shown, the open-cycle turbine in the furnace loop was not recuperated and the exhaust energy was rejected. In the advanced steam and liquid-metal Rankine systems, for the particular cases shown, the exhaust energy from the furnace-loop turbine was used in feedwater heating in the steam cycle, thus increasing the relative power of either primary cycle.

The auxiliary power requirements as a percentage of plant gross power output are given for each system in table 6.2-6. Since auxiliary losses are generally a strong function of the type of furnace and the type of fuel used, each of these variations examined by each contractor has been presented in the table.

For both contractors the auxiliary power requirements are for the following items where applicable: cooling tower fans and pumps, material handling and treatment systems (e.g., for coal-derived fuels, coal, dolomite, limestone, and wastes), fans, stack-gas scrubbers and precipitators, and station auxiliaries (or housekeeping loads). General Electric assumed 1.0 percent of station gross power for housekeeping load for all systems. Westinghouse used 0.5 percent of gross power plus 0.6 percent of steam bottoming-cycle power for all systems except open-cycle gas turbine and combined cycles.

Generally the clean fuel cases have smaller auxiliary power requirements, largely because of the elimination of coal preparation, coal and solid waste handling, and stack-gas cleaning. In such cases the auxiliaries are dominated by the station housekeeping auxiliaries with the exception of those cases with bottoming cycles, where cooling tower auxiliary power requirements are included. Westinghouse open-cycle gas-turbine cases show no auxiliaries. For these cases, the auxiliaries are small and might have been included in the thermodynamic efficiency rather than listed separately (although this was not intended in the definition of thermodynamic efficiency).

Of those systems using coal directly, those using fluidized-bed furnaces with sulfur removal in the bed have the advantage that stack-gas sulfur dioxide removal, which is listed as an auxiliary power, is not required. But they require more solids handling (sorbent and spent sorbent) and higher fan power because of the relatively large pressure drop across the bed. Pressurized fluidized beds (PFB), however, have lower auxiliary power requirements than atmospheric fluidized beds (AFB) since the pressurizing turbocompressor eliminates the need for auxiliary fans for bed fluidization. Both G.E. and Westinghouse AFB auxiliary power requirements range from 5 percent to 7 percent, with one exception. The auxiliaries for the G.E. liquid-metal topping cycles are higher mainly because of their use of large boiler recirculation rates and hence higher liquid-metal boiler recirculation pump power (section 5.7). Notice that the auxiliary power percentages in table 6.2-6 for AFB cases are larger for the less-efficient systems, and the variation can almost be accounted for by the variation in system efficiency. This would be expected if the auxiliaries were more directly proportional to the input coal flow rate than to net system power output. The PFB cases have auxiliaries from 2 to 3.6 percent, again with the exception of the liquid-metal topping cycle.

Systems with integrated gasifiers have auxiliary power requirements similar to those with direct coal firing since they include similar coal preparation and handling systems. All the G.E. integrated gasifier cases, except the gas turbine/steam turbine combined cycle, have low auxiliary power requirements because of an apparent omission of the auxiliary power requirements for the gasifier.

The auxiliary power requirements used for the direct-coal-fired MHD systems are shown by table 6.2-6 to be consistent with the other coal-fired power systems. The seed processing fuel requirements for open-cycle MHD are not included in the auxiliary power requirements listed in the table. These requirements are discussed in section 5.8. The SRC-fired version of the closed-cycle inert-gas MHD system studied by G.E. has higher auxiliary power requirements than other SRC-fired systems listed. This is due to the use of combustion gas recirculation and the consequent higher fan power requirements in the furnace loop.

Among the fuel-cell systems, the most noticeable difference is that the phosphoric-acid-cell, HBTU-fuel case for G.E. is listed as having a 7.4 percent auxiliary power requirement, while the similar Westinghouse case has a 2.5 percent auxiliary power requirement. This difference apparently results from the use of a carbon dioxide scrubber by G.E., which Westinghouse did not include as a necessary requirement.

6.2.1.3 Capital Cost Breakdown

Capital cost is broken down into the cost of power-system major components, balance-of-plant costs, contingency, and interest and escalation during construction in figure 6.2-13 for the lowest capital cost cases given in table 6.2-3. The division shown between major component and balance-of-plant costs is as reported by G.E. and Westinghouse. The balance-of-plant cost includes all materials required on the construction site beyond those defined as major power-system components, all direct and indirect labor costs, and A and E services. The definition of these terms applied to this study and the factors used by G.E. and Westinghouse to estimate indirect labor, A and E services, contingency, and interest and escalation during construction are described in section 5.1.

The capital cost estimates of G.E. and Westinghouse for each system have been compared in sections 5.2 to 5.12. Care should be taken in comparing the results in figure 6.2-13 for several reasons. First, the cost breakdowns in the figure correspond to the minimum capital cost case of all the parametric variations studied by each contractor for each system. Because the two studies were not identical, in some cases this minimum capital cost case differs between G.E. and Westinghouse in power-system operating conditions or even system configuration or fuel used. (These system conditions are identified in table 6.2-2.) Also the items included in such categories as major component costs, balance-of-plant costs, or contingencies are not always identical. These problems are dealt with in the comparisons made on a system-by-system basis in section 5.0. In section 5.0 comparisons are made between the G.E. and Westinghouse results for parametric cases that may be more comparable than those shown in figure 6.2-13.

Comparison of the total capital costs between figures 6.2-4(a) and (b) (or between tables 6.2-2(a) and (b)) shows that G.E.'s and Westinghouse's cost estimates differed the most for closed-cycle inert-gas, liquid-metal, and open-cycle MHD systems and for the liquid-metal topping cycle system. These differences are discussed in sections 5.7 to 5.10, where the sources of the differences are identified.

The high-temperature fuel-cell cases in figure 6.2-13 show a large difference between G.E. and Westinghouse results; however, this is because the G.E. results include the capital cost of a low-Btu (LBTU) gasifier, while the Westinghouse results shown do not. Those Westinghouse cases that do include a gasifier were not included in table 6.2-2 since they were not among the lowest capital cost cases. Comparing a Westinghouse case that includes a gasifier (solid electrolyte case 19 with $858/kWe total capital cost) with the G.E. case in figure 6.2-13(a) shows much closer agreement.

The two closed-cycle gas-turbine organic-bottomed cases included in figure 6.2-13 (and table 6.2-2) also show a large difference between G.E. and Westinghouse results. However, this is again a case where the power-system configurations differ considerably. The G.E. case shown is a recuperated closed-cycle gas turbine with a 460° Fluorinol-85 bottoming cycle and an AFB furnace. The Westinghouse case is an unrecuperated closed-cycle gas turbine in parallel with a 2200° F unrecuperated open-cycle gas turbine and a 950° F sulfur dioxide bottoming cycle that recovers waste heat from both the open- and closed-cycle gas turbines. The Westinghouse case requires a clean fuel because of the open-cycle gas-turbine portion. Even for more comparable system configurations, however, G.E.'s and Westinghouse's cost estimates of organic-bottomed systems do differ. This result is discussed in section 5.12.

Figure 6.2-13 shows that the recuperated open-cycle gas-turbine, air-cooled combined-cycle, and low-temperature fuel-cell systems have the lowest capital costs for both contractors, while the closed-cycle, liquid-metal, and open-cycle MHD systems have the highest capital costs. In general, the relative ranking of all systems is similar for both contractors. The exceptions are the closed-cycle gas turbine with organic bottoming, which as mentioned previously, has different system configurations for each contractor, and the liquid-metal Rankine and open-cycle MHD systems, which have similar system configurations but differ significantly in cost estimates for major components and balance of plant.

6.2.1.4 Cost of Electricity Breakdown

For the cases listed in table 6.2-3, the breakdown of COE into portions due to capital costs, fuel costs, and operating-and-maintenance (O and M) costs is given in figure 6.2-14. The portion of COE due to capital costs follows directly from the total capital cost estimate (given in table 6.2-3), the specified capacity factor (0.65), and the fixed-charge rate (18 percent). The portion due to fuel costs follows directly from the powerplant efficiency (given in table 6.2-3) and the price of the particular fuel used in the plant. The fuel prices specified for the study are given in table 4.1-2.

The O and M costs are generally a small part of the total COE. However, the results in figure 6.2-14 show a consistent difference between the G.E. and Westinghouse estimates. The Westinghouse results are lower for most cases. In some cases the Westinghouse results appear inconsistent between systems, showing for example, no O and M costs for the MHD portion of the closed-cycle MHD system..

As for the figures showing the capital cost breakdown, care should be taken in comparing the results in figure 6.2-14 (or table 6.2-3). Since the cases included for each system are those that yielded lowest COE, and since G.E. and Westinghouse studied different matrices of parametric cases, for some systems the cases in figure 6.2-14 (and table 6.2-3) are for different system parameters, configurations, or fuels. This could not only affect this comparison of capital cost and hence the capital cost portion of COE, but could also have a significant effect on the COE through fuel cost simply because a different fuel (and hence fuel price) was used. In making a detailed comparison between the G.E. and Westinghouse results for a particular system, the discussions in sections 5.2 to 5.12 have chosen more comparable cases.

In examining the fuel cost portion of the COE and comparing it for different systems, the effect of the fuel price should not be forgotten. A variety of fuel types (and hence prices) have been used. For example, consider the Westinghouse results for the closed-cycle gas turbine shown in figure 6.2-8(b). Using a distillate fuel allowed consideration of a higher temperature open-cycle gas turbine in parallel with the 1500° F helium closed-cycle gas turbine. The range of results for the parametric variations using distillate fuel extends to higher powerplant efficiencies than those for the parametric variations using direct coal firing in a PFB. However, this did not decrease the fuel cost portion of the COE but increased it because of the higher fuel price of distillate as compared with coal. As a result, most of the closed-cycle gas-turbine cases included in table 6.2-3 are coal-fired cases.

There is a significant difference in COE between contractors for five comparable systems: liquid-metal Rankine, open- and closed-cycle MHD, liquid-metal MHD, and low-temperature fuel cells. In each case the difference is due to differences resulting from the capital cost that was estimated by each contractor. Of the systems common to both contractors, only air-cooled combined-cycle systems and advanced steam systems ranked among the lowest COE systems for each contractor.

The sensitivity of COE to the total capital cost is shown in figure 6.2-15 for each type of system. The COE was recalculated with arbitrary changes in the total capital cost. The parametric point used for each system was selected from those in table 6.2-4, which lists minimum COE, minimum capital cost, and maximum efficiency cases. These selected cases are listed in the last column of the table.

Obviously, the systems in which the COE is most dominated by the capital cost charges have the greatest slope. Low-capital-cost systems, such as open-cycle gas turbines, have little slope. With a few exceptions, the lowest capital cost systems having the least slope are also at the lower end of the ordinate, that is, at the lowest COE values. As a result, only a few systems change relative ranking when the capital cost estimates are arbitrarily changed over a wide range.

The systems that do change relative ranking are those for which the COE is not among the lowest yet for which the capital cost is relatively low. Two examples are the low-temperature fuel cell and the open-cycle gas turbine with organic bottoming. The open-cycle gas turbine with organic bottoming, for example, has about the same COE as the closed-cycle gas-turbine system but much lower capital cost (as shown in figure 6.2-14 and by its slope in figure 6.2-15). In spite of its higher powerplant efficiency, however, its fuel charges are much higher than those of the closed-cycle gas turbine because it requires a cleaner, more expensive fuel.

Because the low-COE systems shown are also the low-capital-cost systems and hence their COE's are dominated by fuel cost, an increase in fuel price would raise their COE's relative to those of the higher capital cost systems. For higher fuel prices, therefore, the curves in figure 6.2-15 would tend to cross at smaller variations in the capital cost estimate. The fuel prices used were specified as one of the economic ground rules of the study. The sensitivity of the results to changes in these ground rules are examined in the next section.

It is emphasized that the curves in figure 6.2-15 were calculated merely by arbitrarily changing the total capital cost in the mathematical expression for cost of electricity. Table 5.1-1 shows that the total capital cost estimates were arrived at by applying multipliers or adders to the basic estimates of direct materials and labor costs. These multipliers or adders were used to account for indirect labor costs, contingencies, A and E services, and escalation and interest during construction. If a change were made in the total of the major-component cost estimates of, for example, 10 percent and the balance-of-plant materials and labor estimates were not changed, the effect on total capital cost would be less than 10 percent. Even so, for some of the high-capital-cost systems, a few components dominate the total plant cost through both direct materials and installation costs. In such cases, improvements in the technology or design approach of one or a few components could significantly change the competitiveness of the system. Such situations have been discussed in sections 5.2 to 5.14.

One of the variables estimated by G.E. and Westinghouse that affects the total capital cost and hence COE is the plant construction time. The construction time affects the total capital cost through the interest and escalation charges. In addition, the contingency used by Westinghouse also is a function of construction time. The influence of construction time on COE is shown in figure 6.2-16 for each system. The parametric points used are again those listed in the last column of table 6.2-4. The higher capital cost systems show more influence for two reasons. First, the higher cost systems have the longer construction times, and a particular percentage change represents a longer time period. And second, the higher cost systems are more dominated by capital cost, so the interest and escalation multipliers have a greater influence on COE.

6.2.2 <u>Sensitivity to Ground Rules</u>

The results obtained in ECAS for the various power systems under consideration depend on certain common assumptions and ground rules that were employed to make the required calculations. Most of these assumptions affect the economic results and the subsequent COE for the power systems studied.

The contractors results have been published in detail sufficient to easily allow recalculation of the COE with other economic assumptions or ground rules. The COE for the selected points listed in table 6.2-4 have been recalculated for a variety of economic assumptions. The results are presented in this section. In few cases is the relative ranking of the power systems on the basis of COE changed when varying the specified economic ground rules one at a time over a wide range.

The COE values were calculated by the contractors as if construction of each type of system was started in mid-1974. All capital cost estimates before interest and escalation were estimated in mid-1974 dollars. The interest and escalation during construction were added, based on an S-shaped cash flow curve. The result is that plants with different construction periods have the final capital cost in different-year dollars. In all cases the fuel and O and M charges are in mid-1974 dollars. This procedure is referred to here as the "common start-of-construction date" approach. The COE values have been recalculated by several other approaches. These include the assumption of a common end-of-construction date, the COE in terms of constant dollars (deflated back to mid-1974), and the average COE over the lifetime of the plant. These results are included in the following sections (see also section 4.2).

6.2.2.1 COE with Common Start-of-Construction Date

The effect of changes in fuel price is seen in figure 6.2-17 for G.E. and Westinghouse results. For G.E., the low-temperature fuel-cell, open-cycle gas turbine/organic, and open-cycle gas turbine systems show the steepest slope and thus the greatest sensitivity to changes in their fuel price (fig. 6.2-17(a)) because these systems have COE's that are dominated by the fuel component of COE with relatively little contribution from capital or O and M components. Also, these systems use higher priced fuels (high-Btu (HBTU) gas or hydrogen) so that a percentage change in fuel price is large in $/MBtu.

Again for Westinghouse the greatest sensitivity to fuel price is shown for those systems with the higher priced fuels (fig. 6.2-17(b)). These systems are the alkaline, phosphoric acid, and molten carbonate fuel-cell systems and the open-cycle gas turbine/organic, closed-cycle gas turbine/organic, and open-cycle gas turbine systems. The solid electrolyte fuel cell uses intermediate Btu (IBTU) gas at $2/MBtu but does not show as much sensitivity to fuel price changes as the other fuel-cell systems because of its high powerplant efficiency (0.544).

In figures 6.2-18 to 6.2-21, the sensitivity of COE to changes in capacity factor, interest rate, escalation rate, and fixed-charge rate, respectively, is displayed. The COE's of the high-capital-cost systems (i.e., MHD, supercritical carbon dioxide, etc.) are very sensitive to changes in these economic ground rules since they affect only the capital portion of COE. These systems are characterized by large slopes on these figures. Likewise the low-capital-cost powerplants (i.e., open-cycle gas turbines, fuel cells, etc.) are relatively insensitive to the very same changes in ground rules because their capital COE costs are much smaller in comparison with their fuel COE. These systems display small slopes for the ground rules varied.

The capacity factor changes in figure 6.2-18 do not reflect any change in system design. In general a system design and hence cost and performance could be drastically affected by the intended capacity factor. A system design for intermediate service could be substantially different than one for base-load service, for example. For this reason the capacity factor range considered in figure 6.2-18 was not extended below 0.5.

There are few changes in the relative COE rankings of the systems for large changes in the economic ground rules shown in figures 6.2-18 to 6.2-21. Most of the crossover points for the various systems occur at the extreme limits of the ranges chosen for the different ground rules. In a majority of the cases where a crossover does occur, it affects the relative position of only two systems.

6.2.2.2 COE with Common End-of-Construction Date

As a starting point, figure 6.2-22 presents the G.E. and Westinghouse COE's and overall efficiencies for selected cases. Figure 6.2-22 was arrived at by selecting points situated in the lower right portions of the elliptical diagrams in figures 6.2-6. These points represent the best results for each of the systems studied (i.e., highest overall efficiency and lowest COE). These points (designated by solid circles), now enclosed in new ellipses, are used for the calculations that follow.

Analysis based on a common end-of-construction date examines the systems by allowing their construction to end in the same year, in this case 1981. Therefore, the open-cycle MHD system with a 7-year construction time would still begin construction in 1974, but the open-cycle gas turbine with a 2-year construction time would now begin construction in 1979. To make this comparison, the capital costs of the power systems with less than 7-year construction times were escalated to their new start date corresponding to a 1981 end of construction. The appropriate escalation and interest multipliers were then applied by using a cash flow curve that is similar but not identical to those used by the contractors.

The results of NASA's common-end-date analysis are shown for the two contractors in figure 6.2-23. Compared with the contractor's results, the COE's increase slightly for all systems with the exception of open-cycle MHD, for which COE remains the same, and closed-cycle MHD for Westinghouse, for which COE decreases as a result of an 8-year estimated time of construction (cost based on 1973 dollars). As shown, the relative positions of the systems remain about the same with the exception of the MHD systems, which improve relative to the other systems. However, compared with the original results, there is little change in the relative positions of the systems to each other. In figure 6.2-23(a) the COE's for the closed-cycle gas turbine, liquid-metal Rankine, and open-cycle MHD systems become approximately equal. In figure 6.2-23(b), the molten carbonate and solid electrolyte fuel cells have lower COE's than the phosphoric acid and alkaline fuel cells, and the COE's for the open-cycle MHD and advanced steam systems are closer to that for the combined cycle. A further change is seen when other assumptions are employed, namely the use of constant mid-1974 dollars and the average COE over the plant lifetime.

6.2.2.3 COE with Constant-Dollar Assumption

The use of constant mid-1974 dollars is advantageous in that it removes the powerplant time-on-line date from any cost considerations. If the capital cost is expressed in the year that the powerplant comes on line (as is done in ECAS), it is necessary to deescalate the capital costs back to mid-1974 at the prevailing escalation rate. In constant dollars, then, the length of the construction period causes an increase in capital cost only by the interest paid in excess of the escalation rate. For a more detailed comparison of constant-dollar costs with current-dollar costs, refer to section 4.2.

Figure 6.2-24 shows the system on-line COE's for G.E. and Westinghouse, respectively, using constant mid-1974 dollars. Note that this is equivalent to the average COE over the 30-year lifetime of each system, assuming no inflation over that 30-year period, such that all COE components are unchanged during the plant life in constant and current dollars. (Average lifetime COE will be further explained later in this section.) The first noticeable difference in these figures is that the range between the high and low COE points has decreased from about 70 mills/kW-hr using current-dollar analysis to 45 mills/kW-hr using constant dollars. Also, the absolute level of all the COE's is lower. The systems having high capital cost decreased more in COE than the low-capital-cost systems. The reason is that these systems generally have longer construction times. Thus, in current dollars they have a proportionately larger increase in capital cost due to escalation. In constant dollars this increment does not exist.

In figure 6.2-24(a), the low-temperature fuel-cell COE's are approximately equal to those for the liquid-metal MHD, closed-cycle MHD, and supercritical carbon dioxide systems. Likewise, the open-cycle gas turbine, both recuperated and with organic bottoming, has approximately the same COE as closed-cycle gas turbine (both recuperated and bottomed), liquid-metal Rankine, and open-cycle MHD systems. In figure 6.2-24(b) the COE's for open-cycle gas turbines are equal to the COE's for the closed-cycle gas turbine, liquid-metal MHD, and closed-cycle gas turbine/steam systems. Likewise, open-cycle MHD and liquid-metal Rankine systems come very close to the advanced steam and combined-cycle systems in lowest COE.

6.2.2.4 COE Average Over Plant Lifetime

As stated previously, figure 6.2-24 can represent either the on-line constant-dollar COE or equivalently the average COE over the 30-year lifetime of the powerplant, assuming no inflation during that lifetime. The 30-year average COE is defined as the total bus-bar cost of producing electricity for 30 years divided by the total amount of power produced during that time. When constant dollars are used, the average COE decreases as higher inflation rates are assumed during the plant life. (The fixed charge attributed to the capital component of COE becomes smaller in an inflationary period because its constant-dollar value decreases.) The fixed-charge rate of 18 percent assumed in ECAS and the previous results of this section are also assumed here. Again, the reader is referred to section 4.2 for a further discussion of the average COE during a powerplant lifetime.

The average COE's are shown in figure 6.2-25 for G.E. and Westinghouse with an assumed inflation rate of 3.25 percent over the lifetime of the plant. In both cases the low-temperature fuel cells show the highest average COE, and the combined-cycle and advanced steam systems still show the lowest COE. However, the Westinghouse open-cycle MHD systems have COE's about equal to the combined-cycle and advanced steam systems. Also closed-cycle MHD now has a COE approximately equal to the average COE's for the molten carbonate and solid electrolyte fuel cells.

Likewise, figure 6.2-26 shows the average COE's for all the systems assuming a 6.5 percent inflation rate during the plant lifetime. In figure 6.2-26(a) the G.E. low-temperature fuel cells have the highest COE, although combined cycles and advanced steam still have the lowest COE. For Westinghouse (fig. 6.2-26(b)), open-cycle MHD has a lower average COE than the combined-cycle system, and the fuel cells also have the highest COE. The total range between lowest and highest COE is now about 35 mills/kW-hr, as compared with the previously noted 70 mills/kW-hr for the contractor results using the common-start-date approach.

6.2.2.5 Concluding Remarks

Fuel price, capacity factor, interest and escalation rates, and fixed-charge rate were varied one at a time from the NASA specified values. In few cases did the ranking of the systems change in terms of COE for a wide range in variation of these parameters.

The COE for selected parametric points was also recalculated for each system by using approaches other than the common-start-date approach. The assumption of common end-of-construction date produces little change in the results. This is because the end date was chosen as 1981, corresponding to a 1974 construction start for the plant with the longest construction period. Thus the COE value for long-construction-period plants changed very little. For plants with short construction periods the capital cost estimates were escalated to a new start date corresponding to the 1981 completion date. However, the plants with short construction periods generally have low capital cost, and COE is dominated by fuel cost. Hence the change to common end-of-construction date had little effect for these systems also.

The use of a constant-dollar assumption in the calculation of COE does have a substantial effect on the COE values. However, the relative ranking of the systems in terms of COE was not substantially changed.

If it is assumed that the prevailing inflation rate during a plant lifetime is greater than zero, the COE measured in constant mid-1974 dollars decreases (the fixed charge attributed to the capital cost decreases). Under such circumstances the importance of the fuel and O and M costs relative to the capital costs is increased. Systems with higher efficiencies, but higher capital costs, then appear relatively more attractive. The COE values for selected points were calculated for such an assumption by assuming 3.25 and 6.5 percent inflation rates over the 30-year plant life.

TABLE 6.2-1. - MAXIMUM EFFICIENCY POINTS

(a) General Electric results

System	Contractor's case number	Overall energy efficiency, percent	Power-plant efficiency, percent	Thermo-dynamic efficiency, percent	Cost of electricity, mills/kW-hr	Total capital cost, $/kWe	System conditions
Advanced steam	7	39.8	39.8	47.7	36.6	847.2	3500 psi/1200° F/1400° F; AFB
	14	39.3	39.3	47.2	33.3	742	3500 psi/1200° F/1200° F; AFB
Open-cycle gas turbine:							
Recuperated	10	28.2	36.1	36.6	25.7	190.2	SRC fuel; 2200° F; pressure ratio, 12; recuperator effectiveness, 0.85
	19	18.4	36.7	37.0	31.2	169	Ceramic vanes; 2600° F; pressure ratio, 16; recuperator effectiveness, 0.85
Organic bottomed	36	21.7	43.1	44.3	33.7	334.9	HBTU gas; 2200° F; pressure ratio, 12; recuperator effectiveness, 0.85
Combined-cycle gas turbine:							
Air cooled	4	37.6	37.6	----	25.4	459.6	LBTU gas; Montana subbituminous coal; 2200° F; pressure ratio, 12 (1250 psi/950° F)
	5	31.8	45.6	46.9	24.8	255	IBTU gas; 2200° F; pressure ratio, 12 (1250 psi/950° F)
	35	36.7	36.7	----	22.9	395	LBTU gas; Illinois #6 coal; 2600° F; pressure ratio, 12 (1450 psi/1000° F)
Water cooled	5	36.7	47	48.5	23.6	266.6	SRC fuel; 2800° F; pressure ratio, 16 (1450 psi/1000° F)
	14	37.2	37.2	----	24.5	428	SRC fuel; 2800° F; pressure ratio, 16 (1450 psi/1000° F/1000° F)
Closed-cycle gas turbine:							
Recuperated	20	31.6	31.6	38.3	33.7	706	Intercooled; 1500° F; pressure ratio, 4; recuperator effectiveness, 0.85
	23	32.8	32.8	40.3	48.4	1148.1	1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.95
Organic bottomed	41	37.8	37.8	45.7	42.1	993.1	AFB; Illinois #6 coal; 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.90
Steam bottomed	45	33.4	33.4	40.9	45.0	1041.3	1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.90
Supercritical CO_2	14	41.4	41.4	49.1	69.0	1889.9	AFB; 1350° F; pressure ratio, 3.14
Liquid-metal Rankine topping	9	39.6	39.6	51.4	39.6	917.4	PFB (recuperated); 1400° F potassium (3500 psi/1000° F/1000° F)
	17	41.5	41.5	52.2	44.6	1076.9	AFB; 1400° F cesium (3500 psi/950° F/950° F)
Open-cycle MHD	12	52.8	53.9	57.7	41.4	1048	3100° F; 16 atmospheres; direct fired
	26	46.0	58.9	60.4	43.1	939	3600° F; 20 atmospheres; SRC fuel
Closed-cycle MHD	101	41.8	41.8	49.8	61.6	1551	3000° F in; 1800° F out; adiabatic MHD generator efficiency, 0.70
	102	46.0	46.0	55.9	45.6	1109.9	3100° F in; 1755° F out; adiabatic MHD generator efficiency, 0.78
Liquid-metal MHD	12	38.5	38.5	46.6	111.5	3079	1500° F; 50 atmospheres
	101	36.7	36.7	44.2	77.5	2110	1300° F; 50 atmospheres
Low-temperature fuel cells	8	31.1	51.1	----	31.3	242.5	SPE; hydrogen/oxygen
High-temperature fuel cells	1	31.5	31.5	----	45	974	Base case; integrated gasifier plus steam bottoming cycle
	2	34.3	34.3	----	44.4	978.1	Montana bituminous coal; HBTU; integrated gasifier and steam bottoming cycle

TABLE 6.2-1. - Concluded.

(b) Westinghouse results

System	Contractor's case number	Overall energy efficiency, percent	Power-plant efficiency, percent	Thermo-dynamic efficiency, percent	Cost of electricity, mills/kW-hr	Total capital cost, $/kWe	System conditions
Advanced steam:							
AF	57	41.3	41.3	51.6	41.4	1062.8	5000 psi/1200° F/1200° F/1200° F
	65	38.1	38.1	47.6	26.0	555.7	3500 psi/1200° F/1200° F
AFB	31	38.6	38.6	48.5	29.0	619.7	3500 psi/1200° F/1400° F
PF	25	39.5	39.5	----	27.0	578.8	Turbine-inlet temperature, 2500° F; pressure ratio, 10; air equivalence ratio, 1.1; 3500 psi/1000° F/1000° F
	48	42.6	42.6	----	34.5	830.5	Turbine-inlet temperature, 2000° F; pressure ratio, 10; air equivalence ratio, 1.8; 5000 psi/1400° F/1400° F
PFB	31	38.3	38.3	----	22.5	418.6	Turbine-inlet temperature, 1800° F; pressure ratio, 10; air equivalence ratio, 1.1; 3500 psi/1000° F/1000° F
	46	42.8	4[illegible]	---	27.0	588.9	Turbine-inlet temperature, 1600° F; pressure ratio, 10; air equivalence ratio, 1.1; 5000 psi/1400° F/1400° F
Open-cycle gas turbine:							
Nonrecuperated	26	17.4	34.5	34.5	31.9	171.5	Turbine-inlet temperature, 2500° F; pressure ratio, 24; distillate
Recuperated	88	22.2	44.0	44.0	27.5	210.4	Turbine-inlet temperature, 2500° F; pressure ratio, 10; recuperator effectiveness, 0.80; distillate
Organic bottomed	96	22.0	43.7	----	34.9	444.2	Turbine-inlet temperature, 2000° F; pressure ratio, 8; recuperator effectiveness, 0.80; distillate, methylamine
Combined-cycle gas turbine	1	42.3	42.3	----	24.3	496.6	Turbine-inlet temperature, 2200° F; pressure ratio, 12; 2400 psi/1000° F/1000° F; LBTU
	50	25.0	49.5	----	25.9	234.9	Turbine-inlet temperature, 2600° F; pressure ratio, 12; 2400 psi/1000° F/1000° F; distillate
Closed-cycle gas turbine:							
Recuperated	10	19.2	38.0	----	45.4	681.5	Turbine-inlet temperature, 1800° F; pressure ratio, 2.5; recuperator effectiveness, 0.90; pumpup-turbine-inlet temperature, 2200° F; pressure ratio, 10; PF; distillate

	21	34.6	34.6	----	34.6	769.6	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.90; pumpup-turbine-inlet temperature, 1700° F; pressure ratio, 5; PFB
Steam bottomed	7	22.5	44.5	----	36.9	519.0	Turbine-inlet temperature, 1800° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 2200° F; pressure ratio, 10; 3500 psi/950° F, 350 psi/1050° F
	41	38.2	38.2	----	31.5	700.9	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 1700° F; pressure ratio, 10; 3500 psi/900° F, 500 psi/950° F; PFB
Organic bottomed	48	21.8	43.1	----	38.4	544.2	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 2200° F; pressure ratio, 10; methylamine turbine-inlet temperature, 500° F; 2500 psi
Liquid-metal Rankine topping	13	44.6	44.6	----	27.8	623.6	Turbine-inlet temperature, 1400° F; pumpup-turbine-inlet temperature, 1800° F; pressure ratio, 15; feedwater heating; PFB; 3500 psi/1000° F
Open-cycle MHD							
1	14	53.5	53.5	----	32.3	827.2	3532° F preheat; inlet pressure, 8 atmospheres; preoxidized coal
	15	49.6	49.6	----	32.5	826.1	2933° F preheat; inlet pressure, 8 atmospheres; preoxidized coal
2	15	48.9	48.9	----	29.6	723.3	2390° F preheat; inlet pressure, 6 atmospheres; as-received coal
	17	48.7	48.7	----	27.1	641.7	2400° F preheat; inlet pressure, 7 atmospheres; minimum dry coal
3	5	53.5	53.5	----	35.7	856.9	3180° F preheat; inlet pressure, 15 atmospheres; LBTU
Closed-cycle MHD	1	45.5	45.5	59.3	69.8	1972.8	Turbine-inlet temperature, 2367° F; Illinois #6 coal
	4	25.2	50.0	59.3	98.6	1992.8	Turbine-inlet temperature, 2367° F; HBTU
Liquid-metal MHD	14	38.9	38.9	----	45.2	1165.3	Turbine-inlet temperature, 1500° F; adiabatic MHD generator efficiency, 0.80
Fuel cells:							
Phosphoric acid	4	29.3	34.8	----	44.0	440.4	IBTU; electrode thickness, 0.05 cm
	8	23.9	35.5	----	41.5	448.2	HBTU; electrode thickness, 0.05 cm
	15	24.2	36.0	----	49.4	439.6	HBTU; electrode thickness, 0.025 cm
Alkaline	4	30.7	36.6	----	58.9	700.0	IBTU; electrode thickness, 0.05 cm
	11	25.6	38.1	----	46.2	448.2	HBTU; electrode thickness, 0.05 cm
	16	25.8	38.3	----	60.6	620.2	HBTU; electrode thickness, 0.025 cm
Molten carbonate	4	45.7	54.4	60.1	43.9	482.4	IBTU; electrode thickness, 0.1 cm
Solid electrolyte	1	46.9	69.7	76.2	42.1	424.4	HBTU; electrode thickness, 0.004 cm
	4	50.6	60.2	----	40.2	466.4	IBTU; electrode thickness, 0.004 cm; steam bottoming cycle
	18	53.0	53.0	----	47.7	948.3	IBTU; electrode thickness, 0.002 cm; integrated gasifier

TABLE 6.2-2. - MINIMUM CAPITAL COST POINTS

(a) General Electric results

System	Contractor's case number	Overall energy efficiency, percent	Power-plant efficiency, percent	Thermo-dynamic efficiency, percent	Cost of electricity, mills/kW-hr	Total capital cost, $/kWe	System conditions
Advanced steam	11	36.5	36.5	44.0	29.8	610.1	3500 psi/1000° F; AFB; Illinois #6
Open-cycle gas turbine:							
Recuperated	22	17.1	33.9	34.3	33.0	148.3	Turbine-inlet temperature, 2200° F; pressure ratio, 12; recuperator effectiveness, 0.80; HBTU
Organic bottomed	36	21.7	43.1	44.3	33.7	334.9	Turbine-inlet temperature, 2200° F; pressure ratio, 12; recuperator effectiveness, 0.85, HBTU; FL-85; wet cooling tower
Combined-cycle gas turbine:							
Air cooled	8	20.9	41.4	42.6	30.4	225.8	Turbine-inlet temperature, 2200° F; pressure ratio, 12, 1250 psi/950° F; HBTU
Water cooled	5	36.7	47.0	48.5	23.6	266.6	Turbine-inlet temperature, 2600° F; pressure ratio, 16; 1450 psi/1000° F; SRC
Closed-cycle gas turbine:							
Recuperated	6	31.5	31.5	36.4	33.6	668.0	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.85; Montana subbituminous coal; LBTU; PF
Organic bottomed	40	35.3	35.3	42.6	37.8	862.7	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.60; Illinois #6 coal; AFB, FL-85 460° F organic cycle
Steam bottomed	46	30.8	30.8	37.6	37.0	835.5	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0; Illinois #6 coal; AFB
Supercritical CO_2	7	35.3	35.3	47.7	49.6	1218.0	Turbine-inlet temperature, 1350° F; pressure ratio, 2.7; PF; LBTU
Liquid-metal Rankine topping	9	39.6	39.6	51.4	39.6	917.4	Turbine-inlet temperature, 1400° F; 3500 psi/1000° F/1000° F; Illinois #6 coal; PFB
Open-cycle MHD	12	52.8	53.9	57.7	41.4	1048.0	3100° F; 16 atmospheres; direct fired
Closed-cycle MHD	13	35.9	46.0	53.6	58.0	1310.0	3000° F in; 1800° F out; adiabatic MHD generator efficiency, 0.80
	102	46.0	46.0	55.9	45.6	1109.9	3100° F in; 1755° F out; adiabatic MHD generator efficiency, 0.78
Liquid-metal MHD	6	33.6	33.6	43.8	58.5	1460.0	1300° F; 50 atmospheres
Low-temperature fuel cells	8	31.1	51.1	----	31.3	242.5	SPE; hydrogen/oxygen
High-temperature fuel cells	4	27.9	27.0	----	42.3	861.6	Illinois #6; LBTU; integrated gasifier plus steam bottoming

TABLE 6.2-2. - Concluded.

(b) Westinghouse results

System	Contractor's case number	Overall energy efficiency, percent	Power-plant efficiency, percent	Thermo-dynamic efficiency, percent	Cost of electricity, mills/kW-hr	Total capital cost, $/kWe	System conditions
Advanced steam:							
AF	69	35.1	35.1	44.0	23.2	443.5	2400 psi/1000° F/1000° F
AFB	31	38.6	38.6	48.5	29.0	619.7	3500 psi/1200° F/1400° F
PF	49	37.6	37.6	----	25.6	539.3	3500 psi/1000° F/1000° F; turbine-inlet temperature, 2000° F; pressure ratio, 10; subbituminous coal
PFB	49	39.0	39.0	----	21.1	404.9	3500 psi/1000° F/1000° F; turbine-inlet temperature, 1600° F; pressure ratio, 10; subbituminous coal
Open-cycle gas turbine:							
Nonrecuperated	26	17.4	34.5	34.5	31.9	171.5	Turbine-inlet temperature, 2500° F; pressure ratio, 24; distillate
Recuperated	1	19.1	37.8	37.8	30.6	201.2	Turbine-inlet temperature, 2200° F; pressure ratio, 10; recuperator effectiveness, 0.80; distillate
Organic bottomed	96	22.0	43.7	----	34.9	444.2	Turbine-inlet temperature, 2000° F; pressure ratio, 8; recuperator effectiveness, 0.80; distillate; methylamine
Combined-cycle gas turbine:							
Nonrecuperated	50	24.9	49.5	----	25.9	234.9	Turbine-inlet temperature, 2600° F; pressure ratio, 12; 2400 psi/1000° F/1000° F; distillate
Recuperated	27	32.9	32.9	----	30.3	650.6	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.9; pumpup-turbine-inlet temperature, 1100° F; pressure ratio, 10; PFB; subbituminous coal
Closed-cycle gas turbine:							
Steam bottomed	42	37.1	37.1	----	30.3	683.1	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 1700° F; pressure ratio, 10; 3500 psi/900° F; 500 psi/950° F
Organic bottomed	52	21.4	42.5	----	35.1	431.3	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 2200° F; pressure ratio, 10; 1800 psi/950° F; distillate
Liquid-metal Rankine topping	13	44.6	44.6	----	27.8	625.6	Turbine-inlet temperature, 1400° F; pumpup-turbine-inlet temperature, 1800° F; pressure ratio, 15; feedwater heating; PFB; 3500 psi/1000° F
Open-cycle MHD:							
1	12	48.0	48.0	----	27.2	648.7	2931° F preheat; inlet pressure, 12 atmospheres; preoxidized coal
2	10	47.2	47.2	----	27.0	637.2	2402° F preheat; inlet pressure, 6 atmospheres; minimum-dry coal
3	4	51.5	51.5	----	33.9	787.6	3190° F preheat; inlet pressure, 10 atmospheres; LBTU
Closed-cycle MHD	4	25.0	50.0	59.3	71.1	1686.6	Inlet temperature to MHD generator, 3800° F; HBTU gas
Liquid-metal MHD	12	36.0	36.0	----	33.9	790.2	Inlet temperature to MHD, 1200° F; adiabatic MHD generator efficiency, 0.75
Fuel cells:							
Phosphoric acid	11	23.9	35.5	----	42.2	339.3	HBTU; electrode thickness, 0.05 cm
Alkaline	11	25.6	38.1	----	46.2	448.2	HBTU; electrode thickness, 0.05 cm
Molten carbonate	4	45.7	54.4	60.1	43.9	482.4	IBTU; electrode thickness, 0.10 cm; steam bottoming
Solid electrolyte	20	38.2	56.7	62.6	37.3	339.5	HBTU; electrode thickness, 0.002 cm

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TABLE 6.2-3. - MINIMUM COST OF ELECTRICITY POINTS

(a) General Electric results

System	Contractor's case number	Overall energy efficiency, percent	Power-plant efficiency, percent	Thermo-dynamic efficiency, percent	Cost of electricity, mills/kW-hr	Total capital cost, $/kWe	System conditions
Advanced steam	11	36.5	36.5	44.0	29.8	610.1	3500 psi/1000° F/1000° F; AFB, Illinois #6
Open-cycle gas turbine:							
Recuperated	10	28.2	36.1	36.6	25.7	190.2	Turbine-inlet temperature, 2200° F; pressure ratio, 12; recuperator effectiveness, 0.85; SRC
Organic bottomed	36	21.7	43.1	44.3	33.7	334.9	Turbine-inlet temperature, 2200° F; pressure ratio, 12; recuperator effectiveness, 0.85; HBTU; FL-85; wet cooling tower
Combined-cycle gas turbine:							
Air cooled	35	36.7	36.7	----	22.9	395.1	Turbine-inlet temperature, 2600° F; pressure ratio, 12; 1450 psi/1000° F; LBTU; Illinois #6 coal
Water cooled	5	36.7	47.0	48.5	23.6	266.6	Turbine-inlet temperature, 2800° F; pressure ratio, 16; 1450 psi/1000° F; SRC
Closed-cycle gas turbine:							
Recuperated	6	31.5	31.5	36.4	33.6	668.0	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.85; LBTU; Montana subbituminous coal; PF
	20	31.6	31.6	38.3	33.7	706.0	Turbine-inlet temperature, 1500° F; pressure ratio, 4; recuperator effectiveness, 0.85; intercooled; Illinois #6 coal; AFB
Organic bottomed	40	35.3	35.3	42.6	37.8	862.7	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.60; Illinois #6 coal; AFB
	41	37.8	37.8	45.7	42.1	993.1	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.90; Illinois #6 coal; AFB
Steam bottomed	46	30.8	30.8	37.6	37.0	813.5	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0
Supercritical CO_2	5	39.2	39.2	47.7	56.9	1501.0	Turbine-inlet temperature, 1350° F; pressure ratio, 2.7; Illinois #6 coal; PFB
	7	35.3	35.3	47.7	49.6	1218.0	Turbine-inlet temperature, 1350° F; pressure ratio, 2.7; LBTU; PF
Liquid-metal Rankine topping	9	39.6	39.6	51.4	39.6	917.4	Turbine-inlet temperature, 1400° F; 3500 psi/1000° F/1000° F; Illinois #6 coal; PFB
Open-cycle MHD	12	52.8	53.9	57.7	41.4	1048.0	3100° F; 16 atmospheres; direct fired
Closed-cycle MHD	13	35.9	46.0	53.6	58.0	1310.0	3000° F in; 1800° F out; adiabatic MHD generator efficiency, 0.80
	102	46.0	46.0	55.9	45.6	1109.9	3100° F in; 1755° F out; adiabatic MHD generator efficiency, 0.78
Liquid metal MHD	6	33.6	33.6	43.8	58.5	1460.9	1300° F; 50 atmospheres; PF
	10	36.4	36.4	44.0	70.0	1850.0	1300° F; 50 atmospheres; PFB
Low-temperature fuel cells	8	31.1	51.1	----	31.3	242.5	SPE; hydrogen/oxygen
High-temperature fuel cells	1	31.5	31.5	----	45.0	947.0	Base case; integrated gasifier plus steam bottoming cycle
	4	27.9	27.9	----	42.3	861.6	Illinois #6 coal; LBTU

TABLE 6.2-3. - Concluded.

(b) Westinghouse results

System	Contractor's case number	Overall energy efficiency, percent	Power-plant efficiency, percent	Thermo-dynamic efficiency, percent	Cost of electricity, mills/kW-hr	Total capital cost, $/kWe	System conditions
Advanced steam:							
AF	65	38.1	38.1	47.6	26.0	555.7	3500 psi/1000° F/1000° F
	69	35.1	35.1	44.0	23.2	443.5	2400 psi/1000° F/1000° F
AFB	31	38.6	38.6	48.5	29.0	619.7	3500 psi/1200° F/1400° F
PF	25	39.5	39.5	----	27.0	578.8	Turbine-inlet temperature, 2500° F; pressure ratio, 10; 3500 psi/1000° F/1000° F
	49	37.6	37.6	----	25.6	539.3	Turbine-inlet temperature, 2000° F; pressure ratio, 10; 3500 psi/1000° F/1000° F
PFB	31	38.3	38.3	----	22.5	418.6	Turbine-inlet temperature, 1800° F; pressure ratio, 10; 3500 psi/1000° F/1000° F
	49	39.0	39.0	----	21.1	404.9	Turbine-inlet temperature, 1600° F; pressure ratio, 10; 3500 psi/1000° F/1000° F
Open-cycle gas turbine:							
Nonrecuperated	26	17.4	34.5	34.5	31.9	171.5	Turbine-inlet temperature, 2500° F; pressure ratio, 24; distillate
Recuperated	88	22.2	44.0	44.0	27.5	210.4	Turbine-inlet temperature, 2500° F; pressure ratio, 10; recuperator effectiveness, 0.80; distillate
Organic bottomed	96	22.0	43.7	----	34.9	444.2	Turbine-inlet temperature, 2000° F; pressure ratio, 8; recuperator effectiveness, 0.80; distillate, methylamine
Combined-cycle gas turbine	1	42.3	42.3	----	24.3	496.6	Turbine-inlet temperature, 2200° F; pressure ratio, 12; 2400 psi/1000° F/1000° F; LBTU
Closed-cycle gas turbine:							
Recuperated	21	34.6	34.6	----	34.6	769.6	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.90; pumpup-turbine-inlet temperature, 1700° F; pressure ratio, 5; PFB

	27	32.9	32.9	----	30.3	650.6	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; recuperator effectiveness, 0.90; pumpup-turbine-inlet temperature, 1100° F; pressure ratio, 10; PFB; subbituminous coal
Steam bottomed	41	38.2	38.2	----	31.5	700.9	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 1700° F; pressure ratio, 10; 3500 psi/900° F; 500 psi/900° F; PFB
	42	37.1	37.1	----	30.3	683.1	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 1700° F; pressure ratio, 10; 3500 psi/900° F; 500 psi/900° F; PFB
Organic bottomed	52	21.4	42.5	----	35.1	431.3	Turbine-inlet temperature, 1500° F; pressure ratio, 2.5; pumpup-turbine-inlet temperature, 2200° F; pressure ratio, 10; 1800 psi/950° F; distillate
Liquid-metal Rankine topping	13	44.6	44.6	----	27.8	623.6	Turbine-inlet temperature, 1400° F; pumpup-turbine-inlet temperature, 1800° F; pressure ratio, 15; feedwater heating; 3500 psi/1000° F; PFB
Open-cycle MHD:							
1	12	48.0	48.0	----	27.2	648.7	2931° F preheat; inlet pressure, 12 atmospheres; preoxidized coal
2	10	47.2	47.2	----	27.0	637.2	2402° F preheat; inlet pressure, 6 atmospheres; minimum-dry coal
	17	48.7	48.7	----	27.1	641.7	2400° F preheat; inlet pressure, 7 atmospheres; minimum-dry coal
3	4	51.5	51.5	----	33.9	787.6	3190° F preheat; inlet pressure, 10 atmospheres; LBTU
	5	53.5	53.5	----	35.7	856.9	3180° F preheat; inlet pressure, 15 atmospheres; LBTU
Closed-cycle MHD	6	42.2	42.2	55.1	68.5	1912.5	Inlet temperature to MHD generator, 3100° F; Illinois #6 coal
Liquid-metal MHD	12	36.0	36.0	----	33.9	790.2	Inlet temperature to MHD generator, 1200° F; adiabatic MHD generator efficiency, 0.75
Fuel cells:							
Phosphoric acid	8	23.9	35.5	----	41.5	448.2	HBTU; electrode thickness, 0.05 cm; 100 000 hr
Alkaline	11	25.6	38.1	----	46.2	448.2	HBTU; electrode thickness, 0.05 cm; 10 000 hr
Molten carbonate	8	32.9	48.8	54.5	37.9	514.4	HBTU; 100 000 hr
Solid electrolyte	8	35.0	41.6	46.9	35.0	480.7	IBTU; 100 000 hr

TABLE 6.2-4. - PARAMETRIC CASE NUMBERS FROM TABLES 6.2-1 TO 6.2-3

System	Contractor	Maximum overall efficiency	Minimum cost of electricity	Minimum cost in $/kWe	Selected cases
		Contractor's case number[a]			
Advanced steam:					
AFB	General Electric	$\underline{7}$, 14	$\underline{11}$	$\underline{11}$	14
AF	Westinghouse	$\underline{57}$, 65	65, $\underline{69}$	$\underline{69}$	--
AFB	↓	$\underline{31}$	$\underline{31}$	$\underline{31}$	$\underline{31}$
PF	↓	25, $\underline{48}$	25, $\underline{49}$	$\underline{49}$	--
PFB	↓	31, $\underline{46}$	31, $\underline{49}$	$\underline{49}$	--
Open-cycle gas turbine:					
Simple	General Electric	$\underline{10}$, 19	$\underline{10}$	$\underline{22}$	$\underline{10}$
	Westinghouse	$\underline{26}$	$\underline{26}$	$\underline{26}$	--
Recuperated	Westinghouse	$\underline{88}$	$\underline{88}$	$\underline{1}$	$\underline{88}$
Organic bottomed	General Electric	$\underline{36}$	$\underline{36}$	$\underline{36}$	$\underline{36}$
	Westinghouse	$\underline{96}$	$\underline{96}$	$\underline{96}$	$\underline{96}$
Combined-cycle gas turbine:					
Air cooled	General Electric	$\underline{4}$, 5, 35	$\underline{35}$	$\underline{8}$	$\underline{35}$
	Westinghouse	$\underline{1}$, 50	$\underline{1}$	68	$\underline{1}$
Water cooled	General Electric	5, $\underline{14}$	$\underline{5}$	$\underline{5}$	$\underline{14}$
Closed-cycle gas turbine:					
Recuperated	General Electric	20, $\underline{23}$	$\underline{6}$, 20	$\underline{6}$	20
	Westinghouse	10, $\underline{21}$	21, $\underline{27}$	$\underline{27}$	$\underline{21}$
Steam bottomed	General Electric	$\underline{45}$	$\underline{46}$	$\underline{46}$	--
	Westinghouse	7, $\underline{41}$	41, $\underline{42}$	$\underline{42}$	$\underline{41}$
Organic bottomed	General Electric	$\underline{41}$	$\underline{40}$, 41	$\underline{40}$	$\underline{41}$
	Westinghouse	$\underline{48}$	$\underline{52}$	$\underline{52}$	$\underline{48}$
Supercritical CO_2	General Electric	$\underline{14}$	5, $\underline{7}$	$\underline{7}$	$\underline{14}$
Liquid-metal Rankine topping	General Electric	9, $\underline{17}$	$\underline{9}$	$\underline{9}$	$\underline{9}$
	Westinghouse	$\underline{13}$	$\underline{13}$	$\underline{13}$	$\underline{13}$
Open-cycle MHD:	General Electric	$\underline{12}$, 26	$\underline{12}$	$\underline{12}$	1
1	Westinghouse	$\underline{14}$, 15	$\underline{12}$	$\underline{12}$	$\underline{12}$
2	Westinghouse	$\underline{15}$, 17	$\underline{10}$, 17	$\underline{10}$	17
3	Westinghouse	$\underline{5}$	$\underline{4}$, 5	$\underline{4}$	--
Closed-cycle MHD	General Electric	101, 102	13, $\underline{102}$	13, $\underline{102}$	$\underline{101}$
	Westinghouse	1, 4	$\underline{6}$	$\underline{4}$	1
Liquid-metal MHD	General Electric	$\underline{12}$, 101	$\underline{6}$, 10	$\underline{6}$	$\underline{6}$
	Westinghouse	$\underline{14}$	$\underline{12}$	$\underline{12}$	$\underline{14}$
Fuel cells:					
Low temperature	General Electric	$\underline{8}$	$\underline{8}$	$\underline{8}$	--
High temperature	General Electric	1, $\underline{2}$	1, $\underline{4}$	$\underline{4}$	--
Phosphoric acid	Westinghouse	$\underline{4}$, 8, 15	$\underline{8}$	$\underline{11}$	$\underline{8}$
Alkaline	↓	$\underline{4}$, 11, 16	$\underline{11}$	$\underline{11}$	$\underline{11}$
Molten carbonate	↓	$\underline{4}$	$\underline{8}$	$\underline{4}$	$\underline{8}$
Solid electrolyte	↓	1, 4, $\underline{18}$	$\underline{8}$	$\underline{20}$	4

[a]Underlined cases are those with extreme value of denoted output parameter.

TABLE 6.2-5. - COMPARISON OF POWER SPLITS FOR SYSTEMS AND CONTRACTORS

System	Contractor	Integrated-gasifier pressurized furnace with low-Btu gas					Pressurized furnace with clean fuel					Pressurized fluidized bed				
		Case	Power, MW			Ratio of furnace power to total power	Case	Power, MW			Ratio of furnace power to total power	Case	Power, MW			Ratio of furnace power to total power
			Furnace	Primary topping cycle	Primary bottoming cycle			Furnace	Primary topping cycle	Primary bottoming cycle			Furnace	Primary topping cycle	Primary bottoming cycle	
Closed-cycle gas turbine	General Electric	4	441.0	300	0	0.595	7	41.1	300	0	0.120	8	110.7	300	0	0.270
	Westinghouse	30	35.3	331.9		.096	29	46.0	345.5	0	.117	22	84.0	253.2		.249
Supercritical CO_2	General Electric	6	673.0	600		.529	9	168.6	600	0	.219	5	169.0	600		.220
Advanced steam	General Electric	21	944.0	800		.541	—	-----	-----	-----	-----	24	177.0	600		.228
	Westinghouse	7	95.4	586.7		.140	—	-----	-----	-----	-----	7	114.3	617.1		.156
Liquid-metal Rankine topping	General Electric	4	1293	298.4	941.9	.510	7	351.0	298.4	941.9	.221	9	324.5	298.4	941.9	.207
	Westinghouse	44	155.2	129.2	615.6	.172	--	-----	-----	-----	-----	21	229.7	200.7	769.5	.191
Closed-cycle liquid-metal MHD	General Electric	6	639.1	536.2	0	.544	9	59.5	536.2	0	.100	10	160.4	536.2	0	.230

TABLE 6.2-6. - AUXILIARY POWER REQUIREMENTS

(a) General Electric results

System	Auxiliary power, percentage of gross power	Contractor case number
Advanced steam:		
AFB	6.4	1
CF	4.2	17
PF (LBTU gasifier)	1.1	21
PFB	3.6	24
Open-cycle gas turbine:		
Simple	1.1	1
Recuperated	1.2	6
Organic bottomed	2.7	30
Combined cycle - air cooled:		
COED fuel	3.0	10
SRC fuel	3.0	9
LBTU gasifier	3.4	1
Combined cycle - water cooled:		
COED fuel	2.9	6
SRC fuel	3.0	5
LBTU gasifier	3.5	1
Closed-cycle gas turbine:		
AFB	7.6	1
PF (LBTU gasifier)	.7	4
PF (HBTU)	1.2	7
PFB	2.5	8
Organic bottomed - AFB	6.7	34
Steam bottomed - AFB	7.1	42
Supercritical CO_2:		
AFB	5.2	1
PFB	2.0	5
PF (LBTU gasifier)	.4	6
PF (HBTU)	.7	9
Liquid-metal Rankine topping:		
AFB	11.9	1
PF (LBTU gasifier)	3.5	4
PFB	6.8	9
Open-cycle MHD:		
Direct coal fired	2.9	1
SRC fuel	2.3	24
Closed-cycle MHD:		
Direct coal fired	5.5	101
SRC fuel	8.7	1
Liquid-metal MHD:		
AFB	7.1	1
PF (LBTU gasifier)	1.0	6
PF (HBTU)	1.9	9
PFB	3.0	10
Low-temperature fuel cells:		
SPE (HBTU)	6.6	1
SPE (H_2 produced on site)	2.3	8
Phosphoric acid (HBTU)	7.4	12
High-temperature fuel cells (LBTU)	5.4	1

(b) Westinghouse results

System	Auxiliary power, percentage of gross power	Contractor case number
Advanced steam:		
PFB	3.0	1
CF (atmospheric)	7.2	1
AFB	6.9	6
PF (LBTU gasifier)	2.9	1
Open-cycle gas turbine:		
Simple	0	2
Recuperated	0	1
Organic bottomed	1.4	95
Combined cycle:		
Distillate fuel	1.3	42
LBTU gasifier	4.8	1
Closed-cycle gas turbine:		
Atmospheric furnace (distillate)	1.3	48
PF (distillate)	1.2	1
PFB	2.1	21
PF (HBTU)	1.2	29
PF (LBTU gasifier)	6.0	30
Steam bottomed - PF (distillate)	1.8	1
Steam bottomed - PF (HBTU)	1.6	39
Steam bottomed - PFB	2.5	41
Steam bottomed - PF (LBTU gasifier)	5.5	40
Organic bottomed - PF (distillate)	2.4	46
Liquid-metal Rankine topping:		
PF (LBTU gasifier)	5.9	4
PFB	2.5	1
Open-cycle MHD:		
Direct coal fired	3.1	1
LBTU gasifier	3.6	1
Closed-cycle MHD:		
LBTU gasifier	3.5	1
HBTU gas	1.2	4
Liquid-metal MHD (direct coal fired)	5.1	16
Low-temperature fuel cells:		
Phosphoric acid (HBTU)	2.5	1
Alkaline (HBTU)	8.5	1
High-temperature fuel cells:		
Solid electrolyte (HBTU)	4.6	1
Solid electrolyte (IBTU)	5.7	2
Solid electrolyte (LBTU gasifier)/steam	8.2	19
Molten carbonate (HBTU)	6.3	1
Molten carbonate (IBTU)/steam	5.7	4

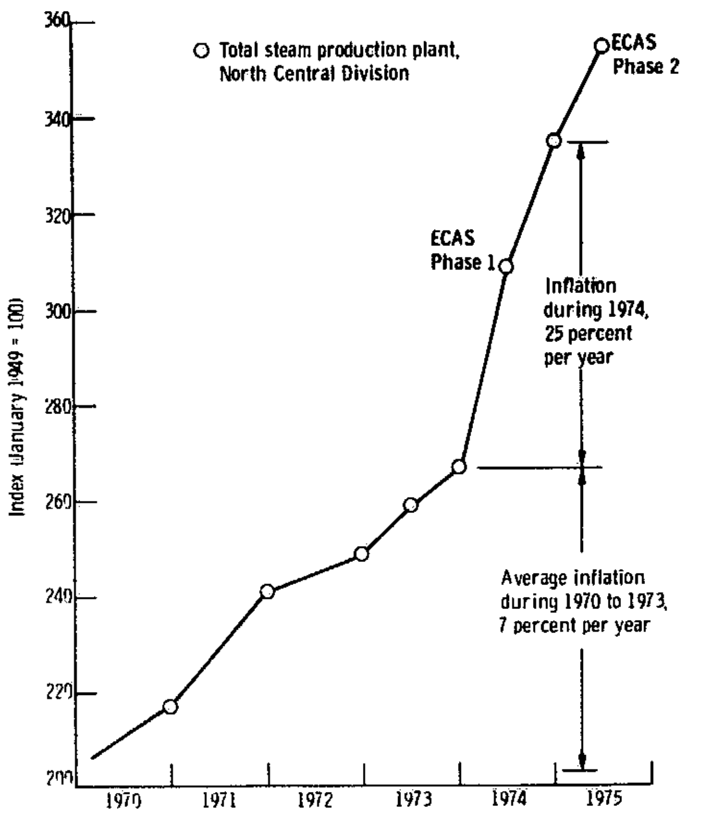


Figure 6.1-1. - Handy-Whitman index of public utilities construction costs (ref. 5).

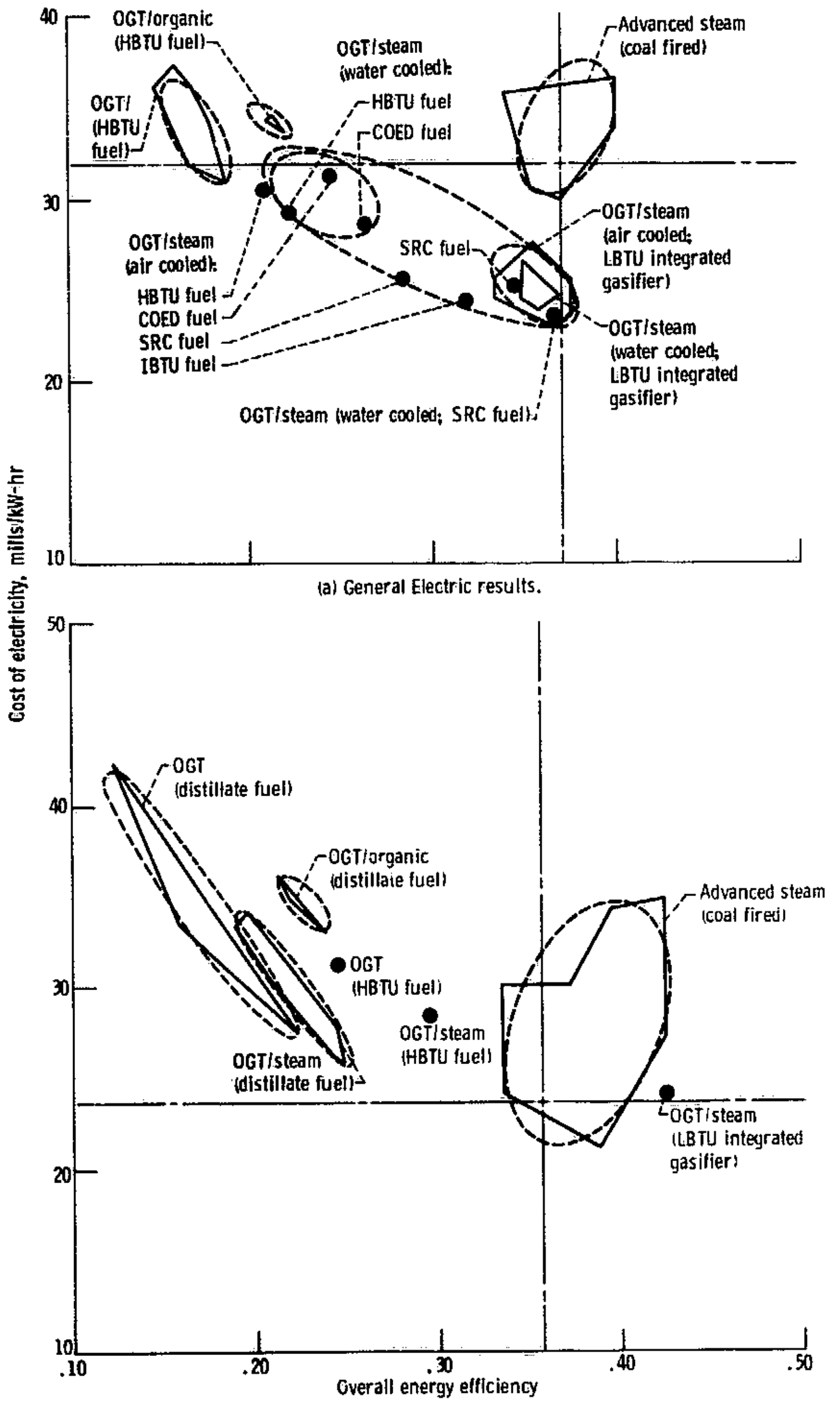


Figure 6.2-1. - Effect of overall energy efficiency on cost of electricity for simple and recuperated open-cycle gas turbine (OGT) systems, recuperated OGT systems with organic bottoming (OGT/organic), combined-cycle systems (OGT/steam), and advanced steam systems.

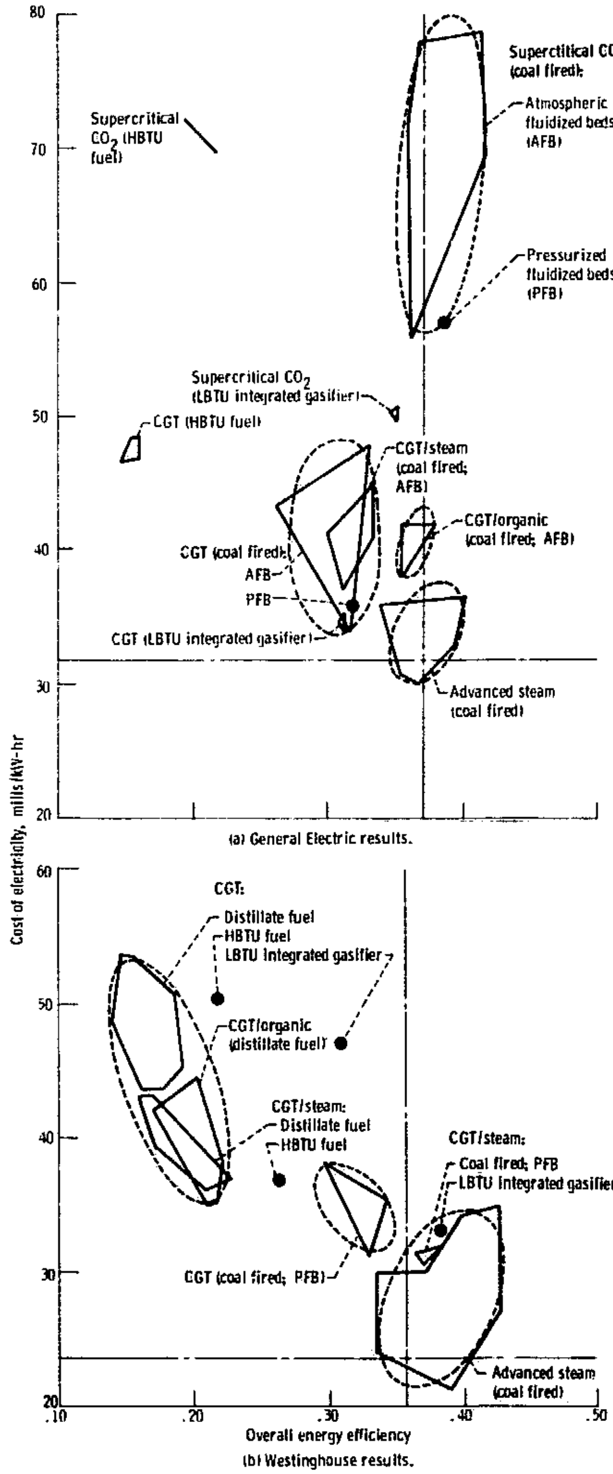


Figure 6.2-2. - Effect of overall energy efficiency on cost of electricity for closed-cycle gas turbine (CGT) systems, CGT systems with organic bottoming (CGT/organic), and CGT systems with steam bottoming (CGT/steam), and advanced steam systems.

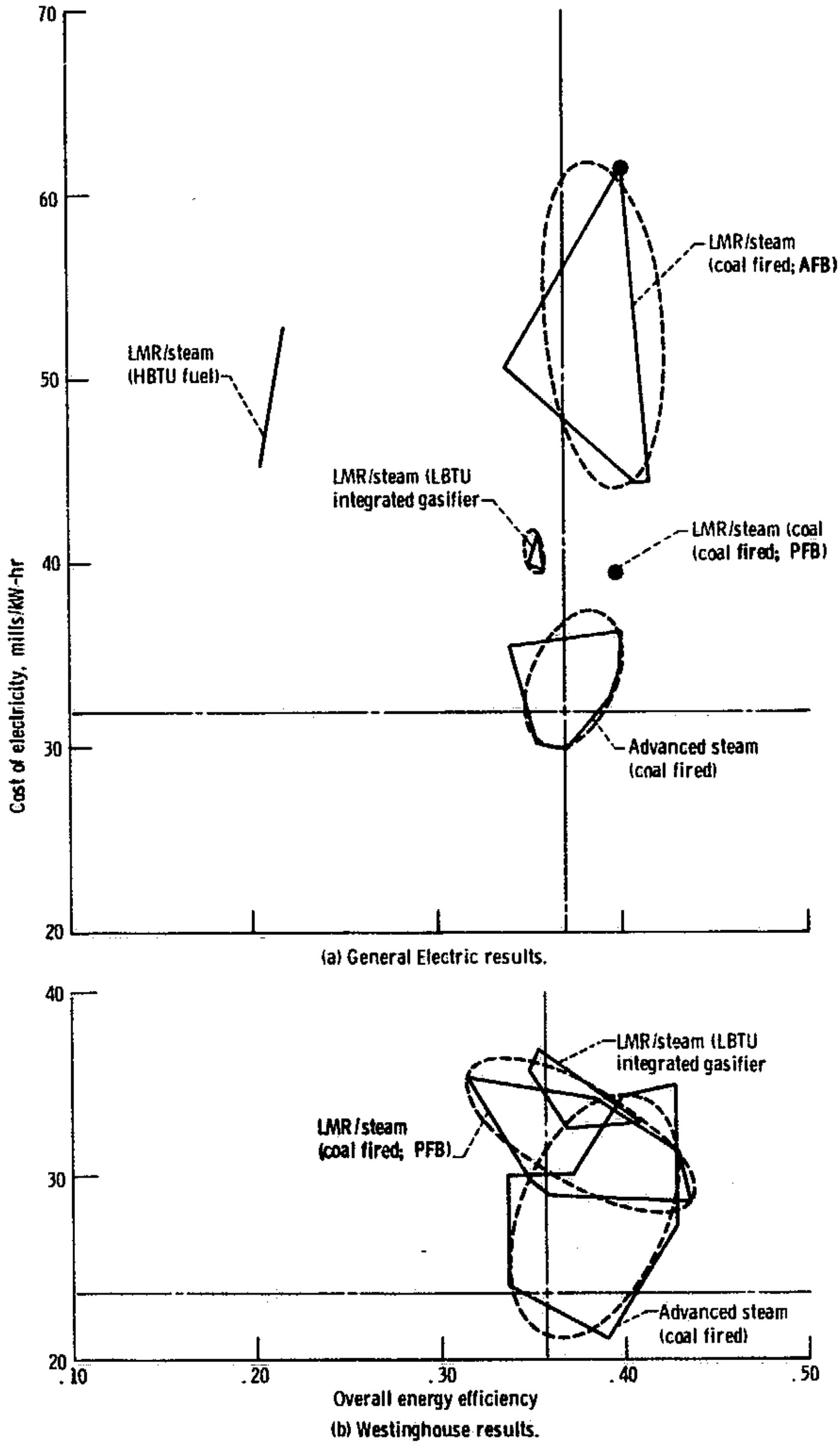


Figure 6.2-3. - Effect of overall energy efficiency on cost of electricity for liquid-metal Rankine topping cycle (LMR), liquid-metal Rankine on top of steam cycle (LMR/steam), and advanced steam systems.

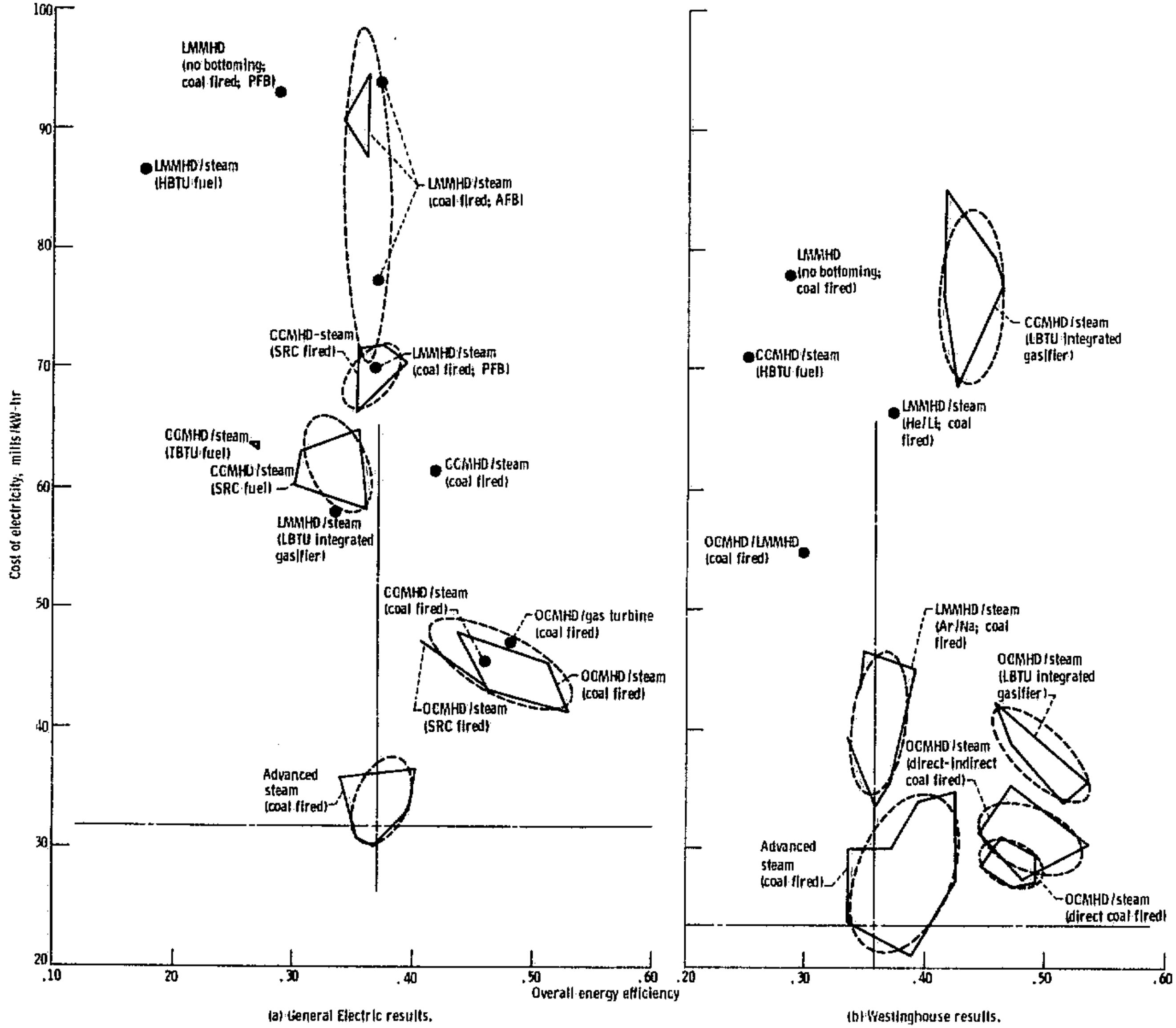
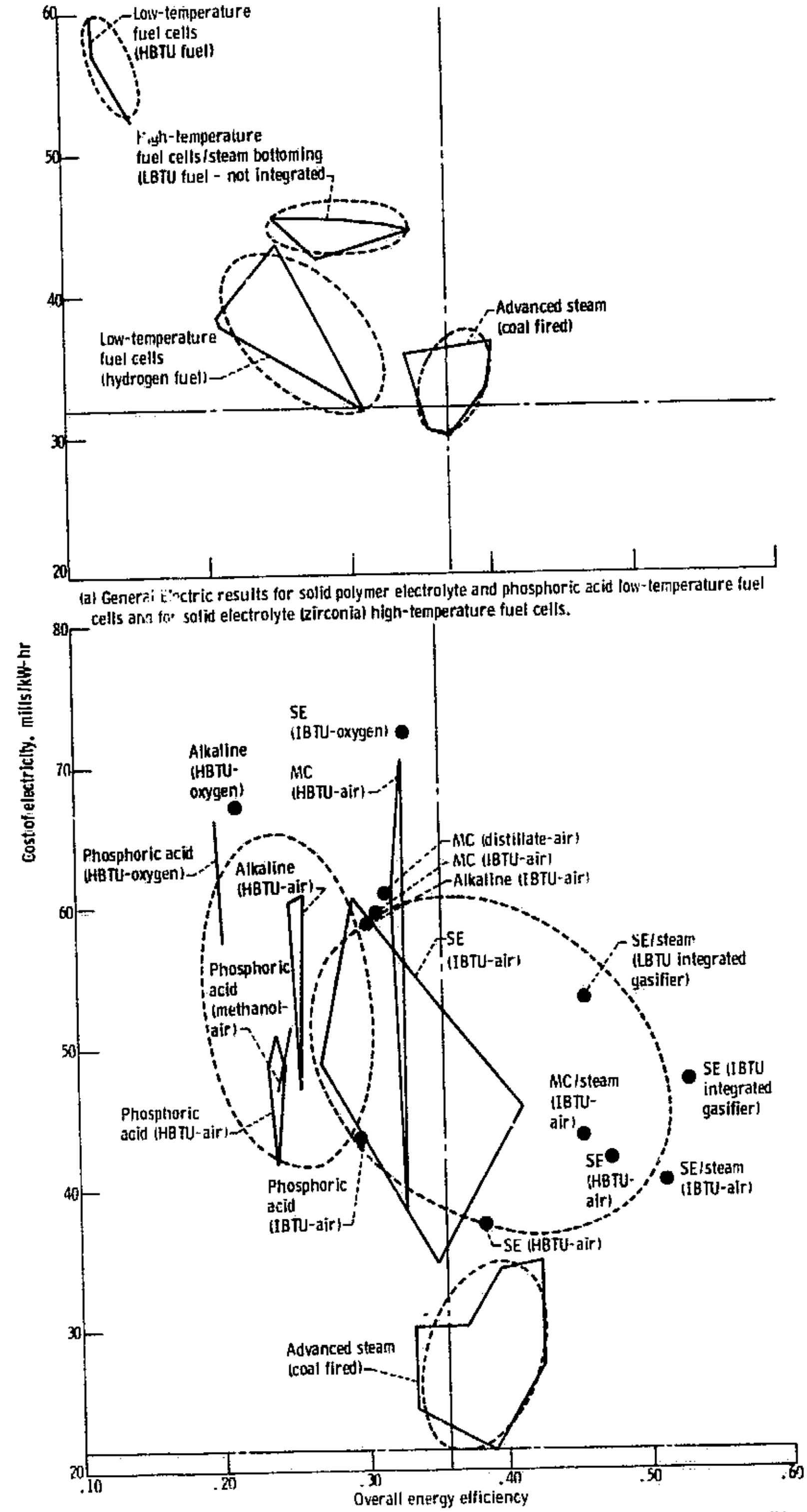


Figure 6.2-4. - Effect of overall energy efficiency on cost of electricity for liquid-metal MHD systems (LMMHD), liquid-metal MHD systems with steam bottoming (LMMHD/steam), closed-cycle inert-gas MHD systems with steam bottoming (CCMHD/steam), closed-cycle inert-gas MHD systems with a parallel steam cycle (CCMHD-steam), open-cycle MHD systems with steam bottoming (OCMHD/steam), open-cycle MHD systems with gas-turbine bottoming (OCMHD/gas turbine), and advanced steam systems.



(b) Westinghouse results for phosphoric acid and alkaline low-temperature fuel cells and for solid electrolyte (SE) (zirconia) and molten carbonate (MC) high-temperature fuel cells.

Figure 6.2-5. - Effect of overall energy efficiency on cost of electricity for fuel cells and advanced steam systems.

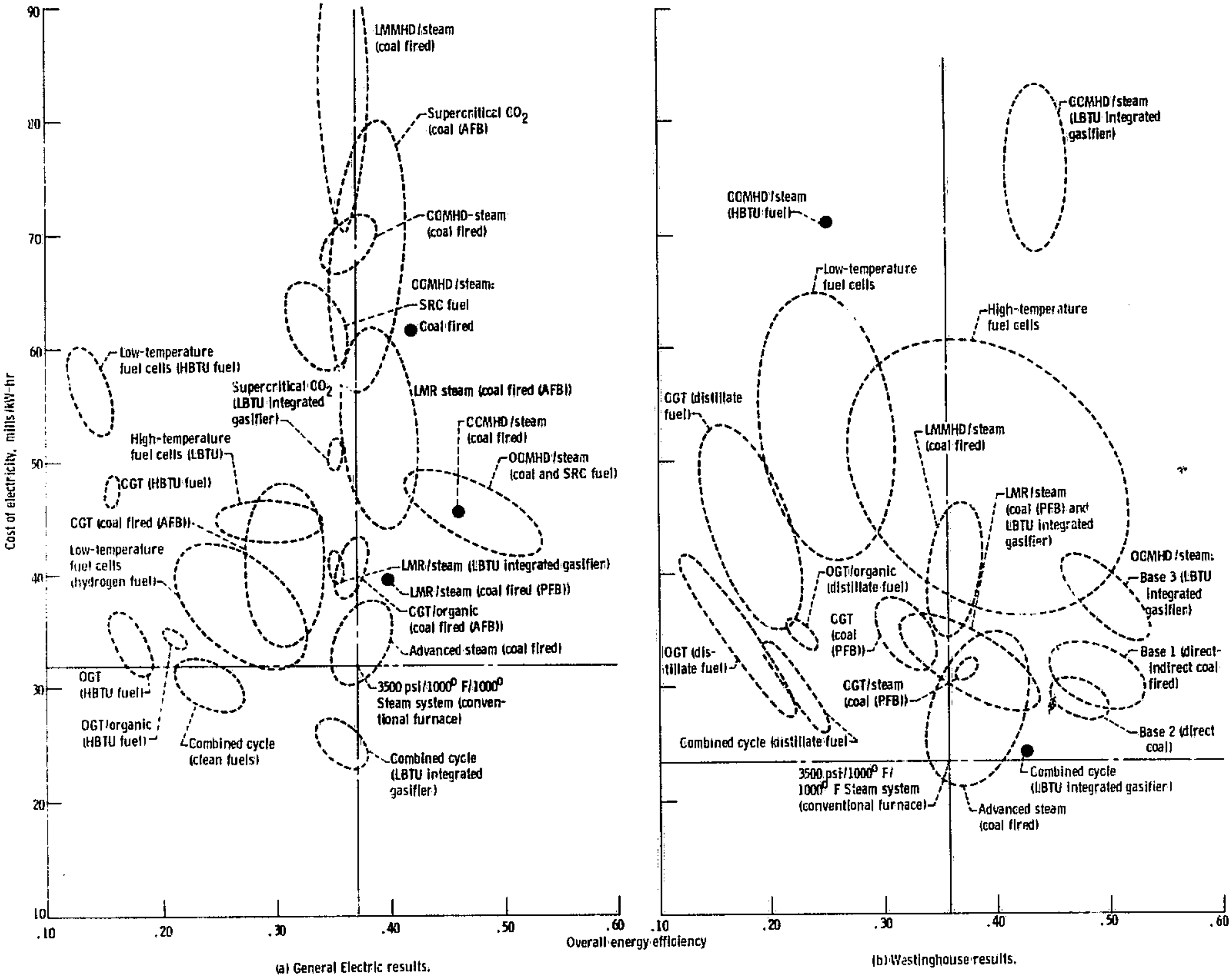


Figure 6.2-6. - Effect of overall energy efficiency on cost of electricity - comparison of systems.

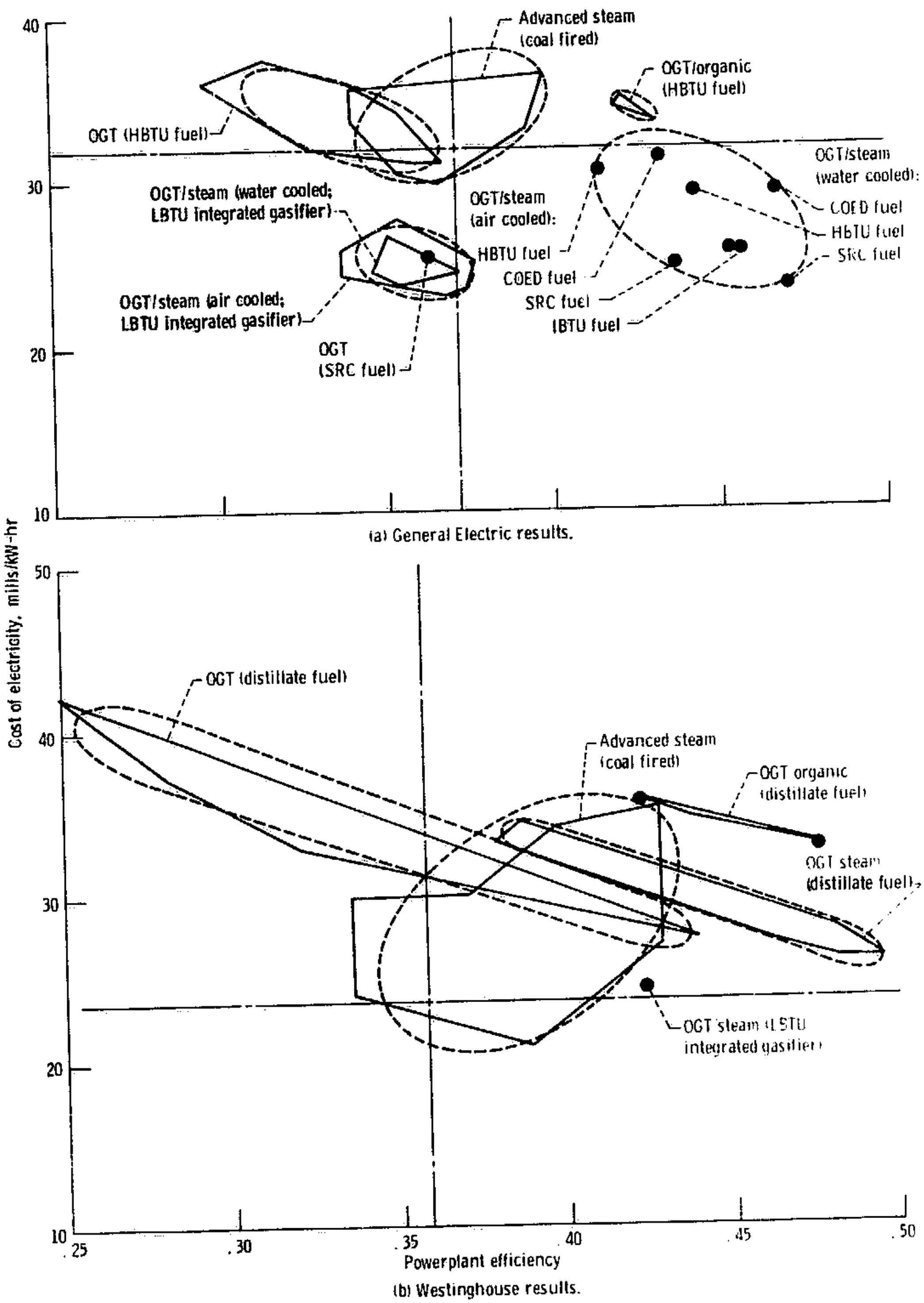


Figure 6.2-7. - Effect of cost of electricity on powerplant efficiency for recuperated and simple open cycle gas turbines (OGT), recuperated open-cycle gas turbines with organic bottoming (OGT/organic), and combined cycles (OGT/steam).

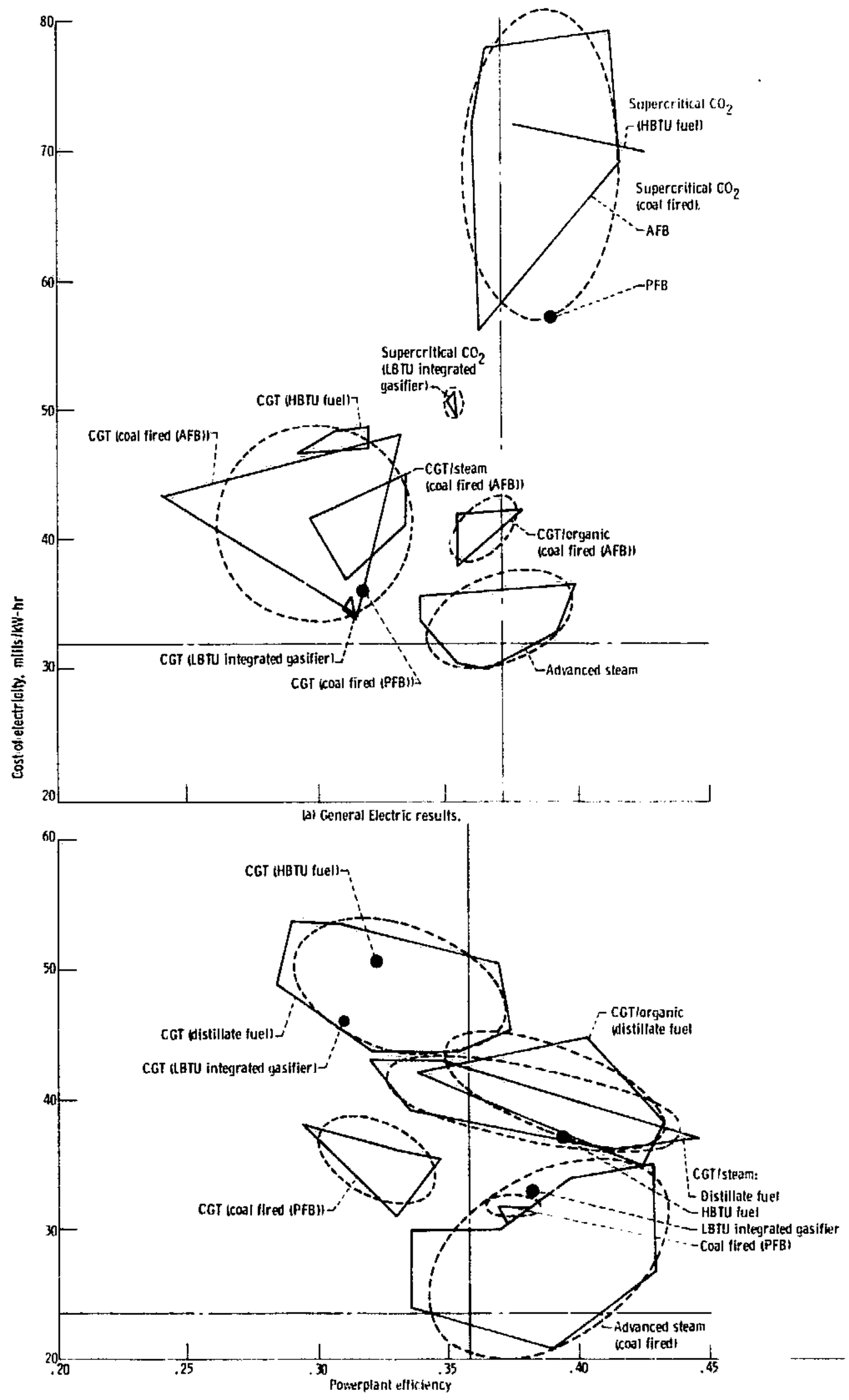


Figure 6.2-8. - Effect of powerplant efficiency on cost of electricity for closed cycle gas turbine (CGT) systems, CGT systems with organic bottoming (CGT/organic), and CGT systems with steam bottoming (CGT/steam), and advanced steam systems.

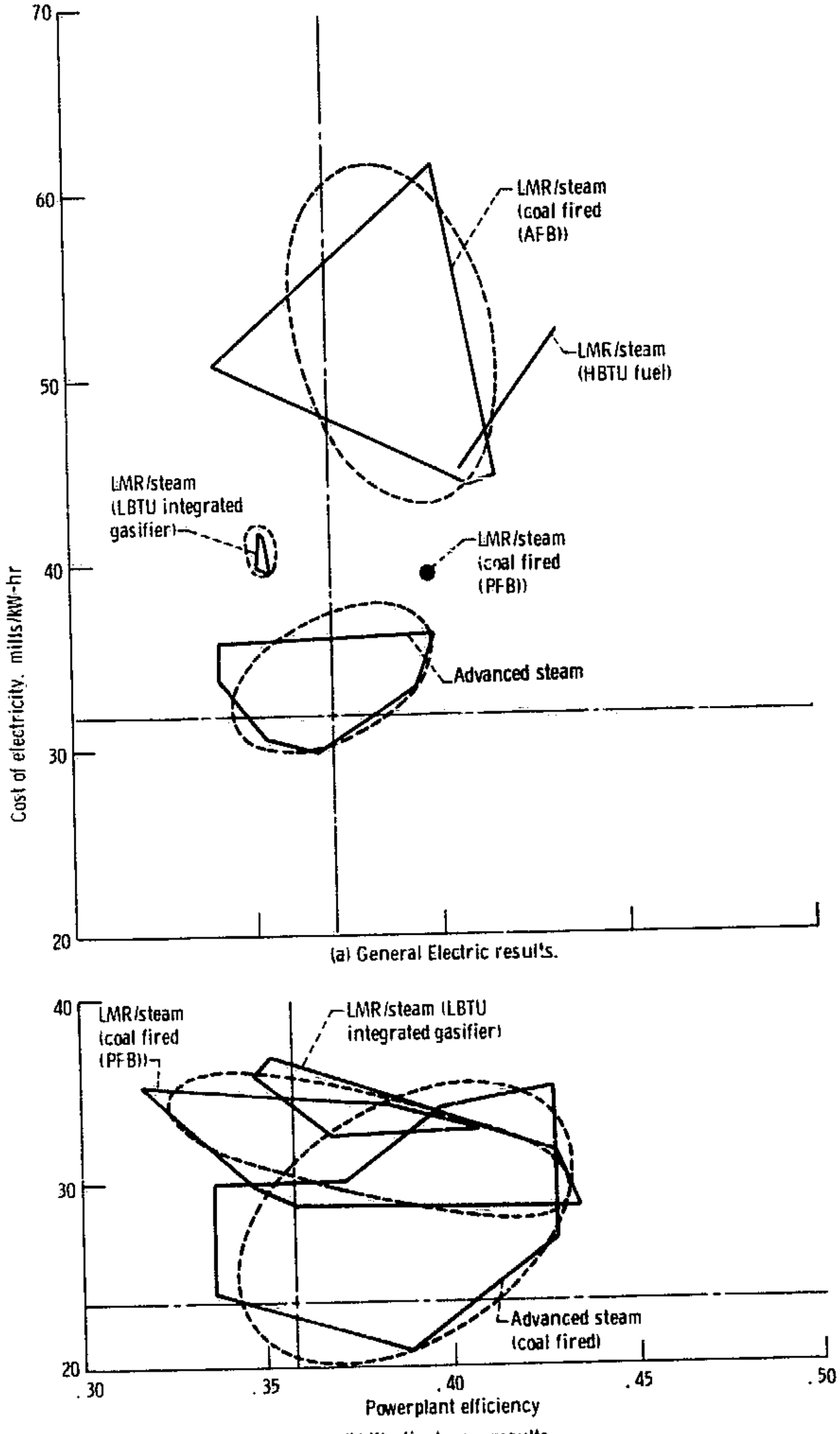


Figure 6.2-9. - Effect of powerplant efficiency on cost of electricity for liquid-metal Rankine topping cycle (LMR/steam) and advanced steam systems

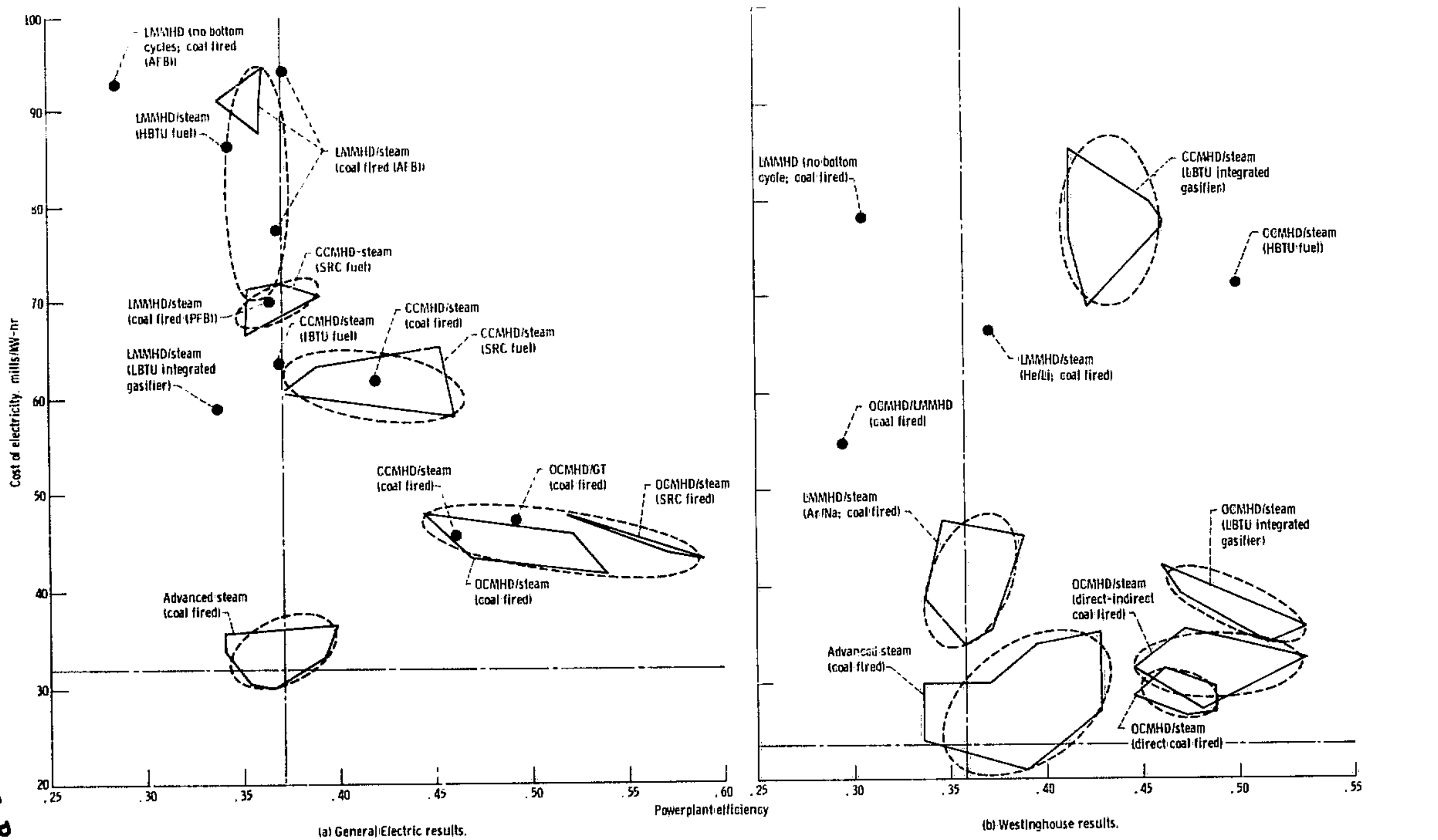
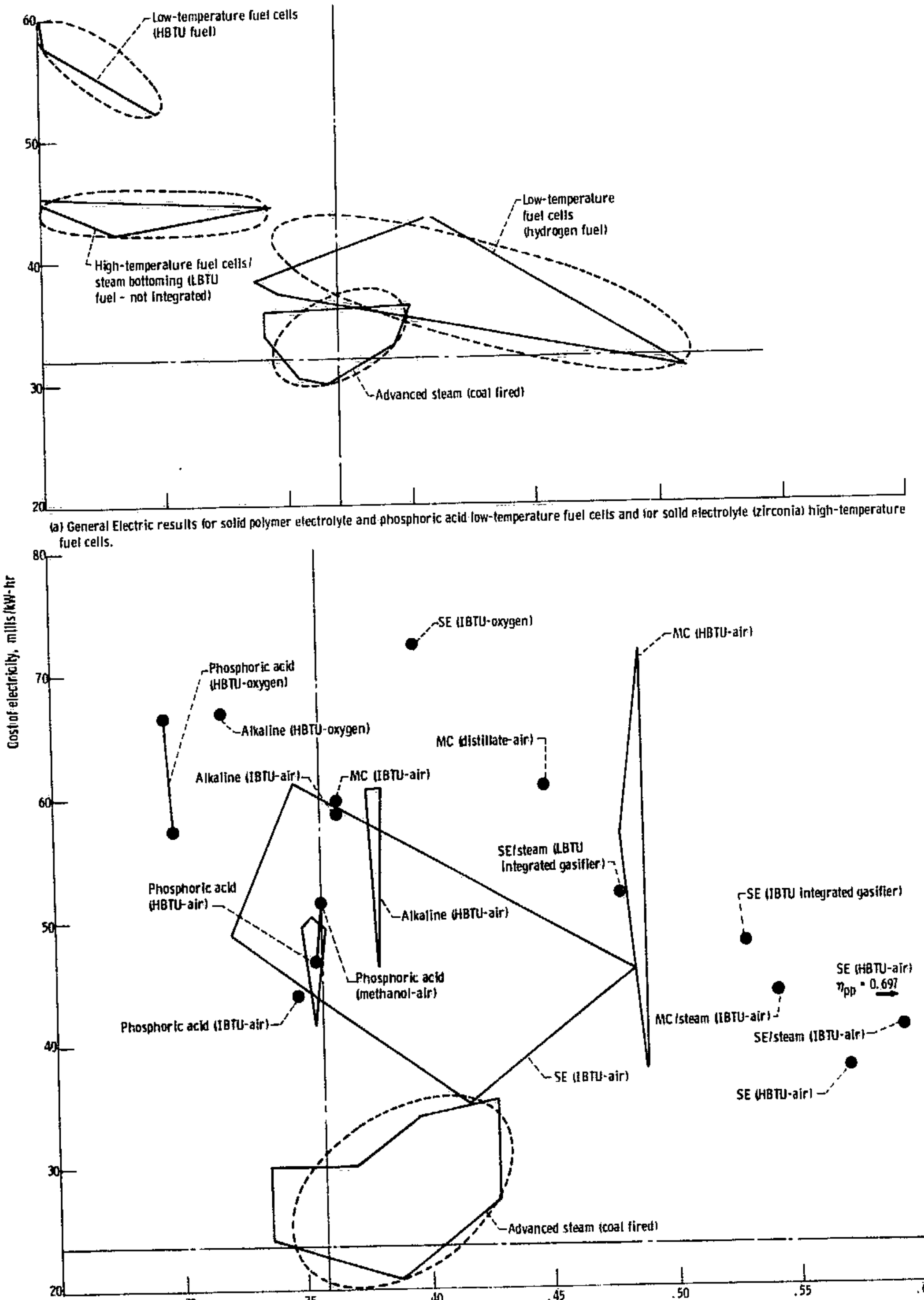


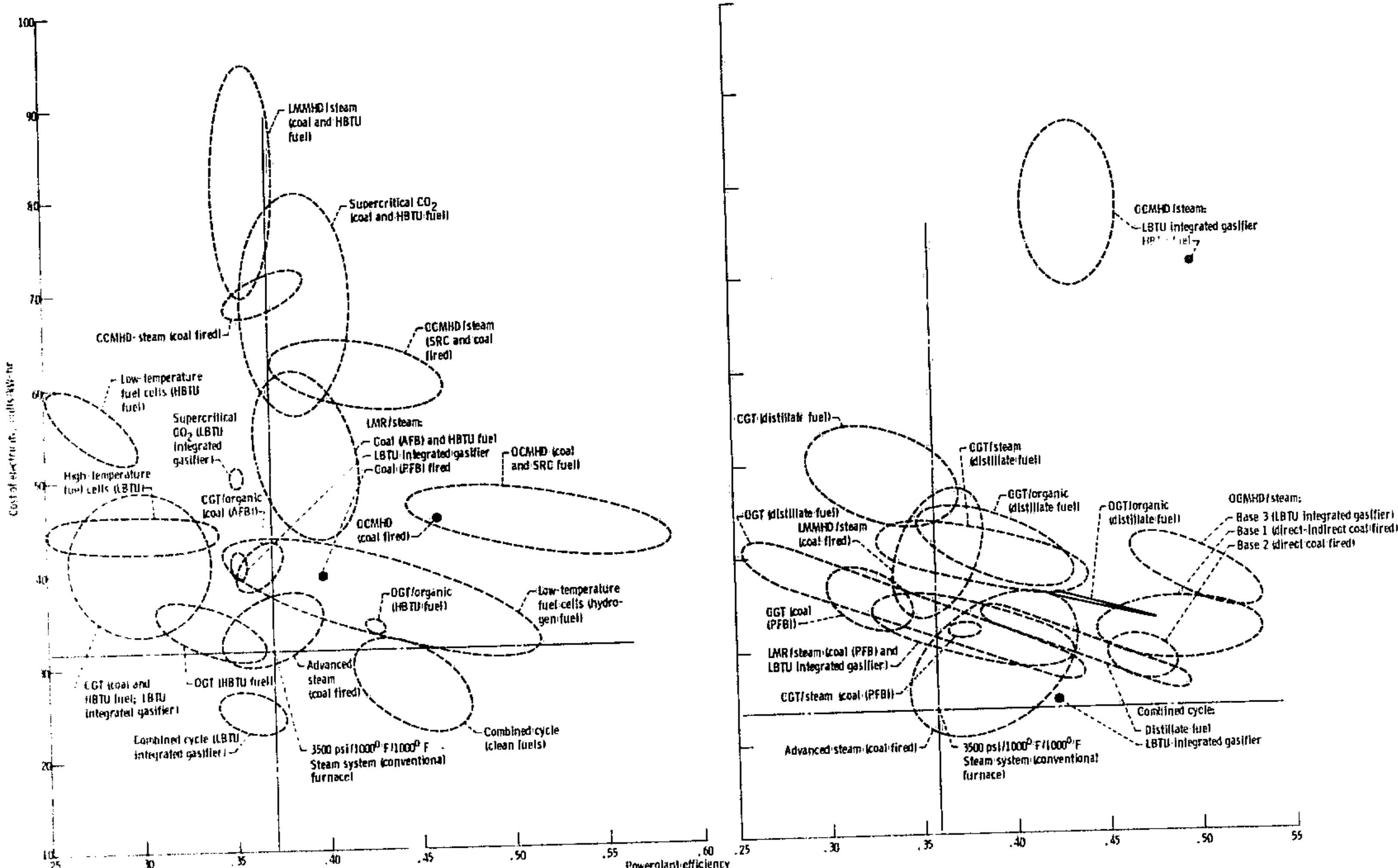
Figure 6.2-10. - Effect of powerplant efficiency on cost of electricity for open-cycle MHD with steam bottoming (OCMHD/steam), open-cycle MHD with gas turbine bottoming (OCMHD/GT), closed-cycle inert-gas MHD with steam bottoming (CCMHD/steam), closed-cycle inert-gas MHD with a parallel steam cycle (CCMHD-steam), liquid-metal MHD with steam bottoming (LMMHD/steam), and advanced steam systems.



(a) General Electric results for solid polymer electrolyte and phosphoric acid low-temperature fuel cells and for solid electrolyte (zirconia) high-temperature fuel cells.

(b) Westinghouse results for phosphoric acid and alkaline low-temperature fuel cells and for solid electrolyte (SE) (zirconia) and molten carbonate (MC) high-temperature fuel cells.

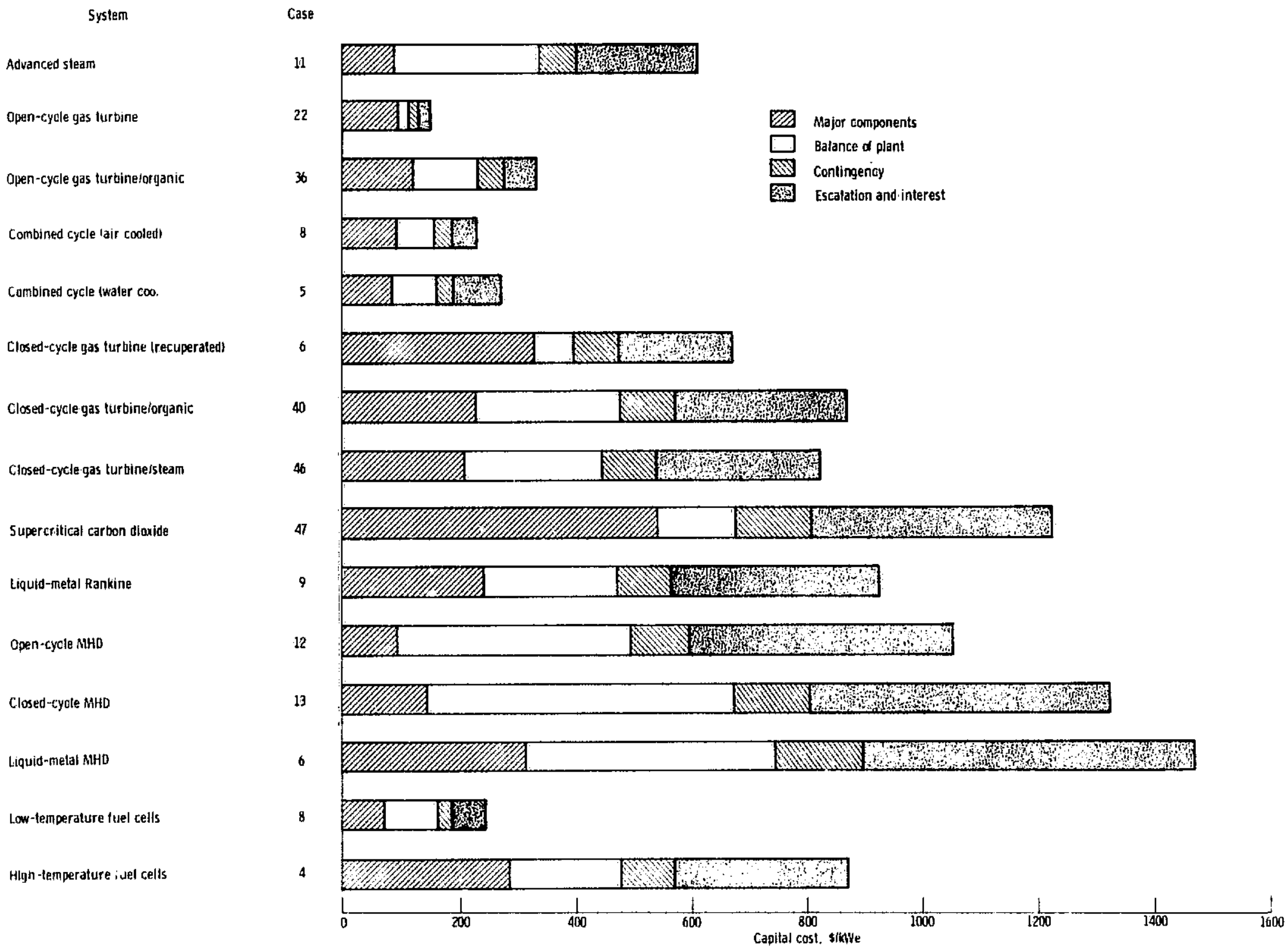
Figure 6.2-11. - Effect of powerplant efficiency on cost of electricity for fuel cells and advanced steam systems.



(a) General Electric results.

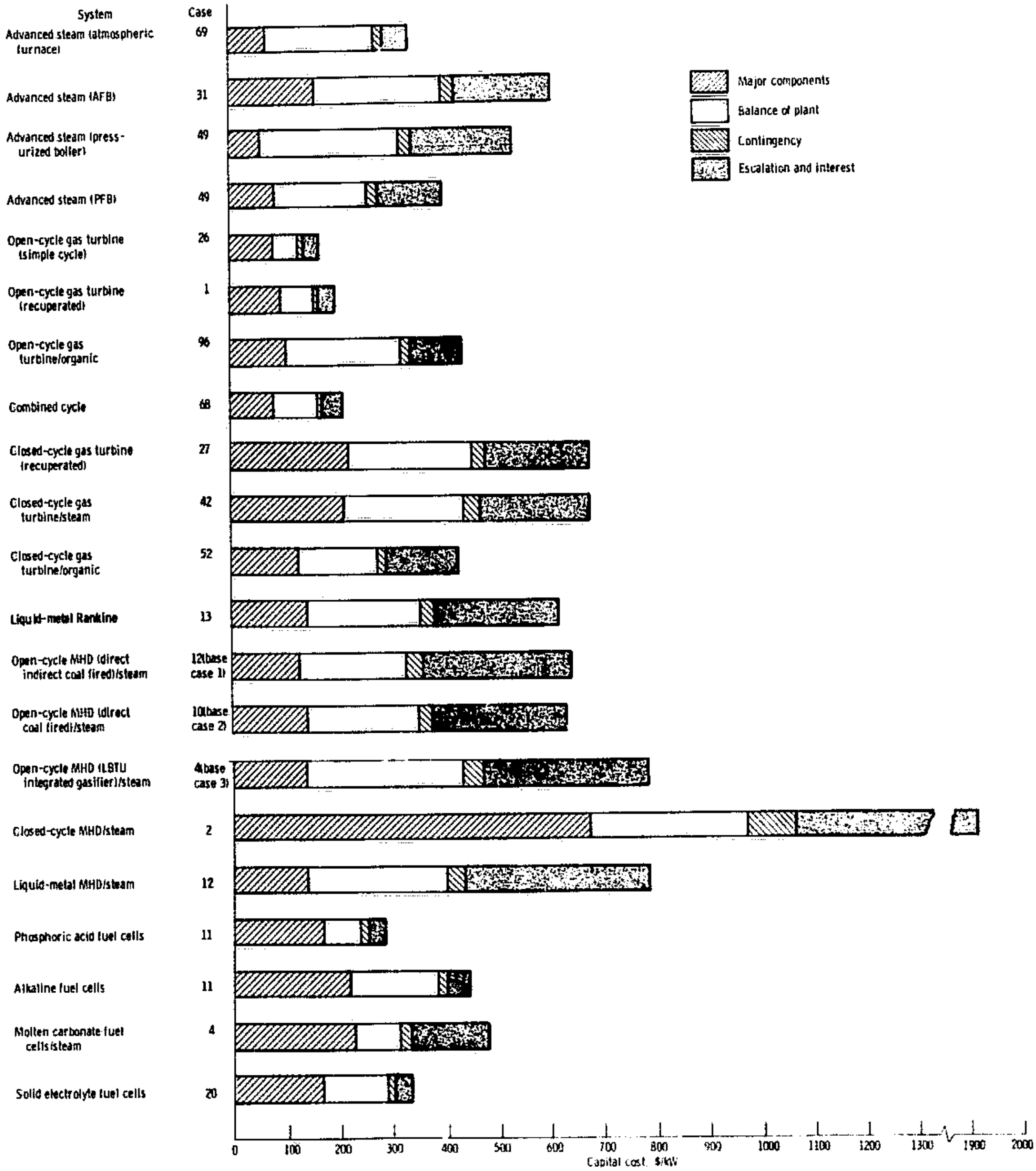
(b) Westinghouse results.

Figure 6.2-12. - Effect of powerplant efficiency on cost of electricity - comparison of results.



(a) General Electric results.

Figure 6.2-13. - Minimum capital cost points.



(b) Westinghouse results.

Figure 6. 2-13. - Concluded.

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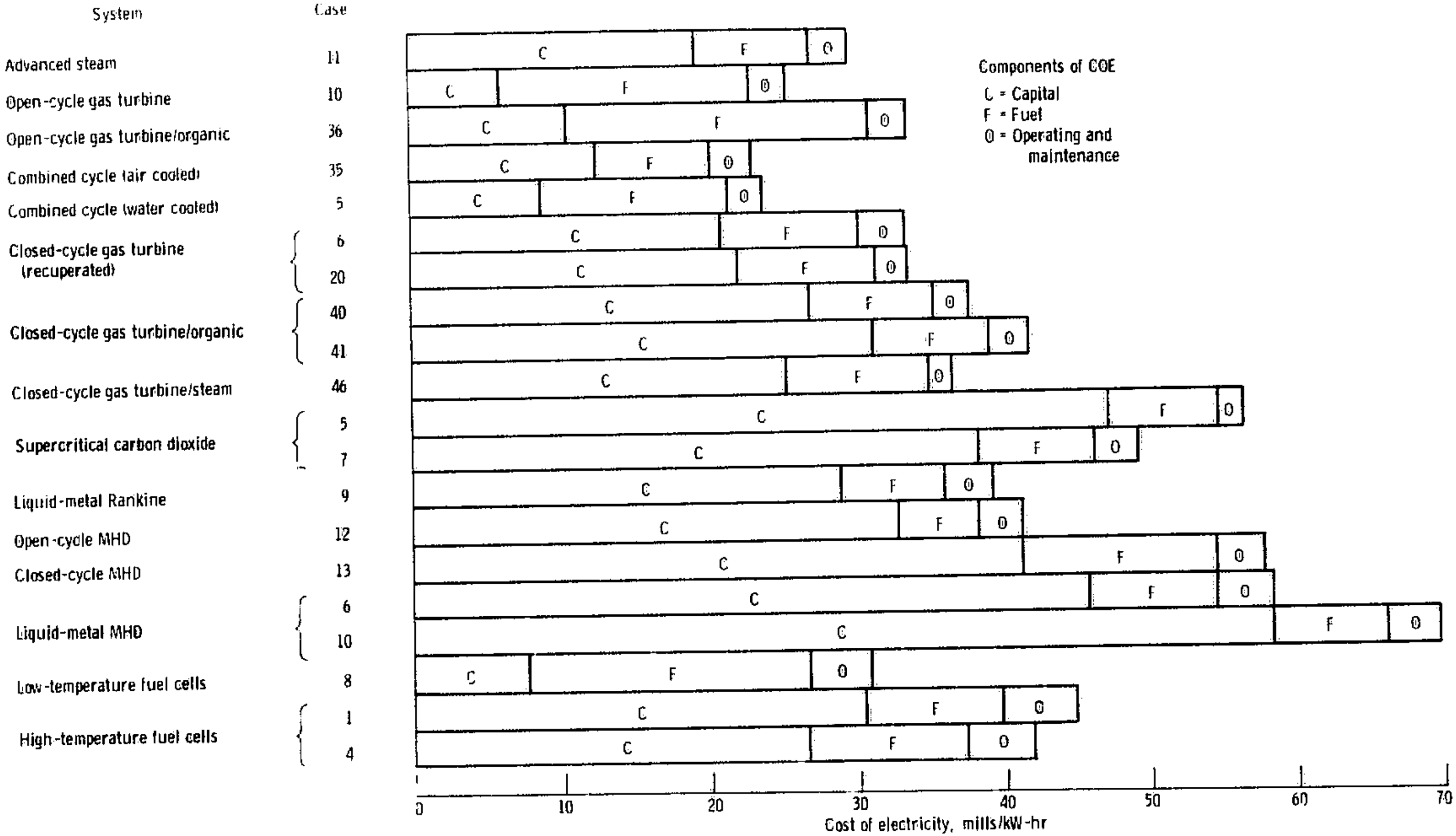
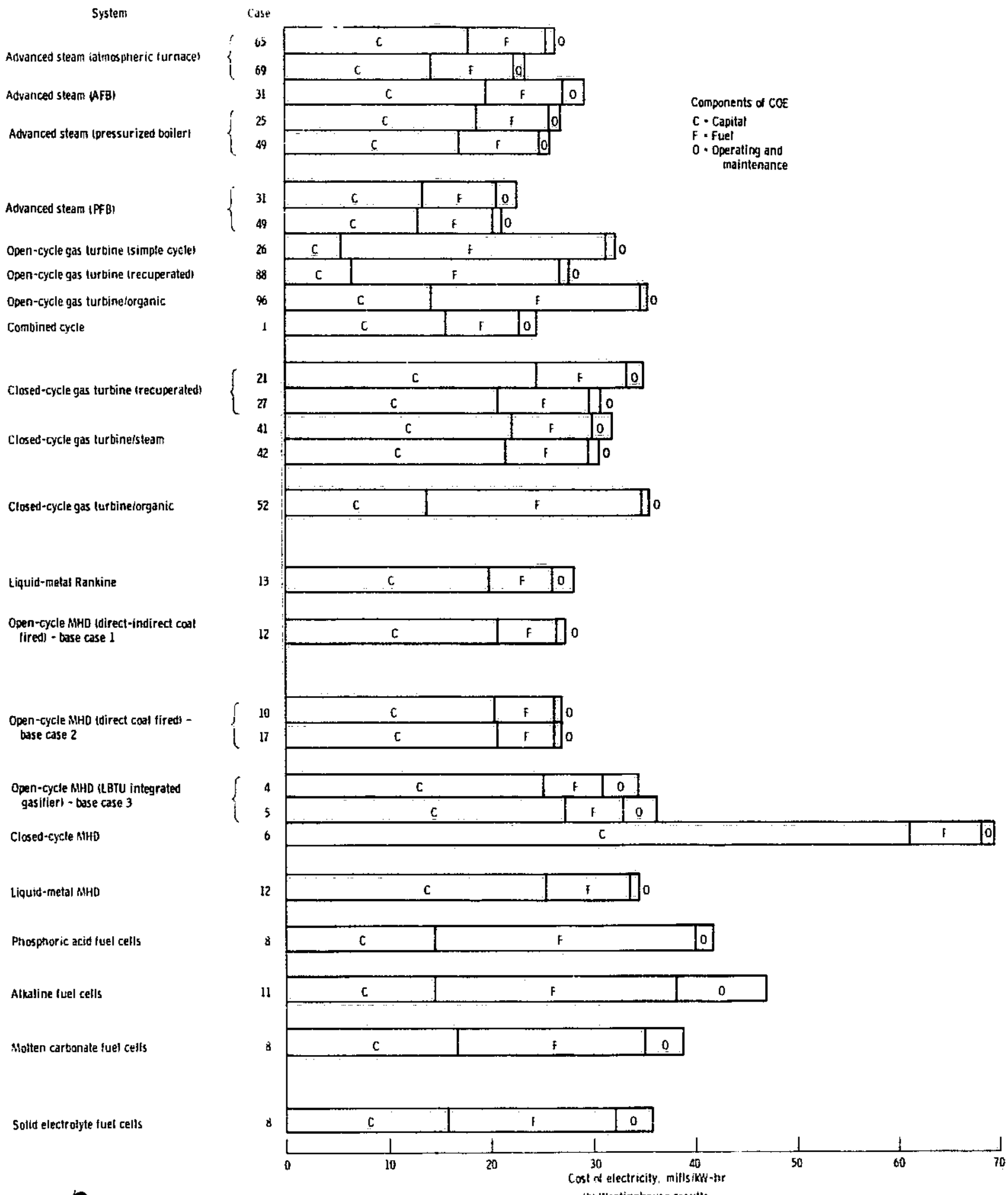


(a) General Electric results.

Figure 6.2-14. - Capital, fuel, and operating and maintenance components of cost of electricity - minimum-COE points.



(b) Westinghouse results.

Figure 6.2-14. - Concluded.

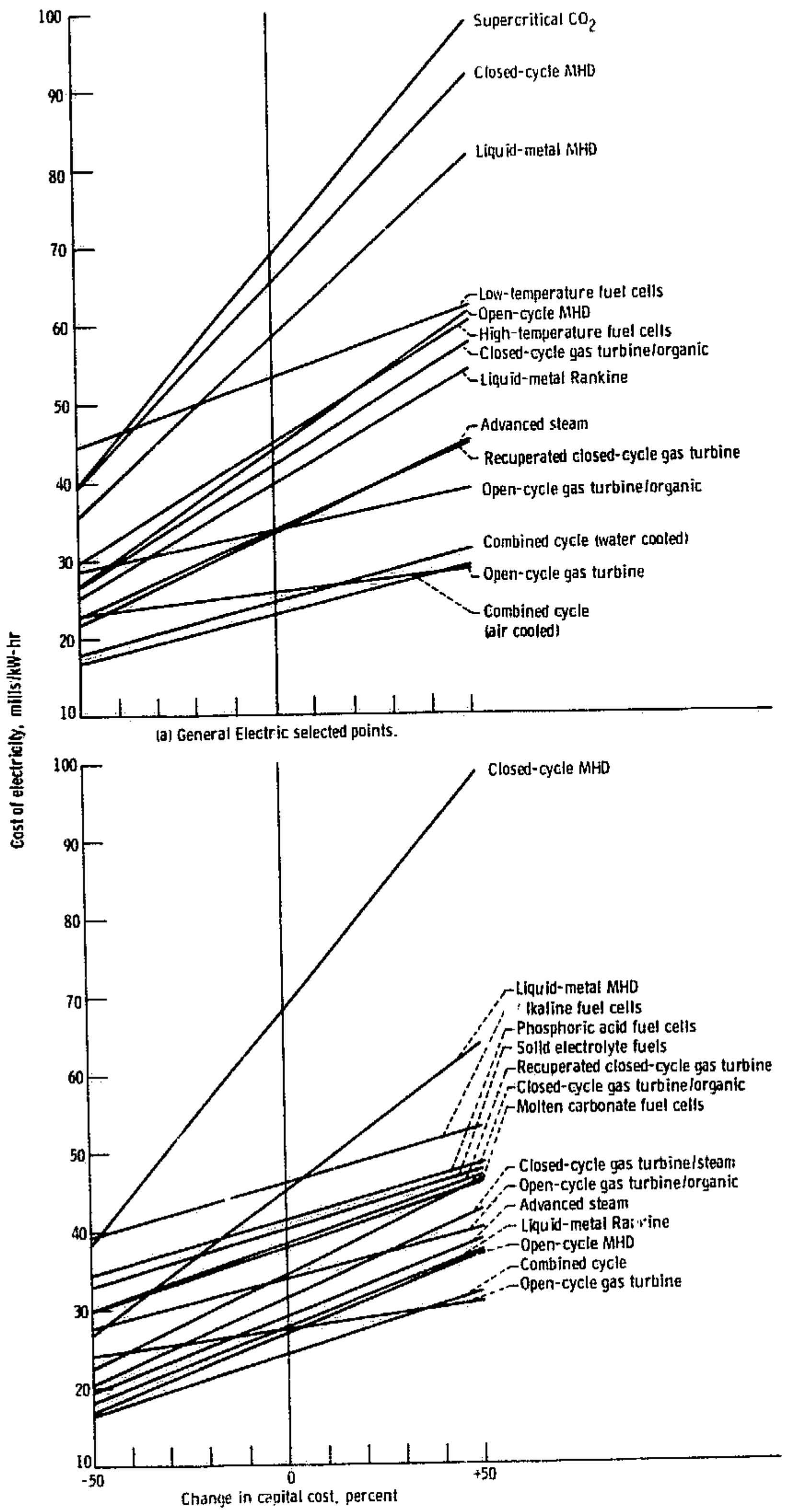


Figure 6.2-15. - Sensitivity of cost of electricity to change in capital cost of ±50 percent.

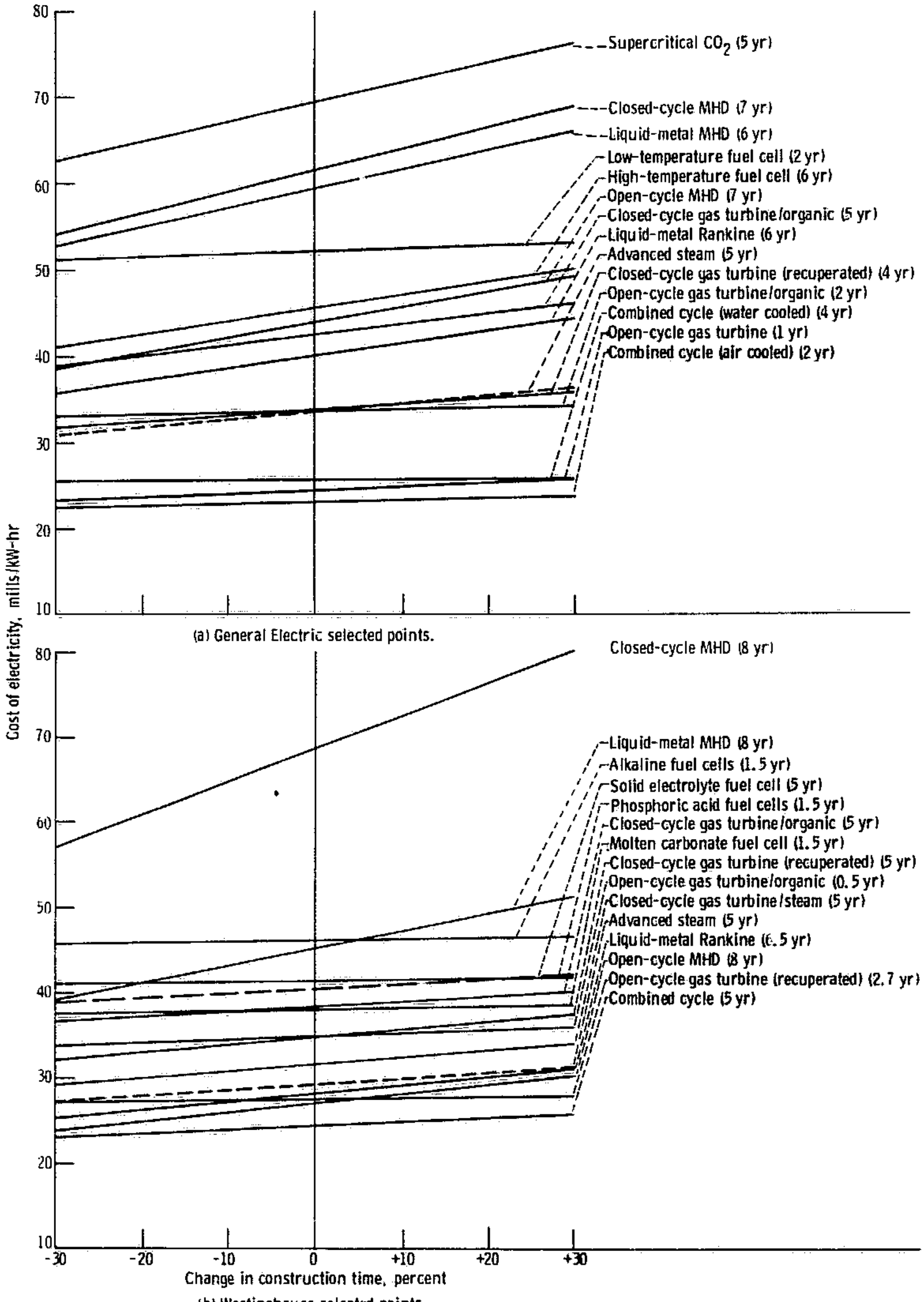


Figure 6.2-16. - Sensitivity of cost of electricity to change in estimated construction time of ±30 percent.

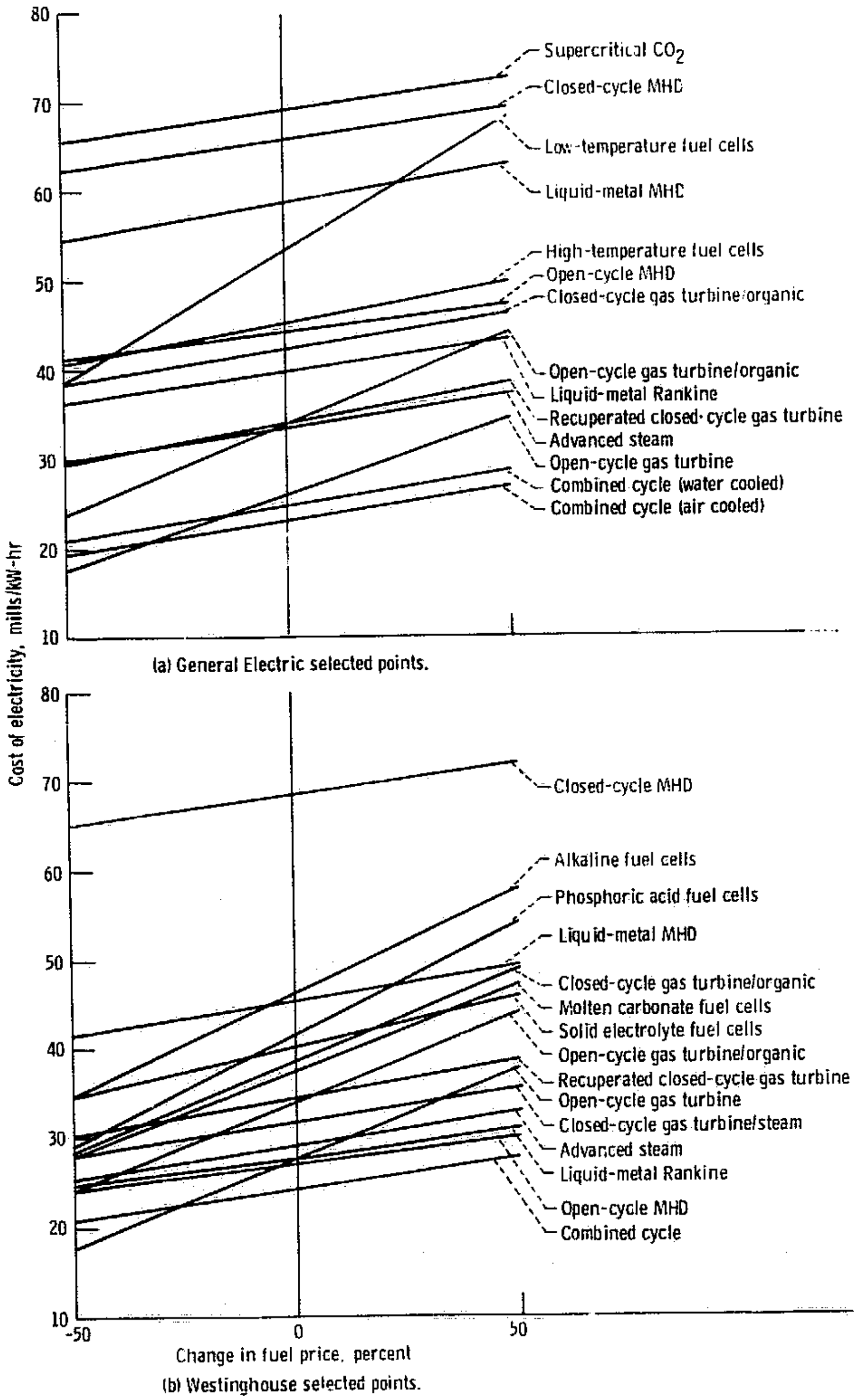


Figure 6. 2-17. - Sensitivity of cost of electricity to change in fuel price of ±50 percent.

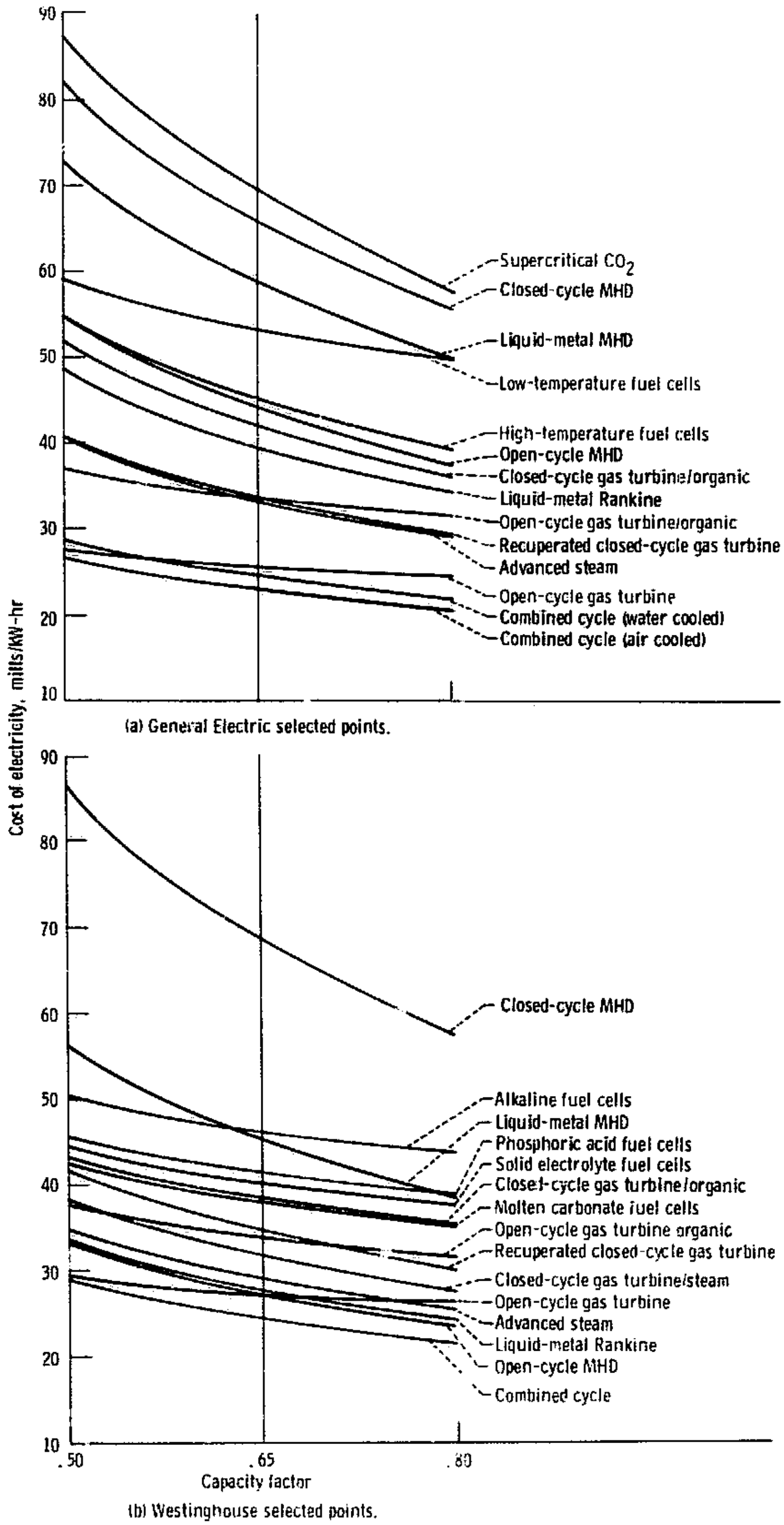
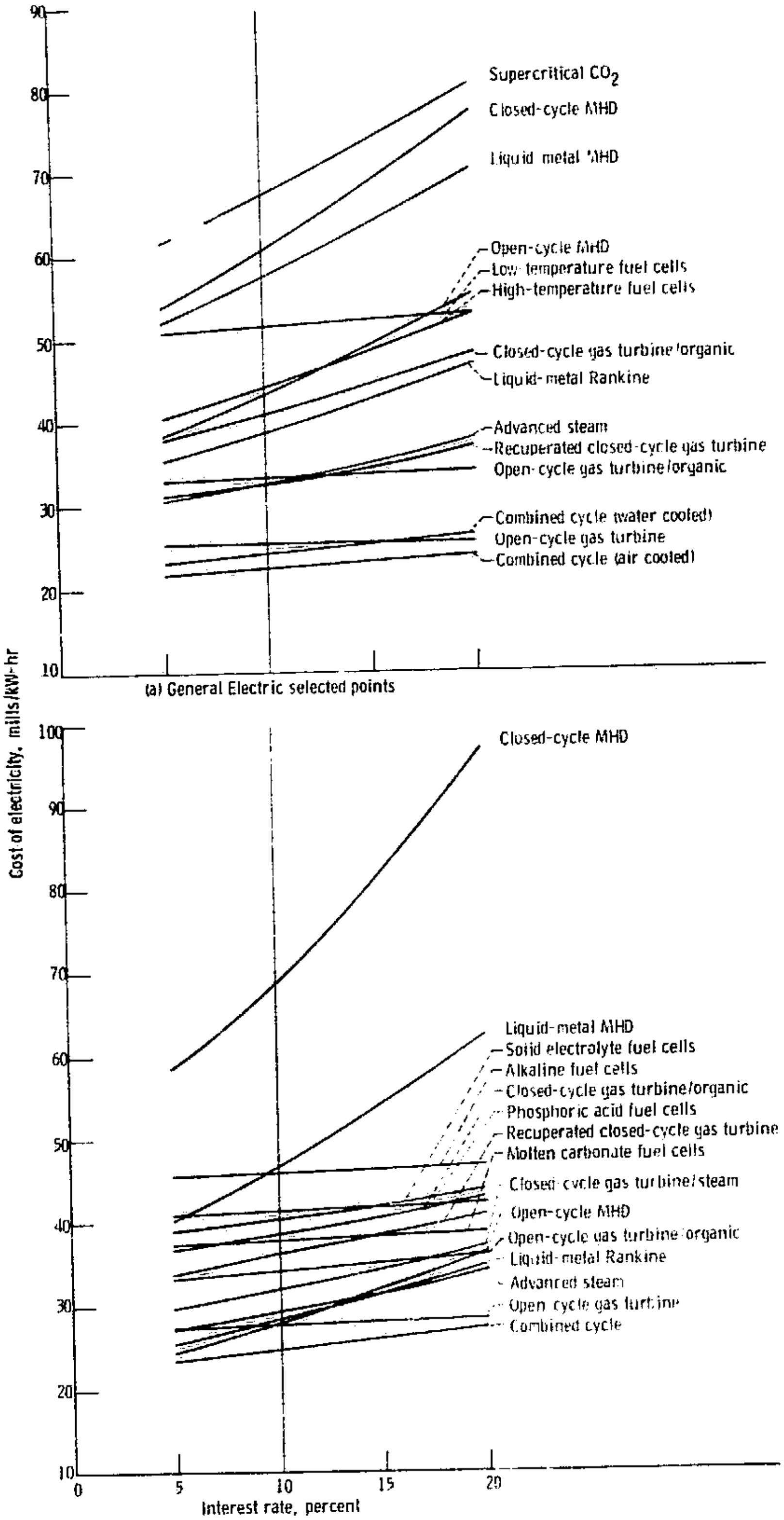


Figure 6. 2-18. - Sensitivity of cost of electricity to change in capacity factor



(a) General Electric selected points

(b) Westinghouse selected points.

Figure 6.2-19. - Sensitivity of cost of electricity to change in interest rate.

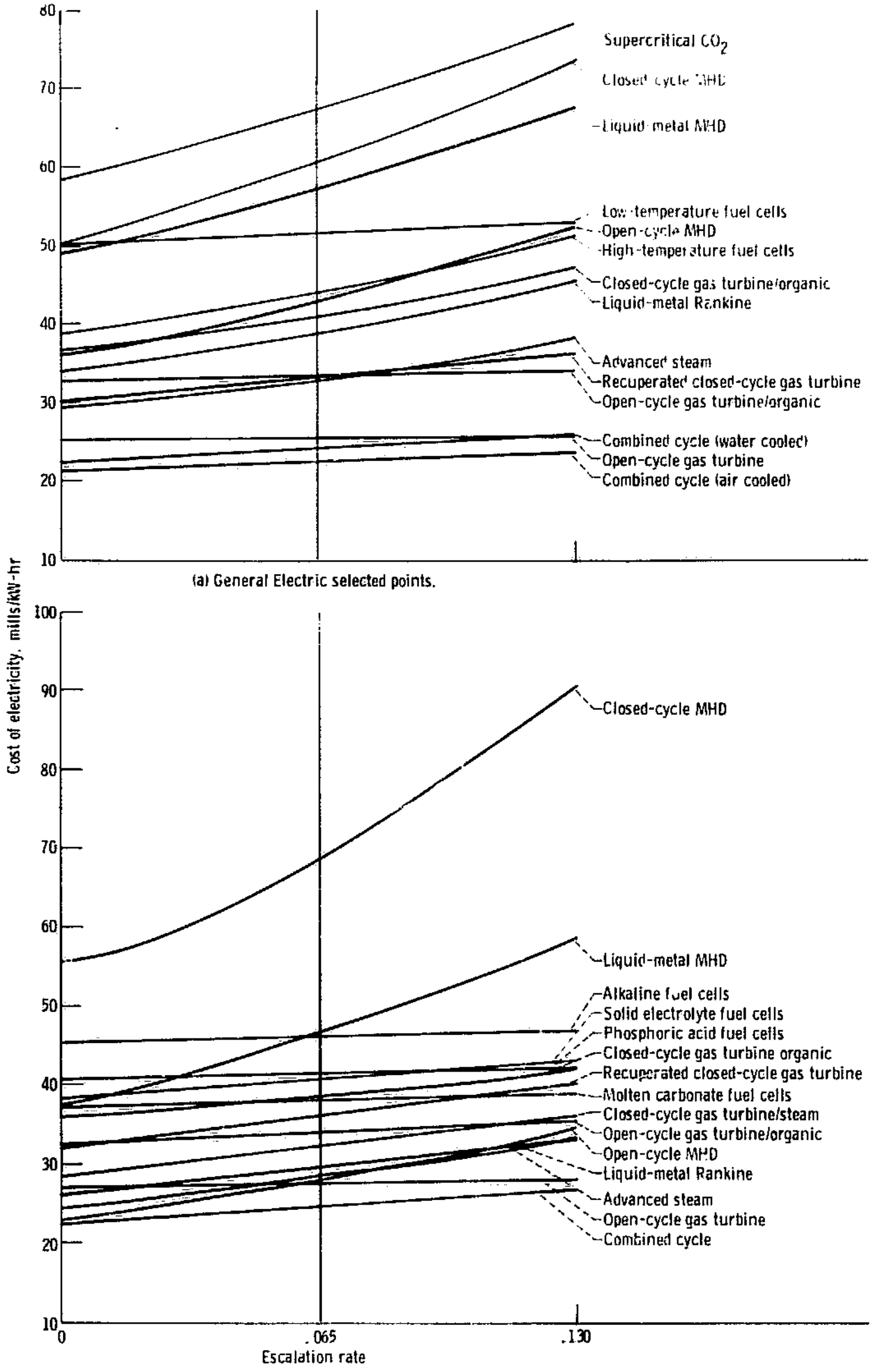


Figure 6.2-20. - Sensitivity of cost of electricity to change in escalation rate

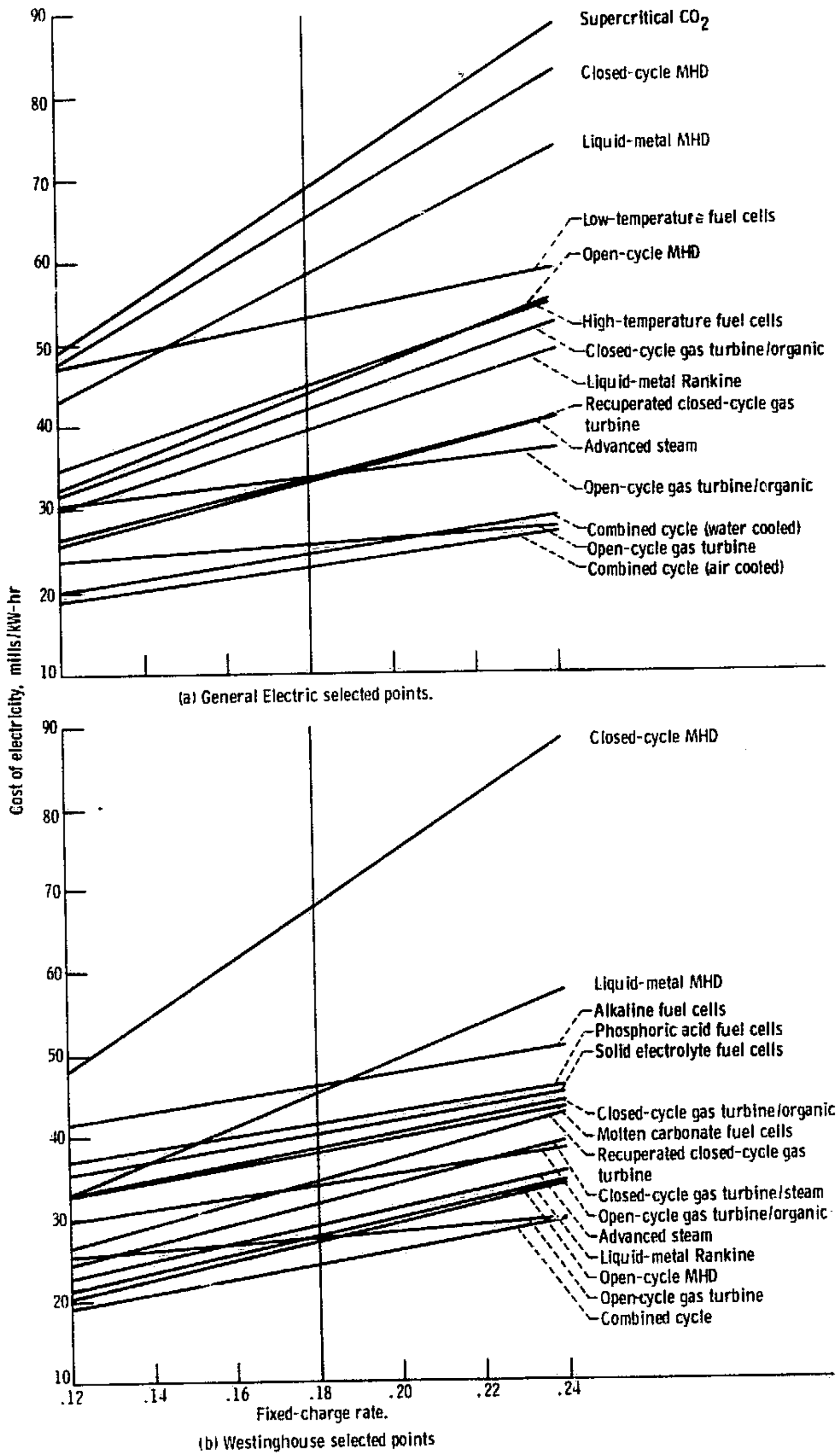
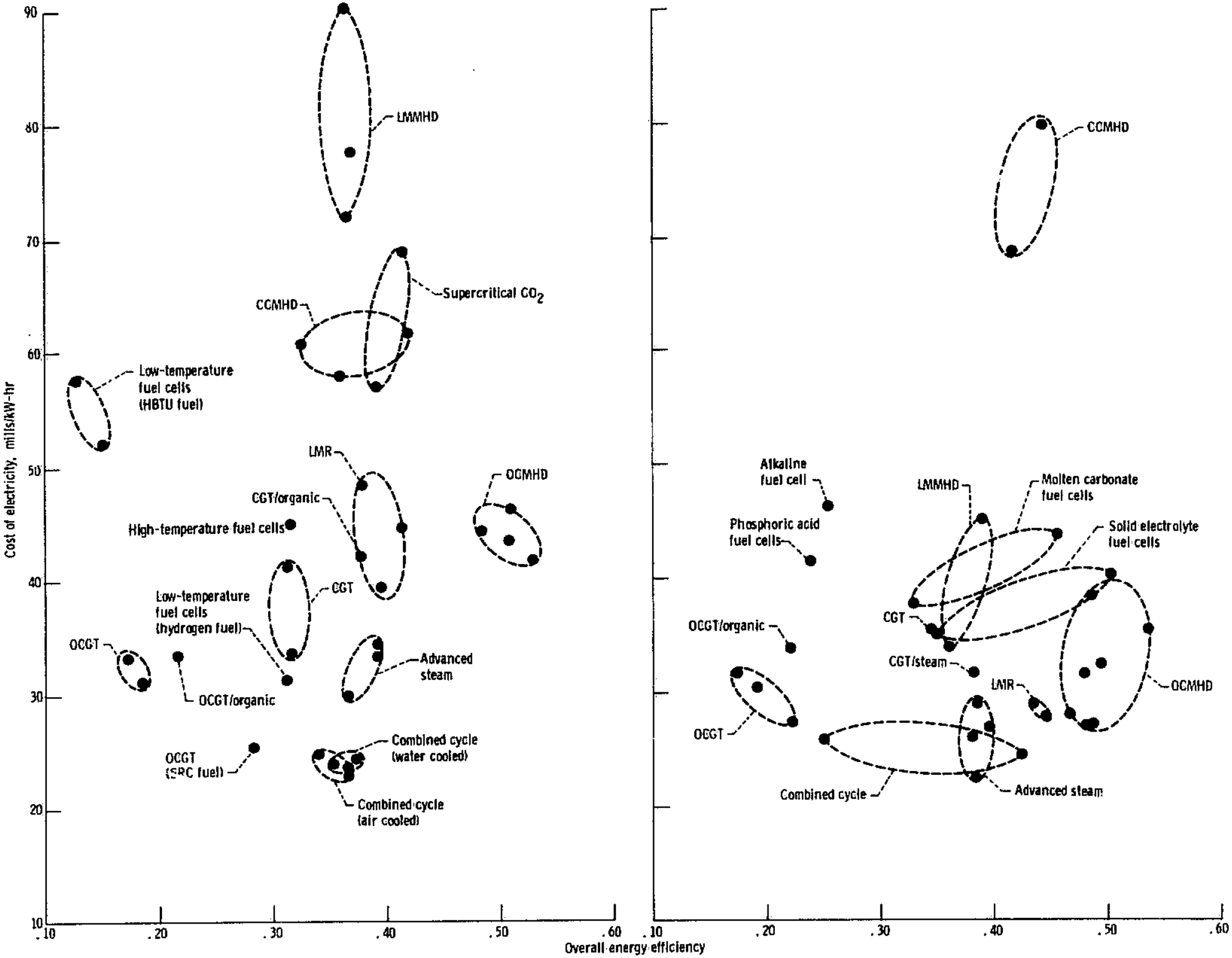


Figure 6.2-21. - Sensitivity of cost of electricity to change in fixed-charge rate.



(a) General Electric.

(b) Westinghouse.

Figure 6.2-22. - Selected contractor results.

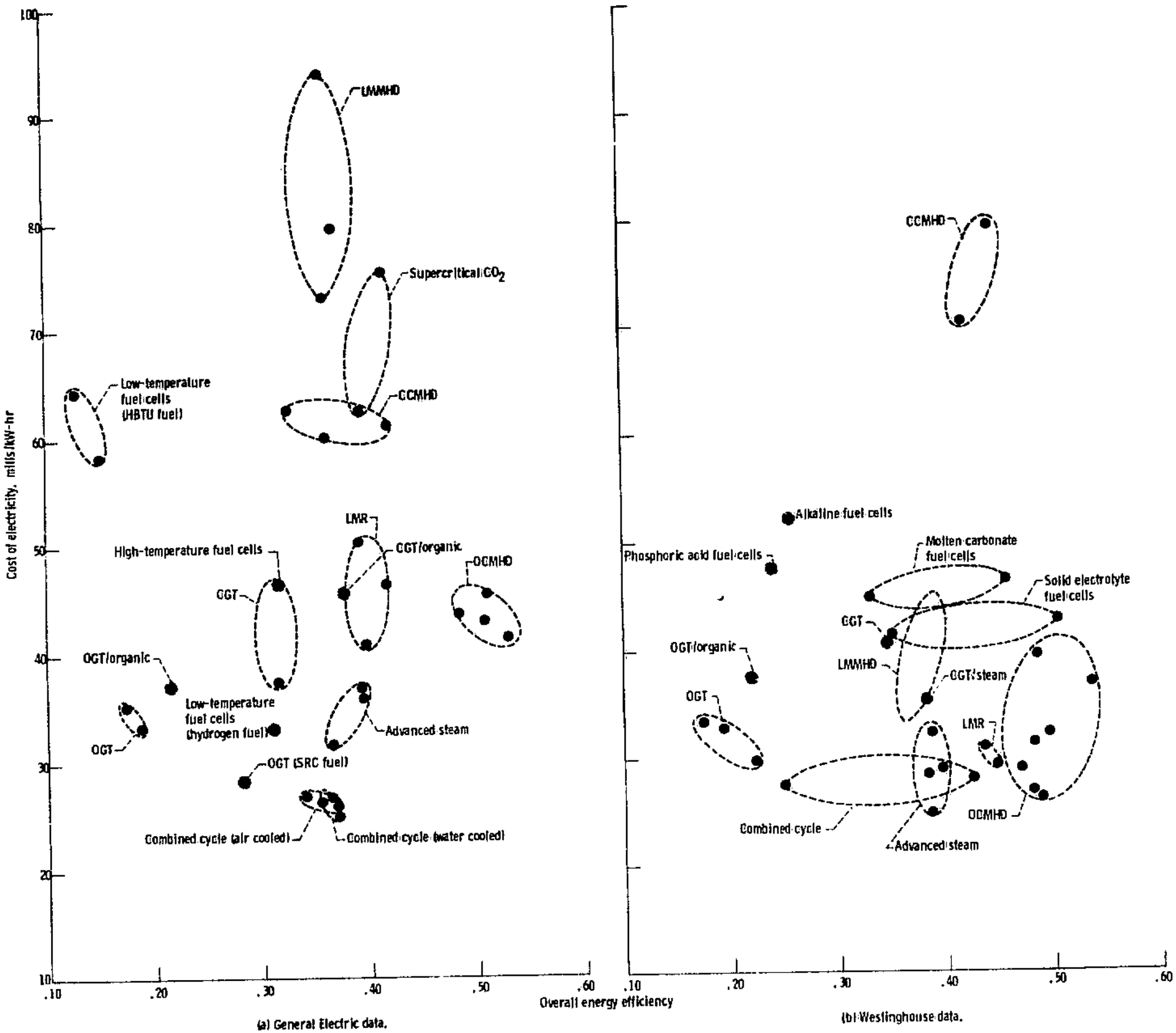


Figure 6.2-23. - Lewis analyses of contractor data based on common end date.

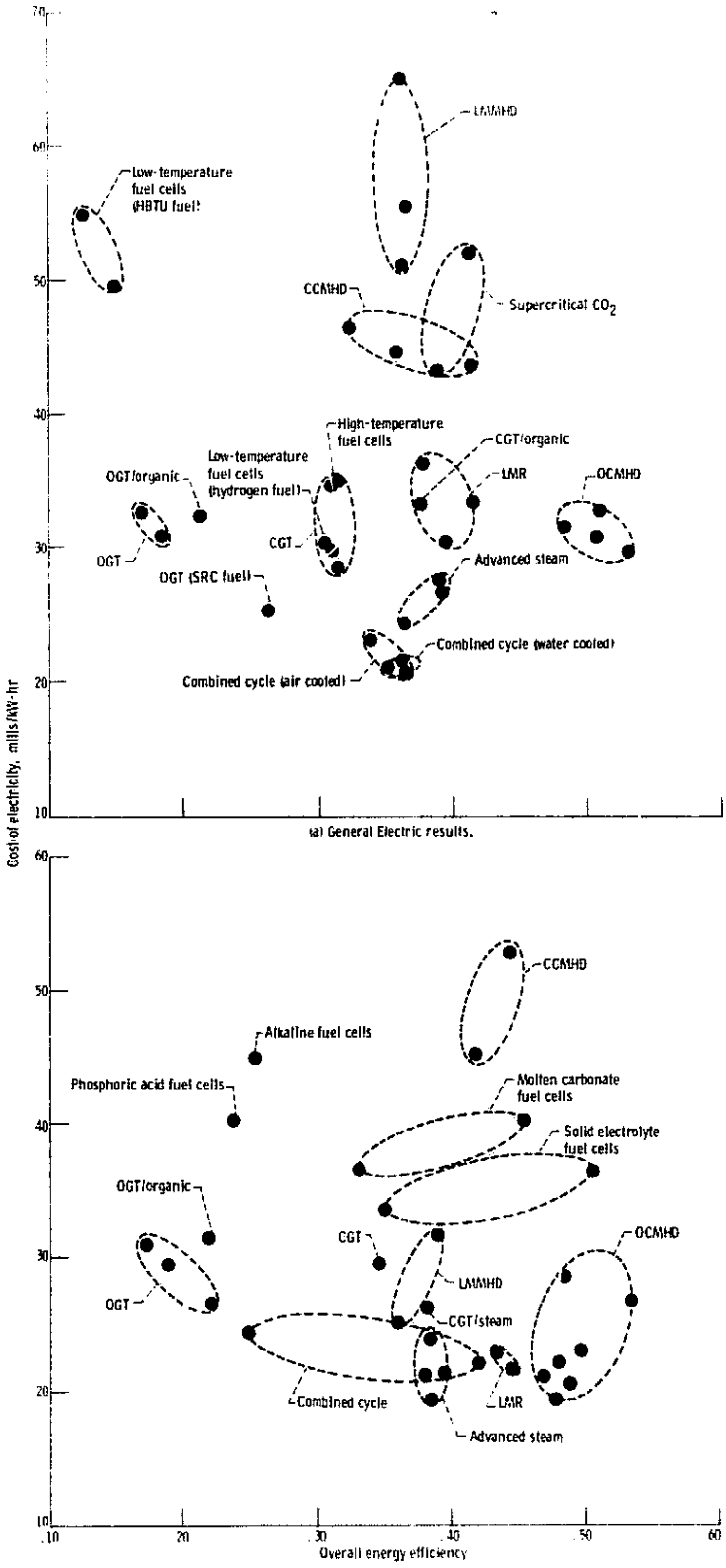


Figure 6.2-24. Average cost of electricity in constant mid-1974 dollars for zero inflation rate.

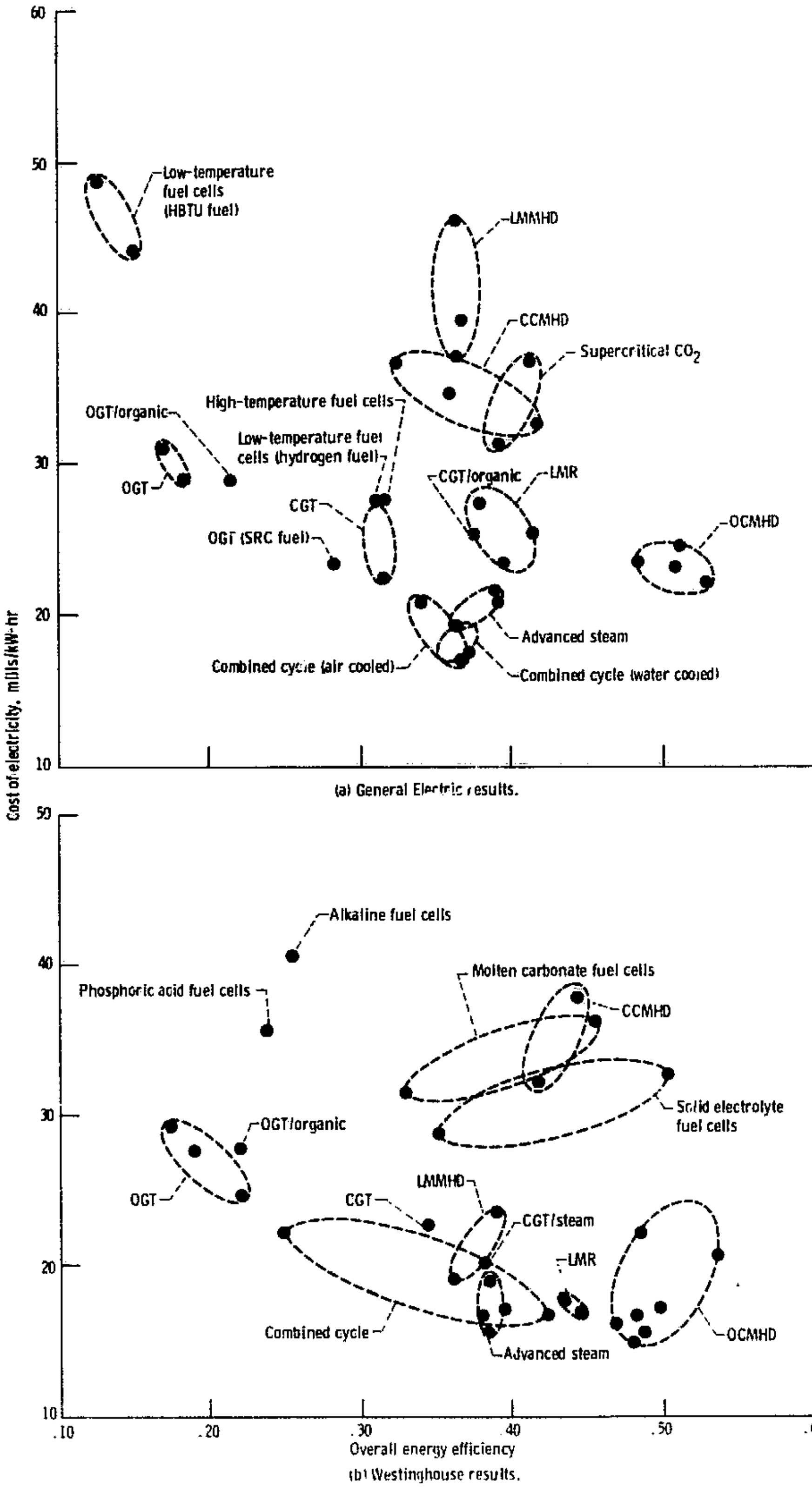


Figure 6.2-25. - Average cost of electricity in constant mid-1974 dollars for inflation rate of 3.25 percent.

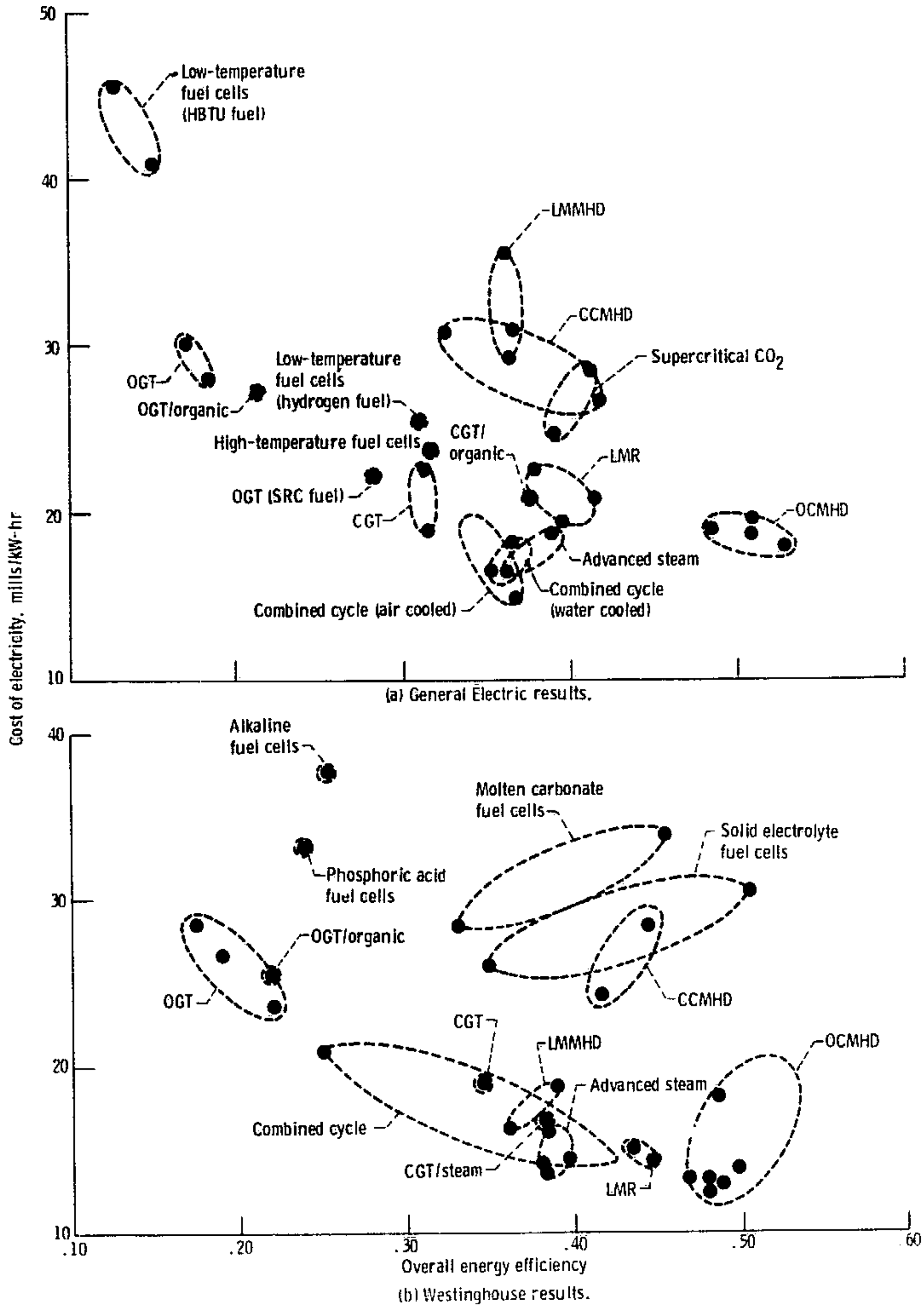


Figure 6.2-26. - Average cost of electricity in constant-year dollars for inflation rate of 6.5 percent.

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7.0 ABBREVIATIONS

a.c.	alternating current
A-E	architect-engineer
AFB	atmospheric fluidized bed
ASME	American Society of Mechanical Engineers
BOP	balance of plant
CF	conventional furnace
COE	cost of electricity
COED	Char Oil Energy Development
CONCEPT	cost computer program
d.c.	direct current
DCT	dry cooling tower
ECAS	Energy Conversion Alternatives Study
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERDA	Energy Research and Development Administration
FL-85	Fluorinol-85 working fluid
F.O.B.	free on board
G.E.	General Electric
HBTU	high-Btu gas
HRSG	heat-recovery steam generator
IBTU	intermediate-Btu gas
IGT	Institute of Gas Technology
ISC	Interagency Steering Committee
LBTU	low-Btu gas
LMFBR	liquid-metal fast breeder reactor
LMMHD	liquid-metal magnetohydrodynamic
MAG	Materials Advisory Group
MC	molten carbonate

MCA	Magnetic Corporation of America
MHD	magnetohydrodynamic
NASA	National Aeronautics and Space Administration
NOX	nitrogen oxides
NSF	National Science Foundation
NTU	number of thermal units transferred
OCR	Office of Coal Research
O and M	operation and maintenance
OMB	Office of Management and Budget
ORNL	Oak Ridge National Laboratory (Hollifield)
OTC	once-through cooling
PERC	Pittsburgh Energy Research Center
PF	pressurized furnace
PFB	pressurized fluidized bed
R-12	working fluid
R-22	Freon
SE	solid electrolyte
SOX	sulfurous oxides
SPE	solid polymer electrolyte
SRC	solvent-refined coal
TVA	Tennessee Valley Authority
WCT	wet cooling tower

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