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Yung K. Choo

Lewis Research Center
Cleveland, Ohio

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Summary

This study evaluated potential benefits of integrated-gasifier combined-cycle (IGCC) units compared with a state-of-the-art coal-fired steam turbine as capacity-expansion candidates in long-range expansion of a reference utility system. This study also evaluated the relative importance to benefits of individual parameters that characterize the IGCC unit. Sufficiently broad ranges of parameters were selected to include IGCC cases designed with state-of-the-art gas-turbine technology as well as advanced technology.

A utility-system expansion-planning-analysis approach was used instead of a simple comparison of individual units. The expansion plan accounts for the effect of unit equivalent forced-outage rate (EFOR), unit size, and generation and load characteristics of a utility system on the overall utility cost (capital cost, fuel cost, and operation and maintenance (O&M) cost less salvage value), as well as the effect of unit efficiency and estimated unit cost.

The reference utility system was selected to represent the median size of the 120 largest generating utilities, which generated about 84 percent of total U.S. electric output in 1979. A 20-yr expansion period and a constant annual-load growth rate of 4 percent were selected.

All the utility-system expansion plans that used the IGCC units showed substantial cost savings compared with the base expansion plan that used only state-of-the-art coal-fired steam turbines. An increase in IGCC unit efficiency from 37 to 45 percent or a reduction in unit EFOR from 15 to 7.5 percent resulted in about equal increases in benefit to the utility system of this study. The 37-percent unit efficiency represents current state-of-the-art gas turbine technology, and the 45-percent efficiency represents advanced technology with turbine inlet temperatures of 1700 to 1922 K (2600° to 3000° F). The EFOR range between 15 and 7.5 percent includes the level of unit reliability assumed for the 500-MW base steam turbine (15-percent EFOR) and existing steam turbines in sizes of 200 MW or less (7.5-percent EFOR). The current average size of coal-fired units being installed by the U.S. utilities is about 500 MW. A reduction in IGCC unit size from 500 to 250 MW provides a saving equivalent to those achieved with an efficiency improvement from 40 (reference IGCC unit) to 45 percent or with an EFOR reduction from 10 to 7.5 percent.

IGCC units, because of their modular nature, are potentially more efficient, cost effective, and environmentally acceptable over a broader range of unit sizes than nuclear or coal-fired steam-turbine units. IGCC units that are smaller than the average-size (500 MW) steam turbines installed during the 1970's could provide a new economically viable option for many U.S. utility systems. This statement is based on the results of this study for the reference utility system and on an analysis of the U.S. electric-utility data that include utility-system size distribution, unit size trend, size and age distribution of generating units, and a recent estimate of load growth rates.

Introduction

Integrated-gasifier combined-cycle (IGCC) power-generation units are potentially more efficient, reliable, and economic over a wider range of unit sizes than current state-of-the-art coal-fired steam turbines with flue-gas desulfurization. Previous studies (refs. 1 to 10) either estimated unit performance and cost or compared units based on estimated efficiency, capital cost, operation and maintenance (O&M) cost, and bus-bar cost of electricity for specified capacity factors. Such a unit-comparison approach does not account for the effects of unit equivalent forced-outage rate (EFOR), unit size, and utility-system characteristics (such as characteristics of existing units, load shape, and load growth rate) on the utility cost requirement. To account for such effects, a utility expansion-planning analysis is necessary. Such an analysis considers all possible plans that meet system reliability constraints and identifies the plan that minimizes the overall utility cost (capital cost, fuel cost, and O&M cost less salvage value) over some specified expansion period.

This study had two objectives: first, to evaluate IGCC units from the perspective of utility expansion planning in order to estimate the potential benefits of IGCC units as expansion candidates compared with a base steam turbine; second, to evaluate the relative importance of the benefits of IGCC parameters. Ranges of parameters were selected to include both IGCC units designed with current state-of-the-art technology and those designed with expected advanced technology.

A utility survey and analysis, summarized in appendix A, provided the necessary information for the rational selection of data for this study and for a qualitative assessment of potential IGCC benefits for the U.S. utility industry. The utility system for this study was selected to represent the median size of the 120 largest generating utilities, which generated about 84 percent of the total U.S. electric output in 1979. A 20-yr period between 1989 and 2008 was used. The median-size utility system, which had a 2000-MW peak in 1979, would have a 3000-MW peak in 1989 for the constant 4-percent annual-load growth rate assumed in this study. A base steam-turbine unit, against which benefits of IGCC units were measured, was sized at 500 MW. This size represents the average size of units installed in the U.S. during the 1970's (appendix A).

A preliminary planning analysis was performed using 500-, 800-, and 1000-MW steam turbines as expansion-candidate units. Results indicated that the 500-MW turbine is economically more attractive than the larger turbines for the reference utility system. A comparison of the 500-MW turbine with a 1000-MW turbine is presented in appendix B.

IGCC unit efficiencies considered range from 37 percent, which could be achieved with current gas-turbine operating conditions, to 45 percent, which could be achieved with gas-turbine inlet temperatures of 1700 to 1922 K (2600° to 3000° F). Two IGCC unit sizes were considered. One size was identical to the 500-MW size of the base steam-turbine unit; the other was 250 MW. The effect on cost of reducing the unit size below 250 MW was small. An IGCC unit in the range of sizes considered would have multiple gasifier modules, more than one gas turbine, and a single steam turbine. Because of the multiple modules, the range of EFOR's for IGCC units was extended from 15 percent, which is representative of the 500-MW base steam-turbine unit, to a lower value of 7.5 percent, which is representative of the existing steam turbines in 200-MW size or less. The effects of combined changes in unit size and EFOR were evaluated. The effect of changes in unit specific capital and O&M cost with change in unit size from 500 to 250 MW was also examined.

This report describes the analysis approaches used and presents assumptions for the generating units existing at the start of the expansion period, utility load characteristics, economic parameters, and expansion-candidate units. Results are presented in terms of meeting the two main objectives of the study.

Approach to Study

The potential benefits of IGCC units as expansion candidates for a reference utility system were evaluated using the WASP II computer code (refs. 11 and 12). WASP employs a typical utility expansion-planning-analysis methodology. This methodology accounts both for the effects of unit EFOR and size of expansion-candidate units and for the effects of unit efficiency, capital cost, and O&M cost on the overall cost of the utility system. It also accounts for the effect of such utility-system characteristics as load shape, load growth rate, and the characteristics of existing generating units. A simplified flow diagram of the expansion-planning-analysis procedure is shown in figure 1.

All possible capacity-addition schedules (using the expansion candidate units allowed) that would maintain the system loss-of-load probability (LOLP) below a specified critical value are derived by the WASP II computer code. From those expansion schedules that meet the system LOLP constraints, WASP II identifies the schedule that minimizes the present worth of overall utility costs over the expansion period. The schedule that minimizes the present worth of overall utility costs is designated a plan.

A state-of-the-art coal-fired steam turbine was selected as the base (expansion-candidate) unit. Several IGCC units were considered as expansion candidates in order to evaluate the relative importance of unit efficiency, EFOR, size, and cost estimates. Each IGCC expansion schedule assumed that only the IGCC units and oil-fired gas-turbine peakers were available as expansion candidates. The base expansion schedule assumed that

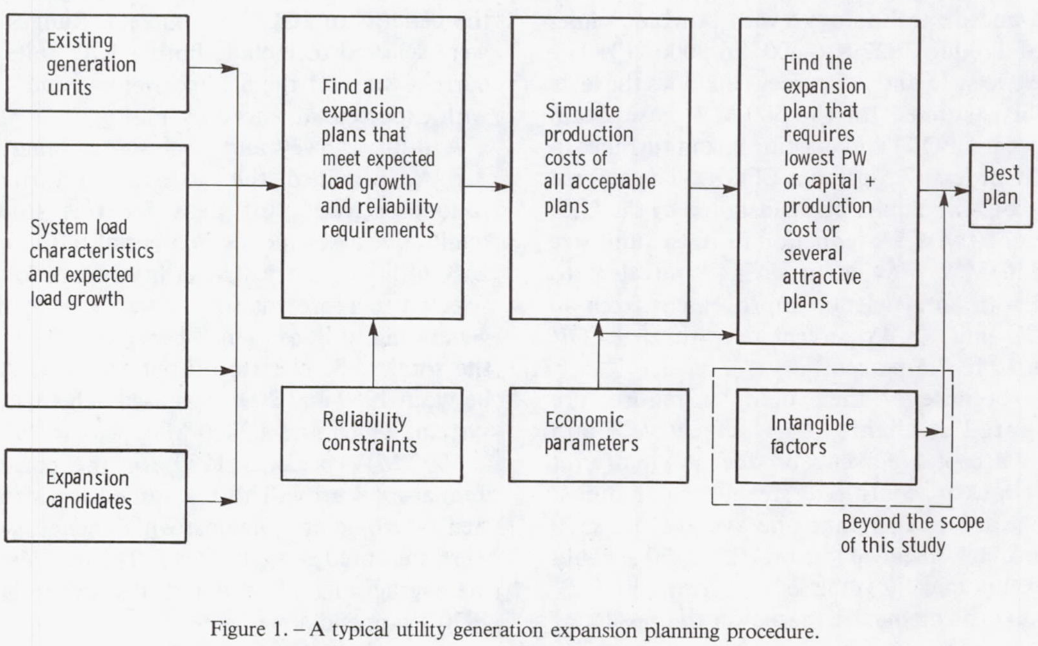


Figure 1. – A typical utility generation expansion planning procedure.

only the coal-fired base steam-turbine unit and oil-fired gas-turbine peakers were available as expansion candidates. The benefit of an IGCC (expansion-candidate) unit relative to the base (expansion-candidate) unit for the reference utility was measured by comparing the present worth of the overall utility cost for the IGCC plan against that for the base plan. Specific items required in each of the WASP II input categories and major output items are listed in table I.

Assumptions

Assumptions for this study are discussed in this section by each input category of table I(a). The assumed 20-yr expansion period spans 1989 to 2008. Each IGCC unit was assumed to be available as a mature generating unit candidate for the utility capacity expansion during the entire period.

Existing Generating Units

Table II describes the mix of generating units for the reference utility system at the beginning of the expansion period. As shown in part (a), the reference utility system is made up of coal-fired and oil-fired steam-turbine units and oil-fired gas-turbine peaking units. At the beginning of the expansion period, this utility system has about 27-percent reserve capacity (3000-MW peak load with 3800-MW installed capacity).

Characteristics of each existing unit are presented in table II(b). The full-load heat rate of 10.46 MJ/kWhr (9919 Btu/kWhr) (34.4 percent efficiency) for the 800-MW coal-fired steam turbine was obtained from reference 13 and is based on a conceptual design of a pulverized-coal-fired steam turbine with flue-gas desulfurizers, used to comply with the Environmental Protection Agency's (EPA's) June 1979 New Source Performance Standard (NSPS). Since reference 13 considered only the 800-MW coal-fired unit, heat rates for the smaller coal-fired and oil-fired units of table II were estimated by modifying those smaller unit estimates given in reference 14 to make them consistent with the heat rates chosen for the 800-MW unit. The modification was based on the difference between the two heat rates of references 13 and 14 for the same 800-MW coal-fired unit.

The O&M costs were based on the estimates given in reference 9, which provides consistent estimates for both coal-fired steam-turbine and IGCC units. The O&M fixed costs include costs of operating labor, maintenance labor, maintenance materials, and administrative and support labor. The O&M variable costs include costs of water, chemicals and consumables, limestone, sludge, and ash disposal.

The O&M fixed cost given in reference 9 was for a 987-MW coal-fired unit. This cost was scaled for smaller capacity units by using a factor of unit-size ratio raised to 0.4 power from reference 15. The specific O&M variable cost ($/MWhr) was not changed for change in size. The O&M fixed costs for the oil-fired steam turbines and gas turbines were estimated based on those for the coal-fired units.

The unit EFOR values and the number of days of scheduled maintenance were obtained from reference 14. The given EFOR values (ref. 14) are plotted in figure 2. The spinning reserve of each unit shown in table II(b) is a percentage of unit-rated capacity that can contribute to the spinning reserve requirement of the utility system when the unit is not fully loaded.

For gas-turbine units, the total rated capacity contributes to the system spinning reserve. Larger base load units were assumed to contribute a lower percentage of their rated capacity to the utility-system spinning reserve than smaller units. Oil-fired units contribute a greater percentage of their capacity than coal-fired units.

System Load Characteristics

The reference utility system for this study was sized to represent the median size of the 120 largest generating utilities. (The results of a survey and analysis of the characteristics of existing utility systems are discussed in appendix A.) These 120 utilities generated about 84 percent of total U.S. electric output in 1979. The median-size system had an annual peak load of 2000 MW in 1979 and would have a 3000-MW peak in 1989, if the load grows at a 4-percent annual growth rate. The reference utility system is a summer-peaking system, and its peak load grows at 4 percent annually for the period 1989 to 2008. This rate is an approximation of the projected average annual rates of the U.S. electric utilities for the 1981–90 period in reference 16. The ratios of the seasonal

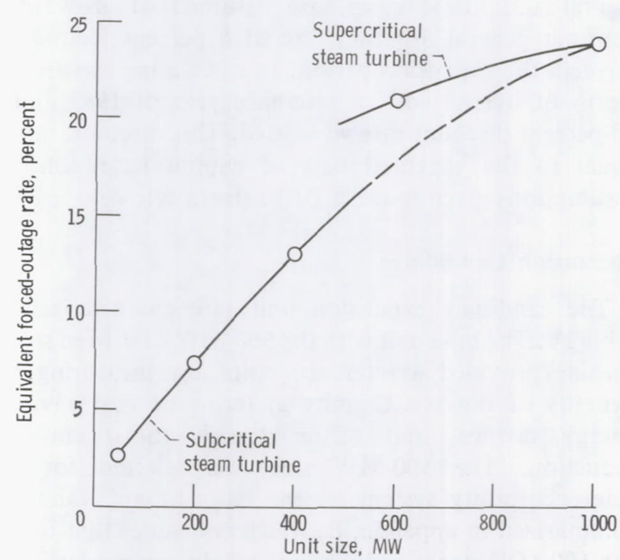


Figure 2. – Equivalent forced-outage rates (EFOR) of steam turbines (data from ref. 14).

peak loads to the annual peak load are assumed as follows:

Spring	0.68
Summer	1.00
Fall	0.73
Winter	0.75

Seasonal-load duration curves used have typical shapes for a utility of the selected size.

System Reliability Constraints

The WASP II computer code determines a generation expansion schedule such that the system LOLP is below some value acceptable to the utility company. This acceptable value, referred to as the critical LOLP, is an input to the analysis. A typical value of the critical LOLP, for the purposes of the reserve determination for interconnected systems, is 0.1 d/yr (ref. 17). The reference utility would maintain its LOLP under the 0.1 d/yr by expanding both the generation capacity and interconnection capability. This study assumed that the interconnected system LOLP constraint of 0.1 d/yr would be met for the reference utility if generation capacity additions ensure the system LOLP under 5 d/yr as an isolated utility system. This simplifying assumption is supported by reference 18, in which a specific utility system was analyzed.

Economic Parameters

The cost of fuel to the utility system was based on the 1980 average delivered fuel cost to electric utilities in the contiguous United States. These costs, obtained from reference 19, are shown in table III(a). Residual-grade oil is used in oil-fired steam-turbine units, distillate-grade oil in gas-turbine peaking units. Fuel prices, as well as capital and O&M costs, are assumed to grow at a constant general inflation rate of 6 percent from 1980 through the expansion period. In calculating the present worth of overall cost, a reference year of 1982 and a 10-percent discount rate were used. This discount rate is equal to the weighted cost of capital based on the assumptions given in table III(b) (from ref. 20).

Expansion Candidates

The candidate expansion units are characterized in table IV. The base unit with the 500-MW coal-fired steam turbine provided a reference point for measuring the benefits of the IGCC units in terms of cost savings, energy savings, and sulfur dioxide (SO_2) emission reduction. The 500-MW size was selected for the reference utility system on the basis of an evaluation summarized in appendix B, which concludes that use of the 500-MW steam-turbine unit would require less total system cost than use of a 1000-MW unit. The 500-MW size is also representative of the average-size unit installed during the 1970's (appendix A). Parameters for the base steam turbine are consistent with those for the existing steam turbines given in table II(b). The capital cost and O&M cost for this 500-MW base unit were obtained by scaling the estimated values for the 987-MW unit from reference 9 using the unit-size ratio raised to the 0.85 power (ref. 20) and 0.4 power (ref. 15). Other parameters were based on the data in references 13 and 14.

The six IGCC (candidate-expansion) units were selected so that the effects of several potentially attractive characteristics of the IGCC units might be evaluated individually. The purpose of each candidate unit and unit characteristic are indicated in table IV. The IGCC unit 1 was used as the reference in evaluating the importance of individual IGCC characteristics. The capital cost and fixed O&M cost for the 500-MW reference IGCC unit were obtained by scaling the estimated values for a 1138-MW unit (from ref. 9) using the unit-size ratio raised to the 0.85 power for the capital cost and 0.4 power for the fixed O&M cost, respectively. The 500-MW IGCC units would be of modular construction with four or more gasifier modules and two or more gas turbines. An outage of one gasifier module or of one gas turbine would not preclude operation of the remainder of the unit, allowing the unit capacity to remain at a significant fraction of the unit-rated capacity. Based on this characteristic of the IGCC units, the reference IGCC unit was assumed to be more reliable (10-percent EFOR) than the base steam turbine (15-percent EFOR).

IGCC units 1 to 3 span the range of unit efficiency from 37 to 45 percent. As seen in figure 3 (ref. 21), this range covers efficiencies from those that could be achieved using gas turbines with state-of-the-art gas-turbine inlet conditions of about 1366 K (2000° F) to those that could be achieved using advanced gas turbines with inlet temperatures of 1700 to 1922 K (2600° to 3000° F). Comparison of the plan using IGCC unit 3 with those using IGCC units 1 and 2 will identify the potential benefits that could result from gas-turbine technology advancements if the other IGCC parameters remained unchanged. Reference 21 explains in detail the gasifier types and the gas-turbine cooling approaches indicated in figure 3.

The unit EFOR effects on the benefits are evaluated by comparing the plan using IGCC unit 1 with those plans using IGCC units 4 and 5. These units span the range of unit EFOR from 15 to 7.5 percent. The 15-percent EFOR represents the same level of EFOR assumed for the 500-MW base steam turbine. The 7.5 percent for the 500-MW IGCC unit corresponds to the level of unit EFOR assumed for the smaller ($\leq$200 MW) existing steam turbines (fig. 2). In figure 4 EFOR values of the six IGCC units discussed above, the base steam turbine, and the gas turbines are shown. The EFOR values of the existing steam units indicated in table II(b) and illustrated in figure 2 are also shown.

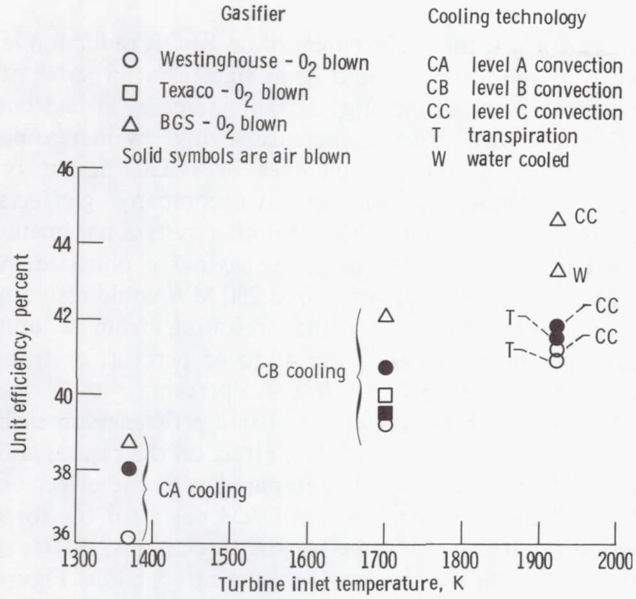


Figure 3. – IGCC unit efficiency as function of gas turbine inlet temperature (ref. 21).

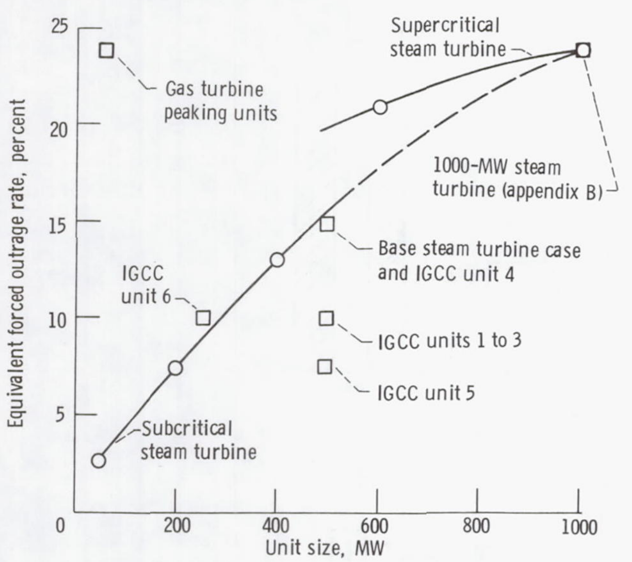


Figure 4. – Equivalent forced-outage rates (EFOR) selected for the expansion candidates. (Steam turbine data from ref. 14.)

The effects of unit size will be evaluated by comparing the plan using the IGCC unit 1 (500-MW) with that using IGCC unit 6 (250-MW).

Additional Cases

The sensitivity of the results to simultaneous changes in unit size and EFOR and to simultaneous changes in unit size and costs was also examined. The EFOR value was varied from 5 to 15 percent for units of 250- and 500-MW size. The effect of cost scaling for changes in unit size was examined for ranges of a scaling factor defined below.

To examine the sensitivity of savings to simultaneous changes in unit size and cost, a scaling factor x was defined as

$$\left(\frac{250}{500}\right)^x = \frac{\text{capital or fixed O\&M for 250-MW unit}}{\text{capital or fixed O\&M for 500-MW unit}}$$

From definition, if $x = 1.0$, then unit specific capital cost (\$/kW) and specific O&M fixed cost (\$/kW-mo) do not change with changes in unit size, as in IGCC units 1 and 6. The use of constant specific capital and O&M costs in IGCC units 1 and 6 is reasonable because the IGCC units in sizes of 500 and 250 MW would be built in multiple modules. Two cost-scaling cases were considered:

(1) $x = 0.6, \ldots, 1.0$ for fixed O&M and $x = 1.0$ for capital

(2) $x = 0.7, \ldots, 1.0$ for capital and $x = 1.0$ for fixed O&M

Specific O&M variable cost in \$/MWhr was held at a constant value in each case.

Results

The best WASP II solution (best expansion schedule explained in Approach section) for the base unit (i.e., the coal-fired steam turbine) is designated the base plan. The best solutions for the IGCC units 1 to 6, defined in table IV, are designated plans 1 to 6, respectively.

One of the objectives of this study was to estimate potential benefits of IGCC units as expansion candidates compared with the base steam-turbine unit. The benefits of IGCC units relative to the base unit were measured by comparing present worth of the overall utility cost for the IGCC plans against that for the base plan. This comparison is shown in figure 5, which shows the present worth of the savings in overall utility cost of each IGCC plan over the 20-yr expansion period compared with that of the base plan. All six IGCC plans showed substantial savings. The IGCC reference plan (plan 1) saved a total

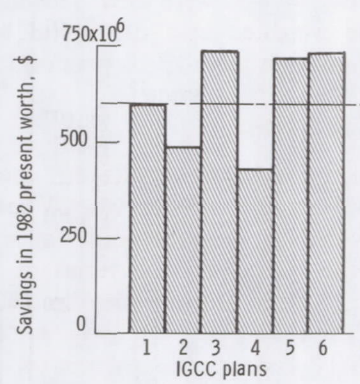


Figure 5. – Saving in revenue requirements due to use of IGCC units as expansion candidates compared with use of base steam turbine. (See table IV for unit descriptions.)

amount of $598 million in 1982 present worth. This particular plan required construction of seven 500-MW IGCC units and ten 50-MW gas turbines during the 20-yr expansion period. The saving is about equal to the construction cost of one IGCC unit and three gas turbines.

The overall cost of each plan consists of capital costs for new unit construction (excluding salvage value at the end of the expansion period) and production costs (fuel and O&M costs) for both newly added units and those which existed at the beginning of the planning period.

The other objective of this study was to evaluate the relative importance of IGCC unit characteristics. The effects of individual IGCC parameters on the benefits may be compared with the aid of figure 5. An increase in IGCC efficiency from the 37 percent achievable with a state-of-the-art technology gas turbine to the 45 percent achievable with a high-temperature gas turbine could increase the saving from about $490 million to about $750 million. A comparable change in saving could be achieved by an improvement in EFOR from 15 to 7.5 percent. Thus, the achievement of an EFOR reduction in IGCC system designs could be as significant in terms of present worth of saving as an increase in system efficiency. Any effort to increase savings by increasing unit efficiency through changes in IGCC design or technology must also consider any accompanying effects of the change on unit EFOR. Another system parameter that could significantly affect the savings is unit size. A reduction in unit size from 500 to 250 MW could result in a saving comparable to that resulting from a unit efficiency improvement from 40 to 45 percent, or from an EFOR reduction from 10 to 7.5 percent.

Figure 6(a) shows the effect of unit efficiency on each component of overall cost. The effect on the capital and O&M costs was negligible compared with the effect on the fuel cost. The capital and O&M costs for the total period are nearly the same for the three plans, differing only slightly in the new-unit-installation schedule. Figure 6(b) shows the fuel energy saving that resulted in the fuel cost saving shown in part (a) of the figure. As an illustration, with the 3.57×10^{11} MJ (338×10^{12} Btu)

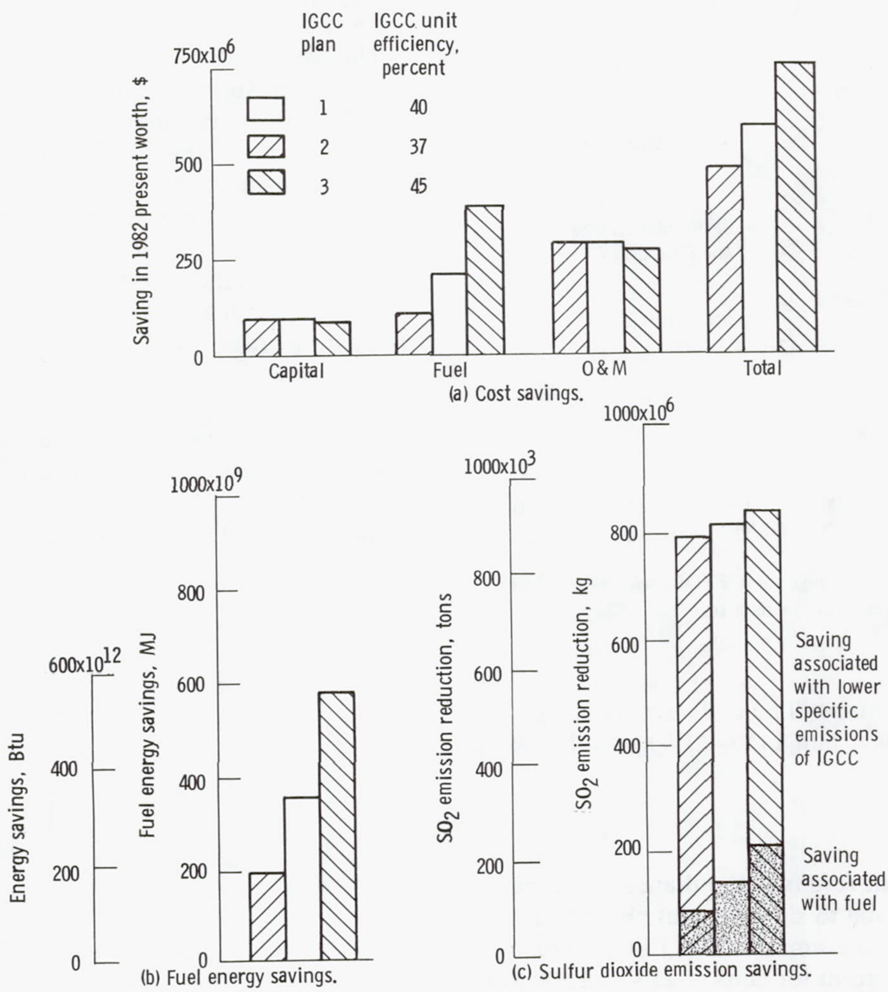


Figure 6. – Effects of unit efficiency on cost saving, fuel energy saving, and emission reduction. (See table IV for IGCC descriptions.)

saving by plan 1 over the 20-yr period, a utility system with 4000-MW installed capacity, 0.6 system capacity factor, and average generating efficiency of 32 percent could be operated for 18 months. The effects of the unit efficiency on the SO_2 emission are shown in figure 6(c). These SO_2 reductions were calculated based on the assumptions in table V. Total emission savings achievable by the IGCC units are due to the reduced fuel consumption and the lower specific emission levels compared with the base steam unit.

The effects of the unit EFOR on the relative savings are shown in figure 7. Plans 1, 4, and 5 show the effects of decreasing EFOR on the savings. As the unit EFOR is decreased from 15, to 10, to 7.5 percent, the capital and O&M savings increase, fuel saving decreases, and net saving increases. These effects of the EFOR on the savings result from changes in the capacity-expansion schedule as illustrated with plans 1 and 4 in figure 8. Plan 1, using the reference IGCC units with 10-percent EFOR, required less system reserve capacity than plan 4, which used IGCC units with 15-percent EFOR; plan 1, therefore, resulted in lower capital and O&M expenses.

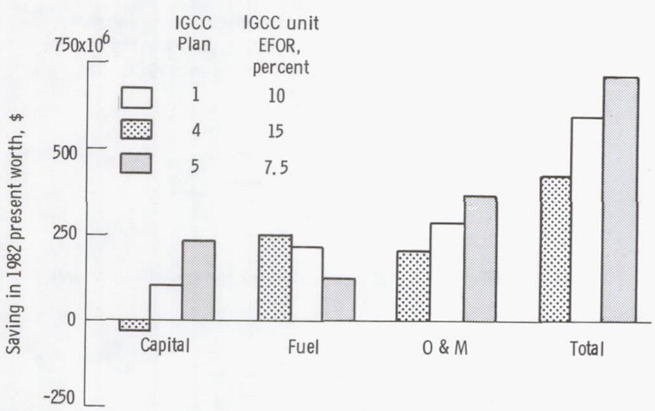


Figure 7. – Effect of unit equivalent forced-outage rate (EFOR) on saving relative to base plan.

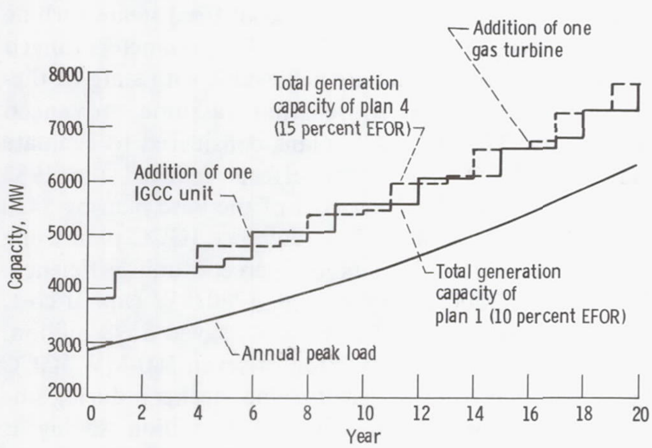


Figure 8. – Effect of IGCC equivalent forced-outage rate (EFOR) on capacity-expansion schedule.

But plan 4, which required more IGCC capacity addition, resulted in a higher fuel saving because of the higher efficiency of the new IGCC units operated at higher capacity factors.

Figure 9 shows the effects of the IGCC unit size on the cost saving for the 20-yr planning period compared with the base plan. Specific capital ($/kW) cost and O&M fixed cost ($/kW-mo) were held at the constant values of the reference IGCC unit for the size reduction. As shown, the reduction of unit size from 500 MW to 250 MW increased capital and O&M savings, but reduced the fuel saving. Net result of the unit-size reduction was an increase in overall saving to the utility system. The effects of unit size on the savings result from changes in the capacity-expansion schedule, as illustrated in figure 10. Plan 6, using smaller IGCC units as expansion candidates, could follow the system load growth more closely than plan 1 and require less system reserve capacity; plan 6, therefore, would result in lower capital and O&M expenses. But plan 1, which requires more IGCC capacity addition, resulted in a higher fuel cost saving because of the higher efficiency IGCC units that would be operated at higher capacity factors.

The effect of EFOR on savings is shown in figure 11 for both 250- and 500-MW units. As seen, the saving for the plans using the 500-MW units is more sensitive to the change in the unit EFOR than those using the 250-MW

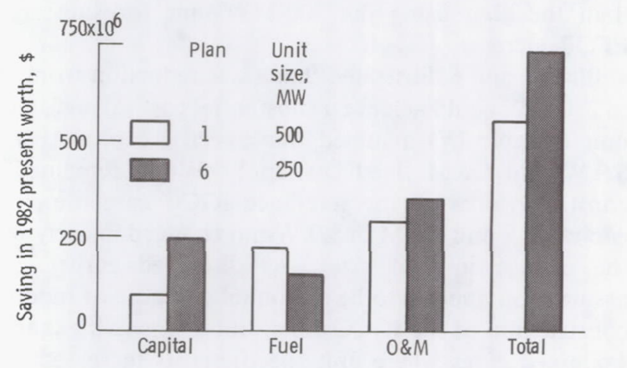


Figure 9. – Effect of IGCC unit size on saving.

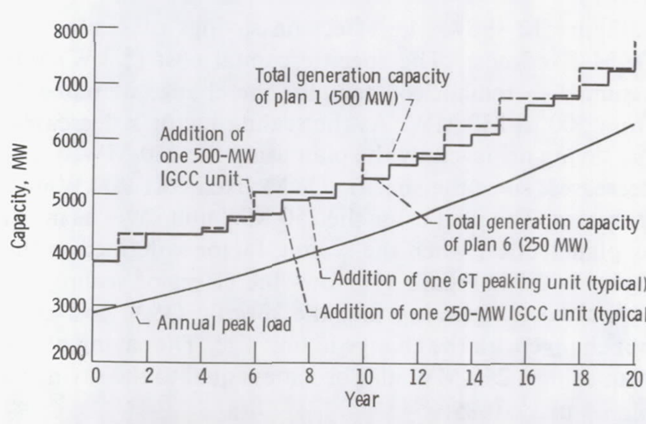


Figure 10. – Effect of IGCC unit size on capacity-expansion schedule.

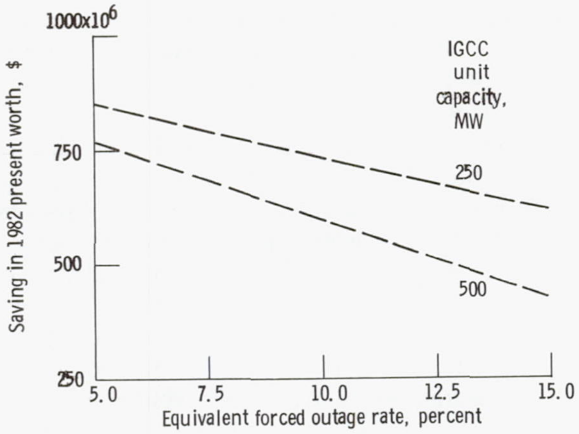


Figure 11. – Combined effect of unit size and equivalent forced-outage rate on saving.

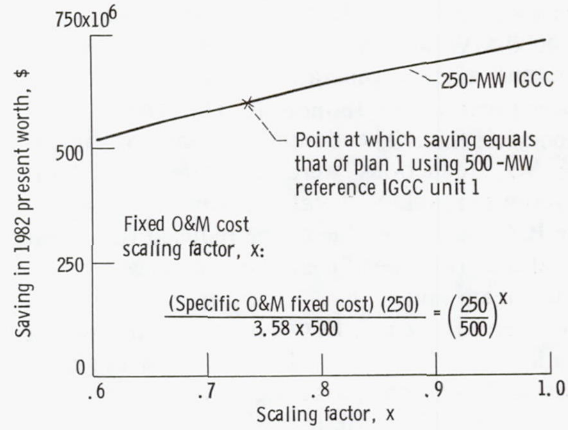


Figure 12. – Effect of O&M fixed cost scaling factor for 250-MW unit.

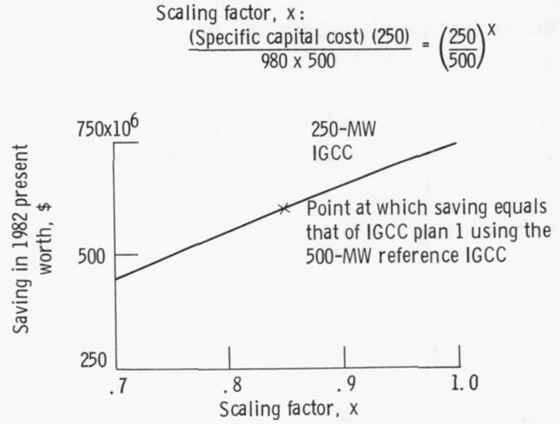


Figure 13. – Effect of capital cost scaling factor for 250-MW unit.

units. This is because the change in system reserve capacity, for the same change in EFOR, is greater in the plan using 500-MW units than in the plan using 250-MW units. The saving was substantial when only unit size was reduced, as illustrated with plans 1 and 6 in figure 9. Figure 11 illustrates that the saving could be further increased if the unit EFOR decreases with the size reduction, as it does for steam turbines. Even if the IGCC EFOR were to increase for the size reduction, the plan using the 250-MW unit still could achieve higher savings than the plan using the 500-MW unit for substantial EFOR increase.

Plans 1 and 6 illustrated that a size reduction from 500 to 250 MW could achieve a substantial cost saving. IGCC unit 6 (table IV) assumed that specific capital cost in $/kW and O&M fixed cost in $/kW-mo remained at constant values of the reference IGCC case (i.e., unit capital in $ and O&M in $/kW-mo changed linearly with the change in unit size). As discussed earlier, this assumption appears to be reasonable because of modular construction of the IGCC units. But a sensitivity analysis examined cases where unit specific costs increased with unit-size reduction; the results are presented in figures 12 and 13.

Figure 12 shows the effect on savings of scaling the O&M fixed cost. The specific capital cost ($/kW) was assumed to remain constant for the change of unit size from 500 to 250 MW. As the scaling factor x decreases, the saving achieved by the plan using the 250-MW IGCC decreases, since the specific O&M fixed cost ($/kW-mo) increases. The plan using the 250-MW unit saves as much as plan 1 does, when the scaling factor x defined in the figure is 0.74. Figure 13 shows the effect of scaling the capital cost, assuming that the specific O&M cost does not change with the change in unit size. The saving of the plan using a 250-MW unit becomes equal to the saving of plan 1 at $x=0.85$.

Conclusions

For the ranges of parameters considered in this study, all IGCC plans showed substantial savings compared with the base plan that used the coal-fired steam turbine as an expansion candidate. The IGCC parameters ranged from characteristics that are achievable with state-of-the-art technology to those that assume advanced technology. The six IGCC plans considered to evaluate individual IGCC parameter effects reduced the 1982 present worth of the 20-yr cost of the base plan by $420 million to $750 million. The reference IGCC plan using the reference IGCC units (40-percent unit efficiency, 10-percent EFOR, 500-MW size, $980/kW capital cost, and 3.58/kW-mo O&M fixed cost) saved $598 million. This plan required construction of seven 500-MW IGCC units and ten 50-MW gas-turbine peakers during the 20-yr expansion period. The $598 million saving is equivalent to the construction cost of one IGCC unit and three gas-turbine peakers.

The effect of IGCC unit efficiency on the utility-system cost savings was significant. The saving achieved by the reference IGCC plan using the units with 40-percent unit efficiency was 22 percent greater than the saving of $488 million achieved by the plan using the units with 37-percent unit efficiency, representing current state-of-the-art technology. As the IGCC unit efficiency was improved from 40 to 45 percent, representing advanced gas turbines with turbine inlet temperatures of 1700 to 1922 K (2600° to 3000° F), the saving of the reference plan increased by 26 percent to $751 million.

The effect on utility overall cost of the IGCC unit reliability for an EFOR range between 7.5 and 15 percent was comparable in magnitude to the effect of the unit efficiency in a range between 37 and 45 percent. When both the IGCC and the base steam turbine had the same 15-percent EFOR, the IGCC plan saved $423 million, because of the higher IGCC efficiency and lower O&M cost. Because of the modular design approach, an IGCC unit would have multiple gasifier trains and gas turbines, and could have an improved effective unit reliability represented by lower unit EFOR's. As the EFOR of the IGCC was decreased from 15 to 10 percent, the saving was increased by about 41 percent to $598 million. For further reduction from 10 to 7.5 percent in EFOR, the saving increased by about 20 percent to $716 million. Expansion plans using more reliable IGCC units, represented by lower EFOR's, required less utility-system reserve capacity in meeting the system LOLP constraints than the plan using less reliable units. Therefore, the plan with more reliable IGCC required less capital and O&M costs.

For the utility system of this study, the size reduction from 500 (reference IGCC) to 250 MW is as important to the benefits of IGCC as the efficiency improvement from 40 to 45 percent or as the EFOR reduction from 10 to 7.5 percent. This comparison was based on the assumption that both 250- and 500-MW units had 10-percent EFOR and 40-percent efficiency, and that unit capital cost ($) and O&M cost ($/mo) changed linearly with the change in unit size (i.e., no change in specific capital in $/kW and O&M fixed cost in $/kW-mo for the size change). This assumption might represent a good first approximation because of the modular design of the IGCC units. The plans using the smaller IGCC units resulted in a higher saving in the capital and O&M cost components because the load growth of the utility system could be followed more closely, resulting in lower reserve margins. Although the plan using the smaller units required higher fuel cost because it had less IGCC capacity and IGCC units are more efficient, the effect of the size reduction on the capital and O&M costs outweighed the effect on the fuel cost, yielding a net increase in savings.

The survey of existing utilities which was done to select an appropriate reference utility for this study also indicated that smaller generating utility systems are numerous. In order to take advantage of the economics of scale of current coal-fired steam-turbine units, such utilities now consider joint ownership of new units. IGCC units might be an attractive expansion-candidate option for such utilities. For those utilities, plans using smaller IGCC units (250 MW or less) could achieve substantially greater overall savings than plans using larger IGCC units (500 MW or larger). Because of modular design, the unit-size reduction would result in substantially greater savings with relatively few adverse effects on benefits from associated changes in specific costs. Unit efficiency would not change substantially for the size reduction.

In addition to the economic benefit, smaller IGCC units could offer electric utilities more certainty in their capacity-expansion plan than larger units can, since the smaller units could be added in shorter time intervals and do not require longer term load forecasting. Smaller IGCC units could reduce the risk associated with any significant discrepancy between actual and forecasted utility-system load growth and could reduce cost risks associated with such a discrepancy.

Appendix A
Summary of Electric Utility Survey and Analysis

A survey of published data (refs. 22 and 23) on existing utility systems and existing or planned power-generation units was made in order to realistically select the characteristics of the reference utility system. This utility survey provided some perspective concerning the size of utility systems, the annual capacity additions required, the size and age of existing power-generating units, and the size of planned generating units.

A reference utility system to be used in the analysis of potential benefits of IGCC was sized to represent the median of the 120 largest generating utility systems in 1979; the size distribution of these systems is presented in figure 14. These utility systems generated about 84 percent of the total national electric output of 1979. Each of the 120 largest systems had an annual peak load greater than 500 MW, and a median load of 2000 MW. The reference utility system selected for this study would have an annual peak load of 3000 MW in 1989 if the 2000-MW peak representing the median size in 1979 escalates at an annual rate of 4 percent as assumed in this study. The 4-percent load growth rate is the approximate average value of the 10-yr projection for the 1981 to 1990 period (ref.16).

The annual capacity additions required by the 120 systems for 2- and 4-percent load growth rates are shown in figure 15. With a 4-percent load growth rate, only the five largest systems would require capacity additions of 400 MW or more per year. Among the 120 generating systems, 70 require annual capacity additions of less than 100 MW. With 2-percent load growth rate, only 20 systems would require annual capacity additions greater than 100 MW. The average unit size of fossil-fired steam turbines installed each year from 1940 to 1979 is shown in figure 16. The average size has sharply increased from about 150 MW in 1960 to about 500 MW currently. A base steam turbine, against which the benefits of IGCC were measured, was sized at this current average size of 500 MW. The size of the largest units in service has

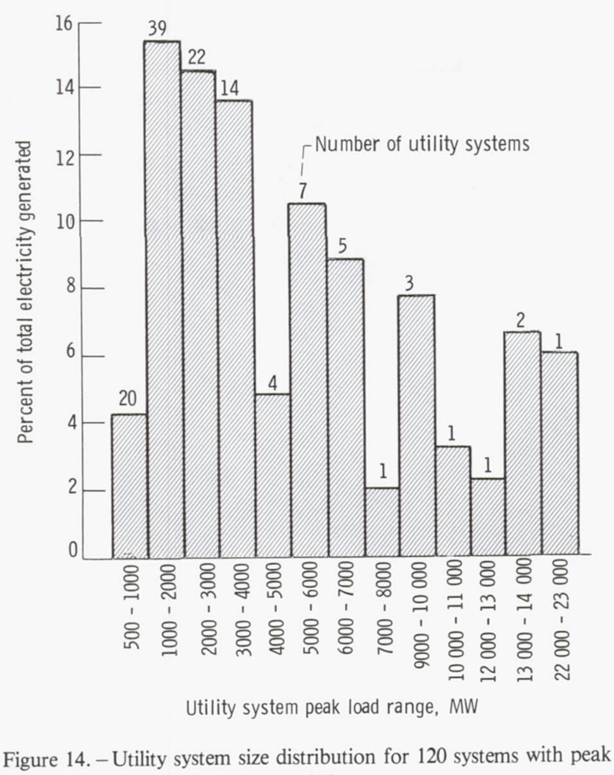


Figure 14. – Utility system size distribution for 120 systems with peak loads greater than 500 MW in 1979.

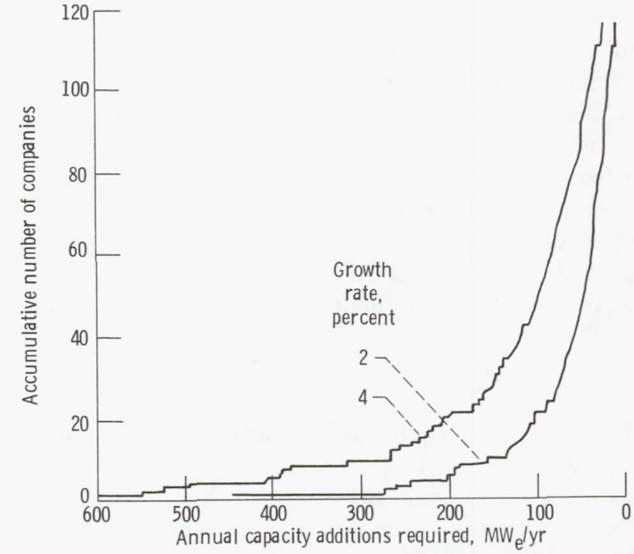


Figure 15. – Annual capacity additions required for utility systems with peak loads greater than 500 MW in 1980.

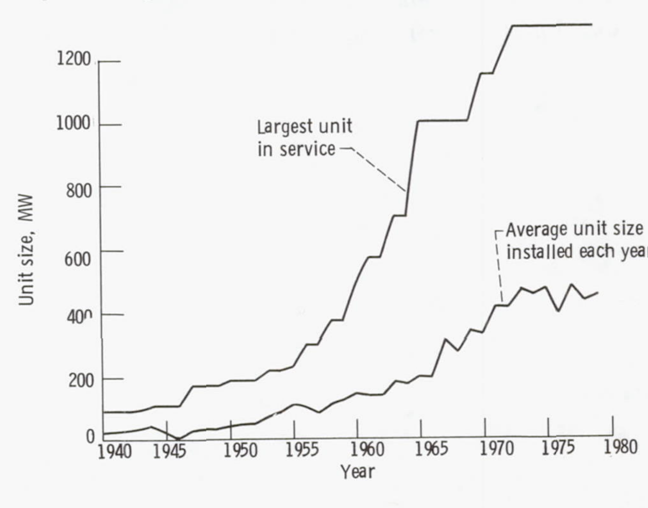
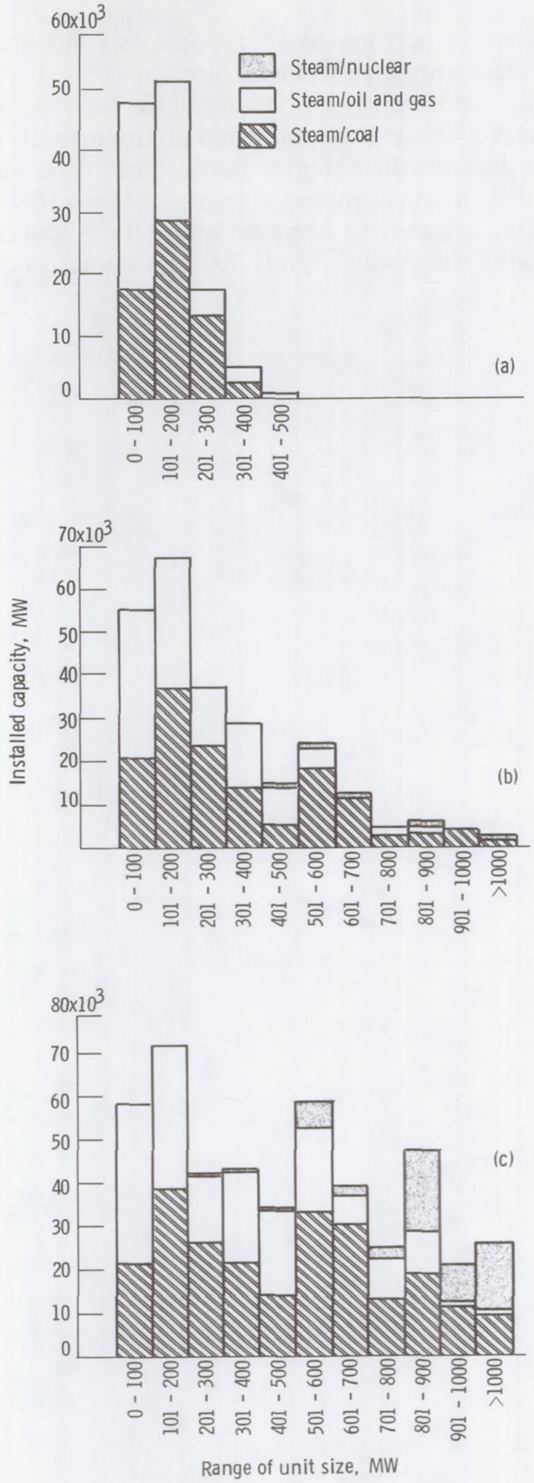


Figure 16. – Fossil-fired steam turbine size as function of year.

increased since the 1960's from 500 to 1300 MW. In the last two decades, the average size of new units installed each year has increased rapidly with respect to (1) the annual capacity additions required by individual utilities to meet their load growth, and (2) the total installed capacity of most utility systems. An important factor in this trend has been the economy of scale of the conventional-technology coal-fired and nuclear steam-turbine units. The trend toward larger units relative to the annual new capacity needs, together with the longer construction periods required for larger units, has forced longer range expansion planning and corresponding greater uncertainty. Many utilities have been able to take advantage of the economics of scale of conventional-technology steam-turbine units by joining power pools or through coordinated or jointly owned capacity expansions.

IGCC units, because of their modular construction, have the potential to be efficient, cost effective, and environmentally acceptable over a broader range of unit sizes, extending to smaller units than steam turbines. IGCC units would have economics of scale different from those of the steam turbines, and units in sizes smaller than 500 MW could be attractive to many utilities. Smaller IGCC units offer utilities more flexibility and certainty in expansion planning by allowing shorter construction time and by following load growth more closely. As indicated by figure 15, a significant number of the 120 largest companies require less than 100-MWe net capacity each year. Further, the utility survey found that more than 400 smaller utility companies, with peak loads between 20 and 500 MWe, account for 12 percent of electricity generated nationwide. Small, efficient IGCC units might provide a new economically viable option for these systems. Therefore, in this study, the range of IGCC size was extended from 500 MW of the base steam case to 250 MW. In appendix B, a plan using a 500-MW steam turbine as an expansion candidate for the reference utility system was compared with a plan using a 1000-MW steam turbine.

Another reason for considering smaller IGCC units can be seen by examining the size and age distribution of all existing steam-turbine units (based on data from ref. 23). The size distribution of existing units is presented in figure 17. Figure 17(a) shows units installed before 1961; (b) shows units installed before 1971; and (c) indicates that the total installed capacity doubled from 1971–1979 and that the new capacity added was dominated by large coal and nuclear steam-turbine units. At the end of 1979, about 50 percent of the generating capacity was produced by units larger than 500 MW. These newer and larger units serve as base-load units. Of the units installed before 1971 (fig. 17(b)), more than 50 percent of the capacity is represented by units of less than 200-MWe rating. As shown in figure 17(a), more than 80 percent of all capacity installed before 1961 was represented by units of less than 200-MW rating. Many of these older, smaller units may now be used in a cycling mode with intermediate capacity factor. When these units are ready for



(a) Steam units installed before 1961.
(b) Steam units installed before 1971.
(c) Steam units installed as of December 1979.
Figure 17. – Size distribution of existing units.

replacement, it may not be appropriate or economic to replace them with large steam-turbine units.

Smaller IGCC units may be attractive for replacing such units. Although not considered in this analysis, the previous data identifies another possible consideration in IGCC system applications, that is, the retrofits of existing oil- or gas-fired steam-turbine units. About half of the units with ratings below 300 MWe and installed before 1961 are oil or gas fired (more than 1100 units). These units may be suitable for retrofits from the standpoint of size, age, and steam-throttle conditions. Replacing the oil- or gas-fired boiler of these units with a coal-fired boiler would decrease the capacity and efficiency, but conversion to coal using a gasifier and topping gas turbine would increase both capacity and efficiency, and, hence, may be more economic

Appendix B

Comparison of 500- and 1000-MW Coal-Fired Steam-Turbine Units as Expansion Candidates

The average size of new steam-turbine units has been steadily increasing, to the present 500-MW average (fig. 16). And, because of apparent further economics of scale, some units exceeding 1000 MW have been constructed. For purposes of planning analysis for the reference utility, the base expansion plan used a 500-MW coal-fired steam-turbine unit. To examine the potential benefit of a larger unit to the reference utility system, a 1000-MW coal-fired steam-turbine unit was considered as an expansion candidate. The unit characteristics of the 1000-MW unit are listed in table VI. The 1000-MW unit was assumed to have one point higher efficiency and lower specific capital ($/kW) and O&M fixed costs ($/kW-mo) than the 500-MW unit; these assumptions were reached by scaling the capital cost with the size ratio raised to 0.85 power and by scaling the O&M fixed cost with that to 0.4 power.

The expansion plan, which uses the 1000-MW expansion-candidate unit, is compared with the base plan using the 500-MW unit in figures 18 to 20. The savings by the plan using the 1000-MW unit relative to the base plan are shown in figure 18. In spite of the lower specific capital cost and higher efficiency, the 1000-MW unit plan shows negative capital savings. This is because the 1000-MW plan requires significantly larger reserve capacity than the base plan (fig. 19) because of the larger unit size and higher EFOR (fig. 2).

The heat rate assumed for the 1000-MW unit is one point higher than that of the 500-MW unit. But the total system fuel costs for the 20-yr expansion period show a negative saving. The plan using the 1000-MW unit does show a fuel energy saving in coal, but it also shows increasing consumption in the oil-fired steam unit, and peaking gas turbines. The increased consumption of the expensive fuels outweighed the savings in cheaper coal (fig. 20).

For the reference utility system, the plan using 500-MW size shows economic advantage over the plan using 1000-MW size. Hence, the 500-MW steam-turbine unit was used as the base expansion candidate, and units larger than 500 MW were not considered further in this study.

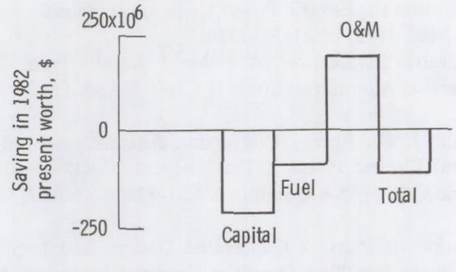


Figure 18. – Cost saving of expansion plan using 1000-MW steam turbines compared with plan using 500-MW steam turbines.

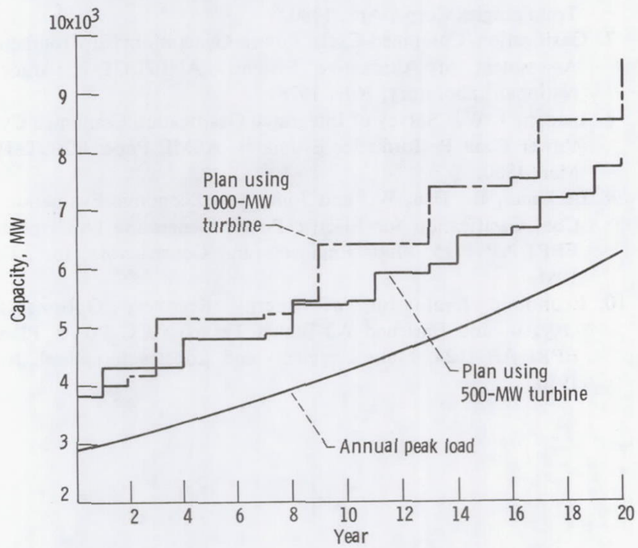


Figure 19. – Effects of steam turbine size on expansion schedule.

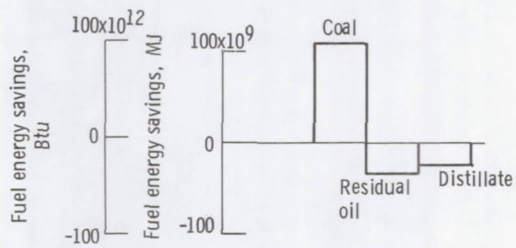


Figure 20. – Fuel saving of expansion plan using 1000-MW steam turbines compared with plan using 500-MW steam turbines.

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TABLE I. - INPUTS AND OUTPUTS OF WASP II

(a) Required inputs

Input category	Input items
Existing generation units	Unit type and size Heat rate at the minimum load, incremental heat rate Equivalent forced outage rate (EFOR) Spinning reserve characteristic O & M cost Scheduled maintenance days
System load characteristics and expected load growth	Normalized seasonal load duration curves Seasonal peak-to-annual peak ratios Annual peak load forecast
Expansion candidate units	Unit type and size Heat rate at minimum load, incremental heat rate EFOR Spinning reserve characteristic O & M cost Scheduled maintenance Capital cost
System reliability constraints	System spinning reserve requirement Critical loss-of-load probability
Economic parameters	Inflation rate Discount rate Real fuel escalation rate Fuel price by fuel type
Other	Expansion period, beginning year Base year for the present worth Base year for the cost escalation

(b) Major outputs for the best WASP II solution

Output category	Output items
Schedule of capacity additions	Capacity addition by unit type Year of addition
Costs	Present worth of yearly and total expenditure for: Capital Fuel O & M Salvage value of usable capital equipment at end of expansion period
Other	Electricity generated, fuel energy required, fuel costs, O & M costs

TABLE II. - DEFINITION OF REFERENCE ELECTRIC UTILITY SYSTEM

(a) Total projected generating capacity and mix of unit types in 1989

Total capacity, MW	3800
Mix of unit types:	
Coal-fired steam turbine, percent	58
Oil-fired steam turbine, percent	34
Distillate-fired gas turbine, percent	8

(b) Existing units in 1989

Type of unit	Number of units	Minimum load, MW	Capacity, MW	Heat rate at minimum load, MJ/kWhr (Btu/kWhr)	Average incremental heat rate, MJ/kWhr (Btu/kWhr)	Equivalent forced-outage rate,[a,b] EFOR, percent	Days of scheduled maintenance	Operation and maintenance[c]		Full load heat rate, MJ/kWhr (Btu/kWhr)	Spinning reserve, percent
								Fixed $/kW-MN	Variable, mills/kWhr		
Coal-fired steam turbine	1	320	800	11.668 (11 060)	9.662 (9 158)	24.0	34	2.610	2.47	10.465 (9 919)	5
Coal-fired steam turbine	2	100	400	12.994 (12 317)	9.932 (9 414)	13.0	31	3.950	2.47	10.698 (10 140)	5
Oil-fired steam turbine	2	100	400	13.410 (12 711)	10.284 (9 748)	13.0	31	1.970	.30	11.066 (10 489)	5
Coal-fired steam turbine	3	50	200	14.110 (13 374)	10.169 (9 639)	7.5	24	5.980	2.47	11.155 (10 573)	10
Oil-fired steam turbine	2	50	200	14.356 (13 608)	10.568 (10 017)	7.5	24	3.000	.30	11.515 (10 915)	15
Oil-fired steam turbine	1	25	100	15.447 (14 642)	10.855 (10 289)	7.5	24	4.540	.30	12.003 (11 377)	20
Distillate-fired gas turbine	2	1	100	16.880 (16 000)	14.728 (13 960)	24.0	8	.022	2.98	14.758 (13 989)	99
Distillate-fired gas turbine	1	1	100	16.880 (16 000)	14.728 (13 960)	24.0	8	.022	2.98	14.758 (13 989)	99

[a]EFOR = (forced partial-outage hours x size of reduction)/(available hours for service and forced-outage hours) (unit rating).
[b]EFOR values are based on figure 2.
[c]Costs in 1980 dollars.

TABLE III. - ECONOMIC PARAMETERS

(a) Fuel cost assumptions (1980 dollars)[a]

Fuel	Average delivered cost, $/MJ ($/10^6 Btu)
Coal	0.00128 [b](1.35)
Residual grade oil	.00409 [b](4.32)
Distillate grade oil	.00550 [c](5.80)

(b) Assumptions for weighted cost of capital[d]

Debt ratio, percent	50
Debt cost, percent/yr	8
Preferred stock ratio, percent	15
Preferred stock cost, percent/yr	8.5
Common stock ratio, percent	35
Common stock cost, percent/yr	13.5

[a]From ref. 19.
[b]For steam-electric units.
[c]For peaking units.
[d]From ref. 20.

TABLE IV. - EXPANSION CANDIDATES

Candidate expansion unit[a]	Unit type	Size, MW	Heat rate, MJ/kWhr (Btu/kWhr): At 25 percent load[b]	Heat rate, MJ/kWhr (Btu/kWhr): At 100 percent load	Efficiency at 100 percent load	Equivalent forced-outage rate, EFOR, percent	Capital cost[c], $/kW	Operation and maintenance cost: Fixed $/kW-mo	Operation and maintenance cost: Variable $/MW-hr	Purpose of expansion units
Base	Coal-fired steam turbine	500	12.416 (11 769)	10.590 (10 038)	34	15	960	3.45	2.47	Base
1	IGCC	500	10.287 (9 751)	9.002 (8 533)	40	10	980	3.58	0.53	IGCC reference
2	↓	↓	11.253 (10 666)	9.731 (9 224)	37	10	↓	↓	↓	Efficiency
3	↓	↓	9.002 (8 533)	8.001 (7 584)	45	10	↓	↓	↓	Efficiency
4	↓	↓	10.287 (9 751)	9.002 (8 533)	40	15	↓	↓	↓	EFOR
5	↓	↓	10.287 (9 751)	9.002 (8 533)	40	7.5	↓	↓	↓	EFOR
6	↓	250	10.287 (9 751)	9.002 (8 533)	40	10	↓	↓	↓	Size

[a]Each candidate case allows, in addition to the base load candidate, a 50-MW distillate-grade oil-fired gas turbine as a peaking load candidate: 24 percent EFOR, 14.77 MJ/kWhr (14 000-Btu/kWhr) heat rate, $280/kW capital.
[b]Minimum load.
[c]Cost estimates are in 1980 price level.

TABLE V. - ASSUMPTIONS FOR THE SULFUR DIOXIDE EMISSION

Fuel	Illinois No. 6 coal
Sulfur content, percent	3.9
High heating value (HHV), MJ/kg (Btu/lb)	25.1 (10 788)
SO_2 emission, kg/J (lb/10^6 Btu):	
Reference steam turbine unit (with 90-percent sulfur removal)	309 (0.72)
IGCC unit (as in the Texaco. entrained-bed case (ref. 7))	142 (0.33)

TABLE VI. - ASSUMPTIONS FOR THE STEAM TURBINE UNITS WITH STACK GAS SCRUBBERS

	Turbine size, MW	
	1000	[a]500
Equivalent forced outage rate, EFOR[b], percent	24	15
Heat rate at full load, MJ/kWhr (Btu/kWhr)	10.287 (9751)	10.590 (10 038)
Efficiency at full load, percent	35	34
Capital cost, $/kW	873	960
Operation and maintenance cost:		
Fixed, $/kW-mo	2.29	3.45
Variable, mill/kWhr	2.47	2.47

[a]Base steam-turbine unit in table IV.
[b]From figure 2.

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16. Abstract

Potential benefits of integrated-gasifier combined-cycle (IGCC) units were evaluated for a reference utility system by comparing long-range expansion plans using IGCC units and gas-turbine peakers with a plan using only state-of-the-art steam-turbine units and gas-turbine peakers. Also evaluated was the importance of the benefits of individual IGCC unit characteristics, particularly unit efficiency, unit equivalent forced-outage rate, and unit size. A range of IGCC units was analyzed, including cases achievable with state-of-the-art gas turbines and cases assuming advanced gas-turbine technology. All utility-system expansion plans that used IGCC units showed substantial savings compared with the base expansion plan using the steam-turbine units.

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