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Comparative Study and Evaluation of Advanced-Cycle Systems

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Prepared by

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ABSTRACT

A number of advanced energy conversion concepts are now being proposed to supplement or supersede conventional power generation technology. They are being proposed by individuals and organizations with widely varied backgrounds, using a diversity of approaches and assumptions for predicting performance, cost, and development requirements.

The present work has been undertaken to assist EPRI in planning R&D for the utility industry by analyzing 19 of the advanced concepts on a common basis using uniform technical and economic assumptions. The concepts range from a steam cycle with an atmospheric fluidized bed furnace to longer term options such as magnetohydrodynamic systems.

The primary purpose of this study is to define techniques for assessing the worth of these concepts to the utility industry and the nation as a whole. Three methods have been developed:

- Levelized Cost of Electricity
- Direct Weighting Method
- Net Present Worth Method

These measure not only the life cycle costs associated with each power plant concept, but also the intangible attributes such as development risk and reliability. They assess the relative importance of costs and intangibles in the context of utility goals.

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Section 1

SUMMARY

INTRODUCTION

A number of advanced energy conversion concepts are now being proposed to supplement or supersede conventional power generation technology. These advanced cycles have the potential for higher efficiencies, environmental acceptability, and, in some cases, lower cost of electricity. They are being proposed by individuals and organizations with widely varied backgrounds, using a diversity of approaches and assumptions for predicting performance, costs, and development requirements.

The work reported here has been undertaken to analyze several of the proposed advanced concepts on a common basis using uniform technical and economic assumptions. This is similar but not identical to the intent of the recently completed Energy Conversion Alternatives Study (ECAS) in which a large number of cycles were analyzed to obtain estimates of capital cost, efficiency, emissions and R&D requirements. Although several new cycles have been analyzed using these methods and are reported below, it is not the intent of the present work to simply extend that of ECAS. Rather, the primary purpose of this study is to develop methodologies for the comparison and assessment of advanced cycle concepts.

Intangible attributes of the advanced cycles such as development risk and reliability are as important as the cycles tangible properties such as cost and performance. The central problem in developing the assessment methodologies has been to integrate these two sets of data in such a way that a trade-off can be made. For instance, if two alternatives have respectively, short R&D time/moderate efficiency and long R&D time/high efficiency, the assessment methodology must be able to distinguish the better alternative.

Another important problem centers around the word "better," since it is necessary to specify to whom this applies. In this study, special emphasis has been given to the viewpoint of the utility industry. Specifically, the importance of a cycle's intangible attributes has been judged by the effect of intangibles upon the utility decision to purchase the cycle. The effect of these decisions has also been evaluated from a national point of view.

The results of this work should permit assessment of the relative merit of the advanced cycle concepts, as well as a prediction of the potential benefits of the implementation of these cycles to the nation and the utility industry. It is hoped that this will assist EPRI in formulating an effective research and development program for the utility industry.

The specific objectives of the study are:

- Develop techniques for evaluating advanced cycle concepts with respect to their intangible attributes, i.e., those attributes not directly accounted for in the cost of electricity
- Develop methods for comparing advanced cycles which express the benefit trade-off between intangible attributes and the quantifiable cycle attributes such as capital cost and efficiency
- Using the methods and groundrules of the Energy Conversion Alternatives Study, estimate cost, performance and R&D programs for several additional cycle concepts which are of interest to EPRI but which were not included in the ECAS program

CYCLE CONCEPTS EVALUATED

Nineteen advanced energy conversion concepts were evaluated in Phase 1; in addition, two conventional cycles were analyzed to serve as reference cases for comparison with the advanced concepts. Coal, oil, nuclear, and coal derived fuels were considered.

The Phase 1 advanced cycles can be grouped into three categories:

Open Cycles

Recuperative Gas Turbine
High-Btu Gas*
Oil
Combined Cycle Gas Turbine
Air Cooled, Low-Btu Gas*
Water Cooled, Low-Btu Gas*†
Water Cooled, Semiclean Liquid Fuel*

Closed Cycles

Advanced Steam
Atmospheric Fluidized Bed (AFB), Coal*†
Conventional Furnace (CF), Oil
High Temperature Gas Cooled Reactor (HTGR)
Liquid Metal Fast Breeder Reactor
Closed Cycle Gas Turbine
Helium, Atmospheric Fluidized Bed, Coal*
Helium, HTGR
Supercritical Carbon Dioxide, AFB, Coal*
Metal Vapor Turbine, AFB, Coal*

Direct Energy Conversion

Open Cycle Magnetohydrodynamics (MHD), Coal*
Closed Cycle Plasma MHD, CF, Coal*
Liquid Metal MHD, AFB, Coal*
Thermionic Topping, CF, Coal
Fuel Cell-Low Temperature
Hydrogen Derived from Coal*
Oil

Data for some of these cycles were taken from Task I of the Energy Conversion Alternatives Study; these are indicated by an asterisk. (*) The remaining cycles are new cases analyzed in the present study at a level of detail comparable to the ECAS Task I analysis.

Two of these cycles (indicated by † in above list) were carried through a more detailed conceptual design analysis in Phase 2. Two additional conventional cycles were also analyzed to make the reference cases more representative of the full range of conventional technologies.

In Phase 3, EPRI selected three advanced cycles to be used in performing a sample application of the assessment methodologies, these are:

- Advanced Steam (24,130 kPa/811 K [3500 psi/1000 F/1000 F]),
Atmospheric Fluidized Bed, Coal
- Combined Cycle Gas turbine (Water Cooled, 1922 K [3000 F]), Low-Btu
Gasifier, Coal
- Open Cycle MHD, Coal

The advanced steam and MHD data were obtained from the General Electric ECAS Task II conceptual designs; the combined cycle was analyzed in Phase 2 of the present study at the same level of detail as the two ECAS cycles. The Phase 2 steam cycle with 922K (1200F) reheat was not selected for Phase 3 because of its high capital cost.

Obviously, the number of cases analyzed in Phases 2 and 3 are not sufficient to make this a definitive comparison of all the advanced cycles. Such a comparison was beyond the funding available for this study. The cases presented here were judged to be the minimum number required to demonstrate the major features of the comparison methodologies.

APPROACH TO ANALYSIS

The approach used by General Electric in the Energy Conversion Alternatives Study was adopted in order to achieve consistency in estimating cost, performance, and R&D requirements. A key element of this approach was that an advocate is chosen for each advanced

cycle concept. Each advocate assisted in selection of the cycle configurations to be studied, and had responsibility for deriving performance and cost estimates for those portions of the power plant which are peculiar to the advanced concept.

Within each power plant, those portions that are common to more than one concept were analyzed by other groups within the organization. For example, most combustion systems and primary heat exchangers were analyzed by the Foster Wheeler Energy Corporation. Steam bottoming cycles, depending on rating, were studied by either the Medium Steam Turbine Department or the Large Steam Turbine-Generator Department of the General Electric Company. The Bechtel Corporation performed the analysis of balance of plant for all of the cycles in Phase 1; General Electric's Installation and Service Engineering Division performed this task in Phase 2. Coordination of the work of all groups within the overall organization was performed by General Electric Corporate Research and Development.

Because of the complexity of the fuel cycle and capital equipment for the advanced nuclear concepts, the detailed subsystem breakdown described above was not applied to the three nuclear cycles in Phase 1 of this study. For this reason, estimates of the cost of electricity for the nuclear cycles are considerably less certain than for the fossil cycles.

In comparing the results of these analyses, it is important to remember the differences in level of detail considered in Phases 1 and 2. The estimates in Phase 2 are based on conceptual design drawings for advanced equipment and equipment arrangement drawings for the balance of plant equipment and construction requirements. This is comparable to the ECAS Task II level of detail, and yielded estimates which are judged to be more accurate than those generated in ECAS Task I or Phase 1 of this study.

ASSUMPTIONS

A number of technical and economic assumptions were made at the beginning of this study. The technical assumptions included:

- Definitions of output power and efficiencies
- Establishment of emission standards
- Specification of fuels
- Definition of the extent of the plant to be studied
- Ambient air temperature and pressure and water temperature

The principal economic assumptions were that the future interest rate will be 10%/yr and that the Gross National Product (GNP) will inflate at 6.5%/yr.

All of the costs in this study are quoted in mid-1975 dollars unless otherwise indicated. All R&D schedules are assumed to start in mid-1975.

Plant capital costs are assumed to inflate at the same rate as the GNP. The capital costs listed in this study are for plants which are completed in the year 2000 and the cost includes an allowance for escalation and interest during construction.

Operation and maintenance (O&M) costs are assumed to inflate at the same rate as the GNP.

In Phase 1, the fossil fuel prices were assumed to inflate at the same rate as the GNP, while the nuclear fuels followed a variable inflation pattern which assumed a breeder reactor economy. In Phases 2 and 3, the following prices and inflation rates were assumed:

Table 1-1
PHASE 3 FUEL PRICES

	Coal (Illinois No. 6)	Uranium	Oil (No. 2)	Semiclean Liquid Fuel (Turbine Grade)
1975 Cost (\$/MBtu)	.94	.52	1.85	3.50
Inflation Rate (%)				
1976-1990	7.2	7.4	8.5	7.2
1991-2000	7.2	7.4	9.5	7.2
2001-2025	7.2	7.4	10.5	7.2

EVALUATION METHODS

Three evaluation techniques have been developed in this study:

- Levelized Cost of Electricity
- Direct Weighting Method
- Net Present Worth Method

Levelized Cost of Electricity

This is a life cycle cost for the energy produced by a particular power plant. It is a present worth average of the investment and production costs over an assumed 30 yr lifetime which starts in the year 2000. The present worth reference year is 2000, and the costs are expressed in 1975 dollars.

This levelization procedure leads to an 18%/yr fixed charge rate on capital investment and a levelization factor for O&M of 1.882. Since the fuel inflation rates were assumed to be greater than 6.5%, their levelization factors were generally larger than this ranging from 1.882 to 3.092.

The cost of electricity was computed for three plant operation modes, base load, midrange and peaking, corresponding to capacity factors of 70%, 45%, and 15% respectively. It should be noted that the presentation of cost data for the three operation modes does not imply that any plant is operationally suitable for all three modes. No allowance was made for part load heat rates or the fact that capital costs might be different for plants designed to operate in different modes.

Direct Weighting Method

The Direct Weighting Method is a technique for summarizing the rating of an advanced cycle with respect to its intangible attributes, where intangibles are defined as those attributes not directly quantifiable in the cost of electricity. Twenty-six intangibles have been identified and defined; these intangibles are:

1. Cost of Research and Development Required
2. Research and Development Time Required
3. Probability of Development Success
4. Plant Capital Cost
5. Plant Operating and Maintenance Requirements
6. Electrical Performance
7. Power Plant Efficiency
8. Capability for Load Change
9. Part Load Efficiency
10. Minimum Load
11. Forced Outage Rate
12. Planned Outage Rate
13. Hardware Materials Availability
14. Industrial Capability for Manufacture
15. Plant Safety
16. Dependence on Other Systems
17. Adaptability to Fuels
18. Life
19. Flexibility of Siting
20. Waste Handling and Disposal

21. Plant Construction Time
22. Unit Rating
23. Byproducts
24. Environmental Intrusion
25. Availability of Fuel and Additives
26. Startup Power Requirements

Some of these items also have a tangible component. For instance, high capital cost has a direct effect on the cost of electricity, but it also increases investment requirements which could affect the marketability of a cycle in an economy where capital is not easily available. It is this latter effect which is considered intangible.

Criteria have been defined for the 26 intangibles which establish a good, fair, or poor rating of an advanced cycle with respect to each item.

The relative importance of each intangible has also been assessed through a detailed evaluation of utility goals, and weighting factors have been developed to express this importance ranking.

To apply the Direct Weighting Method to a given cycle, it is first necessary to determine the cycles ratings with respect to the 26 criteria. These are converted to numerical equivalents by assigning good = 10, fair = 5, and poor = 1. The products of these numerical values and the weighting factors are summed to give an overall figure of merit that would equal 1000 for a "perfect" cycle.

The Figure of Merit can be used with the Levelized Cost of Electricity to express the trade-off between cost and intangibles.

Net Present Worth Method

The Net Present Worth Method presents an alternative way of analyzing this trade-off. The method is a cost-benefit analysis which models the national utility market over a period from 1985 to 2025. Costs are attributed to the R&D program and capital investment requirements. Benefits accrue because an advanced cycle produces electricity at lower cost than conventional technologies. Intangibles affect the magnitude of the benefits by modifying utility acceptance of the advanced cycle as expressed in its market penetration and capacity factors.

Costs and benefits are compared on the basis of present worth in 1975 using a discount rate of 10%/yr.

This method actually consists of four distinct computational operations; these are:

- Generation Phase Diagrams
- Generation Expansion
- Impact of Intangibles
- Net Present Worth

Generation Phase Diagrams are a screening technique used to separate those advanced cycle candidates which offer a clear economic advantage from those which do not. At this stage, it is also possible to identify the marginally competitive cycles which might prove to be winners under a slightly different economic future. The advantage of this comparison is that it eliminates the losers in a simple and rapid way prior to performing the rather complex generation expansion calculation.

The generation expansion program models a typical utility's buy/no buy decision process to obtain estimates of the market penetration for each cycle alternative. The structure of the utility system is specified in 1985 and a demand growth rate is assumed. The program then adds new units to the system to provide for demand growth, retirements, and a reserve margin. In each year, a combination of units is added which minimizes the projected 30 yr system costs. The program includes a load dispatch model which estimates capacity factors for the power plants installed on the system by running them through an hour by hour load model for each year.

The generation expansion program used in this study is the Optimized Generation Planning (OGP-4) program developed by General Electric's Electric Utility System Engineering Department.

Market penetration and capacity factors estimated in this way do not include any consideration of the intangible properties of advanced cycles. The impact of intangibles calculation accounts for this by modifying the expansion results in response to the cycle ratings against the 26 evaluation criteria listed above. The R&D cost estimate is also modified in response to the rating for Probability of Development success. The Impact of Intangibles is based upon a probability argument with respect to market penetration and it uses all of the carefully considered judgments about utility goals which are summarized in the weighting factors of the Direct Weighting Method.

The last step is to combine the cycle cost and performance data with the modified market penetration and capacity factor estimates, and to project the costs and benefits which accrue to the United States as a result of implementing the advanced cycles. The Net Present Worth

is the net saving available because the advanced cycles require less capital investment in the future and/or lower energy production expenditures.

In making these comparisons, it is important to specify which advanced cycles and conventional plants will be allowed to compete for the utility market. These groups of candidates are referred to as scenarios in this study.

PHASE 1 RESULTS

Figure 1-1 is a plot of Levelized Cost of Electricity vs. Figure of Merit for the Phase 1 cycles. This is the most useful of the ways of presenting these results because it expresses the trade-off between cost and intangibles. The most favorable position on this diagram is the lower right corner which corresponds to low cost and a high figure of merit.

The lowest costs of electricity (base load mode) were achieved by the gas turbine combined cycles with integrated low-Btu gasifiers (Cycles 7 and 8) and advanced steam with the atmospheric fluidized bed (AFB) furnace (Cycle 1). The highest cost of electricity was found for the advanced and conventional gas turbines burning high-Btu gas (Cycles 5 and 21) and liquid metal MHD with the AFB furnace (Cycle 15). In the peaking mode, these conclusions change somewhat. The combined cycles burning low-Btu gas (Cycles 7 and 8) still have low costs of electricity but are somewhat higher than the advanced recuperative gas turbine burning oil (Cycle 6) and the advanced combined cycle burning semiclean liquid fuel derived from coal (Cycle 9). Liquid metal MHD (Cycle 15) has the highest cost of electricity in the peaking mode, followed by the closed cycle carbon dioxide gas turbine (Cycle 10) and the liquid metal fast breeder (Cycle 4).

Figure of Merit is independent of operating mode. The highest Figure of Merit (most desirable with respect to intangibles) was achieved by the conventional gas turbine burning high-Btu gas (Cycle 21) because of its low capital cost and immediate availability. The advanced recuperative gas turbines burning high-Btu gas and oil (Cycles 5 and 6) also had low capital cost but had less favorable figures of merit due to their R&D requirements. The lowest figures of merit went to liquid metal MHD (Cycle 15), closed cycle plasma MHD (Cycle 14) and the thermionic topping plant (Cycle 17).

Figure 1-2 is a generation phase diagram for the Phase 1 cycles. It was computed for a scenario in which all of the advanced cycles were introduced into the competition in the order of their date of first commercial service. The diagram shows the cycle candidates having the lowest cost of electricity in each time span.

Figure 1-1. Phase 1 Cycles — Cost of Electricity vs. Figure of Merit for Base Load Mode

* See Appendix D, Tables D-5 through D-8 for cycle name and fuel data file name

Figure 1-2. Generation Phase Diagram — Phase 1 Cycles

Generation Expansions and the other steps in the Net Present Worth method were not carried out for the Phase 1 cycles.

On the basis of these comparisons, four advanced cycles seemed to be clearly superior; these are:

6. Advanced Open Cycle Gas Turbine (Air Cooled, 1477 K 2200 F), Recuperative, Oil
7. Gas Turbine Combined Cycle (Air Cooled, 1589 K 2400 F), Low-Btu Gasifier, Coal
8. Gas Turbine Combined Cycle (Water Cooled, 1922 K 3000 F), Low-Btu Gasifier, Coal
9. Gas Turbine Combined Cycle (Water Cooled, 1811 K 2800 F), Semiclean Liquid Derived from Coal.

Three other advanced cycles were identified as being near contenders:

1. Advanced Steam (24,130 kPa/811 K/922 K 3500 psi/1000 F/1200 F), Atmospheric Fluidized Bed, Coal
5. Advanced Open Cycle Gas Turbine (Air Cooled, 1700 K 2600 F), Recuperative, High-Btu Gas.
18. Fuel Cell, Low Temperature, Hydrogen Derived from Coal.

The conventional gas turbine burning high-Btu gas (Cycle 21) was found to be the best cycle for peaking duty, and the conventional steam plant with stack gas scrubbers (Cycle 20) seemed to be a good candidate for base load and midrange duty through the mid-1980s.

PHASE 2 RESULTS

A detailed conceptual design analysis was performed for two advanced cycles in Phase 2; the results of this analysis are summarized in Table 1-2.

PHASE 3 RESULTS

Table 1-3 lists the three advanced cycles and four conventional plants evaluated in Phase 3, and shows the arrangement of these plants into scenarios. No New Technology is a reference case in which the future energy demand is met with conventional equipment. The Minimum Competition Scenarios consider each advanced cycle as an independent competitor with conventional technology, and the Crowded Market shows the effect of competition among the advanced cycles.

Figure 1-3 shows a Levelized Cost of Electricity (base load mode) vs. Figure of Merit comparison for the Phase 3 cycles. The Phase 2 and ECAS Task II cycles have also been shown in this figure. All three Phase 3 cycles have about the same cost of electricity. The differences in figure of merit are due primarily to R&D requirements.

Table 1-2
PHASE 2 RESULTS

Cycle Parameters	Phase 2 Cycles	
	Open Cycle Gas Turbine Combined-Water Cooled (3000F)-LBtu Gasifier- Coal	Advanced Steam (2400 psi/1000F/1200F) Atmospheric Fluidized Bed-Coal
Plant Rating - MW _e	640	843
Efficiency - %	44.0	37.1
Capital Cost - \$/kW _e	474	542
Operation & Maintenance Costs:		
Fixed - \$/kWyr	1.25	1.06
Variable-mills/kWh	1.83	1.68
Cost of Electricity (70% capacity factor)		
Capital	13.9	15.9
Fuel	15.0	20.8
O&M	3.9	3.5
	32.8	40.2
R&D Cost - M\$	417	328
Date of First Commercial Service	1996	2000

Table 1-3
SCENARIOS — PHASE 3 CYCLES
NET PRESENT WORTH METHOD

CANDIDATE CYCLES	No New Technology Scenario (Reference)	Minimum Competition Scenarios			Crowde Market Scenario
		AFB/Steam	Combined Cycle	Open Cycle MHD	
Steam, Atmospheric Fluidized Bed, Coal		X			X
Gas Turbine (Water Cooled) Combined, LBtu Gasifier					
Open Cycle MHD, Coal				X	X
Steam, Light Water Reactor, Uranium	X	X	X	X	X
Steam, Wet Lime Scrubber, Coal	X	X	X	X	X
Gas Turbine Combined, Oil/Semiclean Liquid	X	X	X	X	X
Gas Turbine, Oil/Semiclean Liquid	X	X	X	X	X

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A generation phase diagram for the Crowded Market Scenario is presented in Figure 1-4. Open cycle MHD is preferred when it is available, followed by the advanced gas turbine combined cycle - low-Btu and the steam/AFB. Since the dates of first commercial service are staggered for these cycles, each enjoys a period of time in which it is better than the previous alternatives and has not yet been superseded by a better candidate. Steam/AFB would continue to share the base load range with the nuclear plant if the advanced combined cycle and MHD were not available; similarly, the combined cycle would continue to take up all of the base load and midrange if MHD were not available.

Figure 1-5 shows the Generation Expansion results for the Crowded Market Scenario. Initially the Optimized Generation Planning program added nuclear plants, then in 1988 when steam/AFB became available, it stopped adding nuclear and chose steam/AFB instead. In the third period, the advanced combined cycle is available and the program added a mix of combined cycle and steam/AFB. Open cycle MHD became available in 2003 but was not added until 2006 because its large unit size (1932 MW) made it uneconomical on a system basis. MHD shared the market with the advanced combined cycle in the last two periods. In the Minimum Competition Scenario, the advanced cycles dominate the market except in the case of steam/AFB where it shares the market with the nuclear plant. Capacity factors determined for the various scenarios are summarized in Table 1-4.

These results were modified to account for the Impact of Intangibles and the Net Present Worth of each scenario was computed as shown in Table 1-5. The total cost of meeting the future electrical energy demand (1985-2054) if the No New Technology Scenario is followed is 3594 B\$. To accomplish the same task using the Crowded Market Scenario would cost 3397 B\$. Thus the saving, or the Net Present Worth of pursuing the Crowded Market Scenario is 197 B\$.

Note that the saving for the Steam/AFB Minimum Competition Scenario is negative; that is, the scenario costs more than No New Technology. This is not an error; it reflects the difference in point of view between the utility industry and the nation† as a whole. Utilities will select power plant additions in such a way as to minimize their total costs, which include tax payments as reflected in a fixed charge rate of 18%. However, from the national point of view, taxes are not a real cost since they represent payments from one part of society to another. The effective fixed charge rate for a national cost benefit analysis is about 11%, which accounts for return on investment and depreciation but excludes taxes.

The results in Table 1-5 are costs as perceived by the nation, using the lower fixed charge rate. If these costs were computed by the utilities, they would be larger, as shown in Table 1-6, due to the greater apparent cost of capital to the utilities.

†The "nation" is modeled by synthetic Utility System D in this study, see Section 6.3

Figure 1-3. Phase 3 Cycles — Cost of Electricity (Base Load) and Figure of Merit

Figure 1-4. Generation Phase Diagram — Crowded Market Scenario — Phase 3 Cycles

Figure 1-5. Generation Expansion — Crowded Market Scenario — Phase 3 Cycles

Table 1-4

PHASE 3 CYCLES
GENERATION EXPANSION
Approximate Capacity Factors (%)

CYCLES	NO NEW TECHNOLOGY	SCENARIOS			CROWDED MARKET
		MINIMUM COMPETITION	GTWCCE	OCMHD	
STLWR-N	71→60*	73	70→72	71→51	72
STSCR-B	30→24		30→16	30→16	
GT-O	6→0	4→0	6→0	7→1	4→0
GT-S	2	1	1	1→3	1
GTCC-S	12→14	2	5	9	
STAFB-C		48→44			49→21
GTWCCE-C			52→62		76→60
OCMHD-C				68→63	68

* Arrows Indicate Change With Time (Earlier→Later)
Single Number Indicates No Change With Time
No Entry Indicates That Cycle Type Was Not Installed

Table 1-5

NET PRESENT WORTH RESULTS
NATIONAL VIEWPOINT*

SCENARIO	PRESENT WORTH OF COSTS \$B	SAVING \$B
No New Technology	3594	
Minimum Competition		
STAFB	3602	-8
GTWCCE	3422	172
OCMHD	3458	136
Crowded Market	3397	197

*Base Case: Includes Impact of Intangibles, Excludes Taxes

Thus, from the utility point of view, the Steam/AFB plants have been used to good advantage in the first Minimum Competition Scenario because they allow the utility to meet the future demand at lower cost than the No New Technology Scenario. This is consistent with using an 18% fixed charge rate in performing the Generation Expansion to determine market penetration. However, Table 1-5 shows that these choices are not optimal from a national point of view. If the expansion had been performed using an 11% fixed charge rate, then the savings in Table 1-5 would all be positive. However, this was not judged to be an appropriate way to proceed since the utilities are in fact the real purchasing agents, and they must make decisions on the basis of costs as they perceive them.

Table 1-7 gives a summary of the for from the Phase 3 cycles with respect to the three evaluation techniques developed in this study. Although the Phase 3 comparisons do not include a large number of advanced cycles, it is still possible to draw some general conclusions; these conclusions are:

1. R&D costs are insignificant in comparison to potential savings which can be realized from implementing most of the advanced cycles
2. Although one cycle may appear to be the big winner, there will always be some combination of cycles which yields a larger cost benefit
3. The most important intangible factor is R&D time because the benefits of an advanced cycle become less important as the date of first commercial service is postponed
4. In order to make optimum use of some technologies from the National viewpoint it may be necessary to change the economic circumstances under which the Utilities select their generation additions.

Table 1-6

NET PRESENT WORTH RESULTS
UTILITY VIEWPOINT*

SCENARIO	PRESENT WORTH OF COSTS B\$	SAVING B\$
No New Technology	4788	-
Minimum Competition		
STAFB	4504	284
GTWCCE	4251	537
OCMHD	4438	350
Crowded Market	4172	616

*Includes Impact of Intangibles, Includes Taxes

Table 1-7

SUMMARY OF RATINGS — PHASE 3 CYCLES

Power Cycles	Levelized Cost of Electricity* mills (1975\$) kWh	Figure of Merit (max = 1000)	Minimum Competition Scenario 1975 Net Present Worth BS
Steam, Atmospheric Fluid- ized Bed, Coal	38.7	815	-8
Gas Turbine (Water Cooled) Combined Cycle, LBtu Gas- ifier, Coal	35.2	704	172
Open Cycle MHD, Coal	33.7	461	136
Steam, LWR, Uranium	38.8	703	NA
Steam, Conventional Furnace, Scrubber, Coal	46.5	736	NA

Net Present Worth (Crowded Market) = 197 BS

* At 70% Capacity Factor

Section 2

INTRODUCTION

BACKGROUND

Domestic shortages of conventional fuels have emphasized the need for more efficient power generation and a wider variety of fuel options. Attention is turning to a number of advanced energy conversion concepts for central station power generation in an attempt to satisfy this need while maintaining environmental standards and high power plant reliability.

A number of advanced energy conversion concepts are now being proposed to supplement or supersede conventional power generation technology. These advanced cycles have the potential for higher efficiencies, environmental acceptability, and, in some cases, lower cost of electricity. They are being proposed by individuals and organizations with widely varied backgrounds, using a diversity of approaches and assumptions for predicting performance, costs, and development requirements.

The recently completed Energy Conversion Alternatives Study (ECAS)* is a significant step towards clarifying these cycle comparisons. The study is an analysis of several advanced cycle concepts on a common basis using uniform technical and economic assumptions. Cost and performance were estimated for each advanced cycle, and the research and development program schedules and costs were outlined. Comparisons were made on the basis of plant capital cost, cost of electricity, efficiency, atmospheric emissions, waste production, natural resource usage, date of first commercial service, development cost, development risk, and operating characteristics such as load following ability and reliability.

Cycles having short R&D programs, low cost of electricity, and high efficiency have been identified in ECAS. Unfortunately, no single advanced cycle possesses all of these desirable characteristics, so it is necessary to make trade-off decisions in selecting the candidate

*Performed by General Electric Company (Contract NAS 3-19406), Westinghouse Electric Corporation (Contract NAS 3-19407) and United Technologies, Inc./Burns and Roe Inc. (Contract NAS 3-19586) under direction of NASA Lewis Research Center for the National Science Foundation (NSF) and the Energy Research and Development Administration (ERDA).

which offers the greatest potential benefit to the nation and the utility industry. The present study was undertaken to develop an assessment methodology to assist in making this selection. The methodology combines cycle cost and performance data with intangible attributes such as development risk and reliability; it also compares the cycles in the context of future fuel price inflation and the utility market for new power plants.

OBJECTIVES

The overall objective of this study is to develop methodologies for the comparison and assessment of advanced cycle concepts. These methodologies will provide a foundation for the formulation of an effective research and development program to be directed by EPRI for the electric utility industry.

Specific objectives are:

- Develop techniques for evaluating advanced cycle concepts with respect to their intangible attributes, i.e., those attributes not directly accounted for in the cost of electricity
- Develop methods for comparing advanced cycles which express the benefit trade-off between the intangible attributes and the quantifiable cycle characteristics such as capital cost and efficiency
- Using ECAS methods and ground rules, estimate cost, performance and R&D programs for several additional cycle concepts which are of interest to EPRI but which were not included in the ECAS program

SCOPE

Program Phases

This program is divided into three work phases.

Phase 1, "Evaluation Rationale and Screening," includes development of evaluation criteria, establishment of methods for evaluating advanced energy conversion cycles, and initial screening of a number of cycles to determine which cycles merit more detailed analysis in the second and third phases.

Phase 2, "Detailed Analysis and Development Plans," consists of a detailed analysis of two specific concepts, with identification of their economic and technical characteristics, and the specific research and development efforts required to establish an engineering base for the design of full scale commercial power plants.

Phase 3, "Assessment of Concepts," includes a detailed evaluation of three advanced cycle concepts selected from Phase 2 of this study and Task II of ECAS, using the evaluation techniques developed in Phase 1.

Figure 2-1 shows the relationship of the ECAS performance schedule to the schedule for this study and identifies the task and phase breakdown for both programs.

Figure 2-1. Relationship of Schedules for ECAS Program and the Present Study

Cycle Concepts Evaluated

Nineteen advanced energy conversion concepts were evaluated in Phase 1. A variety of energy conversion cycles, heat sources, and combinations of bottoming and topping cycles were included. A detailed description of these 19 concepts is given in Section 4, "Selection of Power Cycles for Study."

In addition to the 19 advanced cycles, two reference cases were evaluated, against which the advanced cycles were compared. These reference cases were considered to be conventional cycles which would meet environmental specifications but require no research and development. It is presumed that these reference cases are typical of cycles that would be used in the future if no advanced research and development takes place.

The 19 advanced cycle concepts are grouped in Table 2-1 by type of cycle. Data for cycles marked with an asterisk were generated by the General Electric Company in Task I of the ECAS program and the analysis of these cycles is presented in the ECAS Phase I report.* The

*J.C. Corman, G.R. Fox, et al., Energy Conversion Alternatives Study (ECAS), Phase I Final Report, NASA Contract NAS 3-19406, Corporate Research and Development, General Electric Company, Schenectady, New York, February 1976.

ECAS study included only advanced concepts which burn coal and coal derived fuels. The present EPRI study has expanded this data base by analyzing several additional cycles which use oil and nuclear fuel as indicated in Table 2-1.

Table 2-1
ADVANCED CYCLE CONCEPTS EVALUATED IN PHASE 1

<u>Open Cycle</u>
Recuperative Gas Turbine
High-Btu Gas*
Oil
Combined Cycle Gas Turbine
Air-Cooled, Low-Btu Gas*
Water-Cooled, Low-Btu Gas*
Water-Cooled, Semiclean Liquid Fuel*
<u>Closed Cycle</u>
Advanced Steam
Atmospheric Fluidized Bed, Coal*
Conventional Furnace, Oil
High Temperature Gas-Cooled Reactor (HTGR)
Liquid Metal Fast Breeder Reactor (LMFBR)
Closed Cycle Gas Turbine
Helium, Atmospheric Fluidized Bed, Coal*
Helium, HTGR
Supercritical Carbon Dioxide*
Metal Vapor Turbine*
<u>Direct Energy Conversion</u>
Open Cycle Magnetohydrodynamics MHD*
Closed Cycle Plasma MHD*
Liquid Metal MHD*
Thermionic
Fuel Cell-Low Temperature
Hydrogen*
Oil

*Cost and performance analysis performed in Energy
Conversion Alternatives Study

Two advanced cycles, listed in Table 2-2, were carried through a detailed conceptual design analysis in Phase 2. Estimates were made of cycle cost and performance; R&D programs were outlined and estimates were made of R&D costs. The analysis is comparable in level of detail to that performed in Tasks II and III of the ECAS program.† The seven ECAS advanced cycles are also listed in Table 2-2.

In Phase 3 three cycles were selected from the list in Table 2-2 for further study. These three were compared to each other and rated against four conventional power generation concepts (Table 2-3) using the evaluation methodologies developed in this study.

Table 2-2
ADVANCED CYCLE CONCEPTS
EVALUATED IN PHASES 2 AND 3

<u>CSEACS Phase 2 Advanced Cycles</u>
Advanced Steam (2400 psi/1000 F/1200 F) - Atmospheric Fluidized Bed, Coal
Combined Cycle Gas Turbine (Water Cooled, 3000 F) - Low-Btu Gasifier, Coal*
<u>ECAS Task II and III Advanced Cycles</u>
Advanced Steam (3500 psi/1000 F/1000 F)
Atmospheric Fluidized Bed, Coal*
Pressurized Fluidized Bed, Coal
Combined Cycle Gas Turbine
(Air Cooled, 2400 F), Low-Btu Gasifier, Coal
(Water Cooled, 3000 F), Coal Derived Liquid
Potassium Topping Cycle - Steam - Pressurized Fluidized Bed, Coal
Closed Cycle Gas Turbine (Helium) - Organic Bottoming Cycle - Atmospheric Fluidized Bed, Coal
Open Cycle MHD, Coal*

*Selected for detailed comparison and assessment in Phase 3.

†J.C. Corman, G.R. Fox, et al., Energy Conversion Alternatives Study, Phase II Final Report, NASA Contract 3-19406, Corporate Research and Development, General Electric Company, Schenectady, New York, December 1976.

Table 2-3
REFERENCE CYCLE CONCEPTS
EVALUATED IN PHASES 2 AND 3

Steam - Conventional Furnace - Stack Gas Scrubbers, Coal Steam, Light Water Reactor, Uranium Gas Turbine (Air Cooled, 2000 F), Oil and Coal Derived Liquid Combined Cycle Gas Turbine (Air Cooled, 2000 F), Oil and Coal Derived Liquid

Evaluation Techniques

To adequately describe the benefits of an advanced cycle, the intangible attributes must be defined clearly and quantified in such a way that intangible benefits can be treated in the same manner as benefits derived from low cost or good performance. Economic effects of inflation and interest during the implementation period should be included. Furthermore, because the utilities will ultimately be the customer for advanced power plants, the methodology should assess how well an advanced concept matches with the utility goals for system performance and cost effectiveness.

Three evaluation methods were developed to address these concerns: the Levelized Cost of Electricity, the Direct Weighting Method, and the Net Present Worth Method.

Levelized Cost of Electricity, described in Section 3, is a present worth average cost of energy over the life of a power plant. It summarizes the advanced cycle capital cost and performance estimates, and accounts for inflation of operating, maintenance, and fuel costs during the plant lifetime.

The Direct Weighting Method is a technique for summarizing the rating of an advanced cycle with respect to its intangible attributes. Twenty-six intangibles are identified in Section 5, and criteria are defined for establishing a good, fair or poor rating with respect to each. In Section 7, the relative importance of the intangibles is assessed through a detailed evaluation of utility goals, and weighting factors are developed for each intangible rating. The ratings are then combined with the weighting factors to yield a single numerical Figure of Merit for each advanced cycle. The Figure of Merit can be used in conjunction with Levelized Cost of Electricity to express the trade-off between cost and intangibles.

The Net Present Worth Method presents an alternative way of analyzing this trade-off. The method, explained in Section 6, is a cost-benefit analysis which models the national utility

market over a period from 1985 to 2025. Costs are attributed to the R&D program and capital investment requirements. Benefits accrue because an advanced cycle produces electricity at lower cost than conventional technologies. Intangibles affect the magnitude of the benefits by modifying utility acceptance of the advanced cycle as expressed in its market penetration and capacity factors.

Section 3

APPROACH AND ASSUMPTIONS

3.1 APPROACH TO ANALYSIS

Three methods have been developed for assessing the value of the various advanced cycle concepts; these methods are illustrated in Figure 3-1.

Figure 3-1. Methods for Comparison of Advanced Cycle Concepts

Levelized Cost of Electricity is a present worth average of the investment and production costs for a cycle over its 30 year plant lifetime. It is intended to express the life cycle cost in an average way as discussed in the derivation at the end of this section.

Twenty-six evaluation criteria have been defined in Section 5 to assess each cycle on the basis of its intangible attributes, i.e., characteristics not accounted for in the cost of electricity.

In the Direct Weighting Method, each intangible characteristic is assigned a weighting factor which expresses the relative importance of that characteristic in its effect on the total benefit to be derived from implementing the advanced cycle. These weighting factors are combined with the criteria ratings to yield a figure of merit for the cycle. The derivation of this method is presented in Section 7.

The Net Present Worth Method, described in Section 6, is a cost/benefit analysis which models the utility market from 1985 to 2025 to determine the benefits to be derived from implementing the advanced cycles. The evaluation criteria ratings are included in this analysis through an "impact of intangibles" calculation which operates on the market penetration and capacity factor estimates for each cycle.

The intent in developing these techniques has been to make an explicit trade-off between tangible cycle characteristics such as capital cost and intangible characteristics such as load following ability. Thus, the Levelized Cost of Electricity and the figure of merit are intended to be used in tandem to express this trade-off in an approximate way. The Net Present Worth Method is a much more elaborate analysis intended to model the trade-off more precisely.

Advanced Cycle Analysis

The secondary purpose of this study has been to extend the Energy Conversion Alternatives Study (ECAS) type of analysis to new advanced cycles which are of interest to EPRI but were not included in the ECAS program.

The approach has been identical to that used in the ECAS program; that is, to perform a consistent analysis of each of the advanced cycles under a common set of study parameters, assumptions and ground rules.

In order to achieve this consistency and still derive the benefit of knowledge possessed by specialists in each of the advanced cycles, an overall organization was set up that included an advocate for each advanced concept. Each advocate assisted in selection of the cycle configurations to be studied, and had responsibility for deriving performance and cost estimates for that portion of the energy conversion system peculiar to the advocate's concept.

A major portion of every advanced energy conversion concept consists of common elements currently employed in power plants. Each common element or subsystem — including heat input and combustion systems, bottoming cycles, major heat exchangers, heat rejection

systems, and balance of plant — was evaluated by the same organizations. The auxiliary power requirements and power losses were also evaluated on a common basis. The breakdown of responsibility for the subsystems is shown in Tables 3-1 and 3-2.

For the fossil fired cycles, the approach used resulted in a consistent analysis of each cycle while maintaining a strong advocacy from the organizations that have an interest in the future success of the concepts.

Unfortunately, this subsystem breakdown was not possible for the nuclear cycles because of the complexity of the fuel cycle and capital equipment for the advanced nuclear concepts. For each nuclear concept, a study group was set up to analyze the entire cycle. Wherever possible, cost and performance for certain parts of these plants were derived on the same basis as for the fossil plants. For example, the steam generator and balance of plant for the high temperature gas-cooled reactor were evaluated by the same organizations that evaluated these elements for the fossil cycles.

The integration of the entire power plant follows the outline presented in Figure 3-2. The primary elements and their interconnections are indicated. The advocate had responsibility for the analysis in the block labeled "primary cycle."

Table 3-1
SUBSYSTEM RESPONSIBILITY - PHASE 1 CYCLES

Subsystem	Cycle (Advocate)	Open Cycle Gas Turbine		Helium Closed Cycle Gas Turbine (GE/GT)	Supercritical CO ₂ (Actron)	Advanced Steam (GE/LS)	Metal Vapor Topping (GE/SSL)	MHD			Fuel Cells (GE/DECP)	Thermionic (TE)
		Recuperative (GE/GT)	Combined (GE/GT)					Open Cycle (Avco)	Closed Cycle Inert Gas (GE/SSL)	Closed Cycle Liquid Metal (ANL)		
Heat Input												
Clean fuel production		GE/GT	GE/GT	--	--	--	--	--	--	--	GE/GT	--
Combustion and primary heat exchangers		--	--	FW	FW	FW	FW	--	FW	FW	--	FW
Prime Cycle												
Rotational equipment		Advocate	Advocate	Advocate	Advocate, GE	Advocate	Advocate	--	--	--	--	--
Combustor		Advocate	Advocate	--	--	--	--	Advocate	--	--	--	--
Direct energy conversion		--	--	--	--	--	--	Advocate	Advocate	Advocate	Advocate	Advocate
Inverters		--	--	--	--	--	--	GE	GE	GE	GE	GE
Regenerators		Advocate	--	Advocate, GE/HT	Advocate, GE/HT	--	--	--	Advocate	--	--	--
Seed addition		--	--	--	--	--	--	Advocate	Advocate	Advocate	--	--
Heat recovery heat exchangers												
Fluid boiler		--	GE/MS	--	--	--	FW	FW	FW	FW	--	FW
Combustion air present		--	--	--	--	--	--	Advocate, FW	--	--	--	FW
Bottoming cycle												
Rotational equipment		--	GE/MS	--	--	--	GE/LS	GE/LS	GE/LS	GE/LS/GT	--	GE/LS
Heat rejection												
Condensers		GE/HT	Bechtel	--	--	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	--	Bechtel
Precoolers		--	--	GE/HT	GE/HT	--	--	--	GE/HT	GE/HT	--	--
Cooling towers		Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	--	Bechtel
Environmental intrusion												
Emission characteristics		Advocate	Advocate	FW	FW	FW	FW	Advocate, FW	FW	FW	--	FW
Emission control equipment		Advocate	Advocate, GE/GT	GE/GT, FW	GE/GT, FW	Bechtel, GE/GT, FW	GE/GT, FW	Bechtel, Advocate	Bechtel	GE/GT, FW	--	Bechtel
System integration		GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
Balance of plant		Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel	Bechtel

Actron * Actron, a Division of McDonnell Douglas Corporation
 ANL * Argonne National Laboratory
 Avco * Avco Everett Research Laboratory, Incorporated
 Bechtel * Bechtel Corporation
 FW * Foster Wheeler Energy Corporation
 GE/DECP * GE Direct Energy Conversion Programs
 GE/GT * GE Gas Turbine Division
 GE/HT * GE Heat Transfer Products Operation
 GE/LS * GE Large Steam Turbine-Generator Department
 GE/MS * GE Medium Steam Turbine Department
 GE/SSL * GE Space Sciences Laboratory
 TE * Thermo Electron Corporation

Table 3-2
SUBSYSTEM RESPONSIBILITY — PHASE 2 CYCLES

Cycle (Advocate)	Open Cycle Gas Turbine Combined-Water Cooled- Low-Btu Gasifier	Advanced Steam Cycle (2400 P/1000 F/1200 F) Atmospheric Fluidized Bed
Subsystem	(GE/GT)	(GE/LS)
Heat Input Prime Cycle Rotational Equipment Combustor	GE/GAS Advocate Advocate	FW Advocate —
Heat Recovery Heat Exchangers Fluid Boiler Combustion Air Preheater	GE/MS	FW
Bottoming Cycle	GE/MS	—
Heat Rejection Condensers Cooling Towers	GE/IS GE/IS	GE/IS GE/IS
Environmental Intrusion Emission Characteristics Emission Control Equipment	Advocate GE/GAS, Bechtel	FW FW
System Integration	GE	GE
Balance of Plant	GE/IS	GE/IS

Bechtel = Bechtel Corporation
FW = Foster Wheeler Energy Corporation
GE/GT = GE Gas Turbine Division
GE/GAS = GE Gasification Project
GE/LS = GE Large Steam Turbine-Generator Department
GE/MS = GE Medium Steam Turbine Department
GE/IS = GE Installation and Service Engineering Division

Figure 3-2. Power Plant Integration

3.2 GROUND RULES FOR STUDY

The comparative evaluation of advanced energy conversion concepts was performed under a set of ground rules to help assure a consistent analytical approach. The technical ground rules are listed below. The economic ground rules are discussed in Section 3.3, "Economic Assumptions."

Power Output

The focus of the study was on base loaded plants. However, the economics of the plants in midrange and peaking duty was also explored. The plant ratings ranged from less than 100 MW for the open cycle gas turbine and the low temperature fuel cell to approximately 2000 MW for the open cycle MHD and metal vapor topping cycles.

Plant rated capacity is defined as continuous electrical power output from the transmission voltage side of the transformer with rated system pressures, temperatures, and flow rates, and normal makeup of the working fluid. Rated capacity is the net power after subtracting all auxiliary and station service power. Power is produced at 60Hz, three phase, at transmission line voltage at the output side of the transformer.

Design Goals

The conceptual design goals for the plants were a 30 year useful life and a 90 percent plant availability. For concepts requiring considerable R&D, these goals had little effect on the design assumptions and it was difficult to predict the ability of the concepts to meet these objectives.

Fuels

The fuels for the conversion systems were fossil and nuclear fuels. The characteristics of the fossil fuels are shown in Tables 3-3 and 3-4. Coal was used in several ways:

- Direct combustion with sulfur removal during combustion or with exhaust gas cleanup
- Integrated low-Btu gasifier
- Process fuels produced from coal (semiclean fuel, hydrogen, and high-Btu gas)

The process fuels were assumed to be produced at a remote site and delivered to the plant boundary. Oil was considered both in direct combustion and as a hydrogen source for fuel cells. The two nuclear systems evaluated in Phase 1 were the liquid metal fast breeder reactor (LMFBR) and the high temperature gas-cooled reactor (HTGR). A light water reactor was evaluated in Phase 3.

Table 3-3
FOSSIL FUEL SPECIFICATIONS — PHASE 1

Fuel	Higher Heating Value (Btu/lb)	Assumed Cost in Mid-1975 (delivered; \$/MBtu)	Conversion Efficiency (percent)
Coal (Illinois Number 6)	10,788	1.00	--
Number 6 Oil	18,600	2.20	--
Semi-clean Fuel Derived from Coal	15,682	2.07	78
Hydrogen Derived from Coal	54,047	2.88	61
High-Btu Gas Derived from Coal	22,674	3.00	50

Table 3-4
FUEL SPECIFICATIONS — PHASES 2 AND 3

Fuel	Higher Heating Value (Btu/lb)	Assumed Cost in Mid-1975 (Delivered; \$/MBtu)	Conversion Efficiency (Percent)
Coal (Illinois No. 6)	10,788	.94	—
No. 2 Oil	19,663	1.85	—
Semiclean Fuel Derived from Coal	16,700	3.50	74
Uranium (Light Water Reactor)	—	.52	—

Efficiencies

All efficiencies for the fossil fired plants are based on the higher heating value (HHV) of the fuel. Definitions of efficiencies employed in this study are given in Table 3-5. The efficiency generally used throughout this report is the overall efficiency, which is equal to the power plant efficiency for all plants that do not employ a process fuel.

Table 3-5
DEFINITIONS OF EFFICIENCIES

Thermodynamic efficiency =
$\frac{\text{Total of gross electrical energy generated}}{\text{Thermal input to prime cycle}}$
Power plant efficiency =
$\frac{\text{Net electrical energy generated}}{\text{HHV energy of power plant fuel}}$
Overall efficiency ("coal pile to bus bar")
$(\text{Power plant efficiency}) \times (\text{Process fuel conversion efficiency})$

Emission Standards

The fossil fired plants were all designed to meet the present EPA emission standards. The emission constraints imposed on the energy conversion cycles in this study are shown in Table 3-6.

Table 3-6
EMISSION STANDARDS

Pollutant	Fuel	Standard (Lbs/MBtu Heat Input)
SO _X	Solid	1.2
	Liquid	0.8
	Gaseous	0.2
NO _X	Solid	0.7
	Liquid	0.3
	Gaseous	0.2
Particulates	All fuels	0.1

Extent of the Plant Studied

The extent of the plant accounted for is defined in this subsection for both performance and cost analyses.

For those concepts using direct coal combustion, the following subsystems are included:

- Coal handling equipment at the central station plant, including facilities for coal unloading from rail cars, storage facilities for a 60 day supply, and conveyor equipment (but not including coal transportation from the mine to the plant site)
- Combustors and emission control equipment
- Ash and other waste removal and disposal equipment within the plant site property limits
- The energy conversion subsystems, including heat input heat exchangers, and electrical generators
- All auxiliaries and balance of plant, including buildings, land, offices, shop facilities, special maintenance equipment, water treatment equipment, protective devices, etc.
- Power and voltage control subsystems suitable for isolated operation or operation in parallel with existing generating units in a utility system
- Heat rejection subsystem
- Current inversion equipment for those conversion concepts generating direct current
- Transformers to raise voltage to transmission line or distribution voltage but not the high voltage breaker and switch yard

For those concepts using hydrogen or high-Btu gas as a fuel or oxygen as an oxidizer, it is assumed that the fuel and oxygen are generated at a remote facility and transported to the power plant. The analysis does not include the remote facility or the transportation system but does include all applicable subsystems listed above except the coal handling equipment. The fuel and oxygen are considered to be purchased at the power plant site.

Cycle 19 from Phase 1, the low temperature fuel cell with oil fuel, is the single exception. In this case, the oil is converted to hydrogen in an on-site plant, and the oxygen is produced on-site for the hydrogen plant and for use as the fuel cell oxidizer; the hydrogen and oxygen plants are therefore included in the capital cost of the system.

For the three cycles using low-Btu gas as fuel, the gasifier is located on-site and is integrated with the energy conversion system. The study includes the gasifier and its capital cost in addition to those applicable subsystems listed above.

The light water reactor used as a reference cycle in the Phase 3 comparisons was not analyzed on a common basis with the other cycles in this study. The capital cost and efficiency of this cycle were specified by EPRI.

Unit Rating and Sizing

Units have been rated at an average daily ambient temperature of 288 K (59 F) for the Middletown, U.S.A. site* with a coincident relative humidity of 60 percent. Ambient air absolute pressure was 101 kPa (1 atm). For process and makeup water, a water inlet temperature of 287 K (57 F) was used.

The generator and fuel handling capacity of the plant were sized and costed to handle a maximum power output which would be expected at low-temperature operation, with ambient air at 266 K (20 F), a coincident relative humidity of 60 percent, and an ambient air absolute pressure of 101 kPa (1 atm). The corresponding inlet water temperature was 277 K (39 F).

Evaporative cooling towers are used for heat rejection from all closed cycle systems. The cooling towers are sized and costed for the 5 percent summer condition, corresponding to an ambient wet bulb temperature of 297 K (76 F) and a pressure of 101 kPa (1 atm).

3.3 ECONOMIC ASSUMPTIONS

The principal economic assumptions made throughout this study for the general economy are:

- Discount rate = weighted cost of capital = 10 percent per year
- Gross National Product (GNP) Inflation Rate = 6.5 percent per year.

In Phase 1, capital cost, fuel cost (except nuclear fuel), and operating and maintenance costs were all assumed to inflate at the same rate as GNP. Additional escalation was assumed for the fuel costs in Phases 2 and 3; this escalation is discussed further below.

Capital Costs

The first step in establishing capital costs is to derive the estimated plant cost in 1975 dollars. This is done by estimating the cost of each of the major plant components, and the balance of plant, as if each step in the construction process were performed in mid-1975. A contingency of 20 percent is then added to the total of the major component and balance of plant costs. Up to this point, the costing is the same as was done under the ECAS program.** The estimated capital costs for nuclear systems were derived in a less detailed manner (see the beginning of this section).

*Ref. 3-1, Vol. II, Part 1, Appendix A

**Refs. 3-1 and 3-2

The total of major components, balance of plant, and contingency is the total estimated plant cost in mid-1975 dollars.

So that the capital costs of the various plants can be compared in a consistent way, a fundamental assumption is made that each plant will enter service in the same year; thus, each plant will start generating income at the same time. For this study, the year 2000 was arbitrarily selected as the year in which all plants will enter service. The total estimated plant cost in 1975 dollars is inflated to the year in which construction starts (for example, construction would start in 1993 for a plant requiring a seven year construction period). During the construction period, the accumulated expenditure is assumed to follow the S curve shown in Figure 3-3. Interest and escalation during construction were calculated in accordance with Table 3-7, which is based on the curve of Figure 3-3. This table assumes interest at 10 percent per year and escalation at 6.5 percent per year, and includes the interest on escalated costs. The total of interest and escalation during construction is obtained by multiplying the estimated plant cost at the beginning of construction by the total factor from Table 3-7.

Figure 3-3. Cash Flow During Power Plant Design and Construction (Ref. 3-3)

Table 3-7
ESCALATION AND INTEREST FACTORS
 (Annual Rates: 6.5% Escalation, 10% Interest)

Time from Start of Design to First Commercial Service	Escalation	Interest (Including interest on escalated amount)	Total Factor
0.0	0.000	0.000	0.000
1.0	0.037	0.044	0.081
2.0	0.076	0.094	0.170
3.0	0.116	0.151	0.267
4.0	0.158	0.214	0.372
5.0	0.202	0.285	0.487
6.0	0.247	0.365	0.612
7.0	0.294	0.454	0.748
8.0	0.344	0.554	0.898
9.0	0.395	0.666	1.061
10.0	0.449	0.790	1.239

The interest and escalation during construction is added to the estimated plant cost at the year construction starts to derive the capital cost at the completion date in the year 2000 (see Figure 3-4). This capital cost is then de-escalated to 1975 along a line corresponding to

Figure 3-4. Method for Deriving Capital Cost, Including Escalation and Interest During Construction

*Capital cost quoted in this study

6.5 percent inflation, to arrive at the capital cost expressed in 1975 dollars. This is the "Year 2000 Capital Cost expressed in 1975 Dollars" quoted in this study.

The assumption that all plants enter service in the year 2000 is only a device to arrive at the capital cost, in 1975 dollars, that includes interest and escalation during construction. For all plants except the LMFBR, this final capital cost in 1975 dollars would be identical if any other year for plant startup had been assumed. For example, the start of construction could have been assumed to take place in 1975 and interest and escalation could be applied from that time, as shown by the dashed line denoted "A" in Figure 3-4. That resulting capital cost could then be de-escalated back to 1975. The final capital cost is the same by both approaches because escalation and interest during construction are multiplying factors that are the same irrespective of the year in which construction begins. The logarithmic scale for capital cost in Figure 3-4 produces parallel lines for 6.5 percent escalation and results in the escalation and interest during construction being represented by the same vertical distance, irrespective of year.

In the case of the LMFBR, the plant cost estimate includes an allowance for fuel inventory and does not inflate at 6.5%. Thus, the inflation line from 1975 to start of construction is not parallel to the de-escalation line from 2000 back to 1975, and path A gives a capital cost which differs from the year 2000 estimate. This is discussed in more detail in Appendix D.1.

Fuel Costs

Fuel costs can increase in the future because of inflation of the general economy or cost factors peculiar to the fuel, such as scarcity or increased mining, drilling, extraction, or processing effort. In Phase 1, the prices for all types of fossil fuel were assumed to inflate at the same rate as the GNP. Nuclear fuel was assigned a different inflation rate which assumed that the breeder reactor (LMFBR) becomes available in the year 2000. Details are described in Appendix A, Table A-7 and Appendix D, Tables D-7 and D-8. In Phase 3, the fuel costs and inflation rates were specified by EPRI; these are described in Figure 3-5.

Operating and Maintenance Costs

In Phase 1, most of the operating and maintenance (O&M) costs, in mills/kWh, were taken from the ECAS results.* These results were expressed in 1974 dollars. A 15% increase was imposed to convert them to the 1975 dollar base of this study.

*Ref. 3-1, Vol. II, Part 1, Appendix C

	Coal	Uranium	Oil	Semiclean Liquid Fuel
1975 Cost (\$/MBtu)	.94	.52	1.85	3.50
Inflation Rate (%)				
1976 - 1990	7.2	7.4	8.5	7.2
1991 - 2000	7.2	7.4	9.5	7.2
2001 - 2025	7.2	7.4	10.5	7.2

Figure 3-5. Fuel Cost Inflation Rates — Phases 2 and 3

O&M costs were assumed to be proportional to plant operating hours in Phase 1. Thus, the O&M costs expressed in mills/kWh do not vary with capacity factor. This assumption is more nearly correct for a gas turbine peaking plant, which requires little operating expense that is proportional to total elapsed time but requires maintenance that is proportional to operating time. The assumption is less correct for a base load plant that requires a large operating expense but a low maintenance expense. Ideally, operating expense and maintenance expense would be derived separately and accounted for separately in the cost of electricity. However, since O&M costs are only a small part of the cost of electricity, the error resulting from this assumption was considered negligible in the Phase 1 screening analysis.

In Phases 2 and 3, however, both the fixed (proportional to elapsed time) and variable (proportional to operating time) components of O&M cost were accounted for. A detailed

discussion of the derivation of these costs is given in Reference 3-2* for the ECAS cycles. A similar estimation procedure, used in Phase 2 of this study, is described in Appendixes B.1 and B.2.

Capacity Factors

In the cost of electricity calculations for the three application modes, the following capacity factors are assumed:

- Base load = 0.70
- Midrange = 0.40
- Peaking = 0.15

The capacity factor is defined as:

$$\frac{(\text{kWh generated/yr})}{(\text{rated capacity in kW}) \times (8760 \text{ h/yr})}$$

It is assumed that, while operating, a plant produces power at full rated capacity.

It should be noted that the presentation of cost data for the three application modes does not imply that any cycle is operationally suitable for all three application modes. The costs reflect only the differences in cost of electricity as determined by substituting different values for the capacity factor in the cost of electricity equation. No allowance is made for the fact that in actual practice, the capital cost and other characteristics of a plant designed for a certain application mode might be different from those for the same type of plant designed for a different application mode.

Research and Development Costs

Research and development costs were only approximately estimated in Phase 1 of this study. For the more detailed evaluation of research and development in Phase 2, the following assumptions were made regarding R&D programs.

- All R&D programs start in mid-1975
- All R&D costs are estimated in mid-1975 dollars
- R&D cost includes all development activities up through the end of one year of testing of the demonstration plant

A research program breakdown similar to that used in ECAS Task III* was employed; the programs include at least four phases:

*Vol. II, Part 4, Appendix A.

**Ref. 3-2, Vol. III

- Phase I - Program Definition Study
- Phase II - Component and Subsystem Development
- Phase III - Pilot Plant
- Phase IV - Demonstration Plant

The pilot plant is intended to test the advanced components in a system configuration which will reveal any major component problems that might occur in the final integration of the power plant. The demonstration plant must demonstrate all of the component and system performance characteristics on a plant scale, which will permit a low risk technical decision by a supplier to offer the power plant for commercial sale. The demonstration plant operation must also exhibit a reliability and availability potential sufficient to engender confidence by the utilities to purchase a commercial plant.

Development plans are presented in Appendix B.3 for the cycles analyzed in Phase 2 of this study; plans for the ECAS Task II cycles are summarized in Appendix C.

The ECAS plans have been expanded to include furnace and gasifier development costs, and these costs are also included in the plans for the Phase 2 cycles. The heat source development plans have been defined in the present study, and are included to make the R&D cost estimates represent the total cost of progressing from state of the art (mid-1975) to the desired commercial product.

3.4 LEVELIZED COST OF ELECTRICITY

The cost of electricity (COE) quoted in this study is a life cycle cost in the sense that it is the average cost of the energy produced during a 30 yr plant lifetime. The base year for these averages is 2000.

The overall procedure used in computing COE is outlined in Figure 3-6. First, all of the costs for capital investment, fuel, and O&M expenses are estimated in 1975. These costs are then inflated at the appropriate rates to evaluate COE in the years between 2000 and 2030 when the plant is assumed to be producing power. The cost of electricity is then levelized over the period 2000 to 2030 and expressed in 1975 dollars (using 6.5% GNP deflator) to yield the cost of electricity quoted in this study (indicated by the asterisk in Figure 3-6).

The levelization procedure used here gives a uniform series of COE payments over the 30 yr plant lifetime which satisfies the following equality:

$$\begin{array}{lcl} \text{Present Worth of the} & & \text{Present Worth of} \\ \text{Uniform (Levelized)} & = & \text{Actual Costs} \\ \text{Series of Payments Over} & & \text{Over 30 Years} \\ \text{30 Years} & & \end{array}$$

Figure 3-6. Levelized Cost of Electricity

This is illustrated in Figure 3-7. The levelized payments are larger than the actual payments in the early years and smaller in the later years. The crossover point between levelized and actual costs occurs closer to the year 2000 because this is a present worth averaging technique which de-emphasizes cost in the later years.

Note that the levelized payments are uniform in current dollars (inflated dollars), so the number of dollars paid in each year is the same even though the value of the dollars is decreasing because of GNP inflation. It is also possible to levelize using a uniform series of constant dollar (fixed real value) payments. The levelized cost of electricity computed in this way is initially lower than that quoted in this study, but it increases over the life of the plant so that the present worth of the series of payments is still equal to the present worth of the actual costs. This is illustrated in Figure 3-8.

The levelized cost of electricity equations can be derived as follows. In the year j , the cost of electricity (in current dollars) is

$$COE(j) = \frac{C_{CAP}(j)}{8760 \cdot F(j) \cdot P_{NET}} + \frac{C_{FUEL}(j) \cdot HR}{1000} + \frac{C_{OMF}(j)}{8.760 \cdot F(j)} + C_{OMV}(j) \quad (3-1)$$

Figure 3-7. Levelization of Cost of Electricity

Figure 3-8. Constant vs Current Dollar Levelization

where $C_{CAP}^{(j)}$ = cost due to capital investment charges, taxes, and depreciation which is applied to COE in year j (\$/yr)

$F(j)$ = plant capacity factor in year j (%)

P_{NET} = net power plant output at full load (MWe)

C_{FUEL} = fuel cost in year j (\$/MBtu)

HR = Plant Heat Rate (Btu/kWh)
= $3412 \div \text{plant efficiency}$

$C_{OMF}^{(j)}$ = fixed O&M cost in year j (\$/kW yr)

$C_{OMV}^{(j)}$ = variable O&M cost in year j (mills/kWh)

The revenue collected in year j is given by

$$COE(j) \cdot 8760 \cdot F(j)$$

The present worth of all revenues collected over the life of the power plant is:

$$PWR = 8760 \cdot \sum_{j=1}^L \frac{F(j) \cdot COE(j)}{(1+i)^j} \quad (3-2)$$

where PWR = present worth at the beginning of year $j=1$ of all revenue collected during the plant lifetime

i = weighted cost of capital (%/yr)

L = lifetime of power plant (yrs)

Assume that

- 1) the capacity factor is the same in every year,

$$F(j) = F \quad (3-3)$$

- 2) fuel and O&M costs inflate at a uniform rate over the plant lifetime

$$C_{FUEL}^{(j)} = C_{FUEL} \cdot (1+e)^{j-1} \quad (3-4)$$

$$C_{OMF}^{(j)} = C_{OMF} \cdot (1+e)^{j-1} \quad (3-5)$$

$$C_{OMV}^{(j)} = C_{OMV} \cdot (1+e)^{j-1} \quad (3-6)$$

- 3) the year to year variation of $C_{CAP}^{(j)}$ can be lumped into a function $f(j)$ so that

$$C_{CAP}^{(j)} = C_{CAP} \cdot f(j) \quad (3-7)$$

Substituting equations (3-1) and (3-3) through (3-7) into (3-2) yields the present worth of revenue collected over the plant life:

$$\begin{aligned} \text{PWR} = & \left(\frac{C_{\text{CAP}}}{P_{\text{NET}}} \right) \sum_{j=1}^L \left[\frac{f(j)}{(1+i)^j} \right] + \\ & 8760 \cdot F \cdot \left[\frac{C_{\text{FUEL}}}{1000} \cdot \text{HR} + C_{\text{OMV}} + \frac{C_{\text{OMF}}}{8.760 \cdot F} \right] \sum_{j=1}^L \left[\frac{(1+e)^{j-1}}{(1+i)^j} \right] \end{aligned} \quad (3-8)$$

where

- C_{CAP} = total plant capital cost in year $j=1$ (\$)
- F = average capacity factor over plant lifetime (%)
- C_{FUEL} = fuel cost in year $j=1$ (\$/MBtu)
- C_{OMF} = fixed O&M costs in year $j=1$ (\$/kW-yr)
- C_{OMV} = variable O&M costs in year $j=1$ (mills/kWh)
- e = inflation rate (%/yr)
- $f(j)$ = yearly capital charge rate* in year j (%/yr)

By definition, the levelized cost of electricity is the uniform series of payments which gives the same total present worth of revenue. Thus

$$8760 \cdot F \cdot \sum_{j=1}^L \left[\frac{\overline{\text{COE}}}{(1+i)^j} \right] = \text{PWR} \quad (3-9)$$

where $\overline{\text{COE}}$ = levelized cost of electricity in current dollars (mills/kWh)

Substituting equation (3-8) into (3-9) and rearranging yields the following expression for the levelized COE:

$$\begin{aligned} \overline{\text{COE}} = & \left(\frac{C_{\text{CAP}}}{8760 \cdot F \cdot P_{\text{NET}}} \right) \cdot \text{FCR} + \\ & \left[\frac{C_{\text{FUEL}}}{1000} \cdot \text{HR} + \left(\frac{C_{\text{OMF}}}{8.760 \cdot F} \right) + C_{\text{OMV}} \right] \text{LEV} \end{aligned} \quad (3-10)$$

$$\text{where } \text{FCR} = \sum_{j=1}^L \left[\frac{f(j)}{(1+i)^j} \right] \times \left\{ \sum_{j=1}^L \left[\frac{1}{(1+i)^j} \right] \right\}^{-1} \quad (3-11)$$

$$\text{LEV} = \sum_{j=1}^L \left[\frac{(1+e)^{j-1}}{(1+i)^j} \right] \times \left\{ \sum_{j=1}^L \left[\frac{1}{(1+i)^j} \right] \right\}^{-1} \quad (3-12)$$

*Ref. 3-4, p. 3, Equation 3

LEV is the levelization factor. If e and i are constant throughout the period $j=1,L$, then the series in (3-12) sum to the following expression:

$$LEV = \frac{\left[1 - \left(\frac{1+e}{1+i}\right)^L\right] i (1+i)^L}{(i-e) \left[(1+i)^L - 1\right]} \quad (3-13)$$

For $L = 30$ yr with $e = 6.5\%$ and $i = 10\%$, the $LEV = 1.882$, which is the value used in levelizing fossil fuel costs in Phase 1 and the O&M costs throughout this report. In cases where the inflation rate is different than 6.5% the value of LEV changes. The values used in levelizing the Phase 2 and 3 fuel costs are given in Appendix D.1.

FCR is the levelized fixed charge rate, as described in Reference [3-4]

$$FCR = i + (SSF)_L + \left(\frac{t}{1-t}\right) \left[\left(1 - \frac{bB}{i}\right) \left(i + (SSF)_L - d\right) - (d_t - d) - \frac{K \cdot (CRF)_L}{1+i} \right] - \frac{K \cdot (CRF)_L}{1+i} + a \quad (3-14)$$

where $(SSF)_L =$ sinking fund factor $= i / \left[(1+i)^L - 1\right]$
 $t =$ income tax rate $= 50\%$
 $b =$ interest rate on bonds $= 8\%/yr$
 $B =$ debt ratio, i.e. debt/total capitalization $= 50\%$
 $d =$ depreciation rate for straight line method
 $= 1/L = 3.33\%/yr$
 $d_t =$ accelerated depreciation used in tax calculations $(\%/yr)$
 $K =$ investment tax credit $= 4\%$
 $(CRF)_L =$ capital recovery factor $= (SSF)_L + i$
 $a =$ levelized rate for ad valorem taxes and insurance $= 2\%/yr$

If no accelerated depreciation or investment tax credit is taken, i.e. $d_t = d$ and $K=0$, then $FCR = 17\%$. Equation 3-14 is consistent with but not identical to the expression recommended in Chapter V of the EPRI Technical Assessment Guide.* In the assessment guide a retirement dispersion allowance is added to $(SSF)_L$ in the second and third terms of equation (3-14) to account for uncertainty in the plant lifetime estimate. This increases FCR to 18% which is the figure used in this study.

*Reference 3-5, Chapter V, "Revenue Requirement Calculations for Economic Comparison of Alternatives."

Thus the final expression for levelized cost of electricity is

$$\overline{\text{COE}} = \left(\frac{C_{\text{CAP}} \cdot \text{FCR}}{8760 \cdot F \cdot P_{\text{NET}}} \right) + C_{\text{FUEL}} \cdot \frac{\text{HR}}{1000} \cdot \text{LEV}_F + \left[\frac{C_{\text{OMF}}}{8.760 \cdot F} + C_{\text{OMV}} \right] \cdot \text{LEV}_{\text{OM}} \quad (3-15)$$

where $\text{FCR} = 18\%/yr$

$F = 70\%$ (Base load mode)

40% (Midrange mode)

15% (Peaking mode)

$\text{LEV}_F =$ fuel levelization factor, varies with fuel inflation rate, see Appendix D

$\text{LEV}_{\text{OM}} =$ O&M levelization factor = 1.882

REFERENCES

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- 3-3. "Power Plant Capital Costs: Current Trends and Sensitivity to Economic Parameters," Report WASH-1345, U.S. Atomic Energy Commission Contract W-7405-eng-26, Oak Ridge National Laboratory, Contract AT (11-1)-2226, United Engineers and Constructors Inc., U.S. Government Printing Office, October 1974.
- 3-4. R.L. Jones and W.D. Marsh, "The Complete Fixed Charge Rate," Power Generation Report #142, General Electric Company, Electric Utility Systems Engineering Department, Schenectady, N.Y., August 1976.
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Section 4

SELECTION OF POWER CYCLES FOR STUDY

In Phase 1, 19 advanced cycles were analyzed to provide estimates for cycle efficiency, capital cost, and R&D requirements. These estimates were used to screen the cycles and to select the most promising candidates for further study. The level of detail considered in making these estimates is comparable to the Task I analysis of the Energy Conversion Alternatives Study (ECAS). That is, no formal drawings were made; estimates were made on the basis of engineering sketches.

Two cycles were analyzed in Phase 2. Drawings were made for all of the advanced components and site construction requirements were detailed using plot plans and equipment arrangement drawings. Costs and performance for state of the art equipment were obtained by soliciting vendor quotations. This level of detail is consistent with the ECAS Task II work in which seven advanced cycles were analyzed by General Electric.

It is important to remember these differences in level of detail when using the results of this study. For instance, there are significant differences between the ECAS Task I and Task II estimates for the metal vapor topping cycle, and the estimates of efficiency and cost for the water cooled gas turbine combined cycle with low-Btu gasifier are quite different in Phases 1 and 2 of this present study. The Phase 2 and ECAS Task II estimates are judged to be more accurate than the Phase 1 or ECAS Task I results because of the greater level of detail considered. Thus, the Phase 2/Task II group of estimates should be preferred over the Phase 1/Task I group in comparing the advanced cycle concepts.

4.1 INITIAL SCREENING OF POWER CYCLES

Nineteen advanced cycles were analyzed in Phase 1; twelve were taken directly from the ECAS work,* and seven were new cases which were added to include cycles using oil and nuclear fuels. These can be divided into three categories:

- Open Cycles
- Closed Cycles
- Direct Energy Conversion

A list of the 19 cycles that were selected for the Phase 1 investigation is given in Table 2-1 of Section 2. A brief description of the cycles, grouped by category, is given below. Two reference cases are also described.

Open Cycles

The open cycles consisted of gas turbines in which the products of combustion provide the working fluid for the cycle. These turbines require clean (or semiclean) fuels in order to prevent corrosion of parts in the hot gas path. Two basic cycle configurations were studied: recuperative and combined cycle. In the recuperative configuration, the exhaust of the expansion turbine is utilized to preheat the high pressure combustion air as it exits from the compressor en route to the combustion chamber. Clean fuels were employed for this cycle. Water was injected into the combustion chamber in order to limit thermal NO_x generation. The gas turbine was air cooled by bleed air extracted from the compressor. The pressure ratio was 12 and the first stage turbine bucket inlet temperature was 1477 K (2200 F).

In the combined cycle configuration, the exhaust gas from the gas turbine was cooled in a heat recovery steam generator (HRSG). The steam produced was employed in a steam turbine bottoming cycle. The steam throttle conditions were conventional (steam temperatures of 811 K [1000 F] or below and pressures less than 16,550 kPa [2400 psig]). The air cooled gas turbine used extraction air for cooling parts in the hot gas path. The pressure ratio for this machine was 12 and the inlet temperature was 1589 K (2400 F). The water cooled gas turbine used a circulating closed loop water system to cool the hot gas parts. This machine operates with a pressure ratio of 16 and a turbine inlet temperature of 1922 K (3000 F).

An integrated low-Btu gasifier was used as a fuel supply for two of the combined cycles. This gasifier is a fixed bed system employing low-temperature gas cleanup. The air from the gas

*J.C. Corman, G.R. Fox, et al., "Energy Conversion Alternatives Study (ECAS), Phase I Final Report," NASA Contract NAS 3-19406, Corporate Research and Development, General Electric Company, Schenectady, New York, February 1976.

turbine compressor was supplied to the gasifier along with steam, which was generated in the HRSG, to produce the low-Btu fuel. The coupling of the flow streams thus integrates the gasifier and the energy conversion systems.

A second fuel—a semiclean fuel produced from coal by the solvent refined coal process—was evaluated with the water cooled gas turbine combined cycle. This fuel was selected as representative of a "residual" fuel type which could be produced directly from coal. A fuel processing skid was used in this system to clean the fuel to protect the hot gas path. The semiclean fuel has a high content of fuel-bound nitrogen, which is converted to NO_x in a gas turbine combustor, thus preventing the system from meeting the NO_x specification.

Closed Cycles

In closed cycle configurations, the working fluid circulates through a closed circuit, and heat enters the working fluid through a heat exchanger. Seven closed cycles were evaluated in this study.

Advanced steam cycles were evaluated for four fuels: coal, oil, and two nuclear fuels. The atmospheric fluidized bed employs direct combustion of coal in the presence of limestone, which acts to remove sulfur from the combustion gases. The bed temperature is 1116 K (1550 F), low enough to limit NO_x production. The steam cycle for this furnace type, and for the conventional furnace with oil firing, used throttle conditions of 24,130 kPa (3500 psi) and 811 K (1000 F). For the nuclear energy sources, the steam temperatures were 811 K (1000 F) or lower.

Two working fluids were considered with the closed gas turbine cycle: helium and supercritical carbon dioxide (CO_2). In these plants, heat is added through a heat exchanger to a single phase working fluid (a gas in the case of helium, and a subcooled liquid in the case of CO_2). The gas exiting from the expansion turbine enters a recuperative heat exchanger to preheat the gas exiting from the compressor en route to the heat input heat exchanger. The heat rejection from the cycle is through a cooling tower, with a water loop carrying heat from the working fluid to the cooling tower. The compressor is driven by the expansion turbine shaft.

The helium gas turbine cycle operates with a pressure ratio of approximately 2.5 and a turbine inlet temperature of 1089 K (1500 F). Two energy sources were evaluated: direct combustion of coal in an atmospheric fluidized bed, and a high temperature gas cooled reactor (HTGR).

In the CO_2 cycle, the working fluid is maintained in a supercritical pressure state throughout the fluid circuit. At low temperatures after heat rejection and prior to entering the compressor, the fluid density is approximately 1/3 that of water. This substantially reduces the work of compression in the cycle and requires only a small regeneration of mechanical energy from the expansion turbine. This cycle operates with a maximum cycle pressure of approximately 27,580 kPa (4000 psi), a pressure ratio of 2.7, and a turbine inlet temperature of 1005 K (1350 F).

The metal vapor turbine cycle is a true topping cycle. Heat enters the cycle in an atmospheric fluidized bed furnace and evaporates the potassium liquid metal working fluid. The vapor, at a temperature of 788 C (1450 F), then expands through a metal vapor turbine. The vapor exiting from the turbine (at about [593 C] 1100 F) is condensed in a condenser/boiler to produce steam for the bottoming cycle. The electrical energy output from the cycle is from both the potassium turbine generators and the steam turbine generators.

Direct Energy Conversion

Three types of direct energy conversion cycles were evaluated: magnetohydrodynamics (MHD), thermionics, and fuel cells.

Three configurations of MHD cycles were evaluated, including both open and closed cycles. The open cycle MHD system employs direct combustion of coal to provide the energy source and the cycle working fluid. The products of combustion are seeded with KCO_3 to increase the electrical conductivity of the gases passing through the MHD duct. The oxidizer is preheated air. The preheat temperature of 1644 K (2500 F) is achieved by high temperature regenerative and low temperature recuperative heat exchangers in the exhaust from the MHD duct. The exhaust from the duct is also employed to produce steam for a steam bottoming cycle, operating at 24,130 kPa/811 K/811 K (3500 psi/1000 F/1000 F). The steam bottoming turbines operate in two parallel turbine trains: one to drive the MHD combustion air compressors and one to drive a bottoming cycle ac generator. The seed material is also used to gather sulfur in the combustion gases by reaction to K_2SO_4 . The seed is then reprocessed. The energy source for this seed reprocessing is a gas produced from gasification of coal.

Two closed cycle MHD concepts were studied. The first employed a plasma approach in which a seeded inert gas, argon, is used as the working fluid. This combination makes it possible for a nonequilibrium effect to exist in the MHD duct, thus achieving adequate electrical conductivity at lower temperatures. MHD duct inlet temperature is approximately 1922 K (3000 F). Exhaust from the duct is used to generate steam which is used in a turbine

to drive the argon compressors. The energy source is direct combustion of coal with stack gas cleanup. The products of combustion heat a set of regenerative, ceramic, heat exchangers which periodically give up their stored heat to the working fluid.

The second closed cycle MHD system employs a mixture of liquid metal (sodium) and helium as a working fluid. The helium is the thermodynamic fluid that expands in the MHD duct while the liquid metal supplies the electrical conductivity. Since this cycle does not rely on high temperatures to achieve the electrical conductivity and MHD effect, the inlet duct temperature can be lower (about 977 K [1300 F]). The energy source for heating both fluids is coal combustion in an atmospheric fluidized bed. The exhaust from the MHD duct is separated into liquid metal and helium. The liquid metal is pumped back to the furnace for reheat, and the helium is cooled in a heat recovery steam generator before being cooled for cycle heat rejection and recompressed in a helium compressor. The steam that is produced is expanded in a steam turbine to drive the helium compressor.

In the thermionic concept, coal is burned with preheated air in a conventional furnace. Many thermionic converters are mounted in the furnace walls, with the hot (emitter) ends exposed to the hot furnace gases. The heat extracted from the combustion gases flows through the thermionic converters to the cold (collector) ends. This heat discharges into a stream of air that then flows into a heat exchanger that boils water for a steam bottoming cycle. The air that leaves the boiler (at 589 K [600 F]) is then heated once more by the thermionic converters to a temperature of 811 K (1000 F), after which the air joins the combustion air in the furnace. The combustion gases leaving the furnace provide heat for steam superheating and reheating. DC power is extracted from the thermionic converters, and ac power is generated by the steam bottoming cycle.

Two low temperature fuel cell configurations were evaluated. These systems operate at 422 K (300 F). The fuel cell type was a solid polymer electrolyte using hydrogen fuel and oxygen oxidizer. In one case, the hydrogen was produced by gasification of coal at an off-site location and transmitted by pipeline to the plant site. In the second case, hydrogen was produced from No. 6 oil in a reformer at the plant site.

Reference Cycles

To provide a basis of comparison for evaluating the advanced concepts, two reference cycles were evaluated under the ground rules set up for the advanced concepts. These reference cases were conventional cycles which were modified only to the extent of meeting the same environmental specifications as the advanced cycles, but which would otherwise require no research and development. It is presumed that these reference cases would be typical of future power plants if no research and development of advanced cycles was conducted.

For base and midrange loads, the reference case is a standard steam plant operating with conditions of 24,130 kPa/811 K/811 K (3500 psi/1000 F/1000 F). The energy input is by direct combustion of coal in a conventional furnace with stack gas cleanup used for emission control.

For peaking loads, a simple cycle gas turbine is utilized as the reference case. This cycle uses current pressure ratio and firing temperature parameters and operates with a high-Btu gas fuel.

Cost and performance estimates for these concepts were reported in detail at the end of Phase 1* and are summarized in Appendix A below. Generation Phase Diagrams have been computed for these cycles and are presented in Appendix F.1; Figures of Merit have also been determined and are summarized in Appendix G.1.

*Comparative Study and Evaluation of Advanced Cycle Systems Phase 1 Report, EPRI Report AF-158, NTIS Report PB254392, General Electric Company, Schenectady, N.Y., May 1976.

4.2 DETAILED CONCEPTUAL DESIGNS

Several promising candidate cycles were identified in the Phase 1 screening. Two were selected by EPRI for a more detailed analysis in Phase 2. These cycles are:

Gas Turbine Combined Cycle - LBtu Gasifier. An advanced water cooled gas turbine having an inlet temperature of 1922 K (3000 F) is the prime cycle in this concept. Energy in the turbine exhaust gases is extracted in heat recovery steam generators, and drives a steam bottoming cycle having inlet conditions of 16,550 kPa/811 K (2400 psi/1000 F) with a reheat to 811 K (1000 F). The stack gas is at 422 K (300 F) and heat is also rejected through wet mechanical draft cooling towers.

The gas turbine fuel is low Btu gas produced from coal in fixed bed gasifiers at the plant site. The raw gas contains phenols and tars which are removed by two stages of water washing and are recycled into the gasifier for cracking. Coal fines are also recovered and fed into the gasifier in this concept by using the recovered tar as a binder. Sulfur compounds in the washed gas are removed by an Alkazid low temperature cleanup system which operates in conjunction with a Claus plant to recover elemental sulfur.

A detailed description of this plant is given in Appendix B.1

Advanced Steam, Atmospheric Fluidized Bed. This cycle has an inlet steam condition of 16,550 kPa/811 K (2400 psi/1000 F) to achieve high reliability. It also includes a single reheat to 922 K (1200 F), heaters above the reheat point, and lightly loaded turbine exhausts to provide high efficiency. This reverses the emphasis used in Phase 1 of this study and Task I of ECAS in which the steam cycles were selected to provide lowest cost and not necessarily highest efficiency.

The atmospheric fluidized bed furnace operates at 1116 K (1550 F) with limestone as the sulfur capture medium. Unburned carbon from the main bed cells is recovered from the bed solids drains and fly ash cyclones and is recycled to a carbon burnup cell where higher temperature 1366 K (2000 F) and greater excess air are used to complete the combustion process. Particulates passing through the cyclone separators are captured in an electrostatic precipitator.

Heat is rejected from the stack at 400 K (260 F) and also through wet mechanical draft cooling towers.

The detailed conceptual design for this cycle is presented in Appendix B.2.

Development Plans

Development requirements are identified for these two cycles in Appendix B.3. The major technology issues are listed and programs of experimentation which address these issues are shown. The programs have been constructed according to the ground rules used in the Energy Conversion Alternatives Study (ECAS); that is, the schedules include the following four elements:

- Program Definition Study
- Component Development
- Pilot Plant
- Demonstration Plant

Wherever possible, the development plans outlined in the ECAS work have been adapted. For instance, the R&D program presented here for the 1922 K (3000 F) water cooled gas turbine is identical to that reported in ECAS except in the area of combustor development where low Btu gas combustor work has been substituted for the semiclean liquid combustor effort.

These development plans must be complete to be used in the Net Present Worth calculations. That is, the costs and schedules must include all of the effort necessary to bring the concepts from state of the art in 1975 to full commercial service in the future. In ECAS, the furnaces and gasifier were not included in the development plans; however, the R&D requirements for these subsystems have been accounted for in the plans presented in Appendix B.3.

Reference Cycles

Four cycles were chosen as examples of state of the art power generation technology, and cost and performance estimates were obtained. These cycles are:

Open Cycle Gas Turbine. This is a conventional air cooled gas turbine burning oil or semiclean liquid fuel with an inlet temperature of 1366 K (2000 F); it is intended to represent state of the art technology designed for peaking duty, i.e., about 1500 hours per year of service.

Open Cycle Gas Turbine Combined. This is a plant using four gas turbines of the type described above with the turbine exhaust energy being recovered to drive a steam bottoming cycle (6210 kPa/727 K [900 psi/850 F]). Heat is rejected to the stack at 449 K (348 F) and also to wet cooling towers. This plant is representative of units designed for midrange duty, i.e., about 4000 h/yr.

Conventional Steam with Scrubbers. This plant has a conventional furnace burning high sulfur coal (Illinois No. 6) with wet lime scrubbers to remove sulfur oxides and electrostatic precipitators to remove particles from the flue gas. The steam cycle is conventional with supercritical inlet conditions (24, 130 kPa/811 K [3500 psi/ 1000 F]) and a 811 K (1000 F) reheat. This is a base load plant for applications requiring about 6000 h/yr of operation.

Conventional Steam, Light Water Reactor. This is a subcritical steam cycle rejecting heat through wet cooling towers; it is a base loaded plant.

Cost and performance estimates for these four plant concepts are presented in Appendix B.4.

4.3 CYCLES CHOSEN FOR PHASE 3 STUDY

In Phase 3, the comparison methodologies were applied to three advanced cycle concepts. These concepts were carefully selected by EPRI to demonstrate the major features of the methodologies. The Phase 3 comparisons should be viewed as an example of the methods, not as a definitive selection study. Such a study would have to include a larger number of cycle candidates and compare them under a variety of possible economic futures. However, this is beyond the scope of the present work.

To preserve comparability in level of detail, the three advanced cycles were selected from Phase 2 of this study and Task II of the Energy Conversion Alternatives Study; these cycles are listed in Table 4-1 along with the four reference cycles.

GTWCCE, STAFB, and OCMHD* were selected because they are low cost options which offer stepwise improvements in efficiency with progressively longer development times and larger R&D costs. These three clearly express the typical dilemma—to choose between high performance or near term implementation—and were considered by EPRI to be a good test of the methodologies developed in this study.

*See legend for Table 4-1

Table 4-1
CANDIDATE CYCLES FOR PHASE 3 STUDY

<u>Cycle Name</u>	<u>Capital Cost M\$</u>	<u>Overall Efficiency %</u>	<u>R&D Cost M\$</u>	<u>R&D Time Years</u>	<u>Commercial Plant Construction Time Years</u>	<u>Date of First Commercial Service</u>
Phase 2 Cycles (See Appendix B)						
*GTWCCE	474	44.0	417	14	5.0	1996
AFBHI	542	37.1	328	17	5.5	2000
ECAS Cycles (See Appendix C)						
*STAFB	447	35.8	228	6	5.5	1988
STPFB	511	39.2	380	12	5.5	1994
HEAFB	899	39.9	964	15	5.0	1997
MVTPFB	661	44.4	845	18	5.5	2001
GTWCCN	305	37.8	292	14	5.0	1996
GTACC	562	39.6	228	11	5.0	1993
*OCMHD	477	48.3	1444	19	6.5	2003
Reference Cycles (See Appendix B)						
*STLWR	776	32.8				
*STSCRB	591	31.8				
*GTCC	282	42.6/31.5 **				
*GT	116	31.0/22.9 **				

Legend:

GTWCCE—Advanced Gas Turbine (Water Cooled)
Combined Cycle, LBtu Gasifier, Coal

AFBHI—Advanced Steam (1200 F Reheat), AFB, Coal

STAFB—Steam, Atmospheric Fluidized Bed, Coal

STPFB—Steam, Pressurized Fluidized Bed, Coal

HEAFB—Closed Cycle Helium Gas Turbine,
Organic Bottoming, AFB, Coal

MVTPFB—Metal Vapor Topping Cycle, PFB, Coal

GTWCCN—Advanced Gas Turbine (Water Cooled)
Combined Cycle, Semiclean Liquid

GTACC—Advanced Gas Turbine (Air Cooled)
Combined Cycle, LBtu Gasifier, Coal

OCMHD—Open Cycle MHD, Coal

STLWR—Steam, Light Water
Reactor, Uranium

STSCRB—Steam, Conventional
Furnace, Scrubber, Coal

GTCC—Conventional Gas Turbine
Combined Cycle, Oil/Semi-
clean Liquid

GT—Conventional Gas Turbine,
Oil/Semiclean Liquid

*cycles selected for Phase 3 study

**efficiencies with oil/semiclean liquid

EVALUATION CRITERIA

A major reason for developing energy conversion processes is to achieve the conversion of various forms of energy into electricity at a lower cost than is currently possible with conventional methods. Hence, a major effort in this study has been to analyze the economics of the various advanced processes.

Cost of electricity is not the only factor of interest, however, and to appraise other mainly intangible factors a list of evaluation criteria was proposed. This task began with the list of criteria included in the schedule to the contract; other criteria were added that were considered necessary to complete the list and make the individual criteria as independent as possible. A definition of each criterion was formulated, in most cases including a definition of good, fair, and poor, which could be used to rate each conversion process.

To avoid ambiguity in the definition of these criteria, the usage of several technical terms has been restricted as follows:

- Energy Conversion Process - the basic energy conversion concept, such as open cycle MHD or the metal vapor topping cycle, which is independent of a particular plant configuration
- Unit - a particular version of the process, and the smallest independent division of a power generation system
- Power Plant - the energy conversion equipment located at a particular site; can include one or several units
- System - the collection of power plants and their interconnection by transmission and distribution networks; "system" as used here always refers to the utility system, not to an energy conversion system (unit)

It has been assumed in defining these criteria that the energy conversion process has been formulated as a conceptual design for a particular unit. The criteria are then used to judge the impact on society and the utility industry of developing and using the process in the form exemplified by that unit.

These criteria are concerned mainly with the intangible attributes of the energy conversion unit; that is, those attributes which cannot be directly factored into the cost of electricity.

For example, high capital cost is a shortcoming in an economy in which capital is not easily available. Similarly, high efficiency is a benefit in its impact on fuels conservation irrespective of the cost of electricity.

Two methods have been developed in this study to assess the overall desirability of an energy conversion unit with respect to these criteria. The direct weighting method combines the criteria ratings of good, fair, and poor with weighting factors to yield an overall "figure of merit" for the intangible attributes of a process. The net-present-worth approach combines the criteria ratings with the economic analysis to estimate future market penetration and overall economic benefit of a process.

The following is a list of the criterion definitions used in Phase 3 of this study.

EVALUATION CRITERIA

1. Cost of Research and Development Required

A process would be judged good with respect to this criterion if the technical problems are expected to be solved with relatively small-scale experiments, and with the expenditure of less than \$100 million. A process would be judged fair if the estimated cost is less than \$500 million, and poor if the estimated expenditures are larger than \$500 million.

These costs include all work needed to bring the plants to the point where they are fully commercial. However, these costs include only costs in excess of the costs to produce power commercially. (For example, the capital cost of the first commercial plant would not be included except for those unusual costs associated with the first plant only.)

It is assumed that the R&D effort will be applied neither on a crash basis nor on a minimal effort basis but on a reasonable level between these extremes.

2. Research and Development Time Required

A good process would be one for which the first fully commercial plant could go into service in the time period 1985-1990. A fair process would be one commercially in service in the time period 1990-2000. A poor process would be one available after 2000.

3. Probability of Development Success

Development success is defined here as meeting the goals of performance, capital cost, environmental and safety standards, etc., within the estimated development time and development cost.

A probability of 90 percent or higher is considered good, between 70 and 90 percent fair, and below 70 percent poor.

4. Plant Capital Cost

Apart from its direct effect on plant economics, the level of plant capital cost affects the cost of money to a utility. This is important to the financial condition of the utility.

Plant capital cost will be expressed in 1975 dollars.

A unit would be judged good if unit capital costs (including interest and escalation during construction) is expected to be less than \$300/installed kW. A fair rating would apply between \$300 and \$800/kW, and poor would apply for higher capital costs.

5. Plant Operating and Maintenance Requirements

The tangible effects of operating and maintenance requirements will be accounted for directly in cost of electricity.

The intangible effects will be reflected in rating the energy conversion units as follows. A good unit would be one in which the starting and operating procedures are inherently so simple that it can reasonably be considered an unattended, remote, or automatically operated plant. The maintenance operations would be simple, consisting largely of replacement of expensive parts at predictable times with normally available skilled labor. As an example, the present line of gas turbines would fit into this category. A fair unit would be one more nearly like the present generation of steam plants in which operation is more complex, not easily automated, and in which maintenance procedures are more time-consuming and more specialized in terms of labor skills. A poor unit would be one in which the operational procedures are extremely complex, and in which extensive training is required for operating and maintenance personnel.

6. Electrical Performance

This criterion covers a wide range of electrical operating characteristics. A good unit would be one whose inherent or modified characteristics permit it to operate stably in synchronism with other generating units on the system, a unit which would automatically react under emergency conditions to support the system voltage and frequency.

A poor unit would be one incapable of supplying reactive KVA to the system, and whose power response or control characteristics make it incapable of supporting the power system's need

for power in an emergency. Its inertial and impedance characteristics would result in questionable stability except in the stiffest of power system locations. Its instantaneous power response would be zero or negative, and its long-time response would be 0.5 percent per minute or less.

A fair unit falls between these two extremes.

7. Power Plant Efficiency

This criterion accounts for the relationship of plant efficiency and the need to conserve and make optimum use of fuel resources.

The power plant efficiency is defined here as the net power output from the high voltage transformer divided by the rate of fuel energy input to the plant. For fossil fuels, the higher heating values will be used, and the heating value will apply to the fuel that crosses the power plant boundary, not to the fuel derived at the power plant site. (For example, where low-Btu gas is produced from coal in an on-site gasifier, the heating value of coal, not the gas, will be used.)

A power plant efficiency of 45 percent or better will be considered good, 35 to 45 percent will be fair, and below 35 percent will be considered poor.

8. Capability for Load Change

This criterion refers to mechanical and thermal characteristics that limit the rate of response of a unit to changes in load, or that restrict the time required for startup or shutdown. This factor affects the decision by the utility to dispatch the plant under system load changes, and therefore affects the unit's average capacity factor and efficiency. It is assumed that the same characteristics that affect rate of load following will also affect rate of startup from a warm condition.

The rating of a unit with respect to this criterion will be expressed in terms of the time required to reach full load from a warm start; that is, a start following an overnight shutdown. A good unit is defined as one that requires less than 1 hour to reach full load. A fair unit will require 1 to 2 hours, and a poor unit will require more than 2 hours. The good and fair classifications correspond to current practice with simple cycle gas turbines and cycling steam units respectively.

The effect of time required for startup from a cold condition will be reflected in Criteria 11 and 12 (the forced and planned outage rates).

9. Part Load Efficiency

Part load efficiency will be evaluated by the average slope (S) of the efficiency versus load curve. For the purpose of this criterion the average slope will be defined as

$$S = (1 - \eta^*/\eta_{FL}) / (1 - P^*/P_{FL}) \quad (5-1)$$

where P_{FL} and η_{FL} are the power and efficiency at full load, while P^* and η^* are evaluated at 50 percent load ($P^*/P_{FL} = 0.5$) or at the minimum load if the unit cannot get down to 50 percent load. A unit will be considered good if it has $S < 0.2$, fair if $0.2 \leq S \leq 0.5$, and poor if $S > 0.5$. This criterion is shown graphically in Figure 5-1. The good classification corresponds to current steam turbine practice, while the fair classification exemplifies present-day gas turbines.

Figure 5-1. Evaluation of Part Load Efficiency

10. Minimum Load

The minimum load will be that power output below which the plant cannot operate continuously. A good unit is defined as one that can operate at outputs as low as 20 percent of its full load rating. The minimum load of a fair unit will be between 20 and 60 percent, and a poor unit cannot operate below 60 percent.

11. Forced Outage Rate

Utility system reserve capacity is chosen to maintain an acceptable loss of load probability (typically 0.1 day/year). Unit reliability as expressed by forced outage rate has a direct impact on system reserve requirements, and therefore on system cost.

For purposes of this study, the forced outage rate is defined as the percentage of total elapsed time that the plant cannot operate because of unexpected failure. A good plant will have a forced outage rate of less than 5 percent. Between 5 and 10 percent will be judged fair, and greater than 10 percent will be judged poor. These forced outage rates are assumed to apply to plants that are mature in design and operation.

12. Planned Outage Rated

Planned outage rate often has an impact similar to forced outage rate in the way it affects system reserve requirements. Systems which do not experience well-defined seasonal demand peaks are often forced to purchase additional reserve capacity in order to provide reliable service during unit maintenance shutdowns.

The planned outage rate is the percentage of total elapsed time that the plant cannot be operated because of scheduled maintenance and repair. A good plant will have a planned outage rate of less than 10 percent. A fair plant will have between 10 and 17 percent, and a poor plant will have greater than 17 percent. These planned outage rates are assumed to apply to plants that are mature in design and operation.

13. Hardware Materials Availability

This criterion takes into account implications in the use of strategically important materials, apart from the tangible effects which are reflected in Criterion 4, "Plant Capital Cost." Materials include construction materials, and the inventory of working fluid. Availability refers here to the percentage of the total North American reserves of a particular material that would be required if 100 GW of an energy conversion system were installed.

The energy conversion process would be considered good with respect to this criterion if this percentage is less than 2 percent, fair if between 2 and 10 percent, and poor if greater than 10 percent.

14. Industrial Capability for Manufacture

This criterion refers to the capability for manufacture of process components (for example, large turbine wheels of high-temperature alloys) after technology development is completed. A process would be rated good if machine tools currently in place can manufacture all process components, fair if new specialized machine tools using existing manufacturing technology would have to be purchased, and poor if a large (more than \$25 million) manufacturing development program would have to be undertaken.

15. Plant Safety

Plant safety involves three components:

- Property damage
- Safety to plant personnel
- Safety to the external public

Only the second and third of these aspects will be considered.

There are two multiplicative factors which determine the safety to plant personnel and the external public:

- Probability of an unsafe condition occurring
- Consequences of the unsafe condition (expected number of fatalities)

Probability of Unsafe Event. The following three rankings will be used, on the basis of 1000 MW.

1. High	$\geq 10^{-3}$ per year	Comparable to fossil plants
2. Medium	10^{-4} to 10^{-6} per year	Comparable to existing nuclear reactors
3. Low	$< 10^{-6}$ per year	Goal for future nuclear reactors

Consequences. The following three arbitrary rankings will be used (they are based on the number of fatalities if one unsafe condition arises).

1. Serious	> 10 fatalities or serious injuries
2. Moderate	≤ 10 fatalities or serious injuries
3. Limited	No fatalities or serious injuries

Plant Ratings. The following three ratings will be used.

1. Good	$\leq 10^{-6}$ fatalities or serious injuries/year (1000 MW)
2. Fair	10^{-3} to 10^{-5} fatalities or serious injuries/year (1000 MW)
3. Poor	$\geq 10^{-2}$ fatalities or serious injuries/year (1000 MW)

These can be related to the rankings for probability and consequences. Table 5-1 gives the rough estimate of expected fatalities or serious injuries per year for each combination of probability and consequences; it also relates the expected fatalities or serious injuries per year to the plant safety rankings.

Table 5-1

RATINGS FOR PLANT SAFETY

Consequences	Probability of Unsafe Event Per 1000 MW		
	High	Medium	Low
Serious	10^{-1} (P)	10^{-2} to 10^{-4} (P)	10^{-4} (F)
Moderate	10^{-2} (P)	10^{-3} to 10^{-5} (F)	10^{-6} (G)
Limited	0 (G)	0 (G)	0 (G)

G = good plant safety, F = fair plant safety, P = poor plant safety

For the purpose of this study, it will be assumed that the development necessary to produce plants with a good safety rating will be carried out, and that the time and cost of development will reflect this safety requirement.

16. Dependence on Other Systems

A good unit is one which may be applied at any physical or electrical location in a power system without dependence upon any other energy handling systems for its operational or economic viability. A fair unit must operate in conjunction with and in proximity to other installations (e.g., to absorb byproducts or provide fuel inputs) which are fairly common and widespread. A poor unit is one that requires a unique combination with another energy handling system which is not common.

17. Adaptability to Fuels

This criterion refers to the capability of a plant to adapt to various kinds of fossil fuels so that the utility can select at any time the lowest cost fuel or the fuel most readily available.

A unit will be considered good with respect to this criterion if the unit can be designed and constructed to make possible the burning of solid, liquid, or gaseous fuels without a major modification of the plant. A fair unit is capable of utilizing only one of the above three fuel types but can adapt to several grades or varieties of the fuel type without major modification. A poor unit is not adaptable to various types or grades of fuel, or a major modification is needed to adapt the unit for various types or grades. A unit requiring a clean or refined fuel will be considered poor.

A fair rating will apply to nuclear cycles with respect to this criterion.

18. Life

Unit life has a direct effect on cost of electricity due to its inclusion in the calculation of a fixed charge rate. Life also affects a unit's desirability because short life means that new plants are built more frequently, and each new plant requires a new round of licensing hearings and, in some cases, interactions with public action groups.

Life is defined here as the span of time after which there is no economic justification for operation of the plant. A good unit is one whose life is 30 years or more. A fair unit is one whose life is 20 to 30 years. A poor unit is one whose life is less than 20 years.

For purposes of this study, it will be assumed that the development necessary to produce plants with a good life rating will be carried out, and that the time and cost of development will reflect this life requirement. Criterion 5, "Plant Operating and Maintenance Requirements," will also reflect the need to replace parts to extend life to at least 30 years.

19. Flexibility of Siting

Unit siting is limited by noise, appearance, size, need for cooling water, bulk fuel delivery, or severe public objections. A good unit is one that is suitable for more than 80 percent of potential sites. A fair unit is suitable for 40 to 80 percent of potential sites, and a poor unit is suitable for less than 40 percent of potential sites.

20. Waste Handling and Disposal

A good unit is one in which the waste is nonpolluting and of small enough magnitude to permit disposal at the generating site by conventional land fill methods. A fair unit is one in which the waste is of sufficient magnitude and pollution potential that it must be disposed of off-site, or with special provisions on-site. A poor unit is one in which the wastes are toxic and of such potential danger to public health that special handling is required, with remote disposal at special sites.

21. Plant Construction Time

Plant construction time as applied in this criterion refers to the period which would be required to complete the design, procurement, excavation, and erection activities, assuming that there were no manufacturing or licensing delays. A good unit is one in which the total of manufacturing and installation time is less than 3 years. A fair unit is one requiring 3 to 5 years for manufacture and installation. A poor unit is one requiring more than 5 years for manufacture and installation.

22. Unit Rating

Most energy conversion processes have lower capital costs and higher efficiencies when manufactured in large ratings (MWe). Some depend heavily on large size to achieve desirable cost and performance, while others perform almost as well in small sizes and cost very little more. Conversion processes which can be offered only in large sizes are at a disadvantage for a number of reasons.

For example, small utilities often cannot consider adding a large unit because an outage in that unit would constitute loss of a significant part of the total system capacity. In large utilities, a similar kind of logic leads to the conclusion that larger units require greater system reserve capacity. Unit size is also related to financial risk during initial commercialization.

Thus, for the purpose of this criterion, an energy conversion process will be considered good if it can be manufactured in a rating less than 200 MWe, fair if the rating must be between 200 and 600 MWe, and poor if it must be larger than 600 MWe.

23. Byproducts

Byproducts of the energy conversion plant can be in the form of waste heat that can be sold, or in the form of material products such as sulfur or ash that could be used in concrete. The direct effect of such sales possibilities is to reduce the cost of electricity by reducing the effective fuel cost. There are also intangible benefits such as the improvement of the utility's public image. A good rating will be assigned to units which are designed to be integrated into an industrial or residential market for their waste heat and can also sell some or all of their solid waste; units will be considered fair if they sell waste heat or solid products but not both. A poor unit will have no potential market for heat or solids.

24. Environmental Intrusion

The present Environmental Protection Agency (EPA) standards for air pollution from stationary power plants are listed in Table 5-2 under New Source Performance Standard (NSPS). At the present time, there is no restriction on SO_x release from gas fueled plants. An estimate of possible future standards has been made by EPRI; this is also shown in the table.

By law a power plant is not allowed to operate if it exceeds the standard in any of the pollutant categories. Thus, for the purpose of this criterion, a power generation unit will be judged good if it meets the future standards in all categories, fair if it fails the future standards but passes the NSPS, and poor if it cannot meet the NSPS.

Table 5-2

ENVIRONMENTAL EMISSIONS STANDARDS

Pollutant	Fuel*	New Source Performance Standard (lb/MBtu)	Possible Future Standard (lb/MBtu)
SO _x	S	1.2 (as SO ₂)	0.4 (as SO ₂)
	L	0.8	0.4
	G	**	-
NO _x	S	0.7 (as NO ₂)	0.14 (as NO ₂)
	L	0.3	0.12
	G	0.2	0.06
Particles (Total)	SLG	0.1	0.05
Particles (Fine)	SLG	-	0.02

*S=solid, L=liquid, G=gaseous

**No limit specified in EPA-NSPS

This ranking does not properly distinguish between a plant which is high in one pollutant but low in all others and another plant which is moderately high in all pollutants. The former may be rated poor on the basis of its one high-level emission when it is actually less offensive than the latter, which dumps a moderate level of all pollutants and is rated fair. The Environmental Protection Agency has not found an acceptable way to make this difficult distinction; EPA has therefore been forced to apply the more restrictive interpretation of air pollution standards reflected in this criterion.

25. Availability of Fuel and Additives

The term "fuel and additives" here refers to resources consumed or converted in the energy conversion process, but not to those materials used in unit construction or in the working fluid inventory. Additives are those materials used in the processing and cleanup of fuels, stack gases, or waste. The significance of this criterion is that consumption of a resource for power generation makes the resource unavailable for other uses.

Resource availability in the future entails consideration of reserves, the rate of resource consumption by the energy conversion process being analyzed, and demand for the same resource for other power generation processes, for heating, and for chemical processes. Ultimately, political considerations may also affect future resource availability.

It is obviously very difficult to assess the relative importance of these factors. However, one could hazard a guess that over the next fifty years there will be some reduction in the availability of petroleum products and natural gas as power generation fuels, whereas other fuels are less likely to be restricted (e.g., coal because of large reserves, or uranium because of the potential for greater reserve utilization through the fast breeder reactor). Additives used in coal desulfurization, such as limestone and dolomite for fluidized beds, are not likely to be restricted and can be regenerated at somewhat greater cost. Therefore all petroleum or natural gas fired plants have been rated as fair, while good ratings have been assigned to coal and uranium fueled units.

26. Startup Power Requirements

This criterion is important to plant dispatching, reserve requirements, and planning for system emergencies. A good unit will require a starting power from the electrical grid of less than 5 percent of rated capacity. A fair unit will need a starting power between 5 and 25 percent of rated capacity, and a poor unit will require a starting power of more than 25 percent.

Section 6

NET PRESENT WORTH METHOD

The Net Present Worth Method is comprised of four distinct computational operations; these are:

- Generation Phase Diagrams
- Generation Expansion
- Impact of Intangibles
- Net Present Worth

Figure 6-1 illustrates the interaction of these operations, and describes the input data required at each stage of the calculation.

Figure 6-1. Net Present Worth Method

Generation Phase Diagrams are a screening technique used to separate those advanced cycle candidates which offer a clear economic advantage from those which do not. At this stage, it is also possible to identify the marginally competitive cycles which might prove to be winners under a slightly different economic future.

The input data for the phase diagrams calculation consists of a list of cycle candidates which will be allowed to compete in the marketplace. This list constitutes a guess as to which advanced cycles will be available at various times in the future and is referred to as a "scenario" in this study.

Cost and performance data are also specified for each advanced cycle in the scenario.

The cycles identified as winners or marginal winners in the Generation Phase Diagrams are carried into the next stage, Generation Expansion, which models the utility buy/no buy decision process to obtain estimates of the market penetration for each cycle alternative. This requires plant reliability and load following data as well as the scenario definition and cycle data used in the first stage. It is also necessary to define the utility system characteristics and load growth.

The Generation Expansion program includes a load dispatch model which simulates the operation of power plants installed in the system. An output of this model is the projected annual capacity factor of each plant.

Market penetration and capacity factors estimated in this way do not include any consideration of the intangible properties of advanced cycles. The Impact of Intangibles calculation accounts for this by modifying the Generation Expansion results in response to the cycle ratings against the 26 evaluation criteria listed in Section 5. The R&D cost estimate is also modified in response to the rating for probability of development success.

The last step is to combine all of the cost and performance data with the market penetration and capacity factor estimates and to project the costs and benefits which accrue to the United States as a result of pursuing each of the possible scenarios. The cost in this case is the R&D cost, and the benefit is the decrease in cost of electricity available because the advanced cycle scenario requires less capital investment and/or lower expenditures for fuel. The Net Present Worth of a particular scenario is its net saving as defined in Figure 6-1.

6.1 SCENARIOS

Three advanced cycles were selected by EPRI to be analyzed in Phase 3 of this study. These are listed in Table 6-1 along with four reference cycles which represent state of the art power generation technology.

Table 6-1
SCENARIOS — PHASE 3 CYCLES

NET PRESENT WORTH METHOD

CANDIDATE CYCLES	No New Technology Scenario (Reference)	Minimum Competition Scenarios			Crowded Market Scenario
		AFB/Steam	Combined Cycle	MHD	
Steam, Atmospheric Fluidized Bed, Coal		X			X
Gas Turbine (Water Cooled) Combined, LBtu Gasifier			X		X
Open Cycle MHD, Coal				X	X
Steam, Light Water Reactor, Uranium	X	X	X	X	X
Steam, Wet Lime Scrubber, Coal	X	X	X	X	X
Gas Turbine Combined, Oil/Semiclean Liquid	X	X	X	X	X
Gas Turbine, Oil/Semiclean Liquid	X	X	X	X	X

Five scenarios have been postulated. The No New Technology Scenario describes a future in which no advanced cycles will be available. This is a reference case; all of the savings in the Phase 3 comparisons are measured with respect to this scenario.

"Minimum Competition" describes three scenarios in which only one advanced cycle competes with the four conventional cycles for a market share. This represents the most favorable market situation for the advanced cycles, and it provides an upper limit on the estimate for market penetration.

The crowded market scenario is intended to model the opposite extreme in which the market shares are reduced because the advanced cycles compete with each other as well as with the conventional technologies. The crowded market does not model a "maximum competition" situation because only three advanced cycles are included in the Phase 3 analysis. However, the analysis does provide a good example of competition among the advanced cycles because the Phase 3 cycles were carefully selected for this purpose.

6.2 GENERATION PHASE DIAGRAMS

The Generation Expansion calculation described in the next section is complex, and it can become quite involved if a large number of cycles are analyzed. It is therefore advantageous to screen the advanced cycles before doing the expansion to limit the candidates to those which are likely to compete successfully.

Cycles are selected in the Generation Expansion in such a way as to minimize cost of electricity for the utility system. This involves considerations of unit reliability and outage rates as well as unit response to the variation in electrical load from hour to hour and day to day. However, the most strongly weighted consideration in the selection process is the unit cost of electricity. Thus, a traditional screening curve approach, which identifies cycles producing the lowest cost of electricity, can be quite useful in limiting the number of candidates.

Typical screening curves, shown in Figure 6-2, are a plot of a cost function vs. capacity factor. The function is used instead of cost of electricity to give straight lines on the plot instead of hyperbolas. This is a matter of convenience and is discussed in more detail in Appendix D. The 1975 curves in Figure 6-2 show that Cycle No. 1 has the lowest cost of electricity in the capacity factor range from 0-A*. While Cycle No. 2 is more economical

Figure 6-2. Screening Curves

*Expressed as a percentage of 8760 h/yr

between A and B, and Cycle No. 3 would be the lowest cost choice for capacity factors larger than B. Because capital costs and fuel costs generally inflate at different rates, it is expected that the intersection points of these curves would change with time. For instance, the intersections might have changed to A' and B' by 1980 as shown in Figure 6-2.

A Generation Phase Diagram summarizes these results for several years as shown in Figure 6-3. In 1975, the intersections A and B are plotted, then A' and B' are plotted in 1980, and so on for each year of the study period. These points form curves which define in each year and for each capacity factor the cycle candidate which has the lowest cost of electricity. Those candidates which do not appear in the diagram are more expensive than the successful candidates, and are not likely to be selected for installation in the Generation Expansion computation.

Figure 6-3. Generation Phase Diagram

A more detailed discussion of the Phase Diagram calculation and the input data is given in Appendix D.

6.3 GENERATION EXPANSION MODEL

The Net Present Worth of an Advanced Cycle is strongly affected by the cycle's acceptance by the utility industry. Utilities make the buy/no buy decisions which establish market penetration, and utilities also make the dispatch decisions which establish the capacity factor of a unit after it is installed.

A computer code entitled "Optimized Generation Planning" (OGP) was developed at General Electric and has been used for several years to assist utility customers in planning system additions. It embodies both the buy/no buy decision logic as well as the unit dispatch logic, and is the program used in this study to provide the market penetration and capacity factor estimates required for the Net Present Worth Calculation.

The program input data consists primarily of a description of the existing utility system and a "shopping list" of power plants which can be added in the future. In each year, the program adds units to provide for load growth, retirements, and a reserve margin. The additions are selected from the shopping list in such a way that the total system costs (investment + production, levelized over 30 years) are minimized.

In each year of the study, the installed units are run through a production costing calculation which models the system response to an hour by hour load duration curve. Units are dispatched within the constraints of their load following capability, and spinning reserve is maintained at a level adequate to cover the loss of the largest unit on the system at any time.

The starting date for the expansions performed in this study is 1986. A description of the utility system in 1985 has been obtained from a recent study performed by Power Technologies Incorporated (PTI)* for EPRI. The PTI study describes six typical utility systems which represent the spectrum found in the United States (Table 6-2). To make the present work truly representative of the national impact of advanced cycles, it would be necessary to perform expansions in each of the six regions and then average the results. However, this is beyond the intent of the present study, which is to develop the comparison methodology and present an example of its application. Utility System D has been chosen for this purpose because it is representative of a large number of systems in the United States.

Some difficulties were encountered in using System D because it is quite large, and during the expansion it exceeded the number of units which can currently be handled by the OGP program. To get around this problem, the system was split in half as shown in Table 6-3.

*Synthetic Electric Utility Systems for Evaluating Advanced Technologies, EPRI Report No. EM-285, Power Technologies Inc., Schenectady, N.Y., February 1977.

Table 6-2
SUMMARY OF SYNTHETIC UTILITY SYSTEM
CHARACTERISTICS IN 1985

SYSTEM	GENERATION (MW)	LOAD (MW)	TRANSMISSION (MJ)	COMMENTS
A	53,500	44,000	15,500	Summer Peaking - Mid-range 345, 230, 138 kV network - some 500 and 765 kV - coal, nuclear
B	46,000	38,000	21,000	Winter Peaking; High Summer Peaks - Dispersed 500, 230 kV network - some 345 and 138 kV - hydro, oil, coal
C	22,000	16,500	13,500	Summer Peaking - Highly dispersed 345, 230, 138 kV net- work - coal, nuclear
D	32,000	26,000	5,000	Summer Peaking - Concen- trated 500, 230 kV network - some 138 kV - oil, coal, nuclear
E	45,500	37,000	12,500	Summer Peaking - Mid-range 345, 138 kV network - some 500 and 230 kV - gas, coal, nuclear
F	32,000	26,000	13,000	Summer Peaking; High Winter Peaks - Mid-range 500, 230, 138 k network - oil, nuclear

From Study by Power Technologies, Inc.
(EPRI Report EM-785, Project TPS-615, February, 1977)

The Electrical peak demand in 1985 is 13,124 MW for this system with a 5.6% growth rate as specified by EPRI. The hour by hour variation of demand has been taken from the PTI Study for System D; the approximate annual load factor for these curves is 59%.

Table 6-4 lists some of the other input data used in the generation expansion. The cycle candidates are described in detail in Section 4 and Appendixes B and C. The fuel cost and inflation data are those specified by EPRI for the Phase 3 comparisons which are described in Section 3.

A more detailed description of the OGP program is given in Appendix D along with a complete listing of the input data.

Table 6-3
UTILITY MODEL (1985)

Synthetic Utility System D in 1985 - Split *		
Type	Unit Rating	Number of Units
Steam, Nuclear	1200	3
	800	1
Steam, Coal	800	1
	600	3
	400	3
	200	12
Steam, Oil	800	1
	600	2
	400	1
	200	7
Gas Turbine, Oil	50	48
		82 Units (16,800 MW)
Demand: 13124 MW in 1985		
5.6% Annual Growth Rate		
Load shape and duration data as specified for region D**		

*See Appendix D for discussion of split system

**Synthetic Electric Utility Systems for Evaluating Advanced Technologies," Power Technologies Inc., Schenectady, N.Y., EPRI Rept. #EM-285, Feb. 1977.

Table 6-4
GENERATION EXPANSION-INPUT DATA*

CYCLES: STAFB—Steam (3500 P/1000 F/1000 F), AFB, Coal	
GTWCCE—Gas Turbine, (Water Cooled) Combined, Low Btu Gasifier, Coal	
OCMHD—Open Cycle MHD, Coal	
STSCRB—Steam, Scrubbers, Coal	
GTCC—Conventional Gas Turbine, Combined, Oil/SCL	
GT—Conventional Gas Turbine, Oil/SCL	
STLWR—Steam, Light Water Reactor, Uranium	
SCENARIOS: No New Technology, Minimum Competition, Crowded Market	
Power Plant Life: 30 years	
Inflation Rates	
Capital Costs	6.5%
O&M Costs	6.5%
Fuel Costs	Specified in Section 3 for Phase 3
Discount Rate	10%
Fixed Charge Rate	18%
Levelization Period	30 Years
System Reserve Goal	20%

*Full listing of input data is given in Appendix D.2.

6.4 IMPACT OF INTANGIBLES

All of the 26 evaluation criteria have intangible effects. Of these 26 evaluation criteria, 3 affect the R&D phase of a new cycle, while the other 23 affect its commercial application. Intangible effects of the latter 23 are treated in both the Direct Weighting Method and the Present Worth Method by estimating impact upon market penetration. However, there are significant differences in how market penetration is estimated in the two methods.

In the absence of intangible effects, utilities would make generation installation decisions purely on the basis of optimal dispatching, as reflected in the Optimized Generation Planning Program (OGP). However, utility decision makers subjectively modify results from programs such as OGP in order to incorporate "intangible" effects not present in the programs. In the Present Worth Method, this is modeled by

$$f_k = c_f f_{Ok} f_{Mk} \quad (6-1)$$

where

$$\begin{aligned} f_k &= \text{market penetration for cycle } k \\ f_{Ok} &= \text{market penetration for cycle } k, \text{ as determined by OGP} \\ f_{Mk} &= \text{multiplier for intangible effects of cycle } k \\ c_f &= \text{normalizing factor} \end{aligned}$$

The Present Worth method uses the following expressions for f_{Mk} and c_f in Equation 6-1:

$$f_{Mk} = \sqrt{\text{MIN}(p_{ik}) \cdot \prod p_{ik}} \quad (6-2)$$

$$c_f = 1 / \sum_k f_{Ok} f_{Mk} \quad (6-3)$$

where p_{ik} is the market penetration multiplier for cycle k when evaluation criterion i is fair or poor, while all other evaluation criteria are good. Equation 6-2 for f_{Mk} is based upon Equation D-5 of Appendix D.3, and Equation 6-3 for c_f is based upon Equation D-12 of that appendix.

Two items are noteworthy about Equation 6.2 for f_{Mk} . First, f_{Mk} is a multiplicative function of the p_{ik} , not additive. Second, the functional form implicitly reflects correlation between the evaluation criteria, with an assumed average pairwise correlation coefficient of $\rho=1/4$. The rationale for selecting this functional form for f_{Mk} is explained in Appendix D.3.

Also explained in Appendix D.3 is the rationale for choosing numerical values for the p_{ik} when evaluation criterion i of cycle k is rated good, fair, or poor respectively. The resulting numerical values are listed in Table D-18.

6.5 NET PRESENT WORTH MODEL

The present worth method estimates, for each new power generating cycle considered, the present worth of undertaking R&D upon that cycle. It is a cost-benefit analysis in which all the "intangible" evaluation criteria of Section 5 have been translated to dollar equivalents. A cycle has positive net present worth if the present worth of its savings (compared to installing competing cycles representing current technology) exceeds the present-worth of the costs of its R&D program:

$$\begin{aligned}W_{\text{net}} &= W_{\text{benefits}} - W_{\text{costs}} \\&= W_{\text{savings}} - W_{\text{R\&D}}\end{aligned}$$

(The present-worths of R&D costs and savings are positive by definition.)

Appendix D.4 describes the present-worth method in detail. The basic cost-benefit justifications of this evaluation procedure are presented in the Introduction of Appendix D.4.

- The present worth method is applied to the costs and benefits of the entire United States society, not just the electric utility industry.
- Distributional changes within the United States society are not considered; the only criterion is that there be a net gain for the society as a whole.
- All externalities (e.g., effects of strip mining to produce fuel) are assumed to be internalized into costs.
- All interactions of new cycles with the economy (e.g., increased demand for electric energy if a new cycle produces savings) have been omitted from the analysis or assumed to be incorporated into costs.

The present worth model will now be explained in summary. Define two times, as shown in Figure 6-4:

T_1 = time from 1975 until first installation of a new cycle

T_2 = time from 1975 until last installation of a new cycle

Assume that the R&D program for a new cycle ceases at the time of its first installation, and that the R&D costs occur at a constant rate. Then, as shown in Figure 6-5, there will be a constant negative cash flow to society from now until T_1 . (The many assumptions which underlie this model are discussed in Appendix D.4.)

Figure 6-6 shows that the first year's installations of the new cycle will produce a constant positive cash flow to society over the lifetime of the units installed in the first year (lifetime = L). Figure 6-7 shows that the units installed at T_2 , the last units installed, will

Figure 6-4. Definition of Time Scale for New Cycle R&D and Commercial Application

Figure 6-5. Assumed R&D Spending Schedule for New Cycle

Figure 6-6. Savings from First Year's Installations of New Cycle

Figure 6-7. Savings from Last Year's Installations of New Cycle

also produce a constant positive cash flow over their lifetime—from T_2 until $T_2 + L$. The units installed at T_2 produce a larger yearly cash flow than those installed at T_1 because of growth in demand for electric energy; more units are installed at T_2 than at T_1 . Figure 6-8 shows a hypothesized growth in total installed capacity, which corresponds to a growth in yearly installations (including also replacement of retired units).

Figure 6-8. Projected Increase of Total Installed Capacity during Period of New Cycle Application

However, no new cycle is likely to capture all of the market for installations in any year: a cycle suitable for base load may be poor for peaking; and there are a number of factors such as siting flexibility, load-following capability, and minimum load which could limit the market penetration of a cycle. The Optimal Generation Planning (OGP) computer program determines the market penetration for each cycle in each year of a given scenario of

competing cycles. This penetration from OGP is then adjusted for intangibles, as explained in Section 6.4. Hence, a modification of Figure 6-8 was made in which the new cycle is shown as being applied to some fraction of the total additions each year (Figure 6-9).

Figure 6-9. Market Capture Fraction of New Cycle

Figure 6-10 shows the cash flow when all of the preceding figures are taken into account. First, from the present until T_1 , appears the constant negative cash flow of the R&D program. (For simplicity another possible negative cash flow for manufacturing facilities is not considered.) Then come the positive cash flows from the savings if the new cycle is installed instead of current technology. These annual cash flows may rise nonlinearly from T_1

Figure 6-10. Total Savings Achieved By Application of New Cycle, Accounting for Total Capacity Growth and Market Capture Fraction

to T_2 ; the curve could increase more than linearly because the rate of installations is increasing. After T_2 and until $T_2 + L$ there is still some positive cash flow, even though no more units are being installed, because units still in operation are producing savings.

Figure 6-11 shows the effect of discounting these cash flows to present-worth. Savings far in the future have less present worth than do savings in the relatively near future.

Figure 6-11. Discounting of R&D Costs and Future Savings to Present-Worth

The present worth model which has been developed is a mathematical representation of Figure 6-11. It is a function of seven parameters of the new cycles, as represented in Figure 6-12. The actual expression for W is quite complex, and is detailed by a sequence of equations in Appendix D.4.

$$W = W(C_{R\&D}, C_{CAP}, C_{O\&M}, C_{FUEL}, f, F, T_1)$$

$C_{R\&D}$ = Cost of R&D Programs
 C_{CAP} = Capital Cost of New Cycles
 $C_{O\&M}$ = Operating & Maintenance Cost of New Cycles
 C_{FUEL} = Fuel Cost for New Cycles
 f = Fraction of Installations to which New Cycles are applied
 F = Average Capacity Factor
 T_1 = Date of First Installation

Figure 6-12. Present Worth Model

Section 7

DIRECT WEIGHTING METHOD

RANKING APPROACH

Section 5, "Evaluation Criteria," defined 26 criteria regarding the intangible aspects of the energy conversion processes; that is, to aspects that are not measured directly in the cost of electricity. Also a basis was given for rating each energy conversion process as either good, fair, or poor with respect to each criterion. In this section a method will be described for establishing relative weights for each criterion, and a procedure will be developed for producing an overall figure of merit for each process.

Table 7-1 gives an example of the results of applying the method. The first column is a listing of the evaluation criteria. The next two columns give the good, fair, or poor ratings with the corresponding numerical values, based on good = 10, fair = 5, and poor = 1. These numerical values were chosen to accentuate the differences among the unit ratings. Next, corresponding to each criterion is a weight established by the procedure that will be described in the following paragraphs. The last column contains the products of numerical values and weights for each of the evaluation criteria. The total is 573 out of a possible total of 1000.

DETERMINATION OF CRITERIA WEIGHTS

Any weighting of intangible criteria must ultimately be based upon the subjective judgment of some person or group of persons. It is desirable, however, to establish a logical basis for judgment, and in this case the basis is a simplified version of the "Net Present Worth Method," described in Section 6. The net present worth (cost benefit) of an advanced process is a function of S (the savings in cost of electricity with respect to present-day processes), $C_{R\&D}$ (the cost of required research and development), f (the fraction of new capacity installed using the new process), and T_1 (the time from 1975 to operation of the first commercial plant using the new process). The saving, S , is held constant (at 1 mill/kWh) because this analysis is concerned only with those process attributes (intangibles) which do not directly affect cost of electricity. Under this constraint the net present worth depends only upon the parameters $C_{R\&D}$, T_1 , and f . Thus, the relative weights of the evaluation criteria can be selected by determining the extent to which each of the criteria affect the three parameters.

Table 7-1

MERIT RANKING FOR A PARTICULAR ENERGY CONVERSION PROCESS

Evaluation Criteria	Unit Rating		Criteria Weights	Product
	Good/Fair/ Poor	Numerical Values		
1. Cost of R&D Required	P	1	1	1
2. R&D Time Required	F	5	17	85
3. Prob. of Development Success	P	1	10	10
4. Plant Capital Cost	P	1	8	8
5. Plant O&M Requirements	F	5	1	5
6. Electrical Performance	F	5	5	25
7. Power Plant Efficiency	G	10	2	20
8. Capability for Load Change	P	1	3	3
9. Part Load Efficiency	F	5	1	5
10. Minimum Unit Load	F	5	1	5
11. Forced Outage Rate	P	1	4	4
12. Planned Outage Rate	F	5	3	15
13. Hardware Materials Availability	G	10	2	20
14. Industrial Capability of Manufacture	G	10	2	20
15. Plant Safety	G	10	3	30
16. Dependence on Other Systems	G	10	8	80
17. Adaptability to Fuels	G	10	6	60
18. Life	G	10	1	10
19. Flexibility of Siting	G	10	4	40
20. Waste Handling & Disposal	F	5	3	15
21. Plant Construction Time	P	1	2	2
22. Unit Rating	G	10	3	30
23. Byproducts	F	5	1	5
24. Environmental Intrusion	F	5	3	15
25. Availability of Fuels and Additives	G	10	5	50
26. Startup Power Requirements	G	10	<u>1</u>	<u>10</u>
			100	573

The equations used in the evaluation are listed below. These equations are derived in Appendix E, "Net Present Worth with Discrete Annual Payments," and are based on the assumption of discrete year-end payments, as is customary practice in electric utility economics. The numerical results are very close to the results using continuous compounding, as assumed in the derivations of Section 6, "Net Present Worth Method." (All symbols are defined in Appendices E and H.)

$$\text{Net Present Worth} = W_S - W_{R\&D}$$

where: $W_{R\&D}$ = present worth of R&D expenditures over time, T_1 (7-1)

W_S = present worth of savings from new process

$$W_{R\&D} = \frac{C_{R\&D}}{T_1} \left[\frac{(1+r)^{T_1} - 1}{r(1+r)^{T_1}} \right] \quad (7-2)$$

$$W_S = \frac{S}{(1+r)^{T_1}} \left[\frac{(1+r)^L - 1}{r(1+r)^L} \right] C_n \cdot P \cdot 8760 \cdot F \quad (7-3)$$

where: r = net annual discount rate

T_1 = time to first commercial application of new technology

F = capacity factor

S = savings, \$/MWh

L = life of each unit, years

$C_n = f C_o g (1+g)^{T_1} [1 + (1+g)^{-L}]$

g = annual growth rate of total generating capacity

C_o = 1975 total installed capacity, MW

f = fraction of new capacity installed using new technology

$$P = \frac{1}{r-g} \left[(1+r) - \frac{(1+g)^{(T_2-T_1)}}{(1+r)^{(T_2-T_1)-1}} \right]$$

T_2 = time to last installation using new technology

SENSITIVITY OF THE NET PRESENT WORTH

The first step in the calculation is to select values for the three parameters ($C_{R\&D}$, T_1 , and f) corresponding to good, fair, and poor ratings. For $C_{R\&D}$ and T_1 , these values were chosen to be consistent with the criteria definitions in Section 5. These values are presented below, along with values for f pertaining to base load, midrange, and peaking applications.

	$C_{R\&D}$ (M\$)	T_1 (Yr)	f		
			Base Load	Mid- range	Peak- ing
Poor Values	750	35	0.10	0.10	0.05
Fair Values	250	20	0.25	0.20	0.10
Good Values	050	10	0.50	0.30	0.20

One parameter at a time was varied from poor to good, while the others retained a fair value. Thus, the difference in the Net Present Worth acquired from the variation of a parameter is an indication of the sensitivity of the present worth to extreme variations of the parameter.

As noted previously, the savings (S) of all advanced processes is assumed to be 1.0 mill/kWh. Values of other fixed parameters are:

C_o	= 480,000 MW (1975 total installed capacity)
F	= 0.45 (average capacity factor)
r	= 0.03 (discount rate)
T_2	= 45 years (last year of installation)
g	= 0.0473 (annual growth rate - corresponds to doubling time of 15 years)

Table 7-2 gives sensitivities calculated for the base load case.

Table 7-2
SENSITIVITY OF NET PRESENT WORTH
BASE LOAD CASE

Parameter	Variations		Net Present Worth	
			M\$	Normalized
$C_{R\&D}$	Good Value	50 million	23652	1
	Poor Value	750 million	23131	
	Sensitivity		521	
T_1	Good Value	10 years	30289	34
	Poor Value	35 years	10439	
	Sensitivity		19850	
f	Good Value	0.50	46845	65
	Poor Value	0.10	09220	
	Sensitivity		37625	

When this calculation is repeated using the values of f selected for the peaking case, the absolute values of sensitivities for $C_{R\&D}$, T_1 , and f change in such proportion that the normalized values are very nearly the same (2, 35, 63). Accordingly, it is believed to be unnecessary to develop different criterion weights for the three operating modes.

The next step in establishing the criteria weights is to note that Criteria 1, 2, and 3 are primarily under the control of, and to be appraised by, the managers of the R&D program associated with each conversion process. These three criteria, therefore, have direct impact

and are measured by the parameters $C_{R\&D}$ and T_1 of the net present worth equation. The remaining criteria, 4 through 26, however, relate to the advanced process in its commercial form and to its acceptability to the utility industry. The factor f in the net present worth equation represents the acceptance of the new process by utilities and, thus, is a logical parameter for measuring the impact of Criteria 4 through 26.

This observation provides an approach to relating the parameters of the cost benefit equation to the evaluation criteria, as indicated in Table 7-3. At the bottom of this table is listed the normalized sensitivity of each parameter as developed above. The columns above these

Table 7-3
DERIVATION OF CRITERION WEIGHTS

EVALUATION CRITERIA	$C_{R\&D}$	T_1	f	RELATIVE WEIGHT (%)
	IMPACT FRACTIONS			
1. Cost of R&D Required	0.8			1
2. R&D Time Required		0.50		17
3. Probability of Development Success	0.2	0.30		10
4. Plant Capital Cost			0.12	8
5. Plant O&M Requirements			0.01	1
6. Electrical Performance			0.08	5
7. Power Plant Efficiency			0.03	2
8. Capability for Load Change			0.04	3
9. Part Load Efficiency			0.01	1
10. Minimum Load			0.01	1
11. Forced Outage Rate			0.07	4
12. Planned Outage Rate			0.05	3
13. Hardware Materials Availability		0.05	0.01	2
14. Industrial Capability of Manufacture		0.05	0.01	2
15. Plant Safety			0.05	3
16. Dependence on Other Systems		0.10	0.07	8
17. Adaptability to Fuels			0.10	6
18. Life			0.01	1
19. Flexibility of Siting			0.06	4
20. Waste Handling and Disposal			0.04	3
21. Plant Construction Time			0.03	2
22. Unit Rating			0.05	3
23. Byproducts			0.01	1
24. Environmental Intrusion			0.04	3
25. Availability of Fuels and Additives			0.08	5
26. Startup Power Requirements			0.02	1
Total Impact	1.00	1.00	1.00	100
Normalized Sensitivity for $C_{R\&D}$, T_1 , and f	1	34	65	100

figures indicate for each criterion the per-unit impact fraction to be applied to the parameter sensitivity. The derivation of these impact fractions is described below. The sum of the impact fractions in each of the columns is 1.0. This is necessary to preserve the relative sensitivities of $C_{R\&D}$, T_1 , and f . The relative criterion weights given are simply the sums of products of the impact fractions and the sensitivities of the three parameters, rounded and adjusted to total 100.

DETERMINATION OF IMPACT FRACTIONS

As noted earlier, subjective judgments must enter into the establishment of relative weights at some point. In the case of the evaluation criteria identified as affecting parameters $C_{R\&D}$ and T_1 , the impact fractions shown in Table 7-3 were chosen subjectively, without further elaboration. The impact fractions for Criteria 4 through 26 relating to parameter f could also have been determined subjectively at this point, but it was believed that a more objective judgment could be made by relating these criteria to a comprehensive list of basic utility objectives or needs. The following list of utility objectives has been developed from information provided by the EPRI Research Advisory Committee.*

- Maximum Service Reliability
- Flexibility in Meeting Load
- Minimum Cost to Customer
- Minimum Capital Requirements
- Minimum Environmental Impact
- Minimum Natural Resource Usage

While this list has been useful in defining the major categories of utility objectives, it is too general to suit the purpose of the present study. For example, "Flexibility in Meeting Load" includes more specific objectives, such as the requirement that the utility system have good operating characteristics; it also includes the longer range requirement for flexibility in planning additions of power plants to the system. "Minimum Environmental Impact" and "Minimum Natural Resource Usage" are not internalized objectives of the utility industry, but rather result from an intent to obey government regulations and maintain good public relations. The following expanded list of objectives was therefore drawn up:

- A. Low Transmission Costs
- B. Low Administrative Costs
- C. Low Utility System Production Cost
- D. Good Financial Position

*Future Trends in Electric Energy, EPRI SR-10, March 1975 (not available).

- E. Good Public Relations
- F. Good Government Relations
- G. Good Utility System Frequency
- H. Good Utility System Voltage
- I. Reliable Fuel Supply
- J. Predictable Fuel Costs
- K. Predictable Construction Schedule and Costs
- L. Independence of Action
- M. Flexibility of Operation
- N. High Service Reliability
- O. Minimum Reserve Requirements

These objectives are defined and discussed in more detail in Appendix H.

In Table 7-4 the objectives are shown as column headings; the horizontal rows are formed by the list of unit evaluation criteria. The impact of a particular criterion (e.g. Electrical Performance) on an objective (Low Transmission Costs) has been indicated by entering a number (in this case 0.50) at the row/column intersection. The objectives have been assigned weights (1,2,3) according to their importance, and the impact numbers in each column have been adjusted so that the column total equals this weight. The total impact of a criterion (e.g., Forced Outage Rate) is computed by summing the numbers along that row (2.10). In the last column of the table the total impacts have been normalized so that the impact of all the criteria together sums to 1.00; these normalized weights are the impact fractions listed previously in Table 7-3.

The assignment of impacts and utility objective weights in Table 7-4 involved subjective judgment. The logic used in making the impact choices is described in Appendix H, and is not discussed further in this section.

The utility objective weights were chosen by dividing the objectives into three groups, according to the effect upon the utility as a business if the objective is not achieved. This classification also includes judgment about how difficult it is for the utility to avert the potential threat by careful planning. The three groups are:

High Priority (Weight = 3.00) — The needs implied by these objectives are very important to the utility, and the utility cannot easily control the achievement of the objectives. "Good Public Relations" (objective E) is an example of something the utility cannot easily control; yet public opinion may severely limit the installation of nuclear power plants in the future, and may even force the shutdown of existing facilities.

Table 7-4
IMPACT FRACTIONS - PARAMETER f

Utility Objectives	A Low Transmission Costs	B Low Adminstrn. Costs	C Low Util. Sys. Production Costs	D Good Financial Position	E Good Public Relations	F Good Government Relations	G Good Util. System Frequency	H Good Util. System Voltage	I Reliable Fuel Supply	J Predictable Fuel Costs	K Predictable Const. Sched. & Costs	L Indep. Of Action	M Flexibility Of Operation	N High Service Reliability	O Minimum Reserve Requirement	Criteria Weighting	
																Total Impact	Normalized Impact Fraction
Evaluation Criteria																	
4. Plant Capital Cost				3.00		0.30					0.25	0.11				3.66	0.12
5. Plant O&M Requirements		0.07											0.07			0.14	0.01
6. Electrical Performance	0.50															2.40	0.08
7. Power Plant Efficiency					0.60	0.30	0.50	1.00				0.11	0.07	0.33		1.01	0.03
8. Capability for Load Change			0.22				0.50					0.11	0.07	0.33		1.23	0.04
9. Part Load Efficiency			0.22										0.07			0.29	0.01
10. Minimum Load			0.22									0.11	0.07			0.40	0.01
11. Forced Outage Rate		0.07	0.22			0.30	0.50					0.11	0.07	0.33		2.10	0.07
12. Planned Outage Rate		0.07	0.22			0.30						0.11	0.07		0.50	1.60	0.05
13. Hardware Materials Availability		0.07									0.25	0.11			0.50	0.43	0.01
14. Industrial Capability of Manufacture		0.07									0.25	0.11				0.43	0.01
15. Plant Safety		0.07			0.60	0.30					0.25	0.11	0.07			1.40	0.05
16. Dependence on Other Systems		0.07					0.50	1.00			0.25	0.11	0.07			2.00	0.07
17. Adaptability to Fuels		0.07	0.22			0.30			1.00	1.00		0.11	0.07	0.33		3.10	0.10
18. Life		0.07				0.30										0.37	0.01
19. Flexibility of Siting	0.50	0.07			0.60	0.30					0.25	0.11				1.83	0.06
20. Waste Handling & Disposal		0.07			0.60	0.30						0.11				1.08	0.04
21. Plant Construction Time		0.07									0.25	0.11			0.50	0.93	0.03
22. Unit Rating	0.50		0.22									0.11	0.07		0.50	1.40	0.05
23. By-products		0.07	0.22									0.11	0.07			0.47	0.01
24. Environmental Intrusion					0.60	0.30					0.25	0.11	0.07			1.33	0.04
25. Availability of Fuels & Additives		0.07							1.00	1.00		0.11	0.07	0.33		2.58	0.08
26. Startup Power Requirements	0.50		0.22													0.72	0.02
Utility Objective Weighting	2.00	1.00	2.00	3.00	3.00	3.00	2.00	2.00	2.00	2.00	2.00	2.00	1.00	2.00	2.00	31.00	1.00

Medium Priority (Weight = 2.00) — These are of two types. The first are those objectives where the implied threats are significant but can easily be averted by careful planning. For example, the utility must have fuel to operate; however, by diversifying the system fuel mix the utility can minimize effects of events such as the Arab oil embargo. Thus, Reliable Fuel Supply (objective I) has been assigned medium priority.

The second type of objective in this category involves activities which may not be easily controlled, but which pose only a moderate threat. For instance, Flexibility of Operation (objective M) includes interactions with other utilities and similar external contacts which are difficult to control; however, failure to achieve flexibility of operation may result in lower system efficiency, and the cost of this can usually be recovered through increased rates.

Low Priority (Weight = 1.00) — These objectives pose a moderate threat with easy controllability, or a small threat. Since administrative costs are generally a small proportion of total utility costs, objective B, Low Administrative Costs, is judged to fall in this category.

SUMMARY OF DIRECT-WEIGHTING METHOD

The final relative weights of the evaluation criteria, as shown in the last column of Table 7-3 and in Table 7-1, are based on the assumption that the criteria represent intangible qualities not measured in the cost of electricity. The weights were derived in part by determining the effect of certain criteria on the net present worth.

Using the assumption that an advanced conversion process can produce a nominal net saving in generation cost, the weightings indicate that the cost of the R&D program is relatively unimportant. The outstanding criterion is R&D Time Required, while Probability of Development Success, Plant Capital Cost, and Dependence on Other Systems are the most heavily weighted of the remaining criteria. Adaptability to Fuels, Electrical Performance, Availability of Fuels and Additives, Forced Outage Rate, and Flexibility of Siting rank next in importance.

Section 8

RESULTS AND EVALUATION

Capital Cost is plotted vs. overall efficiency for the Phase 1 cycles in Figure 8-1. In general, improvements in efficiency are purchased at higher capital cost reflecting the use of more complex systems integration and more expensive materials in the higher efficiency plants.

Figure 8-1. Phase 1 Cycles - Plant Capital Cost vs. Overall Efficiency

Figures 8-2 and 8-3 summarize the ranking of the Phase 1 cycles with respect to cost of electricity for the base load mode and peaking mode of operation. All of the cycles have been included in both figures, although some are clearly suitable for one mode and not for the other. For instance, the nuclear reactors cannot be operated in the peaking mode, but they

are listed in Figure 8-3 for completeness. A detailed breakdown of the cost of electricity for these cycles is listed in Appendix A.

Figure 8-2. Phase 1 Cycle Ranking by Cost of Electricity, Base Load Mode (capacity factor = 70%)

The results of the Direct Weighting Method are given in Appendix G for the Phase 1 cycles. These results are summarized here in Figures 8-4 and 8-5, where the Figures of Merit are plotted vs. Levelized Cost of Electricity for the base load and peaking modes.

Figure 8-3. Phase 1 Cycle Ranking by Cost of Electricity, Peaking Mode (capacity factor = 15%)

Figure 8-4. Phase 1 Cycles - Cost of Electricity vs. Figure of Merit for Base Load Mode

Figure 8-5. Phase 1 Cycles - Cost of Electricity vs. Figure of Merit for Peaking Mode

Generation Phase Diagrams were also computed for the Phase 1 cycles; these are presented in Appendix F.1. The results are summarized in Figure 8-6 for a crowded market type scenario in which all of the cycles were introduced into the market in the order of their date of first commercial service.

Figure 8-6. Generation Phase Diagram - Phase 1 Cycles

On the basis of these comparisons, four advanced cycles seem to be clearly superior, these are:

6. Advanced Open Cycle Gas Turbine (Air Cooled, 1477 K [2200 F]), Recuperative, Oil
7. Gas Turbine Combined Cycle (Air cooled, 1589 K [2400 F]), Low-Btu Gasifier, Coal
8. Gas Turbine Combined Cycle (Water Cooled, 1922 K [3000 F]), Low-Btu Gasifier, Coal
9. Gas Turbine Combined Cycle (Water Cooled, 1811K [2800 F]), Semiclean Liquid Derived from Coal.

Three other advanced cycles were identified as being near contenders:

1. Advanced Steam (24,130 kPa/811 K/922 K [3500 psi/1000 F/1200 F]), Atmospheric Fluidized Bed, Coal
5. Advanced Open Cycle Gas Turbine (Air Cooled, 1700 K [2600 F] , Recuperative, High-Btu Gas
18. Fuel Cell, Low Temperature, Hydrogen Derived from Coal

The conventional gas turbine burning high-Btu gas (Cycle 21) was found to be the best cycle for peaking duty, and the conventional steam plant with stack gas scrubbers (Cycle 20) seemed to be a good candidate for base load and midrange duty through the mid 1980s.

Cycles 8 and 1 (with 16,550 kPa [2400 psi] throttle) were selected by EPRI for conceptual design analysis in Phase 2 of this study. The results of this analysis are reported in Appendix B. The reference cycles were also re-evaluated, and two new reference cycles were added to give a more complete picture of state of the art power generation technology. These results are listed in Appendix B.4.

In Phase 3, three advanced cycles were selected by EPRI to be evaluated using the comparison methodologies developed in this study. As noted in Section 4, these cycles were chosen from among the concepts analyzed by General Electric in Phase 2 of this study and Task II of the Energy Conversion Alternatives Study (ECAS)*. The Phase 3 candidates are listed in Table 8-1 along with the four reference cycles evaluated in Phase 2.

Figure 8-7 presents a capital cost and overall efficiency summary for the Phase 3 cycles. The other ECAS Task II cycles have also been included for comparison.

Figures 8-8 and 8-9 list the cost of electricity breakdown for these cycles in the base load and peaking modes. As before, the inclusion of a cycle in the listing for a particular mode does not imply that that cycle is mechanically suited for that mode. The details of these comparisons are given in Appendixes B and C.

Figures of Merit are derived for the Phase 3 cycles in Appendix G; these are summarized in Figures 8-10 and 8-11. The ECAS Task II cycles have also been shown on these figures.

Figures 8-12 through 8-16 display the Phase 3 Generation Phase Diagram results presented in Appendix F.2. These figures are arranged according to the scenarios described in Section 6. The No New Technology Scenario is a reference case which represents a future without

*Energy Conversion Alternatives Study, General Electric Phase II Final Report, NASA Contract 3-19406, Corporate Research and Development, General Electric Company, Schenectady, N.Y., December 1976. See also summary in Appendix C below.

technological advances. The Minimum Competition Scenario's consider each advanced cycle as an independent competitor with state of the art cycles, and the Crowded Market Scenario shows the effect of competition among the advanced cycles.

Table 8-1
PHASE 3 CYCLES

Power Cycles	Date First Comm. Service	Fuel Cost (1975 \$) \$/MBtu	Plant Capital Cost (1975\$) \$/kW	Heat Rate at Full Load Btu/kWh	O&M Costs (1975\$)		Unit Rating MWe	Min. Load		Forced Outage Rate %	Planned Outage Rate %
					Fixed \$/kW-yr	Variable mills/kWh		(P min) (P Full)	(T min) (T Full)		
								%	%		
STAFB	1988	.94	447	9536	2.68	1.75	814	20	75	9	9
GTWCCE	1996	.94	474	7759	1.25	1.83	640	20	87	12	9
OCMHD	2003	.97	477	7068	1.37	1.50	1932	60	85	20	15
STSCRB	—	.94	591	10736	2.44	2.18	747	20	75	18	9
GTCC	—	1.85 Oil 3.50 SCL	282	8014	1.44	1.29	417	20	87	10	9
GT	—	1.85 Oil 3.50 SCL	116	11013	.53	1.37	76	30	70	12	4
STLWR	—	.52	776	10400	2.67	.68	1000	50	95	15	15

STAFB — Steam (3500 P/1000 F/1000 F), AFB, Coal

GTWCCE — Gas Turbine, (Water Cooled) Combined, Low BTu Gasifier, Coal

OCMHD — Open Cycle MHD, Coal

STSCRB — Steam, Scrubbers, Coal

GTCC — Conventional Gas Turbine, Combined, Oil/SCL

GT — Conventional Gas Turbine, Oil/SCL

STLWR — Steam, Light Water Reactor, Uranium

Figure 8-7. Phase 3 Cycles - Plant Capital Cost vs. Overall Efficiency

Figure 8-8. Phase 3 Cycles - Levelized Cost of Electricity
(base load mode, capacity factor: 70%)

Figure 8-9. Phase 3 Cycles - Levelized Cost of Electricity
(peaking mode capacity factor: 15%)

Figure 8-10. Direct Weighting Method (Phase 3 cycles)

Figure 8-11. Phase 3 Cycles — Cost of Electricity (Base Load) and Figure of Merit

Plant Type:
 STLWR — Steam, Light Water Reactor
 STSCRB — Steam, Conventional Furnace, Scrubber
 GTCC — Conventional Gas Turbine Combined Cycle
 GT — Conventional Gas Turbine
 STAFB — Steam, Atmospheric Fluidized Bed
 GTWCCE — Advanced Gas Turbine (Water Cooled) Combined Cycle, L8tu Gasifier
 OCMHD — Open Cycle MHD
 STPFB — Steam, Pressurized Fluidized Bed
 HEAFB — Closed Cycle Helium Gas Turbine, Organic Bottoming, AFB
 MVTFFB — Metal Vapor Topping Cycle, PFB
 GTWCCN — Advanced Gas Turbine (Water Cooled) Combined Cycle, Liquid Fuel
 GTACC — Advanced Gas Turbine (Air Cooled) Combined Cycle, L8tu Gasifier
 AFBHI — Advanced Steam (1200 F Reheat), AFB

Fuel Type:
 N — Uranium
 C — Coal
 O — Oil
 S — Semiclean Liquid Derived from Coal

Figure 8-12. Generation Phase Diagram — No New Technology Scenario — Phase 3 Cycles

Plant Type:
 STLWR — Steam, Light Water Reactor
 STSCRB — Steam, Conventional Furnace, Scrubber
 GTCC — Conventional Gas Turbine Combined Cycle
 GT — Conventional Gas Turbine
 STAFB — Steam, Atmospheric Fluidized Bed
 GTWCCE — Advanced Gas Turbine (Water Cooled) Combined Cycle, L8tu Gasifier
 OCMHD — Open Cycle MHD
 STPFB — Steam, Pressurized Fluidized Bed
 HEAFB — Closed Cycle Helium Gas Turbine, Organic Bottoming, AFB
 MVTFFB — Metal Vapor Topping Cycle, PFB
 GTWCCN — Advanced Gas Turbine (Water Cooled) Combined Cycle, Liquid Fuel
 GTACC — Advanced Gas Turbine (Air Cooled) Combined Cycle, L8tu Gasifier
 AFBHI — Advanced Steam (1200 F Reheat), AFB

Fuel Type:
 N — Uranium
 C — Coal
 O — Oil
 S — Semiclean Liquid Derived from Coal

Figure 8-13. Generation Phase Diagram — Minimum Competition Scenario — Steam, Atmospheric Fluidized Bed — Phase 3 Cycles

Plant Type:
 STLWR — Steam, Light Water Reactor
 STSCRB — Steam, Conventional Furnace, Scrubber
 GTCC — Conventional Gas Turbine Combined Cycle
 GT — Conventional Gas Turbine
 STAFB — Steam, Atmospheric Fluidized Bed
 GTWCCE — Advanced Gas Turbine (Water Cooled)
 Combined Cycle, LBTu Gasifier
 OCMHD — Open Cycle MHD
 STPFB — Steam, Pressurized Fluidized Bed
 HEAFB — Closed Cycle Helium Gas Turbine
 Organic Bottoming, AFB
 MVTFFB — Metal Vapor Topping Cycle, PFB
 GTWCEN — Advanced Gas Turbine (Water Cooled)
 Combined Cycle, Liquid Fuel
 GTACC — Advanced Gas Turbine (Air Cooled)
 Combined Cycle, LBTu Gasifier
 AFBH — Advanced Steam (1200 F Reheat), AFB

Fuel Type:
 N — Uranium
 C — Coal
 O — Oil
 S — Semiclean Liquid Derived from Coal

Figure 8-14. Generation Phase Diagram — Minimum Competition Scenario — Gas Turbine (Water Cooled) Combined Cycle, LBTu Gasifier — Phase 3 Cycles

Plant Type:
 STLWR — Steam, Light Water Reactor
 STSCRB — Steam, Conventional Furnace, Scrubber
 GTCC — Conventional Gas Turbine Combined Cycle
 GT — Conventional Gas Turbine
 STAFB — Steam, Atmospheric Fluidized Bed
 GTWCCE — Advanced Gas Turbine (Water Cooled)
 Combined Cycle, LBTu Gasifier
 OCMHD — Open Cycle MHD
 STPFB — Steam, Pressurized Fluidized Bed
 HEAFB — Closed Cycle Helium Gas Turbine
 Organic Bottoming, AFB
 MVTFFB — Metal Vapor Topping Cycle, PFB
 GTWCEN — Advanced Gas Turbine (Water Cooled)
 Combined Cycle, Liquid Fuel
 GTACC — Advanced Gas Turbine (Air Cooled)
 Combined Cycle, LBTu Gasifier
 AFBH — Advanced Steam (1200 F Reheat), AFB

Fuel Type:
 N — Uranium
 C — Coal
 O — Oil
 S — Semiclean Liquid Derived from Coal

Figure 8-15. Generation Phase Diagram — Minimum Competition Scenario — Open Cycle MHD — Phase 3 Cycles

Figure 8-16. Generation Phase Diagram — Crowded Market Scenario — Phase 3 Cycles

No New Technology (Figure 8-12) shows the Light Water Reactor to be the most economic choice over a wide range of capacity factors. The competitive range for the steam plant with scrubbers is probably larger than shown because the practical lower limit of capacity factor for the reactor is greater than 3000 h/yr.

If the steam plant with atmospheric fluidized bed furnace were introduced in 1986 (Figure 8-13), it would produce cheaper electricity than the steam/scrubber and would compete successfully with the nuclear plant in the midrange of capacity factors.

The gas turbine combined cycle (water cooled) with low-Btu gasifier would behave in much the same way (Figure 8-14), but it would also compete with the nuclear plant for base load operation. Open cycle MHD (Figure 8-15) could also compete successfully over a wide range of capacity factors; however, the low capacity factor range might not be available due to equipment limitations.

When the advanced cycles compete against each other (Figure 8-16), the open cycle MHD is preferred when it is available followed by the gas turbine combined cycle-low-Btu and the steam/AFB. Since the dates of first commercial service are staggered for these cycles, each enjoys a period of time in which it is better than the previous alternatives and has not yet been superseded by a better candidate.

It is tempting to infer market penetration from these results; however, this is dangerous because the generation phase diagrams only show competition on the basis of cost of electricity, whereas market penetration is determined by the cycle operating characteristics and intangibles as described in Section 6. Market penetration estimates based on the Generation Expansion calculation are presented in Appendix F.4 and are summarized in Figures 8-17 through 8-22.

Figure 8-17 shows the nuclear reactor taking a large market share in No New Technology with the remainder being divided between the steam/scrubber and gas turbine. A few combined cycles are added in the third period, but these plants do not compete well at other times. The large addition of gas turbine capacity in the third period occurs because many of the older gas turbines are retired in this period.

Figure 8-17. Generation Expansion — No New Technology Scenario — Phase 3 Cycles

The Crowded Market Scenario (Figure 8-18) shows nuclear plants purchased in the first period but none added thereafter. Steam/AFB dominates the market from 1988 to 1995, and then shares the market with the advanced gas turbine combined cycle. Open cycle MHD becomes available in 2003, but is not purchased until 2006 because of its large size and high forced outage rate. This is discussed further below. MHD also loses part of the potential market because of its poor cycling ability. The advanced combined cycle is purchased instead to fill the load following needs of the utility system.

Figure 8-19 shows the market behavior of the steam/AFB plant when it competes only with conventional technology. There is an initial surge of purchases when this plant becomes

Figure 8-18. Generation Expansion — Crowded Market Scenario — Phase 3 Cycles

available (1988) because the steam/AFB fills a need for load following capability in the existing system. Thereafter, this plant shares the market with the light water reactor.

Figure 8-19. Generation Expansion — Advanced Steam Atmospheric Fluidized Bed — Phase 3 Cycles

The advanced combined cycle also shows a surge of market acceptance in the period of its first commercial availability (Figure 8-20). However, unlike the steam/AFB it continues to dominate the market thereafter.

Open cycle MHD is not purchased until six years after its date of first commercial availability (Figure 8-21). This is similar to the delay noted previously in the crowded Market Scenario (Figure 8-18). The delay is caused by the large size (1932 MW) and high forced

Figure 8-20. Generation Expansion — Open Cycle Gas Turbine (Water Cooled) — Combined Cycle, LBTu Gasifier — Phase 3 Cycles

Figure 8-21. Generation Expansion — Open Cycle MHD — Phase 3 Cycles

outage rate (20%) used in this analysis. These factors combine to make this plant uneconomical on a system basis until the later years. If this plant could be built in a 1000 MW size for the same cost and with the same efficiency, it would be more acceptable to the utility. This is shown clearly in Figure 8-22 where the smaller plant is purchased immediately as it becomes available in 2003.

The Generation Expansion program includes a calculation which models the economic dispatch of the cycles in response to a simulated load which determines the capacity factors. These results are listed in detail in Appendix F.4; a summary is given here in Table 8-2. The nuclear and MHD plants are generally run close to their availability limits in all scenarios, which is consistent with their having the lowest dispatch costs of all the cycles considered.

Figure 8-22. Generation Expansion — Effect of Unit Size — Phase 3 Cycles

Table 8-2

PHASE 3 CYCLES
GENERATION EXPANSION
Approximate Capacity Factors (%)

CYCLES	NO NEW TECHNOLOGY	SCENARIOS			CROWDED MARKET
		STAFB	GTWCCE	OCMHD	
STLWR-N	71→60*	73	70→72	71→51	72
STSCRB-C	30→24		30→16	30→16	
GT-O	6→0	4→0	6→0	7→1	4→0
GT-S	2	1	1	1→3	1
GTCC-S	12→14	2	5	9	
STAFB-C		48→44			49→21
GTWCCE-C			52→62		76→60
OCMHD-C				68→63	68

*Arrows Indicate Change With Time (Earlier→Later)
Single Number Indicates No Change With Time
No Entry Indicates That Cycle Type Was Not Installed

As discussed in Section 6, the next steps in the Net Present Worth Method are to modify these market penetration and capacity factor results to account for intangibles, and extrapolate them to a national scale to compute the Net Present Worth of pursuing a particular scenario. Note that in this study the "Nation" is modeled using Synthetic Utility System D. The limitations of this approach are discussed in Section 6.3 and Appendix D.

Table 8-3 gives an example of the effect of intangibles on market penetration in the STAFB Minimum Competition Scenario. The left hand column shows the penetrations determined by OGP (see Figure 8-19). When these penetrations are adjusted for the impact of intangibles, the nuclear reactor (STLWR), because of its high capital cost, waste disposal and siting problems, loses part of its market share to the steam AFB (STAFB) plant. The semiclean liquid fuel specified for this study had a high nitrogen content making the NO_x emissions from the conventional gas turbine (GT/SCL) exceed the New Source Performance Standards. Thus GT/SCL was rated poor with respect to criterion 24 (Environmental Intrusion) and lost part of its market share to STAFB.

Table 8-3

IMPACT OF INTANGIBLES ON MARKET PENETRATION
(STAFB Minimum Competition Scenario)

	MARKET PENETRATION IN YEAR 2000	
	FROM OGP	AFTER ADJUSTMENT FOR INTANGIBLES
STAFB	0.49	0.55
STLWR	0.44	0.40
GT/SCL	0.07	0.05
	<u>1.00</u>	<u>1.00</u>

Table 8-4 shows the results of the Net Present Worth calculation for two scenarios. The total cost of meeting the future electrical energy demand (1985 to 2054) if the No New Technology scenario is followed is 3594B\$.* To accomplish the same task using the crowded market scenario would cost 3397B\$. Thus, the saving, or the Net Present Worth of pursuing the Crowded Market Scenario is 197B\$. This conclusion is also listed in Table 8-5 along with the present worths of the other scenarios.

Table 8-4

NET PRESENT WORTH RESULTS
(1975 Present Worth)

Cost	No New Technology Scenario B\$	Crowded Market Scenario B\$
Capital	1730	1124
Fixed O&M	115	71
Variable O&M	142	318
Fuel	1607	1882
R&D	—	<u>2</u>
Total	3594	3397

Net Present Worth
of Crowded Market = 197 B\$
Scenario

Note that the saving for the Steam/AFB Minimum Competition Scenario is negative, that is, the scenario costs more than No New Technology. This is not an error; it reflects the difference in point of view between the utility industry and the nation as a whole. Utilities

*Present worth 1975.

Table 8-5

**NET PRESENT WORTH RESULTS
NATIONAL VIEWPOINT***

SCENARIO	PRESENT WORTH OF COSTS B\$	SAVING B\$
No New Technology	3594	
Minimum Competition		
STAFB	3602	-8
GTWCCE	3422	172
OCMHD	3458	136
Crowded Market	3397	197

*Base Case: Includes Impact of Intangibles, Excludes Taxes

will select power plant additions in such a way as to minimize their total costs which include tax payments as reflected in a fixed charge rate of 18%. However, from the national point of view, taxes are not a real cost since they represent payments from one part of society to another. The effective fixed charge rate for a national cost benefit analysis is about 11%, which accounts for return on investment and depreciation, but excludes taxes.

The results in Table 8-5 are costs as perceived by the nation, using the lower fixed charge rate. If these costs were computed by the utilities, they would be larger, as shown in Table 8-6, due to the greater apparent cost of capital to the utilities.

Table 8-6

**NET PRESENT WORTH RESULTS
UTILITY VIEWPOINT***

SCENARIO	PRESENT WORTH OF COSTS B\$	SAVING B\$
No New Technology	4788	
Minimum Competition		
STAFB	4504	284
GTWCCE	4251	537
OCMHD	4438	350
Crowded Market	4172	616

*Includes Impact of Intangibles, Includes Taxes

Thus, from the utility point of view, the steam/AFB plants have been used to good advantage in the first Minimum Competition Scenario because they allow the utility to meet the future demand at lower cost than the No New Technology Scenario. This is consistent with using an 18% fixed charge rate in performing the Generation Expansion to determine market penetration. However, Table 8-5 shows that these choices are not optimal from a national point of

view. If the expansion had been performed using an 11% fixed charge rate, the savings in Table 8-5 would all be positive. However, this was not judged to be an appropriate way to proceed since the utilities are in fact the real purchasing agents, and they must make decisions on the basis of costs as they perceive them. This is discussed in more detail in Appendix F.6.

Table 8-7 gives a summary of the ratings for the Phase 3 cycles with respect to the three evaluation techniques developed in this study:

- Levelized Cost of Electricity
- Direct Weighting Method
- Net Present Worth Method

Table 8-7

SUMMARY OF RATINGS — PHASE 3 CYCLES

Power Cycles	Levelized Cost of Electricity* mills (1975\$) kWh	Figure of Merit (max = 1000)	Minimum Competition Scenario 1975 Net Present Worth B\$
Steam, Atmospheric Fluid- ized Bed, Coal	38.7	815	-8
Gas Turbine (Water Cooled) Combined Cycle, LBtu Gas- ifier, Coal	35.2	704	172
Open Cycle MHD, Coal	33.7	461	136
Steam, LWR, Uranium	38.8	703	NA
Steam, Conventional Furnace, Scrubber, Coal	46.5	736	NA
Net Present Worth (Crowded Market) = 197 B\$			

*At 70% Capacity Factor

Although the Phase 3 comparisons do not include a large number of advanced cycles, it is still possible to draw some general conclusions; these conclusions are:

1. R&D costs are insignificant in comparison to potential savings which can be realized from implementing most of the advanced cycles.
2. Although one cycle may appear to be the big winner, there will always be some combination of cycles which yields a larger cost benefit.
3. The most important intangible factor is R&D time because the benefits of an advanced cycle become less important as the date of first commercial service is postponed.
4. In order to make optimum use of some technologies from the National viewpoint it may be necessary to change the economic circumstances under which the Utilities select their generation additions.

Since the major thrust of this study was to develop evaluation techniques, a final note is included here about the uses and misuses of these techniques.

Levelized Cost of Electricity/Figure of Merit

These numbers should be used together in plots similar to Figures 8-4, 8-5, and 8-11 because they summarize the two sides of the utility selection process; that is, cost and efficiency vs. intangibles. Levelized Cost of Electricity gives an average cost for the energy produced over a plant lifetime, whereas Figure of Merit summarizes the rating of the plant with respect to load following ability, probability of development success, etc. It would be a mistake to judge a cycle without considering both measures of its desirability.

These two indices cannot provide a definitive answer as to which cycles are better, but they can be useful in screening out the big winners and big losers.

Perhaps the most important function of these methods is to organize the argument by providing a clear and unambiguous framework in which to catalog a candidate cycle's desirable and undesirable attributes.

Net Present Worth Method

This method answers the question: "Is the advanced cycle cost effective in the long term?" For instance, it is possible to make clear distinctions among alternatives like the steam/AFB which have short R&D programs but only moderately high efficiencies and those like MHD which have high efficiency but lengthy R&D.

The method helps in understanding the effect of intangibles (as expressed in the 26 evaluation criteria) on the market penetration.

Finally, if a cycle does not do well in the Net Present Worth comparison, it is possible to go back to the Cost of Electricity and Figure of Merit evaluations to pinpoint the areas in which the cycle must be improved to become competitive.