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HTGR Market Assessment
Interim Report

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Gas-Cooled Reactor Associates

September 1979

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Acknowledgments

GCRA would like to acknowledge the following utility personnel whose diligent labors resulted in the timely execution of the HTGR Market Assessment - Interim Report: S. P. Harnden of Arizona Public Service Company, J. A. Hynds of Public Service Electric and Gas Company, and E. F. Sproat III of Philadelphia Electric Company. GCRA also wishes to express its appreciation to O. Gildersleeve of the Electric Power Research Institute for lending valuable insight to the early efforts of this study.

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1.0 Introduction

Previous HTGR market studies have identified the potential benefits of the HTGR for electric power generation and concluded that there is a potential market large enough to justify the commercialization of the HTGR. These studies did not, however, include a direct utility evaluation of the value of the HTGR benefits or assess the ability of the HTGR to fit into a utility's projected generation mix. Accordingly, the purpose of this Assessment is to establish the utility perspective on the market potential of the HTGR. The majority of issues and conclusions in this report are applicable to both the HTGR-Gas Turbine (GT) and the HTGR-Steam Cycle (SC). This phase of the HTGR Market Assessment used the HTGR-GT as the reference design as it is the present focus of the U.S. HTGR Program. A brief system description of the HTGR-GT is included in Appendix A.

1.1 Utility Background in the HTGR Program

HTGR development in the U.S. has a 25-year history of utility interest and involvement. Various utility groups have been organized and have supported the HTGR Program. Most notable of these groups was the High Temperature Reactor Development Associates (HTRDA), which was organized in 1958 by 53 utilities to sponsor the design and construction of the 40 MWe Peach Bottom prototype HTGR. Direct utility involvement in the HTGR-GT Program began in 1971 with guidance provided through the Utility Steering Committee. Through such groups, the utilities have contributed over $150 million to the HTGR Program, including design, development and plant capital costs.

During the 1971-1974 time period, 5 utilities placed commercial orders for HTGR-Steam Cycle twin-unit plants with General Atomic Company. However, due to reduced growth projections, utility financing difficulties, and inordinate commercial risk, these orders and the commercial option for the HTGR-SC were withdrawn during 1975. The timeframe 1976-1977 was a period of critical re-evaluation of gas-cooled reactor technology. A number of technical and commercial assessments of gas-cooled reactors were performed. A particularly important study was one performed by Arthur D. Little, Inc. (Ref. 1) for the Energy Research and Development Administration (ERDA), now the Department of Energy. The A. D. Little study evaluated the economic and technological feasibility of gas-cooled reactors and generally concluded that the development of this reactor type should be continued through commercialization because of the potential realization of large economic, conservation, safety, and environmental benefits relative to alternative nuclear and coal fired power plants.

The culmination of all of these studies was an ERDA funded commercialization study conducted by RAMCO (Ref. 2), with substantial inputs by government, industry and the utilities. The significant conclusions of the study were: (1) the user industry must provide leadership and overall program coordination; (2) the industrial base must be broadened to assure a stable and competitive supply industry; and (3) any HTGR program must be adopted as part of the National Energy Plan and hence, receive stable and affirmative government support.

Representatives of 30 utilities met with ERDA in August 1977 to discuss the future of thermal gas-cooled reactor technology. The outgrowth of this and further meetings was the incorporation of Gas-Cooled Reactor Associates (GCRA) in February 1978. Through GCRA, the electric utility industry acknowledges its interest in having the HTGR as an advanced power system alternative.

Beginning in May 1979, GCRA initiated its first formal attempts to broaden utility participation in the HTGR Program. Through these efforts, utility support of and participation in GCRA have grown to represent approximately 20% of the U.S. generating capacity. The utilities currently involved in GCRA are given on Table 1.1-1.

The GCRA utilities have a substantial investment and extensive experience with LWRs. GCRA participants represent approximately 25% of the installed nuclear capacity and approximately 35% of the nuclear capacity under construction. This provides a most credible comparative base for assessing the evaluated and perceived benefits of the HTGR.

1.2 Study Approach

This initial report provides the proposed structure for conducting the HTGR Market Assessment plus preliminary analyses to establish the magnitude and nature of key factors that affect the HTGR market. Section 2 discusses the HTGR market factors and their relationship to the present HTGR Program. This report discusses two of these factors in depth: economics and water availability. The other factors identified in Section 2 will be further examined in subsequent phases of this Assessment.

Section 3 discusses the water availability situation in the U.S. and its impact on the potential HTGR market. Section 4 describes the approach for applying the HTGR within a framework of utility systems analyses. Section 5 provides preliminary results of these systems analyses for selected regions and, by performing sensitivity analyses, investigates the major variables that affect the HTGR's applicability to the utility's generation plan. Specific proposed actions for the next phase of this Assessment are given in Section 6.

GCRA will use this initial report both with the GCRA utilities and with non-member utilities to solicit their active participation in the subsequent phases of this Assessment.

Table 1.1-1

Utilities Participating in GCRA

September 1979

Arizona Public Service Company
City of Tacoma
Colorado UTE Electric Association, Inc.
Delmarva Power & Light Company
Florida Power & Light Company
Gulf States Utilities
Idaho Power Company
Long Island Lighting Company (ESEERCO)*
Northeast Utilities Service Company
Pacific Gas & Electric Company
Pacific Power & Light Company
Philadelphia Electric Company
Public Service Company of Colorado
Public Service Company of New Mexico
Public Service Electric & Gas Company
Puget Sound Power & Light Company
Salt River Project
San Diego Gas & Electric Company
Tennessee Valley Authority
Yankee Atomic Electric Company

*Empire State Electric Energy Research Corporation

2.0 HTGR Market Factors

The factors affecting the market for HTGRs are varied and complex. Further, they are overshadowed by the question of the political viability of the nuclear option in the future. It is beyond the scope of this document to examine this latter issue, and therefore it is assumed that the current political uncertainties of the nuclear power market will have been favorably resolved in the timeframe examined by this study. It is not reasonable at this point in time to assume that the HTGR would survive or cause a reversal of an adverse political decision on the future of the nuclear option.

The market factors discussed herein are those which have been identified as having the greatest potential impact on the HTGR's introduction to the commercial market. Phase I of this Assessment will examine two of these factors in detail. The remainder will be further examined in subsequent phases.

2.1 Generic Market Factors

When a utility makes a decision to purchase a particular type of generation facility, it considers several generic factors regardless of the type of generation being considered and evaluates the alternative choices with regard to these factors. The generic market factors that affect a utility's decision to make a particular capital expenditure are discussed below with reference to the HTGR:

- Demand Forecast - The projected growth rates for the electric utility industry have steadily decreased during recent years due to the general decline in economic and population growth rates. Published electric load growth rates through the end of the century indicate the general trend of 5-6% in the near term decreasing to 2-4% by the end of the century. Extrapolating far beyond the year 2000 would be haphazard at best and of little significance to the utility system planner. However, during the decade of 1995-2005 in which the HTGR-GT is projected for commercial market entry, the load growth rates are reasonably projected to be in the 2-4% range.

  Lower growth rates will have a twofold effect on the utility market. First, new units ordered will tend to be of smaller size in order to limit unnecessarily high reserve margins and to minimize capital investment requirements. The expected trend toward smaller baseload additions has been considered in adopting 800 MWe as the nominal rating of the HTGR-GT reference design. The economic effects of deploying smaller baseload units on utility system total power costs are briefly addressed in Section 5.0. Second, the lower growth rates will decrease the demand for new capacity. The effects that a diminishing demand for all types of generation will have on the introduction of the HTGR is not clear. However, assuming that nuclear power will expand as a major energy contributor beyond the year 2000, current DOE estimates project a cumulative nuclear capacity in the range of 615 to 910 GWe by the year 2025. This represents approximately 290 to 515 GWe of nuclear additions during the time period of 2000 to 2025. The percentage of this nuclear market that the HTGR-GT will be able to capture is a key element in assessing the HTGR's market potential.

- Lead Time - The commitment for new generation capacity must be made by the utility many years (approximately 8 years for coal, 12 years for nuclear) prior to the actual need date. Because the uncertainty of the future load demand increases with time, and because shorter lead time reduces total costs by reducing interest during construction, utilities favor generation options with shorter lead times. New technologies generally have more uncertain lead times. Accordingly, emphasis is being placed on the licensability and constructability of the HTGR-GT plant design with the intent of minimizing the required lead time.

- Siting Flexibility - There must be a suitable location for a new generating station. Whereas once system configuration, stability, and economic considerations were the determining factors in site selection, now site suitability is determined by environmental rules and regulations, public health and safety issues, and public intervention. Also, the number of available sites for new stations is very limited for most utilities; therefore, the technology which is most adaptable to specific site conditions while still satisfying regulatory and environmental requirements will possess a great advantage over its competitors.

  The HTGR has evaluated radiological and water consumption advantages in this area. The water issue will be examined in Section 3.0 of this report.

- Technology Development Status - A new power technology, to be considered as a viable alternative by the utility market, must be accepted as having performance and cost characteristics which have uncertainties associated with them which are not much greater than those associated with the other choices with which it must compete. Developing and demonstrating the current energy technologies have required decades and billions of dollars. Alternatives can be expected to require the same to bring them to the same technological status. The HTGR has progressed through previous development and demonstration programs. It is recognized, however, that extensive RD&D is still needed to bring the HTGR-GT to a viable commercial status.

- Regulation and Licensing - A new alternative technology system is at a disadvantage in a utility analysis if the regulations governing its siting, design, construction, and operation are not sufficiently developed to allow analysis of their impact on performance, costs, and schedules. If this is the case, the less mature alternative cannot be realistically compared with the other choices. Correspondingly, the certainty level of the licensability of the alternatives must also be comparable. The HTGR program intends to minimize licensing uncertainty in the plant lead time by incorporation of a pre-licensing review program to establish licensing criteria for HTGRs. In addition, the HTGR-GT Demonstration Plant is intended to provide adequate licensing experience prior to commercialization.

- Commercial Status - Important in the utility's decision to procure a particular type of alternative is the adequacy and reliability of the supply system behind the alternative. Regardless of the presumed merits of the alternative, a clear commitment on the part of a credible segment of the supply industry is necessary for the alternative to receive consideration from the utility industry. Engineering, manufacturing and field services must be made available by the supplier to the utility for the life of the product.

  In addition, an alternative technology must be sufficiently firm in terms of cost, regulations, licensing, and warranties so as to not require commercial terms and conditions which are substantially different from the terms and conditions under which competitive alternatives can be procured.

- Plant Capabilities - The capabilities of alternative technologies must be able to meet the specified requirements of the utility industry. For generation alternatives, a new technology must at least be able to offer the same capabilities as do the currently available technologies and should offer additional features to provide an incentive for commercialization. Specifically, load-following capability, net plant output, planned and forced outage rates and maintainability are all factors with which a new generation technology will be compared to existing alternatives.

- Economics - Economic considerations constitute the single most important factor in the selection of any capital expenditure decision. Utility practice, law, and normal business prudence dictate the choice of a generation system which provides the lowest cost of power, consistent with meeting all applicable regulations and reliability criteria.

  For a generation alternative, the utility must examine all of the component costs which comprise the total power costs. These are the capital cost, fuel cost, and operation and maintenance (O&M) costs. It is the interaction of these factors on the total power cost and how that total cost compares to the available alternatives that will affect the utility's selection. The reliability of the generation alternative is also an important economic factor. The utility must take into account the amount of time that the generation will not be available and must be replaced with other forms of capacity. A new generation alternative must have an eventual reliability comparable to its established competitors.

Sections 4.0 and 5.0 of this report provide an economic analysis of the HTGR, comparing it with other generation alternatives. The economic factors mentioned herein have been taken into account and their values varied to determine their relative impact on total power costs of the various alternatives.

2.2 Specific Nuclear Market Factors

There are several factors which affect only the nuclear power generation market and, therefore, must be mentioned as they will have a bearing on the HTGR's market penetrability. In order to understand how the HTGR will be evaluated against the LWR with regard to these factors, one must be familiar with the design and inherent features of the HTGR. Appendix A presents a system description of the HTGR-GT as well as a general discussion of the incentives for HTGR-GT deployment.

- Capital Risk - This factor, even though economic in nature, is considered unique to nuclear alternatives and must be considered separately. As a result of the Three Mile Island incident, both the utility industry and the investment community have perceived greater capital risks with nuclear power--specifically, that a combination of human and mechanical failures can render a billion dollar capital investment inoperative for an indefinite period of time. This realization has caused the utility industry to take a "hard second look" at the nuclear option, and correspondingly, many investment brokers have recommended against the debt and equity issues of nuclear-oriented utilities. The result has been the indefinite stagnation of the nuclear market.

  A new nuclear technology which has less capital risk than the present LWR would have a perceived advantage in the market, possibly even to the point of commanding a higher capital cost.

- Safety - Even in the wake of Three Mile Island, the safety experience record of LWRs is unparalled. While the LWR has met all safety and licensing requirements imposed by regulatory agencies, the LWR must provide rapid response to transient conditions affecting core cooling. Following a design basis accident, LWR fuel damage can begin to occur within a few minutes if the mitigating systems fail to function. A new technology which would allow a longer time period for operator corrective action would have a perceived advantage over the present LWR system.

- Personnel Radiation Exposure - Operating and maintenance personnel at nuclear power plants receive doses of radiation in excess of background during performance of their duties. The NRC places limitations on the amount of exposure that can be received over a set time period. When the exposure limit is reached, the employee may not continue to work in "hot" areas until the beginning of the next exposure time period. This leads to hiring of additional personnel in stations where high exposure rates are experienced and, therefore, increases costs. This factor is becoming a major element of the operation and maintenance costs for the operating LWR plants. A new nuclear technology which has the inherent feature of significantly reducing personnel exposure rates would have an advantage over existing systems.

- Fuel Cycle Flexibility - Future directions for nuclear fuel cycles are complicated by uncertainties arising from national policies, economic factors, and industry commercialization problems. It is desirable for utilities to have access to reactors that can operate economically on a once-through fuel cycle in the near term but can accommodate more efficient fuel cycles as policies and facilities allow. This consideration has not traditionally been a major factor in the utility selection process because it was generally assumed until recently that a closed fuel cycle would be available in the near term. Because the various fuel cycle options will not become available for at least a decade, a utility must consider the effects that a changing fuel cycle will have on its reactor systems. A reactor that can operate economically and efficiently with several anticipated fuel cycles would be advantageous.

- Advanced Applications - Some utilities have shown interest in expanding and/or enhancing their present energy supply markets through the sale of waste steam from generating stations to industrial customers. Several utilities have been in this "process heat" market for a number of years. As fuel oil for industrial boilers becomes more expensive, it is reasonable to expect that an expanded market could develop for nuclear or coal-fired process heat that is generated in a central station and distributed by a utility to industrial customers. The HTGR has the unique potential for becoming not only a source for electric power but also a substitute for fossil fuels in process heat applications.

3.0 Water Availability - Its Effects on the HTGR Market

As stated in Section 2.0, one of the factors most often cited as an incentive for the commercialization of the HTGR-GT is its adaptability to dry cooling. This section will discuss the results of previous studies that identify regions where some form of dry cooling will become a necessity for power generation in the future. It will also discuss the various options that are available for power plant cooling and their relative costs. Finally, this information will be related to the HTGR's perceived cooling system advantages as they affect its marketability. The conclusions will be tested further in subsequent phases of this study.

3.1 National Water Availability and Forecast

Present and planned electric generating stations in the U.S. use water for turbine exhaust steam condensation. Recently, a trend has developed away from once-through cooling (where water is withdrawn from a body of water, passed through the condenser, possibly cooled in a tower, and then discharged back to the source) and towards the use of evaporative ponds or towers which then recycle the water back through the system (closed-loop cooling). This trend is caused by many power stations being precluded from using once-through cooling because of thermal and chemical release limitations. The trend towards closed-loop evaporative cooling will have a combined effect of increasing the power industry's demand for water because such systems consume by evaporation more water than a similar sized once-through system.

Water resource constraints are anticipated to be severe by the end of the century. In 1975, ERDA (now the Department of Energy) reported (Ref. 3) that the currently available supply of freshwater runoff, underground water, and saline water is approximately 400 billion gallons per day (bgd). The current withdrawal of water for all uses is 315 bgd, and the consumption portion of this total is 85 bgd. The projected total national withdrawal of water for all uses in 1985 will grow to 600 bgd, of which 130 bgd will be consumed. Because the total potential freshwater runoff in the U.S. is 1200 bgd, this increase can be accommodated, but large regional problems will become evident and will persist. This trend will be aggravated by the future substitution of synthetic fuels and oil shale for natural gas and crude oil, which will create a tenfold increase in water requirements per unit of energy.

Several studies have been conducted to evaluate the potential for future water shortages and to correlate the areas where these shortages are likely to occur with the areas predicted to experience large additions of electric capacity. Three of these studies (Ref. 4, 5, 6) were reviewed and their results combined in EPRI Report NP-150, "Future Needs for Dry or Peak Shaved Dry/Wet Cooling and Significance to Nuclear Power Plants," dated February 1976 (Ref. 7). This effort identified regions where critical water-related energy problems will probably exist during the balance of this century. Using these three reports, EPRI first assembled forecasted bounds for fossil and nuclear electric generation up to the year 2000. Using various scenarios for load growth, expected generation capacity additions were segregated by the eighteen regions of the Water Resources Council. These eighteen areas are shown in Figure 3.1-1. The shaded areas in this figure indicate areas where critical water-related energy problems can be expected by 1985, as forecasted by the Water Resources Council in 1974. In order to further define these potential water shortage areas, EPRI applied the results developed by Ref. 6 which examined specific water basin areas. Figure 3.1-2 identifies 230 power generation growth areas. The 43 areas that are shaded will have limited cooling capacity for generation additions while the nine areas that are blackened are considered to be critical water/energy areas.

The Hanford Engineering Development Laboratory (HEDL) has developed an extensive national water availability information system. Using this data base, HEDL published a report titled "Assessment of Requirements for Dry Towers" in September 1976 (Ref. 8). It compared the expected high electric power growth areas with critical water availability areas. It indicated that the Southwest from California to Texas is the area of the U.S. where critical water availability problems are likely to occur before the year 2000. According to Ref. 8, the shortage in this region is related to increasing competition for available supplies and to potential federal and/or state policy decisions that may have a significant effect on power plant cooling. Ref. 8 also concluded that "by the year 2000, severe-to-major problems are projected for the Lower Colorado and California Regions, with major-to-moderate problems projected for the Great Basin, Upper Colorado, Rio Grande, Texas Gulf, Missouri and Middle Atlantic Regions." Specific descriptions of the causes and effects of the water shortages in these regions are given in Appendix B, which is taken directly from Ref. 8.

Based on the above information, both EPRI and HEDL concluded that in certain areas some form of dry/wet or completely dry cooling will have to be employed on new generating plants. HEDL also concluded that whereas economic alternatives to dry/wet or dry cooling will exist in most areas of the country prior to 1990, between 1990 and 2000 a total of 22 to 40 GWe of capacity will be added which will require either wet/dry or dry cooling.

The nuclear siting study done by the Institute for Energy Analysis (Ref. 9) investigates the advantages of concentrating the growth of nuclear power on basically existing nuclear sites for the balance of this century. This study addresses the water availability at these existing sites and identifies eight particular sites that have water problems due to natural limitations and five particular sites with water problems due to regulatory allocation of water supply. The geographic locations of these sites are generally consistent with the EPRI and HEDL reports.

None of the above reports examined water requirements or supplies past the year 2000. However, based on the information presented, it can be concluded that the water shortages of the 1990's will continue to expand beyond the year 2000. This trend will require the continued use and expansion of dry/wet or dry cooling systems on electric power plants.

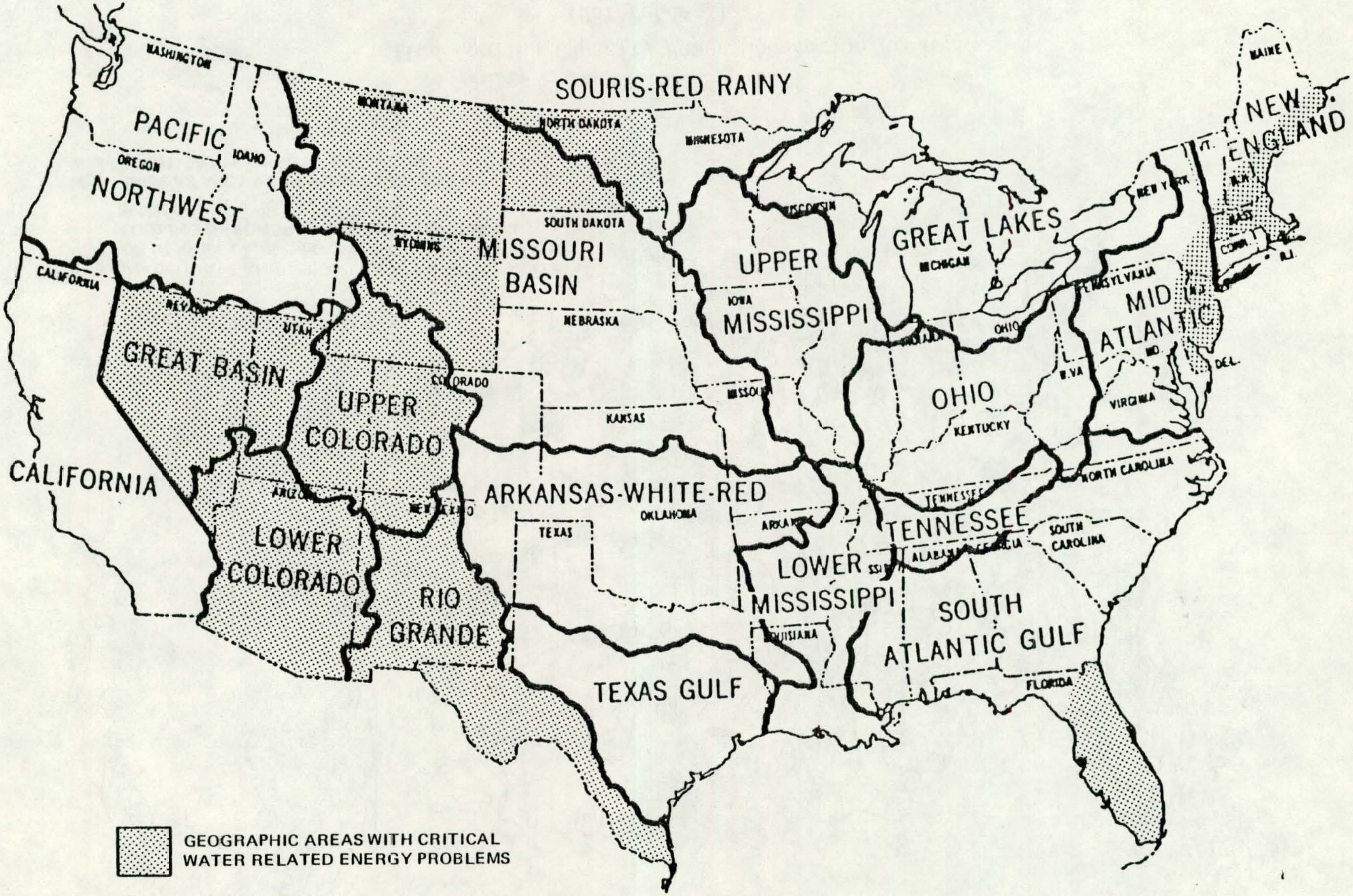


Figure 3.1-1

Water Resource Council Regions

(Reference 7)

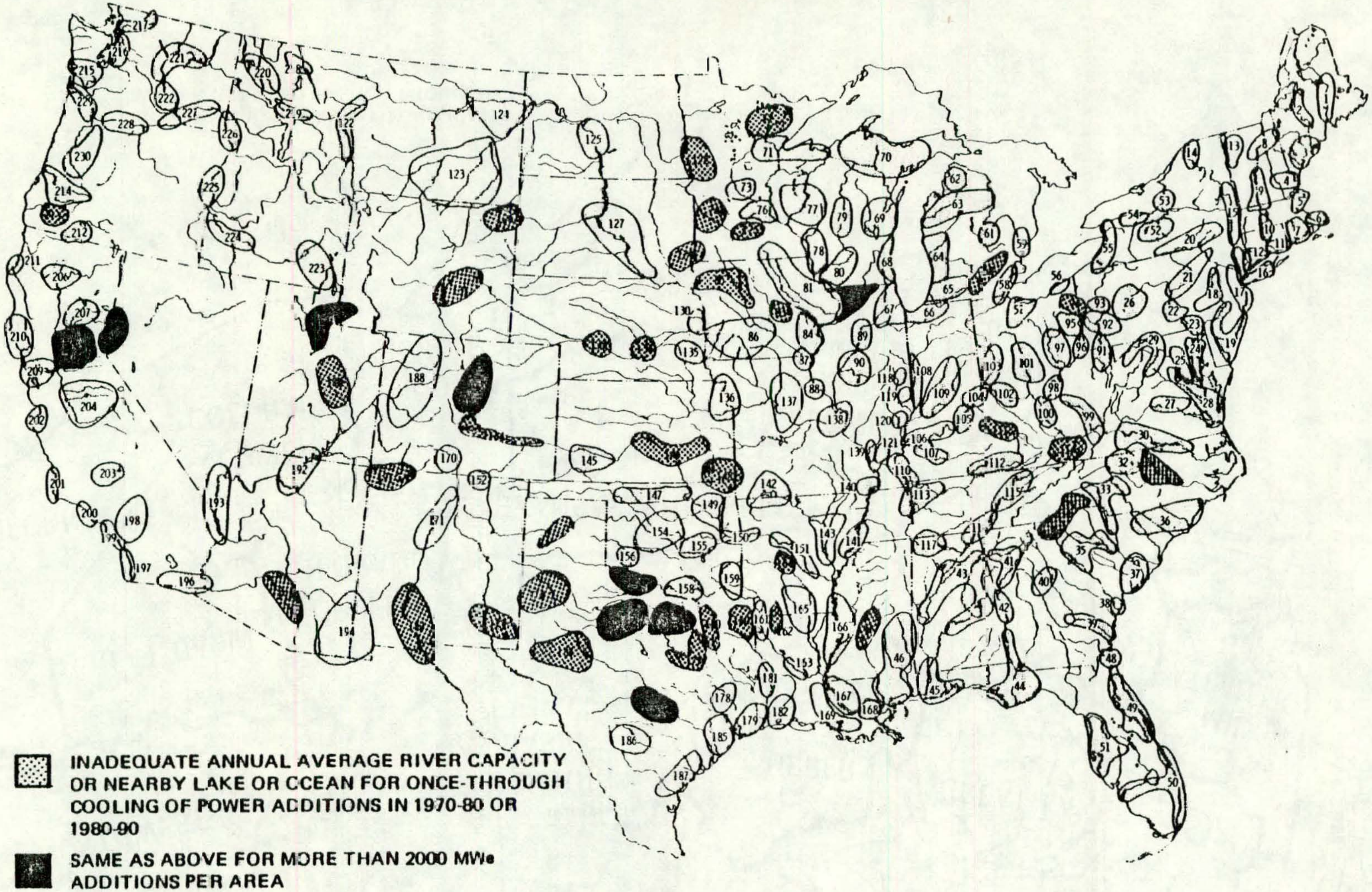


Figure 3.1-2

Limited Cooling Capacity Power Generation Areas
(Reference 7)

3.2 Description of Power Plant Cooling Systems

Typical water consumption data are shown in Table 3.2-1 for various types of cooling systems. In order to understand why consumption varies with alternate cooling system types, one must be familiar with their design features. This section will describe the three types of systems that will be receiving the most attention in the future: wet cooled, dry cooled, and peak shaved dry/wet cooled.

3.2.1 Wet Cooling

Figure 3.2-1 taken from Ref. 7 shows how a wet cooling tower works when the heated return water from the condenser is sprayed into the air. The air can absorb heat to cool the water in two ways. One is by raising the sensible (dry bulb) temperature of the air; the other is by raising the moisture content (humidity) of the air by evaporation of part of the cooling water. Approximately 25% of the heat rejection takes place by the first process and 75% by evaporation which rejects the latent heat.

The amount of heat that a tower can reject is limited by the wet bulb temperature of the incoming ambient air. The water can only be cooled to a temperature that "approaches" the ambient wet bulb temperature. Therefore, a particular cooling tower approach temperature is the differential of the wet bulb temperature and the temperature of the cooled water coming out of the tower. The "range" of a cooling tower is the hot water temperature into the tower, minus the cold water temperature exiting the tower. The sum of the Approach and Range is the Initial Temperature Difference as shown in Figure 3.2-1.

3.2.2 Dry Cooling

Figure 3.2-2 from Ref. 7 shows the dry cooling tower performance relationships. The dry tower does not use evaporative heat dissipation, but because the cooling is pressurized in a closed system, it can operate at higher temperatures than a wet tower. The dry tower in essence is an air-cooled heat exchanger and, therefore, the dry bulb temperature of the incoming air limits the dry tower design. Because there is no evaporation, the system must provide about four times as much heat rejection by sensible heating of the air as compared to wet cooling towers. Also, because the dry bulb temperature of the ambient air is greater than or equal to the wet bulb temperature, the Initial Temperature Difference (ITD) is less for the dry tower at a given condenser pressure than for a similar wet system and, therefore, more cooling capacity must be added to provide the same amount of heat rejection.

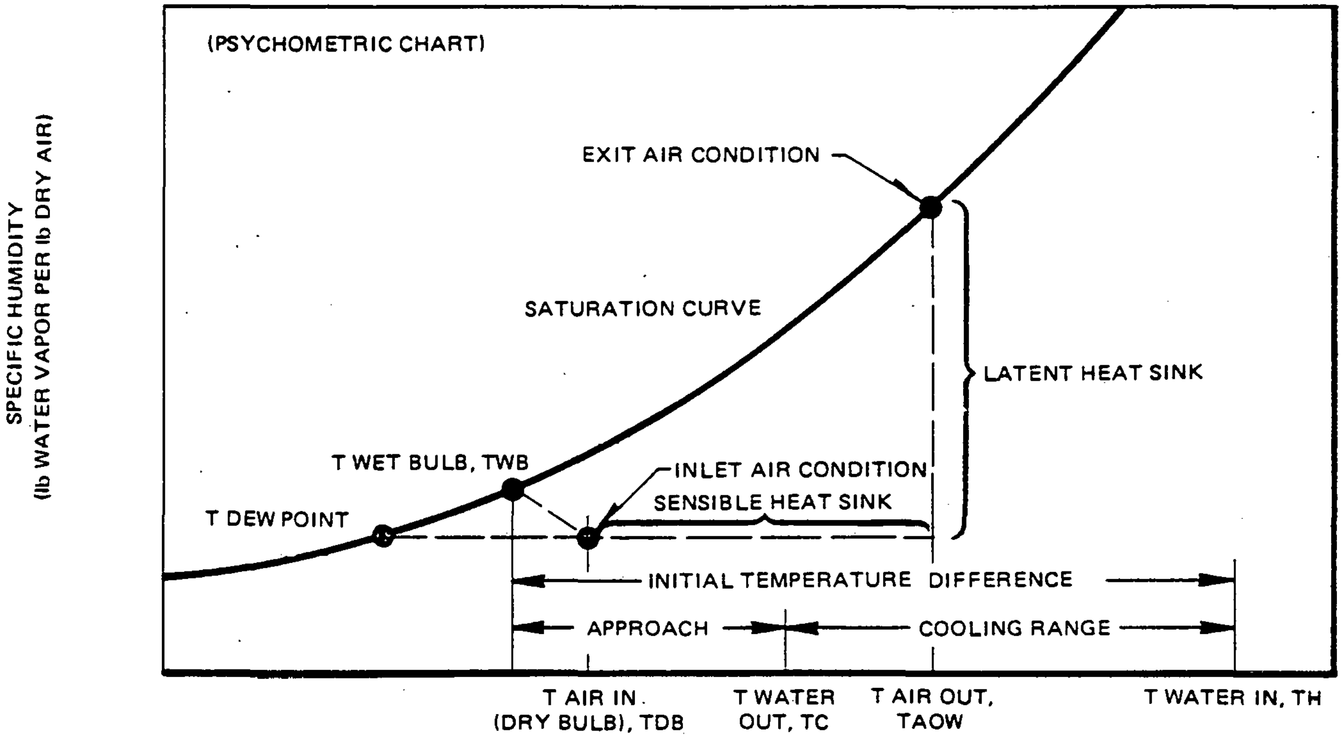
For a conventional steam plant, either fossil or nuclear, the circulating water would remove heat from the condenser and then be piped under pressure to the dry cooling towers.

Table 3.2-1

Typical Water Consumption Data
(Ref. 7)

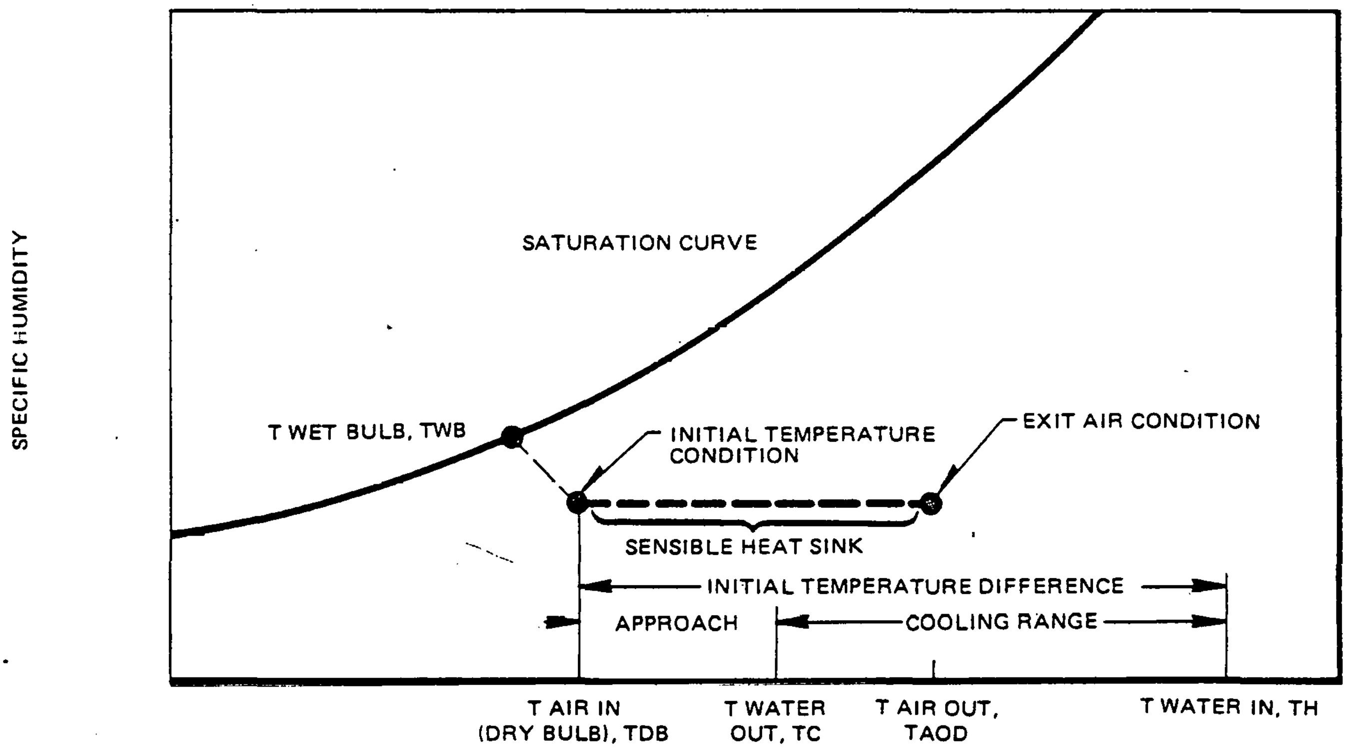
Cooling Mode	Approximate Gallons/Hour Per Gross MWe Fossil	LWR
Once-Through	300	450
Spray Pond	400	600
Mechanical Draft Wet Tower/Closed Loop	430	650
Natural Draft Wet Tower/Closed Loop	380	570
Dry Tower*	22	15
Peak Shaved Dry/Wet System	20-50	20-70

*Includes in-plant usage.



Wet Cooling Tower Performance

Figure 3.2-1



Dry Cooling Tower Performance

Figure 3.2-2

For the HTGR-GT, Figure 3.2-3 shows that reject heat is removed from the reactor system through the precooler, which is a helium to water heat exchanger. The water from the precooler is then piped under pressure to the dry cooling towers. The dry cooling system is more adaptable to the HTGR-GT than an LWR or fossil-fired steam cycle plant because of the higher reject heat temperatures of the HTGR. This higher reject heat temperature creates a much larger Initial Temperature Difference (ITD) and, therefore, the heat rejected per dry tower unit is also much greater. This allows the use of fewer dry tower modules with the HTGR-GT than with a comparably sized steam cycle plant.

3.2.3 Peak Shaved Dry/Wet Cooling

By adding a small amount of evaporative cooling for peak temperature periods, the peak shaved dry/wet cooling system (PSD/WCS) combines the advantages of both the dry and wet cooling towers. In designing the dry/wet tower system, a dry cooling tower is sized to carry the plant heat load at and below a certain design point ambient temperature. A separate wet tower is added to augment the heat rejection of the dry tower at higher ambient temperatures so that the turbine back pressure is equal to a specified design value at the high ambient temperature design point.

The percentage of heat rejected via the wet or dry tower will vary from site to site depending on ambient conditions and economic tradeoffs. For example, a 50-50 PSD/WCS will reject 50% of the heat through the dry tower modules and 50% through the wet tower modules when operating at the design dry and wet bulb temperatures. Below the design temperature, the heat removal capability of the dry towers is increased and the wet towers can be shut down in stages to shift more of the cooling load to the dry towers. The control of this system for starting and shutting down the wet towers will vary from site to site depending on water costs and availability and how they relate to the total operating cost of the system.

Even though a 50-50 PSD/WCS uses 50% of the water of an evaporative system at its design point, it may, depending on the cooling system design point, only operate at this design point for approximately 1-5% of the time; therefore, annual water requirements can be expected to typically be 3-10% of the water required for a totally wet cooled system.

Figure 3.2-4 shows two alternative arrangements of a PSD/WCS with a typical steam cycle plant. The optimum arrangement for a particular plant is site dependent. Figure 3.2-5 shows schematically how a PSD/WCS would be used for a HTGR-GT plant.

3.3 Cooling System Economics and the HTGR

Thus far, we have examined the future water requirements for electricity production and have come to the conclusion that either dry or peak

DIRECT CYCLE HTGR PLANT WITH DRY COOLING

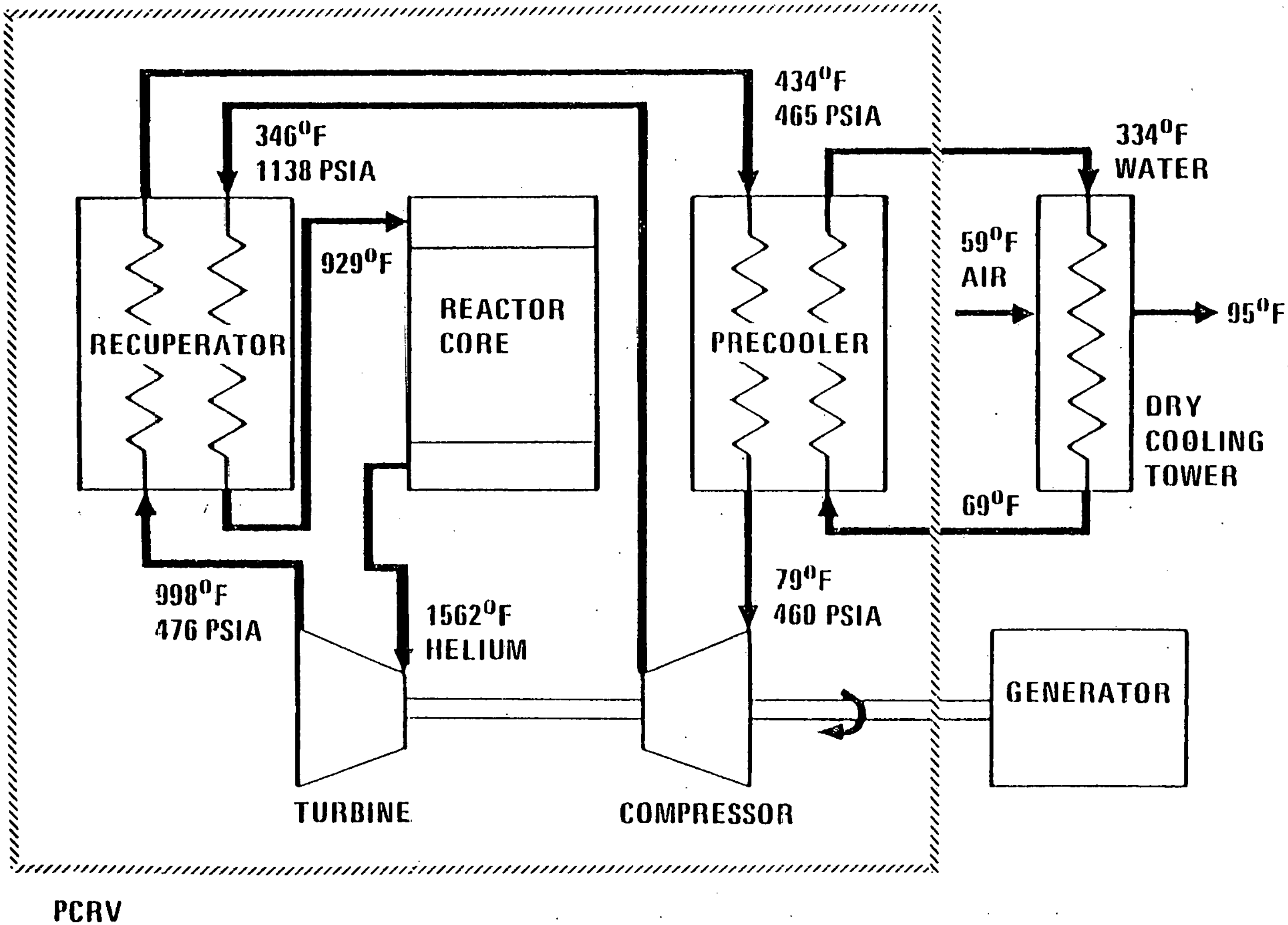
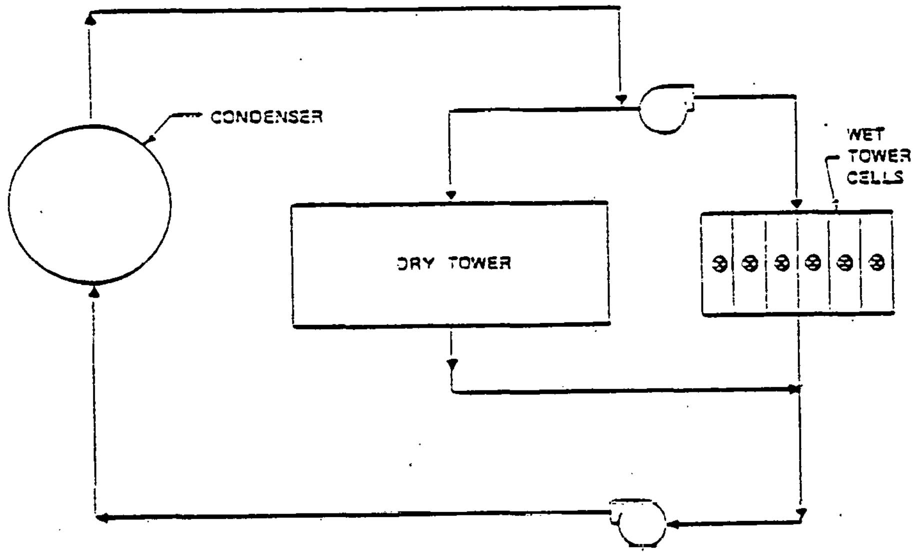
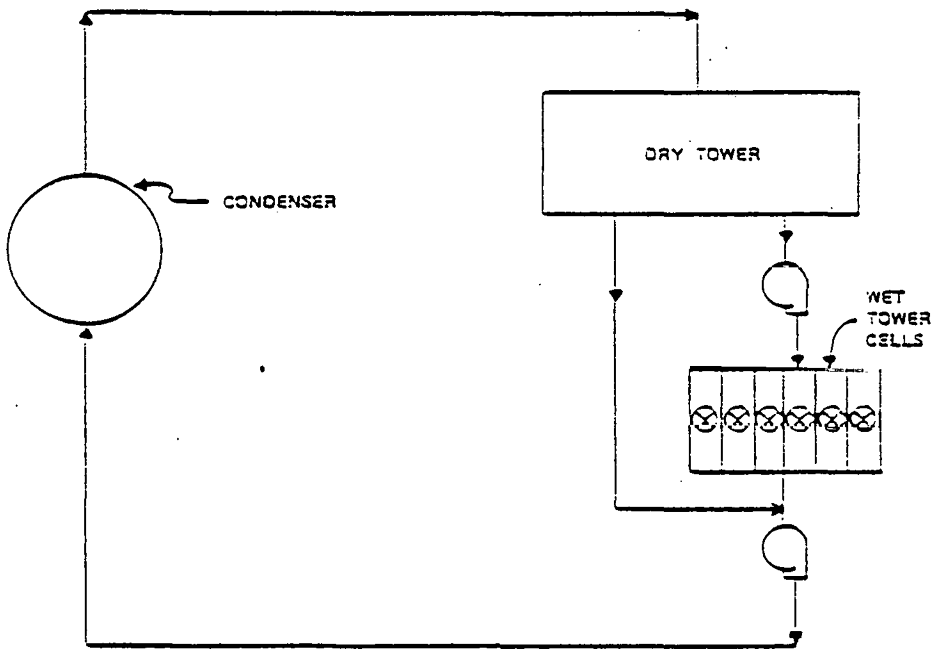


Figure 3.2-3



Parallel-Water Flow Wet/Dry Tower



Series-Water Flow Wet/Dry Tower

Figure 3.2-4

PSD/WCS for Steam Cycle Plants

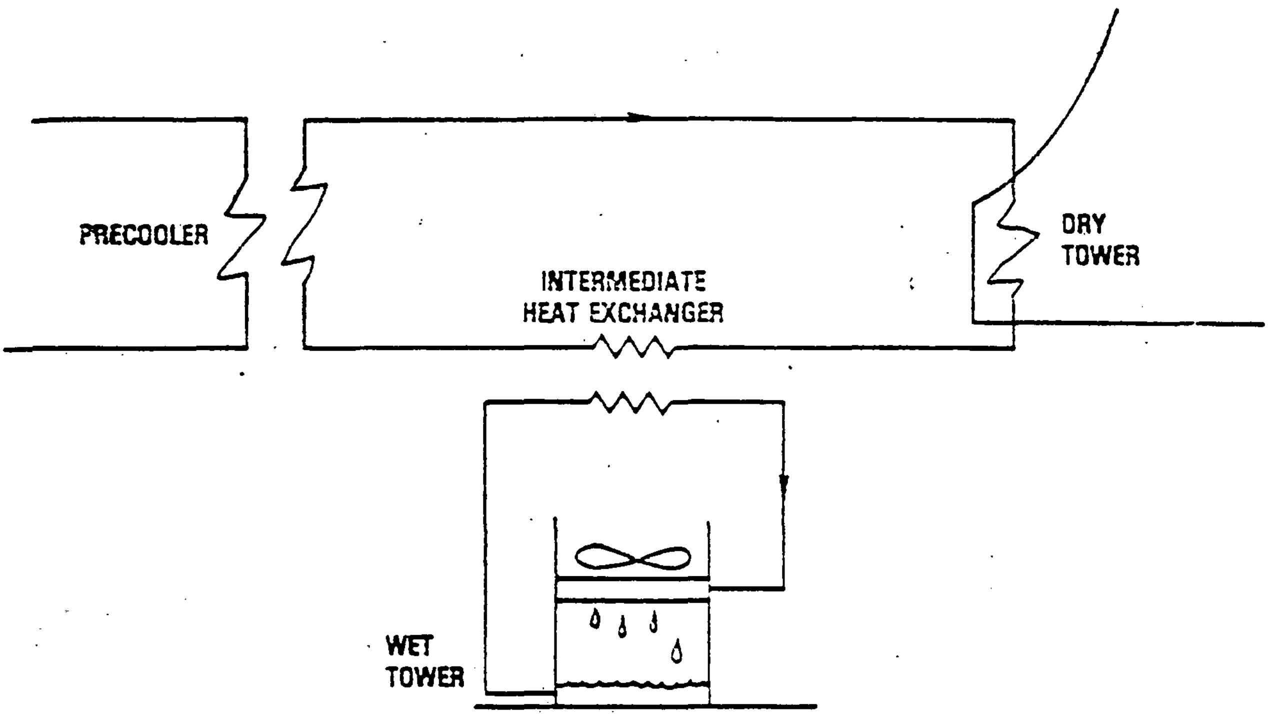


Figure 3.2-5

Dry/Wet Cooling Tower System for HTGR-GT shaved dry/wet cooling will be required in certain regions of the U.S. prior to the year 2000. We have also concluded that the HTGR-GT can be cooled by one of these systems more readily than either an LWR or fossil-fired steam plant. The question remaining to be answered is: "How large is the economic advantage of using a dry or PSD/WCS with an HTGR as compared to an LWR or conventional fossil plant?"

It is not possible to answer the above question in terms of absolute dollars for several reasons. First, because of the conceptual stage of development of the HTGR-GT, reliable cost studies are not yet available. Secondly, dry and PSD/WCS cooling systems are not widely deployed and have not been applied to large base load plants to date.

Therefore, reliable cost estimates are not yet available for these cooling systems. However, based on preliminary cost data and engineering judgement, it is possible to quantify relative cost differentials for the various cooling options. This is done by determining the cooling system evaluated costs in $/KWe. Table 3.3-1 shows these costs for the LWR and the HTGR-GT.

The data in Table 3.3-1 are from Ref. 7 and are based on optimized cooling systems for three specific sites and several different reactor types. These cooling systems evaluated costs include the carrying charge on capital investment, the capital cost, the operating penalties such as loss of capacity at high ambients, water costs, and all operating costs. The numbers represent 1977 dollars. A 50-50 PSD/WCS was used in this evaluation because it provides lower evaluated costs over a wide water cost range than cooling systems using other dry to wet ratios.

Four conclusions can be drawn from the data in Table 3.3-1. First, wet cooling for an LWR is the most economic choice and should be employed if water is available. Second, the HTGR-GT is more readily adaptable to some form of dry or dry/wet cooling than the LWR. Third, a PSD/WCS is more economic than a dry-cooled system by a considerable margin for both reactor types. Fourth, if a future change is required in the cooling system design from PSD/WCS to totally dry cooling, the added evaluated cooling system costs will be less for the HTGR-GT than for the LWR.

Based solely upon the data in Table 3.3-1, the choice for cooling system type would always be wet cooling for the LWR and PSD/WCS for the HTGR-GT. However, water availability cannot be ignored. Assuming that the scarcity of water at a particular site is directly proportional to its cost, a break-even water cost can be calculated for each type reactor and cooling system. Above the break-even point, the high cost of water makes the more capital cost intensive cooling system the economic choice. Table 3.3-2 (Ref. 7) shows the break-even water costs for the LWR and the HTGR-GT for the various cooling systems. It shows conclusively that 100% dry cooling will remain uneconomical for both reactor types for well into the foreseeable future and that wet/dry cooling systems will become the economical cooling system choice in certain areas of the country in the near future. For example, water

Table 3.3-1

Cooling System Evaluated Costs, $/KWe
(1977 Dollars)

LWR

	Southwest	Southeast	West
Wet-Cooled	47	48	44
PSD/WCS (50-50)	85	79	76
Dry-Cooled	138	122	122

HTGR-GT

	Southwest	Southeast	West
Wet-Cooled*	41	41	40
PSD/WCS (50-50)	38	37	39
Dry-Cooled	82	58	70

*A wet-cooled HTGR-GT case is presented here for the sake of completeness. No design presently exists for such a plant.

Note: The cooling system evaluated costs for the HTGR-SC are somewhat less than those of the LWR but are higher than those for the HTGR-GT.

Table 3.3-2

Water Break-Even Costs, $/1000 Gallons*
(1977 Dollars)

LWR

	Southwest	Southeast	West
Wet-Cooled to PSD/WCS (50-50)	2.20	1.80	1.90
PSD/WCS (50-50) to Dry-Cooled	20.00	40.00	60.00

HTGR-GT

	Southwest	Southeast	West
Wet-Cooled to PSD/WCS (50-50)	0.40	0.30	0.40
PSD/WCS (50-50) to Dry-Cooled	55.00	54.00	31.00

*Based on an average cost of water = $0.50/1000 gallons.

Note: This table indicates the cost of water per 1000 gallons that would be required for an economic incentive to shift from wet cooling to a PSD/WCS, and from a PSD/WCS to dry cooling.

costs must rise to $2.20 per 1000 gal. before a PSD/WCS is economically superior to a wet-cooled system for an LWR in the Southwest. To provide a benchmark for comparison, the break-even costs in this table were generated assuming a present water cost of $0.50/1000 gallons, which is a reasonable national average cost.

3.4 Conclusions

The following conclusions can be drawn from the information presented in this section:

- Water availability and load growth forecasts indicate that future power plants in large areas of the U.S. will not be able to employ evaporative wet cooling systems after 1990 due to lack of water for consumptive use.

- Based on present water costs and availability, little or no economic or resource incentive exists to develop 100% dry cooling for any type power plant in the foreseeable future except at specific, isolated sites.

- With a limited amount of water available in the future for power plant cooling, more electric capacity will be able to be added as dry/wet cooling systems are more widely used.

- LWRs, HTGR-SCs, and HTGR-GTs are adaptable to a peak shaved dry/wet cooling system that would limit consumptive water use to between 3% and 10% of a wet-cooled evaporative system.

- Because of its efficiencies and the high temperatures of its thermodynamic cycle, the HTGR-GT is suited for operation with a peak shaved dry/wet cooling system that has a lower evaluated cost than a similar system would have for an LWR or HTGR-SC. The HTGR-GT has an average cooling system evaluated cost advantage of $50/KWe (1977 dollars) over the LWR.

Even though the HTGR-GT enjoys a cooling system evaluated cost advantage over the LWR, it should be remembered that the cooling system costs are only a portion of the total plant power costs. Nevertheless, if the HTGR-GT were to come into comparable commercial status with the LWR, then this evaluated advantage could have a major impact on HTGR-GT market penetration based on the water availability forecasts previously discussed.

4.0 Systems Analysis - Approach

Assessments have been conducted in the past involving the HTGR's ability to net national benefits, but the advantages or disadvantages of this technology relative to utility systems analyses have heretofore not been widely addressed. Through the utilization of utility systems models, systems methodology, and generation planning techniques, the market penetrability of the HTGR has been analyzed from the perspective of the electric utility industry.

4.1 Systems Models

Introduction - In 1976, the Electric Power Research Institute (EPRI) initiated a project to develop flexible and representative utility systems for use in performing utility planning studies. Sufficient data was to be developed to allow synthesis of such utility systems to be broadly representative of the systems of EPRI member utilities throughout the United States. This project culminated in February 1977 with the publication of "Synthetic Electric Utility Systems for Evaluating Advanced Technologies" (Ref. 10).

These models are being used by EPRI to assist in the challenging task of establishing research and development priorities. Specifically, EPRI is using this approach of adapting utility system generation-planning techniques for evaluating future technology power system options, as well as the currently available options. The result is a consistent economic analysis that has the following capabilities (Ref. 11):

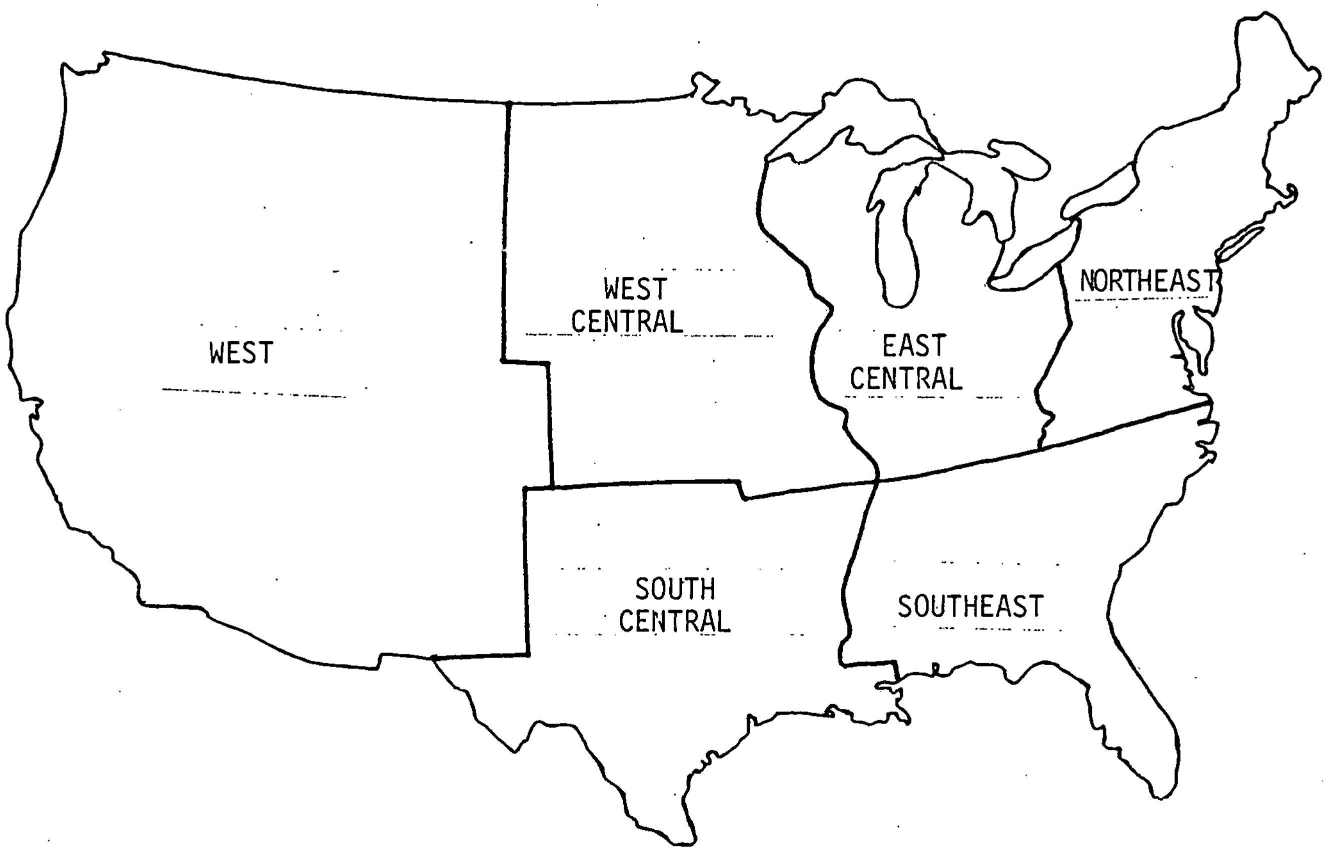
- Defines the most appropriate role of each technology in the generation mix,
- Yields the market penetration potential for each technology,
- Shows the degree by which some technologies must improve to become economic, and
- Estimates the present-value savings and cost-benefit ratios that may be achieved if successful R&D results are put into practice.

When analyzing alternative technologies, it is desirable to maintain overall consistency of methods and assumptions. To this end, EPRI developed the "Technical Assessment Guide" (TAG) (Ref. 12), which was published in June 1978. The TAG contains certain assumptions, data, and methodology that are used by EPRI as a basis for assessing the value of research and development programs.

System Definition and Selection - The data contained in the TAG are presented on a national basis or on regional bases where regional differences are considered significant. These regions are depicted in Figure 4.1-1.

Figure 4.1-1

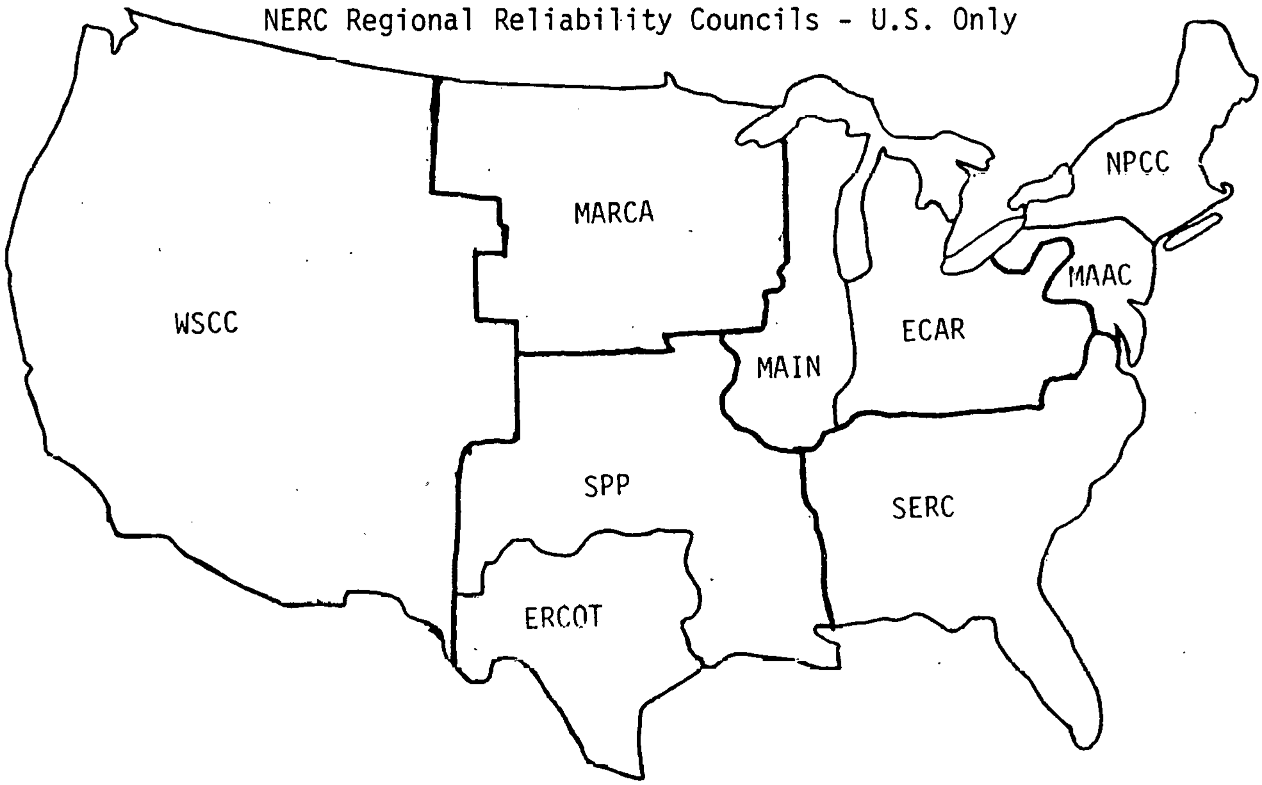
EPRI Data Regions



(EPRI TAG Fig. I-1)

Figure 4.1-2

NERC Regional Reliability Councils - U.S. Only



(NERC 9th Annual Review Inside Cover)

In 1968, the National Electric Reliability Council (NERC) was formed "to augment the reliability and adequacy of bulk power supply in the electric utility systems of North America" (Ref. 13). NERC consists of nine regional reliability councils and encompasses essentially all of the power systems of the United States and the Canadian systems in Ontario, British Columbia, Manitoba, and New Brunswick. Because of the HTGR Market Assessment objectives, the review of the NERC systems focused on the contiguous U.S. regions. These regions are depicted in Figure 4.1-2.

A comparison of Figures 4.1-1 and 4.1-2 reveals reasonable correspondence between the regions utilized by EPRI and NERC. For Phase I of this study, two regions of the continental United States were modeled. The base EPRI and NERC regions from which the study models were developed are as shown in the table below:

Table 4.1-1

Regional Utility Systems

EPRI Data Region	NERC Reliability Council(s)
Northeast	MAAC, NPCC
West	WSCC

The Northeast and West regions were chosen for this study due primarily to siting and economic factors which are believed to be potential benefits in the deployment of the HTGR in these areas. These regions should represent, although not uniquely or exclusively, attractive markets for any emerging generation technology.

The EPRI synthetic utility systems are described in detail in Reference 10. The synthetic systems include data for the generating system characteristics, transmission network characteristics, and load characteristics. Table 4.1-2 shows the major characteristics of the EPRI synthetic systems in 1985. As indicated on Table 4.1-2, the EPRI systems may be reasonably applicable to one or more regions. The EPRI synthetic systems also exist as scaled-down systems which are representative of single utility systems within the particular region. For this study, scaled-down systems were used. This results in the synthetic utilities being representative of large single utilities in either region. Reference data are found in Appendix C. The NERC 8th Annual Review contains summary information which forecast peak loads, net electrical energy generated, and installed generating capabilities for the 10-year period 1978 to 1987. Table 4.1-3 shows the major characteristics of the study regions in 1985, based on these data.

Based on the recommended applications of the synthetic systems in the TAG and a comparison of system characteristics shown in Tables 4.1-2 and 4.1-3, the regional utility systems modeled for this study were

Table 4.1-2

Major Characteristics of EPRI Synthetic Utility Systems (1) (1985)

	Synthetic System					
	A	B	C	D	E	F
Applicable Regional Systems	Northeast Southeast East Central	West	West Central	Northeast	South Central	Northeast Southeast
Peak Load - MW	44,000	38,000	16,500	26,000	37,000	26,000
Generating Capacity - MW	53,500	46,000	22,000	32,000	45,500	31,800
Generation Mix - %						
Steam - Coal	60	20	50	35	25	10
Oil	8	23	15	25	5	45
Gas	-	-	-	-	50	-
Nuclear	21	10	20	25	15	30
Combustion Turbine	8	5	5	15	5	5
Combined Cycle	-	2	-	-	-	-
Conventional Hydro	1	38	7	-	-	5
Pump Storage Hydro	2	2	3	-	-	5
Installed Reserve - %	21.6	21.1	33.3	23.1	23.0	22.3
Annual Load Factor - %	59	69	57	59	56	63
Time of Annual Peak	Summer	Winter	Summer	Summer	Summer	Summer

Notes: (1) From EPRI Technical Assessment Guide, EPRI PS-866-SR, June 1978.

<u>Table 4.1-3</u>

Major Characteristics of
Regional Utility Systems (1)
(1985)

	Regional System		
	Northeast	Southeast	West
Regional Reliability Council(s)	MAAC, NPCC	SERC	WSCC
Summer Peak Load - MW	88,094	128,325	99,418
Generating Capacity - MW	113,357	161,143	131,665
Generation Mix - %			
Steam - Coal	18.5	42.6	22.0
Oil	35.1	11.7	18.1
Gas	-	0.1	1.6
Nuclear	24.6	27.8	12.8
Combustion Turbine	11.6	7.1	4.2
Combined Cycle	0.8	0.6	3.5
Conventional Hydro	5.7	6.7	33.4
Pump Storage Hydro	3.5	3.5	2.9
Other	0.1	-	1.7
Installed Reserve - %	28.7	25.6	32.4
Annual Load Factor - %	62.1	63.6	65.8
Time of Annual Peak	Summer	Summer	Summer

Notes: (1) Based on the NERC 8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, August 1978.

derived from the EPRI synthetic systems shown in the table below:

Table 4.1-4

Application of
EPRI Utility Models

Region	Synthetic System
Northeast	D
West	B

These synthetic systems, and their associated data, are believed to be a reasonable representation of the corresponding regional utility systems. They may not be, and are not intended to be, representative of any individual utility. Indeed, there is often more variation among utilities within a region than among regions as a whole. The details of the basic data assumptions are discussed in Appendix C.

System Load Growth - The NERC 8th Annual Review summarizes the forecast peak loads for the Regional Reliability Councils for the years 1978 to 1987. A comparison of the regional forecast loads indicates large differences in load growth rate among the regions, although the differences do decline toward the end of the 10-year period. Based on these NERC data, it was felt appropriate to use varying growth rates for our selected regions, as shown in the table below:

Table 4.1-5

Regional Loads and Growth Rates (1)

		U.S. Regional System	
		Northeast	West
Regional Reliability Council(s)		MAAC, NPCC	WSCC
Peak Load - MW	1978	68,398	71,282
	1983	82,104	90,739
	1987	94,376	108,151
Growth Rate - %	1978-83	3.71	4.95
	1983-87	3.54	4.49
Study Growth Rate - %	1985-1989	3.50	4.50
	1990-2020	3.50	4.00

Note: (1) From the NERC 8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, August 1978.

4.2 Methodology

4.2.1 Generation Planning Methods

Traditionally, generation expansion planning analyses involve the following three major steps:

1. System reliability evaluation.

2. Production cost evaluation.

3. Investment cost evaluation.

The first step is the determination of types of new generation to be available and their sizes, a measurement of their worth against a system reliability standard, and a determination of necessary installed capacity for any given year. The production and capital investment costs of the various alternatives are calculated and total annual system costs are determined.

The total costs for each alternative are frequently expressed in terms of either levelized annual revenue requirements or present worth of all future revenue requirements (PWAFRR). When using the revenue requirement method, the optimum plan will be the one which minimizes PWAFRR. The revenue components for the revenue requirement method are shown in Figure 4.2-1.

For short-range studies, or studies related to specific situations, the selection of generation alternatives is a manual process. Detailed computer programs are employed to calculate system reliability and production costs, and to evaluate the effects of the required investment on corporate finances.

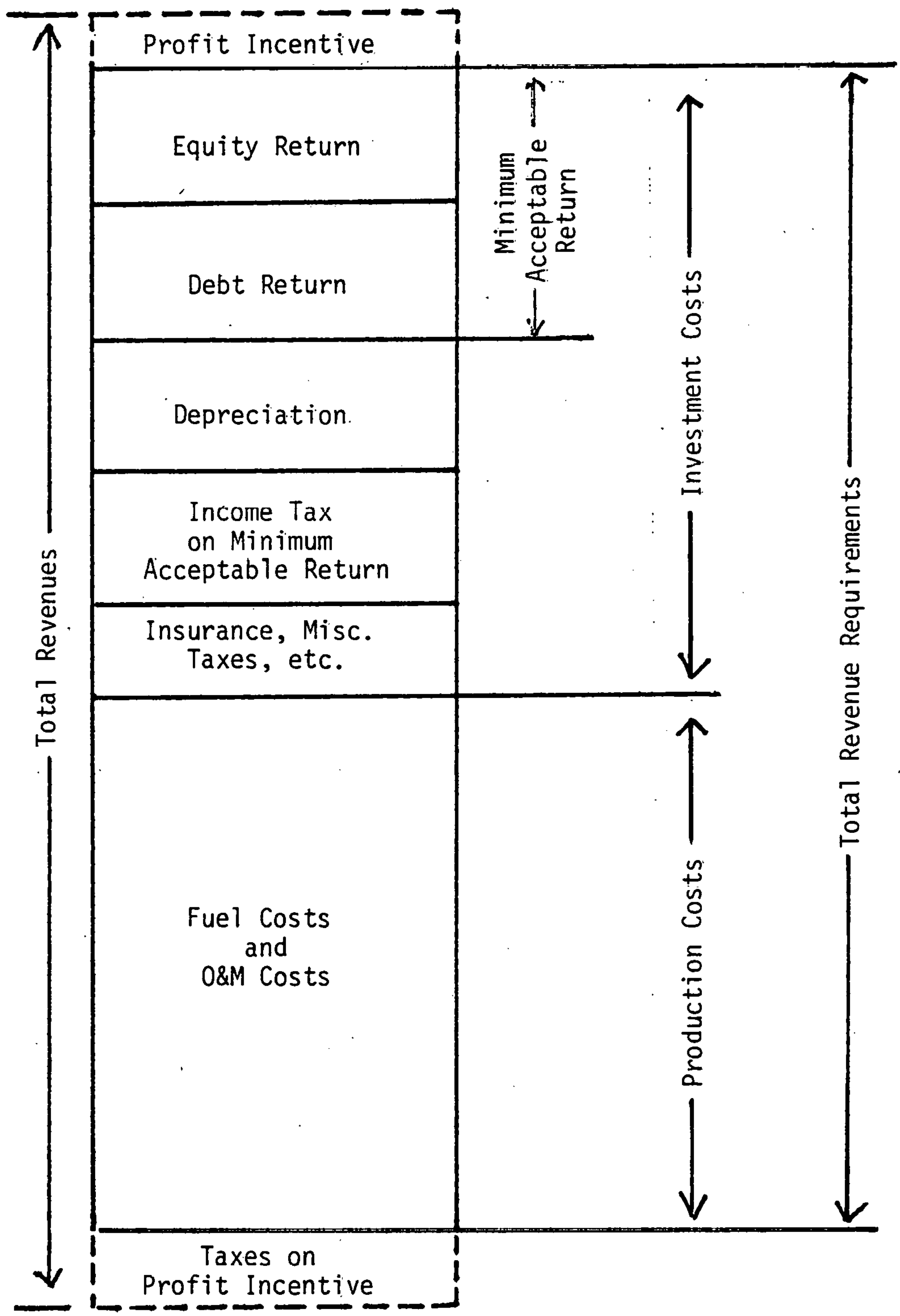
For long-range optimum expansion studies, such as in this study, the detailed analyses described above can become prohibitively time-consuming and expensive. For this type of study, several generation expansion computer programs have been developed which combine all of the planning steps into a single program package using simplified calculation methods. One such program is General Electric Company's Optimized Generation Planning (OGP) program. OGP was chosen for use in this study because of its high level of utility acceptance and because the EPRI synthetic utility system data bases have been used previously with OGP and were readily available.

The following sections describe in more detail the three significant steps previously outlined.

System Reliability Evaluation - The purpose of reliability evaluation is to determine the amount of generation that must be installed on a system in order to satisfy a specified reliability criterion for meeting the load demand. The reliability criterion is usually expressed as a loss-of-load probabil-

Figure 4.2-1

Revenue Categories for the
Revenue Requirement Method



ity (LOLP), in terms of expected days per year of insufficient generating capacity to meet the load. A capacity outage probability model is developed from the ratings and forced outage rates of the generating units. The model is modified as units are added, retired, outaged for maintenance, or returned from maintenance. A load distribution model is developed from the daily or weekly peak loads. LOLP is obtained by convolving the capacity and load models. If the LOLP for the system does not meet the specified criterion, additional generating capacity must be added to the system. Different types of generating unit additions will generally have different effects on system reliability due to variations in size and forced outage rate. When comparing alternatives, it is important that the resulting systems have equal reliability.

Production Cost Evaluation - Production cost computer programs simulate the operation of a power system. The generating units are represented by their heat rates at various load levels, their fuel and O&M costs, and their forced and planned outage rates. Loads may be represented either by load distribution curves or hour-by-hour load patterns. Hydro and energy storage units are typically dispatched first. The amount of energy produced (or consumed for charging) is reflected in the load model by reducing (or increasing) the loads. Thermal units are then dispatched on an equal incremental cost basis to meet the remaining loads. Various operating constraints may be introduced such as spinning reserve, unit commitment, and minimum down time requirements, and environmental effects. Most production cost programs also have provisions for simulating sales and purchases of energy from outside systems. The methods of modeling outage rates, operating constraints, and energy interchange vary from program to program.

Investment Cost Calculation - The investment cost for a new unit is expressed as a levelized annual fixed charge calculated by applying a fixed charge rate to the unit's capital cost at the time of installation. The components and calculation of a fixed charge rate are shown on Table 4.2-1. Financial simulation programs, or "corporate models," are available to determine the financial impact of a generating unit addition. Financing, rate adjustments, and accounting procedures are simulated. The resulting effects on important quantities such as cash flow, net income, earnings per share, and the various corporate financial statements may influence the selection of the generation plan.

4.2.2 Optimized Generation Planning (OGP) Program

The preceding steps are integrated by OGP in the logic depicted on Figure 4.2-2 to automatically develop an optimum generation plan.

A brief description of the program logic follows. For a more detailed discussion, please consult the "Descriptive Handbook

Table 4.2-1 (1)

Example of Levelized Annual Fixed
Charge Rate Calculation (2)

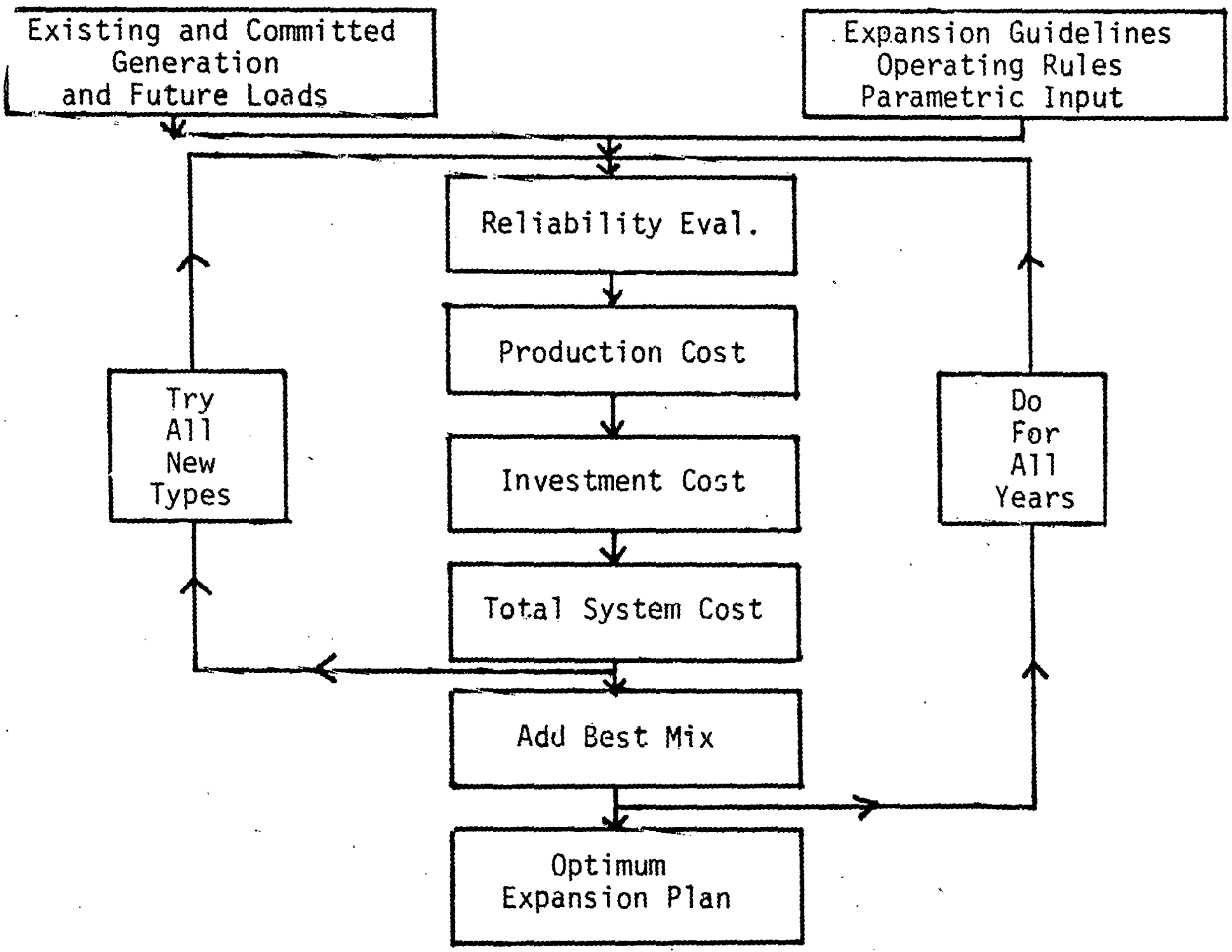
Total Return (Weighted Cost of Capital)	10.00%
Book Depreciation (Sinking Fund)	.61
Allowance for Retirement Dispersion (Iowa Type S1)	.56
Levelized Annual Income Tax	4.70
Property Taxes, Insurance, etc.	2.00
Total, w/o Income Tax Preference Allowances	17.87%
Levelized Annual Accelerated Depreciation Factor	(2.47)
Levelized Annual Investment Tax Credit at 4%	(0.77)
Total, w/Income Tax Preference Allowances	14.63%

Notes: (1) From EPRI Technical Assessment Guide, PS-866-SR, June 1978.

(2) Based on a 30-year book life and a 20-year tax life and using flow-through accounting.

Figure 4.2-2 (1)

The Optimized Generation Planning Program Conceptual Flow Chart



Notes: (1) Descriptive Pamphlet for the Optimized Generation Planning Program, General Electric Company.

for the Optimized Generation Planning Program," General Electric Company, January 1979.

1. The user supplies input data describing:

   a. The operating costs and characteristics of all existing and committed generating units and the expansion candidate generating unit types.

   b. Load data describing the daily and monthly load patterns, annual MW peaks, and forecast load growth.

   c. Study factors such as escalation rates, reliability criteria, and minimum acceptable rate of return.

2. For each year, the program will develop a list of generation addition alternatives from the list of specified candidate expansion units. Each alternative is tested for its ability to meet the specified LOLP system reliability criterion. Using a "look ahead" option, mature unit outage rates are used for these calculations to anticipate future conditions.

3. System production costs are calculated for each alternative. Using a "look ahead" option, levelized annual fuel and O&M costs and mature unit outage rates are used for these calculations to anticipate future conditions which may affect generating unit operation.

4. Levelized annual capital investment costs are calculated for each alternative.

5. Total production plus investment cost is determined for each alternative. The alternative with the lowest total cost is selected as the "optimum" addition to the system.

6. System reliability is rechecked for the selected alternative using current year outage rates.

7. System production costs for the selected alternative are recalculated using current year costs and outage rates.

8. The program repeats steps 2-7 for each succeeding year in the study.

4.3 System Expansions

General - Generation and load data for the selected synthetic systems were used as input to General Electric's Optimized Generation Planning (OGP) package. OGP develops an optimum generation expansion plan, based on maintaining a specified level of system reliability and minimizing total production plus capital investment cost as discussed in Section 4.2.

Many types of generating units may be considered for expansion candidates, including existing unit types, advanced technologies leading to improved versions of existing unit types, advanced technologies leading to new unit types, and advanced technologies leading to alternate fuels for both existing and new unit types.

It is impractical to attempt to consider all of the numerous possibilities in developing a long-range system expansion. The OGP program itself is limited to consideration of six types of thermal capacity and three types of energy storage capacity in any one run. Finally, it was not the intent of this assessment to evaluate all of the possible competing technologies. Immediate interest was in evaluating the HTGR in the context of utility generation mixes. Given the objective and the constraints, the expansion unit candidates shown in Table 4.3-1 were selected for the study.

<u>1985-2000 Expansion</u> - The EPRI synthetic system models represent 1985 systems. Since the HTGR-GT is not expected to become commercially available until the year 2000, it was first necessary to expand the synthetic systems to this future date. This was done by initially selecting additional generation alternatives which are expected to become commercially available during this period. A combination of utility assumptions and OGP verification led to the year 2000 utility systems which are described briefly in Section 5.0 and in greater detail in Appendix C. These systems as they appeared in the beginning of the year 2000 were inputted as the reference systems for analyzing the HTGR during the 2000-2020 time period.

<u>2000-2020 Expansion</u> - Three base case optimum mix scenarios were developed for the Northeast and West regions:

1. No nuclear unit additions allowed.

2. LWR nuclear unit additions allowed.

3. LWR and HTGR nuclear unit additions allowed.

The first scenario, with no nuclear additions after the year 2000, establishes a base line to evaluate the economic attractiveness of nuclear power in general. The second scenario, allowing LWR type nuclear units in the optimum mix, establishes a base line to evaluate the attractiveness of the HTGR in particular as an alternative nuclear power source. The third scenario, when compared with the first two, provides an estimate of the potential impact of the HTGR. OGP was utilized to develop optimum utility systems for each of these scenarios for the 20-year period, and the resulting generation mixes are described in Section 5.

In developing the West region scenarios, the potential of limited availability of future supplies of cooling water was recognized. For this reason, nuclear and fossil steam units installed in the West in the 2000-2020 period were assumed to have peak shaved dry/wet cooling systems.

Table 4.3-1

Expansion Unit Candidates

Unit Type	Size	Available for Commercial Service
Nuclear:		
LWR	1200 MW	Current
HTGR	1200 MW	2000
Coal:		
Conventional w/FGD (1)	1000 MW	Current
	600 MW	Current
Atmospheric Fluidized-Bed	1000 MW	1990
Gas Turbine (2):		
Current Technology	75 MW	Current
Advanced Technology	100 MW	1987
Combined Cycle (2):		
Current Technology	250 MW	Current
Advanced Technology	285 MW	1989
Advanced Batteries	100 MW	1990

Notes: (1) FGD = Flue Gas Desulfurization

(2) The advanced technology units will replace the current technology units as expansion candidates in the year they become commercially available.

Key variables affecting the HTGR's penetrability into utility systems were studied to investigate the relationship of these variables and their relative impact on the application of the HTGR. These results are discussed in Section 5.

While there are several applications for the HTGR, the HTGR Market Assessment is primarily directed at the HTGR-Gas-Turbine. All subsequent references to the HTGR in this Assessment are in relation to this particular application.

5.0 Systems Analysis - Results

Through the use of systems analysis as described in Section 4, the HTGR's ability to penetrate into the utility environment was assessed and is discussed in this section. This environment includes baseload, intermediate, peaking and storage type generation and their complex system interaction. Because of the uncertainty in cost data associated with the HTGR, all unit cost inputs, except fuel cost, were assumed to be at parity with an LWR for the Northeast base case evaluation. The fuel costs of the HTGR are believed to be more firm estimates because of well understood physical differences, and were inputted as such. In the West, it was assumed that LWRs would incur a penalty in capital cost due to expected requirements for some measure of dry cooling. Other costs were inputted as described above. The key characteristics of the reference nuclear systems evaluated in this Assessment are shown in Table 5.1-1. More detailed data on these and the other analyzed units are shown in Appendix C. The abbreviations of these units which are used in subsequent tables and figures are found in Table 5.1-2.

5.1 Northeast Region

No Nuclear Option - The initial Northeast situation addressed was no nuclear option available after the turn of the century. Beginning in the year 2000, the Northeast region had the generation characteristics as shown in Table 5.1-3. This situation expanded to the year 2020 had the generation characteristics shown also in Table 5.1-3 with the generation type deployment pattern shown in Figure 5.1-1. The change in generation mix as a percentage by year can be found in Figure 5.1-2. Nuclear capacity had dropped from 40% to around 15% of the total system mix, as none were available for purchase and two units were retired. This 15% nuclear capacity produced 22% of the power in the final year of the study. Similar margins exist today throughout the U.S. as a tribute to advantageous nuclear operations costs. The coal mix was greatly increased and nearly doubled to over 55% in the 20 years of this study. The system added sixteen 1000 MWe atmospheric fluidized bed (AFB) units. The advantage in capital cost of the AFB over the conventional coal units overshadowed the expected operation and maintenance disadvantages as the utility consistently chose the former over the latter. As older oil and coal units were retired, they were replaced by more economic baseload coal, intermediate combined cycle units, and peaking combustion turbine units. Batteries became a significant system contribution at approximately 13% total mix as energy storage became increasingly important.

In this environment, the older nuclear units were consistently run at higher capacity factors than the coal units, due primarily to the fuel cost savings associated with these units. In addition, several older coal units were generally run at higher capacity factors than the newer coal units, until they were retired. This was attributed primarily to lower outage rates and lower maintenance costs.

Table 5.1-1

Nuclear System Unit Cost Data (1977 $)

	Size (MWe)	Effficiency %	Capital Cost(1) ($/KWe)	Fuel Cost(2) (¢/MBtu)	O&M Cost Fixed ($/KWe)	O&M Cost Variable ($/MWhr)
Northeast						
LWR	1200	33.8	828	.54	8.00	1.20
HTGR	1200	39.6	828	.583	8.00	1.20
West						
LWR	1200	33.8	823	.54	8.20	1.23
HTGR	1200	39.6	781	.583	8.20	1.23

Notes: (1) Includes contingencies, startup costs, and AFDC.
(2) Based on once-through fuel cycle.

Table 5.1-2

Generation Type Abbreviations

BATT	-	Battery
CC	-	Combined Cycle
C/AFB		Coal/Atmospheric Fluidized Bed
GT	-	Gas Turbine
C/600	-	Pre-1985 Coal
C/1000	-	Coal/1000 MWe w/Flue Gas Desulphurization
C/O	-	Pre-1985 Coal Plus Oil
H	-	Conventional Hydroelectric
HTGR	-	High Temperature Gas-Cooled Reactor
LWR	-	Light Water Reactor
PH	-	Pumped Storage Hydroelectric

Table 5.1-3

Northeast - No Nuclear Option

		Beginning Year: 2000 System Capacity: 17855 MW		End Year: 2019 System Capacity: 32380 MW	
		MW	% Mix	MW	% Mix
LWR	=	7200	40.3	4800	14.8
Coal					
1000	=	1000	5.6	1000	3.1
AFB	=	1000	5.6	17000	52.5
Pre-1985	=	3000	16.8	0	0
Subtotal	=	5000	28.0	18000	55.6
Oil	=	2200	12.3	800	2.5
Gas Turbine	=	1750	9.8	2200	6.8
Combined Cycle	=	1105	6.2	2280	7.0
Battery	=	600	3.4	4300	13.3
Total		17855	100.0	32380	100.0

Figure 5.1-1

Generation Deployment Pattern 2000 to 2020

Northeast - No Nuclear Option

GENERATION SYSTEM

TYPE	LWR	C-600	G.T.	C.C.	C-1000	C-AFB	TYPES	
	1	2	3	4	5	6	7-10	

****

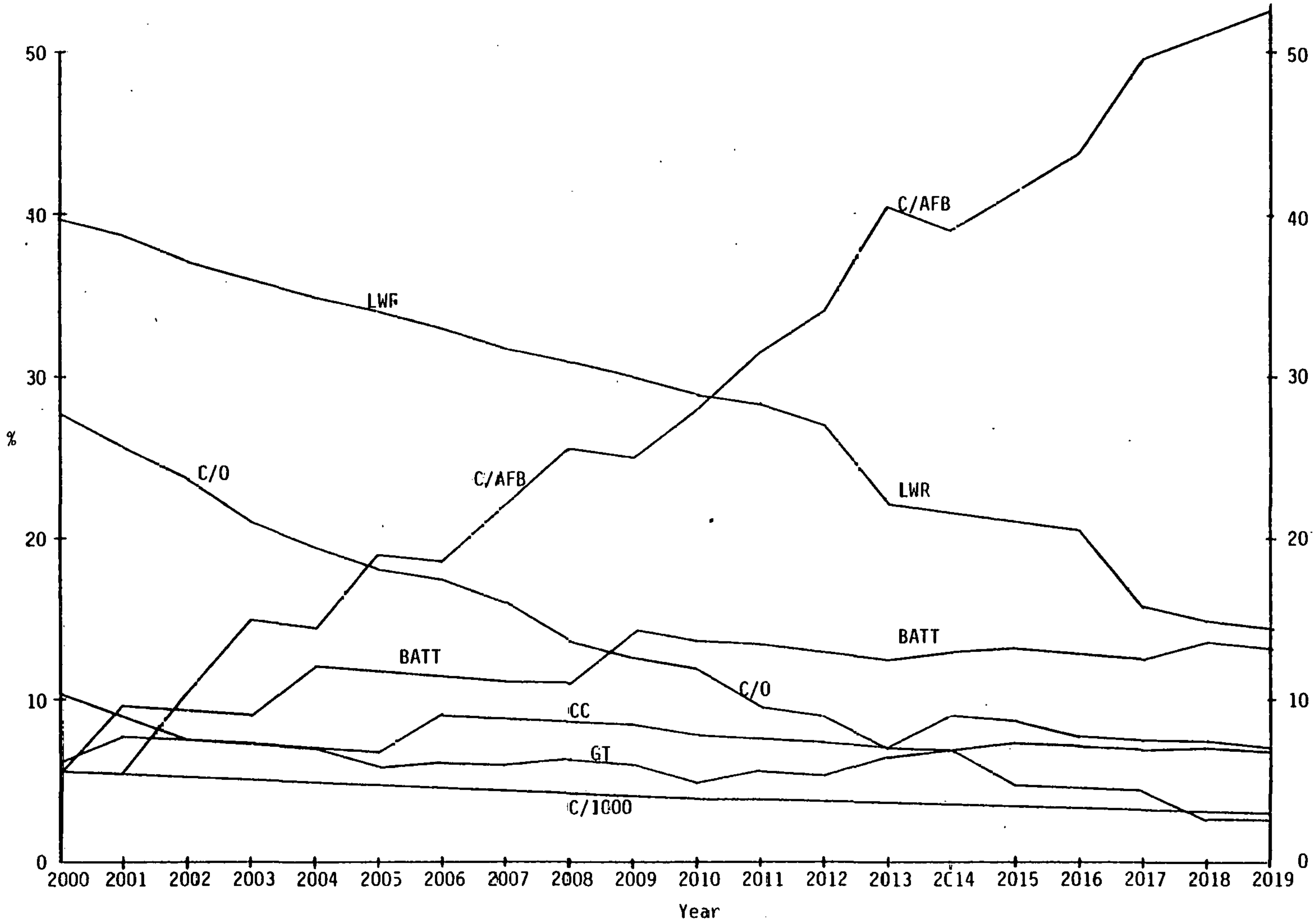
YR	Y E A R L Y		M W			A D D I T I	O N S	TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
0			300*				400*	18155
1				1X 285			600	18640
2						1X1000		19240
3						1X1000		19840
4							900	20540
5						1X1000		21140
6			1X 100	2X 285				21810
7						1X1000		22610
8			1X 100			1X1000		23310
9							900	24010
10						1X1000		24810
11			2X 100			1X1000		25410
12						1X1000		26360
13			4X 100			2X1000		27160
14			1X 100	2X 285			200	28030
15			2X 100			1X1000	200	28830
16						1X1000		29580
17						2X1000		30380
18			1X 100			1X1000	500	31380
19						1X1000		32380

****

****

Figure 5.1-2

Yearly Generation Mix
Northeast - No Nuclear Option



LWR Option - Next, the scenario where the LWR was a continuing and unconstrained option in the Northeast was then evaluated. This situation expanded to the year 2020 had the generation characteristics shown in Table 5.1-4 with the generation type deployment pattern shown in Figure 5.1-3. The change in generation mix as a percentage by year can be found in Figure 5.1-4. Installed nuclear capacity increased from 40% to nearly 67% of total mix, but as depicted on Figure 5.1-4 the nuclear percentage is reaching an asymptote. It would appear that this utility will limit itself to approximately 70% nuclear capacity. The trend of approximately 60% to 70% of system capacity being baseload plants is witnessed throughout the U.S. today. Optimum baseload mix would, therefore, appear unrelated to absolute utility system size.

The coal mix was reduced from 28% to about 6%, and seven oil units were retired as fifteen 1200 MWe LWRs were added and two were retired during the 20-year study period. Gas turbine mix was changed downward slightly from 10% to 7%, and the mix of combined cycle units remained nearly identical. Again, batteries became a significant system contribution at over 12% as energy storage became increasingly important.

In this scenario, nuclear units were added in favor of other baseload coal units despite a capital cost penalty of nearly 30%. The fuel cost savings was as is today the major factor in the choice of nuclear over coal. In addition, the nuclear units were consistently run at higher capacity factors than the coal units. This was again because of the fuel cost savings associated with the nuclear units. Several older coal units were generally run at higher capacity factors than the newer coal units, until they were retired. This was attributed primarily to lower outage rates and lower maintenance costs.

At the beginning of the year 2000, nuclear power generated 62% of the electricity yet represented only 40% of the installed capacity, and by the beginning of the year 2020, the 67% nuclear generated 92% of total system power.

Table 5.1-4

Northeast - LWR Option

		Beginning Year: 2000 System Capacity: 17855 MW MW	% Mix	End Year: 2019 System Capacity: 34195 MW MW	% Mix
LWR	=	7200	40.3	22800	66.7
Coal					
1000	=	1000	5.6	1000	2.9
AFB	=	1000	5.6	1000	2.9
Pre-1985	=	3000	16.8	0	0
Subtotal	=	5000	28.0	2000	5.8
Oil	=	2200	12.3	800	2.3
Gas Turbine	=	1750	9.8	2300	6.7
Combined Cycle	=	1105	6.2	1995	5.8
Battery	=	600	3.4	4300	12.6
Total		17855	100.0	34195	100.0

Figure 5.1-3

Generation Deployment Pattern 2000 to 2020

Northeast - LWR Option

GENERATION SYSTEM

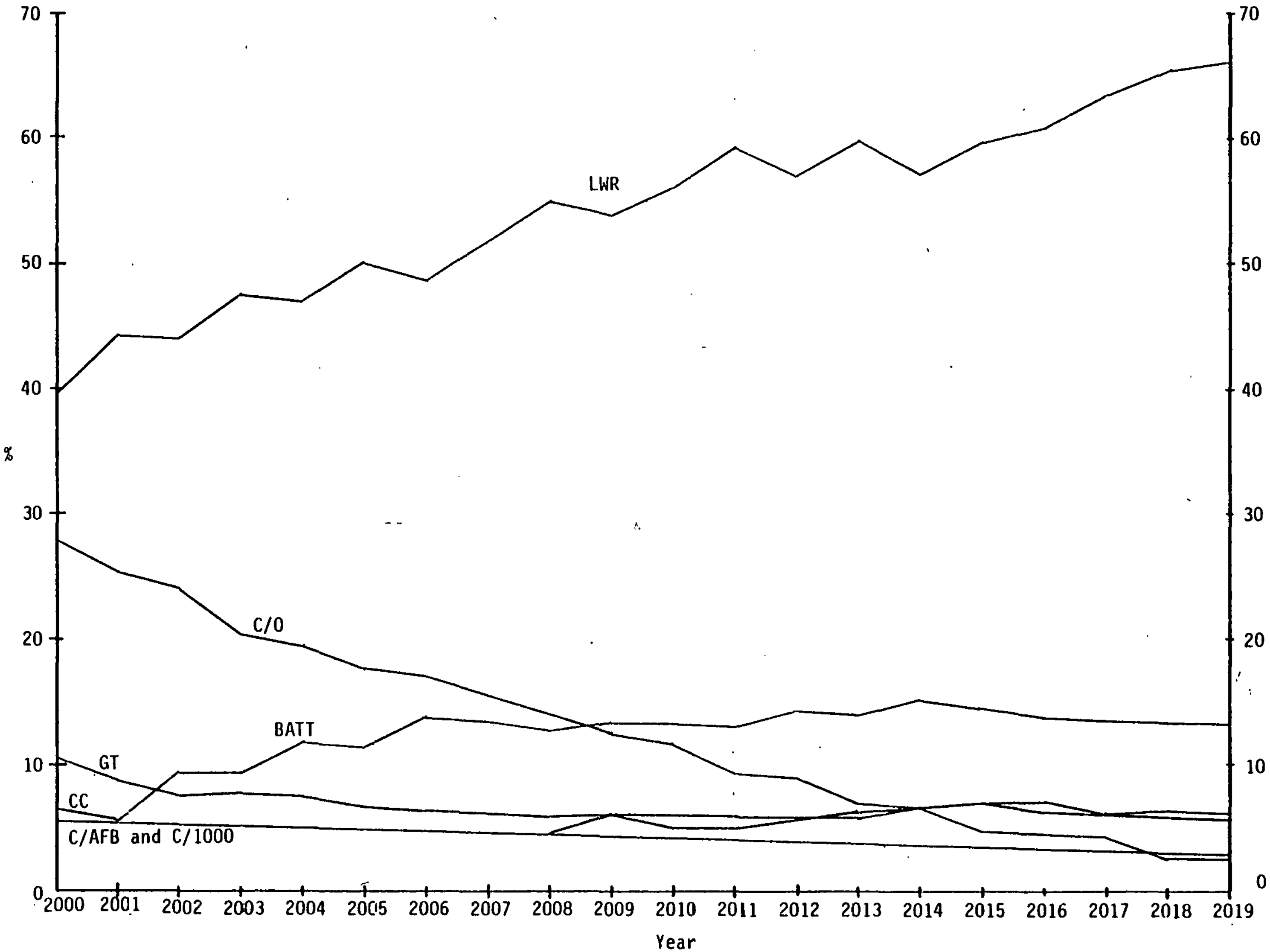
TYPE	LWR 1	C-600 2	G.T. 3	C.C. 4	C-1000 5	C-AFB 6	TYPES 7-10	

YR	YEARLY		MW		ADDITIONS			TOTAL CAPAB. + TIES
0			300*				400*	18155
1	1X1200							18955
2							700	19255
3	1X1200		1X 100					20155
4							700	20655
5	1X1200		1X 100					21555
6							600	22155
7	1X1200							23155
8	1X1200							23955
9			1X 100	2X 285			300	24725
10	1X1200							25725
11	1X1200							26325
12			3X 100				600	27175
13	2X1200		2X 100					28175
14			2X 100	1X 285			400	29060
15	1X1200		2X 100	1X 285				30145
16	1X1200							31095
17	2X1200							32295
18	1X1200		1X 100					32995
19	1X1200							34195

Figure 5.1-4

Yearly Generation Mix

Northeast - LWR Option



LWR and HTGR Options - The scenario in the Northeast where the LWR was a continuing option as well as the HTGR becoming an available option in the year 2000 had the year 2020 generation characteristics as shown in Table 5.1-5 with the generation type deployment pattern shown in Figure 5.1-5. The change in generation mix as a percentage by year can be found in Figure 5.1-6. Total nuclear capacity increased from 40% to 50%, but the LWR fraction had dropped to 14% by the beginning of the year 2020, as all nuclear additions were of the HTGR type. Total nuclear capacity will probably reach an asymptote of around 70% as retired baseload units will likely be replaced by the HTGR. The HTGR was added in favor of the LWR in the Northeast due to the small input advantages in fuel costs. The trend of 60% to 70% of system capacity being baseload is generally consistent with utilities throughout the U.S. Utility system/reserve margins averaged 28.7% and were inclusive of 1200 megawatts of spinning reserve over the study period.

The coal mix was reduced to 6% down from 25%, and seven oil units were retired as fourteen 1200 MWe HTGRs were added and two LWRs were retired during this 20-year study period.

In this scenario, nuclear units were consistently run at higher capacity factors than coal units. After several years, maturing HTGRs were run at slightly higher capacity factors than LWRs, and in the year 2014 and again in 2016, an HTGR set a capacity factor record of 78% for baseload units for the Northeast. HTGRs were generally run between 60% and 70% capacity factors and averaged 68% over the study period despite the penalty associated with the immaturity of new plant additions. LWRs were also generally run between 60% and 70% capacity factors and averaged 67.6% over the study period.

By the year 2020, the 64% installed nuclear capacity was generating 89% of total system power. The HTGR contributed 70% of this total. Similar nuclear margins exist today in certain areas of the U.S. as a tribute to economical nuclear operations costs.

Table 5.1-5

Northeast - LWR and HTGR Option

		Beginning Year: 2000 System Capacity: 17855 MW		End Year: 2019 System Capacity: 33965 MW	
		MW	% Mix	MW	% Mix
LWR	=	7200	40.3	4800	14.1
HTGR	=	0	0	16800	49.5
Coal					
1000	=	1000	5.6	1000	2.9
AFB	=	1000	5.6	1000	2.9
Pre-1985	=	3000	16.8	0	0
Subtotal	=	5000	28.0	2000	5.8
Oil	=	2200	12.3	800	2.4
Gas Turbine	=	1750	9.8	2300	6.8
Combined Cycle	=	1105	6.2	2565	7.6
Battery	=	600	3.4	4700	13.8
Total		17855	100.0	33965	100.0

Figure 5.1-5

Generation Deployment Pattern 2000 to 2020

Northeast - LWR and HTGR Option

GENERATION SYSTEM

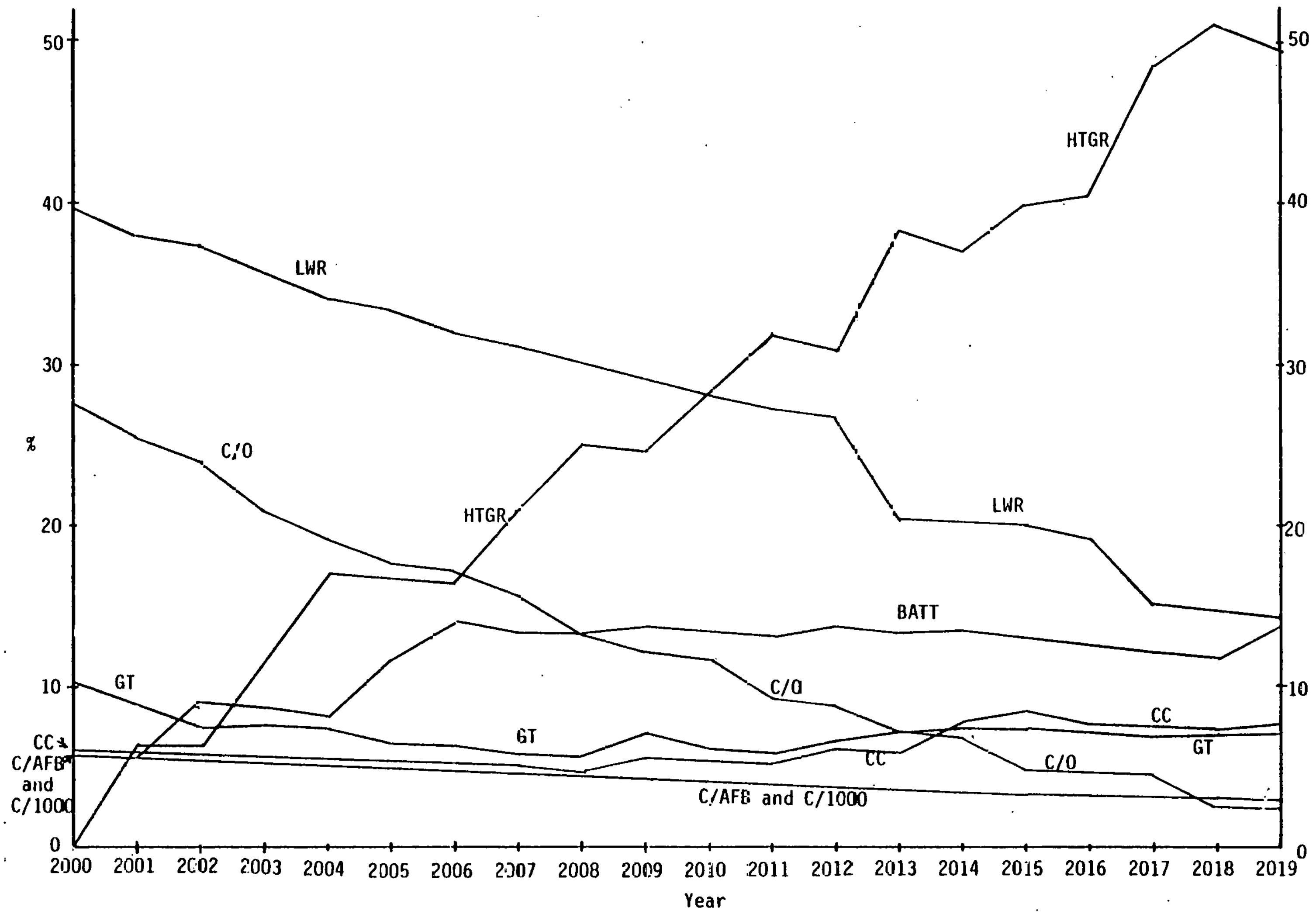
YR	LWR	HTGR	G.T.	C.C.	C-1000	C-AFB	TYPES	TOTAL CAPAB. + TIES
TYPE	1	2	3	4	5	6	7-10	
	YEARLY		MW		ADDITIONS			
0			300*				400*	18155
1		1X1200						18955
2							700	19255
3		1X1200	1X 100					20155
4		1X1200						21155
5							800	21555
6							600	22155
7		1X1200						23155
8		1X1200						23955
9			4X 100	1X 285			300	24740
10		1X1200						25740
11		1X1200						26340
12			3X 100	1X 285			300	27175
13		2X1200	2X 100					28175
14			1X 100	2X 285			200	29045
15		1X1200	1X 100	1X 285				30030
16		1X1200						30980
17		2X1200						32180
18		1X1200	1X 100					32880
19				1X 285			800	33965

5-10

Figure 5.1-6

Yearly Generation Mix

Northeast - LWR and HTGR Option



Comparative Economics - The cost values discussed herein are cumulative present worth 1977 dollars and are also end-year adjusted to properly account for plant costs beyond the year 2020. The process of end-year adjustment is described in Appendix C.

In the no nuclear option, the Northeast region spent nearly $3.5 billion in capital investment, $12.6 billion for fuel, and $3.3 billion for operation and maintenance, for a total system expenditure of $19.4 billion.

In the LWR option, the Northeast region spent $4.8 billion in capital investments, $9.1 billion for fuel, and $2.3 billion for operation and maintenance, for a total system expenditure of $16.2 billion. The Northeast opted to spend $1.3 billion more in capital expenditures with the LWR available than if it were not. This increase, however, produced for the utility a system savings of $3.5 billion in fuel costs and an additional $1 billion in O&M costs. The total net system savings with the LWR option available was nearly $3.2 billion or approximately 20%.

In the LWR plus HTGR option, the Northeast region spent $4.7 billion in capital investment, $9.0 billion for fuel, and $2.3 billion for operation and maintenance, for a total system expenditure of around $16.0 billion. The total net system savings with the HTGR as an option compared to having the LWR as the only available nuclear option was $150 million, or a 1% system savings, which is attributed to the fuel cost differences. Analysis showed that in the years in which HTGRs were added, the difference in system savings over that if LWRs had been added instead varied from .04% to .87%. These analyses provided insight to the trivial effect the reference HTGR fuel cycle cost advantage has on overall system cost. Of course, the system savings over a non-nuclear system were substantial, but the difference in the nuclear options is insignificant, and indeed when plotted by year as a function of system expenditure as in Figure 5.1-7, they are indistinguishable.

Sensitivity analyses discussed in Section 5.3 were conducted to define the relationship of the key cost parameters and their relative impact on the HTGR for establishing it as an economically attractive generation alternative.

Comparative Cooling Water Consumption

The OGP code used for this analysis also has the capability to analyze environmental factors. One such parameter addressed briefly was water. Water consumption for power plant cooling was analyzed through utilization of the following Northeast reference cases:

1. No nuclear unit additions allowed.

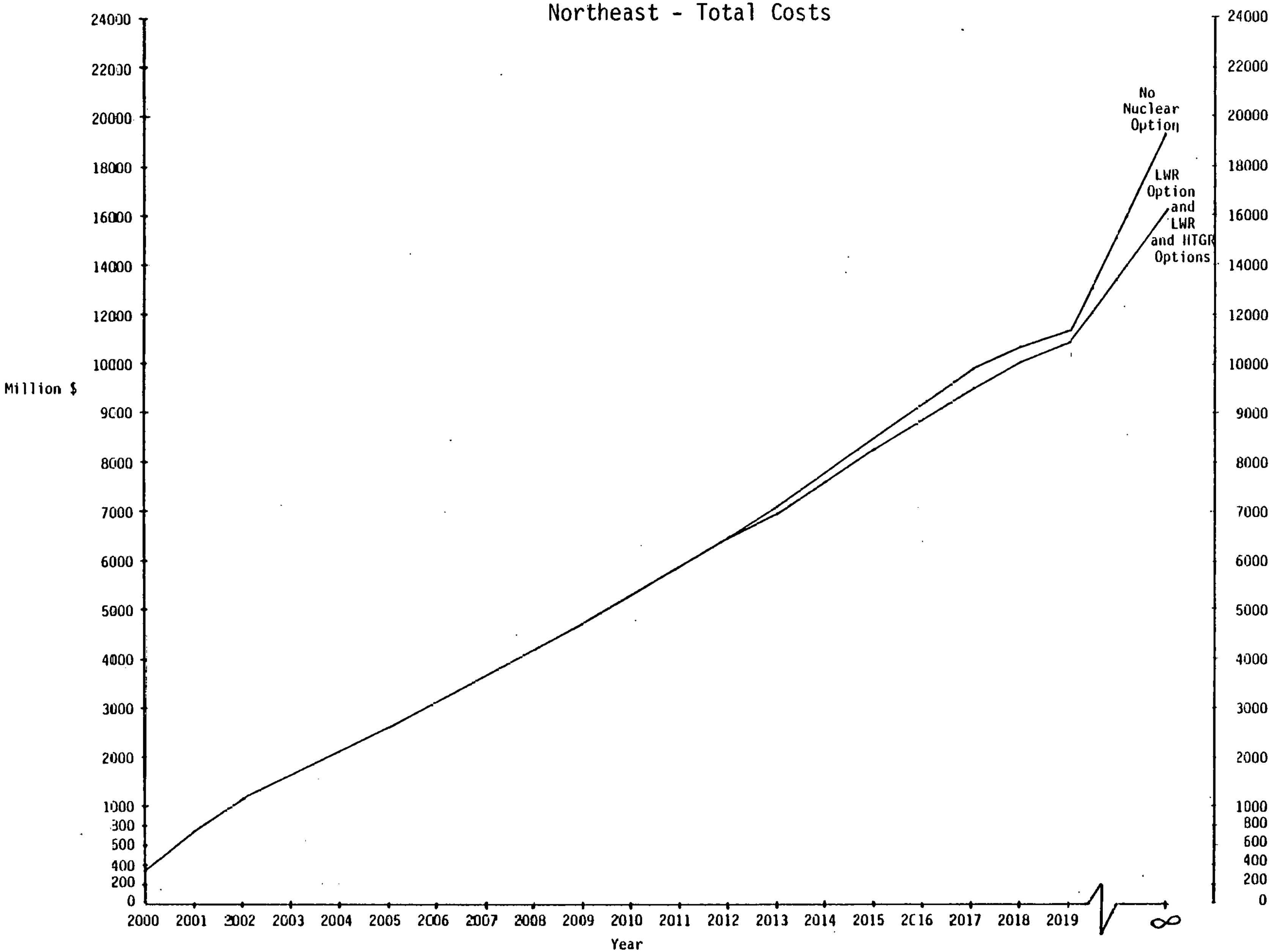
2. LWR nuclear unit additions allowed.

3. LWR and HTGR nuclear unit additions allowed.

Figure 5.1-7

Cumulative Present Worth

Northeast - Total Costs



Water Consumption (Billions Gallons Per Year)

Case	2000	2010	2020
No Nuclear	38	59	84
LWR	38	67	99
LWR and HTGR	38	40	31

As can be seen from the values above, the LWR environment was the most costly in terms of water consumption. By eliminating this nuclear option in favor of coal technologies, 15 billion gallons of water were saved annually by the year 2020. By introduction of the HTGR, 68 billion gallons of water were saved annually by the year 2020. This amount is indeed significant and is directly attributable to the capability of the HTGR to be economically operated with a peak shaved dry/wet cooling system.

5.2 West Region

No Nuclear Option - The initial West situation evaluated was no nuclear option available after the turn of the century. Beginning in the year 2000, the West region had the generation characteristics as shown in Table 5.2-1. This scenario expanded to the year 2020 had the generation characteristics shown also in Table 5.2-1 with the generation type deployment pattern shown in Figure 5.2-1. The change in generation mix as a percentage by year can be found in Figure 5.2-2. Nuclear capacity had dropped from 35% to around 14% of the total system mix as none were available for purchase and one unit was retired. This 14% nuclear capacity produced 22% of the power in the final year of this study. Similar margins exist today throughout the U.S. as a tribute to advantageous nuclear operations costs. The coal mix was greatly increased and more than doubled to over 54% in the 20 years of the study. The system added six 1000 MWe coal units with FGD and thirteen 1000 MWe AFB coal units during the study period. The system selected both types of units to fill particular system needs in particular years. For example, in the year 2006, the addition of a conventional coal unit led to a higher system investment and fuel cost, but O&M savings were enough to swing the economics over to that system. In the year 2016, the system added two 1000 MWe AFB units even though the addition of two 1000 MWe conventional and one 1000 MWe AFB units would have netted system fuel and O&M savings. The decisive factor in this instance was the differential investment costs.

Batteries increased only slightly as hydro still had a significant system fraction at 9% of capacity. Older oil and coal units were retired during this time and were largely replaced by combined cycle and combustion turbine units. In this environment, the nuclear units were consistently run at higher capacity factors than either of the coal units. This was because of the fuel cost savings associated with the nuclear units. In addition, several older coal units were generally run at higher capacity factors than the newer coal units until they were retired. This was attributed primarily to lower outage rates and lower maintenance costs.

Table 5.2-1

West - No Nuclear Option

		Beginning Year: 2000 System Capacity: 20100 MW		End Year: 2019 System Capacity: 42050 MW	
		MW	% Mix	MW	% Mix
LWR	=	7000	34.8	6000	14.3
Coal					
1000	=	2000	10.0	8000	19.0
AFB	=	1000	4.9	14000	33.3
Pre-1985	=	2000	10.0	800	1.9
Subtotal	=	5000	24.9	22800	54.2
Oil	=	2000	10.0	400	1.0
Gas Turbine	=	1400	7.0	3600	8.6
Combined Cycle	=	0	0	2850	6.8
Hydro	=	3800	18.9	3800	9.0
Process Heat	=	200	1.0	200	0.5
Battery	=	700	3.5	2400	5.7
Total		20100	100.1	42050	100.1

Figure 5.2-1

Generation Deployment Pattern 2000 to 2020

West - No Nuclear Option

GENERATION SYSTEM

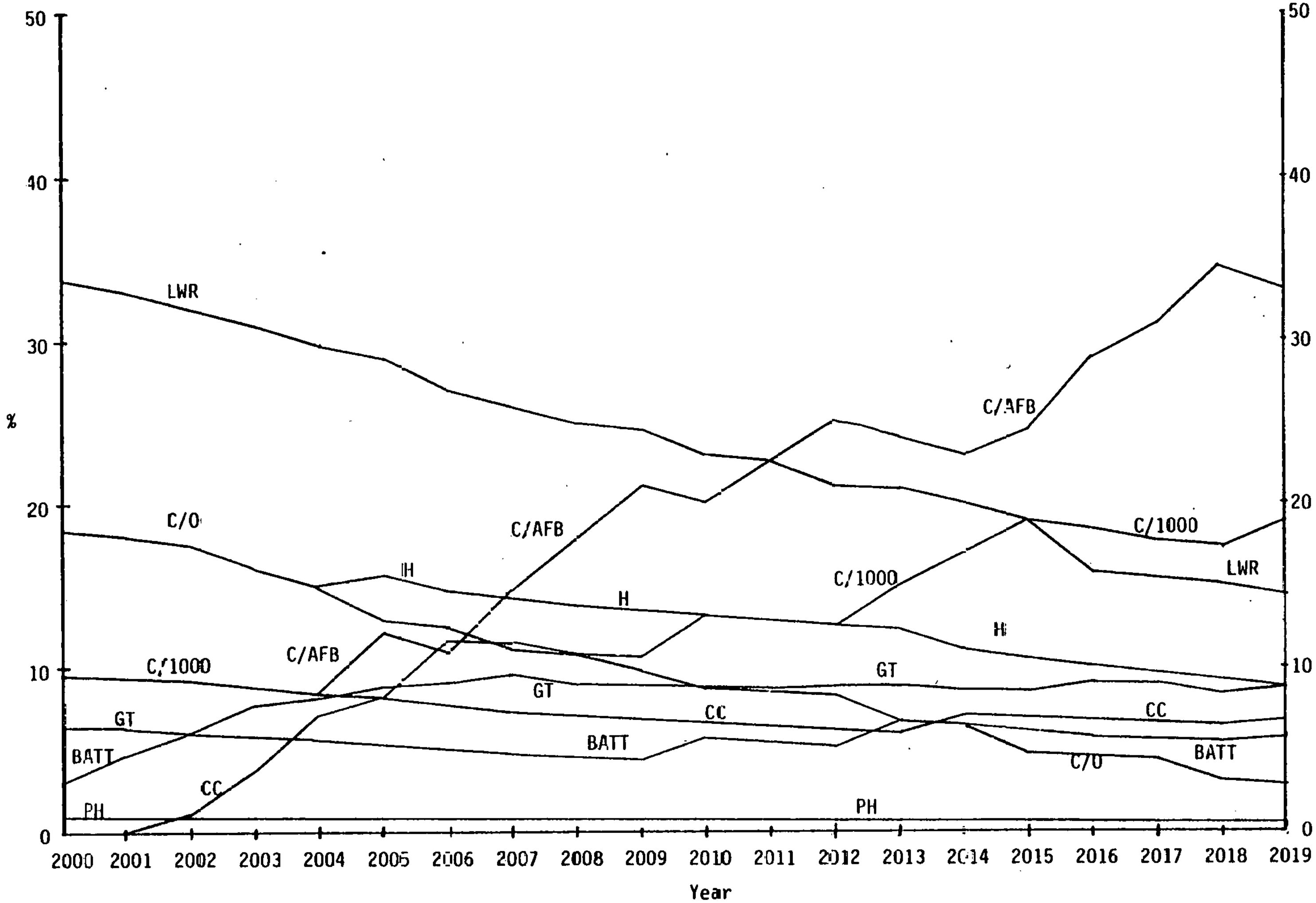
	LWR	C-600	G.T.	C.C.	C-1000	C-AFB	TYPES
TYPE	1	2	3	4	5	6	7-10

YR	Y E A R L Y		M W		A D D I T I O N S			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
0						1000*		20800
1							300	21100
2			1X 100	1X 285			300	21685
3			4X 100	2X 285				22455
4			2X 100	3X 285				23510
5			2X 100	1X 285		1X1000		24595
6			2X 100		1X1000			25795
7			2X 100			1X1000		26795
8						1X1000		27695
9			1X 100			1X1000		28595
10			2X 100		1X1000		400	29895
11						1X1000		30895
12			2X 100			1X1000		32095
13			1X 100		1X1000		500	33295
14			2X 100	2X 285	1X1000			34965
15			1X 100		1X1000	1X1000		36665
16			3X 100			2X1000		37965
17			1X 100			1X1000		39065
18			1X 100			2X1000		40365
19			2X 100	1X 285	1X1000		200	42050

Figure 5.2-2

Yearly Generation Mix

West - No Nuclear Option



LWR Option - Next, the scenario where the LWR was a continuing and unconstrained option in the West was evaluated. This situation expanded to the year 2020 had the generation characteristics as shown in Table 5.2-2 with the generation type deployment pattern shown in Figure 5.2-3. The change in generation mix as a percentage by year can be found in Figure 5.2-4. Installed nuclear capacity increased from 35% to nearly 60% of total mix, but as can be seen on Figure 5.2-4, this fraction is reaching an asymptote. As in the Northeast, it would appear that this utility system will limit itself to about 70% nuclear capacity, as it is reasonable to assume that nuclear units will replace retired baseload plants.

The coal mix was reduced from 25% to 11% as sixteen 1200 MWe LWRs were added and one nuclear unit was retired during the 20-year study period. Eight oil units were retired during this time. The combustion turbine mix stayed significantly the same, going from 7.0% to 7.4%. Combined cycle units were added to give a total year 2020 fraction of 4.1%. Battery capacity nearly doubled but was still less than 7% of the system total mix.

Nuclear units were added over other baseload technology even though in the West region LWRs had a 9% and 16% capital cost penalty relative to conventional and AFB 1000 MWe coal units, respectively. In addition, in this scenario, the nuclear units were consistently run at higher capacity factors than all coal units. In addition, older coal units were also generally run at higher capacity factors than the newer coal units, until they were retired. This was attributed primarily to lower outage rate and lower maintenance costs.

At the beginning of the year 2000, nuclear power supplied 47% of system electrical output yet represented only 35% of the installed capacity, and by the beginning of the year 2020, the 60% nuclear capacity was generating 87% of total system power. Similar margins exist today in certain areas of the U.S. as a tribute to economical nuclear operations costs.

Table 5.2-2

West - LWR Option

		Beginning Year: 2000 System Capacity: 20100 MW		End Year: 2019 System Capacity: 42110 MW	
		MW	% Mix	MW	% Mix
LWR	=	7000	34.8	25200	59.8
Coal					
1000	=	2000	10.0	2000	4.7
AFB	=	1000	4.9	2000	4.7
Pre-1985	=	2000	10.0	800	2.0
Subtotal	=	5000	24.9	4800	11.4
Oil	=	2000	10.0	400	0.9
Gas Turbine	=	1400	7.0	3100	7.4
Combined Cycle	=	0	0	1710	4.1
Hydro	=	3800	18.9	3800	9.0
Process Heat	=	200	1.0	200	0.5
Battery	=	700	3.5	2900	6.9
Total		20100	100.1	42110	100.0

Figure 5.2-3

Generation Deployment Pattern 2000 to 2020

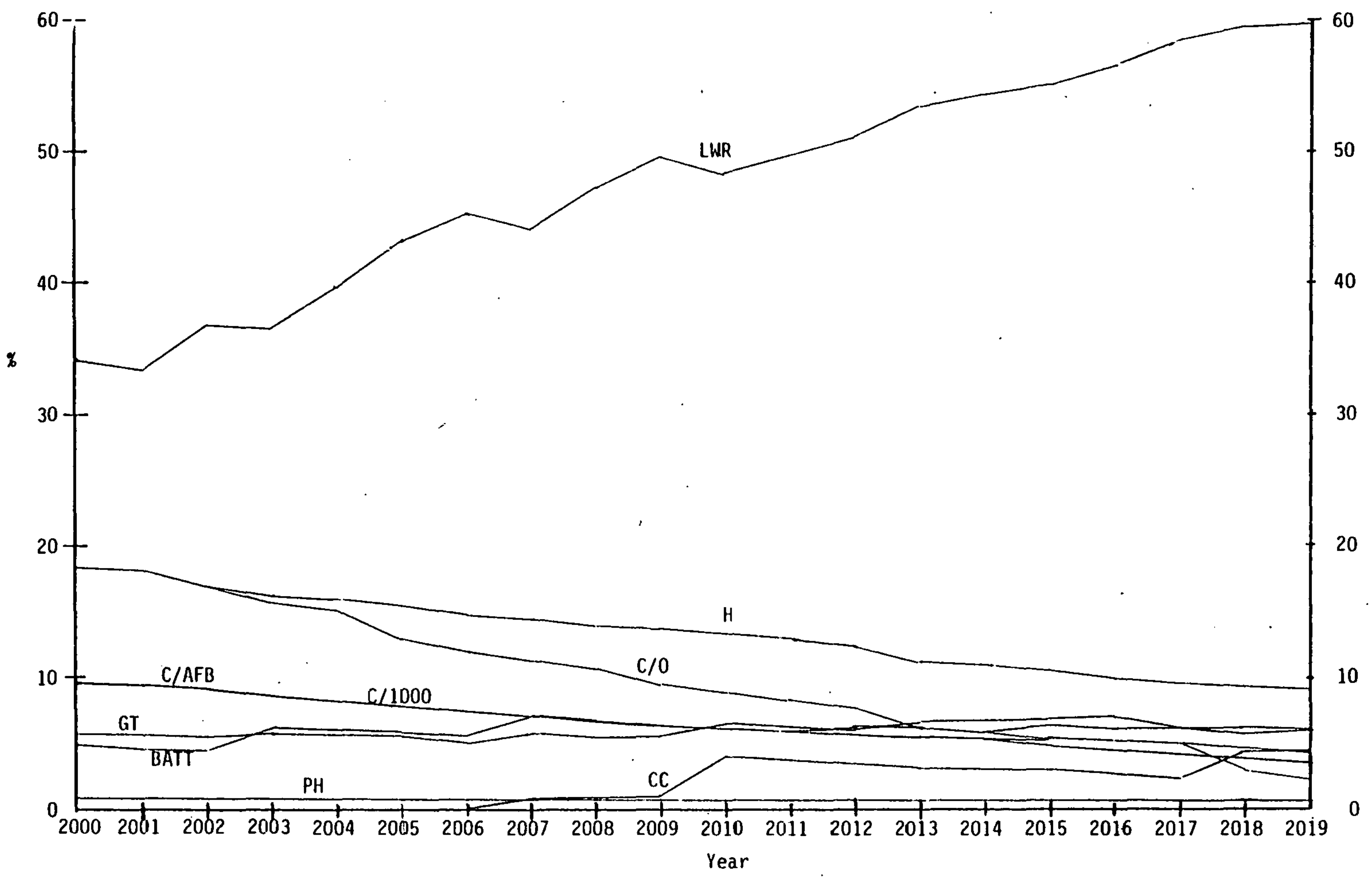
West - LWR Option

GENERATION SYSTEM

	LWR	C-600	G.T.	C.C.	C-1000	C-AFB	TYPES	
TYPE	1	2	3	4	5	6	7-10	
******	******	******	******	******	******	******	******	******
YR	YEARLY		MW		ADDITIONS			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
0						1000*		20800
1							300	21100
2	1X1200							22200
3			1X 100				500	22600
4	1X1200							23800
5	1X1200							24600
6	1X1200							25800
7			3X 100	1X 285			400	26585
8	1X1200							27685
9	1X1200		1X 100					28785
10			7X 100	3X 285				30040
11	1X1200							31240
12	1X1200							32440
13	1X1200		2X 100				200	33640
14	1X1200		2X 100					34940
15	1X1200		2X 100				300	36240
16	2X1200		2X 100					37840
17	1X1200						300	39340
18	1X1200		2X 100	2X 285			200	40710
19	1X1200		2X 100					42110

Figure 5.2-4

Yearly Generation Mix
West - LWR Option



LWR and HTGR Option - The scenario in the West where the LWR was a continuing option as well as the HTGR becoming an available option in the year 2000 was then evaluated. This scenario expanded to the year 2020 had the characteristics as shown in Table 5.2-3 with the generation type deployment pattern shown in Figure 5.2-5. The change in generation mix as a percentage by year can be found in Figure 5.2-6. Total nuclear capacity increased from 35% to 60%, but the LWR fraction had dropped to 14% by the beginning of the year 2020, as all nuclear additions were of the HTGR type. Total nuclear capacity will probably reach an asymptote of around 70% as retired baseload units will likely be replaced by the HTGR. The HTGR was added in favor of the LWR in the West due to advantages in capital and fuel costs. The trend of 60% to 70% of system capacity being baseload is generally consistent with utilities throughout the U.S.

The coal mix was reduced to 11% down from 25%, and eight oil units were retired as sixteen 1200 MWe HTGRs were added and one LWR unit was retired during this 20-year study period. Even though there were the same number of nuclear additions as with the LWR as compared to the LWR and HTGR, the West mix in the area of intermediate and storage was somewhat different for the two cases. The intermediate combined cycle units represented a larger fraction while the battery storage units represented a smaller fraction in the LWR plus HTGR case. Peaking combustion turbines represented nearly identical system fractions for the two cases.

In this scenario, nuclear units were consistently run at higher capacity factors than coal units. After several years, mature HTGRs were run at slightly higher capacity factors than LWRs, and in 2015 an HTGR set a capacity factor record of 78.5% for baseload units for the West. This unit, however, was less than 3 years old. LWRs were run generally between 65% and 75% capacity factors.

By the beginning of the year 2020, the 60% installed nuclear capacity was generating 82% of total system power. The HTGR contributed 63% of this total. Similar nuclear margins exist today in certain areas of the U.S. as a tribute to economical nuclear operations costs.

Table 5.2-3

West - LWR and HTGR Option

		Beginning Year: 2000 System Capacity: 20100 MW		End Year: 2019 System Capacity: 42380 MW	
		MW	% Mix	MW	% Mix
LWR	=	7000	34.8	6000	14.2
HTGR	=	0	0	19200	45.3
Coal					
1000	=	2000	10.0	2000	4.7
AFB	=	1000	4.9	2000	4.7
Pre-1985	=	2000	10.0	800	1.9
Subtotal	=	5000	24.9	4800	11.3
Oil	=	2000	10.0	400	0.9
Gas Turbine	=	1400	7.0	3200	7.6
Combined Cycle	=	0	0	2280	5.4
Hydro	=	3800	18.9	3800	9.0
Process Heat	=	200	1.0	200	0.5
Battery	=	700	3.5	2500	5.9
Total		20100	100.1	42380	100.1

Figure 5.2-5

Generation Deployment Pattern 2000 to 2020

West - LWR and HTGR Option

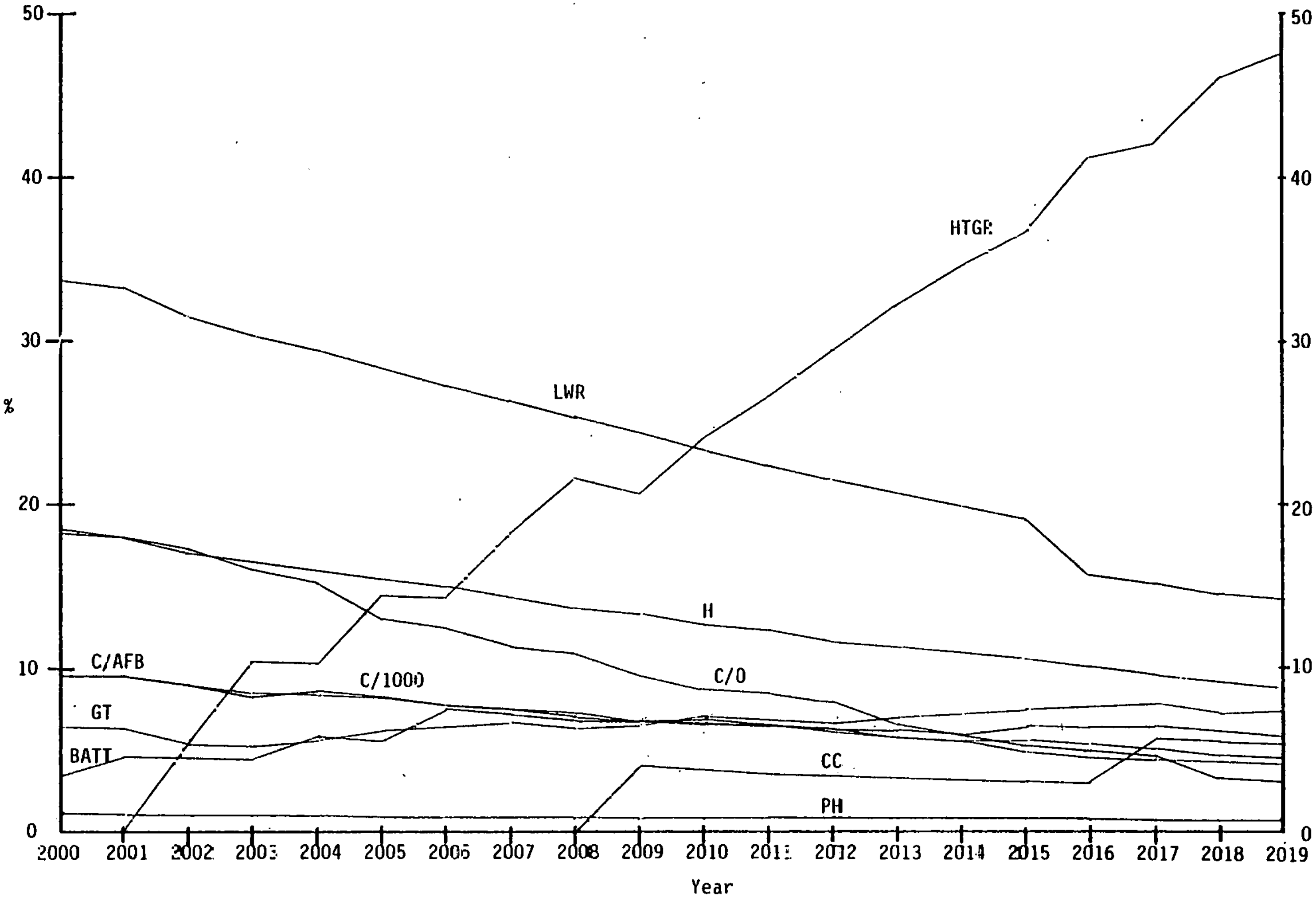
GENERATION SYSTEM	LWR	HTGR	G.T.	C.C.	C-1000	C-AFB	TYPES
TYPE	1	2	3	4	5	6	7-10

YR	YEARLY		MW		ADDITIONS			TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
0						1000*		20800
1							300	21100
2		1X1200						22200
3		1X1200						23200
4			1X 100				400	23700
5		1X1200	2X 100					24700
6			1X 100				500	25300
7		1X1200	2X 100					26500
8		1X1200						27600
9			2X 100	4X 285			100	28840
10		1X1200	3X 100					30040
11		1X1200						31240
12		1X1200						32440
13		1X1200	3X 100				100	33640
14		1X1200	2X 100					34940
15		1X1200	2X 100				300	36240
16		2X1200	2X 100					37840
17			2X 100	4X 285			100	39280
18		2X1200	1X 100					40980
19		1X1200	2X 100					42380

Figure 5.2-6

Yearly Generation Mix

West - LWR and HTGR Option



Comparative Economics - The following cost values are cumulative present worth 1977 dollars and are also end-year adjusted. With no nuclear option available, the West region spent $3.9 billion in capital investment, $15.5 billion for fuel, and $3.6 billion operation and maintenance (O&M), for a total system expenditure of $23 billion.

In the LWR option, the West region spent $4.9 billion in capital investment, $10.8 billion for fuel, and $2.8 billion for O&M, for a total system expenditure of $18.5 billion. The West opted to spend $1 billion more in capital expenditures with the LWR available than if it were not. This increase, however, produced for the utility a system savings of $4.7 billion in fuel costs and $0.8 billion in O&M costs. The net systems savings for the West was $4.6 billion, or 25%.

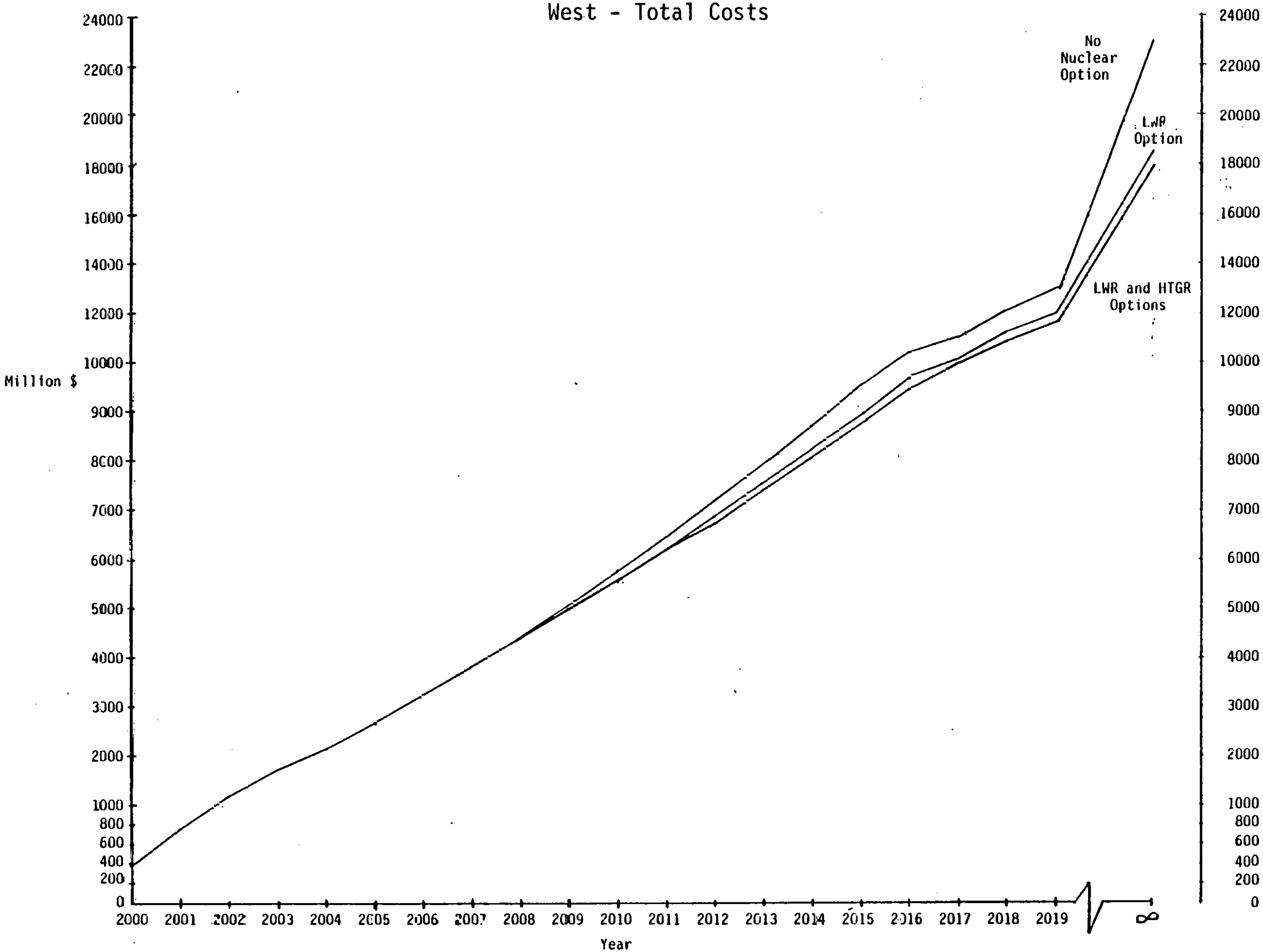
In the LWR and HTGR option, the West chose to add exclusively HTGRs as the nuclear option because of capital and fuel cost advantages. The West region spent $4.7 billion in capital investment, $10.6 billion for fuel, and $2.8 billion for O&M, for a total system expenditure of $18 billion. The net system savings was $0.5 billion or 2.5%. Compared to the scenario where the LWR is not an available option, the total systems savings of having the HTGR as an available option is $5.1 billion or nearly 30%.

The economic comparisons of the three West scenarios are plotted by year as a function of system expenditure and are shown in Figure 5.2-7.

Figure 5.2-7

Cumulative Present Worth

West - Total Costs



5.3 Sensitivity

In Sections 5.1 and 5.2, the effect of non-nuclear and nuclear environments was discussed with both the LWR and the HTGR as available generation alternatives. In this section, perturbations in HTGR variables were analyzed as to their effect on the total utility system, including economic effects due to changing the variable of interest and economic effects due to alterations in the mix of other generation systems. The economic effects are discussed relative to the LWR option reference case, and the generation mix trends are discussed as system alterations relative to the LWR and HTGR option reference case. With the Northeast as the sensitivity analysis reference, the following parameters were individually varied: capital cost, fuel cost, operation and maintenance cost, planned outage rate, and plant size. The model that has been used for this Assessment has the capability to analyze many other parameters as well. Several of these will be addressed in greater detail in subsequent phases of the HTGR Market Assessment.

Capital Cost

With nuclear power plants, capital cost is the most dominant factor in any economic analysis. In a direct comparison between the LWR and HTGR with the unit costs ascribed in the reference cases of this study, a 5% increase in HTGR capital cost would more than offset the small fuel cycle cost advantage of the HTGR. However, in utility systems analyses, an increased capital cost for the HTGR may still result in HTGR penetration due to alterations in the optimum generation mix that meets the given constraints of system reliability. For example, when the capital cost of the HTGR was increased by 5%, it was not completely replaced in the market by the addition of LWRs, as one third of all nuclear additions were HTGRs. The utility increased its capital expenditures by $200 million yet netted system savings of $170 million due primarily to fuel cost factors. These system savings were due to the better efficiency of the HTGR and also from the replacement of 570 megawatts of intermediate duty (oil-burning combined cycle) units which otherwise would have been added. When the capital cost of the HTGR was reduced by 5%, the system savings were over $800 million. Total capital expenditures were approximately the same, but system fuel savings were $770 million due again to the efficiency of the HTGR and more importantly to the total replacement of 1140 megawatts of intermediate duty generation which would have been added. Further reductions in capital cost continued to net significant savings, and at a decrease of 10% the system savings to the utility reached $1 billion. Successful programs that have the cited goal of reducing HTGR plant capital costs in the range analyzed in this assessment could result in the realization of these system savings.

Several system trends were apparent with perturbations to HTGR capital costs. As capital costs were increased, the market penetrability of the HTGR was clearly compromised, and it would be fair to conclude that in the range of 5% above to parity capital cost, the HTGR can be considered only marginally competitive with LWRs. As capital costs were decreased, the HTGR became very competitive and dominated not only the baseload market but also a significant fraction of the intermediate load generation market as well. When the HTGR was reduced by 5% in capital cost, two additional HTGRs were added and 1710 megawatts of intermediate capacity were effectively replaced as were 600 megawatts of storage (battery) capacity. Further reduction in capital cost tended to continue to slightly decrease the rate of storage capacity additions.

Fuel Cost

When the fuel costs of the HTGR were decreased by 10%, total system savings to the utility were over $950 million. There were increased system capital expenditures, but these were offset by $1.2 billion in fuel savings. These were derived from the better efficiency of the HTGR and by the replacement of 855 megawatts of intermediate duty units that would have been added. Further reductions in fuel costs continued to net significant savings, and at a decrease of 20% the system savings to the utility were $1.4 billion. With the advent of fuel recycle, introduction of highly enriched fuel, or increases in uranium ore costs, comparable savings and potentially more could indeed be realized.

There were several apparent trends associated with reductions in HTGR fuel costs. As fuel costs were reduced, the HTGR dominated the baseload market. With a fuel cost reduction of 10%, it also captured a large fraction of the intermediate market but did not eliminate it altogether as one intermediate duty unit was still added. By the time the HTGR's fuel cost had been reduced by 20%, however, this unit disappeared. Storage capacity deployment slowed somewhat as HTGR fuel costs were reduced, and this trend continued with further reductions.

Operation and Maintenance Cost

When the fixed and variable operation and maintenance (O&M) costs of the HTGR were decreased by 10%, total system savings to the utility were $500 million. Only $140 million of the total savings were derived directly from O&M savings as the larger fraction was derived from fuel savings from the better efficiency of the HTGR and also from the replacement of 855 megawatts of intermediate duty capacity that would have been added. A reduction of HTGR O&M costs by 20% netted a system savings of over $750 million, of which $260 million was direct O&M savings. An additional nuclear plant was added and 600 megawatts of storage capacity was replaced that would have been added. Utility input has recommended the HTGR plant be of a simpler and more reliable design, and if this is accomplished, these system savings could potentially be realized.

There were several apparent trends associated with reductions in HTGR operation and maintenance costs. As these costs were reduced, the HTGR dominated the baseload market. It also captured a significant fraction of the intermediate market; however, nowhere in the range of reduction of O&M costs analyzed in this Assessment did it altogether replace the additions of intermediate duty units. The trend to a smaller amount of storage capacity was also evident.

Planned Outage Rate

When the HTGR planned outage rate (POR) was improved by one week (14%), total system savings to the utility were $540 million. Combined with the better efficiency of the HTGR and the replacement of 1140 megawatts of intermediate duty units was the HTGR's higher reliability. The additional "up" time enabled further savings from the consumption of nuclear fuel. When the POR was improved by 2 weeks (28%), total system savings were over $680 million, again derived primarily from fuel cost savings as described previously. Programs are in place to effectively reduce planned outage particularly in the area of refueling times. If successful, reductions in the range as analyzed in this Assessment could potentially be realized, therefore netting the savings comparable to those cited above.

There were two apparent trends associated with reduction in HTGR planned outage rates that were in addition to its domination of the baseload market and its significant capture of the intermediate market. These were the reduction in system reserve margins and also the reduction in total utility system size. The change in reserve margin over the 20-year study period was from 29.4% to 24.4% and to 23.7%, respectively, for the two cases described above. There were minor fluctuations to system reserve margins caused by other HTGR perturbations but not to this degree. The reason was that a reduction in POR had a more direct positive effect on system reliability than the others. This increase in HTGR availability also created the situation where the utility could build a smaller system and still meet its load requirements. Storage capacity remained nearly the same over the POR reduction range analyzed.

Plant Size

Plant size sensitivities were analyzed by maintaining the same capital cost ($/KWe) as applied for the reference case. Whereas, this is not a real input, the application of systems analyses provides an indication of the value for having a smaller plant and hence an indicator for the allowable premium of small plant sizes. When the HTGR plant size was reduced from 1200 MWe to 1000 MWe (17%), a total system savings to the utility of $400 million was realized. The bulk of the savings was derived from nuclear fuel cost savings with the better efficiency of the HTGR and the replacement of 1140 megawatts of intermediate duty units. When the HTGR plant size was reduced to 800 megawatts (34%), the total system savings to the utility were increased to $510 million. These savings again were derived primarily from fuel savings as described above. The current HTGR program is completely responsive to these benefits of smaller generating plants, as the HTGR now cited as the reference is an 800 MWe unit.

There were several noticeable trends associated with reductions in HTGR plant size that were in addition to its domination of the baseload market and its significant capture of the intermediate market. These trends, which began to be readily observed by reducing HTGR planned outage rates such as the reduction in system reserve margins with time and the reduction in total utility system size, were magnified by plant size perturbations. The change in reserve margin over time was from 29.4% to 24.0% and to 22.5%, respectively, for the two cases described above. With the reduction of plant size, the utility could add capacity that could more readily match load growth, thereby eliminating the overbuilding normally present due to discrete capacity additions. This tended to make the total system a more reliable one. The system installed capacity was reduced by 510 and 910 megawatts, respectively, for the two cases described above. By reducing plant size, then, the utility matched load requirements with a smaller generation system.

A third apparent trend was the significant alteration in the deployment of storage and peaking capacity (gas turbines). In the case where the HTGR plant size was reduced to 1000 megawatts, 500 megawatts of peaking capacity was added in favor of 500 megawatts of storage capacity. The trend continued when the HTGR plant size was reduced to 800 megawatts as 400 megawatts of peaking capacity and 400 megawatts of baseload capacity (HTGR) were added in favor of 1200 megawatts of storage capacity. This trend of displacing expensive-to-build/economical-to-operate storage capacity with economical-to-build/expensive-to-operate peaking capacity would probably continue beyond the plant size reduction range analyzed in this Assessment.

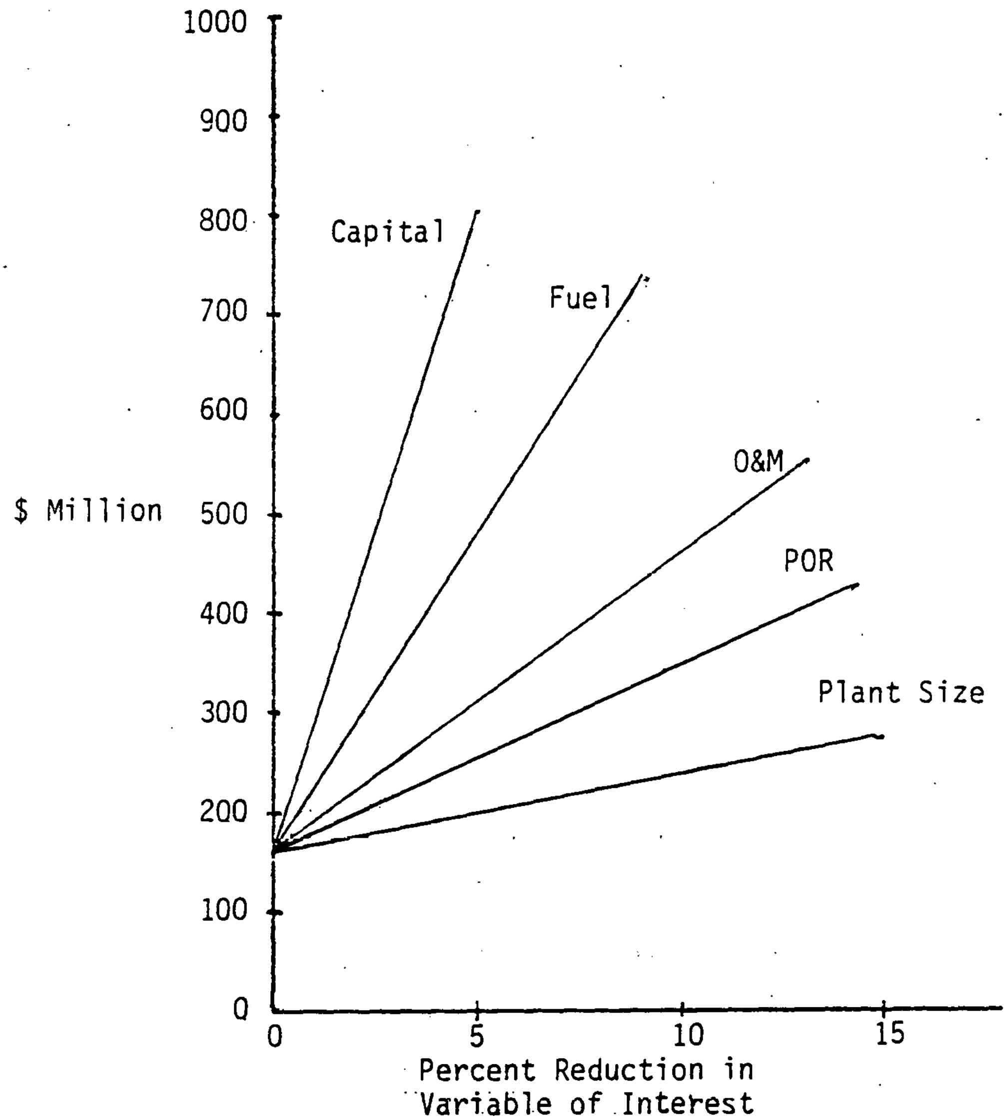
Comparison

As expected, similar reductions of dissimilar HTGR parameters do not net equal system savings. Further, the savings are non-linear to the parameter of interest due to the discrete addition of capacity and also with the replacement of one type of generation for another, e.g., baseload for intermediate. These non-linear effects do not detract from the accuracy of the economic impact trends depicted on Figure 5.3-1 as these are real utility characteristics. They do, however, raise the issue of the absoluteness of the dollar values cited in this Assessment.

Applying the results in Figure 5.3-1, one can estimate the equivalent percent reduction in the respective variables to achieve an equal system savings. The following table gives the percent reduction for each variable needed to be equivalent to a 5% reduction in capital cost.

Figure 5.3-1

Total Utility System Savings
for HTGR Deployment



Comparative Impact of Variable Reduction

HTGR Variable	% Reduction Necessary to Equal 5% Decrease in HTGR Capital Cost
Capital Cost	Reference
Fuel Cost	9.6
O&M Cost	20.6
Planned Outage Rate	29.9
Plant Size	55.5

From Figure 5.3-1 and the values above, it is clear that reductions in certain HTGR variables can net significant utility system savings, yet efforts resulting in the reduction of plant capital cost prove the most rewarding. Table 5.3-1 summarizes the trends apparent from reductions in certain HTGR variables. All reductions in parameters provoke some system alterations, but the most significant are derived from reductions in planned outage rates and plant size.

5.4 Summary

Through the use of synthetic utility systems and the Optimized Generation Program, a model has been created to analyze the HTGR in the environment in which it would exist--the utility environment. Several conclusions can be drawn from the system analysis conducted to date, and these are summarized as follows:

- An HTGR with capital and O&M costs equal to or slightly higher than those of an LWR is competitive when considering the present level of fuel cost advantages.
- Reductions in HTGR capital costs dramatically increase economic marketability and can net significant utility system savings.
- Substantial savings can be derived from reductions in all HTGR parameters, but reductions in capital cost prove the most significant and should be pursued with highest priority.
- Reductions in plant size net system savings especially with regard to increased system reliability and reduced reserve margins.
- Introduction of the HTGR can save a single utility the consumption of billions of gallons of water annually.

In conclusion, this effort provides a comprehensive model on which further analysis can be conducted. Issues such as siting considerations, environmental impacts, plant efficiency, institutional and financial restrictions, and, of course, water availability and economic considerations can all be addressed in greater detail. Subsequent phases will look at several of these in specific utility environments as described in Section 6.0.

Table 5.3-1

Comparative Trends of Variable Reduction

Variable	Generation Trend Effect (1)	Savings ($ Million) (2)
Capital Cost	Displaces Intermediate Units	808
Fuel Cost	Displaces Intermediate Units Reduces Storage Capacity	494
O&M	Displaces Intermediate Units Reduces Storage Capacity	310
Planned Outage Rate	Displaces Intermediate Units Reduces Reserve Margins Reduces System Size	260
Plant Size (3)	Displaces Intermediate Units Reduces Storage Capacity Increases Peaking Capacity Reduces Reserve Margins Reduces System Size	210

Notes: (1) Relative to HTGR Base Case.
(2) Normalized to 5% (20-year savings in 1977 $).
(3) Analyses assumed equal capital cost ($/KWe) for all plant sizes. Savings relate to allowable premium for smaller plant size.

6.0 HTGR Market Assessment - Subsequent Phases

Phase I of this Assessment identifies the market factors associated with the marketability of the HTGR and provides an initial analysis of two key factors: water and economics. Subsequent phases will evaluate the market factors and involve increased direct utility input, analysis, comment, and review.

6.1 Market Assessment Method

6.1.1 Identification of the Potential Market

The applications of the HTGR are twofold: electricity generation and process heat. For electricity production, the utility industry is the obvious market. Process heat includes many potential applications of the HTGR that may eventually involve industrial owner/operators of HTGR plants. However, the potential HTGR market for the foreseeable future lies with utilities that sell electricity and/or natural gas. The utility industry could generate a demand for an electricity producing HTGR, a process heat HTGR for synthetic gas production or a "multiplex" HTGR which produces both electricity and process heat.

Because other recent market assessments have focused on the market potential of the HTGR for process heat applications with non-utility industries, this report will only assess the U.S. utility industry as being the HTGR's potential market.

There are 169 investor-owned utilities in the U.S. with a service area of more than 10,000 square meters. GCRA estimates that 120 of these are of sufficient financial size that they would be capable of at least partial ownership of a nuclear power plant. In addition to these investor-owned utilities, several large public power systems would also be potential owners of a nuclear plant. The utility input to the Assessment will be solicited from a broad segment of this group of utilities.

6.1.2 Formulation of the Assessment

The HTGR Market Assessment - Interim Report will be distributed to a group of utilities which are representative of the potential market identified above. GCRA will solicit these utilities' comments on this report for the purposes of confirming the approach and preliminary conclusions, and to solicit utility participation in the remainder of the Assessment.

After receiving and analyzing the utility comments, a Phase I - Final Report will be issued which incorporates and summarizes the utility industry responses. The Phase I - Final Report is scheduled for release during December 1979.

Using the information received from utility comments, GCRA will focus upon the market factors which were of most importance to the utilities. Detailed analyses will then be performed for each of those factors relative to the HTGR. These analyses will be forwarded to the utilities for review and comment.

The utility analysis of HTGR market factors may take one of three forms:

- Utility review and comment on analyses performed by GCRA along with utility initial input to the analyses.
- Utility review of a National or Regional Systems Analysis performed by a subcontractor to GCRA.
- Individual utility analysis of market factors relative to its own system.

In preparation for an analysis of the personnel radiation exposure factor, GCRA has already prepared a questionnaire which will be forwarded to the utilities to collect their initial input to the GCRA analysis of this factor. This questionnaire is included in Figure 6.1-1 as an example of the method that will be used to obtain initial utility input to GCRA analyses. Upon completion of the analysis, the report will be sent to the participating utilities for their comments. This procedure is an illustrative example of the first type of utility participation.

An example of the second type of utility participation would be the further use of the HEDL Water Use Information System to analyze a specific region. For this example, the HEDL system would be used to analyze the water requirements of an area of the country where a particularly high load growth rate is expected. The resultant analysis would be used to evaluate specific water availability for power station cooling systems as well as predicting the time frame of when the use of a peak shaved dry/wet cooling system would become economical. The result would then be reviewed and commented on by the individual utility participants of that region.

The third form of utility participation could result in the utility actually performing a particular analysis itself with GCRA assistance. It might also entail GCRA performing the analysis for the specific utility. For example, a systems analysis could be performed using the OGP code into which the particular utility's system has been inputted. Similar analyses to those performed in Section 5 could then be performed so that the utility system planner could investigate the HTGR on his own system.

Figure 6.1-1

GCRA Questionnaire on Personnel Exposure

During Plant Maintenance Operations

- In planning your current LWR maintenance personnel needs, what is considered the maximum acceptable radiation exposure limit in total man-rems per crew during either a routine maintenance operation or major component overhaul or inspection (e.g., BWR steam turbine or PWR primary coolant circulatory pump)?
- If your Utility does have a "maximum acceptable" radiation exposure limit during such maintenance operations, how is this limit set--is it the maximum exposure limit imposed by the Government, or is it some lower limit selected by your Utility to allow some margin of exposure for future operations during the quarter (year)?
- Does your Utility typically have to bring on extra maintenance personnel solely because of radiation exposure limits, and if so, how many per year, at what cost per year?
- In today's market and projected to the year 2000, does your Utility foresee a shortage of temporary maintenance help and if so, what are the ramifications?
- How does your Utility see the plant activity levels and personnel exposure limits changing between now and the year 2000?
- How much improvement in lowering personnel exposures would have to be attributed to an HTGR to make it a selling point vis-a-vis a LWR (assuming similar economics for the two)?
- What is the evaluated cost of a man-rem?
- Please try to further quantify the real benefit, if any, there is to your Utility in having a reactor that is cleaner than those offered today.

6.2 Market Evaluation

The utility responses to the above process will constitute the data base for the HTGR Market Assessment. This information will be structured such that the data base, when properly analyzed, will document the utility market's attitudes toward the HTGR in the following areas:

- Utility perception of the HTGR relative to the identified market factors
- Utility understanding of HTGR technical status relative to the market factors

It is envisaged that a series of reports will be issued which document and analyze the specific utility perspectives on the various HTGR market factors.

A final report will be issued which will summarize the phased reports and which will constitute the evaluated utility industry position on whether or not the HTGR is a marketable product.

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Appendix A

HTGR-Gas Turbine (HTGR-GT)

A.1 HTGR-GT System Description

The HTGR-GT plant described herein employs a 2000 MWt heat source with a prismatic core and fuel configuration similar to previous HTGR-Steam Cycle designs. The nominal electrical output of this plant is 800 MWe. This two loop, integrated gas turbine configuration is currently under development and was based on GCRA recommendations and guidance. The two loop, 2000 MWt HTGR-GT represents a modification of the three loop, 3000 MWt HTGR-GT reference plant concept. Among the reasons cited for selecting the two loop plant are: simplified turbomachinery removal and replacement, substantial reduction in isolated phase bus duct requirements, reduced PCRV complexity, and utility plant size preferences. The plant design will reflect specific GCRA functional requirements and objectives and is intended to be a standard replicable reference plant design of the HTGR-GT concept.

A.1.1 General Description

The reactor core is cooled with pressurized helium, moderated and reflected with graphite, and fueled with a mixture of uranium and thorium. It is constructed of prismatic hexagonal graphite blocks with vertical holes for coolant channels, fuel rods, and control rods. Both the core and the two power conversion loops (PCL) are integrated in the multicavity prestressed concrete reactor vessel (PCRV). The turbomachines are located in horizontal cavities in a parallel chordal arrangement at an elevation below the core cavity. The other major PCL components, the recuperator and precooler, are located in vertical cavities around the central core cavity. In addition to the PCL equipment, three Core Auxiliary Cooling System (CACS) loops are also provided for safety-related core cooling capability. The CACS loops, the PCL equipment, and the core are connected by a series of ducts internal to the PCRV. The internal surfaces of the PCRV cavities and ducts are lined with an impermeable steel membrane and covered with a thermal barrier to limit system heat losses and at the same time maintain liner and concrete temperatures within design limits.

The 1562°F core outlet gas energizes the gas turbine which, in turn, powers the compressor and a 400 MWe, 60 Hz generator. The HTGR-GT utilizes a recuperator to increase system efficiency and reduce heat rejection through the precooler. The precooler is a helium to water heat exchanger which rejects cycle waste heat to the plant cooling system, or potentially a bottoming power cycle. Depending on the particular site conditions, the cooling system may utilize all dry or a combination of dry and wet cooling towers to reject heat to the atmosphere.

The PCRV and ancillary systems are enclosed within a secondary containment building. This containment, together with the PCRV, incorporates safety features that limit the loss of primary coolant and minimizes releases in the event of failures in the turbomachinery, shaft seals, generators, heat exchangers, or PCRV enclosures. Certain nuclear heat source (NHS) related systems, such as fuel handling and helium purification, and most balance of plant (BOP) systems and equipment are located outside the secondary containment in separate structures. Among the plant structures envisioned are the reactor service building (RSB), the controls, auxiliaries and diesel (CAD) building, the fuel storage building (FSB) with 10-year onsite storage capability, and a turbomachinery maintenance facility. Railroad access for shipping and receiving is also provided at the site.

A.1.2 Reactor Turbine System (RTS)

The RTS for the 2000 MWt HTGR-GT are those nuclear, control, heat transfer, and auxiliary systems and components necessary to operate the core and power conversion loops. These systems and components are described briefly in the succeeding sections.

Prestressed Concrete Reactor Vessel and Reactor Internals

The PCRV consists of the prestressed concrete structure, cavity liners, penetrations, and closures; a thermal barrier on the gas-side surfaces of the liner; and two independent pressure-relief trains. It functions as the primary containment for the reactor core, the primary coolant system, and the safeguards cooling system. It also provides the necessary biological shielding and minimizes heat loss from the primary coolant system. The prestressed-concrete portion of the PCRV and those portions of the penetrations unbacked by concrete, including their closures, form the primary coolant pressure-resisting boundary. The cavity and penetration liners, including the closures, form the continuous gas-tight boundary of the PCRV. Penetrations and closures also restrict the leakage-flow area from the vessel to acceptable limits in the event of postulated failures. Liner and penetration anchors transmit loads from internal equipment support structures to the PCRV concrete.

The PCRV core cavity, offset from the PCRV center by 1.1m (3 ft. 9 in.) is surrounded by two recuperator, two precooler, and three CACS cavities. Two horizontal turbomachine cavities are located below the core cavity in a parallel chordal arrangement. The PCRV is constructed of high-strength concrete reinforced with steel rebar. The PCRV is prestressed by three independent prestressing systems: (1) a longitudinal prestressing system which consists of tendons arranged around the cavities and ducts to counteract the cavity and duct pressures in the longitudinal direction; (2) a circumferencial prestressing system which consists of multilayered bands of wire strands wound under tension into channels precast in the surface of the vessel walls; and (3) a system of diagonal tendons which replace the wire winding of the circumferencial prestressing system in the area of the horizontal turbomachine cavities. The wire for the circumferencial prestressing system is wrapped around the outside of the PCRV by a special wire winding machine. The PCRV diameter is 37.2m (122 ft.) and the height is 35.4m (116 ft.).

The reactor internal structures consist of all the graphite components of the core-support floor, the permanent side reflector, and the core peripheral seal; the metal peripheral-seal support structure, including those items that attach the structure to the PCRV liner and others providing the interface with adjacent thermal barrier; the metal core-lateral-restraint and side-shield assemblies; and the metal plenum elements fitting over the top permanent-side-reflector blocks.

Reactor Core

The reactor core includes the fuel elements, the hexagonal reflector elements, the top layer/plenum elements, and the startup neutron sources. The fuel element is a graphite block that both contains the fuel and acts as a moderator. Each fuel element consists of a hexagonal graphite block containing drilled coolant passages and fuel channels into which the fuel rods are inserted. The individual fuel rods contain the fissile and fertile coated particles distributed in a graphite matrix. The initial core elements and the reload elements, whether containing fresh or recycle fuel, are of identical geometry. The fissile particle will have either a uranium carbide or oxide kernel with a TRISO coating. The TRISO coating has four layers: an inner buffer layer of low-density pyrolytic carbon, a thinner layer of high-density pyrolytic carbon, a layer of silicon carbide that provides containment of gaseous and solid fission products, and an outer high density pyrolytic coating. The fertile particle has a thorium oxide kernel with either a TRISO or a Si-BISO coating. The Si-BISO coating has two layers: an inner buffer layer of low-density pyrolytic carbon and an outer coating of high-density silicon-doped pyrolytic carbon. The latter provides the containment.

The fuel elements and hexagonal reflector elements are arranged in columns supported on core-support blocks, with each support block normally corresponding to one fuel region. Each region consists of seven columns of fuel elements, with a central column of control fuel elements and six surrounding columns of standard fuel elements. The fuel regions are surrounded by two rows of hexagonal reflector-element columns, which are in turn surrounded by the permanent side reflector. The reflector elements may have coolant holes, control-rod and reserve shutdown holes, and shielding material as required, but they do not contain fuel.

The present reference fuel cycle uses 20 percent enriched uranium (Medium-Enriched Uranium)/thorium (MEU/Th) and is currently optimized for no recycle. The ultimate goal, however, is to employ high enriched uranium (HEU) and thorium fuel with full recycle. Moreover, the plant, core, and fuel designs are such that flexibility in the fuel cycle design is retained to ensure that a variety of fuel cycle schemes and uranium enrichments may be adopted in the future. Depending on the fuel cycle being applied, the conversion ratio for the HTGR may vary from .6 to .92.

Primary Coolant System

The primary coolant system includes the PCL components such as the turbomachine, recuperator, precooler, and valves required to generate power. A simplified schematic diagram exhibiting the primary cycle for the HTGR-GT is shown in Figure A.1-1. The helium coolant flows downward through the reactor core into the core outlet plenum. The hot gas from the core outlet plenum flows radially outward through the two large ducts on opposite sides of the plenum to the turbine inlet, which is located in the center of the machine. The vertical portion of the core outlet duct is concentric with the compressor outlet duct. The gas flows through the turbine and exits into a plenum located directly under the recuperator. It then flows upward through a short duct and enters the recuperator on the shell side, exiting below the upper recuperator tubesheet into the recuperator-precooler cross duct. The warm gas from the recuperator flows through the horizontal cross duct into the shell side of the water-cooled precooler, where its temperature is reduced further. The cool gas from the precooler flows downward through another short vertical duct into the compressor inlet plenum and passes through the compressor to exit near the center of the machine. High-pressure compressor outlet gas then flows upward through a vertical duct to enter the inlet of the recuperator on the tube side. It flows downward through the tubes, picking up heat from the shell side gas, and exits into integral return tubes at the bottom of the recuperator. The gas then returns upward through the return tubes and enters the core inlet plenum through the inclined radial ducts at the top of the core cavity.

Helium Turbomachine - The 400 MWe helium turbomachine has 18 compressor stages (for a pressure ratio of 2.5 with the low molecular weight gas) and 8 turbine stages. The rotor is of welded construction. Welded rotors have a long, successful history in Europe for both gas and steam turbines. With the 60,800Kg (67-ton) rotor supported on two journal bearings (with state-of-the-art loading and peripheral speed), the overall length of the machine is 11.3 m (37 feet). Rotor burst protection is incorporated in the machine design in the form of burst shields around the compressor and turbine rotor bladed sections. Man-access cavities are provided in the PCRV for inspection and limited maintenance work on the journal bearings,

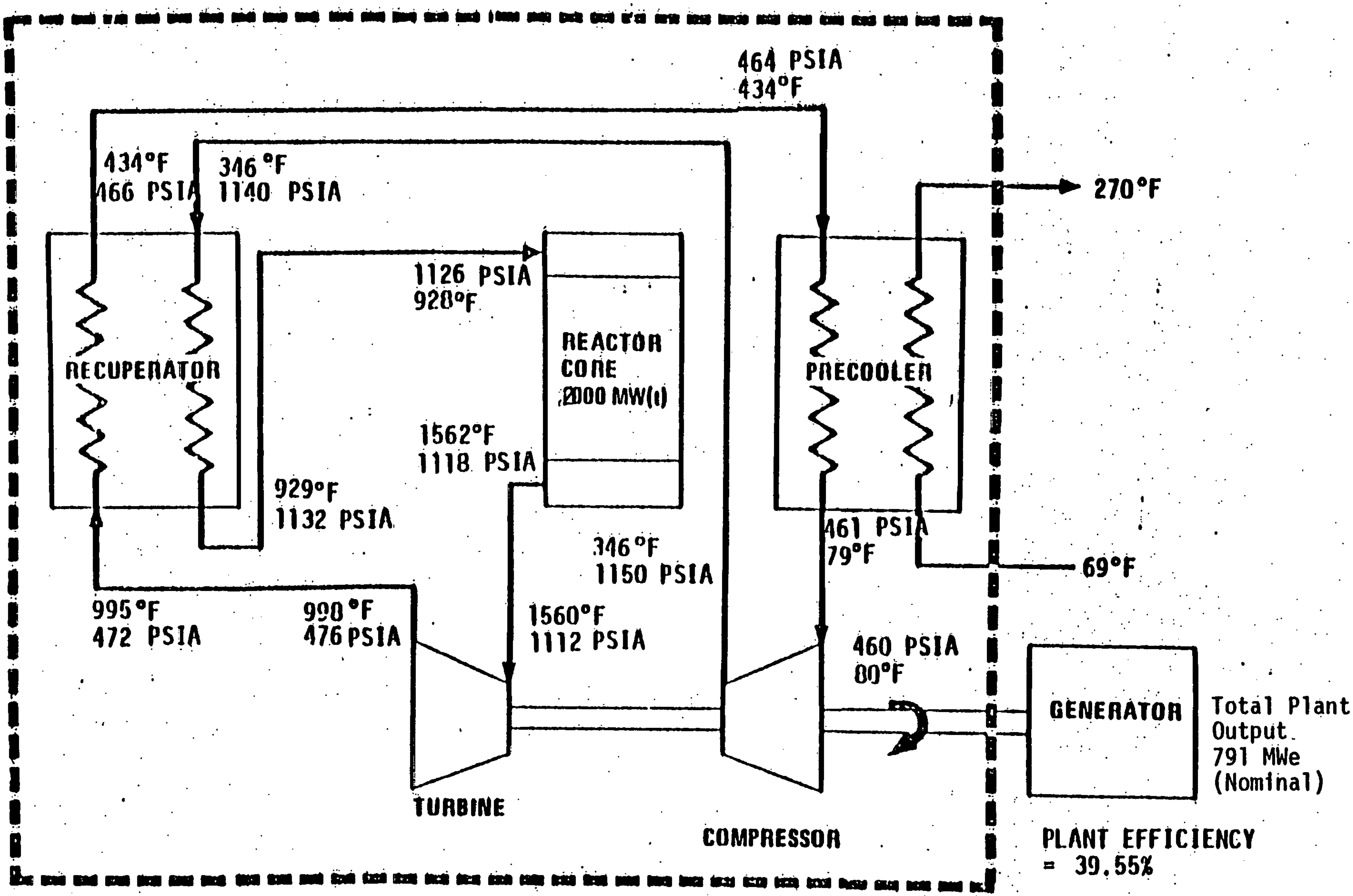

Figure A.1-1 Gas Turbine HTGR Cycle Diagram which are of the multiple, tilting-pad, oil-lubricated type. The spaces in which the bearings are located are isolated from the primary loop working fluid by shielding (purged gas from the purification system is used to give an acceptable radiological environment for man access). The drive to the generator is from the compressor end of the turbomachine, and the thrust bearing is located external to the PCRV to facilitate inspection and maintenance. For a single-shaft helium turbomachine with a net power output of 400 MWe, the rotating section is compact and is substantially smaller than an equivalent air-breathing machine because of the high degree of pressurization (particularly at the turbine exit) and because the enthalpy drop in the helium turbine is many times greater (i.e., increased specific power). The external dimensions of the 400 MWe helium gas turbine are similar to those of an air-breathing, advanced open-cycle industrial gas turbine in the 100 MWe range. The fact that the helium turbine (particularly the rotor assembly and casings) is comparable in size to the existing machines substantiates the claim that conventional fabrication methods and facilities can be used.

Recuperator and Precooler - The recuperator in the reference plant design is of straight-tube design and embodies a modular assembly having many heat transfer elements. For this gas-to-gas heat exchanger, inspection and repair are provided for down to the module level. An alternate recuperator design which would facilitate individual tube inspection and repair is currently being developed and evaluated. In the case of the gas-to-water precooler, concern had been expressed regarding the very large number of small diameter tubes associated with the straight-tube design. Recognizing the increasing importance of maintenance and inservice inspection on heat exchanger design, a precooler embodying a helical bundle geometry with finned tubes is the reference precooler design for the HTGR-GT plant. This configuration is also much better suited for the gas to water heat exchanger application. The large reduction in the number of tubes associated with this flow configuration enables inspection and repair to be accomplished down to the individual tube level, rather than the module level, as in the straight-tube variant. Even though the single-phase working fluids (helium and water) can realize relatively high heat transfer coefficients, large surface areas are necessary because of the large heat transfer rates. However, the modest metal temperatures and internal pressure differentials compared to modern steam generators, permit the use of code-approved lower-grade alloys of reduced cost.

The ferritic materials selected for both exchangers have been used extensively in industrial and nuclear plant heat exchangers. Though the exchanger assemblies are large, state-of-the-art manufacturing methods can be used, and the modular approach in the case of the recuperator eases the fabrication, handling and assembly. The overall size and weight of both the recuperator and precooler are similar to the contemporary steam generators, and transport methods, handling, and installation techniques developed for these units will be equally applicable to the heat exchangers for the nuclear gas turbine plant.

Core Auxiliary Cooling Systems (CACS)

The CACS is an engineered safety system incorporated in the HTGR design for reactor core residual and decay heat removal. The system, installed in the PCRV, consists of three auxiliary primary coolant loops, each having a variable speed electric induction motor driven auxiliary circulator, an auxiliary shutoff valve, and a water-cooled heat exchanger. The CACS's function is to provide a separate independent means of cooling the reactor core with the primary system pressurized or depressurized. Each loop is capable of cooling the core following loss of main primary loop circulation and reactor trip from full rated power conditions with the PCRV pressurized. Any two loops can cool the core under the same conditions with the PCRV at containment building atmospheric pressure.

Auxiliary Systems

A helium purification system is required to remove chemical impurities, particulates, and long-lived radioactivity from the primary coolant. The radioactive gas waste system collects all radioactive gas wastes. The fuel handling systems consists of a fuel handling machine, fuel transfer casks, and the auxiliary service cask, together with the necessary valves, hoists, dollies and controls. The core is refueled by regions of seven columns, each centered under its own refueling penetration. The auxiliary service cask is used to remove the control rod drive from the penetration, whereupon the fuel handling machine can be installed. The fuel handling machine removes the elements from the PCRV and transfers them to the fuel transfer casks which transports the fuel elements to the reactor service building, where they are canned and routed to spent fuel storage. A similar reverse process is used to insert fresh fuel into the region.

A.1.3 Balance of Plant (BOP)

Structures, equipment and systems not supplied as part of the RTS are considered to be BOP. The scope of the HTGR-GT BOP is reduced substantially because the turbine and its related support systems are now included in the RTS. Most of these systems and structures are standard to operating nuclear and/or fossil fuel power plants in the U.S. A brief description of the features and characteristics of the BOP systems and structures is provided in the following sections.

Major BOP Systems

The major BOP systems may be categorized into three major areas of electrical plant equipment, cooling water, and RTS support. The electrical plant equipment, in general, is quite similar to other nuclear plants and is designed to provide for off-site or on-site power for house loads. In addition, safety related on-site DC and AC power is supplied by qualified and redundant sets of batteries and diesel generators. Plant cooling water systems include the precooler cooling water system for primary cycle heat rejection, and the core auxiliary cooling water system (CACWS) for safety grade core heat removal; the reactor plant cooling water system for such heat loads as PCRV liner cooling and the helium purification system heat exchangers; and the service water system for other plant component cooling requirements. Included among the RTS support systems are helium storage, fuel storage, and the radwaste systems.

Major BOP Structures

All plant structures, other than the PCRV are included in the BOP. The major plant structures include the containment building, the containment penetration and annulus buildings, the reactor service building (RSB), the fuel storage building (FSB), the control auxiliary and diesel (CAD) building, the administration building, and the turbomachinery maintenance facility. All of the safety-related systems and equipment are housed in Seismic Category I structures. With the exception of the administration building and the turbomachinery maintenance facility, all the other listed buildings are Seismic Category I.

A.2 Incentives for HTGR-GT Deployment

The following material discusses the projected and perceived benefits that will accrue to the nation, the utility industry as a whole, or specific utilities as a result of HTGR-GT deployment. Table A.2-1 provides a summary of these incentives.

A.2.1 High Degree of Inherent Safety Features

While current LWR technology has achieved a record of safety unmatched by available and practical energy alternatives, the recent accident at Three Mile Island has nonetheless resulted in new emphasis being placed upon the safety characteristics of proposed reactor systems. In this regard, the HTGR concept can only be considered to be a superior technology. This HTGR advantage results from a number of "inherent" safety characteristics, i.e., characteristics which are intrinsic to the basic concept and which are substantially independent of operator action. Important in this regard are the following:

Table A.2-1

Incentives for HTGR-GT Deployment

- High Degree of Inherent Safety Features - Improved Protection of Utility Investment
    - Inert, Single Phase Coolant
    - Ceramic Fuel and Coatings
    - Graphite Core and Reactor Internals
    - High Core Heat Capacity/Low Power Density
    - Pre-stressed Concrete Reactor Vessel
- Reduced Difficulty in Siting and Licensing
    - Less Cooling Water Required (Near Zero For Dry Cooling)
    - Less Radioactive Effluents
- Improved Fuel Cycle
    - Extends U_3O_8 Resource Base
    - Fuel Cycle Flexibility
    - Optimum Symbiosis With Fast Breeder Reactors
- Reduced Exposure of O&M Personnel
- Potential For Reduction in Power Generation Costs
    - Initial Plant Savings Modest to Significant, Depending Upon Water Availability
    - Evolution to Higher Temperatures Produces More Savings
- Cogeneration and Process Heat Applications
    - Utilization of High Temperature Waste Heat
    - Supports Technical Base and Provides Industry Infrastructure for Process Heat Applications

- Inert, Single Phase Gaseous Coolant - Resultant advantages of using helium as the core coolant include low stored energy (no flashing), predictable fluid dynamics, unambiguous indication of primary system integrity through pressure readings, physical impossibility of a complete loss of coolant (heat can be removed by helium or even air at atmospheric pressure), coolant does not become activated or react with core.

- Ceramic Fuel and Coatings - The HTGR fuel particle design provides significant improvements in fuel integrity and fission product retention capability as a function of time and temperature relative to cores incorporating metallic cladding.

- Graphite Core and Reactor Internals - A significant advantage of the HTGR under postulated accident conditions is the maintenance of the geometrical integrity (and hence predictable behavior) of the core at extreme temperatures (up to the order of 5500-6000°F).

- High Core Heat Capacity/Low Power Density - Temperature transients are slow and predictable. For example, a complete loss of forced circulation in the core can be endured for a period in the range of five hours without damage to the plant assuming reference HTGR-GT conditions. Over longer periods, initial damage would be to metallic components of the system. A substantially longer period of time would elapse before significant core damage would occur. The importance of this characteristic is nowhere better expressed than in Fort St. Vrain (FSV) Project Manager Fred Swart's recent report at the August 1979 "Utility Conference on the HTGR:"

  "When FSV runs, it runs beautifully. Load changes, responses to transients reflected from the system or due to loss of equipment within the plant are accepted gracefully. The high heat capacity core and the low power density provide the operator with the time he needs to evaluate and to respond to unexpected operational occurrences. This isn't a statement that was taken from a sales brochure, it comes from experience. We have experienced operational upsets that have resulted in periods of no forced circulation cooling of the reactor on four or five occasions and have experienced no degradation of the fuel that we can detect."

- Pre-stressed Concrete Reactor Vessel - Multiple redundant structural members render catastrophic failure incredible. Low temperatures and negligible neutron irradiation of structural members makes all types of failures less likely. Integral design eliminates major primary cooling system piping.

While the accident at Three Mile Island could be interpreted as verifying the industry's capability to protect the public, it correspondingly illustrated that an intolerable financial burden could be placed upon an owenr/operator in the event of a serious accident even though public safety is not compromised. The same inherent features which have been described as enhancing HTGR safety also make such a catastrophic fiscal burden much less likely. Of particular importance in this regard are unambiguous performance data resulting from the single phase coolant and the lack of pressure upon operating personnel to take precipitous action in the event of system upsets. The HTGR provides the operator's greatest asset--an abundance of time.

A.2.2 Reduced Difficulty in Siting and Licensing

The HTGR-GT offers environmental advantages with regard to water utilization and reduced radiological discharge, which result in potential siting and licensing advantages.

One of the prominent advantages of the HTGR is the reduced water requirements for waste heat rejection. The two factors which significantly impact the quantity of water used for waste heat rejection are plant thermal efficiency and the quality of the waste heat. Section 3.0 of this report provides an initial assessment of the value of this benefit to the utility.

The inherent safety features, reduced radioactive effluent releases and reduced cooling water requirements may have a significant impact on a utilities' ability to license any particular site. These advantages add flexibility to the utilities' application of a site and may result in any combination of the following:

1. Application of a site that is otherwise not available for LWR siting
2. Installing more HTGR capacity on a given site than could be accommodated with LWRs
3. Locating the plant nearer to load centers

A.2.3 Improved Fuel Cycle

The HTGR offers considerable improvements in U_3O_8 utilization efficiency over the LWR, independent of which fuel cycle policy direction might be adopted by government. This results from improved plant thermal efficiency and reactor conversion ratios. Table A.2-2 summarizes U_3O_8 requirements for several fuel cycle alternatives, for both LWR and HTGR plants. The table shows inventory requirements as well as annual makeup requirements. An enrichment tails assay of 0.1% has been selected, since a lower assay is expected after the turn of the century as a result of improved enrichment technologies.

Present data indicate that the MEU/Th Once-Through cycle allows a 30-year U_3O_8 commitment for the HTGR which is only 75% of

Table A.2-2

U_3O_8 REQUIREMENTS AND Pu_f DISCHARGE

FOR ALTERNATIVE FUEL CYCLES IN LWR AND HTGR PLANTS*

(LOAD FACTOR = 70%; ENRICHMENT TAILS = 0.1%)

REACTOR	FUEL CYCLE	INVENTORY, ST U_3O_8/GWe	ANNUAL MAKEUP ST U_3O_8/GWe-yr	30-YR TOTAL ST U_3O_8/GWe	Pu PRODUCTION kg/GWe-yr
LWR	3.2% LEU; O.T. (Once-Through)	566.	155.	5061	152.
LWR	4.4% LEU; O.T.	734.	131.	4533	110.
LWR	3.2% LEU; U RECYC	559.	120.	4039	152.
LWR	MEU/TH; RECYC	655.	93.	3352	57.
LWR	HEU/TH; RECYC	590	77.	2823	6.
HTGR	MEU/TH; O.T.	435.	114.	3741	31.
HTGR	MEU/TH; RECYC	400.	79.	2691	31.
HTGR	HEU/TH; RECYC	500.	43.	1747	3.
HTGR	HEU/TH; RECYC (Heavy Load)	750.	29.	1591	3.

*LWR thermal efficiency assumed at 33.4% (Wet cooling);
HTGR-GT thermal efficiency assumed at 39.6% (Dry cooling).

the standard LWR Once-Through; i.e., a U_3O_8 commitment improvement of 34% over the LWR. The improvement is still about 20% relative to the LWR with an extended fuel burnup lifetime. For the MEU/Th recycle mode of fuel management, the HTGR offers a reduction in the 30-year U_3O_8 commitment of almost 50% over that of the LWR Once-Through mode; or a commitment improvement of 86%. Other comparisons are equally as impressive.

As noted on Table A-2-2, both the LWR and the HTGR have potential for fuel improvements. As economic analyses are applied to the respective reactors and fuel cycles given in Table A.2-2, the fuel cycle cost advantage for the HTGR becomes most pronounced for the more efficient fuel cycle compairons (i.e., advanced converters). Further, The HTGR has fuel-cycle flexibility to accommodate any of the possible fuel cycle policy directions with a single reactor/core design. This allows an evolution to more advanced technology possibilities as policy definition, technology development and commercialization favor the appropriate evolutionary steps. With the HTGR, it is quite practical to deploy an HTGR industry solely on the basis of a once-through fuel-cycle strategy and subsequently adopt a recycle fuel management plan if and when it becomes desirable, with no significant change to the reactor. In contrast, the development of an advanced LWR involving movable fuel control (as in the LWBR) or spectral-shift control would require major changes in the reactor design. In addition, the introduction of breeder reactors would require the deployment of an entire recycle industry before the breeder reactors could be used. The flexibility of the HTGR, however, would allow an evolutionary fuel-cycle path with no inconvenience during successive steps.

In the near term, it is expected that the MEU/Th fuel cycle with fuel storage would represent the optimum direction for the HTGR in terms of national policies, energy economics and industry commercialization. At some appropriate future date, the U-233 stored in the spent fuel could be separated and recycled in the same reactor. Finally, when U-233 becomes available from an external source such as an FBR, the same HTGR plant could then utilize the U-233 as a makeup fuel and the plant would perform as a near-breeder reactor; i.e., with a conversion ratio of approximately 0.9.

Though traditional thinking some five-to-ten years ago envisaged the complete replacement of thermal-spectrum reactors by fast-breeder reactors (FBRs) in the long-range future, it is now becoming apparent that the optimum nuclear system will consist of a symbiotic combination of advanced converter reactors and FBRs. Several factors contributing to this realization are:

- Nuclear growth projections now indicate that severe resource strains will not be imposed on the mining and milling industry for some 30 years, and longer if more resource-efficient reactors and fuel cycles are introduced.

- The cost penalty associated with increased U_3O_8 prices will not be substantial if resource-efficient reactors and fuel cycles are introduced.

- The capital cost and operating costs of FBRs now appear to be such that very high U_3O_8 prices would be required to justify FBR deployment on an economical basis.

- The concerns of plutonium diversion may require that FBR plants be located in secure reservations, possibly under government control.

Accordingly, a strategy featuring a symbiotic relationship which couples several, low capital cost advanced converter reactors to one FBR provides potentially, significant long-range benefits. The HTGR offers the unique capability of introducing the technology on a restrained fuel cycle with eventual application as an advanced converter. This feature provides significant flexibility to the government for coping with the policy uncertainties of the nuclear future and flexibility to the utilities with the associated operational uncertainties.

A.2.4 Reduced Exposure of Operating and Maintenance Personnel

With continued operation of Fort St. Vrain (FSV), it is becoming increasingly clear that the radiological characteristics of the HTGR comprise a most significant advantage of the technology. Current allowable dose rates to nuclear power industry personnel are being reached fairly frequently. This problem is of major concern for many reasons:

- The activation of the coolant circuits increases with the age of the plant.

- The ratio of the number of nuclear plants/total utility O&M personnel is increasing. The practice of borrowing personnel from fossil plants to stay within allowable dose has limited applicability.

- The allowable dose may well be reduced, and even if it is not, the "as low as reasonably achievable" (ALARA) guidelines from NRC has set precedent.

The fission product retention characteristics of the HTGR coated particle fuel along with low circuit activity resultant from primary system corrosion products is being shown at FSV to result in exceptionally low primary system activity. FSV Project Manager Fred Swart reported the following at the August 1979 Utility Conference on the HTGR:

"Personnel exposures to radiation at FSV to date have been minimal.

We have removed three helium circulators from the primary system following prolonged power operation of the reactor with control rods attached and have been through one refueling of the reactor that included an extensive examination of selected fuel and reflector elements in the Hot Service Facility, and still our highest integrated exposures are measured in the range of 100-150 millirem. To date only six to eight people in the plant have received measurable exposures. Our health physics people indicate that the exposure rates have been so low we cannot supply the exposure data the NRC wants.

At no time, to my knowledge, during normal reactor power operation have we not had access to all areas of the reactor building and to the PCRV except for the top head. This is not to say we haven't had radiation problems. On three or four occasions we have experienced contaminated helium leakage into the reactor building and have had to enter using full Anti-C's and Self Contained Breathing Apparatus. In all of these instances, following termination of the leak, unrestricted access to the Reactor Building was gained within a few hours. No residual surface contamination was found that had to be removed."

A recent EPRI report on FSV first refueling/maintenance outage experience notes the total personnel exposure of 0.27 man rem for normal refueling activities and several special inspection and maintenance activities related to the primary system. Included among the maintenance tasks was circulator replacement, comparable to main coolant pump replacement on an LWR, which exposed plant personnel to 0.013 man rem of the 0.27 total. According to NUREG 0323, actual LWR radiation exposure in 1976 was approximately 39 man rem per refueling. The FSV experience, when extrapolated to large HTGR design conditions, agrees well with man rem exposure estimates by General Atomic Company and remains a factor of eight below that of the 1976 LWR experience. Of more significance is the high radiation exposures experienced during LWR primary system maintenance due to radioactive crud buildup. The clean primary helium circuit of the HTGR experienced at both Peach Bottom and FSV should contribute substantially to lower all-around annual HTGR personnel exposure.

In the Gas Turbine version of the HTGR, higher fuel operating temperatures and the requirement for periodic turbine maintenance would tend to result in higher radiation exposures than has been demonstrated in the most impressive FSV Steam Cycle experience. Continuing improvements in fuel technology and design provisions for turbine maintenance, however, should result in a significant net decrease relative to current LWR facilities.

A.2.5 Potential for a Significant Reduction in Power Generation Costs

The basic simplicity of the HTGR-GT along with improved fuel utilization, higher efficiency and favorable heat rejection characteristics can potentially result in a significant cost advantage relative to competing systems. Important factors contributing to this projection include the following:

- Capital Cost

  While a definitive capital cost estimate for the HTGR-GT has yet to be developed, scoping estimates suggest that the potential exists for a near-term cost advantage ranging from modest to significant depending upon water utilization requirements.

  The basic potential cost advantage projected for the HTGR-GT arises from the simplicity of the GT concept. Incorporation of the single phase Brayton Cycle into the primary system of the reactor results in a significant reduction in the BOP, most notably the entire steam plant including secondary piping, supporting auxiliaries, control and protection systems, as well as associated structures. The advantages of this reduced complexity are also reflected in operation and maintenance costs elements.

  Where water scarcity is a factor, the advantage of the HTGR-GT becomes even more significant. The high reject temperature of the Brayton cycle results in a significant reduction in heat rejection equipment for the HTGR-GT when operated in a dry or peak-shaved dry cooling mode.

- Total Power Costs

  In addition to a potential for lower capital costs, fuel and operation and maintenance cost components are also expected to be lower for the HTGR-GT. The HTGR-GT offers lower fuel costs associated with the lower U_3O_8 requirements and lower O&M costs associated with plant simplicity and expected low contamination levels.

- Growth Potential

  A significant factor in cost comparisons is the fact that while LWR costs are based upon a system which has been largely optimized, the HTGR-GT estimates relate to a system which has significant growth potential. As HTGR-GT experience accrues and the state of the art in materials progresses, HTGR-GT core outlet temperatures can be raised to even more efficient ranges, thus further improving the HTGR cost advantage. The high temperature capability of the HTGR, a path not available to the LWR reactors, should more than offset any uncertainties in near-term estimates.

A.2.6 Potential for Co-generation and Process Heat Applications

The relatively high temperature at which heat is rejected from the HTGR-GT has been identified in Section 3.0 as facilitating dry or peak-shaved dry cooling in water scarce areas. A more desirable use of the reject heat, however, may be found in its potential for co-generation of low temperature process steam, use in a bottoming cycle, or use in other appropriate energy conserving applications such as district heating. To the extent this feature is utilized, the HTGR-GT could further contribute to replacement of expensive and strategically important fuels such as oil. The energy content of heat rejection from the HTGR-GT over and above that for any steam cycle system is approximately 10% of the thermal rating of the plant. Assuming a 50% conversion efficiency, this energy content is equivalent to 1700 barrels of oil per day per 1000 MWe plant.

Further, the deployment of the HTGR-GT would provide a supportive technical base and industrial infrastructure for deploying the HTGR for process heat applications. In the case of intermediate temperature process heat, technical commonality is such that a Gas Turbine Demonstration Plant would largely fulfill requirements for process heat demonstration. The balance of technical requirements can be provided through an integral program which includes the Base Technology program and appropriate non-nuclear component and systems testing.

Appendix B

Regional Water Availability Forecasts

In Section 3.1, several regions of the U.S. were identified where "moderate to severe" water problems are expected to exist by the year 2000. The identification of these areas is the result of work performed at the Hanford Engineering Development Laboratory as assessed in their report titled "Assessment of Requirements for Dry Towers," HEDL-TME 76-82 (Ref. 8). This Appendix is presented from that report to provide further insight into the water supply problems of these specific regions.

Mid-Atlantic

Fresh water flows in the Delaware River appear inadequate under present development for additional consumptive use requirements unless storage is provided for low-flow periods (at Trenton the 30-day in 10 year low for August is 2,200 cfs). Mean runoff in the Delaware Basin is ∿ 1.6 cubic feet per second per square mile (cfm). Studies have uncovered glacial deposits with a potential groundwater yield of 5 cfm that could provide make-up supplies for up to 10,000 MWe of new capacity along the Delaware. Unless the drainage area for the glacial deposits is considerably larger than the 50 square mile area indicated in the study, there would be a long-term decline in yield under sustained pumping.

Similar low flow problems exist in the Susquehanna Basin (at Marieta, Pa. 30-day in 10 year flows for September are 3,3000 cfs). Diversions and consumptive use requirements are presently not as great as in the Delaware Basin; consequently, the resource is not as fully committed. However, there have been indications by the basin states that additional consumptive use of water from the Susquehenna River may be restricted or prohibited.

In the Washington, D. C. area, the Potomac has a once in 10 year low of 1,000 cfs in August and September. In general, these flows are presently committed to municipal supply.

Rio Grande

The only significant source of water for cooling in this region is brackish groundwater and low-quality surface waters. Because of the relatively low power projection for year 2000 (9 to 14 GWe), brackish water supplies appear marginally adequate as sources of make-up.

Upper Colorado

The major water use in the region in 1965 was irrigation of 1,621,000 acres. Irrigation is largely concentrated in the headwaters of the Colorado and its tributary streams. In 1965, 1,490,000 acres were under irrigation, with a consumptive use of 2,340 cfs. Total depletions in the Upper Colorado Basin in 1965 amounted to 4,770 cfs. In addition to these uses, commitments had been made for approximately 670 cfs of additional supply, bringing the total depletion at Lee Ferry, Arizona to 5,440 cfs. By the year 2000 irrigation depletions alone are projected to be 4,120 cfs, 2,250 in Colorado, 840 in Utah, 560 in Wyoming and 450 in New Mexico.

Annual runoff for the Colorado River drainage at Lee Ferry, Arizona averages 0.16 cfm and has ranged from 0.24 cfm in 1917 to 0.07 cfm in 1934. Average flow for the 1931-65 period was 18,100 cfs, undepleted; 1917 flow was 33,200 cfs and the 1934 flow (low of record) was 7,700 cfs. In general, the flow originates in mountainous regions such as the Colorado Rockies where the local flow ranges as high as 0.9 cfm. Headwater flow is generally initiated as snow melt and shows some variation due to the wide latitudinal range in the basin. Flow is highly regulated, and is used and depleted extensively upstream of Glen Canyon Dam, the farthest downstream point of control in the system.

The Colorado River compact, signed in 1922, the Mexican Water Treaty of 1944, and the Upper Colorado River Basin compact of 1948 have provisions to apportion to each of the Upper and Lower Colorado Basins the exclusive beneficial consumptive use of 10,360 cfs, plus to allot to Mexico 2,070 cfs. The anomaly in this is that the total flow being apportioned is approximately 22,800 cfs, whereas the undepleted average flow was approximately 18,000 cfs for the 1931-1965 period. The Upper Basin's share of Colorado River water for consumptive use is apportioned as follows: Colorado - 5,390 cfs; Utah - 2,380 cfs; New Mexico - 1,140 cfs; and Wyoming - 1,450 cfs.

In summary, sufficient undeveloped supplies of water appear to be available in the Upper Colorado Region to provide make-up supplies for evaporative cooling through year 2000 in most areas. Local problems exist, however. At the present time, in the State of New Mexico, limited water rights will result in wet/dry towers for the number III and IV units at the San Juan site.

Lower Colorado

In 1965 there were 1,315,000 acres under irrigation in the Lower Colorado Region with an estimated consumptive use of 5,560 cfs. Municipal and industrial consumption in 1965 was 280 cfs. By the year 2000 irrigation consumptive use alone is projected to be 6,040 cfs. In addition, there are distribution losses associated with irrigation development.

Runoff is low in the region, ranging from 0.04 cfm in the Gila subbasin to less than 0.01 cfm in the area around Yuma. Reservoir storage and regulation of streamflow is extensive, and consumptive use of available supplies is total in many areas. Flow of the Colorado River, which averages 18,100 cfs (1931-65 period of record) near the Colorado-Utah state line, is essentially fully utilized by the time it reaches the Mexican border except for treaty flows of 2,070 cfs (average). Forecasted releases from Glen Canyon Dam in 1972 to the Lower Colorado Basin ranged from 15,700 in June to 11,700 in September. If flows of 12,430 cfs are available in a given year for the Lower Colorado area, 6,080 cfs are allocated to California, 3,870 cfs to Arizona, 410 cfs to Nevada, and 2,070 cfs to Mexico. In 1934, the total flow was only 7,700 cfs. When flows below 12,430 cfs occur, a special distribution procedure is put into effect. This procedure, however, has not been clearly defined in terms of percentages for each state. When flows are greater than 12,430 cfs, California and Arizona share equally in the surplus, and Nevada is allowed to appropriate 4% of the surplus, which is to come from the Arizona half. In southern

Arizona an existing water deficit is being satisfied by pumping groundwater in excess of recharge. There have been large declines in water tables in the Casa Grande and Phoenix areas as a result of this pumping. Completion of the Central Arizona Project is not expected to provide surplus water in southern Arizona during the 1990's. A recent proposal before the Arizona State Legislature would place meters on pumps within the state and would charge the user for the quantity pumped. Since metering has historically reduced the consumption of water wherever it has been utilized, the proposal, if enacted, would improve the water situation somewhat. In general, future supplies for electric power consumption by cooling towers or cooling ponds will have to come from existing supplies of water (largely from agricultural uses) or by developing low-quality groundwaters.

Of the 10 to 15 GWe of capacity projected for the region between 1990 and 2000, most if not all could be expected to use wet/dry or dry cooling.

Great Basin

The Great Basin extends from central Utah through Nevada to the California state line. It includes about 80% of Nevada, the western half of Utah, the southeastern part of Idaho, the southwestern tip of Wyoming and small parts of the states of Oregon and California. The principal water use in the region has been for irrigation, with a total of 2,114,000 acres under irrigation in 1965. Consumptive use of water by irrigation is estimated to be 4,050 cfs, of which 750 are projected to come from groundwater supplies. In this region, as in much of the Southwest, reservoir storage of streamflow is extensive and consumptive use of available supplies is total in many areas.

Seasonal records of flow in the Salt Lake City area indicate inadequate supplies to satisfy projected year 2000 cooling requirements. Comprehensive surveys indicate, however, that with additional storage facilities plus transfer of some of Utah's share of Colorado River waters, year 2000 requirements can be met. A potential water deficit in the Reno, Nevada area may result in 500 MWe of dry or wet/dry cooling by year 2000.

Missouri

Statistical summaries of flows for the streams in the Missouri Region's 30 subareas were developed from monthly and annual data normalized to 1970 conditions of depletion and regulation.

Runoff in the Missouri Basin varies from 0.3 cfm in the headwaters of the Missouri to 0.2 cfm in the Yellowstone subbasin and less than 0.1 cfm in the Great Plains. Average runoff of the Osage River in Missouri is 0.6 cfm.

The Missouri region contains the only large-scale dry cooling tower in use in the United States. A 330-MWe coal-fired steam plant located at Gillette, Wyoming is coupled to a dry cooling tower (under construction). Gillette is near the drainage divide of the Yellowstone and Cheyenne subbasins in an area of abundant near-surface coal reserves. Drainage divides are recharge areas; however, mean runoff is low (0.02 cfm) in the Gillette vicinity. Consequently, local water supplies are inadequate. Projected requirements for the Wyoming-Montana area together for the year 2000 are slightly greater than 100 cfs, which appears to be available given intra-regional water transfer. Monthly low flows of the Bighorn River below Boysen Dam (in Wyoming) are approximately 550 cfs. Competing uses and more extensive development of coal deposits for power generation may result in the Wyoming area being more marginal in terms of available water supply by the year 2000.

The Denver area along the South Platte is a potential problem area. An increase of 7 to 10 GWe in the subarea would result in make-up difficulties in an area where the local water supplies are already fully developed and appropriated. One alternative may be to generate power in northwestern Colorado coal fields, with long-distance transmission to the Denver area; another is to buy up water rights for cooling supply; a third is wet/dry or dry cooling for part or all of the requirements.

For the Missouri Basin as a whole, water supplies appear adequate through the year 2000. Total consumptive use requirements for the basin are less than 500 cfs. Once in 10 year low monthly flows of the Missouri at Kansas City are 15,000 cfs in the winter months and 38,000 cfs in the summer months.

California

This region of 10 subareas includes the entire state of California plus Klamath County, Oregon. In 1972 gross demand for water was 6,950 cfs for urban uses and 43,800 cfs for agricultural uses (chiefly irrigation). At present, nearly 9 million of the 10.5 million acres of cultivated land are irrigated. Net water use (depletions) in 1972 amounted to 37,300 cfs. Depletion in this case includes evaporation-transpiration plus related consumptive losses and waste water discharges to the ocean or other saline water bodies, such as the Salton Sea. It does not include potentially useable return flow or waste discharges on coastal areas.

Runoff is highly variable in the region, ranging from 2.1 cfm in the Klamath North Coastal subarea to less than 0.01 cfm in the southeastern deserts. In general, the mountainous areas are the major source of seasonal runoff from spring snow melt in the Sierra Nevada and winter rains along the north coast. In the southeastern deserts significant runoff is usually associated with flash floods, related in turn to summer convective storms. Average runoff in California is approximately 98,000 cfs, 40% in the Klamath-North Coastal subarea, 31% in the Sacramento, 9% in the San Joaquin, 5% in the San Francisco Bay, 4% in the Tulare and 3% in the Central Coastal subarea. A total of 8% occurs in the South Coastal, Colorado Desert, South Lahontan and Sacramento-San Joaquin Delta. About 60% of present water supplies are derived from regulation and division by reservoirs, with a total storage capacity of 39 million acre-feet. Most of the larger reservoirs are in the Central Valley. In addition to indigenous runoff, 1,930 cfs enter the area from Oregon. California's share of Colorado River water is 6,080 cfs; outflow to Nevada is 1,660 cfs.

Undeveloped water supplies in California are 37,600 cfs. Much of this is too dispersed to be developed economically, such as waters from flash floods in the southern deserts. However, there are a number of potentially large additions to the Central Valley and Klamath-North Coastal reservoir systems that would have significant impact in terms of increased water supply. These include in the Central Valley: Cottonwood Creek Project - 380 cfs; Millville project - 50 cfs; Schoenfield Reservoir and Galatin Reservoir - 100 cfs;

Glen Reservoir and Sacramento Diversion Plan - 1,240 cfs; Marysville Project - 210 cfs; Los Banos Reservoir - 280 cfs; Consumnes River system - 200 cfs. In the Klamath - North Coastal area: Dos Rios and English Ridge Projects - 700 to 1,400 cfs (depending on size of reservoirs and plan of operation), Butter Valley Dam - 160 cfs. In aggregate, these projects would develop up to 10% of the remaining undeveloped water supply and would add 10% to existing supplies Many of the above projects have been authorized, but funds have not been appropriated for construction.

Water supplies in the Central Valley Project of 12,100 cfs are expected to satisfy contractural 1990 demands; by year 2000 contractural requirements of 12,150 cfs would be marginal under conditions of moderately high growth with respect to facilities presently existing or under construction. If the Auburn or New Melones reservoirs plus the Peripheral Canal in the Sacramento-San Joaquin Delta are completed, the capability of the Central Valley Project would be 13,000 cfs. Possible demands in addition to present contracts could range between 1,900 cfs and 4,000 cfs in 1990 and up to 2,200 cfs and 5,400 cfs by the year 2000. Without new reservoir capacity (e.g., facilities indicated in previous paragraph) and associated conveyance facilities, the Central Valley Project could not satisfy this additional demand.

By 1990 water supplies of 4,700 cfs in the State Water Project are expected to be fully utilized under present contracts; maximum contractural commitments could run as high as 6,160 cfs. Possible additional demands ranging from between 30 cfs and 680 cfs in 1990 to between 220 cfs and 2,680 cfs by year 2000 could also exceed the system's capability.

Included in the additional demand is water for evaporative cooling. The state recently made 138 cfs (7 to 11 GWe of wet cooling) available for power plant cooling in the Mojave Desert near Blythe and up to 83 cfs (5 to 7 GWe of wet cooling) in the Tulare subarea. Some use of brackish agricultural drainage for cooling supplies is also expected in the San Joaquin Valley. Reclaimed waste water is defined as "new water" in California and is subject to appropriation. Municipal and industrial waste water production suitable for reclamation by year 2000 is estimated to be: 1,600 cfs in the San Francisco Bay area; 250 cfs in Monterey Bay; 400 cfs in Santa Barbara - Ventura; 2,500 cfs in metropolitan Los Angeles; 400 cfs in the San Diego metropolitan area

Fresh water supplies in California are ample to satisfy the needs of wet cooling in California through the year 2000 in terms of physical availability. At present, however, the two major sources of water for development in the state, the Colorado River and Sacramento River, are either presently committed by contract to supply projects other than steam electric plants, or will be fully committed (possibly overcommitted) by 1990.

Because of uncertainty over the transfer of water rights from agricultural uses or the practicality of reclaiming waste water from dissemination sources, it is difficult to predict what percentage of the 56 to 89 GWe of the thermal capacity increase projected between 1990 and 2000 will require wet/dry or dry cooling.

At consumptive rates near 12 cfs/GWt for southern California, minimum consumption would range between 700 cfs and 1,100 cfs (for a capacity factor of 53% and an efficiency of 33%). At present, approximately 4 to 6 feet per year (6 ft/yr $\sim$ 0.008 cfs/acre) is used for irrigation in the Central Valley and in southern California. The agricultural equivalent of 1,100 cfs would range between 130,000 and 190,000 acres of high-intensity irrigated farmland, which would either not be placed into production or removed from production to satisfy the 1990-2000 wet cooling requirements.

Under a reasoning process in which all aspects of the state's economy must share in providing the necessary power, it is assumed that three-fourths of the projected wet cooling requirements would come from the reclamation of waste and the transfer of water rights from irrigation to electric power uses. Thus, only 14 to 22 GWe would be expected to require wet/dry or dry cooling.

<u>Texas-Gulf</u>

This region includes 11 subareas, largely in Texas. Streamflow has generally been fully developed in the region for irrigation, municipal and other purposes. Reservoirs are numerous. On the basis of seasonal once in ten-year 30-day low flows, the water resources of this region are noticeably inadequate to provide make-up supply for projected year 2000 wet tower demands. However, groundwater was utilized for 44% of the total water supply in 1970, and will continue to be a major source of supply. Because of possible long distance transmission coupled with salt water cooling on the Gulf Coast, it is expected that only 2 to 4 GWe of capacity located in the headwaters of the Colorado (of Texas) and Brazos Rivers would require dry or wet/dry cooling by year 2000.

Appendix C

Data Base and Assumptions

C.1 Regional System Characteristics

Two regions of the U.S. were selected for evaluation in the HTGR Market Assessment. The regions were modeled for study purposes using EPRI synthetic utility system models. The selected models are as follows:

Region	EPRI Synthetic System Model
Northeast	D
West	B

The selection of these regions and the corresponding synthetic systems is discussed in Section 4.2.

The data and assumptions used in this Assessment were derived from the various sources listed on page 6-4. The assumptions are believed to be realistic for the synthetic systems used, although they may not, nor are they intended to, represent specific utility systems.

C.1.1 Load Models

A. Load Shapes - As contained in the EPRI data bases for the scaled-down synthetic systems. All load factors are assumed to remain constant throughout the study period:

Synthetic System	Annual Load Factor
D	59%
B	70%

The monthly load models for these systems are found in Tables C.1-1A through C.1-1B.

B. Peak Loads - As contained in the EPRI data bases for the synthetic systems:

Synthetic System	1985 Peak		Comments
	Full	Scaled-Down	
D	26248	8375	Summer peak
B	38261	8350	Winter peak

From the NERC 8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, August 1978 (NERC) for the study regions:

Northeast Region
Scaled-Down Synthetic System D
Monthly Load Models

1985

JAN. PROBABILITY DURATION	JAN. PROGRAM LOADS MW	JAN. PROGRAM LOADS P.U.	FEB. PROBABILITY DURATION	FEB. PROGRAM LOADS MW	FEB. PROGRAM LOADS P.U.	MARCH PROBABILITY DURATION	MARCH PROGRAM LOADS MW	MARCH PROGRAM LOADS P.U.	APRIL PROBABILITY DURATION	APRIL PROGRAM LOADS MW	APRIL PROGRAM LOADS P.U.
0.	6281.	1.000	0.	6030.	1.000	0.	5946.	1.000	0.	5695.	1.000
0.2	6156.	0.980	0.2	5909.	0.980	0.2	5827.	0.980	0.2	5604.	0.984
0.4	6149.	0.979	0.4	5903.	0.979	0.4	5821.	0.979	0.4	5490.	0.964
1.0	6024.	0.959	1.0	5763.	0.959	1.0	5702.	0.959	1.0	5353.	0.940

JAN. HOURLY WEEKDAY MW LOAD 22 DAYS	JAN. HOURLY WEEKEND MW LOAD 9 DAYS	FEB. HOURLY WEEKDAY MW LOAD 19 DAYS	FEB. HOURLY WEEKEND MW LOAD 9 DAYS	MARCH HOURLY WEEKDAY MW LOAD 21 DAYS	MARCH HOURLY WEEKEND MW LOAD 10 DAYS	APRIL HOURLY WEEKDAY MW LOAD 22 DAYS	APRIL HOURLY WEEKEND MW LOAD 8 DAYS
6281.	4932.	6030.	4779.	5946.	4435.	5695.	3946.
6224.	4777.	6030.	4629.	5603.	4285.	5544.	3875.
6158.	4705.	5967.	4559.	5544.	4233.	5444.	3838.
6122.	4651.	5933.	4506.	5512.	4184.	5386.	3807.
6088.	4597.	5899.	4454.	5481.	4138.	5319.	3801.
6031.	4579.	5844.	4436.	5430.	4120.	5263.	3730.
6009.	4525.	5623.	4385.	5410.	4063.	5207.	3696.
5973.	4468.	5788.	4329.	5378.	4016.	5154.	3659.
5926.	4385.	5742.	4249.	5336.	3921.	5082.	3551.
5887.	4314.	5705.	4180.	5300.	3872.	4998.	3426.
5836.	4285.	5655.	4162.	5254.	3837.	4910.	3392.
5762.	4196.	5583.	4066.	5187.	3756.	4781.	3352.
5581.	4108.	5408.	3980.	5024.	3678.	4686.	3313.
5378.	3999.	5211.	3875.	4842.	3589.	4575.	3256.
5184.	3923.	5023.	3801.	4667.	3519.	4468.	3239.
4889.	3829.	4737.	3710.	4402.	3438.	4268.	3227.
4600.	3773.	4457.	3656.	4142.	3384.	3931.	3153.
4330.	3718.	4196.	3602.	3899.	3346.	3700.	3108.
4056.	3665.	3930.	3551.	3652.	3277.	3562.	3026.
3926.	3595.	3804.	3484.	3535.	3225.	3468.	3003.
3857.	3538.	3737.	3428.	3473.	3138.	3408.	2994.
3791.	3375.	3673.	3271.	3414.	2994.	3331.	2861.
3644.	3253.	3530.	3153.	3261.	2921.	3137.	2784.
3370.	3215.	3265.	3115.	3035.	2892.	3030.	2750.
3633477. MWH		3156597. MWH		3250300. MWH		3029983. MWH	

Table C.1-1A (Continued)

1985

MAY PROBABILITY DURATION	MAY PROGRAM LOADS MW	MAY PROGRAM LOADS P.U.	JUNE PROBABILITY DURATION	JUNE PROGRAM LOADS MW	JUNE PROGRAM LOADS P.U.	JULY PROBABILITY DURATION	JULY PROGRAM LOADS MW	JULY PROGRAM LOADS P.U.	AUG. PROBABILITY DURATION	AUG. PROGRAM LOADS MW	AUG. PROGRAM LOADS P.U.
0.	6030.	1.000	0.	7789.	1.000	0.	8375.	1.000	0.	7956.	1.000
0.2	5934.	0.984	0.2	7641.	0.981	0.2	8216.	0.981	0.2	7805.	0.981
0.4	5813.	0.964	0.4	7508.	0.964	0.4	8073.	0.964	0.4	7670.	0.964
1.0	5668.	0.940	1.0	6955.	0.893	1.0	7479.	0.893	1.0	7105.	0.893

MAY HOURLY WEEKDAY MW LOAD 22 DAYS	MAY HOURLY WEEKEND MW LOAD 9 DAYS	JUNE HOURLY WEEKDAY MW LOAD 20 DAYS	JUNE HOURLY WEEKEND MW LOAD 10 DAYS	JULY HOURLY WEEKDAY MW LOAD 22 DAYS	JULY HOURLY WEEKEND MW LOAD 9 DAYS	AUG. HOURLY WEEKDAY MW LOAD 22 DAYS	AUG. HOURLY WEEKEND MW LOAD 9 DAYS
6030.	4175.	7789.	6053.	8375.	6440.	7956.	6130.
5860.	4095.	7545.	5983.	8033.	6337.	7647.	6032.
5755.	4058.	7392.	5855.	7871.	6209.	7492.	5910.
5694.	4027.	7318.	5757.	7791.	6081.	7416.	5789.
5623.	4019.	7160.	5633.	7624.	5929.	7257.	5644.
5563.	3970.	7028.	5531.	7483.	5819.	7123.	5539.
5504.	3920.	6989.	5434.	7335.	5615.	6982.	5345.
5448.	3808.	6911.	5235.	7252.	5500.	6903.	5236.
5372.	3810.	6726.	5157.	7161.	5483.	6817.	5219.
5283.	3695.	6640.	5145.	7070.	5436.	6730.	5175.
5189.	3616.	6504.	5087.	7010.	5386.	6673.	5127.
5054.	3553.	6500.	5021.	6920.	5308.	6588.	5053.
4953.	3517.	6243.	4974.	6647.	5273.	6327.	5019.
4835.	3452.	6043.	4896.	6434.	5151.	6125.	4903.
4723.	3424.	5746.	4791.	6118.	5081.	5823.	4837.
4511.	3406.	5456.	4713.	5809.	5000.	5530.	4759.
4155.	3330.	5138.	4670.	5471.	4959.	5208.	4721.
3911.	3276.	4794.	4580.	5104.	4826.	4859.	4594.
3765.	3193.	4527.	4455.	4927.	4693.	4690.	4467.
3665.	3172.	4428.	4365.	4714.	4664.	4488.	4440.
3603.	3118.	4339.	4342.	4620.	4536.	4398.	4318.
3521.	3003.	4283.	4058.	4560.	4262.	4341.	4057.
3316.	2939.	4179.	3894.	4449.	4140.	4235.	3940.
3203.	2906.	4038.	3793.	4300.	4033.	4093.	3839.

MAY	JUNE	JULY	AUG.
3289876. MWH	4068358. MWH	4503083. MWH	4286234. MWH

Table C.1-1A (Continued)

1985

SEPT.			OCT.			NOV.			DEC.		
ROBABILITY URATION	PROGRAM MW	LOADS P.U.	PROBABILITY DURATION	PROGRAM MW	LOADS P.U.	PROBABILITY DURATION	PROGRAM MW	LOADS P.U.	PROBABILITY DURATION	PROGRAM MW	LOADS P.U.
0.	6867.	1.000	0.	6114.	1.000	0.	6281.	1.000	0.	6532.	1.000
0.2	6758.	0.984	0.2	6016.	0.984	0.2	6158.	0.980	0.2	6402.	0.980
0.4	6620.	0.964	0.4	5894.	0.964	0.4	6149.	0.979	0.4	6395.	0.979
1.0	6455.	0.940	1.0	5747.	0.940	1.0	6024.	0.959	1.0	6265.	0.959

SEPT. HOURLY WEEKDAY MW LOAD 20 DAYS	SEPT. HOURLY WEEKEND MW LOAD 10 DAYS	OCT. HOURLY WEEKDAY MW LOAD 23 DAYS	OCT. HOURLY WEEKEND MW LOAD 8 DAYS	NOV. HOURLY WEEKDAY MW LOAD 20 DAYS	NOV. HOURLY WEEKEND MW LOAD 10 DAYS	DEC. HOURLY WEEKDAY MW LOAD 21 DAYS	DEC. HOURLY WEEKEND MW LOAD 10 DAYS
6867.	4823.	6114.	4191.	6281.	4717.	6532.	5145.
6776.	4736.	5888.	4116.	5948.	4580.	6500.	4971.
6654.	4691.	5782.	4076.	5885.	4500.	6432.	4910.
6583.	4653.	5721.	4043.	5851.	4447.	6394.	4853.
6502.	4646.	5649.	4037.	5818.	4395.	6358.	4800.
6432.	4559.	5589.	3962.	5764.	4377.	6299.	4780.
6364.	4517.	5530.	3925.	5743.	4334.	6276.	4713.
6299.	4472.	5473.	3886.	5708.	4276.	6239.	4659.
6211.	4340.	5397.	3772.	5663.	4213.	6189.	4548.
6109.	4188.	5308.	3639.	5626.	4131.	6149.	4491.
6000.	4146.	5214.	3603.	5577.	4105.	6095.	4451.
5844.	4097.	5078.	3560.	5506.	4039.	6017.	4357.
5727.	4049.	4977.	3518.	5333.	3943.	5828.	4267.
5591.	3979.	4858.	3458.	5139.	3831.	5617.	4163.
5461.	3958.	4745.	3440.	4954.	3760.	5414.	4082.
5216.	3944.	4533.	3428.	4672.	3667.	5106.	3989.
4804.	3854.	4175.	3349.	4396.	3617.	4804.	3925.
4522.	3799.	3930.	3301.	4139.	3554.	4523.	3881.
4353.	3698.	3783.	3213.	3877.	3522.	4236.	3801.
4238.	3670.	3683.	3189.	3753.	3444.	4100.	3741.
4166.	3660.	3620.	3180.	3686.	3409.	4028.	3640.
4071.	3496.	3538.	3038.	3624.	3279.	3959.	3472.
3834.	3403.	3332.	2957.	3483.	3116.	3805.	3389.
3703.	3361.	3218.	2921.	3222.	3074.	3520.	3355.
3633980. MWH		3334503. MWH		3336275. MWH		3762684. MWH	

1985 LOAD FACTOR = 69.0

LL AVAILABLE DATA HAVE BEEN PROCESSED

Table C.1-1B

Western Region
Scaled-Down Synthetic System B
Monthly Load Models

1985

	JAN.			FEB.			MARCH			APRIL		
	PROBABILITY DURATION	PROGRAM LOADS MW	P.U.	PROBABILITY DURATION	PROGRAM LOADS MW	P.U.	PROBABILITY DURATION	PROGRAM LOADS MW	P.U.	PROBABILITY DURATION	PROGRAM LOADS MW	P.U.
	0.	7476.	1.000	0.	7209.	1.000	0.	6942.	1.000	0.	7654.	1.000
	0.2	7454.	0.997	0.2	7187.	0.997	0.2	6921.	0.997	0.2	7501.	0.980
	0.4	7431.	0.994	0.4	7166.	0.994	0.4	6900.	0.994	0.4	6957.	0.909
	1.0	6960.	0.931	1.0	6712.	0.931	1.0	6463.	0.931	1.0	6690.	0.874

JAN. HOURLY WEEKDAY MW LOAD 22 DAYS	JAN. HOURLY WEEKEND MW LOAD 9 DAYS	FEB. HOURLY WEEKDAY MW LOAD 19 DAYS	FEB. HOURLY WEEKEND MW LOAD 9 DAYS	MARCH HOURLY WEEKDAY MW LOAD 21 DAYS	MARCH HOURLY WEEKEND MW LOAD 10 DAYS	APRIL HOURLY WEEKDAY MW LOAD 22 DAYS	APRIL HOURLY WEEKEND MW LOAD 8 DAYS
7476.	6093.	7209.	5891.	6942.	5318.	7654.	5348.
7121.	5980.	6886.	5782.	6225.	5224.	7097.	5214.
6974.	5897.	6744.	5701.	6096.	5143.	6984.	5188.
6890.	5817.	6662.	5625.	6022.	5065.	6842.	5166.
6783.	5713.	6558.	5524.	5929.	4984.	6684.	5107.
6694.	5575.	6472.	5390.	5851.	4844.	6578.	4988.
6649.	5495.	6429.	5313.	5812.	4799.	6505.	4962.
6568.	5450.	6350.	5270.	5741.	4760.	6459.	4877.
6467.	5431.	6253.	5252.	5652.	4744.	6398.	4825.
6419.	5350.	6207.	5173.	5611.	4659.	6250.	4732.
6376.	5266.	6165.	5092.	5573.	4601.	6143.	4524.
6321.	5224.	6112.	5051.	5525.	4565.	5885.	4447.
6250.	5143.	6043.	4972.	5463.	4487.	5739.	4350.
6118.	4887.	5916.	4725.	5347.	4264.	5641.	4246.
5889.	4694.	5694.	4538.	5147.	4092.	5428.	4102.
5626.	4611.	5440.	4458.	4918.	4033.	5254.	3994.
5222.	4369.	5049.	4215.	4565.	3806.	4952.	3942.
4836.	4125.	4676.	3989.	4227.	3585.	4579.	3764.
4590.	4045.	4438.	3911.	4012.	3530.	4352.	3616.
4441.	3969.	4294.	3837.	3882.	3465.	4213.	3575.
4235.	3947.	4095.	3817.	3702.	3436.	4148.	3371.
4027.	3839.	3894.	3712.	3620.	3339.	3950.	2956.
3720.	3675.	3596.	3553.	3251.	3177.	3777.	2793.
3602.	3614.	3483.	3494.	3149.	3157.	3396.	2730.
4128265. MWH		3587205. MWH		3595132. MWH		3790476. MWH	

Table C.1-1B (Continued)

1985

MAY PROBABILITY DURATION	MAY PROGRAM LOADS MW	MAY P.U.	JUNE PROBABILITY DURATION	JUNE PROGRAM LOADS MW	JUNE P.U.	JULY PROBABILITY DURATION	JULY PROGRAM LOADS MW	JULY P.U.	AUG. PROBABILITY DURATION	AUG. PROGRAM LOADS MW	AUG. P.U.
0.	7209.	1.000	0.	8455.	1.000	0.	8900.	1.000	0.	8811.	1.000
0.2	7066.	0.980	0.2	8328.	0.985	0.2	8767.	0.985	0.2	8679.	0.985
0.4	6553.	0.909	0.4	8075.	0.955	0.4	8500.	0.955	0.4	8415.	0.955
1.0	6301.	0.874	1.0	7905.	0.935	1.0	8322.	0.935	1.0	8238.	0.935

MAY HOURLY WEEKDAY MW LOAD 22 DAYS	MAY HOURLY WEEKEND MW LOAD 9 DAYS	JUNE HOURLY WEEKDAY MW LOAD 20 DAYS	JUNE HOURLY WEEKEND MW LOAD 10 DAYS	JULY HOURLY WEEKDAY MW LOAD 22 DAYS	JULY HOURLY WEEKEND MW LOAD 9 DAYS	AUG. HOURLY WEEKDAY MW LOAD 22 DAYS	AUG. HOURLY WEEKEND MW LOAD 9 DAYS
7209.	5071.	8455.	6570.	8900.	6862.	8811.	6792.
6729.	4959.	8141.	6469.	8501.	6763.	8414.	6694.
6622.	4924.	8016.	6351.	8371.	6627.	8285.	6559.
6487.	4905.	7974.	6229.	8327.	6505.	8242.	6439.
6338.	4883.	7944.	6132.	8295.	6413.	8210.	6348.
6237.	4762.	7882.	6060.	8230.	6335.	8146.	6270.
6168.	4716.	7821.	6022.	8167.	6305.	8083.	6240.
6124.	4667.	7757.	5938.	8100.	6231.	8017.	6168.
6066.	4614.	7661.	5804.	8000.	6100.	7918.	6037.
5926.	4519.	7564.	5732.	7898.	6016.	7817.	5954.
5824.	4352.	7484.	5690.	7815.	5959.	7735.	5898.
5580.	4244.	7362.	5467.	7687.	5776.	7608.	5717.
5442.	4146.	7239.	5374.	7559.	5619.	7481.	5562.
5349.	4037.	6976.	5244.	7284.	5507.	7210.	5451.
5146.	3902.	6517.	5126.	6804.	5364.	6735.	5310.
4982.	3787.	6112.	4747.	6383.	4961.	6317.	4910.
4695.	3721.	5663.	4697.	5913.	4908.	5853.	4858.
4342.	3537.	4917.	4629.	5135.	4841.	5082.	4791.
4127.	3419.	4717.	4520.	4925.	4703.	4875.	4655.
3995.	3376.	4498.	4318.	4697.	4501.	4649.	4455.
3933.	3015.	4293.	4192.	4482.	4370.	4437.	4326.
3746.	2742.	4207.	4120.	4393.	4297.	4348.	4253.
3581.	2641.	4133.	4065.	4315.	4241.	4271.	4198.
3220.	2587.	4059.	3973.	4238.	4142.	4195.	4099.
3690743. MWH		4422529. MWH		4817330. MWH		4768214. MWH	

Table C.1-1B (Continued)

1985

SEPT.			OCT.			NOV.			DEC.		
PROBABILITY DURATION	PROGRAM LOADS MW	P.U.	PROBABILITY DURATION	PROGRAM LOADS MW	P.U.	PROBABILITY DURATION	PROGRAM LOADS MW	P.U.	PROBABILITY DURATION	PROGRAM LOADS MW	P.U.
0.	8633.	1.000	0.	7387.	1.000	0.	7565.	1.000	0.	8099.	1.000
0.2	8460.	0.980	0.2	7239.	0.980	0.2	7542.	0.997	0.2	8075.	0.997
0.4	7847.	0.909	0.4	6715.	0.9C9	0.4	7520.	0.994	0.4	8050.	0.994
1.0	7546.	0.874	1.0	6456.	0.874	1.0	7043.	0.931	1.0	7540.	0.931

SEPT. HOURLY WEEKDAY MW LOAD 20 DAYS	SEPT. HOURLY WEEKEND MW LOAD 10 DAYS	OCT. HOURLY WEEKDAY MW LOAD 23 DAYS	OCT. HOURLY WEEKEND MW LOAD 8 DAYS	NOV. HOURLY WEEKDAY MW LOAD 20 DAYS	NOV. HOURLY WEEKEND MW LOAD 10 DAYS	DEC. HOURLY WEEKDAY MW LOAD 21 DAYS	DEC. HOURLY WEEKEND MW LOAD 10 DAYS
8633.	6145.	7387.	5164.	7565.	5814.	8099.	6629.
8155.	5992.	6353.	5035.	6788.	5702.	7759.	6512.
8026.	5962.	6744.	5010.	6648.	5630.	7599.	6411.
7862.	5936.	6507.	4989.	6567.	5562.	7507.	6314.
7681.	5868.	6455.	4931.	6465.	5455.	7391.	6213.
7558.	5732.	6352.	4817.	6380.	5339.	7294.	6039.
7475.	5702.	6281.	4792.	6338.	5241.	7245.	5982.
7422.	5604.	6237.	4709.	6260.	5199.	7156.	5934.
7352.	5544.	6178.	4659.	6164.	5180.	7046.	5913.
7182.	5438.	6035.	4570.	6118.	5115.	6994.	5808.
7059.	5199.	5932.	4369.	6077.	5022.	6947.	5735.
6762.	5110.	5683.	4294	6025.	4981.	6887.	5691.
6595.	4999.	5542.	4201.	5957.	4908.	6810.	5594.
6483.	4880.	5448.	4100.	5831.	4665.	6666.	5315.
6237.	4713.	5241.	3961.	5613.	4484.	6417.	5100.
6038.	4590.	5074.	3857.	5363.	4392.	6130.	5028.
5690.	4530.	4782.	3807.	4978.	4158.	5690.	4745.
5262.	4326.	4422.	3635.	4610.	3950.	5270.	4469.
5001.	4155.	4203.	3492.	4375.	3860.	5001.	4401.
4841.	4108.	4068.	3452.	4233.	3786.	4839.	4320.
4766.	3874.	4005.	3255.	4037.	3775.	4614.	4283.
4540.	3397.	3815.	2854.	3838.	3674.	4388.	4162.
4340.	3209.	3647.	2697.	3545.	3534.	4053.	3960.
3902.	3137.	3279.	2636.	3434.	3446.	3925.	3936.
4278776. MWH		3790462. MWH		3792905. MWH		4471200. MWH	

1985 LOAD FACTOR = 63.0

ALL AVAILABLE DATA HAVE BEEN PROCESSED

Region	1985 Peak	Comments
Northeast	88,094	Summer peak
West	99,418	Summer peak

C. Load Growth - Developed from NERC for the study regions and associated synthetic systems:

Region (System)	Compound Annual Growth Rate 1985-1989	1990-2020
Northeast (D)	3.5%	3.5%
West (B)	4.5%	4.0%

Annual peak loads and load growths for these systems and also the systems utilized for this study are shown in Table C.1-2.

C.1.2 Generation System Models

A. Base System Generation Mixes - As outlined in the EPRI report Synthetic Electric Utility Systems for Evaluating Advanced Technologies, EM-285, February 1977 (SUS) for the scaled-down synthetic systems.

1985 System:	D		B	
Type	Capacity (MW)	Mix (%)	Capacity (MW)	Mix (%)
Coal	3,600	36	2,000	20
Oil	2,600	26	2,400	24
Nuclear	2,400	24	1,000	10
GT	1,450	14	600	6
Hydro	--	--	3,800	38
Pump Storage	--	--	200	2
	10,050		10,000	

A tabularized description of the scaled-down synthetic utility systems is found in Tables C.1-2A through C.1-2B.

B. Generating Unit Additions - The synthetic systems were expanded to the year 2000 using the following expansion candidate unit types:

Table C.1-2

Annual Peak Loads
and
Load Growth Rates

	Regional Peaks - MW	
Study Region	Northeast	West
NERC Regional Reliability Council(s)	MAAC, NPCC	WSCC
Year: 1985	88,094	99,418
2000	147,600	183,400
2019	283,700	386,400

	Synthetic System Peaks - MW	
Scaled-Down Synthetic System	D	B
Year: 1985	8,375	8,350
2000	14,031	15,403
2019	26,975	32,452

	Compound Annual Growth Rates - %	
Study Region	Northeast	West
Scaled-Down Synthetic System	D	B
Period: 1985-1989	3.5	4.5
1990-2019	3.5	4.0

Table C.1-2A

Scaled-Down Synthetic System D
Generation Characteristics

System Size: 10,050 MW
Number of Thermal Units: 52

Quantity	Unit Size (MW)	Unit Description
2	1200	LWR, nuclear steam
1	800	Oil, fossil steam
2	600	Coal, fossil steam
2	400	Coal, fossil steam
1	400	Oil, fossil steam
8	200	Coal, fossil steam
7	200	Oil, fossil steam
29	50	Gas turbine

Mix of Unit Type
(% Capacity)

36%	Coal, fossil steam
26%	Oil, fossil steam
24%	LWR, nuclear steam
14%	Gas turbine

Table C.1-2A (Continued)

Scaled-Down Synthetic System D
Thermal Generation Installation Dates

Unit Description	Installation Date
1 - 200 MW, Coal	1951
1 - 200 MW, Oil	1952
1 - 200 MW, Coal	1953
1 - 200 MW, Coal 1 - 200 MW, Oil	1954
1 - 200 MW, Coal	1955
1 - 200 MW, Oil	1956
1 - 200 MW, Coal	1957
1 - 200 MW, Coal 1 - 200 MW, Oil	1958
1 - 200 MW, Coal	1959
1 - 200 MW, Oil	1960
1 - 200 MW, Coal	1962
1 - 400 MW, Coal	1963
1 - 200 MW, Oil	1964
1 - 400 MW, Coal 1 - 200 MW, Oil 4 - 50 MW, GT	1966
1 - 400 MW, Oil	1968
4 - 50 MW, GT	1969
1 - 600 MW, Coal 4 - 50 MW, GT	1970
4 - 50 MW, GT	1971
4 - 50 MW, GT	1972
1 - 600 MW, Coal	1973
4 - 50 MW, GT	1975
1 - 800 MW, Oil	1976
1 - 1200 MW, LWR	1978
4 - 50 MW, GT	1980
1 - 1200 MW, LWR 1 - 50 MW, GT	1982

Table C.1-2B

Scaled-Down Synthetic System B
Generation Characteristics

System Size: 10,000 MW
Number of Thermal Units: 27

Quantity	Unit Size (MW)	Unit Description
1	1000	LWR, nuclear steam
1	800	Coal, fossil steam
1	600	Coal, fossil steam
1	400	Coal, fossil steam
2	400	Oil, fossil steam
1	200	Coal, fossil steam
8	200	Oil, fossil steam
12	50	Gas turbine
--	3800	Hydro, conventional
--	200	Hydro, pump storage

Mix of Unit Type (% Capacity)	
38%	Hydro, conventional
24%	Oil, fossil steam
20%	Coal, fossil steam
10%	LWR, nuclear steam
6%	Gas turbine
2%	Hydro, pump storage

Table C.1-2B (Continued)

Scaled-Down Synthetic System B
Thermal Generation Installation Dates

Unit Description	Installation Date
1 - 200 MW, Oil	1951
1 - 200 MW, Oil	1953
1 - 200 MW, Oil	1955
1 - 200 MW, Oil	1958
2 - 200 MW, Oil	1960
1 - 200 MW, Oil	1962
1 - 200 MW, Oil	1964
1 - 200 MW, Coal	1965
1 - 400 MW, Coal 2 - 50 MW, GT	1968
1 - 400 MW, Oil 2 - 50 MW, GT	1970
2 - 50 MW, GT	1972
1 - 600 MW, Coal	1973
1 - 400 MW, Oil 2 - 50 MW, GT	1978
2 - 50 MW, GT	1980
1 - 1000 MW, LWR	1981
1 - 800 MW, Coal 2 - 50 MW, GT	1984

Scaled-Down Synthetic System B
Monthly Conventional Hydro Generation

	Monthly Energy (MWHr)*
Total Annual Conventional Hydro Energy	23,304,000

*Corresponds to 3,800 MW of conventional hydro with a capacity factor of approximately 70%.

Type	Size (MW)	Year Available
Nuclear, LWR	1200	Current
Conventional Coal w/FGD	1000	Current
Conventional Coal w/FGD	600	Current
Atmospheric Fluidized-Bed Coal	1000	1990
Gas Turbine - Conventional	75	Current
- Advanced	100	1987
Combined Cycle - Conventional	250	Current
- Advanced	285	1989
Advanced Batteries	100	1990

The advanced technology combustion turbine and combined cycle units replaced the current technology units as generation options when they become available. After the year 2000, the HTGR became an expansion candidate.

Refer to Section 4.2 for discussion of the expansion candidate unit selection and the system expansions.

C. Generating Unit Retirements - Base system units were retired based on unit installation dates as outlined in SUS and the following expected useful lives proposed for the DOE study Technical and Economic Assessment of Electrochemical Energy Storage Systems (EESS) (Ref. 14), study in progress by Public Service Electric and Gas Company:

Fossil Steam	45 years
Nuclear	35 years
Gas Turbine	30 years
Combined Cycle	30 years

These useful lives were used only to establish the retirement schedules. They should not be confused with the book lives, which are used for accounting and financial purposes.

Hydro and expansion system units were not retired during the study period.

D. Installed Generation Reserves - Prior to the 1985 generating unit additions, the base system reserves for all three systems were 20%.

The synthetic systems were expanded to the year 2000 to meet a loss-of-load probability (LOLP) criterion of 10 days per year. The resulting installed reserves vary from year to year and from system to system:

Synthetic System	Installed Reserve
D	25-42%
B	28-37%

These reserve margins may not be representative for a given utility. However, in this study the results of interest from the synthetic system expansions are the generation mixes. Due to the small size of the scaled-down synthetic systems, it was felt that reducing the installed reserve margins would unduly penalize the large base load units and distort the resulting generation mixes.

In applying the synthetic system generation mix results to the real study regions, it was assumed that the regions would maintain approximately 20% installed reserve margins.

C.1.3 Generating Unit Performance Data

A. Heat Rates

For existing base system steam units, the full load heat rates were based on the EPRI-prepared data bases for the selected synthetic systems. The minimum load generation levels and heat rates are based on SUS data, as a percentage of full load generation and heat rate. The coal unit heat rates were regionalized. For base system gas turbine (GT) and combined cycle (CC) units, the heat rates were based on SUS data.

For candidate expansion units similar to existing unit types, the heat rates were based on the comparable base system units. The conventional coal unit heat rates include the effect of FGD systems. For advanced technology expansion system thermal units, the heat rates were based on TAG data. The AFB unit heat rates were regionalized, and for advanced batteries, the cycle efficiency and storage capacity values were based on EESS data.

B. Outage Rates

For existing base system units, the outage rates were based on SUS data. For candidate expansion units similar to existing unit types, the outage rates were based on the comparable base system units. The conventional coal unit outage rates include the effect of flue gas desulfurization (FGD) systems. The atmospheric fluidized-bed (AFB) outage rates were based on the EPRI Technical Assessment Guide, PS-866-SR, June 1978 (TAG), as revised in March 1979, and the advanced battery outage rates were based on EESS data.

Base and expansion candidate generating units' heat rates and outage rates are shown in Tables C.1-3A and 3B.

Table C.1-3A

BASE SYSTEM GENERATING UNIT HEAT RATES AND OUTAGE RATES

Unit Type	Size (MW)	Minimum Load (% Full Load)	Heat Rates at Full and Minimum Loads (Btu/KWHr)		Equivalent Forced Outage Rate (%)	Planned Maintenance (%)	Availability (%)
			Full	Minimum			
Nuclear	All	75	10,100	10,140	15.0	13.4	73.6
Coal (1)	200	25	10,085	12,300	7.4	9.9	83.4
	400	25	9,555	11,360	13.0	12.3	76.3
	600	25	9,450	11,490	21.0	12.3	69.3
	800	40	9,290	10,220	24.0	13.4	65.8
Oil	200	25	9,795	11,960	7.4	9.9	83.4
	400	25	9,300	11,050	13.0	12.3	76.3
	600	25	9,200	11,180	21.0	12.3	69.3
	800	40	9,000	9,900	24.0	13.4	65.8
Gas Turbine							
Pre '75	50	100	15,000	--	24.0	4.9	72.3
Post '75	50	100	11,500	--	24.0	4.9	72.3
Combined Cycle	400	33	8,400	9,000	26.0	7.5	68.5
Conventional Hydro	All				1.2	3.6	95.2
Pumped Hydro	200	67% cycle efficiency, 10 hr. storage			5.0	9.3	86.2

Note: (1) The following regionalizing factors apply to the coal unit heat rates:

Study Region	Synthetic System	Regionalizing Factor
Northeast	D	1.000
West	B	1.048

Table C.1-3B

EXPANSION CANDIDATE GENERATING UNIT HEAT RATES AND OUTAGE RATES

Unit Type	When Available	Size (MW)	Minimum Load (% Full Load)	Heat Rates at Full and Minimum Loads (Btu/KWHr) Full	Minimum	Equivalent Forced Outage Rate (%)	Planned Maintenance (%)	Availability (%)
Nuclear								
LWR	1985	1200	75	10,100	10,140	15.0	13.4	73.6
HTGR	2000	1200	25	8,916	9,073	15.0	13.4	73.6
Coal								
Conventional	1985	1000	40	9,635	10,600	26.0	13.4	64.1
w/FGD (1)		600	25	9,910	11,770	22.5	12.3	68.0
Atmospheric Fluidized-Bed (AFB)	1990	1000	50	9,870	10,460	12.4	10.0	78.8
Gas Turbine								
Conventional	1985	75	100	11,500	--	24.0	4.9	72.3
Advanced	1987	100	100	9,500	--	24.0	4.9	72.3
Combined Cycle								
Conventional	1985	250	33	8,400	9,000	25.5	7.5	68.9
Advanced	1989	285	33	7,500	8,040	25.5	7.5	68.9
Advanced Batteries	1990	50	75% cycle efficiency, 5 hr. storage			4.0	2.0	94.0

Note: (1) The following regionalizing factors apply to the coal unit heat rates:

Study Region	Synthetic System	Regionalizing Factors Conventional	AFB
Northeast	D	1.000	1.000
West	B	1.056	1.036

C.1.4 Generating Unit Cost Data

A. Fuel Costs

Based on the TAG and utility experience as shown in Table C.1-4A.

B. Operation and Maintenance Costs

Cost figures for generating unit O&M vary widely from source to source. The TAG contains cost estimates for several current technology unit types and for various advanced technology unit types which may become available in the future. The cost values are low but reasonable. The EESS costs developed by Public Service Electric and Gas Company (PSE&G) are also reasonable but are in most cases higher than the TAG costs, particularly for fixed O&M. The Draft NASAP Provisional Data Base for U.S. Electric Utility Industry Conditions, U.S. Department of Energy, February 1979 (NASAP) (Ref. 15) contains O&M data for nuclear and coal fired generating units. The NASAP fixed O&M and coal unit variable O&M costs are higher than either the TAG or EESS costs, while the nuclear unit variable O&M costs are lower than either TAG or EESS.

Given these variations, the EESS O&M costs were used for the following reasons:

1. EESS is believed to give the most complete and consistent set of O&M data of any of the reference sources, listing almost all unit types and sizes, existing and future.

2. PSE&G is a utility which does its own engineering and design, with experience in the construction and operation of nuclear, coal, and oil-fired steam, combustion turbine, and combined cycle power plants; thus, the data reflect design expectations tempered by operating experience.

3. PSE&G has performed numerous technical and economic assessments for both EPRI and DOE (and its predecessor agencies), lending their data and judgement additional credibility.

The AFB O&M costs were based on TAG, since EESS did not develop values for this type of unit.

Base and expansion candidate units' operation and maintenance costs are shown in Tables C.1-4B through 4E.

Table C.1-4A

Regional Fuel Costs
(EOY $/MBtu)

Year	1977	1985	2000	2020
Northeast (System D)				
Fuel: Nuclear (1)				
LWR	.54	.93	2.56	9.91
HTGR	.58	1.00	2.76	10.69
Coal	1.01	1.74	4.79	18.53
Oil - Residual, 0.5%S	2.44	4.19	11.57	44.76
Distillate	2.59	4.45	12.28	47.51
West (System B)				
Fuel: Nuclear (1)				
LWR	.54	.93	2.56	9.91
HTGR	.58	1.00	2.76	10.69
Coal	1.02	1.75	4.84	18.71
Oil - Residual, 1.0%S	2.24	3.85	10.62	41.09
Distillate	2.59	4.45	12.28	47.51

Inflation Rate	6%
Real Escalation	1%
Apparent Escalation	7%

Note: (1) Based on once-through fuel cycles.

Table C.1-4B

Base System Unit
Variable Operation and Maintenance Costs
(EOY 1977 $/MWHr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear	1200	1.20	1.23
	1000	1.29	1.32
	800	1.41	1.45
	600	1.58	1.62
Coal	800	1.20	1.23
	600	1.35	1.38
	400	1.58	1.62
	200	2.09	2.14
Oil	800	.70	.72
	600	.78	.80
	400	.92	.94
	200	1.22	1.25
Gas Turbine	50	6.00	6.15
Combined Cycle	400	5.00	5.13
Conventional Hydro		.50	.51
Pumped Storage Hydro		.50	.51

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

Table C.1-4C

Base System Unit
Fixed Operation and Maintenance Costs
(EOY 1977 $/KW-Yr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear	1200	8.00	8.20
	1000	8.90	9.12
	800	10.25	10.51
	600	12.50	12.81
Coal	800	5.50	5.64
	600	6.50	6.66
	400	8.15	8.35
	200	12.00	12.30
Oil	800	4.95	5.07
	600	5.85	6.00
	400	7.35	7.53
	200	10.80	11.07
Gas Turbine	50	.00	.00
Combined Cycle	400	.70	.72
Conventional Hydro		.00	.00
Pumped Storage Hydro		.00	.00

Inflation 6%
Real Escalation 0%
Apparent Escalation 6%

Table C.1-4D

Expansion Candidate Unit
Variable Operation and Maintenance Costs (1)
(EOY 1977 $/MWHr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear			
LWR	1200	1.20	1.23
HTGR	1200	1.20	1.23
Coal			
Conventional w/FGD	1000	2.30	1.48
	600	2.90	1.83
Atmospheric Fluidized-Bed	1000	4.43	4.54
Gas Turbine			
Current	75	6.00	6.15
Advanced	100	6.00	6.15
Combined Cycle			
Current	250	5.00	5.13
Advanced	285	5.00	5.13
Advanced Batteries	100	3.00	3.08

Inflation 6%
Real Escalation 0%
Apparent Escalation 6%

Notes: (1) Includes consumables (lime plus sludge and ash disposal) for coal unit FGD systems.

Table C.1-4E

Expansion Candidate Unit
Fixed Operation and Maintenance Costs
(EOY 1977 $/KW-Yr)

Unit Type	Size (MW)	Region (Synthetic System) Northeast (D)	West (B)
Nuclear			
LWR	1200	8.00	8.20
HTGR	1200	8.00	8.20
Coal			
Conventional w/FGD	1000	6.00	6.15
	600	8.00	8.20
Atmospheric Fluidized-Bed	1000	6.11	6.26
Gas Turbine			
Current	75	.00	.00
Advanced	100	.00	.00
Combined Cycle			
Current	250	.70	.72
Advanced	285	.70	.72
Advanced Batteries	100	.00	.00

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

C. Capital Costs

The capital cost data are based on TAG. The AFB cost was based on the regionalized costs for a conventional coal unit without flue gas desulfurization. The GT and battery costs were not regionalized.

The carrying charge rates are also based on TAG, excluding income tax preference allowances as recommended by EPRI.

Expansion candidate unit's capital costs are shown in Table C.1-4F.

D. Cost of Money

A weighted cost of money of 10% was used. This value is recommended by EPRI in TAG.

E. Inflation and Escalation

A general inflation rate of 6% was assumed for all costs. This value is recommended by EPRI in TAG and is consistent with the 10% cost of money and the capital cost carrying charges.

An additional real escalation rate of 1% was assumed for all fuel costs. Real escalation is independent of, and in addition to, inflation. It results from factors such as resource depletion, regulation effects, etc.

Apparent escalation is the total annual increase in cost resulting from both inflation and real escalation. The apparent escalation rates resulting from the inflation and real escalation rates discussed above are:

Fuel	7%
O&M	6%
Capital	6%

C.2 End-Year Adjustments

End-year adjustments must be made to output data for two key reasons. First, two systems that begin the year 2020 with unequal system reliabilities are unequal, and it is necessary to normalize these for discussion purposes. Second, operating costs for the systems continue past the final study year and must be calculated to compare systems. These two factors are described below.

C.2.1 Adjustments for Comparing Cases of Unequal System Reliabilities

Problem: One of the systems is more reliable than the other and has, therefore, incurred an unwarranted capital cost penalty.

Table C.1-4F

Expansion Candidate Unit
Capital Costs and Carrying Charges

Unit Type	Size (MW)	Regional Capital Costs, EOY 1977 $ ($/KW) Northeast (D)	West (B) (1)	Carrying Charge (%)	Life (Years)
Nuclear					
LWR	1200	828	781/823	18	30
HTGR	1200	828	781	18	30
Coal					
Conventional w/	1000	735	715/754	18	30
FGD	600	793	772/814	18	30
Atmospheric Fluidized-Bed	1000	642	669/710	18	30
Gas Turbine	75	160	160	19	20
	100	160	160	19	20
Combined Cycle	250	330	295	18	30
	285	330	295	18	30
Advanced Batteries	100	275	275	19	20

Inflation	6%
Real Escalation	0%
Apparent Escalation	6%

Note: (1) Wet Cooled/Peak Shaved Dry-Wet Cooled. Peak Shaved Dry-Wet cooled steam units are assumed in the West after the year 2000.

Solution: Assume that the systems will ultimately achieve equal reliability as a result of the more reliable system installing less capacity at some future date. Quantify this by pricing out the current system excess capacity at the gas turbine cost in the last year of the study.

Example:

Northeast Expansions, 2000-2020

No Nuclear: LOLP = 9.47, excess capacity = 63 MW

LWR Option: LOLP = 8.51; excess capacity = 192 MW

Delta Excess Capacity: 129 MW

LWR Option: 9-100 MW GTs change system excess by 655 MW

1-100 MW GT = 72.8 MW of excess

Delta Excess: 129/72.8 = 1.77 GTs

GT Capital Cost:

in 1977 \$: 1.77×100 MW $\times$ 160 \$/KW $\times .19 = 5.38$ \$ $\times 10^6$

in 2019 \$: $5.38 \times (1.06)^{42} = 62.18$ \$ $\times 10^6$

LWR Option:

Year 2019 case investment cost = 23041.4 \$ $\times 10^6$

Year 2019 adjusted investment cost = 22979.3 \$ $\times 10^6$

Present Worth of adjustment = $62.18 \times (1/1.10)^{44} = 0.9$ \$ $\times 10^6$

C.2.2 Adjustments for Years Beyond Study Period

Problem: Operating costs continue, with escalation, after the capital investment has been made. The effects of this are lost for units installed near the end of the study period. Note that when expressed as an annual carrying charge, investment costs do continue, but they have no escalation beyond the installation date.

Solution: Assume the end-year results will continue into the future. Implicit in this assumption are two additional assumptions: (1) no growth beyond the end year, and (2) replacement in kind as units retire.

Example:

1. Develop Present Worth/Escalation (PW/E) combined levelizing factors end-year +1 to ∞.

PW/E rate = (1 + PW rate) ÷ (1 + Esc. rate)

Factor: $\infty\ [1/(1 + PW/E)]^n$
$n = EY + 1$

Capital: PW/E = (1.10 ÷ 1.00) - 1 = 10.00%

Fuel: PW/E = (1.10 ÷ 1.07) - 1 = 2.80%

O&M: PW/E = (1.10 ÷ 1.06) - 1 = 3.77%

2. Apply factors to end-year costs to get cumulative PW $ for the period end-year + 1 to ∞, as of EY +1.

3. Present worth from end-year +1 to base year.

4. Add to cumultive PW values from case.

Northeast 1985-2000 Expansion

	Investment	Fuel	O&M
Year 2000 $ Costs	2903.8	2981.8	893.3
Factors*	2.18	22.92	14.65
Cum 2001 → ∞, PW 2001	6318.7	68324.4	13086.6
Cum 2001 → ∞, PW 1975	530.2	5733.1	1098.1
Cum 1985-2000, PW 1975	3059.8	4471.1	1370.3
Cum 1985 → ∞, PW 1975	3590.0	10204.21	2468.4

*Factor, n = 1 → ∞	10.00	35.67	26.50
n = 1 → EY	7.82	12.75	11.85
n = EY + 1 → ∞	2.18	22.92	14.65