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IMPACTS AND BENEFITS OF A SATELLITE POWER SYSTEM ON THE ELECTRIC UTILITY INDUSTRY

Final Report

for

Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

JPL — Contract No. 954639 No

C-80020

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This report is submitted by Arthur D. Little, Inc. (ADL) in fulfillment of JPL Contract No. 954639. The ADL study manager was Dr. B.M. Winer. The work presented herein was performed by a study team which included Mr. Gerald Larocque, Dr. James Nicol, Dr. Peter Glaser and Dr. John Bzura. In the course of this program, the staff has received information and advice from several sources. We are grateful for the information provided by Dr. Piet Bos of EPRI. We are particularly grateful to Mr. Irving Stein, the Program Technical Manager for the Jet Propulsion Laboratory.

Submitted By: B. M. Winer

Dr. B.M. Winer
Senior Staff Member
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INTRODUCTION AND SUMMARY

1.1 Executive Summary

The purpose of this limited study was to investigate six specific issues associated with interfacing a Satellite Power System (5 GW) with large (by present standards) terrestrial power pools to a depth sufficient to determine if certain interface problems and/or benefits exist and what future studies of these problems are required. The issues investigated and the conclusions reached are as follows:

1. Stability of Power Pools Containing a 5 GWe SPS
   Using present control methods, the power pools investigated in this study are unlikely to be able to maintain stable operation without shedding part of the load if the SPS shuts down unexpectedly. This might be a severe problem and further studies of (a) the likely magnitude of the problem, (b) the most cost effective method of alleviating the problem are needed.

2. Extra Reserve Margin Required to Maintain the Reliability of Power Pools Containing a 5 GWe SPS
   The use of any type (SPS or conventional) of 5 GWe generator instead of five 1 GWe generators requires a significant increase in the power pool reserve margin if the system reliability is to be maintained; the cost of the extra capacity need not be excessively expensive. The problem is significant and deserves further study, but a solution is available at a reasonable cost.

3. Use of the SPS in Load Following Service (i.e. in two independent pools whose times of peak demand differ by three hours)
   The use of the SPS in this manner does not allow the economics of the SPS to be directly compared with the

economics of terrestrial peaking plants. The use of the SPS reduces the magnitude of the peak demand for conventional generation capacity in each pool by only 2% but reduces the duration of this peak significantly. The effect would be to change the optimum mix (base, cycling and peaking capacity) of generation equipment in the pools. Further study of this issue is required before any further conclusions can be reached.

4. Ownership of the SPS and Its Effect on SPS Usage and Utility Costs

   Of the three ownership and energy marketing alternatives considered, the most promising appears to be ownership of SPS by an independent corporation, not the operating utility, and the sale of energy generated by the SPS under long-term contracts.

5. Utility Sharing of SPS related RD&D Costs

   A review of the electric utilities' financial commitment to EPRI indicates that, given the most optimistic assumptions about the desire of the utilities to support SPS related RD&D, the utilities will be unable to contribute any more than 10% of the required $44 billion. Present utility and EPRI RD&D funding priorities indicate that the electric utilities will be unwilling to contribute as much as 1% of the SPS's development costs.

6. Utility Liability for SPS Related Hazards

   At present, the magnitude and geographic limits of the potential hazards are poorly defined. No utility can afford to assume the legal liabilities which might be associated with these risks.

Other conclusions reached in this study are as follows:

- The large size and high plant cost of the SPS are major impediments to its inclusion in terrestrial power pools as presently constituted.

- SPS outages which are limited to the actual duration of an eclipse of the sun by the earth would have no effect on the power pool's fixed costs (total required amount of generating capacity), if the power demand in the pool varies by a factor of two during the day.

- The large size of the SPS will probably force the power pool to "shed load" if and when the SPS shuts down unexpectedly; this could be true even if there were enough spinning reserve available to compensate for the loss of the generation capacity.

- Utility ownership of the SPS will be financially difficult if the "fuel adjustment clause" continues in widespread use.

- The risks associated with selling SPS energy at the incremental costs of terrestrial base-load alternatives are probably too large to be assumed by a private corporation.

Recommendations

Because of the limited resources available for this study, models with insufficient detail to fully validate the conclusions had to be used. The following, more extensive studies of the SPS-utility interface are recommended before any final decision is made to build the SPS.

- Perform a stability analysis for a specific large power pool to determine (1) the required stability of the SPS output, and (2) the probable "loss of load" associated with an unexpected SPS shutdown.

- Investigate various methods and the associated costs of reducing SPS induced stability problems, e.g., transmitting SPS power via multiple high voltage dc transmission lines (1 GW per circuit) to five different power pools remote from the rectenna site.

- Calculate the optimum generating mix and operating costs for each of the two separate power pools in which the SPS is used in load following service.

- Re-calculate the reserve margin requirements of the power pool with and without the SPS using more realistic models of the power pool generation mix and the SPS.

- Calculate the cost of the required increase in the power pool spinning reserve caused by the inclusion of the SPS.

- Calculate the power pool operating costs with and without the SPS using a more realistic model of the power pool (use Production Costing Programs).

- Using utility expansion planning programs and a more realistic model of the power pool than was used in this study, calculate the utility costs (fixed and operating) as a function of the year after the SPS becomes operational, if (a) the utilities purchase the SPS, (b) the utilities purchase energy from the owner of the SPS, or (c) they follow normal (non-SPS) expansion.

- Determine how the availability of SPS power is likely to affect the utility generation expansion plans.

- Determine the maximum amount of SPS power that can be absorbed by power pools of various sizes.

- Perform those studies which will will be required to define the magnitude and location of the hazards, if any, likely to be associated with the SPS.

1.2 Reliability and Stability

The overall reliability of the bulk electric power network has been given the highest priority by the utilities and the FPC. The following are some of the many aspects of system reliability.*

---

*"Design of Electric Power Systems for Maximum Service Reliability" by C. Concordia, CIGRE, 1968, Report No. 32-08.

- The assurance of sufficient generating and transmission capacity, in view of the projected loads and equipment availability, so that the Loss of Load Probability* (LOLP) shall not exceed the design level;

- The ability to withstand the sudden loss of a major generator or transmission line, without inducing any other outages;

- The ability to withstand line faults without losing any generators;

- The minimization of system breakdown, as measured by loss of generation, cascading line outage, and loss of load when disturbances more severe than expected may occur; and

- The ability to restore service quickly and smoothly after a complete system breakdown and source interruption.

*Probability that power demand exceeds generation capacity.

It should be noted that roughly half of these system aspects relate to the ability of the system to respond to disturbances without undue reaction (what we shall call system stability) and the other half refers to the adequacy of generation and transmission equipment to meet the demand for electric power (what we shall call system reliability). These two criteria are related; a system which is inadequate to meet the power demand is more likely to over-react to certain types of system disturbances.

The question addressed in this report was: What kind of stability and reliability problems will arise when an SPS is added to a power pool? Within the limits of available resources, the purpose of the study was to describe the nature of the problems and estimate their magnitudes.

The problems investigated were:

- Stability
    - Frequency disturbances caused by sudden changes in the amount of generation capacity in the power pool.
    - Effect of protection device operation on machine stability.
- Reliability
    - Reserve margin requirements to maintain prescribed reliability in power pools containing one or more SPS with a variety of assumed outage characteristics.
    - Use of the SPS in load following service.

The relatively qualitative investigation of stability indicates that:

1. The sudden loss of the 5 GWe SPS output would probably cause a loss of load whenever the power pool was meeting a total load of roughly 40 GWe or less. The largest power pool considered in this study (peak demand = 50 GWe) meets a load of 40 GWe or less 88% of the time.

2. Sudden fluctuations in the SPS output could cause the operation of protective devices which themselves could exacerbate the stability problems.

The investigation of reliability turned out to be basically a calculation of the total required installed capacity needed in a power pool if one or more SPS's (each with a generating capacity of 5 GWe) were installed instead of a number of conventional generating plants (each with a generation capacity of 1 GWe). This analysis was concerned primarily with the size of the proposed SPS, and therefore, most of the results would apply equally well to a 5 GWe terrestrial plant. The results indicate that whenever a 5 GWe generation is used instead of five 1 GWe generators (no change in the forced outage rate) an additional one to two gigawatts ($124 - $250 million) of extra reserve capacity (gas turbines at $125/kW) must be added if the system reliability is to be maintained. The magnitude of the assumed reliability criterion is not critical, since it is not likely to be changed when the SPS is added to the power pool.

The total amount of reserve generating capacity required in various power pools was calculated for power pools having yearly peak power demands of either:

- 30 GWe, or
- 40 GWe, or
- 50 GWe, or a

- Composite Power Pool made up of two independent 30 GWe Power Pools whose times of peak demand differ by 3 hours.

These power pools contained either

- No SPS (all conventional equipment), or
- One (5 GWe) SPS, or
- Two (5 GWe) SPS, or
- Six (5 GWe) SPS.

Three different scheduled interruptions of the power from the SPS were considered:

- Power interruption due to eclipses only during the actual eclipse period; no scheduled maintenance requirements. [This was a best case calculation.]

- Power interruption due to eclipses only during the actual eclipse period, plus scheduled maintenance for 20% of the year. [This was a worst case calculation.]

- Power interruption due to eclipses for the entire day for all days during which an eclipse occurs (90 days). [This was a worst case calculation; the SPS is unlikely to be economically attractive under these circumstances.]

The magnitude of the installed reserve under each of the indicated conditions is entered in Table 1.1. The difference between the entry of interest and the entry for the power pool which does not contain an SPS is the extra installed margin that is required by the

TABLE 1.1

Installed Generating Margin (GWe)
For the Various Pools as a Function of the Circumstances

	30 GWe	40 GWe	50 GWe	Composite
NO SPS	8-9	9-10	10-11	16-18
ONE SPS				
No maintenance	10-11	11-12	11-12	17-19
Maintenance	11-12	12-13	12-13	17-19
Eclipses	11-12	12-13	13-14	17-19
TWO SPSs				
No Maintenance	11-12	11-12	12-13	-
Maintenance	13-14	13-14	14-15	-
Eclipses	14-15	13-14	14-15	-
SIX SPSs				
No Maintenance	-	15-16	14-15	-
Maintenance	-	17-18	17-18	-
Eclipses	-	18-19	19-20	-

SPS. For example: If a power pool, which has a peak power demand of 50 GWe contains no SPS, only 10 to 11 GWe of installed margin (60 to 61 GWe total) are required to provide for system reliability. If this same power pool contains an SPS which must be shut down for scheduled maintenance, 12 to 13 GWe of installed margin are required. The power pool which contains an SPS needing scheduled maintenance requires two more gigawatts of generating capacity than does the power pool that contains no SPS. If the SPS needs no scheduled maintenance, only one more gigawatt of generating capacity would probably be needed (11-12 GWe minus 10-11 GWe).

The results shown in Table 1.1 indicate that if one or more 5 GWe generators (SPS, nuclear or fossil fuel) are installed in a power pool, the installed generating margin must be increased if the system reliability is to be maintained. The percentage increase would depend on the size of the power pool; the larger the power pool, the smaller the required percentage increase. To demonstrate how the installed margin must vary with the power pool size, the percentage installed margin is plotted as a function of the power pool size in Figures 1.1, 1.2 and 1.3. The plotted values for the composite* power pool clearly indicate that the composite power pool cannot be treated as if it were a 60 GWe power pool.

The additional generating capacity that the results of this study indicate will be required need not be expensive. The extra capacity will not be used very often and could be in the form if inexpensive peaking units ($125/kW), causing an increased capital requirement of $250 million, 3.3% of the cost of the SPS ($7.6 billion)** and

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* Two independent 30 GWe Power Pools whose times of peak demand differ by three hours.

** "Space-Based Solar Power Conversion and Delivery Systems Study -- Interim Summary Report" by ECON, Inc., March 1976, Report No. 76-145-IB.

FIGURE 1.1

REQUIRED PERCENT INSTALLED MARGIN AS A FUNCTION OF THE POWER POOL SIZE
POWER POOLS CONTAINING ONE SPS

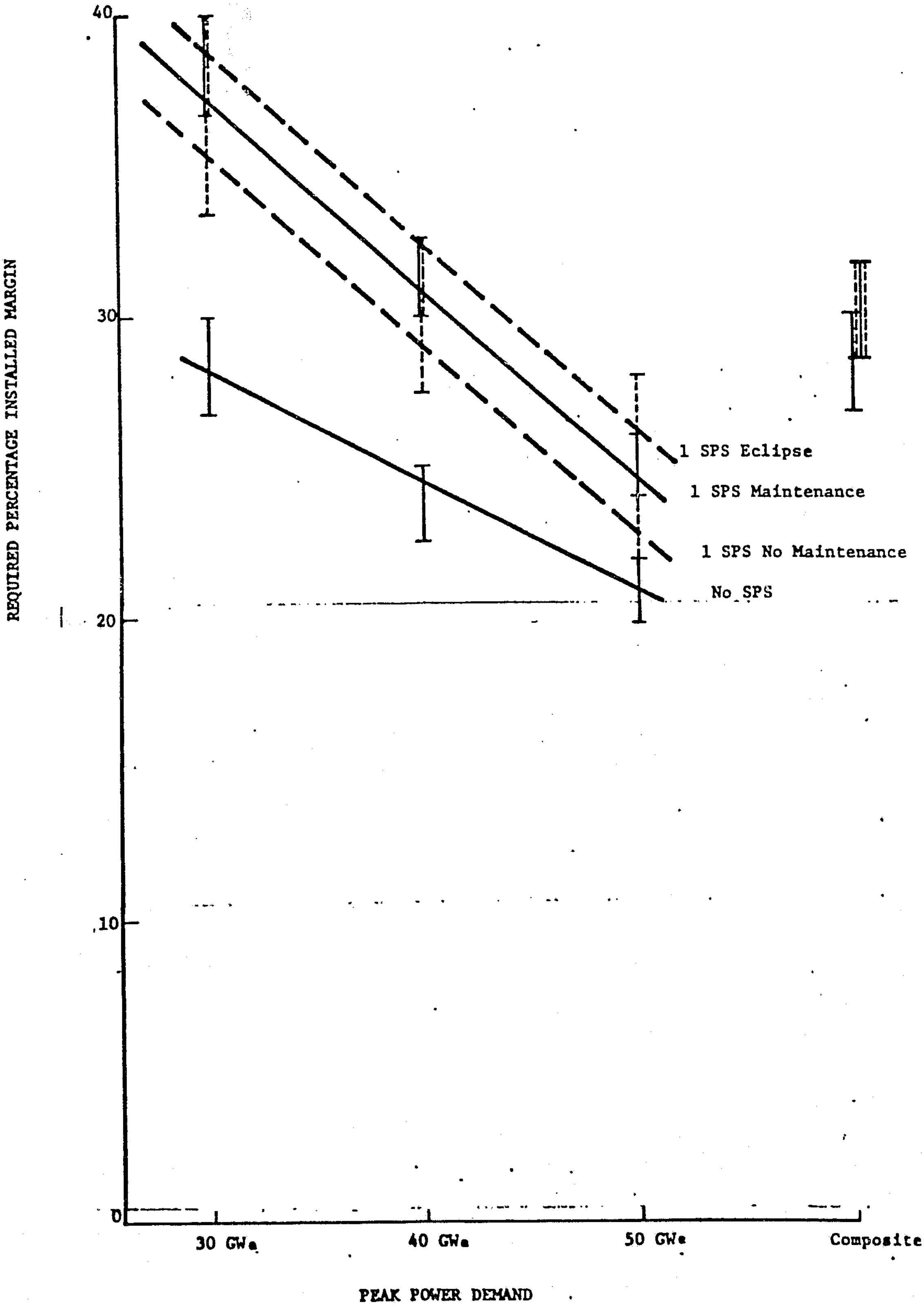


FIGURE 1.2

REQUIRED PERCENT INSTALLED MARGIN AS A FUNCTION OF THE POWER POOL SIZE

POWER POOLS CONTAINING TWO SPSs

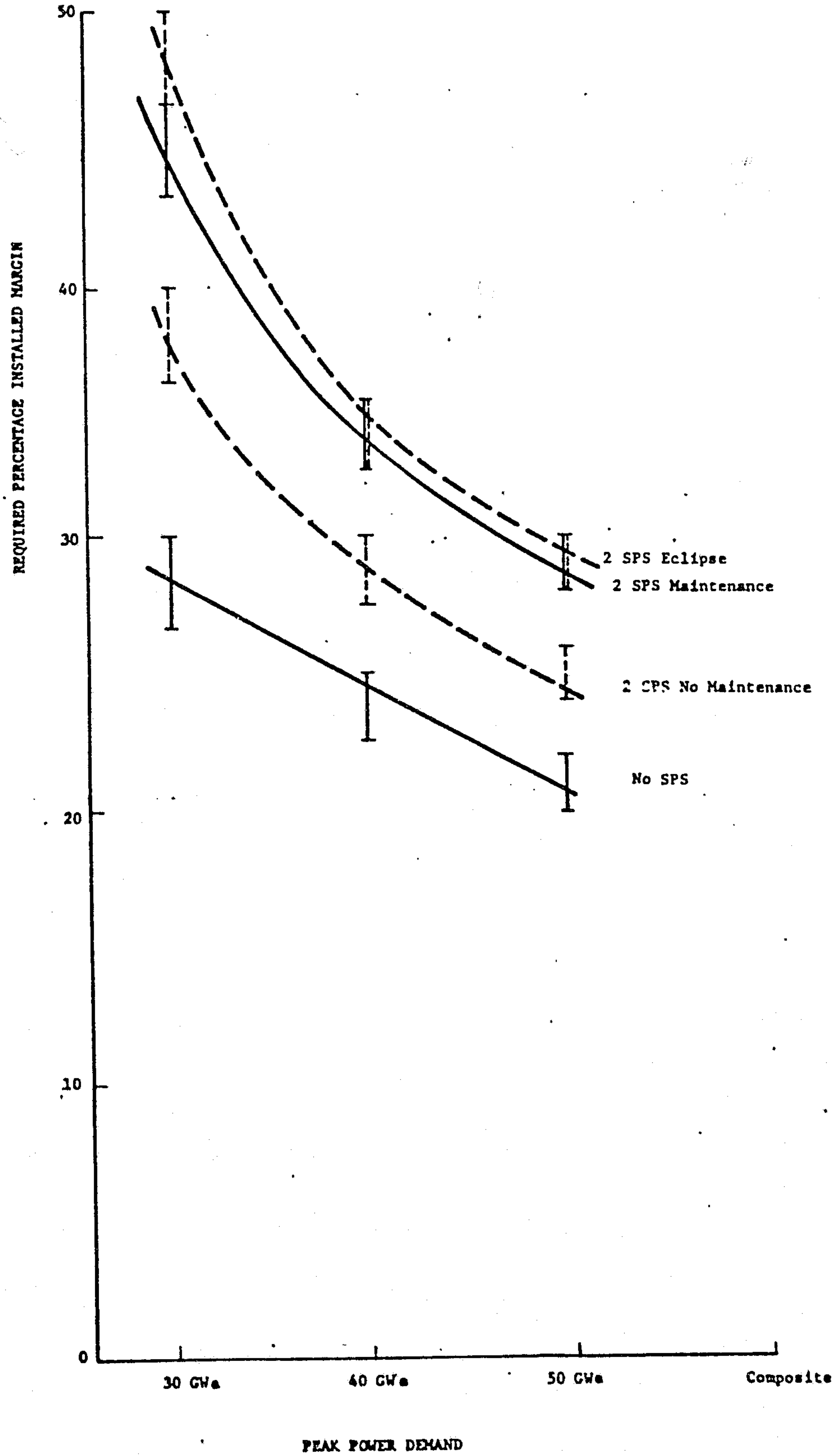
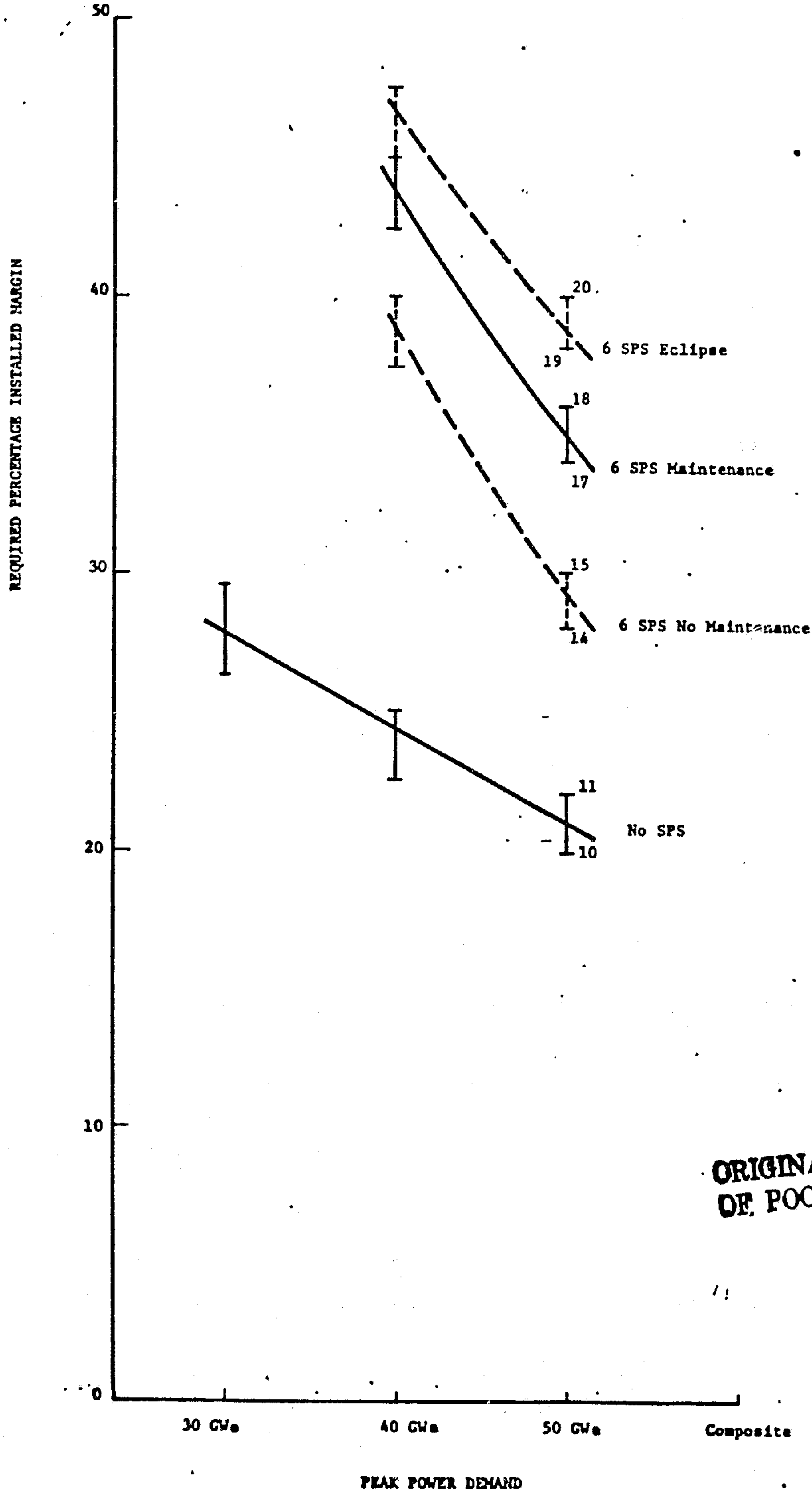


FIGURE 1.3

REQUIRED PERCENT INSTALLED MARGIN AS A FUNCTION OF THE POWER POOL SIZE
POWER POOLS CONTAINING SIX SPSs



roughly $50 million/year for fuel. If a completely redundant antenna were built to eliminate the need for scheduled maintenance, the total cost increase (including 1 GW of gas turbines) would be $1.47 billion, 19% of the cost of the SPS.

An additional conclusion was reached while actually performing the calculations; if the SPS is shut down by the earth eclipses for only the duration of the eclipse, the eclipses will have no effect on the system reliability. The demand for power during these eclipse periods was only half the daily peak and the probability that other generation would not be available to supply the required power was virtually zero. If the shutdown were to last from one hour before the eclipse to one hour after the eclipse, the results would be the same. This particular problem had no effect on the system LOLP and should be considered further only if it is expected that the daily load curve was tending to become flat.

The composite power pool was found to be unaffected by either the SPS maintenance requirements or problems due to the eclipse. Because the power produced by satellite in this power pool could be used in some way or other throughout the year, it is understandable that the maintenance requirements of the ground stations would have little effect on the installed margin. The margin's insensitivity to the eclipse stems from the large size of the required margin when the pool contains no SPS and the uncertainties in the calculation.

1.3 Possible Ownership of the SPS

Three different ownership and/or energy pricing arrangements for the SPS have been investigated. These arrangements were:

- Purchase of the SPS by a utility or consortium of utilities.

- Purchase of the SPS by an independent corporation and "lease" (commitment to purchase a share of the SPS energy) of the output by several utilities.

- Purchase of the SPS by an independent corporation and the energy sold to the utilities, at below cost initially, at a price equal to the incremental cost of the utilities' most expensive base load generator.

How the SPS is purchased and by whom can determine how it is used. Of these three arrangements, the most promising appears to be the purchase of the SPS by an independent entity (corporate or governmental) and "lease" of the output by several utilities.

While all the calculations performed in this analysis assumed that the capital cost of the SPS was $7.6 billion, the general conclusions reached can be used to infer the effect of the more recent, significantly higher estimate of $12.2 billion. The basic conclusion of this study, i.e., that the "leasing" arrangement is the most promising of the three arrangements considered, would be true if the higher cost had been assumed.

The results of this investigation are as follows:

1. Utility Ownership of the SPS
   - When the ($7.6 billion) SPS first becomes operational, a very small increase in the <u>total</u> cost of meeting the demand for electrical energy will probably occur.

- If the capital cost of the SPS is $12.2 billion, the inclusion of the SPS related costs in the utility rate structure would require an increase in the total cost of electrical energy to the consumer.

- Utilities which use a semi-automatic fuel adjustment rate to recoup the cost of fuel will have to request a sizable increase in their base rates to cover their increased plant equity when the SPS comes on-line. Fuel rate reductions can occur within a month; base rate increases can take as long as a year to obtain. The higher the capital cost of the SPS, the greater may be the financial stress caused by regulatory delays.

2. "Leasing" of the SPS Output by the Utilities

   - The cost of purchasing energy could be recouped by many utilities via fuel adjustment rates.

   - At present, the reduction of the utility capital requirements caused by "leasing" energy from the SPS would have a beneficial effect on the utilities' financial ratings. It is not clear that this situation will prevail over the next fifty years, nor is it clear if the utilities would accept this arrangement over such a long term.

   - Since the utilities make no profit on purchased energy, the effect of the SPS on the total cost of electrical energy would be the same for both the utility ownership and the private ownership/utility leasing plans (assuming that the discount rate is the same for both the utility and the private corporation).

3. SPS Energy Sold at the Incremental Cost of Base-Load Alternatives

- If the inflation rate continues at roughly the same as present rates, it would be possible to price energy from an SPS (capital cost = $7.6 billion) at the incremental cost of alternative fossil fueled generation and eventually make a profit. The size of the profit depends on the inflation rates.

- If the capital cost of the SPS is significantly higher than $7.6 billion, the inflation rates necessary to eventually make a profit using this pricing alternative, would be significantly greater than the present inflation rates.

- Pricing SPS generated energy in this manner requires the operation of the SPS at a loss for roughly twenty years. The risks associated with this arrangement are too large for private industry- financial guarantees from the government would be required.

- If the government provides financial guarantees to a corporation intending to price SPS energy in this manner, the interpretation of this decision may be that either the government is willing to subsidize the SPS or that the government expects the inflation rate to continue at its present level or higher.

1.4 Utility Participation in SPS Related RD&D

While the participation of the electric utilities in the SPS research, design and development (RD&D) program may be desirable, utility activities in this area are likely to be very limited during the next five years. EPRI's budget for all solar energy research during this time period is only 2% of EPRI's total budget.

The total research EPRI budget for the next five years is roughly $1 billion, including an allowance for inflation. Of this, only $20 million (approximately $4 million/year) has been allocated for all forms of solar energy research, including solar heating and cooling. Unless EPRI's priorities shift significantly, the funding available from this source to support SPS related R&D will probably be small. Even if EPRI supported SPS-related RD&D at the same rate as all other solar energy projects combined, its contribution between now and 1995 would probably be less than 1% of the required total of $44 billion. If all of EPRI's resources were devoted to the SPS, EPRI could only contribute roughly 10% of the $44 billion required.

The probability of attracting substantial participation by individual utilities in SPS related research is also small; utility research priorities are primarily near-term and investment in the SPS is unlikely to be a high priority item.

1.5 Utility Liabilities Associated with the SPS

Whoever owns the SPS - the electric utilities, a private or semi-private corporation or a government agency, this owner could be liable for all the adverse effects that could results from SPS related activities; the cost of these liabilities would presumably be added to the cost of SPS generated electrical energy via the cost of insurance. At present, too little is known about the potential adverse effects either to:

- identify <u>all</u> the possible liabilities,

- estimate the magnitude of all identified liabilities,

- reliably estimate the cost of meeting the liabilities, or

- determine whether the electric utilities would assume these liabilities.

In the past, the electric utilities have assumed the liabilities associated with the degradation of radio and television reception along transmission right-of-ways. This liability is localized geographically and can be reasonably well defined before the transmission circuit is energized. On the other hand, the similar problem associated with the interference of the SPS microwave beams with communications channels, radar, etc., may be neither localized geographically nor well defined before the first two SPSs are built. The utilities would be unlikely to accept this type of liability as a condition of purchasing an SPS or SPS delivered energy.

1.6 Structure of the Report

Each of the six issues investigated in this study is discussed in some detail in the following chapters. Since there was some relationship among the first three issues, they were grouped together in Chapter 2. All others are described in independent chapters. The results of the study in each area are summarized at the beginning of each chapter so that each chapter can stand alone.

2.0 RELIABILITY AND STABILITY

2.1 Background

The overall reliability of the bulk electric power network has been given the highest priority by the utilities and the FPC. The following are some of the many aspects of system reliability.*

- The assurance of sufficient generating and transmission capacity, in view of the projected loads and equipment availability, so that the Loss of Load Probability** (LOLP) shall not exceed the design level;
- The reliable operation of the individual pieces of equipment;
- The ability to withstand the sudden loss of a major generator or transmission line, without inducing any other outages;
- The ability to withstand line faults without forcing any generators to shut down;
- The minimization of system breakdown, as measured by loss of generation, cascading line outage, and loss of load when disturbances more severe than expected may occur; and

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* "Design of Electric Power Systems for Maximum Service Reliability" by C. Concordia, CIGRE, 1968, Report No. 32-08.

** Probability that power demand exceeds generation capacity.

- The ability to restore service quickly and smoothly in case of a partial or complete system breakdown and source interruption.

It should be noted that half of these system aspects relate to the ability of the system to respond to disturbances without undue reaction (what we shall call system stability) and the other half refer to the adequacy of generation and transmission equipment to meet the demand for electric power. These two criteria are related; the less the excess of generation capacity over power demand, the more likely is the system to react with instability to certain types of system disturbances.

The question addressed in this report was how is the SPS likely to affect either the stability or reliability of the existing or expected power pools? The resources allocated for this study were too small to allow an evaluation of these problems in the depth they deserve. The purpose of the study was to describe the nature of the problems and to estimate their magnitudes.

Regional Reliability Councils

The 1965 "Northeast Blackout", followed by another extensive blackout in another area in 1967, had wide repercussions within the industry. Many questions were raised such as:

- Are the planning criteria correct?
- Are design concepts adequate?
- Should interconnections between power systems be strengthened or eliminated?

Extensive studies of these questions were undertaken by both the utilities and the Federal Power Commission (FPC). The results of these studies indicated a need for a high degree of coordination of the system planning, design, and operating functions between interconnected utilities. The National Electric Reliability Council (NERC) and the Regional Reliability Councils were established to encourage this coordination.

The nine Regional Reliability Councils encompass essentially all of the power systems of the United States and the Canadian systems in Ontario, British Columbia, Manitoba, and New Brunswick. The area covered by each of these councils and the abbreviations commonly used for each are shown in Figure 2.1.

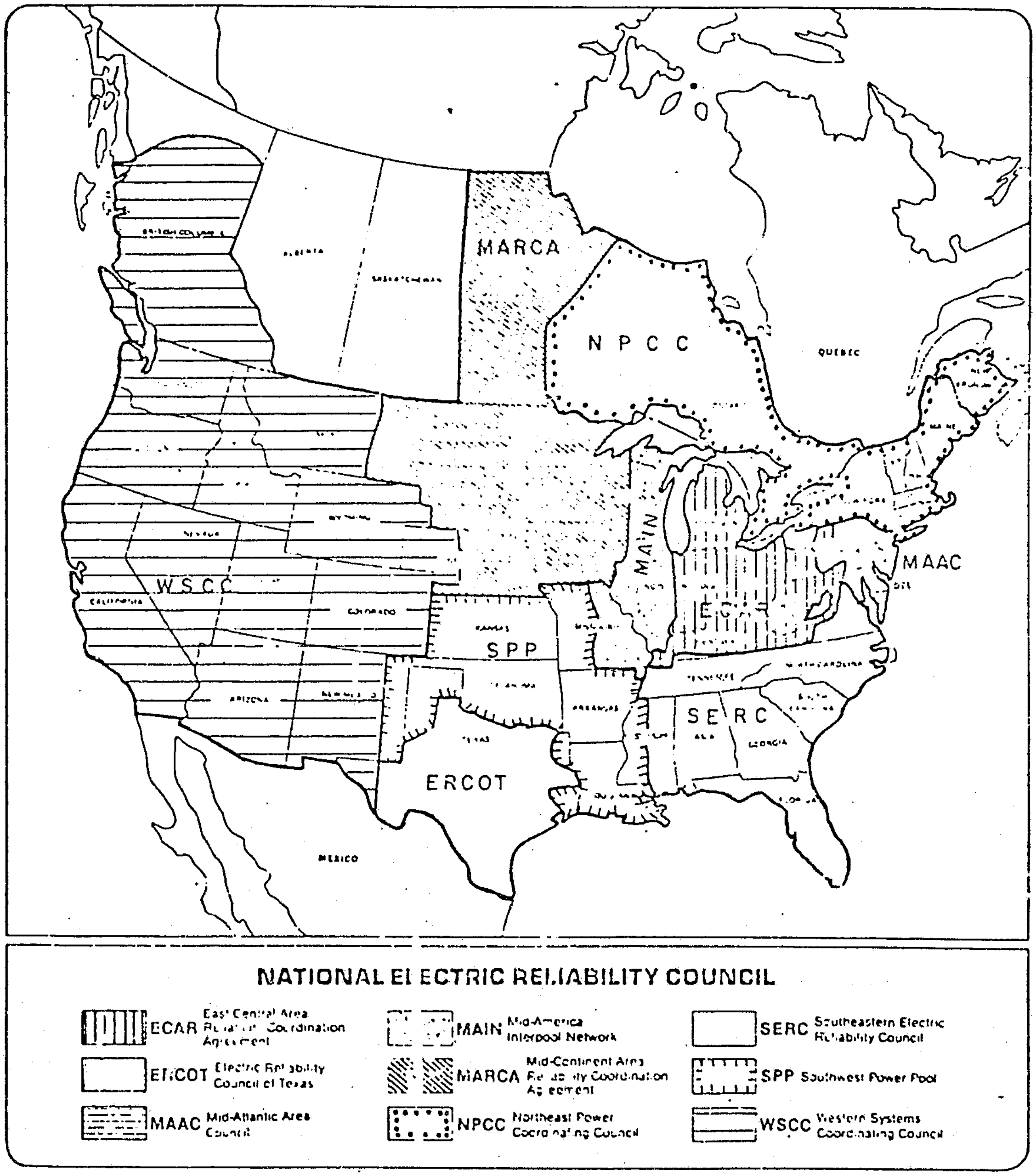
Each of the Regional Reliability Councils has developed slightly different reliability criteria for testing and evaluating simulated future system designs which reflect the differences which exist in geography, population density, load pattern, power sources, etc. The variation of the load densities from region to region is shown in Table 2.1 as an example. However, the overall goals of the various councils are essentially uniform.

Regional boundaries are only arbitrary lines of demarcation, thus criteria in adjoining regions or continguous utilities on regional borders must be compatible. Joint agreements between regions exist and studies to assure compatibility of reliability criteria are performed.

Table 2.1

Regional Load Density (1974)
(contiguous U.S. only)

Region	Load Density (MW/square mile)
ECAR	257
ERCOT	121
MAAC	636
MAIN	169
MARCA (U.S. only)	36
NPCC (U.S. only)	272
SERC	216
SPP	87
WSCC (U.S. only)	52



REFERENCE: "National Electric Reliability Council", 6th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems, July 1976.

FIGURE 2.1

ORIGINAL PAGE IS OF POOR QUALITY

The North American bulk power supply is not only the largest but, by far, the most reliable electrical network in the world. The 1975 NERC annual report stated: "The record of the past year (1975) attests to the successful operation of the network even under various stresses caused by violent weather conditions, equipment failures and several acts of sabotage." Another mute testimony to the strength of the system was provided by its successful operation during the adverse conditions caused by the fuel shortages and bad weather conditions of January 1977.

The Reliability Councils and the operating utilities and/or power pools are quite different. Each of the Reliability Councils is based on a voluntary agreement among the member utilities to uphold the basic principles of reliable system planning and operation; membership in the Reliability Council is a voluntary agreement. An operating utility is a centrally controlled organization having the direct responsibility of building, operating and maintaining the equipment (generation, transmission and distribution) necessary to meet the load in its area reliably and at the lowest possible cost. An operating power pool centrally controls all the generation and transmission equipment owned by its member utilities; the contracts which define the power pool contain legal penalties for nonconformance to reliability criteria.

A decision to build and operate a 5 GWe SPS to be placed in one of the Reliability Regions may have a significant effect on the regional planning process; the effect may be no greater than the effect of placing any similarly sized generator in the region. The purpose of this section of the report is to investigate the likely magnitude of the effects. Since each reliability council operates somewhat differently, it has been impossible to do more than indicate the circumstances under which problems would occur so as to guide the SPS design team in their efforts.

2.2 Power System Stability Characteristics

2.2.1 Introduction and Results

Predicting the stability of a large scale power network is an extremely complex problem. In general, because of the intricate interactions among the various lines, generators and load devices, a full modelling of an electric power network requires the solution of a complex system of coupled time varying differential equations. Solutions, generally, cannot be obtained within normal time and budget constraints on a digital computer. They are certainly beyond the resources of this limited study, but even with the larger studies one must usually be content with results based on average network properties and with qualitative descriptions of potential difficulties at the level of individual elements. This section presents a qualitative discussion of the system characteristics in order to convey an appreciation of the problems that can occur. It should be noted that the stability characteristics discussed herein, are the same as those required of conventional generation capacity.

The results of this relatively qualitative investigation of stability indicate that:

1. The sudden, unexpected loss of the SPS output would cause a loss of load whenever the power pool was meeting a total load of roughly 40 GWe or less. The largest power pool considered in this study meets a load of 40 GWe or less, 88% of the time.

2. Sudden fluctuations in the SPS output could cause the operation of protective devices which themselves could exacerbate the stability problems.

The key points to be made in the following discussion are that if satellite power systems create frequent fluctuations in system generation capacity, the introduction of such a power source may increase the number of transients of the power network and cause frequent redistributions of power flow throughout the network. The SPS should be designed so that any fluctuations in output power occur as slowly as is necessary to allow earth-bound regulator systems to correct for them without creating significant transients.

Section 2.2.2 provides a discussion of the transient in system frequency due to system dynamics resulting from a loss of generation capacity. This transient is of concern because off-frequency operation has a severely adverse effect on many types of load elements and also places undue stress upon generator turbines as a result of governor operation at other than design frequencies. In Section 2.2.3 the effects of protection devices operation on machine stability is discussed, indicating the potential for large scale network instability as a result of switching operations.

An example of stability problems is found in the Northeast blackout where a variation in the load caused a normally functioning protection device to initiate a sequence of events resulting in loss of power to most of the northeastern United States. This incident is discussed in some detail in Section 2.2.4.

2.2.2 System Dynamics

After the loss of a generator unit in an electric power network, a frequency transient will occur whose precise characteristics are a function of many factors; e.g., the magnitude of power loss with respect to the remaining generation, the time constants of the remaining generators and the dynamics of the governors attached to the network. The detailed solution for such transient problems is complex, and in most instances, it is possible only to deal with average system properties. In so doing, it is necessary to apply weighting factors to the properties of each of the generators in the network. There are many ways in which these factors may be selected, but the basic analysis is unaltered.

In a system with only a single generator, or in which all generators are identical, the average system frequency is governed by the following differential equation:

$$\frac{2H}{f_o}\frac{d\xi}{dt} = P_{set} - \frac{\xi g(t)}{Rf_o} - P_L(\xi) \tag{2.1}$$

where

$\xi(t) =$ $f-f_o$, the deviation from the nominal system frequency of $f_o = 60$ cps,

$P_{set} =$ generated power set by the regulator system,

$P_L(\xi) =$ load imposed on the power system (a weak function of the frequency),

H = the inertia constant of a particular generator,

R = the unit change in the power set by the governor for a unit frequency deviation, and

$g(t)$ = a time function describing the combined dynamics of the turbine and governor system.

The same equation gives a good approximation to the solution for a more complex system if parameters derived from appropriate weighted averages of shaft kinetic energy, governor dynamics, etc., are used.

Solving this equation for $\xi(t)$ assuming that there is a change in the available generation capacity at t = 0 provides the following expression for the transient response:

$$\xi(t) = -\frac{\Delta P_g f_o}{2HT_g}\left[\frac{(\omega_o-\omega_1)e^{\omega_o t} + \omega_1 e^{\omega_o t} - \omega_o e^{\omega_1 t}}{(\omega_o)\,(\omega_o-\omega_1)\,(\omega_1)} + \frac{T_g}{\omega_o-\omega_1}\left(e^{\omega_o t} - e^{\omega_1 t}\right)\right] \tag{2.2}$$

where ω_o and ω_1 are the complex natural frequencies of the system given as the roots of the equation:

$$s^2 + s\left(\frac{2H + f_o L_C T_g}{2HT_g}\right) + \frac{f_o L_C + \frac{1}{R}}{2HT_g} = 0 \qquad (2.3)$$

and

T_g = the Laplace transform of g(t),

ΔP_g = the change in P_{set} due to sudden change in the amount of available generation, and

L_C = the percent change in load for a unit frequency deviation.

The meaning of these expressions can be demonstrated if values typical of a network whose generators are primarily steam turbines are substituted for the system parameters.

Letting

$R = 0.05$

$L_C = 0.03$ %/cps

$T_g = 10$ sec.

$H = 4$ sec.

$f_o = 60.00$ cps,

the natural frequencies are computed to be

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$$\omega_o = -0.163 + j0.496$$
$$\omega_1 = -0.163 - j0.496$$

The resulting damped sinusoidal transient in the system frequency is

$$\xi(t) = \Delta P_g[-2.75+2.76 \text{ cost}(0.496t) - j\ 14.11 \sin(0.496t)]e^{-0.163t} \qquad (2.4)$$

The form of the transient is shown in Figure 2.2; the maximum deviation from nominal frequency is given approximately by

$$\xi_{max} = -10.22\ \Delta P_g\ . \qquad (2.5)$$

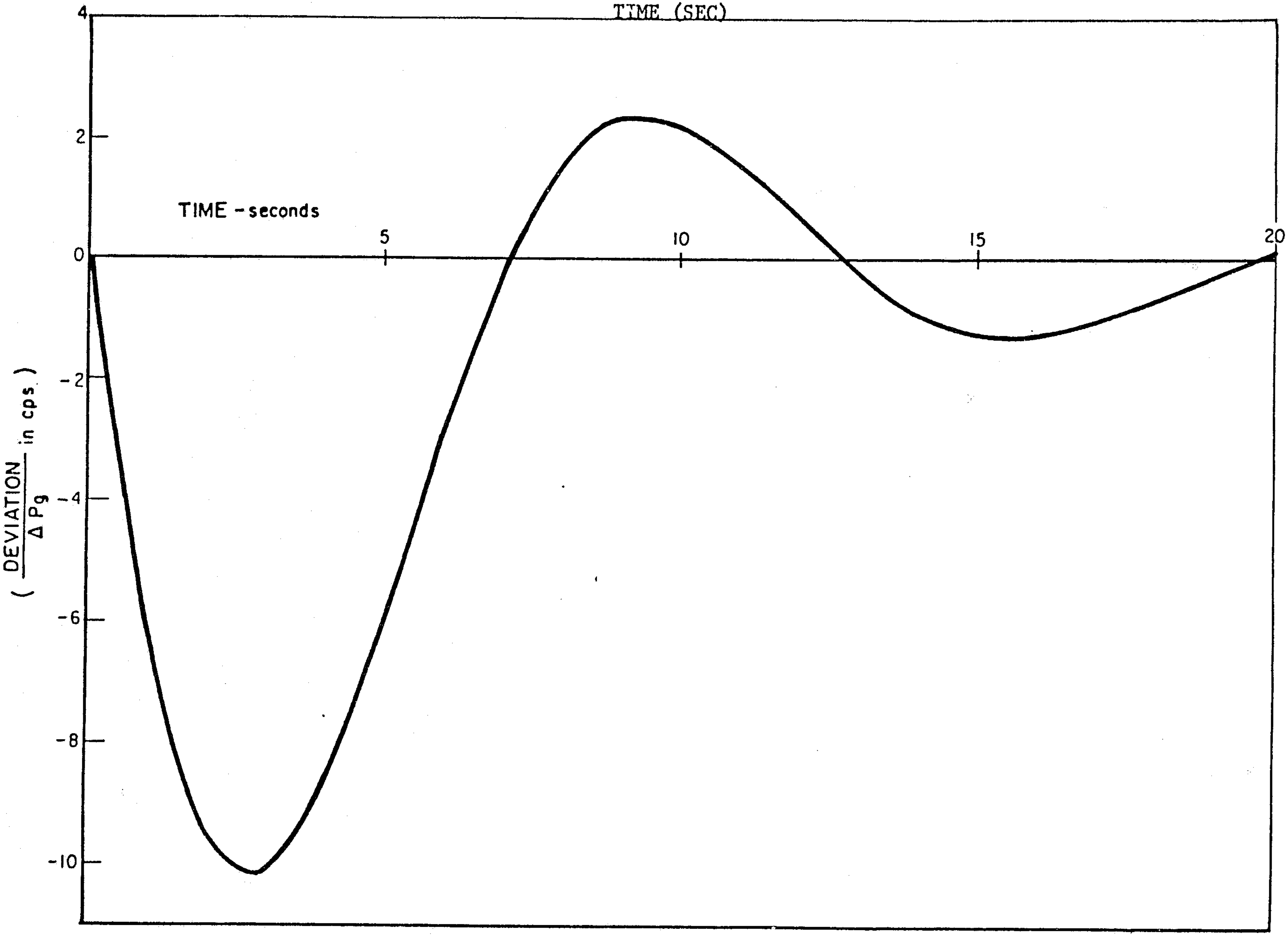

FIGURE 2.2 FREQUENCY DISTRIBUTION AS A FUNCTION OF TIME AFTER PERTURBATION

ΔP_g is the fraction of the total power being generated.

The above result indicates that a sudden reduction in generation capacity (assuming the system is able to absorb the loss of generation with available spinning reserve) will create an approximately sinusoidal frequency transient whose peak value is directly proportional to the magnitude of the power loss; this helps to define the required stability of the output of the satellite power system. If for example, a 2% change in frequency is the maximum to be tolerated, the satellite power system would have to maintain its generation level so as to produce maximum power fluctuations of no more than .12 of the total network generation at the time of the change in the SPS output. If the total power pool demand were 30 GWe, the maximum allowable fluctuation would be 3.6 GWe. If the total power pool demand were 10 GWe, the maximum allowable fluctuation would be 1.2 GWe.

Normally, a power pool will have sufficient generation capacity on-line to meet the expected load plus a certain amount of spinning reserve; the required amount of spinning reserve is equal to either a percentage of the maximum expected load (typically 3-7% of the system load) or to the output of the largest generator on-line, which ever is larger. This ensures that the system will be able to absorb any unexpected loss of generation without large frequency changes. The large size of the SPS will probably require a significant increase in the level of spinning reserve and the operating cost of the power pool would consequently increase.

The modern use of load shedding relays have reduced the probability of large scale system shutdowns occurring as a result of the sudden loss of generation capacity. These relays disconnect part of the load so that the system can still meet the larger part of the load. Even if the spinning reserve were provided for the example given, the sudden loss of the SPS output would force a loss of load operation of the relays whenever the total load is less than 42 GW.

This loss of load is undesirable except as an alternative to the total shutdown of the power pool.

2.2.3 Protection Devices

The use of circuit breakers to protect lines against faults is common practice even though their use may cause generator instabilities. This section describes the nature of the instability that can be caused by the normal operation of circuit breakers.

When a line is faulted, generators connected electrically close to the fault experience a sharp decrease in their load (since the voltage at the fault is zero, no real power can flow in the faulted line except for line loss) while other units in the system are required to pick-up the fraction of load isolated from the generators on the other side of the fault. This means that during the faulted condition, some generator rotors are accelerated while others are decelerated. Consequently, when the fault is cleared, the system is in a configuration in which some generators are advanced and some are retarded from their previous equilibrium values. There is a maximum angular displacement from which a generator can recover a stable equilibrium.

To illustrate this point, consider the simplified case of a generator supplying an infinite bus through a series of transmission lines. Under such circumstances, the power balance of the system is described by the following differential equation.

$$\frac{2H}{\omega_o} \frac{d^2\delta}{dt^2} = P_m - P_{elec} = P_m - \frac{EV_t}{X} \sin \delta \qquad (2.6)$$

where

δ = the generator power angle.

P_m = the mechanical power from the prime mover.

P_{elec} = the electric power out of the machine.

V_t = the infinite bus voltage.

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X = the combined reactance of the machine and the transmission lines.

H = the inertia constant.

ω_o = the initial system angular frequency.

E = equivalent internal generator voltage.

The maximum power that can be transferred is sinusoidal with respect to power angle. For two different circuit configurations, the maximum power transfer as a function of power angle might appear as curves I and II in Figure 2.3. The difference might be a higher reactance between the generator and the infinite bus (e.g., switching out of a line) in curve II.

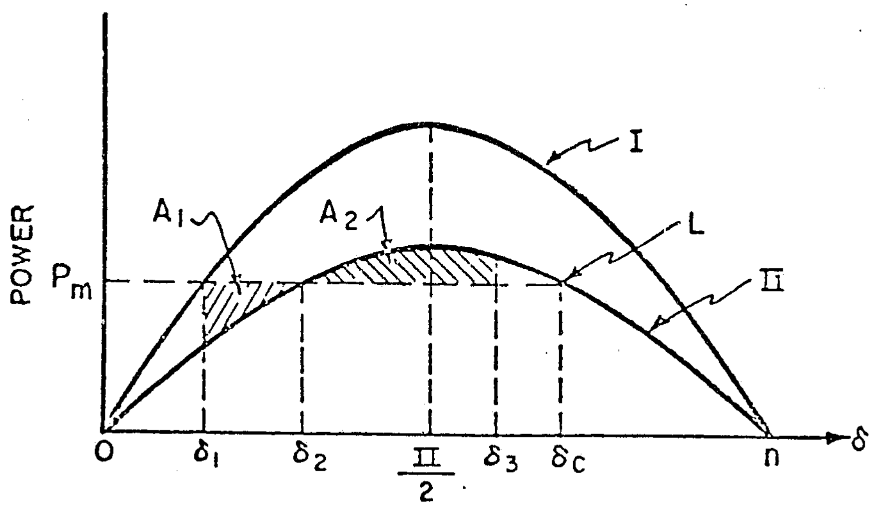


FIGURE 2.3 TRANSMITTED POWER AS A FUNCTION OF THE GENERATOR POWER ANGLE

In condition I, the equilibrium value of δ is δ_1. When the line is switched out, the generator rotor begins to accelerate because the power transmitted is less than the mechanical power to the rotor. The rate of change of the rotor angle is given by

$$\frac{d\delta}{dt} = \sqrt{\frac{\omega_o}{H} \int_{\delta_1}^{\delta_3} (P_m - P_{elec})\, d\delta}. \tag{2.7}$$

The integral is graphically represented by the difference between areas A_1 and A_2 on Figure 2.3. $\frac{d\delta}{dt}$ will be zero when $A_2 = A_1$. At this point, where the electrical power is greater than the mechanical power, and the rate of change of δ reverses, the rotor swings back towards angle δ_1. Because there are always losses to damp a real system, the rotor will eventually stabilize at a new equilibrium angle δ_2.

Generator instabilities can occur because there is a critical value δ_c for δ. If the rotor exceeds this critical power angle, the generator cannot regain equilibrium. This critical power angle exists because, as shown on the figure, A_2 has a maximum value equal to the area between curve II and the line $P = P_o$. If A_1 is larger than this maximum, the rate of change of δ never reaches zero, and the power balance tends further to increase the machine's angle. Thus, there are certain critical machine angles which must not be exceeded during a switching operation or else some of the machines will not be able to re-establish equilibrium states.

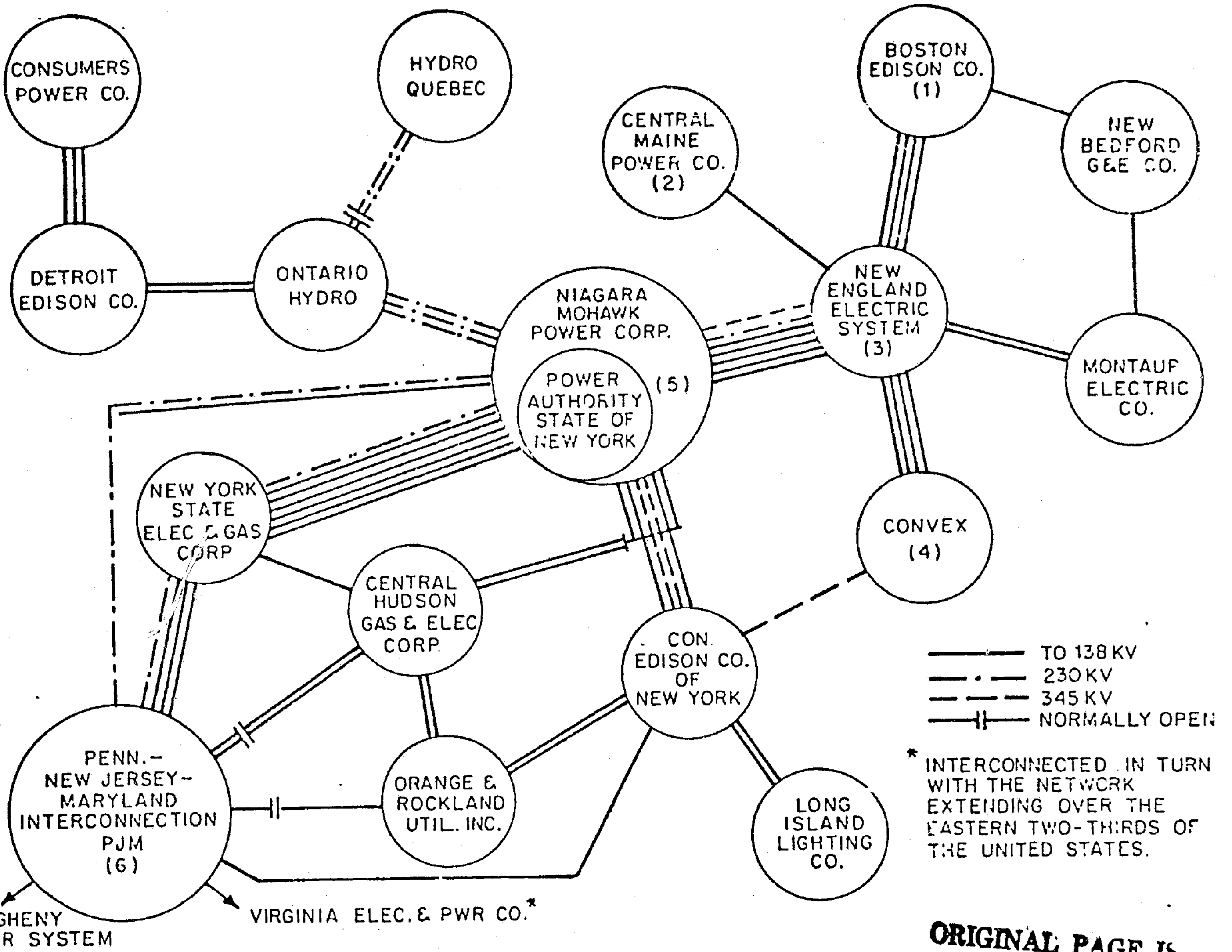
If the power network is subjected to frequent changes in generation capacity, the power distribution over the lines of the network will be changing often. It is not inconceivable that redistribution of power over a network due to generation fluctuation could cause the power on some line to exceed the setting of its protective device, causing the line to be disconnected, creating the sort of transient problem described above in addition to the frequency transient set up by the loss of generation. Since the switching of the line again redistributes the power flow, a chain reaction could occur, magnifying the stability problem.

The magnitudes and frequencies of fluctuations likely to initiate a chain reaction of this sort are difficult to forecast; the sort of system breakup just discussed is a line-by-line and machine-by-machine process which does not lend itself to description by average characteristics. It is more than a simple cascade of analyses like that of the previous two pages, because after the first event the system is usually not in equilibrium when the next discontinuity occurs. Determination of such a sequence of events requires a detailed transient load flow analysis at each change of network configuration (i.e., loss of generation, switching of lines, or change of load) coupled with a line-by-line examination of power flow and protection device setting, along with examination of machine stability limits at the power demands involved. This sort of analysis is tantamount to a complete simulation of the entire power network. In a study of this sort, it is impossible to make general statements about the magnitude and frequency of power shifts likely to cause large scale network shutdown. However, the potential for such situations does exist and the larger and more frequent the power fluctuations, the greater the probability of such an occurrence.

2.2.4 Northeast Blackout

The Northeast Blackout is an example of instability problems which arose from the normal operation of protective devices. Before discussing the series of events leading to the blackout, it is necessary to indicate some of the important characteristics of the Canada-United States Interconnection (CANUSE). Hydroelectric power constituted approximately 26 percent of the CANUSE generation and is largely concentrated in the Niagara Falls area. Most of this power is transmitted to loads located far from the generation site. Power which is generated by Power Authority of the State of New York (PASNY) plants in the Niagara Falls area is transmitted in large part by twin 345 kV lines from Niagara to Albany to New York City.

Niagara and PASNY were interconnected with the Connecticut Valley Electric Exchange (CONVEX) and the New England Electric System (NEES) by one 345 kV line, one 230 kV and five 115 kV lines (see Figure 2.4.) Seven transmission lines carrying from 115 to 230 kV connect CANUSE with the Pennsylvania-New Jersey-Maryland (PJM) power pool.



Numbers refer to following list of " ystems normally controlling sublisted systems"

1. Boston Edison Co.
   Cambridge Electric Co.

2. Central Maine Power Co.
   Bangor Hydro Electric Co.

3. New England Electric System
   Central Vermont Public Service Corp.
   Citizens Utilities Co.
   Green Mountain Power Corp.
   Public Service Co. of New Hampshire
   Fitchburg Gas & Electric Co.
   Yankee Atomic Electric Co.

4. Connecticut Valley Electric Exchange–CONVEX
   Connecticut Light & Power Co.
   Hartford Electric Light Co.
   United Illuminating Co.
   Western Massachusetts Electric Co.

5. Niagara Mohawk Power Corp.
   Rochester Gas & Electric Co.
   Power Authority State of New York
   New York State Elect and Gas Co. (Part)

6. Pennsylvania–New Jersey–Maryland Interconnection–PJM
   Atlantic City Electric Co.
   Baltimore Gas and Electric Co.
   Delaware Power & Light Co.
   Jersey Central Power & Light Co.
   Lucerne Electric & Gas Div.
   United Gas Improvement Co.
   Metropolitan Edison Co.
   New Jersey Power & Light Co.
   Pennsylvania Electric Co.
   Pennsylvania Power & Light Co.
   Philadelphia Electric Co.
   Potomac Electric Power Co.
   Public Service Electric and Gas Co.

FIGURE 2.4 DIAGRAM OF LOAD CONTROL AREAS AND POWER SYSTEM INTERCONNECTIONS, CANUSE AND PJM.

The event leading to the Northeast Blackout originated at the Sir Adam Beck generation complex at Kingston, Ontario (part of the Ontario Hydro System). Immediately prior to the blackout, the Hydroelectric Power Commission of Ontario was meeting a system load of approximately 6400 MW with Sir Adam Beck generating 1335 MW and with a 500 MW inflow on two tie lines with PASNY. Approximately 200 MW of the 500 MW inflow was being returned to New York via other interconnections. The Beck complex is connected with the Toronto load center via five parallel 230 kV lines.

In 1963, a backup relay on one of the 230 kV lines had been set substantially below the line's rating at 375 MW in order to achieve coordination with other protection devices in the power network. On the day of the blackout, the average power flow in this line reached a level of 365 MW and at 5:16 PM, the 375 MW rating was exceeded during a fluctuation in load. This caused the line to be opened by the protective relay, resulting in the power flow to Toronto being distributed among the remaining four lines, causing each of them to be overloaded with the result that they were disconnected by their relays. Thus, within a few seconds, the 1335 MW being generated at Sir Adam Beck was isolated from its load center in Toronto. This caused the generators in the Niagara area to accelerate due to the loss of electric load and with this increase in speed came a rapid increase in power output.

This power had to be distributed via the interconnections with PASNY and caused the remaining lines interconnecting Ontario and PASNY to become overloaded. Thus, the sole interconnection between Ontario at New York existed at Niagara where the Beck plant was isolated from Ontario but still connected to New York. The excess power output from the Niagara area could not be handled by the remaining lines and resulted in the stability limit opening of the two 345 kV lines connecting Niagara with Albany and New York. Almost simultaneously, connections with PJM were broken. The result of this chain reaction was the creation of several "islands" or relatively small networks isolated from the overall network. Some were deficient in generation and others had excess generation. The generators were typically unable to respond quickly enough to the changing load, resulting in massive shutdowns due to overloading of some units and overspeeding of others.

The above events illustrate the potential instability problems associated with normally functioning protective devices. Fluctuating load and generation capacity on a power network alters the power distribution over the network lines and, in a complex network, the distribution resulting from such a fluctuation may be quite difficult to forecast. The more widely varying the network power distribution becomes, the more likely it is that lines may become momentarily overloaded with the potential for chain reactions similar to the Northeast blackout.

2.3 Power Pool Reliability

2.3.1 Introduction and Summary

Whenever a large conventional generator is added to a power pool there can be a significant impact on the adequacy of the total system to meet the expected load at the design level of the reliability. The interface between the new generator and the grid must be carefully designed so as to minimize any negative impacts on the system. The large size and unconventional nature of the SPS makes the design of the interface more important than usual. Because of the limited resources available for this study not all of these problems have been examined in depth. However, some of the critical issues can and have been investigated.

Electric power networks are designed to provide reliable power to the consumer with redundant installations of reliable equipment. Given the nature and size of conventional equipment, it is technically and economically feasible to provide a system that will meet the demand except for 1 day in 10 years. The Loss of Load Probability (LOLP) is, therefore, 0.1 day/year. The use or a 5 GW SPS to meet the demand for power could either reduce the system reliability (increase the LOLP) or, for the same reliability, increase the required amount of redundant equipment.

This section discusses the impact on a power pool's total required installed capacity of installing one or more SPSs each with a generating capacity of 5 GWe instead of a number of conventional generating plants each with a generation capacity of 1 GWe. The analysis concerned primarily with the size of the proposed SPS and, therefore, most of the results would apply equally well to a 5 GWe terrestrial plant.

The results indicate that whenever a 5 GWe generator is used instead of five 1 GWe generators (no change in the forced outage rate) an additional one to two gigawatts ($125 to $250 million) of reserve capacity must be added if the system reliability is to be maintained. The magnitude of the assumed reliability criterion is not critical; whatever the criterion, it should not change when the SPS is added to the power pool.

The most important simplications made in this study and a description of the effect that each would have on the required total installed generating capacity in the power pool are given below:

- The conventional generators in the power pools were assumed to be identical in their maintenance characteristics, fuel economy and power generating capacity (1 GWe). This assumption tends to increase the required generating margin. Gas turbines are usually used to provide the reserve margin. The maximum expected size of these units in 1995 is 300 MWe.

- The assumed forced outage rate of .05 is relatively low for thermal units; large fossil fired units can have forced outage rates as high as .2. This assumption tends to reduce the required margin.

- The twenty percent scheduled maintenance requirements assumed for all plants, SPS ground station and conventional, is the upper limit on this parameter. This assumption tends to increase the required margin.

- Individual power pools were assumed to be controlled by a central dispatcher. This assumption tends to reduce the margin from what would be required if the power pool had the transmission system appropriate to a centrally controlled system.

- The effects of the transmission network on system reliability were ignored. This assumption tends to decrease the generating margin.

- The probability that the demand for power as a function of time would exceed the expected values was assumed to be zero. This assumption tends to decrease the required generating margin.

- When examining the use of redundant ground stations in order to eliminate any requirement for scheduled maintenance of the SPS, it was implicitly assumed that the power output of the spaceborne part of the SPS had a zero probability of being interrupted by any mechanism other than an eclipse of the sun by the earth. This tends to decrease the required reserve margin. (Scheduled maintenance of the satellite will probably be required, since an SPS with no scheduled maintenance is virtually impossible. However, the effect of this scheduled maintenance on the availability of SPS energy <u>may</u> be quite small.)

- Eclipses of the sun by the moon and other SPSs were ignored. This decreases the required reserve margin from what would be required if all eclipses were considered.

<u>Results</u>

All of the above assumptions have had some effect on the results of the reliability study; thus, although the results of the calculations indicate that the proposed size of the SPS is likely to cause a significant increase in the required reserve margin, these results are not conclusive. They merely indicate that a problem exists and that a more detailed study is required.

Since the proposed size of the SPS would affect the installed reserve, it follows that there would be a parallel effect on the pool's spinning reserve requirements. This last subject was not addressed in this study but should be considered in any future work.

The total amount of reserve generating capacity required in various power pools was calculated for power pools having yearly peak power demands of either

- 30 GWe, or
- 40 GWe, or
- 50 GWe, or a
- Composite Power Pools made up of two independent 30 GWe Power Pools whose times of peak demand differ by three hours (see Figure 2.5).

These power pools contained either

- No SPS (all conventional equipment), or
- One (5 GWe) SPS, or
- Two (5 GWe) SPSs, or
- Six (5 GWE)SPSs.

Three different scheduled interruptions of the power from each SPS were considered:

- Power interruption due to eclipses only during the actual eclipse period; no scheduled maintenance requirements. [Best case calculation.]

- Power interruption due to eclipses only during the actual eclipse period, plus scheduled maintenance for 21% of the year (an upper limit).

- Power interruption due to eclipses for the entire day for all days during which an eclipse occurs (90 days). [The SPS is unlikely to be economically attractive under these circumstances; worst case.]

The magnitude of the installed reserve under each of the indicated conditions is entered in Table 2.2. The difference between the entry of interest and the entry for the power pool which does not contain an SPS is the extra installed margin that is required by the SPS. For example: If a power pool, which has a peak power demand of 50 GWe contains no SPS, only 10 to 11 GWe's of installed margin (60 to 61 GWe's total) is required to provide for system reliability. If this same power pool contains an SPS which must be shut down for scheduled maintenance, 12 to 13 GWe's of installed margin is required. The power pool which contains an SPS needing scheduled maintenance requires two more gigawatts of generating capacity than does the power pool that contains no SPS. If the SPS needs no schedule maintenance, only one more gigawatt of generating capacity would probably be needed (11 - 12 GWe minus 10 - 11 GWe).

The results of these calculations indicate that if one or more 5 GWe generators (SPS, nuclear or fossil fuel) are installed in a power pool, the installed generating margin must be increased if the system reliability is to be maintained. The amount of the increase depends on the size of the power pool; the larger the power pool, the smaller the required increase.

To demonstrate how the installed margin must vary with the power pool size, the percentage installed margin is plotted as a function of the power pool size in Figures 2.6, 2.7 and 2.8. The

TABLE 2.2

Required Installed Generating Margin (GWe)

For a Range of Power Pools According to Various Circumstances

	30 GWe	40 GWe	50 GWe	Composite
NO SPS	8-9	9-10	10-11	16-18
ONE SPS				
No maintenance	10-11	11-12	11-12	17-19
Maintenance	11-12	12-13	12-13	17-19
Eclipses	11-12	12-13	13-14	17-19
TWO SPSs				
No Maintenance	11-12	11-12	12-13	-
Maintenance	13-14	13-14	14-15	-
Eclipses	14-15	13-14	14-15	-
SIX SPSs				
No Maintenance	-	15-16	14-15	-
Maintenance	-	17-18	17-18	-
Eclipses	-	18-19	19-20	-

plotted values for the composite* power pool clearly indicate that the composite power pool cannot be treated as if it were a 60 GWe power pool.

For the power pools considered in this study, the smallest increase in the generating margin was 1 GWe for every 5 GWe SPS (no scheduled maintenance) installed. This means that if an SPS is installed instead of 5 GWes of conventional baseload capacity, 1 GWe of reserve capacity (probably gas turbines) must also be installed. When scheduled maintenance was required, the increase in the generating margin became 2 GWe for every 5 GWe SPS installed.

The additional generating capacity that this study indicates will be required need not be expensive. The extra capacity will not be used very often and will probably be inexpensive peaking units ($125/kW), requiring capital of $250 million, 3.3% of the cost of the SPS ($7.6 billion).** If a completely redundant antenna were built, the total cost increase (including 1 GW of gas turbines) would be $1.47 billion, 19% of the SPS cost.

The analysis above revealed that the eclipses will have no effect on the system reliability if the SPS is shut down by the earth eclipses only for the duration of the eclipse. The demand for power during these eclipse periods was only half the daily peak and the probability that other generation would not be available to supply the needed power was virtually zero. If the shutdown were to last from one hour before the eclipse to one hour after the eclipse, the results would be the same. This particular problem should be

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* Two 30 GWe power pools whose times of daily peak demand differ by 3 hours.

** "Space-Based Solar Power Conversion and Delivery Systems Study - Interim Summary Report", by ECON, Inc., March 1976, Report No. 76-145-IB.

FIGURE 2.5

DEMAND FOR POWER IN THE TWO POWER CONSUMING ELEMENTS OF THE COMPOSITE POWER POOL AS A FUNCTION OF THE TIME-OF-DAY

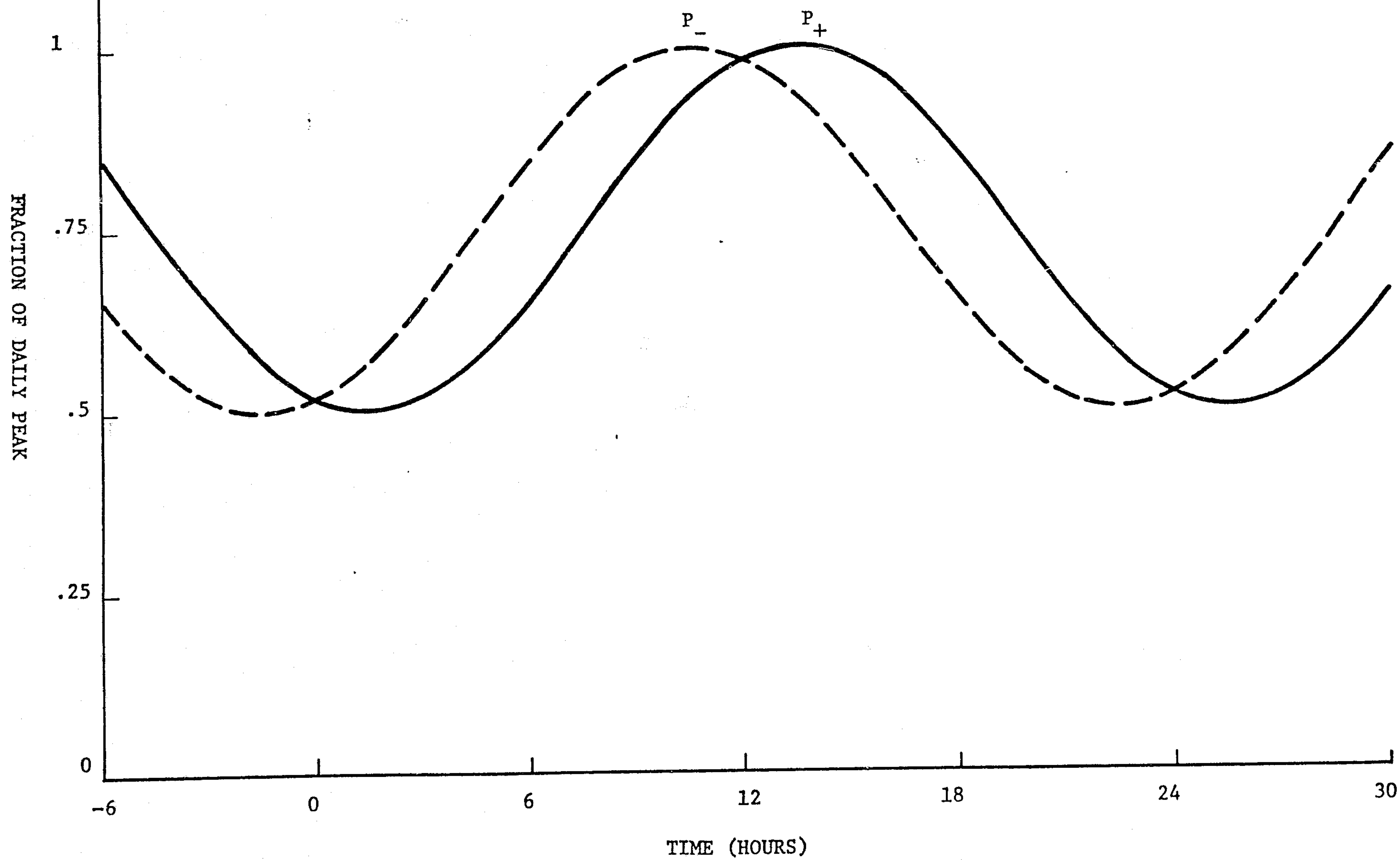


FIGURE 2.6

REQUIRED PERCENT INSTALLED MARGIN AS A FUNCTION OF THE POWER POOL SIZE
POWER POOLS CONTAINING ONE SPS

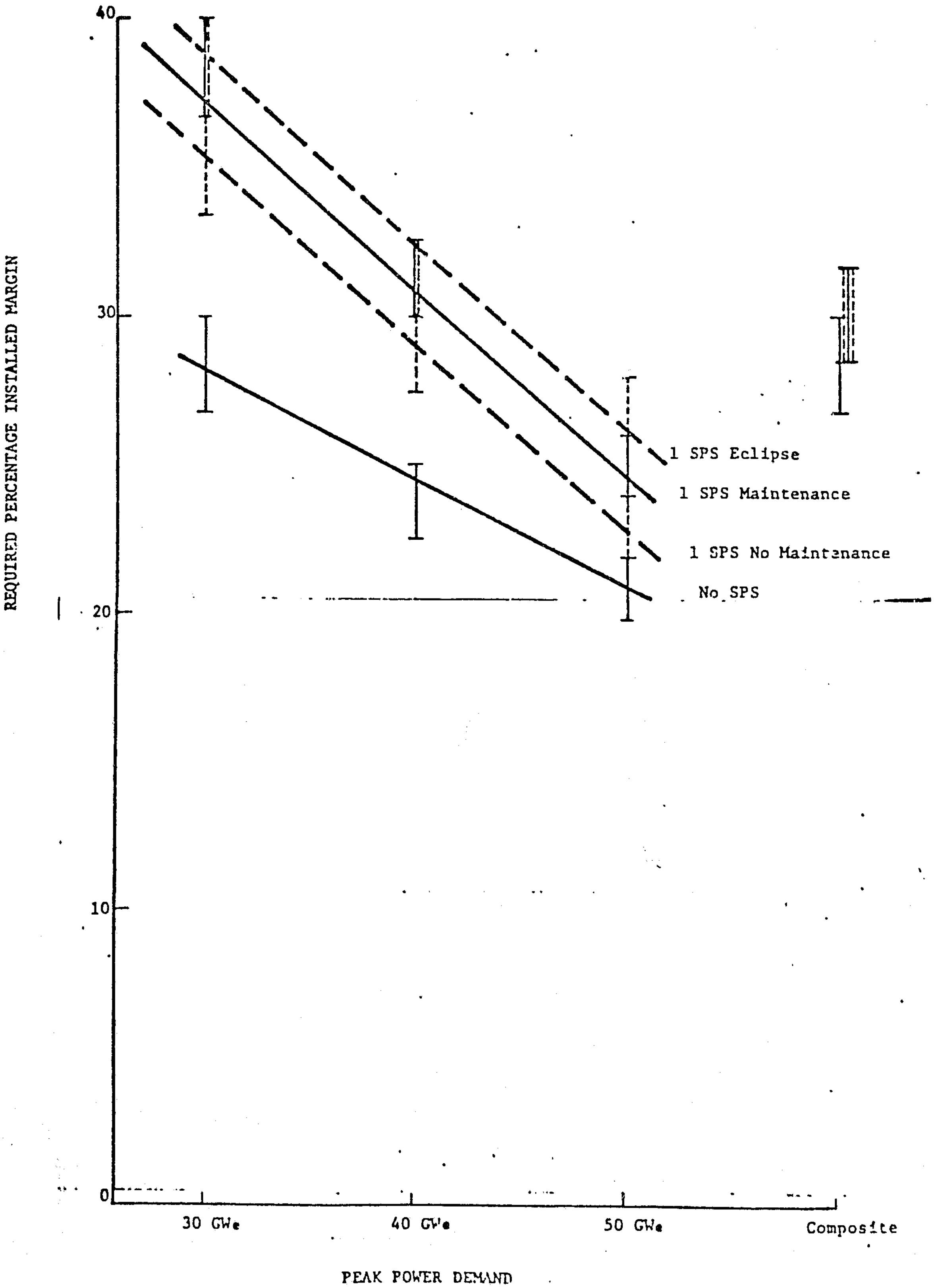


FIGURE 2.7

REQUIRED PERCENT INSTALLED MARGIN AS A FUNCTION OF THE POWER POOL SIZE

POWER POOLS CONTAINING TWO SPSs

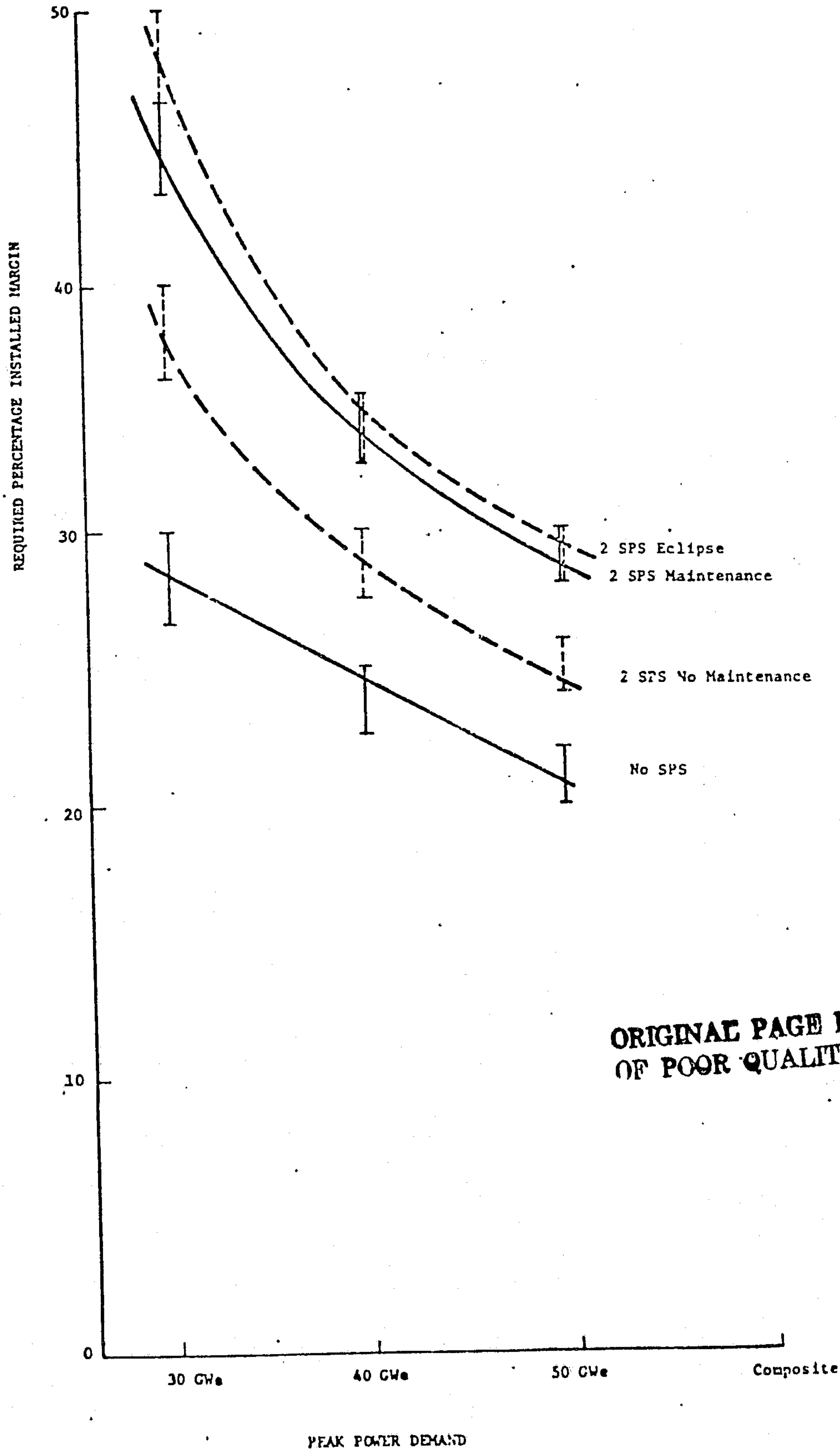
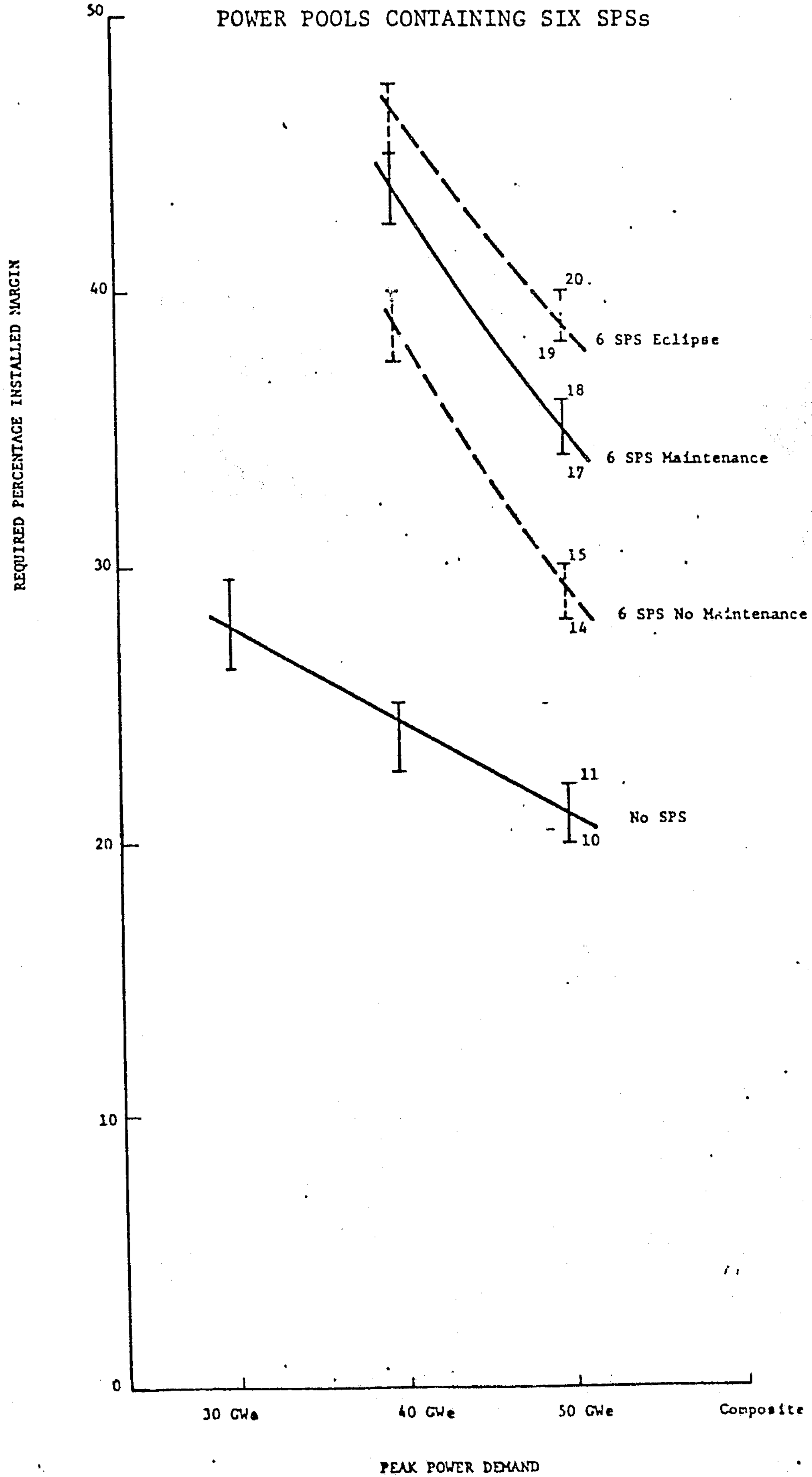


FIGURE 2.8

REQUIRED PERCENT INSTALLED MARGIN AS A FUNCTION OF THE POWER POOL SIZE

POWER POOLS CONTAINING SIX SPSs



reconsidered only if the daily load curves begin to flatten significantly.

The composite power pool was found to be unaffected by either the SPS maintenance requirements or problems due to the eclipse. Because the power produced by satellite in this power pool could be used in some way or other throughout the year, the maintenance requirements of the ground rectenna stations will have little effect on the installed margin. The margin's insensitivity to the eclipse comes from the size of the required margin when the pool contains no SPS and the uncertainties of the calculation.

2.3.2 Formulation of the Problem

2.3.2.1 Definitions

The demand for electric power in any particular power pool varies during each day and the daily peak varies during the year. Each power pool is designed to have enough individually reliable generating units so that there is a high probability of having enough generating capacity on-line at any one time to meet the demand when it occurs. The probability of meeting the load at any time is the probability that the available generating capacity exceeds the probable demand for power. The probability of not meeting the load (the "Loss of Load Probability" or LOLP) is therefore the difference between unity and the probability of meeting the load. The design LOLP for most U.S. power pools is 1 day in 10 years.

Since all equipment has some probability of breaking down and needing repair, it is necessary to install more generating capacity than the expected peak demand. The total generating capacity in a power pool minus the peak demand is called the installed margin. Another way of stating the LOLP criterion is that the reserve margin shall be greater than or equal to zero except for .1 days/year.

The characteristics of conventional terrestrial generating equipment are such that a power pool's installed margin must be roughly 25% of the yearly peak power demand in order to meet the reliability criterion. The problem addressed in this study is as follows: Given that the power pool shall meet the present reliability criterion, how will the installed margin of various sized power pools change if some of the conventional generators in the pool are replaced by one or more 5 GWe Solar Power Systems having a variety of reliability characteristics? The magnitude of the assumed reliability criterion is not critical; whatever the criterion, it should not change when an SPS is added to the power pool.

The systems considered were:

- Power Pools
  - Peak Power Demand = 30 GWe
  - Peak Power Demand = 40 GWe
  - Peak Power Demand = 50 GWe
  - Two 30 GWe Pools whose daily peaks are displaced relative to each other by 3 hours.
- Conventional Generating Equipment in Power Pool
  - Generating Capacity = 1,000 MWe
  - Unavailability due to forced outages = .05
  - Unavailability due to schedule maintenance = .2
- Solar Power Satellite Characteristics
  - Delivered Generating Capacity = 5,000 MWe per unit
  - Unavailability due to forced outages = .05
  - Effect of eclipses
    - No power during actual time of eclipse, or
    - No power during the 90 days when eclipses occur
  - Scheduled Maintenance

- No scheduled maintenance (two rectennas) or
- Unavailability due scheduled maintenance = .2

The problem is to calculate the probability that the demand for electric power is likely to exceed the generating capacity of the power pool during the year. This calculation is obtained by the following steps:

1. Calculate the probability that the demand for power shall be between specific levels m and (m-1) GW at at an arbitrary time t.

2. Calculate the probability that available generating capacity shall be m GWe or more at an arbitrary time t.

3. Multiply the two previously calculated probabilities together to get the probability that the load between m and (m-1) GW will be met by the power pool whenever the load occurs.

4. Sum over all the possible power demand states of the power pool to get the probability that the load, whatever it is, will be met by the power pool.

5. Calculate the probability of not meeting the load (the loss of load probability).

The power demand as a function of time used in these calculations was determinate in nature, i.e., the power demand P_o at time t_o was assumed known with certainty. Thus, the probability that the power demand is between m and (m-1) GWe at an arbitrary time t is the source as the probability that t is inside those time intervals when the power demand is between m and (m-1) GWe. This probability is the fraction of the total time, T, when the power demand is as described. We have defined this time interval to be δt_m; the probability that t falls in that time interval is $\delta t_m/T$.

The calculated probability that the available power generating capacity shall be greater than some specific value depends strongly on the number, power generating capacity and the reliability of the individual generator on-line in the power pool. These numbers are not constant throughout the year but vary from maintenance interval to maintenance interval; i.e., each machine must be taken off-line (not available for use as standby generation) for 20% of the year. Thus, the installed margin must be calculated for each maintenance interval independent of all the others and the results for all the maintenance intervals combined to give the yearly average. The total required installed generating capacity is that which allows the appropriate number of machines to be on-line during each maintenance interval and still allows each machine to be off-line for 20% of the year.

The prcblem of calculating the probability that the available power generating capacity shall be equal to or greater than some specific value during a specific maintenance interval for a general set of power pool characteristics is complex. In order to simplify the problem, we have assumed the power pool to be made up of either (a) n identical machines, each with a generating capacity of 1 GWe and a forced outage probability of .05 or (b) n' identical machines with the same characteristics and one or more SPS with generating capacities of 5 GWe and forced outage probability of .05.

The forced outage probability for any piece of equipment is obtained from historical data and is really a composite of the forced outage rate (the probability that the unit will fail in a unit of time) and the average time required to repair the unit. The interpretation of this single number is somewhat ambiguous. It can either be the probability that the unit is completely unavailable at an arbitrary time t or it can be the probable fraction of capacity of the equipment that is unavailable 100% of the time, or a combination of both. For the purposes of this calculation, we have assumed that former interpretation.

2.3.2.2 Power Pool Loads

Four different power pool loads were considered in this study. To simplify the analyses, load curves were idealized as simple closed-form analytical expressions. For example, the first three varied with time according to the following equations:

$$L = \frac{P}{16}\left(3 + \cos\left(\frac{2\pi t}{182\ \text{days}} + \phi_1\right)\right)\left(3 + \cos\left(\frac{2\pi t}{24\ \text{hrs}} + \phi_2\right)\right) \qquad (2.8)$$

where P, the maximum yearly demand, was taken to be 30 GWe, 40 GWe and 50 GWe for the three different sized power pools. ϕ_1 and ϕ_2 were chosen so that the SPS eclipses occurred when the load was at the yearly minimum, P/4.

The power demand in power pools described in Equation 2.8 varies by a factor of 2 during each day and the daily peak varies by a factor of 2 throughout the year. The absolute peak demand occurs twice a year, assumed to occur once at noon of the longest day of the year and once at noon at the shortest day of the year. The minimum yearly demand also occurs twice a year, assumed to occur at midnight during the autumnal equinox and at midnight during the vernal equinox. These latter time periods coincide with the times when the longest earth eclipses of the SPS occur.

The fourth power pool was actually made up of two independent (except for the SPS) 30 MWe power pools each varying with time as shown in Equation 2.8. The variation of this load with time is shown in Equation 2.9.

$$L = \frac{30\ MW_e}{16}\left(3 + \cos\left(\frac{2\pi t}{182\ \text{days}} + \phi_1\right)\right)\left\{\left(3 - \cos\left(\frac{2\pi[t+1.5\ \text{hrs}]}{24\ \text{hrs}} + \phi_2\right)\right) + \left(3 - \cos\left(\frac{2\pi[t-1.5\ \text{hrs}]}{24\ \text{hrs}} + \phi_2\right)\right)\right\} \qquad (2.9)$$

The variations of the demand for electric power described in Equations 2.11 and 2.12 are ideal models of what the demand can be. This variation is quite different in real power pools. There are only a few power pools whose summer and winter peaks have exactly the same magnitude. In the southern U.S., the summer peak is significantly larger than the winter peak while, in the north, the opposite is often true. In the north, the urban areas may have a summer peak while the suburban and rural areas may have a winter peak. In all areas, the daily peaks during the weekdays are significantly higher than the peaks during Saturday and Sunday.

In a limited study it is not possible explicitly to take into account all the possible load variations that can occur and only idealized power demand curves can be considered. However, the difference in peak demand between weekdays and weekends can easily be allowed for.

The probability of <u>not</u> meeting the power demand is a dimensionless number. The probable number of days per year when the load will not be met is obtained by multiplying this probability by the effective number of days in a year. If there is no reduction in power demand during the weekend, this number is 365. When the daily peak demand during the week is significantly less than that during the weekend, the effective number of days in the year is 261. This implies that the peak demands during the weekend are so low that if there is a 99.95% chance of meeting the weekday peaks, the probability of meeting the weekend peaks is 100%. This approximation is often used by the utilities and was used in this study. An LOLP of .1 days/year = 3.83×10^{-4}.

Each piece of generating equipment required to meet the loads described in Equations 2.8 and 2.9 must be taken off-line sometime during the year for scheduled maintenance. In order that this activity can later be taken into account, it is necessary to break the year up into "maintenance intervals". The number of machines in the power pool scheduled to be available does not change during a maintenance interval. In utility practice, the year is broken up into thirteen (13) four week intervals. Because of the double yearly peak assumed for our model load curves, thirteen intervals turned out to be inconvenient; instead fourteen (14) intervals, each 26 days long, were used. Two of these intervals (numbers 1 and 8) are centered about the summer and winter peaks. Four of these intervals (numbers 4, 5, 10 and 11) have one of the days at the end of the interval occurring at one of the two equinoxes, the days when the daily peak is at a minimum.

$\delta t_{\ell m}$ is the length of time (hours) during each maintenance interval, ℓ, when the demand for power is between m and m-1 gigawatts. Using equation 2.8 it is possible to calculate the values of $\delta t_{\ell m}$ for each maintenance interval for the three primary power pools. (See Appendix A.)

The composite power pool has three major components. Two of the components are power pools (in each power pool, the yearly peak demand for power is 30 GWe) and the third component is a 5 GWe capacity SPS which can feed its output into either power pool as required. The demand for power in each of the power pools as a function of the time-of-day is shown in Figure 2.5. P_- represents a power pool on the East Coast and P_+ represents a power pool on the West Coast. The demand for power in P_- is greater than the demand in P_+ for t between 0 and 12 hours. The opposite is true for t between 12 and 24 hours. For maximum economic impact, the output from the SPS should be fed into whichever power pool has the larger demand for power at that time. Thus, for 12 hours each day, the power output of the SPS is delivered to the power pool on the East Coast and for the rest of the day, the power from the SPS is delivered to the power on the West Coast. The demand for power from the conventional generators in P_+ as a function of time is shown in Figure 2.9. The use of the SPS in this manner reduces the peak demand met by the conventional generators in each power pool by only 2% but reduces the duration of this peak significantly.

Each power pool must be evaluated as if it were completely made up of conventional generators for half of the day and made up of conventional generator plus one 5 GWe SPS for other half of the day. There must be one set of $\delta t_{\ell m}$'s for that half of the day when the demand for power in one particular power pool is greater than in the other and another set when the conditions are reversed. These two sets of $\delta t_{\ell m}$, the same for each 30 GWe power pool, are given in Appendix A.

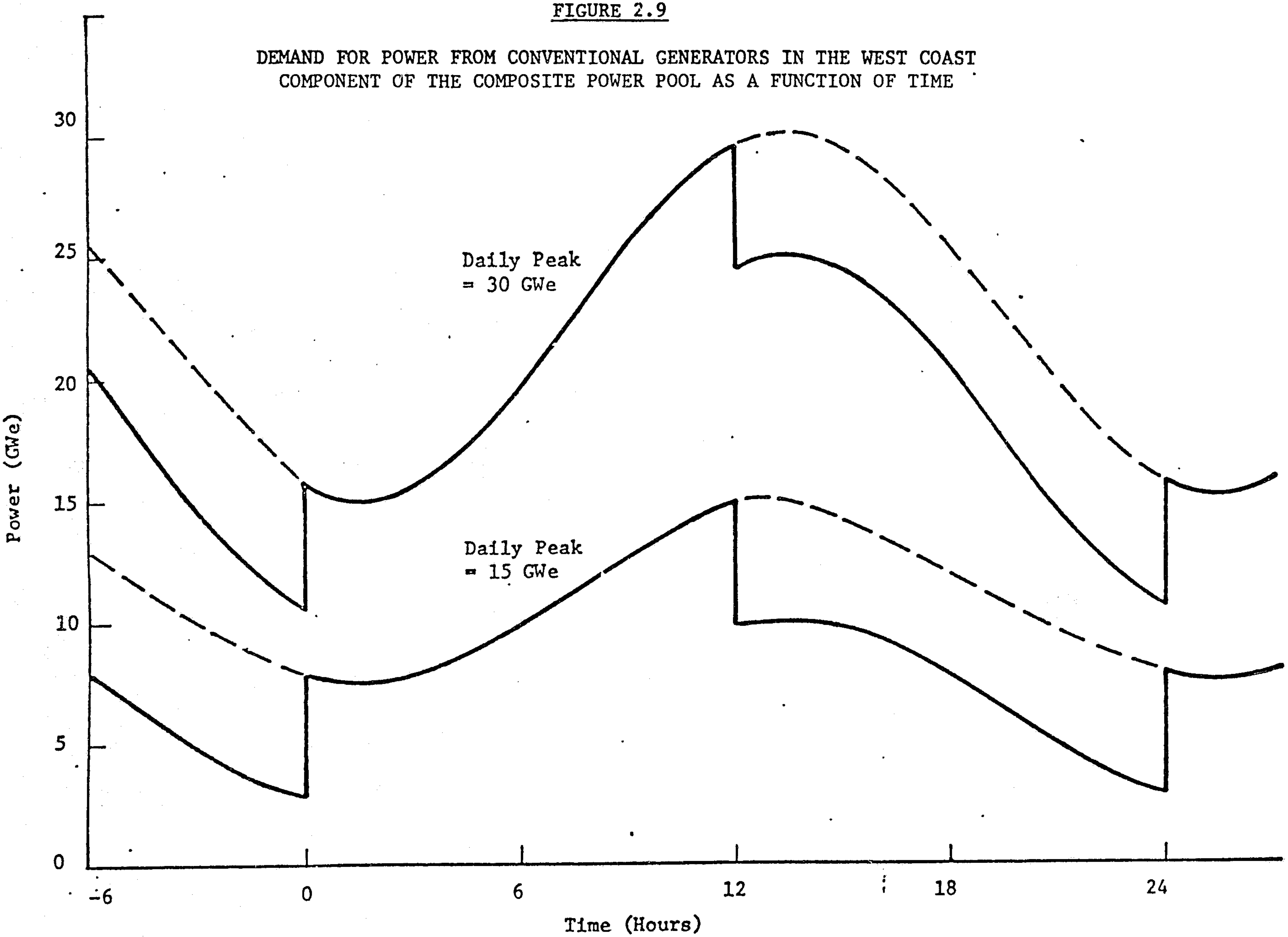
2.3.2.3 Number of Required Generators

The LOLP of a power pool containing no SPS during the ℓ^{th} maintenance interval would be

$$LOLP_\ell = \sum_{m=1}^{n_\ell} \frac{\delta t_{\ell m}}{T} \left(1 - \sum_{j=0}^{n_\ell - m} \frac{n_\ell!}{(n_\ell - j)!j!} (.95)^{n_\ell - j} (.05)^j \right) \quad (2.10)$$

FIGURE 2.9

DEMAND FOR POWER FROM CONVENTIONAL GENERATORS IN THE WEST COAST COMPONENT OF THE COMPOSITE POWER POOL AS A FUNCTION OF TIME



where

T_ℓ = the total time in the ℓ'th maintenance interval;

$\delta t_{\ell m}$ = the number of hours in the ℓ'th maintenance interval during which the demand for power is between m and (m-1) gigawatts; and

n_ℓ = the number of generators not scheduled for maintenance during the ℓ'th interval.

The LOLP of a power pool containing one SPS during the ℓ'th maintenance interval would be

$$LOLP_\ell = \sum_{m=1}^{n'_\ell+5} \frac{\delta t_{\ell m}}{T_\ell} \left[1 - \left(\sum_{j=0}^{n'_\ell-m} \frac{n'_\ell!}{(n'_\ell-j)!j!} (.95)^{n'_\ell-j} (.05)^j\right)(.05) - \left(\sum_{j=0}^{n'_\ell-m+5} \frac{n'_\ell!}{(n'_\ell-j)!j!} (.95)^{n'_\ell-j} (.05)^j\right)(.95)\right] \tag{2.11}$$

The yearly average value for the LOLP would be

$$LOLP = \frac{1}{14} \sum_{\ell=1}^{14} LOLP_\ell \tag{2.12}$$

The number of generators, n, required to meet the reliability criteria and the maintenance requirements must also satisfy the following equation

$$\sum_{\ell=1}^{14} \frac{n-n_\ell}{3} \geq n \tag{2.13}$$

That is, each machine needs to be off-line for scheduled maintenance for three maintenance intervals each year (3/14 = .21). The derivation of these equations is explained in Appendix A. The way that these equations were used to calculate the values of n_ℓ presented in Table 2.2 is also described in Appendix A.

3.0 POSSIBLE OWNERSHIP OF SPS

3.1 Introduction

3.1.1 Summary

Three different ownership and/or energy pricing arrangements for the SPS have been investigated. These arrangements were:

- Purchase by the SPS by a utility or consortium of utilities (Section 3.2).

- Purchase of the SPS by an independent corporation and "lease" (commitment to purchase a share of the SPS energy) of the output by several utilities during the year (Section 3.3).

- Purchase of the SPS by an independent corporation and the energy sold to the utilities, at below cost initially, at a price equal to the incremental cost of the utilities' most expensive base load generator (Section 3.4).

How and by whom the SPS is purchased can determine how it is used.

Of these three arrangements, only the purchase of the SPS by an independent entity (corporate or governmental) and "lease" of the output by several utilities has the promise of overcoming the present institutional barriers to the base load utilization of the SPS.

While all of the calculations performed in this analysis assumed that the capital cost of the SPS was $7.6 billion, the general conclusions reached using this cost can be used to infer the effect of using the more recent, significantly higher estimate of $12.2 billion. The basic conclusion reached in this study, i.e. that the "leasing" arrangement is the most promising of the three arrangements considered, would be true if the higher cost had been assumed.

The results of this investigation are as follows:

1. Utility Ownership of the SPS

   - When the ($7.6 billion) SPS first becomes operational, a very small increase in the total cost of meeting the demand for electrical energy will probably be seen.

   - If the capital cost of the SPS is $12.2 billion, the inclusion of the SPS related costs in the utility rate structure would require an increase in the total cost of electrical energy to the consumer.

   - Utilities which use a semi-automatic fuel adjustment rate to recoup the cost of fuel will have to request a sizable increase in their base rates to cover their increased plant equity when the SPS comes on-line. Fuel rate reductions can occur within a month; base rate increases can take as long as a year to obtain. The higher the capital cost of the SPS, the greater will be the financial stress caused by regulatory delays.

2. "Leasing" of the SPS Output by the Utilities

- The cost of purchasing energy could be recouped by many utilities via fuel adjustment rates.

- At present, the reduction of the utility capital requirements caused by "leasing" energy from the SPS would have a beneficial effect on the utilities' financial ratings. It is not clear that this situation will prevail over the next fifty years, nor is it clear if the utilities would accept this arrangement over such a long term.

- Since the utilities make no profit on purchased energy, the effect of the SPS on the total cost of electrical energy would be the same for both ownership plans (assuming that the discount rate is the same for both the utility and the private corporation).

3. SPS Energy Sold at the Incremental Cost of Base-Load Alternatives

- If the inflation rate continues at roughly the same as present rates, it would be possible to price energy from an SPS (capital cost = $7.6 billion) at the incremental cost of alternative fossil fueled generation and eventually make a profit. The size of the profit depends on the inflation rates.

- If the capital cost of the SPS is significantly higher than $7.6 billion, the inflation rates necessary to eventually make a profit using this pricing alternative, would be significantly greater than the present inflation rates.

- Pricing SPS generated energy in this manner requires the operation of the SPS at a loss for roughly twenty years. The risks associated with this arrangement are too large for private industry- financial guarantees from the government would be required.

- If the government provides financial guarantees to a corporation intending to price SPS energy in this manner, this may be interpreted as a statement that the government is either willing to subsidize the SPS or that it expects the inflation rate to continue at its present level or higher.

3.1.2 General Financial Characteristics of the Generation Mix

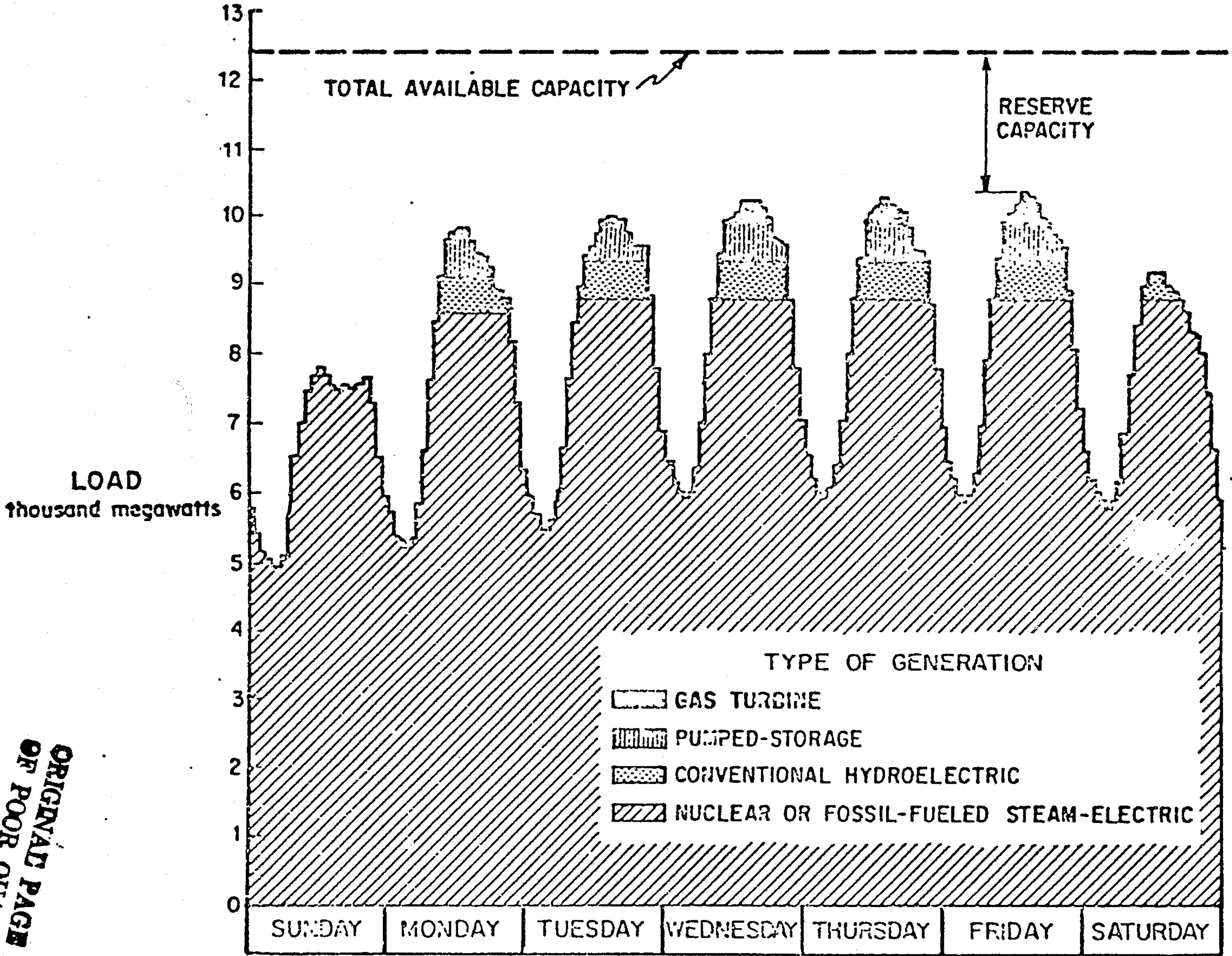
The demand for electric power from the utilities varies with the time of day, the day of the week, the weather, and the season. The shape and magnitude of these variations will vary from utility to utility. An example of how the demand varied during a particular week for a particular utility is shown in Figure 3.1. During this period, the demand varied from a minimum of 4.9 GW at 2 a.m. Sunday morning to a maximum of 10.3 GW at 2 p.m. on Friday afternoon. Looking at Figure 3.1, one can distinguish three different types of demand for electric power which can be met by different types of equipment.

Base Load Demand - a power demand which exists 24 hours a day for several weeks at a time. The base load demand for the sample power pool would be about 5 GW. The equipment used to meet this demand would be characterized by relatively high capital costs and low operating costs such that the total cost of electrical energy from these units, operating between 6,000 and 7,000 hours per year, would be less than that of energy from other types of generators. Fossil-fueled base load equipment operates at temperatures and pressures close to the physical limit of the materials used in its construction. Frequent thermal cycling of this equipment in load following service normally leads to expensive maintenance.

Intermediate or Cyclic Demand - a power demand which exists for 10 to 20 hours a day. The intermediate load demand for the sample power pool would be about 3.5 GW. The equipment used to meet this demand would be characterized by moderately high capital and operating costs such that the total cost of electrical energy from these units, operating between 3,000 and 5,000 hours per year, would be less than that of energy from other types of generators. Much of this equipment is older, less efficient base load equipment. However, equipment built to sustain the thermal cycling associated with load following service is used extensively.

FIGURE 3.1

DEMAND FOR ELECTRIC POWER OVER A WEEKLY CYCLE



REF: THE 1970 NATIONAL POWER SURVEY-PART I

Peak Power Demand - a power demand which exists for up to 10 hours a day. The peak power demand for the sample power pool would be about 2 GW. The primary generators used to meet this demand and to provide the reserve capacity are characterized by low capital costs and high operating costs such that the total cost of electrical energy from these units, operating less than 2,000 hours per year, would be less than that of energy from other types of generators.

Storage generators, both pumped hydro-storage units and conventional hydro-generators with associated storage capacity (dams), are used to meet the daily peak demands but have the general cost characteristics of the generators used to meet the intermediate or base load demand. They are operated, however, to meet the daily peak demand throughout the year rather than only during the season when the demand is the highest, and easily meet the 3,000 and 5,000 hours/year operation criterion of intermediate load generators.

While generators are purchased by considering the total cost of the generated power, each generator, once acquired, is scheduled for duty according to the incremental cost of generation. The incremental costs are the operating costs that depend directly on the amount of power actually being generated (e.g. fuel costs). The scheduling criterion requires that the cost of operating the system to meet the power demand shall be a minimum. (The fixed costs of each generator must be met no matter how many hours they are used.) When the demand is low, it is met with those generating units whose generating costs are the lowest of all the available units. When the demand increases, the generating units have higher operating costs are brought on-line and the average cost per kilowatt hour increases. Thus, the number of hours a year a generator is likely to be used depends on the time variations of the power demand and the relative operating costs of all the other generators in the system.

The decision to add specific types of generation equipment to the generation mix is based on the criterion that the "present worth

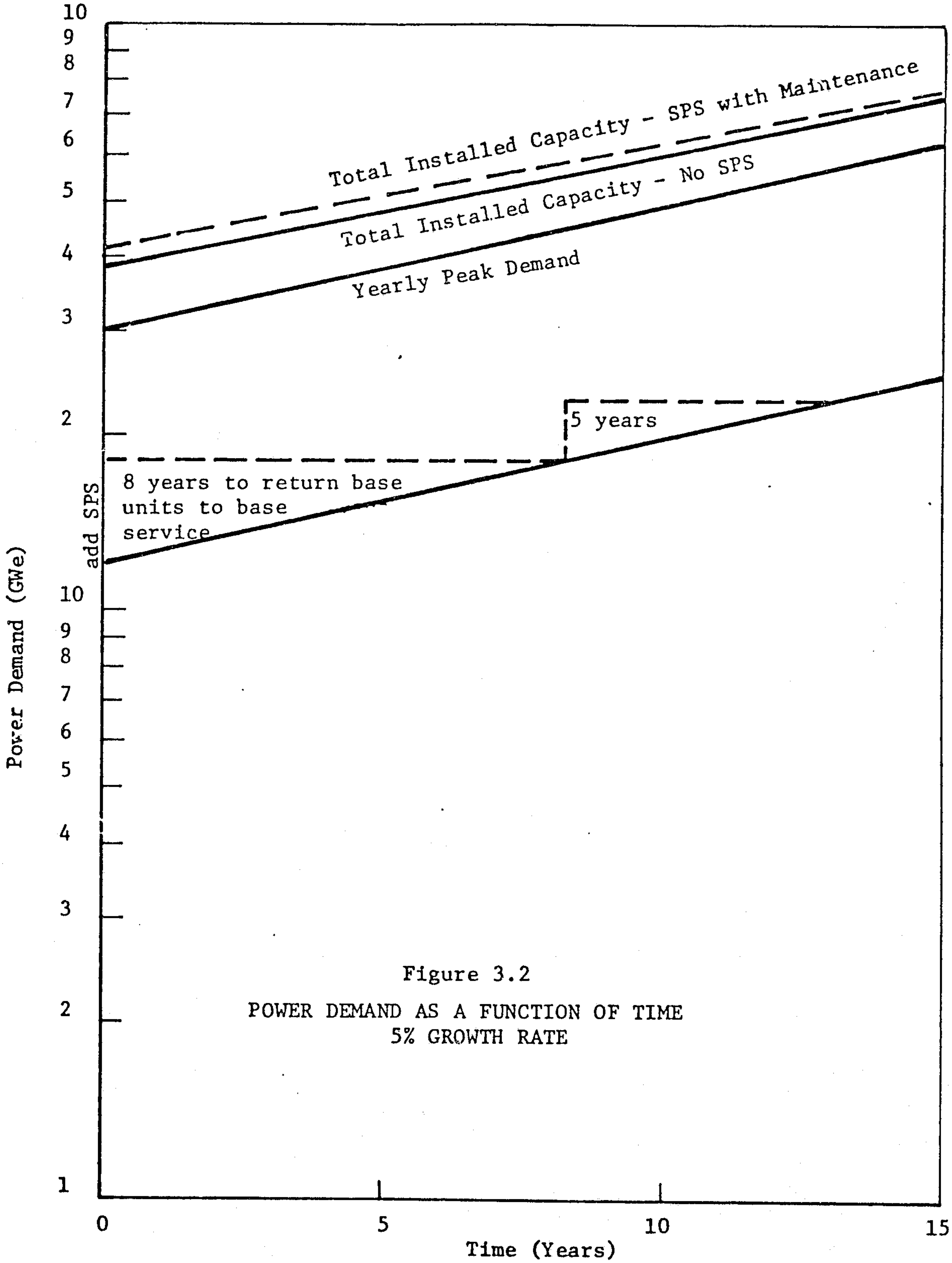


Figure 3.2

POWER DEMAND AS A FUNCTION OF TIME
5% GROWTH RATE

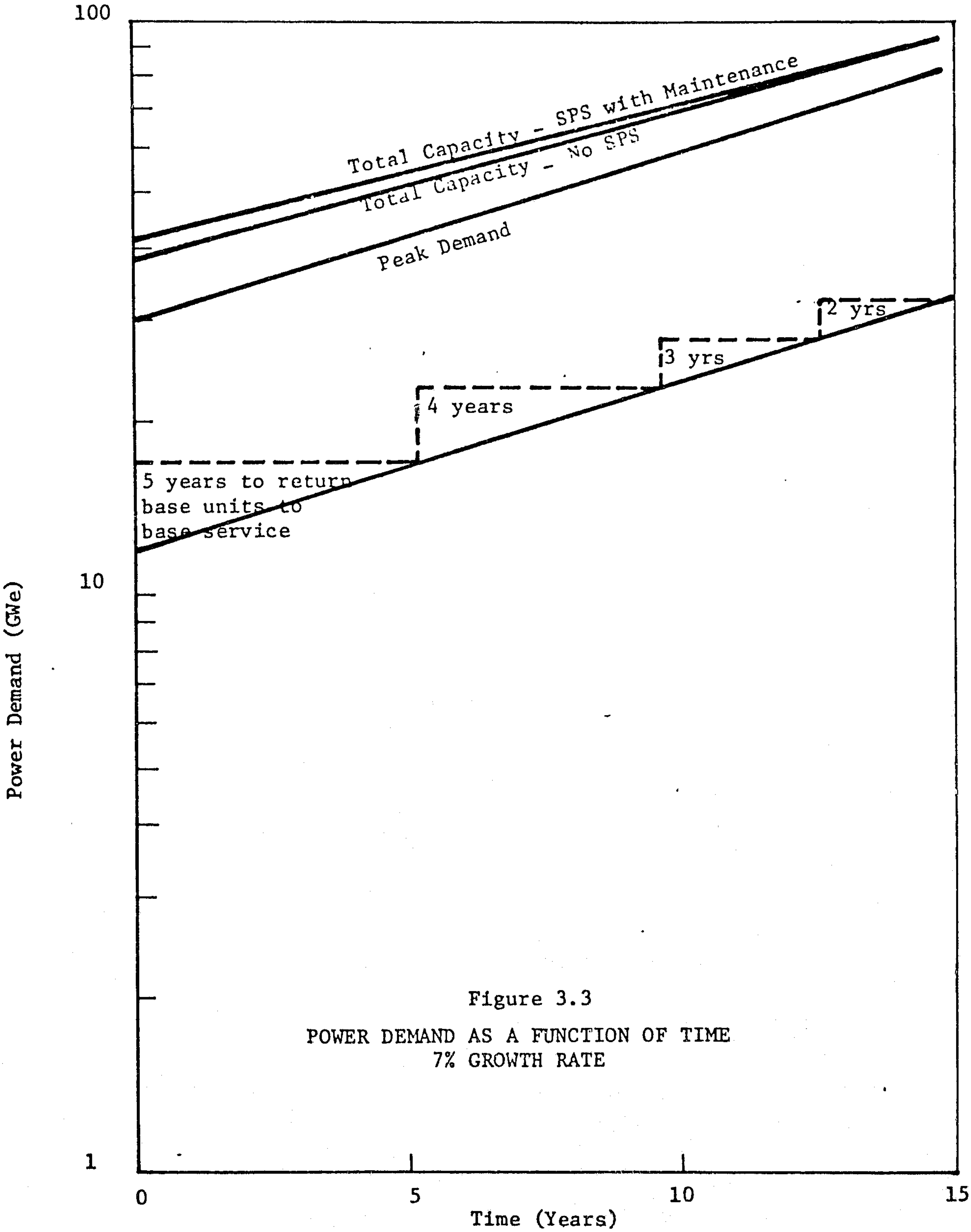


Figure 3.3

POWER DEMAND AS A FUNCTION OF TIME
7% GROWTH RATE

of all future revenue requirements" (pwafrr) for a generator operating in the expected manner shall be less than for the other available generators. A calculation of the optimum expansion plan for a utility must include a calculation of how the power plant is likely to be used. The "pawfrr" for each candidate generator can be calculated once the expected usage is determined.

When the SPS comes on-line, and is used to meet base load, plants which were base-loaded will be transferred to intermediate load service until the demand growth requires them for base load service again. Cycling of this equipment in load following service can cause expensive maintenance problems and should be terminated as soon as possible. The time required before all of these units can be returned to base load service depends on the power pool characteristics.

Two examples of how the duration of this undesirable situation varies with the power pool characteristics are shown in Figure 3.2 and 3.3. Both figures show the peak power demand for a power pool as a function of time; the growth rate is 5% per year in Figure 3.2 and 7% per year in Figure 3.3. As demonstrated in Chapter 2, the SPS should not be placed in small power pools; both power pools have a yearly peak demand of 30 GWe in year zero. The plotted values of the total required installed capacity are taken from the results of Section 2.3. The base load was taken to be 40% of the yearly peak demand; for the power demand described in Equation 2.11, 40% of all generators could be operated without daily cycling for six of the 14 maintenance intervals.

The effect on the total generating capacity of adding a 5 GWe generator to the power pools is quite small and, except for the increased margin requirement, disappears within a couple of years. However, adding a 5 GWe generator to a pool has a lasting effect on the base load equipment.

If the SPS is added to a 30 GW power pool, 5-8 years (depending on growth rates) must pass before all base load units are returned to base load service; the corresponding time for the addition of a 1 GW unit is 1 - 1 $\frac{1}{2}$ years. If the SPS is added to a 50 GW power pool, 3-4 years are required to return the base load units to base load service. Increased maintenance costs for these units will result from this displacement but the resources available for this program were insufficient to assess the size of this increase.

Purchase of Bulk Power

Power is often purchased from nearby utilities either directly or by automatic purchases directed by regional power pools encompassing several different utilities (e.g. New England Power Exchange). Utilities purchase this power because they cannot generate it themselves or it would cost them more to do so. Base load power is usually purchased only when the utility has not built the appropriate base load generators (e.g., non-generating municipal utilities and slippage of the construction schedules for nuclear power plants). However, utilities often purchase power to meet their intermediate and peak load requirements.

As previously discussed, each generator is scheduled for use according to its incremental cost of generation. Since the incremental or operating costs of the SPS should be low it should be used as a base load plant. This would be true even if the total cost of energy from the SPS is higher than from conventional plants. However, if the SPS is owned by an independent organization and the energy is priced at its total cost, the SPS may be used only to meet intermediate or peak loads. For this reason, two other ownership/pricing concepts have been investigated.

If the SPS were "leased" to the utilities, the rental costs would be fixed and payment would be required even if the power were not used. The incremental cost to the utilities would be zero. On the other hand, if the incremental cost of SPS energy were artifically set at the incremental cost of alternative base load generation, the SPS energy would be used to meet the base load. Thus, the SPS could be owned by an independent corporation and the power still be used to meet base load.

Financial Comment

Despite the possibility of purchasing bulk power from nearby producers, utilities frequently prefer to install sufficient generating capacity to meet all of their normal power requirements. In large part, the nation's electric utilities are privately-owned and the primary financial duty of their management is to secure an adequate return on the stockholder's investment. The regulatory commissions in each state allow for a return on plant equity but set the rates so that operating costs are merely recovered. The financial effect of not building base load plants and purchasing base load power from a neighboring utility is to transfer revenues from the equity cost category, on which there is an allowance for return to the investors, to the operating cost category on which there is no return. This provides a significant incentive to the utilities to maintain their own generation mix. This effect is explained by the Averich-Johnson theory of utility operations. On the other hand, if a utility has difficulty in raising the required funds, the only choice may be to postpone or eliminate capital projects such as base load generators.

Broadly speaking, utility companies were once preferred customers in the capital markets. This is not now the case. Bond ratings provide the best indication as to the borrowing abilities of the electric utilities and other companies. Over the last five years, most utilities have experienced some decline in ratings. Moreover, given the reluctance of many regulatory commisssions to authorize timely rate increases, many investors tend to apply different standards to industrial and utility issues. For example, an institution might invest in industrial bond offerings rated A or higher, but might only invest in utilities rated AA or AAA.

While many utilities experience delays in receiving rate increases on their equity, the "fuel adjustment clause" has made the recovery of increased fuel costs relatively easy and timely compared to conventional rate increases. This factor provides a significant disincentive to purchase high capital cost equipment.

3.2 Purchase of the SPS by a Utility or Consortium of Utilities

The major financial obstacles to utility ownership of the SPS are all associated with the SPS's high total capital cost ($7.6 billion). While all solar energy systems will experience some problem with gaining utility acceptance because of their high capital costs per kilowatt, the problems associated with the SPS are exacerbated by the SPS's large size. The reliability problems previously discussed apply to any 5 GWe generator, but the problems discussed in this Section apply only to 5 GWe, high capital cost, low operating cost systems like the SPS. Fusion and possibly breeder generators are the other proposed new power system which may have this combination of characteristics.

Regulatory Issues

The operations of the electric utilities are supervised by the regulatory commissions in each state. Besides performing the classical utility regulation functions of granting a local monopoly and requiring the utility to give service to all legitimate customers in the area served. these commissions deal with three main issues.

- The rates which the utilities can charge;
- The siting and safety of new facilities - generation, transmission, etc.; and
- The quality of service, etc.

The specific operations and responsibilities of each commission vary from state to state. The basic responsibility of all the commissions is to protect the interests of the consumers, both commercial and residential, in an area where the normal mechanics of competition have been suspended. The rate-setting part of a commission's responsibility has an obvious effect on the well-being of the consumer, but the other two responsibilities also have a large effect. The siting of unnecessary facilities could drive the utility rates up by forcing the present customers to pay for the operationg of equipment that may not be needed for several years. While excess power can be sold to neighboring utilities, utility commissions try to ensure that only needed capacity is actually constructed.

In recent years, the participation of consumers and environmental groups in the commission hearings concerned with electric power rate changes and the siting of new facilities has become more common. This trend has lengthened the time required for a utility to win approval of any proposed action. The effect has been to make the utilities even more conservative in the methods they are willing to use in providing power of the accepted quality. If a new method of meeting the demand can result in increased costs, it is unlikely to be implemented unless these costs can be recovered as they are incurred.

The addition of an SPS to a power pool will probably cause an increase in the utilities' costs. When the SPS comes on-line, plants which were base-loaded would be pushed up into intermediate load service; it has already been shown that the duration of this situation can be substantial. The effective of purchasing the SPS would be a sudden jump in the total utility equity, with the proceeds from energy sales insufficient to cover this jump for many years. This situation would lead to an increase in the utilities costs. A corresponding reduction in the fuel cost which could almost totally offset the increased fixed costs might be expected.

Calculation of Utility Cost Increases

The correct method of calculating the aforementioned cost increases and decreases would compare the total utility costs when only conventional equipment is used, with the corresponding costs if an SPS were added to the generation mix. Such a calculation, using the production costing computer programs used by utilities, is too time consuming for this study. The costing programs are run twice, once for the power pool assumed to contain an SPS and once with no SPS. The fixed costs and the production costs (the fuel and operating costs) required to meet the load, given the two assumptions would automatically be provided in the computer output. The cost of providing spinning reserve and extra reserve margin could also be included. This approach has been used by ERDA and EPRI to assess the desirability of using fuel cells and batteries.* Unfortunately, the resources available for this study do not allow this approach to be used and a significantly simpler and somewhat less accurate approach has been taken.

To avoid having to consider, in detail, the costs associated with every piece of equipment in the power pool, a simple economic model unit was used. This model assumed:

- The average cost of electrical energy in 1974 was 40 mills/kW-hr
- The average fixed costs (equity costs, insurance costs, maintenance, etc.) of electricity in 1974 was 25 mills/kW-hr
- The fixed costs increased with the general inflation rate, i_i - inflation affects the equity costs by affecting the capital cost of equipment added to meet a growing demand for power.
- The average cost of fuel to generate electricity was 15 mills/kW-hr - fuel costs increase at a fuel inflation rate, i_f, which is not necessarily equal to the general inflation rate but is unlikely to be less.
- The yearly peak power demand increases at a growth rate, g, which is equal to the utilities yearly growth in energy sales.
- The system load factor** remains constant at .56.

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* "Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems", Public Service Electric and Gas Company, EPRI EM-336, November, 1976.

**

$$\ell f = \frac{\text{energy sold/yr}}{\text{peak demand x8760 hrs/yr}}$$

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The per unit change of a utility's fixed and operating costs with time under a variety of circumstances can be estimated by using the methodology described in Appendix B. This variation with time (with and without the SPS) is plotted in Figures 3.4 and 3.5

If no SPS were to be included in the power pool, the unit cost of electrical energy would be

$$\frac{25 \text{ mills}}{\text{kW-hr}} (1 + i_i)^n + \frac{15 \text{ mills}}{\text{kw-hr}} (1 + i_f)^n \qquad (3.1)$$

where n is the number of year after 1974. These costs are plotted as solid lines in Figures 3.4 and 3.5 for the indicated inflation rates.

When an SPS comes on-line, there are cost increases associated with the capital and operating costs of the SPS and cost decreases associated with fuel savings and the fixed costs of unbuilt, alternative base load equipment. Alternative base load capacity would have been required in increments of $P_{max}g$ beginning the year the SPS is installed (P_{max} is the yearly peak power demand). As the total amount of deferred base load capacity reaches 5 GW, an extra 2 GWe of reserve capacity ($125/kW) would be added to the power pool. The resulting fixed and fuel costs are shown as dotted lines in Figures 3.4 and 3.5.

The fuel savings would initially be based on the <u>average</u> system fuel costs, not the cost of the unbuilt base load generators. For 5 to 8 years after the SPS is built, base load units would be used to meet the intermediate load and this would tend to decrease the overall fuel costs for the power pool.

The total per unit cost of energy plotted in Figures 3.4 and 3.5 indicate that the purchase of an SPS (capital cost = $7.6 billion in 1974) would, under a variety of circumstances, lead to only a very slight increase in total costs. If the capital cost of the SPS were significantly greater than the assumed value, clearly the increase would be much larger.

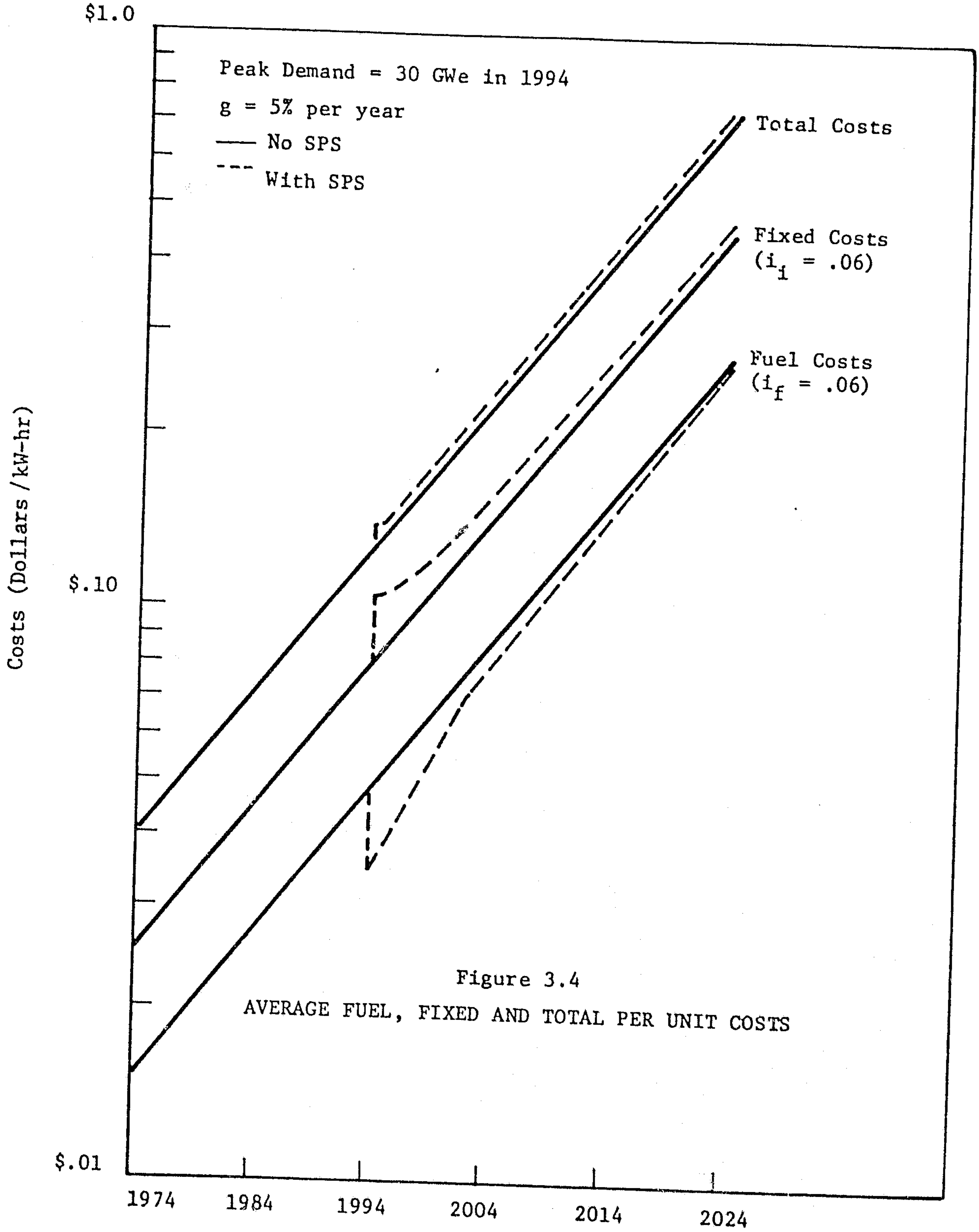

Figure 3.4

AVERAGE FUEL, FIXED AND TOTAL PER UNIT COSTS

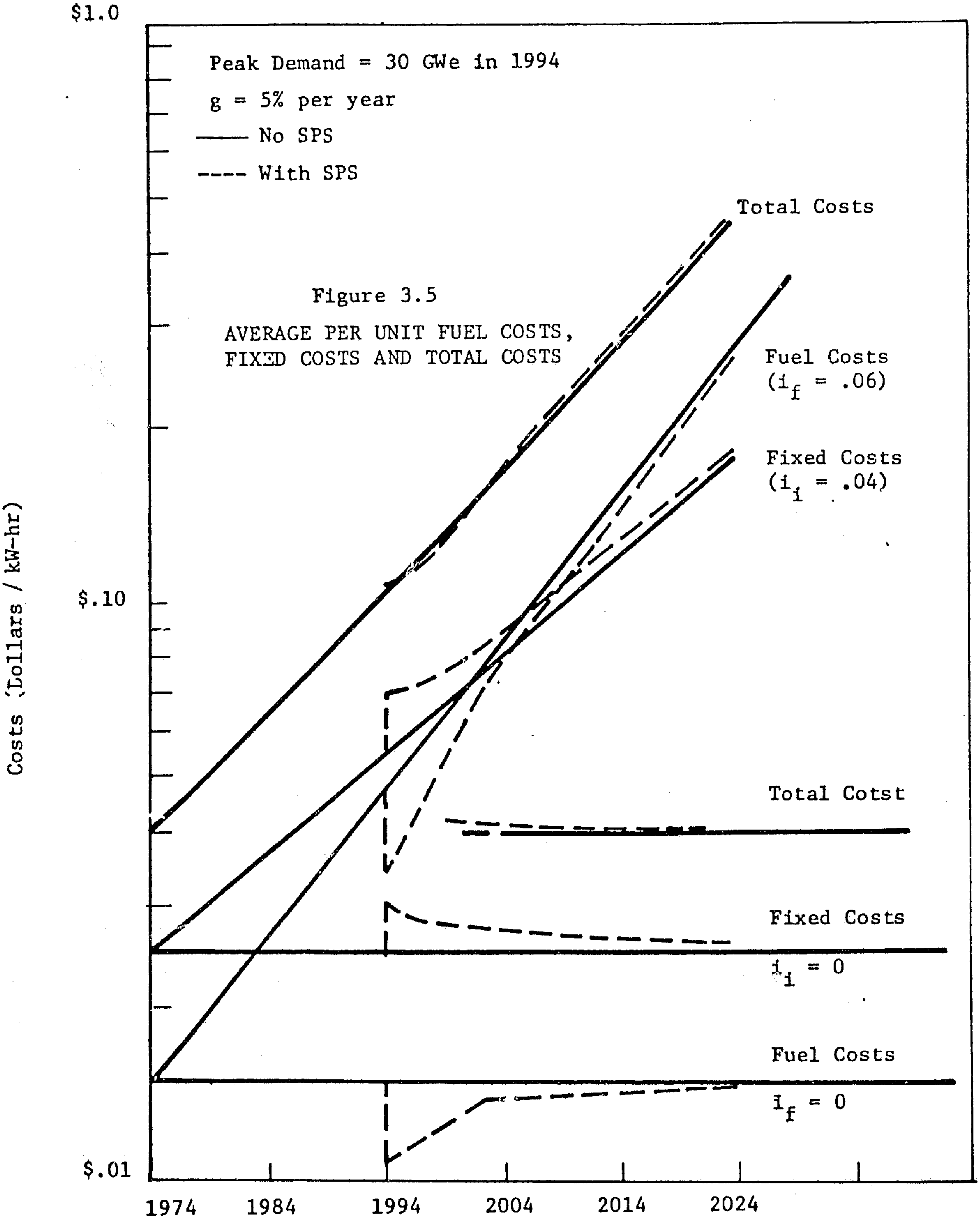

Figure 3.5

AVERAGE PER UNIT FUEL COSTS, FIXED COSTS AND TOTAL COSTS

This same conclusion could have been reached by calculating the "present worth of all future revenue requirements" of the SPS and the terrestrial alternatives.

The total per unit _fixed cost_ of energy also plotted in Figures 3.4 and 3.5, indicate that the purchase of an SPS (capital cost = \$7.6 billion in 1974) will require those utilities which have semi-automatic fuel adjustment clauses to request a better than 20% rate increase on their base rates; the base rate would have not have reached this level until at least five years later. If the capital cost of the SPS were higher, clearly, this increase would have been higher. The regulatory delay in answering such a request would probably be quite long.

The curves in Figures 3.4 and 3.5 indicate that those utilities that do _not_ have the fuel adjustment clause or which could include the cost of SPS energy in the fuel adjustment clause will find it much easier to pay the increased fixed system costs by transferring fuel cost savings as needed. Those rate increases that would have been required because of inflation would still be required despite the addition of the SPS.

3.3 "Leasing" the SPS

An alternative to ownership through outright purchase of the SPS would be provided by utility "leasing" of the plant. The SPS would be owned by an independent organization and its power sold to the utilities under the condition that they purchase energy at a constant rate throughout the plant life (except while SPS was off-line for scheduled maintenance). The payment (rent) would be due even if a particular utility could not or wished not to accept the SPS energy. There are several advantages to this approach:

- The incremental cost of SPS energy would be zero (except for negligible transmission costs) and the SPS energy could be expected to be used to meet the base load. Payment would be required, like any other fixed cost, no matter how often the SPS were used.

- Many of those utilities which have semi-automatic fuel adjustment clauses are allowed to include the cost of purchased power in their calculation of the fuel rate.

- Operating costs are usually included in the electric power rates without any provision for a return to utility stockholders. Since the rental costs are likely to be passed on to the consumer without a mark-up, the effect of this approach on utility rates would probably be the same as if the utility owned the equipment itself.

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- The utility would not have to exhaust its credit in order to provide the large capital required to construct an SPS.

- The rental fees would increase only slightly due to inflation.

The "leasing" of the SPS *may* be unattractive to the utilities because the SPS will, when it comes on line, represent a completely foreign technology. For example, there is unlikely to be any long term reliability and stability data for the plant. In light of the unknowns and uncertainties, if the utilities are required to make an extremely long term comitment in order to be permitted to purchase *any* energy from the SPS, it is possible that they will not be interested.

3.4 Pricing SPS Produced Energy at the Incremental Cost of Alternative Generation

3.4.1 Introduction

If the SPS is purchased and operated by an independent corporation, and the energy sold to an operating utility or consortium of utilities without a fixed term purchase agreement, the price of the electrical energy to the utilities would have to be competitive with the incremental costs of alternative generation if the SPS is to be used to meet the base load. The incremental cost of the conventional generation would depend on the mix of different generation equipment in the power pool and the cost of the primary fuel. The question is, if the SPS generated energy were priced at the incremental costs of the base load alternatives, what type of economic pressures would be experienced by the corporation owning the SPS? How much of a return on the stockholder's investment would the corporation be able to pay under these circumstances, and what would be the repayment schedule? These questions would be best answered by examining the cash flow of the hypothetical corporation.

Under certain economic conditions, it is possible for the corporation that owns the SPS to sell energy to the utilities at a price slightly less than the incremental cost associated with conventional generators and still allow for capital recovery and a reasonable rate of return to its stock/bond holders. However, the ability to every pay dividends would depend on the federal government's inability to control inflation. Even if it is eventually possible to recover all of the SPS capital costs, it will not be possible to begin repaying the stock/bond holders until after the year 2010. The risks associated with this type of pricing scheme are likely to be too high for any private corporation; only the federal government is able to assume such a risk.

When the SPS begins operation in 1994, the parent corporation will owe their stock and/or bond holders approximately $7.6 billion (1974),*

*"Space-Based Solar Power Conversion and Delivery Systems Study - Interim Summary Report", by ECON, Inc., Report No. 76-145-IB, March, 1976.

the capital cost of the SPS (D_o); however, it will take some time before this money can be repaid. During the first year of operation, the corporation will incur expenses equal to $513 million (1974) for system maintenance, taxes and insurance plus the amount $i_{cc}D_o$, the cost of using the capital during that year. On the other hand, it will receive revenues equal to $ICxE_{SPS}$.* If there is no inflation between now and 1994, the revenues received when the alternative base load generators are nuclear or coal-fired are insufficient to cover the $513 million operating expenses. The revenue received when the alternative is oil-fired generation is sufficient to cover operating expenses and service the debt (principal and interest in equal payment) if the discount rate is only .03%.

3.4.2 Calculated Maximum Discount Rates

Three different types of base load generators that might provide the base load during the years from 1994 to 2024 are:

- Nuclear (light water reactors) generators
- Coal-fired generators; and
- Oil-fired generators.

The incremental costs associated with operating these generators and the revenues that could be realized by the corporation if the SPS energy were priced the same as these incremental costs are given in Table 3.1.

If the SPS revenues are to be fixed by a consideration of the conventional alternatives, the revenues (and costs) must inflate with time or it will never be possible to provide a reasonable return to the investors. However, it takes some time to perceive the effects of inflation, i.e. during the first years, the corporation's debt will increase substantially and begin to decrease only after the inflationary sprial has had time to affect a significant increase in fuel prices.

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*1. D_o = The capital cost of the SPS.
2. i_{cc} = The average discount rate paid to stock/bond holders.
3. IC = The incremental cost of conventional base load generators.
4. E_{SPS} = The energy delivered by a 5 GW SPS in 1 year = 4.16×10^{10} kW-hrs.

Using the equations derived in Appendix C, different assumed rates of inflation and the assumption that all debt was to be repaid by the year 2024. The maximum allowed rate of return that the corporation could pay to stock/bond holders have been calculated. The maximum rates of return that the corporation could pay (given that the corporation revenues are set at the fuel costs of the alternative generation) are given in Table 3.2 through 3.4. The blanks in these tables indicate that the maximum allowable discount rate is either zero or that under the indicated conditions , the debt can never be zero. The numbers in parenthesis are the real maximum rates of return to the investors, i.e.

$$i_{real}(max) = \frac{1+i_{cc}(max)}{1+i_i} - 1$$

TABLE 3.1

Incremental Costs of Conventional Generation

Energy Source	IC $\left(\frac{\text{mills}}{\text{kW-hr}}\right)$ *	REV (10^6 dollars)
Light water reactor	6	$250\ (1+i_f)^{20}$
Coal	10.9	$453\ (1+i_f)^{20}$
Oil	29	$1210\ (1+i_f)^{20}$

*"Economic Assessment of the Utilization of Fuel Cells in Electric Utility Systems", by PSE&G, EPRI EM-336, Project 729-1, November, 1976.

TABLE 3.2

Maximum Allowed Discount Rate As a Function of Inflation*

Revenues Set Equal to Fuel Costs of Nuclear Generator

i_c \ i_f	.04	.06	.08	.1
.04	-	-	.067 (.027)	.142 (.098)
.06	-	-	-	.184 (.023)
.08	-	-	-	-
.1	-	-	-	-

TABLE 3.3

Maximum Allowed Discount Rate as a Function of Inflation*

Revenues Set Equal to Fuel Costs of Coal Generators

i_c \ i_f	.04	.06	.08	.1
.04	-	.060 (.019)	.145 (.101)	.231 (.184)
.06	-	-	.077 (.016)	.163 (.097)
.08	-	-	-	.098 (.017)
.1	-	-	-	-

*Numbers in parentheses are the "real" rates of return.

TABLE 3.4

Maximum Allowed Discount Rate as a Function of Inflation

Revenues Set Equal to Fuel Costs of Oil Generators

i_c \ i_f	.04	.06	.08	.1
.04	.122 (.079)	.230 (.183)	.358 (.306)	.529 (.470)
.06	-	.143 (.078)	.248 (.177)	.374 (.296)
.08	-	-	.161 (.075)	.266 (.172)
.1	-	-	-	.180 (.073)

The maximum allowable discount rates in Table 3.4 indicate that under most economic conditions, it would be possible to set the price of SPS energy in the proposed manner (for oil) and the corporation would still make a profit. However, it is unlikely that oil will be used to meet the base load in the years frmm 2004 to 2024 and these particular numbers should be used with great caution.

Cash Flow

It has been shown that if there is significant inflation over the years, the price of SPS energy can be set at the fuel cost of alternative generators, and the corporation would still make a profit. However, the number of years that must pass before the corporation would <u>begin</u> to pay back the incurred debt can be large. This year depends on the inflation rates, the discount rate and the magnitude of the revenues received from the sale of SPS energy. We have investigated two examples in detail, i.e. the total debt and the debt incurred each year as a function of time have been calculated and the results are shown in Figures 3.6 and 3.7.

The years that must pass before the corporation can begin to repay the debt (assuming that the rate of return is set at the maximums given in Tables 3.2 and 3.4) have been calculated and are shown in Tables 3.5 through 3.7. There are blanks in these tables when no acceptable value of i_{cc} was found.

TABLE 3.5

Year ΔD Becomes Negative as a Function of Inflation*

Revenues Set Equal to Fuel Costs of Nuclear Generator at Maximum Allowable Discount Rates (See Table 3.2)

i_i \ i_f	.04	.06	.08	.1
.04	-	-	18 (2012)	22 (2016)
.06	-	-	-	16 (2010)
.08	-	-	-	-
.1	-	-	-	-

*Numbers in parentheses are dates the debt begins to be repaid.

TABLE 3.6

Year ΔD Becomes Negative as a Function of Inflation*

Revenues set Equal to Fuel Costs of Coal Generator at Maximum Allowable Discount Rates (See Table 3.3)

i_i \ i_f	.04	.06	.08	.1
.04	-	15 (2009)	21 (2015)	24 (2018)
.06	-	-	18 (2012)	22 (2016)
.08	-	-	-	20 (2014)
.1	-	-	-	-

TABLE 3.7

Year ΔD Becomes Negative as a Function of Inflation*

Revenues set Equal to Fuel Costs of Oil Generator at Maximum Allowable Discount Rates (See Table 3.4)

i_i \ i_f	.04	.06	.08	.1
.04	16 (2010)	17 (2011)	17 (2011)	17 (2011)
.06	-	21 (2015)	23 (2717)	23 (2017)
.08	-	-	22 (2016)	23 (2017)
.1	-	-	-	22 (2016)

*Numbers in parentheses are dates the debt begins to be repaid.

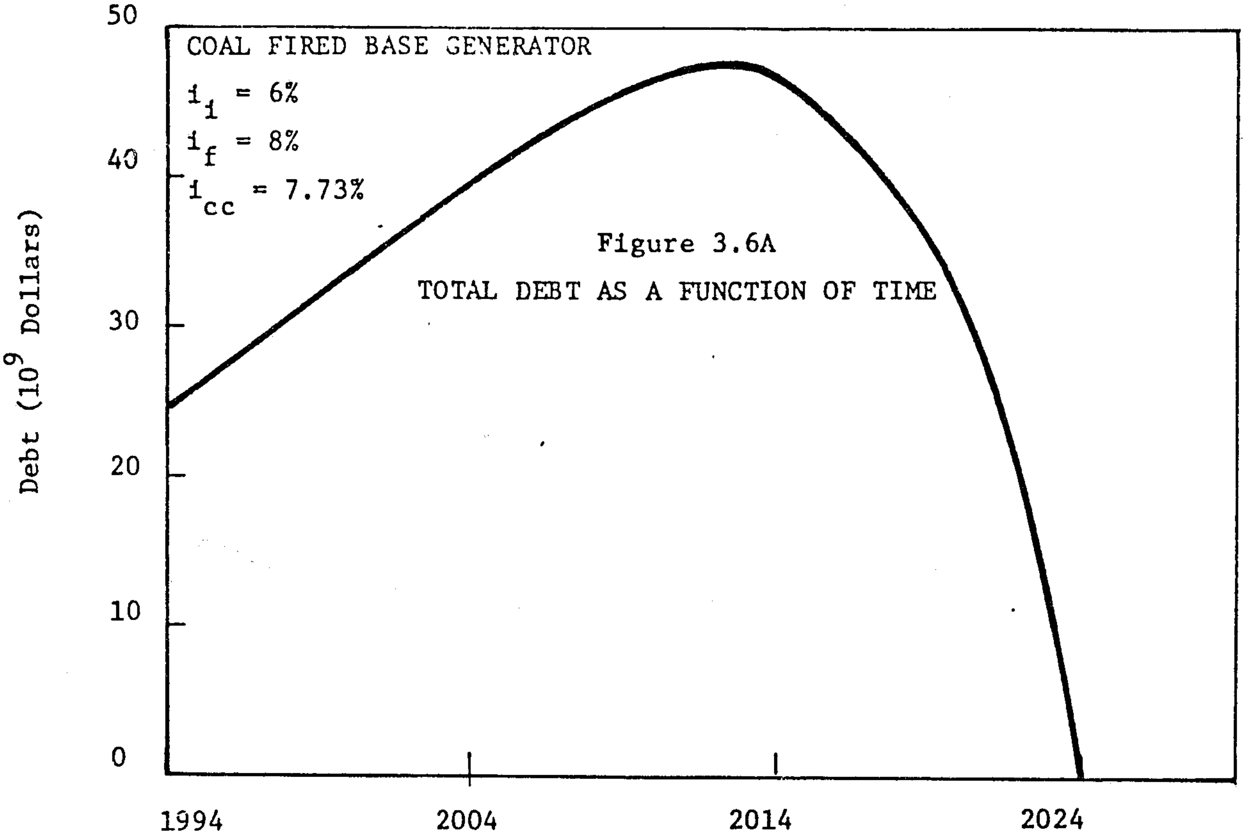

Figure 3.6A

TOTAL DEBT AS A FUNCTION OF TIME

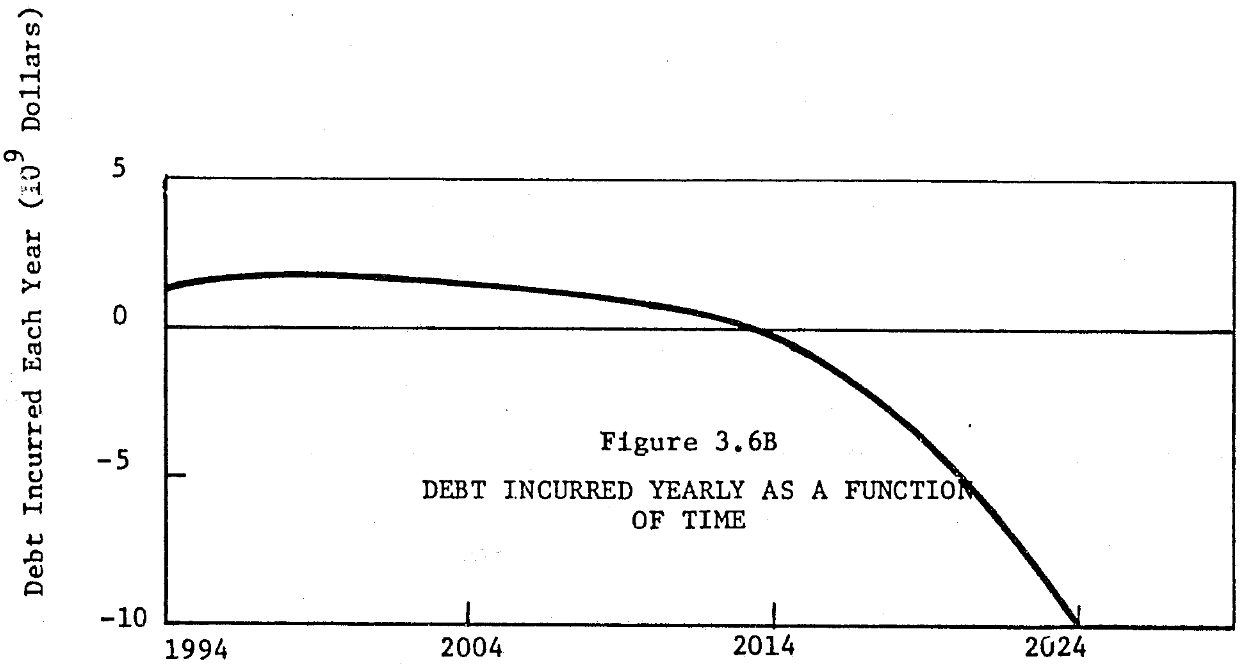

Figure 3.6B

DEBT INCURRED YEARLY AS A FUNCTION OF TIME

C-2

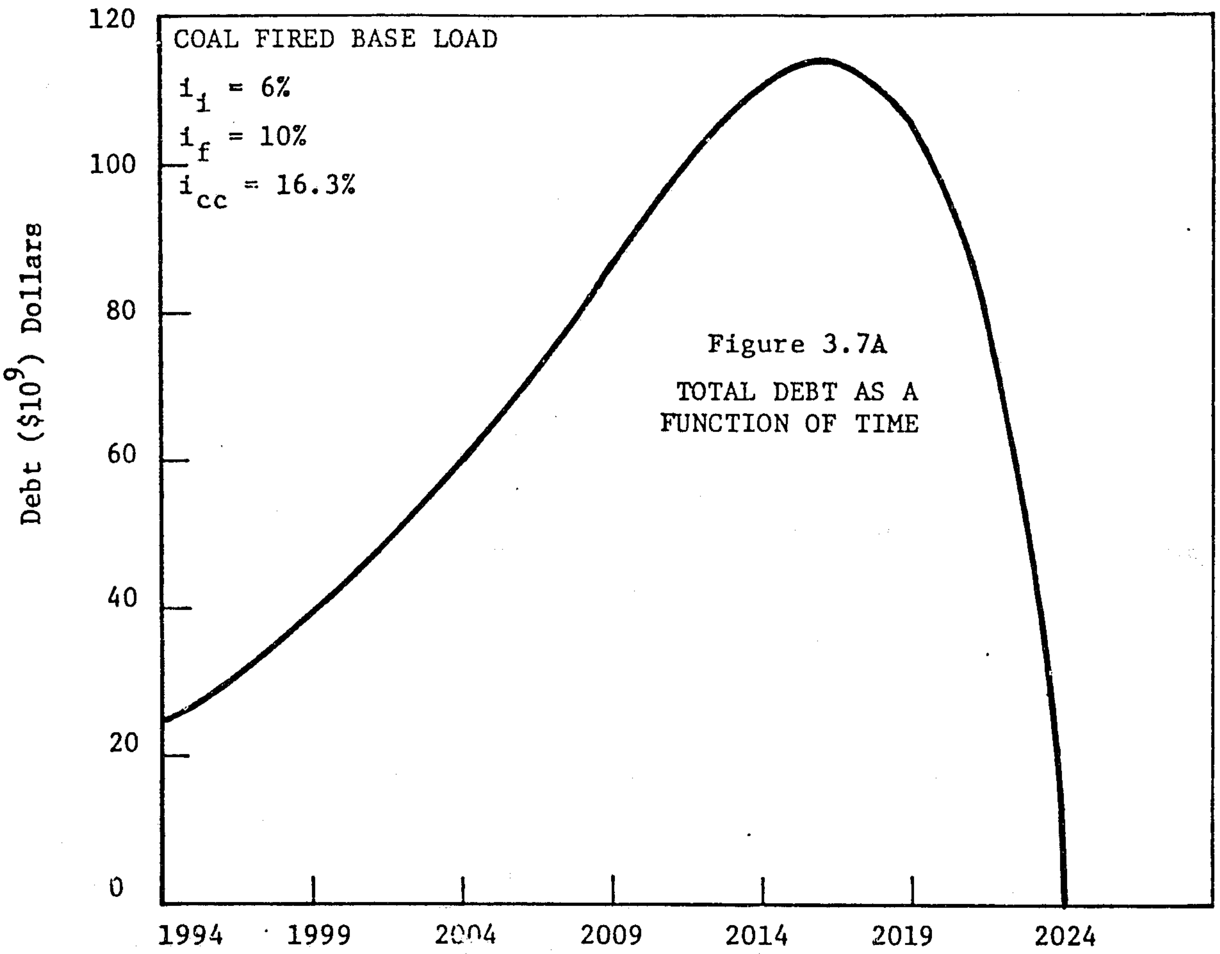

Figure 3.7A

TOTAL DEBT AS A FUNCTION OF TIME

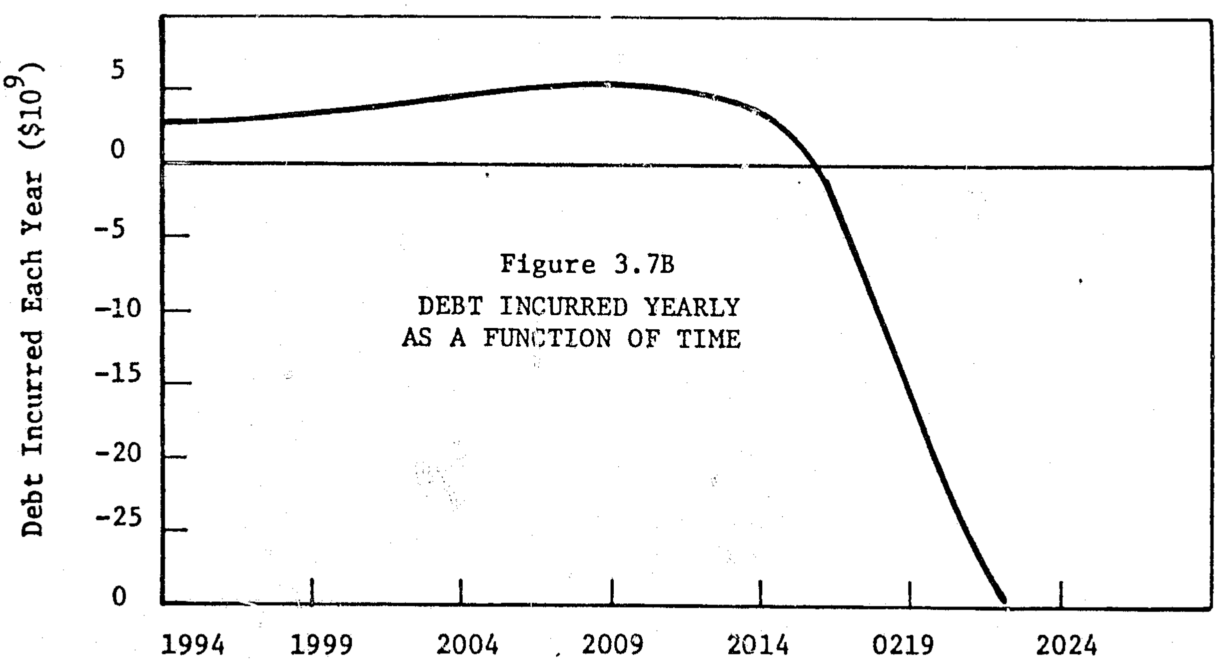

Figure 3.7B

DEBT INCURRED YEARLY AS A FUNCTION OF TIME

4.0 UTILITY PARTICIPATION IN THE SPS RD&D PROGRAMS

Introduction and Summary

While the participation of the electric utilities in the SPS research, design and development (RD&D) program would be desirable, utility activities in this area are likely to be very limited during the next five years. EPRI's budget for all solar energy research during this time period is only 2% of EPRI's total budget.

The total research EPRI budget for the next five years is roughly $1 billion, including an allowance for inflation. Of this, only $20* million (∿ $4 million/yr.) has been allocated for all forms of solar energy research, including solar heating and cooling. The solar energy budget for 1976 was $2.9 million.** Unless EPRI's priorities shift significantly, the funding available from this source to support SPS related R&D will be small compared to the total requirements for the SPS ($44 billion).***

The probability of attracting the substantial participation by individual utilities in SPS related research is also very small; utility research priorities are primarily near-term and investment in the SPS is unlikely to be attractive.

Regulatory Restrictions

The participation of the electric power utilities in RD&D programs was, until recently, severely limited by their ability to finance the associated costs. Until recently, few state regulatory commissions allowed utilities to include the cost of RD&D programs in their statement of operating costs and these programs had to be financed out of

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*Private Communication; consistent with published information.

**"A Summary of Program Emphasis for 1976", Electric Power Research Inst.

***ECON, Inc., "Space-Based Solar Power Conversion and Delivery Systems Study", Report No. 76-145-IB, March, 1976.

profits. The regulatory argument was that today's consumer should not be required to pay the costs of developing the technology required to meet the needs of future consumers.* This situation generally changed about four years ago; however, the fraction of RD&D costs allowed in the rate base still varies from state to state.

While it can be argued that substantial benefits might accrue to the utilities from participation in the design, development and testing of those SPS components which will directly affect the SPS utility interface, the utilities' ability to contribute to the development of the support equipment (e.g., launch vehicles) will be limited. Hence, the electric power utilities are unlikely to perceive any legitimate role for themselves in the latter area nor are the regulatory commissions likely to allow the associated costs to be included in the rate base.

Electric Power Research Institute

The Electric Power Research Institute (EPRI) was formed in 1973 under the voluntary sponsorship of many of the electric utilities - private, public and cooperative. Its mission was to conduct a broad, coordinated program of R&D with the aim of improving electric power production, transmission, distribution, and utilization.

The EPRI program emphasis is primarily on those technologies which are likely to have a significant impact on the utilities before 2000. However, it is recognized that very long lead times, on the order of decades for various systems, make it necessary to begin the development of credible technical options decades ahead of the projected need. Three different time frames, indications of when the research results are likely to become commercially available to the utilities, have been defined. These time frames, their present definitions and their approximate allocation of EPRI research funds

*This is the same rationale used to disallow the inclusion of CWIP (Cost of Work in Progress) from the rate base.

are*

- Near-term (1976 - 1985) 45%
- Mid-term (1985 - 2000) 45%
- Long-term (beyond 2000) 10%

The SPS is now perceived by EPRI to be a "long-term" technology** and shares the quest for funds with other "long-term" technologies, such as:

- Fusion
- Electric power generation from solar energy
- Super-conducting magnetic energy storage
- Cryoresistive and super-conducting transmission lines

Given the relative emphasis of the EPRI on those technologies which are likely to be commercailly available before the year 2000, the probability that it will divert a substantial amount of resources to SPS must be considered small.

R&D Sponsored by Individual Utilities

Individual utilities directly support R&D projects of their own. These utility funds, however, are unlikely to be available to support SPS related work. Utility projects usually address the utility's more immediate problems;*** for example, testing semi-conducting glazes which might reduce high voltage ceramic insulator failure rate. Most of these projects deal with "near-term" technologies, and the funds that support these projects are not likely to be available to support SPS research.

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*"A Summary of Program Emphasis for 1976", Electric Power Research Inst.

**Private Communication: consistent with published information.

***"1976 Report of Member Electric Corporations of the New York Power Pool and the Empire State Electric Energy Research Corporation (ESEERCO) pursuant to Article VIII, Section 49-b of the Public Service Law".

Some utilities have been recognized for their participation in solar energy projects, principally because one of their staff, either from the research or the planning departments, has participated in one or more key studies. These individuals can make a major contribution, but it should be remembered that the time available for these studies is often limited and other (near-term) tasks usually have priority over more esoteric subjects.

5.0 UTILITY LIABILITY DUE TO THE ADVERSE EFFECTS OF SPS RELATED ACTIVITIES

Introduction and Summary

Whoever owns the SPS - the electric utilities, a private or semi-private corporation or a government agency - this owner could be liable for all the adverse effects that could result from SPS related activities; the cost of these liabilities would presumably be added to the cost of SPS generated electrical energy via the cost of insurance. At this point in time, too little is known about the potential adverse effects to either

- Identify all the possible liabilities,
- Estimate the magnitude of all identified liabilities,
- Reliably estimate the cost of meeting the liabilities, or
- Determine whether the electric utilities would assume these liabilities.

It is possible to come to reliable conclusions on only a limited number of questions; questions such as

- What type and level of liability are the electric utilities likely to accept, and

- What level of liability would indicate that the hazards associated with the SPS are large enough to prevent its construction?

This latter question is beyond the scope of this study. An approximate answer to the first question can be obtained by examining the history of this issue vis-a-vis nuclear power plants.

In the past, the electric utilities have assumed the liabilities associated with the degradation of radio and television reception along transmission right-of-ways; they would be unlikely to accept this liability for the SPS. The liability for RFI caused by transmission lines is localized geographically and can be reasonably well defined before the transmission circuit is energized. On the other hand, the parallel problem associated with the interference of the SPS microwave beams with communications channels, radar, etc., may be neither localized geographically nor well defined before the first two SPSs are built. The utilities would be unlikely to accept this type of liability as a condition of purchasing an SPS unless the cost of SPS delivered energy were low enough to compensate for any foreseeable claims. The standard criterion used to purchase generators is that the total levelized costs (including the cost associated with RFI) shall be less than the alternative generation equipment. The present projected costs of the SPS are high compared to the nuclear alternatives. A very large, but undefined liability might increase the cost of the SPS or SPS energy significantly.

Classification of Hazards

The various public hazards of any industrial activity can be broken down into the following two categories;

- Hazards that pertain despite the proper design or operation of equipment, or

- Hazards that result due to improper and/or negligent operation of equipment.

Each of these categories can be further broken down into

- Localized, direct hazards, or
- Indirect hazards.

Potential hazards are associated with every industrial activity; examples of hazards that could pertain despite the proper design and/or operation of equipment are:

- General
  - low level radiation for nuclear power plants
  - air pollutants within clean air guidelines

- SPS Related Hazards
  - bio-sphere modifications due to the SPS microwave beam
  - interference of harmonics of the microwave beams with radio communications
  - genetic damage to wildlife passing through the microwave beam

Examples of hazards that could be created by the improper and/or negligent operation of equipment.

- General
  - radiation release from nuclear power plants
  - puncture of chemical tank cars in railroad accident
  - shocks from ungrounded metallic objects along the ROW of a UHV transmission line
  - fires, explosion, etc.

- SPS Related Hazards
  - radiation exposure of rectenna maintenance personnel
  - shuttle crashes

Localized, direct hazards are well defined hazards which can be unequivocally associated with a specific location and piece of equipment. The hazards, however small, associated with high voltage power transmission lines fall in this category. The electric shock that could be received when touching an ungrounded metal fence in the vicinity of a 765 kV overhead transmission line is large enough to cause severe discomfort. The source of this hazard is definitely the activated transmission line; the hazard exists only within a few hundred feet of the right-of-way.

Indirect hazards can either occur unpredictably, many miles from the origin of the hazard or else its origin cannot be unequivocally identified with a particular piece of equipment. The ground hazards posed by a crash of a space shuttle being used to build an SPS can occur hundreds of miles from the launch site or the SPS ground station.

Pollution problems also fall into this category. Air pollution standards are enforced by the Environmental Protection Agency, not via the mechanism of making the polluter liable for the damages caused by the pollution, because it is usually impossible to prove a direct cause and effect relationship between the hazard and the incremental pollution caused by specific polluters.

Interference of the SPS microwave beams with other users of the electromagnetic spectrum (RFI) may be similar to air pollution problems. RFI could cause a reduction in the signal to noise ratio in equipment located thousands of miles from the SPS rectenna. Because of the distance, it may be impossible to prove a direct cause and effective relationship between the RFI and the microwave beam of any particular SPS.

Interference of Microwave Beam with Other Users

While several studies of how the Microwave Beam might affect other users of the radio spectrum have been performed, there is still no definitive list of what equipment might be affected and how far from the rectenna site these effects might be observed. Various lists of the types of effects that might be observed have been compiled but the experiments that will indicate the magnitude of these effects and the resulting magnitude of the Radio Frequency Interference (RFI) have not been performed.

Even the optimistic estimates indicate that the SPS Microwave Beam will interfer strongly with the following units:

- Citizen's band radios,
- State police radar,
- Radio location for defense radar, and
- Air traffic control radar systems.

While it may be possible to retrofit this equipment with filters to remove much of the SPS induced noise from the received signal, because the magnitude of the interference is undefined, it is not now possible to reliably estimate the cost of each retrofit project nor the number of pieces of equipment that may need retrofitting in 1995. It is possible that _every_ single piece of equipment in these categories will require filters in order to function once the SPSs are built.

The Price Anderson Act

The utilities have previously faced an undefined liability question in connection with a new technology; that new technology was the light water reactor. The issues at that time were

- The Atomic Energy Act of 1954 as amended required, as a condition for a nuclear facility construction permit, proof of financial protection against public liability claims arising out of a nuclear incident.

- No one could reliably define the claims that might be lodged against a utility as a result of a major reactor incident.

- No one could reliably estimate the probability of various types of reactor incidents - this question is still the subject of a significant amount of controversy.

- The damage that could result from the worst possible nuclear incident was so high that the utilities would have had to purchase more insurance than was available from private carriers.

- The AEC was anxious to encourage the use of nuclear energy for generating electricity.

- The cost of electrical energy from light water reactors used in base load service was significantly lower than the energy derived from fossil fuels.

In 1955, the AEC* requested the private insurance industry to study the problems involved in insuring private companies against reactor risks. In 1957, four private insurance pools were formed; NELIA and MAELU provided liability insurance in amounts up to $46.5 and $13.5 million per incident, respectively. These policies cover third party liability but do not cover damage to the on-site property of the insured; damage to the property of the insured is covered through joint policies from NEPIA and MAERP. The Price-Anderson Act was passed in 1957. The Price Anderson Act essentially limited the required utility insurance coverage for each accident to the level at which insurance coverage was privately available; all other insurance coverage (up to $500 million per incident) was to be purchased from the government. Liabilities over the limits set by the Price Anderson Act were to be disallowed.

It appears that the question was not how much of a liability would the utilities accept but how much of a liability would an insurance company or consortium of insurance companies accept and for what price? The answer in 1957 was $60 million per incident. The cost of this insurance was to depend upon the specific reactor type, its use, its rated thermal output, the degree of containment, the location of the facility, the population density of the environment, etc. The desirability of special legislation to address those issues for the SPS which were addressed by the Price Anderson Act for the lightwater reactor, might be addressed in future studies.

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*J.F. Hogerton, Arthur D. Little, Inc., The Atomic Energy Deskbook, Reinhold Publishing Corporation, New York, 1963.

APPENDIX A

CALCULATIONS OF THE POWER POOL GENERATING MARGINS REQUIRED TO MEET THE LOLP CRITERIA

A.1 Introduction

A variety of criteria are available to assess the reliability with which terrestrial power pools meet the demand for electric power. Of these, one of the most common is the Loss of Load Probability (LOLP), the probability that the demand for power shall exceed its availability. The most commonly used power pool design criteria is that despite the inherent fallibility of generating equipment, the demand for power shall exceed the available generating capacity for only one-tenth of a day each year (LOLP = .1 days/year). Extra generating capacity (reserve margin) must be installed in the power pool to ensure the ability of the pool to meet this criterion.

Power pools are usually made up of a variety of different types and sizes of generators and these generators each have a different forced outage rate. The larger the generator capacity, the higher the likely forced outage rate. Calculating the LOLP of such a power pool and then the required reserve margin using standard techniques* is conceptually simple but computationally complex.

Because of the limitations on the time and resources available for this program, a simpler model (as described in Section 2.3) of the generation mix has been used.

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* R. Billinton, et. al. "Power System Reliability Calculations," The MIT Press, Cambridge, Mass., 1973.

This Appendix contains the derivation of the equations used to calculate the LOLP for each of the maintenance intervals; the LOLP for the year is the average of the LOLP during each maintenance interval. The total amount of installed generating capacity required to meet this criteria and the scheduled maintenance requirements of each generator is also derived. A detailed description of the calculations for the power pools and generators considered in this study are presented in Section A.3.

A.2 Calculation of the LOLP

The probability of m out of a total of n machines are all available at the same time (available generating capacity = m GWe) is

$$\frac{n!}{(m)!\ (n-m)!}(.95)^{m}(.05)^{n-m}$$

The probability that m machines <u>or more</u> are available at the arbitrary time t is

$$\sum_{i=0}^{n-m}\frac{n!}{(m+i)!\ (n-m-i)!}(.95)^{m+i}(.05)^{n-m-i}$$

The probability that the demand for electric power between m GWe and (m-1)GWe can be met at the arbitrary time t <u>when it occurs</u> is

$$\frac{\delta t_m}{T}\sum_{i=0}^{n-m}\frac{n!}{(m+i)!\ (n-m-i)!}(.95)^{m+i}(.05)^{n-m-i}$$

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where δt_m, is the time during which the demand for power is between m and (m-1) gigwatts and T is the total time.

The probability of meeting the load, what ever it is and whenever it occurs is

$$\sum_{m=1}^{n} \frac{\delta t_m}{T} \sum_{i=0}^{n-m} \frac{n!}{(m+i)!\ (n-m-i)!} (.95)^{m+i} (.05)^{n-m-i}$$

The probability of not meeting the load is

$$\text{LOLP} = 1 - \sum_{m-1}^{n} \frac{\delta t_m}{T} \sum_{i=0}^{n-m} \frac{n!}{(m+i)!\ (n-m-i)!} (.95)^{m+i} (.05)^{n-m-i} \quad \text{(A-1)}$$

Manipulating equation A.1 using

$$\sum_{m=1}^{n} \frac{\delta t_m}{T} = 1 \text{ and } \sum_{i=0}^{n} \frac{n!}{i!\,(n-i)} (.95)^{i} (.05)^{n-i} = 1 \quad \text{(A-2)}$$

yields the equation used in this study to calculate the LOLP for each maintenance interval for the power pools that did <u>not</u> contain a Satellite Power System,

$$\text{LOLP}_\ell = \sum_{m=1}^{n_\ell} \frac{\delta t_{\ell m}}{T_\ell} \left(1 - \sum_{j=0}^{n_\ell - m} \frac{n_\ell!}{(n_\ell - j)!\,j!} (.95)^{n_\ell - j} (.05)^{j}\right) \quad \text{(A-3)}$$

where the subscript ℓ indicates that this equation holds independently for each maintenance interval. n_ℓ is the number of generators available (not off-line for scheduled maintenance) during the ℓ^{th} interval, T.

This equation was used to calculate the $LOPL_\ell$ for the various values of n_ℓ and the sets of $\frac{\delta t_{\ell m}}{T}$ in Tables A.1 to A.2; those values of n_ℓ which yielded an LOLP approximately equal to .1 days/year were used in the later calculations.

Power Pools that Contain One SPS

The method just described of calculating the LOLP for a power pool made up of a number of identical 1 GWe capacity generators must be modified slightly if the power pool also contains one or more 5 GWe SPSs.

The probability that a capacity of m GWe is available at an arbitrary time t is

$$P(m) = p(m)\cdot(1 - p\ (SPS)) + p\ (m - 5)\cdot p\ (SPS) \quad (A.4)$$

where P (m) = the probability that m GWe of capacity is available

p (m) = the probability that m one gigawatt generators are available

p (SPS) = the probability that the SPS is available

The probability of not meeting the load in the ℓ'th maintenance interval would thus be

$$LOLP_\ell = \sum_{m=1}^{n'_\ell+5} \frac{\delta t_{\ell m}}{T_\ell} \left[1 - \left(\sum_{j=0}^{n'_\ell-m} \frac{n'_\ell!}{(n'_\ell-j)!j!} (.95)^{n'_\ell-j} (.05)^j\right)(.05) - \left(\sum_{j=0}^{n'_\ell-m+5} \frac{n'_\ell!}{(n'_\ell-j)!j!} (.95)^{n'_\ell-j} (.05)^j\right)(.95)\right] \quad (A\text{-}5)$$

LOLP for the Year

The relationship between the average yearly value for the LOLP and the LOLPs for the individual maintenance intervals is the same as the relationship when there is no SPS in the power pool. However, when the SPS must be taken off-line for maintenance or is shut down because of the effects of the earth eclipses, this must be done explicitly. Those maintenance intervals during which the SPS in not on-line are specified and the LOLPs for those intervals are calculated as if the SPS did not exist. The yearly average LOLP is calculated for several different assumed numbers of conventional machines in the power pool.

We assumed that the year was broken into 14 equal maintenance intervals (utilities use 13 maintenance intervals). The average yearly value for the LOLP would be -

$$\mathrm{LOLP} = \frac{1}{14}\sum_{\ell=1}^{14} \mathrm{LOLP}_{\ell} \qquad \text{(A-6)}$$

The ℓth maintenance interval may contain one, two, three, six, or no SPSs. If the LOLP for every interval is just slightly less than .1d/year, then the yearly LOLP is just slightly less than .1d/year.

Number of Generators Required in the Power Pool

Enough generating capacity must be available during each maintenance interval to meet the LOLP criterion and yet be able to take each machine off-line for scheduled maintenance for the required number of intervals (assumed in this model to be 3 intervals out of every 14) each year. This defines the total installed generating capacity required for a power pool and thereby the installed generating margin (Margin = total minus peak demand).

The total required number of one gegawatt generators, n, can be defined by the following equation:

$$\sum_{\ell=1}^{14} \frac{n-n_\ell}{a} \geqslant n \tag{A-7}$$

where n_ℓ is the number of <u>conventional</u> generators required to meet the LOLP criterion during the ℓ'th maintenance interval and "a" equals the number of maintenance intervals per year when each generator must be off-line. A 5 GWe SPS may or may not be on-line during the ℓ'th interval; its availability should be explicity assumed when deriving n_ℓ.

A.3 Description of Calculations and Results

The total amount of generation capacity required to ensure that each candidate power pool's demand for electric power is reliably met had been calculated for the following circumstances:

- No SPS in the power pool
- Power pool includes one or more SPSs with the following scheduled maintenance requirements.
  - No scheduled maintenance requirements
  - Scheduled maintenance for three maintenance intervals/ year
  - Shutdown for total earth eclipse period (four maintenance intervals/year)

A.3.1 Length of Time During Which Demand is Between m and m-1 GWe

$\delta t_{\ell m}$ is the length of time (hours) during each maintenance interval, ℓ, when the demand for power is between m and m-1 GWe. Using equation 2.8, it is possible to calculate the values of $\delta t_{\ell m}$ for each maintenance interval for the primary power pools. The results of these calculations are shown in Tables A.1, A.2 and A.3. Those intervals for which no number is given have a $\delta t_{\ell m}$ of zero. These tables allow the reader to appreciate the non-linear dependence of $\delta t_{\ell m}$ on ℓ and m.

In the composite power pool, the output from the SPS should be fed into whichever power pool has the larger demand for power <u>at that time</u>. For 12 hours each day, the power output of the SPS is delivered to P_- and for the rest of the day, the power from the SPS is delivered to P_+.

TABLE A.1

LENGTH OF TIME (HOURS) DURING WHICH POWER DEMAND IS BETWEEN m and m-1 GWe

30 GWe POWER POOL

m	MAINTENANCE INTERVALS #1&8	#2,7,9&14	#3,6,10&13	#4,5,11&12	TOTAL
30 GWe	88.8	2.9			189.2
29	49.9	24.6			198.2
28	37.6	33.1			207.6
27	32.4	37.8			216.0
26	29.7	43.0			231.4
25	28.0	46.0	.9		243.6
24	27.0	37.1	13.9		258.0
23	26.7	32.7	22.7		275.0
22	26.9	30.8	30.3		298.2
21	27.6	30.0	37.1		323.6
20	29.1	30.0	44.6		356.6
19	31.1	31.0	52.7		397.0
18	35.2	32.8	49.7	13.3	453.6
17	43.5	36.4	41.7	36.9	547.0
16	79.0	44.3	39.9	72.1	783.2
15	31.7	65.0	40.6	79.3	803.0
14		45.7	43.6	56.4	582.8
13		20.8	54.9	51.3	508.0
12			64.1	50.9	460.0
11			52.3	54.6	427.6
10			33.7	67.2	403.6
9			1.0	95.5	386.0
8				46.8	187.2
TOTAL HRS	624	624	624	624	8736

TABLE A.2

LENGTH OF TIME (HOURS) DURING WHICH POWER DEMAND IS BETWEEN m and m -1GWc

40 GWe POWER POOL

m	MAINTENANCE INTERVALS #1&8	#2,7,9&14	#3,6,10&13	#4,5,11&12	TOTAL ----
40 GWe	70.7				141.4
39	45.8	13.7			146.4
38	32.5	21.5			151.0
37	27.4	25.5			156.8
36	24.6	27.9			160.8
35	22.9	31.0			169.8
34	21.6	33.3			176.4
33	20.8	34.6	.9		183.6
32	20.4	28.3	9.4		191.6
31	20.0	25.4	14.6		200.0
30	20.0	23.8	19.6		213.6
29	20.3	22.9	23.4		225.8
28	20.6	22.5	27.2		240.0
27	21.3	22.4	31.0		256.2
26	22.4	22.7	35.8		278.8
25	23.7	23.3	40.3		301.8
24	25.8	24.4	36.4	7.8	326.0
23	29.6	26.0	34.3	20.9	384.0
22	36.5	28.9	30.4	34.1	444.8
21	65.6	34.2	30.0	59.5	626.0
20	31.8	49.8	30.3	63.2	636.8
19		40.8	31.6	45.2	470.4
18		28.4	34.5	40.2	412.4
17		12.8	42.9	38.2	375.6
16			49.7	38.0	350.8
15			42.5	39.6	328.2
14			35.4	42.9	313.2
13			22.9	52.2	300.4
12			1.0	71.7	290.8
11					
TOTAL HRS	624	624	624	624	8736

TABLE A.3

LENGTH OF TIME (HOURS) DURING WHICH POWER
DEMAND IS BETWEEN m and m -1 GWe
50 GWe POWER POOL

m	MAINTENANCE INTERVALS #1&8	#2,7,9&14	#3,6,10&13	#4,5,11&12	TOTAL
50 GWe	56.6				113.2
49	44.3	6.7			115.4
48	29.6	14.5			117.2
47	25.6	18.8			126.4
46	21.8	20.6			126.0
45	19.9	22.4			129.4
44	18.7	23.7			132.2
43	17.7	26.0			139.4
42	17.0	26.7			140.8
41	16.6	28.1	.9		149.2
40	16.3	23.0	7.1		153.0
39	16.2	20.8	10.6		158.0
38	16.1	19.6	14.2		167.4
37	16.1	18.8	16.5		173.4
36	16.1	18.3	18.6		179.8
35	16.3	18.0	21.9		192.2
34	16.6	17.9	23.7		199.6
33	17.2	18.0	26.8		213.6
32	18.2	18.2	29.1		225.6
31	19.1	18.7	33.0		245.0
30	20.5	19.4	31.7	4.8	264.6
29	22.5	20.3	26.6	14.0	288.6
28	25.9	21.7	24.9	21.8	325.4
27	32.3	23.9	24.2	30.9	380.6
26	56.5	28.1	23.9	50.7	523.8
25	31.1	39.6	24.1	53.2	529.8
24		36.2	24.8	38.0	396.0
23		27.6	26.2	33.6	349.6
22		19.4	28.7	31.4	318.0
21		8.7	35.5	30.5	298.8
20			39.6	30.4	280.0
19			37.2	30.9	272.4
18			30.6	32.6	252.8
17			26.1	36.0	248.4
16			16.8	42.8	238.4
15			1.0	57.7	234.8
14				56.5	226.0
13					
TOTAL HRS	624	624	624	624	8736

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Each power pool must be evaluated as if it were completely made up of conventional generators for half of the day and made up of conventional generator plus one 5 GWe SPS for other half of the day. There must be one set of $\delta t_{\ell m}$'s for that half of the day when the demand for power in one particular power pool is greater than in the other and another set when the conditions are reversed. These two sets of $\delta t_{\ell m}$, the same for each 30 GWe power pool, are given in Table A.4. The set of numbers labelled H is the set that applies when the demand for power in the candidate power pool is higher than the demand in the other power pool and is used to calculate the LOLP when the power pool includes the SPS. The set of numbers labelled L apply when the opposite is true and is used to calculate the LOLP when the power pool includes only the conventional generators of the previous calculation. The LOLP used in the final analysis is the average of the two different LOLPs.

A.3.1 Calculational Techniques - Simple Power Pools

Using Equations A.3 and A.5 and the values of $\delta t_{\ell m}$ in Tables A.1, A.2 and A.3, the LOLP was calculated for the three power pools described by Equation 2.8 as a function of the following parameters

- Maintenance interval
- Number of available conventional generators
- Number of available SPS in the power pool
  - No SPS
  - One SPS
  - Two SPS

TABLE A.4

LENGTH OF TIME (HOURS) DURING WHICH POWER DEMAND IS BETWEEN m and m-1 MWe

COMPOSITE (30 GWe + 30 GWe) POWER POOL

m	Maintenance Interval #1,8 H	#1,8 L	#2,7,9,14 H	#2,7,9,14 L	#3,6,10,13 H	#3,6,10,13 L	#4,5,11,12 H	#4,5,11,12 L	TOTAL
30	82.1	6.7	2.9						189.2
29	26.3	23.6	22.3	2.3					198.2
28	18.8	18.8	24.7	8.4					207.6
27	16.2	16.2	25.7	12.1					216.0
26	14.8	14.9	28.2	14.8					231.4
25	14.0	14.0	28.6	17.4	.9				243.6
24	13.5	13.5	18.9	18.2	12.5	1.4			258.0
23	13.4	13.3	16.3	16.4	17.0	5.7			275.0
22	13.5	13.4	15.4	15.4	21.1	9.2			298.2
21	13.8	13.8	15.0	15.0	24.6	12.5			323.6
20	14.6	14.5	15.0	15.0	28.7	15.9			356.6
19	15.6	15.5	15.5	15.5	33.2	19.5			397.0
18	17.6	17.6	16.4	16.4	26.9	22.8	12.1	1.2	453.6
17	21.8	21.7	18.2	18.2	20.9	20.8	28.2	8.7	547.0
16	16.1	62.9	21.7	22.6	20.0	19.9	53.8	18.3	783.2
15		31.7	17.0	48.0	20.3	20.3	45.7	33.6	803.0
14			9.0	36.7	21.8	21.8	28.2	28.2	583.6
13			1.2	19.6	24.6	30.3	25.6	25.7	508.0
12					23.7	40.4	25.5	25.4	460.0
11					14.4	37.9	27.3	27.3	427.6
10					4.1	29.6	33.0	34.2	403.6
9						1.0	29.6	65.9	386.0
8							3.2	43.6	187.2
TOTAL HRS	312	312	312	312	312	312	312	312	8736

• Six (three)* SPS

The calculated value of the LOLP never equaled .1 day/year exactly. However, it was possible to identify the minimum number of available conventional generators required to yield LOLPs of approximately .1 days/year for each maintenance interval independent of the others. (Equation A.5 clearly indicates that meeting this condition is sufficient to ensure that the LOLP during the whole year will be approximately equal to .1 day/year.) The number of pieces of conventional equipment needed to meet this criteria during each maintenance interval, n_ℓ, are given in Tables A.5, A.6, and A.7 in the columns labelled NO SPS and ONE, TWO, or SIX SPSs with "no maintenance required".

Six SPSs in Power Pools

Including six SPS generators (total generating capacity = 30 GWe) in a power pool whose peak yearly demand is only 30 GWe would clearly be uneconomical in that their outputs would be used in that power pool only 56% of the year. No calculations were performed for this case. The economics of including six SPSs in a 40 GWe power pool are also questionable. However, these calculations were performed. In the 50 GWe power pool, the six SPSs would have to be used to meet the intermediate loads; the daily minimum is always less than the combined output of the six units.

Scheduled Maintenance for the SPSs

If there is no need to schedule maintenance for the SPS, then the SPS is always on-line and the values of n_ℓ contained

*Three SPSs at a time are shut down for scheduled maintenance.

TABLE A.5

Required Number of Conventional Generators in a 30 GWe Power Pool as a Function of Maintenance Interval and Circumstances

MAINTENANCE INTERVAL	NO SPS	ONE SPS			TWO SPSs			SIX SPSs		
		No Maintenance Required	Maintenance Required	Eclipses	No Maintenance Required	Maintenance Required	Eclipses	No Maintenance Required	Maintenance Required	Eclipses
1	38–39	34–35	34–35	34–35	31–32	31–32	31–32	–	–	–
2	35–36	32–33	32–33	32–33	29–30	29–30	29–30	–	–	–
3	28–29	26–27	26–27	26–27	23–24	26–27	23–24	–	–	–
4	22–23	20–21	22–23	22–23	17–18	20–21	25–26	–	–	–
5	22–23	20–21	22–23	22–23	17–18	20–21	25–26	–	–	–
6	28–29	26–27	26–27	26–27	23–24	23–24	23–24	–	–	–
7	35–36	32–33	32–33	32–33	29–30	29–30	29–30	–	–	–
8	38–39	34–35	34–35	34–35	31–32	31–32	31–32	–	–	–
9	35–36	32–33	32–33	32–33	29–30	29–30	29–30	–	–	–
10	28–29	26–27	26–27	26–27	23–24	26–27	23–24	–	–	–
11	22–23	20–21	20–21	22–23	17–18	20–21	25–26	–	–	–
12	22–23	20–21	20–21	22–23	17–18	20–21	25–26	–	–	–
13	28–29	26–27	26–27	26–27	23–24	23–24	23–24	–	–	–
14	35–36	32–33	32–33	32–33	29–30	29–30	29–30	–	–	–
No. of Conventional Generators Installed	38–39	35–36	35–36	36–37	31–32	33–34	34–35	–	–	–
Total Installed Capacity (GWe)	38–39	40–41	41–42	41–42	41–42	43–44	44–45	–	–	–
Installed Margin (GWe)	8–9	10–11	11–12	11–12	11–12	13–14	14–15	–	–	–
Percent Installed Margin	26.7–30%	33.3–36.7%	36.7–40%	36.7–40%	36.7–40%	43.3–46.7%	46.7–50%	–	–	–

TABLE A.6

Required Number of Conventional Generators in a 40 GWe Power Pool as a Function of Maintenance Interval and Circumstances

MAINTENANCE INTERVAL	NO SPS	ONE SPS			TWO SPSs			SIX SPSs		
		No Maintenance Required	Maintenance Required	Eclipses	No Maintenance Required	Maintenance Required	Eclipses	No Maintenance Required	Maintenance Required	Eclipses
1	47-48	45-46	45-46	45-46	41-42	41-42	41-42	25-26	25-26	25-26
2	45-46	43-44	43-44	43-44	39-40	39-40	39-40	22-23	23-22	23-22
3	37-38	35-36	35-36	35-36	31-32	35-36	31-32	14-15	27-28	14-15
4	28-29	26-27	28-29	28-29	23-24	26-27	28-29	6-7	19-20	28-29
5	28-29	26-27	28-29	28-29	23-24	26-27	28-29	6-7	19-20	28-29
6	37-38	35-36	35-36	35-36	31-32	31-32	31-32	14-15	14-15	14-15
7	45-46	43-44	43-44	43-44	39-40	39-40	39-40	22-23	22-23	22-23
8	47-48	45-46	45-46	45-46	41-42	41-42	41-42	25-26	25-26	25-26
9	45-46	43-44	43-44	43-44	39-40	39-40	39-40	22-23	22-23	22-23
10	37-38	35-36	35-36	35-36	31-32	35-36	31-32	14-15	27-28	14-15
11	28-29	26-27	26-27	28-29	23-24	26-27	28-29	6-7	19-20	28-29
12	28-29	26-27	26-27	28-29	23-24	26-27	28-29	6-7	19-20	28-29
13	37-38	35-36	35-36	35-36	31-32	31-32	31-39	14-15	14-15	14-15
14	45-46	45-46	45-46	45-46	39-40	39-40	39-40	22-23	22-23	22-23
No. of Conventional Generators Installed	49-50	46-47	47-48	47-48	41-42	43-44	43-44	25-26	27-28	28-29
Total Installed Capacity (GWe)	49-50	51-52	52-53	52-53	51-52	53-54	53-54	55-56	57-58	58-59
Installed Margin (GWe)	9-10	11-12	12-13	12-13	11-12	13-14	13-14	15-16	17-18	18-19
Percent Installed Margin	22.5-25%	27.5-30%	30-32.5%	30-32.5%	27.5-30%	32.5-35%	32.5-35%	37.5-40%	42.5-45%	45-47.5%

TABLE A.7

Required Number of Conventional Generators in a 50 GWe Power Pool as a Function of Maintenance Interval and Circumstances

MAINTENANCE INTERVAL	NO SPS	ONE SPS			TWO SPSs			SIX SPSs		
		No Maintenance Required	Maintenance Required	Eclipses	No Maintenance Required	Maintenance Required	Eclipses	No Maintenance Required	Maintenance Required	Eclipses
1	58–59	55–56	55–56	55–56	52–53	52–53	52–53	35–36	35–36	35–36
2	56–57	53–54	53–54	53–54	49–50	49–50	49–50	32–33	32–33	32–33
3	46–47	43–44	43–44	43–44	39–40	43–44	39–40	22–23	35–36	22–23
4	35–36	32–33	35–36	35–36	28–29	32–33	35–36	12–13	25–26	35–36
5	35–36	32–33	35–36	35–36	28–29	32–33	35–36	12–13	25–26	35–36
6	46–47	43–44	43–44	43–44	39–40	39–40	39–40	22–23	22–23	22–23
7	56–57	53–54	53–54	53–54	49–50	49–50	49–50	32–33	32–33	32–33
8	58–59	55–56	55–56	55–56	52–53	52–53	52–53	35–36	35–36	35–36
9	56–57	53–54	53–54	53–54	49–50	49–50	49–50	32–33	32–33	32–33
10	46–47	43–44	43–44	43–44	39–40	43–44	39–40	22–23	35–36	22–23
11	35–36	32–33	35–36	35–36	28–29	32–33	35–36	12–13	25–26	35–36
12	35–36	32–33	32–33	35–36	28–29	32–33	35–36	12–13	25–26	35–36
13	46–47	43–44	43–44	43–44	39–40	39–40	39–40	22–23	22–23	22–23
14	56–57	55–56	55–56	55–56	49–50	49–50	49–50	32–33	32–33	32–33
No. of Conventional Generators Installed	60–61	56–57	57–58	58–59	52–53	54–55	54–55	34–35	37–38	39–40
Total Installed Capacity (GWe)	60–61	61–62	62–63	63–64	62–63	64–65	64–65	64–65	67–68	69–70
Installed Margin (GWe)	10–11	11–12	12–13	13–14	12–13	14–15	14–15	14–15	17–18	19–20
Percent Installed Margin	20–22%	22–24%	24–26%	26–28%	24–26%	28–30%	28–30%	28–30%	34–36%	38–40%

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in the columns labelled "No Maintenance" in the tables are always the appropriate values. This ability to ignore the scheduled maintenance requirements of the SPS equipment on the ground can be obtained by providing a second, completely redundant, ground station for the SPS. It should be noted that the forced outage availability has not been changed. This implies that the level of redundancy has not been significantly increased. What has changed is the ability to shut one ground station completely down for maintenance while keeping the second station operating. The implication that there is a zero probability of any interruption of the power delivered to either ground station should also be noted.

The values of n_ℓ in the columns labelled "Maintenance Required" and "Eclipses" are determined as follows: during those intervals when the SPS is scheduled to be removed from the power for maintenance, the power pool would resemble a completely conventional power pool. The appropriate values of n_ℓ would be those given in the columns labelled "No SPS". When the SPS is not off-line for maintenance, the appropriate values of n_ℓ are those in the columns labelled "No Maintenance".

The maintenance of a single SPS in a power pool would be scheduled for intervals 4, 5 and 11, (or 12), intervals during which the demand for power is near the minimum. The maintenance of each SPS in a power pool containing two SPSs would occur sequentially during intervals 3, 4 and 5 or 10, 11 and 12. Only one SPS would be off-line for scheduled maintenance at a time. Treating the periods when the sun is eclipsed by the earth as if they were removals of the SPS from service for scheduled maintenance is the simplest way of calculating the amount of conventional generating capacity required in the power pool. The SPS is assumed to be unavailable for power generation during maintenance intervals 4, 5,11 and 12. (104 days.)

When there are six SPSs in a power pool, only three would be unavailable at any one time because of scheduled maintenance. A separate set of n_ℓ's was calculated for maintenance intervals, 3, 4, 5, 10, 11 and 12 for a power pool containing three SPSs.

A.3.3 Calculational Techniques - Composite Power Pool

Calculating the required installed margin when the SPS is used to meet the load in two independent 30 GWe power pools whose times of peak demand differ by 3 hours is more complex than in the previous discussion. When there is no SPS in the composite power pool, each of the two 30 GWe power pools operate independently. The appropriate values for n_ℓ in each of these power pools are the same as those contained in Table A.5.

The times of peak demand for power in the two power consuming elements of the composite power pool are separated from each other by three hours. The variation in the power demand in the two pools with the time-of-day is shown in Figure 2.5. The output of the SPS at any particular time is fed to whichever of the two power pools has the highest demand for power at that time. Thus, for half of each day of the two power pools would operate as if it were a 30 GWe power pool which contained one 5 GWe SPS and for the other half of the day, each would operate as if it contained only conventional generators. The calculation of $LOLP_\ell$ (and consequently n_ℓ) for each of these two power pools took this shift into account explicitly.

Two different sets of values for $\delta t_{\ell m}$ have been calculated for each of the 30 GWe power pools. In one set of numbers the demand for electric power in the power pool being considered was higher than in the other. For the other set of numbers, the demand for electric power in the power pool being considered is lower than in the other. These sets of $\delta t_{\ell m}$'s (Table A.4) apply to each of the GWe power pools independently.

$LOLP_\ell$ for each of the two power consuming elements of the composite power pool was calculated independently with various assumed values of n_ℓ for both the L and H sets of $\delta t_{\ell m}$'s. The L set assumed that this pool contained n_ℓ conventional generators and the H set assumed that the pool contained the n_ℓ conventional generators plus a 5 GWe SPS. These two LOLPs were averaged to give the LOLP for each of the component power pools containing n_ℓ conventional generators for that particular maintenance interval. The values of n_ℓ which gave approximately the design LOLP (for one SPS) are entered in Table A.8 in the two columns labelled "No Maintenance Required".

If each of the component 30 GWe power pools contained only one SPS ground station; each of these stations would have to be shut down for 3 maintenance intervals each year. During these intervals the power pool whose antenna is shut down would not be able to accept power from the SPS and could be treated as if it were made up of only conventional generators. During the intervals when one power pool has its antenna shut down, the antenna in the other power pool would accept power from the SPS 24 hours a day.

TABLE A.8

Required Number of Conventional Generators in Each Portion of the Composite Power Pool (30 GWe and 30 GWe) as a Function of Maintenance Interval and Circumstances

MAINTENANCE INTERVAL	NO SPS		ONE SPS: No Maintenance Required		ONE SPS: Maintenance Required		ONE SPS: Eclipses	
	P_+	P_-	P_+	P_-	P_+	P_-	P_+	P_-
1	38-39	38-39	35-36	35-36	35-36	35-36	35-36	35-36
2	35-36	35-36	33-34	33-34	33-34	33-34	33-34	33-34
3	28-29	28-29	27-28	27-28	26-27	28-29	27-28	27-28
4	22-23	22-23	21-22	21-22	20-21	22-23	22-23	22-23
5	22-23	22-23	21-22	21-22	20-21	22-23	22-23	22-23
6	28-29	28-29	27-28	27-28	27-28	27-28	27-28	27-28
7	35-36	35-36	33-34	33-34	33-34	33-34	33-34	33-34
8	38-39	38-39	35-36	35-36	35-36	35-36	35-36	35-36
9	35-36	35-36	33-34	33-34	33-34	33-34	33-34	33-34
10	28-29	28-29	27-28	27-28	28-29	26-27	27-28	27-28
11	22-23	22-23	21-22	21-22	22-23	20-21	22-23	22-23
12	22-23	22-23	21-22	21-22	22-23	20-21	22-23	22-23
13	28-29	28-29	27-28	27-28	27-28	27-28	27-28	27-28
14	35-36	35-36	33-34	33-34	33-34	33-34	33-34	33-34
No. of Conventional Generators Installed	38-39	38-39	36-37	36-37	36-37	36-37	36-37	36-37
Total Installed Capacity (GWe)	76-78		77-79		77-79		77-79	
Installed Margin (GWe)	16-18		17-19		17-19		17-19	
Percent Installed Margin	26.7-30%		28.3-31.7%		28.3-31.7%		28.3-31.7%	

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APPENDIX B

CHANGE IN POWER POOL COSTS DUE TO SPS

When a five gigawatt SPS is included in a power pool (peak yearly demand = P_{max}) instead of five one gigawatt nuclear power plants (installed over a 5 - 8 year period), there is a significant decrease in the power pool fuel costs and a corresponding increase in the power pool fixed and operating costs. Since many utilities have separate fuel and fixed rates, the size of these individual changes may have a significant impact on the financial position of the utilities. In this Appendix, the equations used to calculate the changes in both cost categories are derived.

Fuel Cost Savings

When the SPS comes on-line, the fuel cost savings per kilowatt hour of energy sold (per unit fuel savings) during the first year would be

$$\text{p.u. fuel savings} = \frac{\text{energy delivered by the SPS x average cost of power pool energy}}{\text{total energy delivered by the power pool}}$$

It is expected that the SPS will deliver 4.16×10^{10} kW-hrs per year. The average cost of energy from the power pool is assumed to be \$.015/kW-hrs in 1974. If the cost of fuel inflates at the rate of i_f per year, the average cost of energy from the power pool, n years after 1974, would be $\$.015(1 + i_f)^n$ per kW-hr.

The amount of energy sold by the power pool each year is defined to be P_{max} x .56 x 8760 kW-hrs per year where P_{max} is the yearly peak power demand in 1994 and .56 is the assumed system load factor.* If the yearly peak demand grows at the rate of g per year, the peak demand would be $P_{max}(1 + g)^{n-20}$.

The total cost of fuel per kW-hr (p.u. fuel cost) of all the energy sold by the power pool would be the per unit cost if the generation mix remained the same <u>minus</u> the per unit savings caused by the SPS:

$$\text{p.u. fuel costs} = 15 \frac{\text{mills}}{\text{kW-hr}} (1 + i_f)^n \left\{ 1 - \left[\frac{4.75 \times 10^6 \text{ kW}}{.56 \, P_{max}(1 + g)^{n-20}} \right] \right\}$$

<u>Fixed and Operating Cost Increases</u>

The change in the fixed and operating costs of a power pool caused by installing an SPS in 1994 is the increase in costs caused by adding the SPS and a corresponding decrease caused by <u>not</u> adding the otherwise required conventional capacity.

The cost increases due to the SPS are the sum of the following capital recovery costs and the SPS operating costs;

- Capital recovery costs = $\$7.6 \times 10^9 (1 + i_i)^{20} \dfrac{i_{cc}}{1 - (1 + i_{cc})^{-30}}$

  where i_i = the inflation rate between 1974 and 1994, and

  i_{cc} = the discount rate.

*load factor = $\dfrac{\text{average demand per year}}{\text{peak demand per year}}$

- SPS operating costs = $\$513 \times 10^6(1 + i_1)^n$

  where n = the number of years since 1974.

Cost decreases are due to the deferral of the conventional generation capacity that would have been required that year. The amount of capacity deferred in 1994 would be $P_{max} \times g$ where g is the power pool growth rate. If all the deferred capacity is assumed to be in the form of nuclear generation capacity, the decrease in 1994 would be

$$P_{max} \times g \times \$490/\text{kW} \times (1 + i_1)^{20} \times f$$

where f is the fixed cost factor assumed to be .15. Forty-six percent (46%) of the fixed costs are assumed to continue to rise with inflation and the rest is fixed once the plant is built.

If the SPS had not been built, other conventional generation capacity $[P_{max} \cdot g \cdot (1 + g)]$ would have been built the following year. The savings associated with this capacity must be added to the savings due to conventional capacity deferrals from the previous year. This continued until the total amount of deferred conventional capacity equals 5 GWe. At that point, the cost of the extra reserve capacity must be added. Thereafter, the changes in the utilities fixed and operating costs are governmend by the general rate of inflation.

The per unit fixed and operating cost of the energy sold by the power pool is defined as follows:

$$\text{per unit fixed costs} = \frac{\$.025}{\text{kW-hr}} (1 + i_1)^{20+n} + \frac{\text{cost increases}}{.56 \times P_{max} \times (1 + g)^{n-20}}$$

APPENDIX C

CASH FLOW ANALYSIS - SPS ENERGY PRICED AT THE COST OF ALTERNATIVE BASE LOAD GENERATION

It is possible for the owner of an SPS to price the SPS energy to the utilities at the incremental cost of alternative base load generation; if the inflation rates are high enough, the SPS owner will eventually make a reasonable profit. The amount of debt incurred each year as a result of this pricing arrangement and the total corporate debt as a function of time, are derived in this Appendix. The maximum allowed rate of return is defined by the condition that the corporate debt shall be zero at the end of the SPS life (30 years). It is this rate of return (i_{cc}) which will determine if this pricing concept is feasible. The numbers of years that must pass before the corporation can <u>begin</u> to repay the stock/bond holders will also be important and can be derived from the maximum allowable discount rate.

Inflation Rates

It is possible to define two different inflation rates; the general inflation rate, i_i, and the fuel inflation rate i_f. The fuel inflation rate is the rate at which the price of fuel increases each year. While historically, these two rates have been roughly the same. This is unlikely to remain true as the more convenient fuels become scarce; it is the expectation of scarcity which is the basic rational for proposing to build the SPS. While i_f need not equal i_i, it is unlikely to be less than i_i. The general inflation rate affects the capital and

and operating costs of the SPS and the fuel inflation rate affects the revenues received.

Corporate Debt

At the beginning of year one (1994), the corporation's debt would be D_o. During this first year, the corporation would spend OC to operate, incur an additional debt of $D_o i_{cc}$ and receive revenues of REV. The corporation's debt at the end of year one would be:

$$D_1 = (1 + i_{cc})\ D_o + OC - REV \tag{3.4}$$

where

D_n = is the debt at the end of the n^{th} year after 1994

D_o = \$7.6 billion $(1 + i_i)^{20}$

i_i = general inflation rate

OC = is the operating cost in 1994 dollars

= \$513 million $(1 + i_i)^{20}$.

REV = is the revenue received in 1994 dollars

= IC $(1 + i_f)^{20} \times 4.16 \times 10^{10}$ (kW-hrs)

IC = the incremental cost of the alternative generation in 1974 dollars

i_f = the fuel inflation rate

The corporation's debt at the end of the n^{th} year would be:

$$D_n = D_{n-1}\ (1 + i_{cc}) + OC\ (1 + i_i)^{n-1} - REV\ (1 + i_f)^{n-1}$$

or

$$D_n = D_o \ (1+i_{cc})^n + OC\left\{\frac{(1+i_i)^n - (1+i_{cc})^n}{(i+i_i) - (1+i_{cc})}\right\}$$

$$-REV \left\{\frac{(1+i_f)^n - (1+i_{cc})^n}{(1+i_f) - (1+i_{cc})}\right\} \qquad (3.6)$$

The debt incurred during the nth year would be:

$$\Delta D_n = D_o \ (1+i_{cc})^{n-1} \ i_{cc} + OC\left\{\frac{i_{cc}(1+i_{cc})^{n-1} - i_i \ (1+i_i)^{n-1}}{(1+i_{cc}) - (1+i_i)}\right\}$$

$$- REV \left\{\frac{i_f \ (1+i_f)^{n-1} - i_{cc}(1+i_{cc})^{n-1}}{(1+i_f) - (1+i_{cc})}\right\} \qquad (3.7)$$