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THE ABILITY OF ELECTRIC UTILITIES WITH FGD TO MEET ENERGY DEMANDS

by

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SUMMARY

A more stringent New Source Performance Standard (NSPS) for SO_2 emissions is presently being considered. The implementation of this NSPS will require utilities to employ flue gas desulfurization (FGD) or equivalent SO_2 removal techniques on all new coal-fired boilers. The addition of FGD systems to all new coal-fired generating units will reduce a utility's ability to meet consumer demand because of reduced unit and system reliability and increased in-plant energy consumption. The FGD system can thus affect both generating unit and utility system adequacy. A reduction in individual utility system reliability may affect power pool reliability as well. Therefore, it is important to determine the overall impact of the widespread implementation of FGD on electric utilities.

This study evaluated the overall impact of FGD systems on U.S. electric reliability and adequacy through 2000. Coal-fired units on-line before 1986 and between 1985 and 2000 were considered separately for each of the nine National Electric Reliability Council (NERC) reliability regions. Different generation mixes and typical demand characteristics for each region were calculated. With this information, an assessment of the ability of each region to meet power demand (and to maintain reasonable and typical reserves) as a power pool with and without FGD was made. Several different FGD module configurations and expected module availabilities were considered. It was assumed that a generating unit would be required to be temporarily derated upon FGD module failure if a spare module were not available. Bulk power interchange capabilities which might be used in the event of such FGD-induced outages or reductions in capacity were also evaluated, as were expected system reserves.

This study concluded that the proposed NSPS would have little effect on system reliability and adequacy prior to 1985 because of long lead times required for the construction of new coal-fired generating units.

However, for the period between 1985 and 2000 it was found that the proposed standard would have a significant effect on system reliability and adequacy.

For four different FGD modular availabilities and configurations, nationwide additional capacity requirements in 2000 due to the impact of FGD availability and energy requirements were found to range from approximately 38,000 megawatts to 105,000 megawatts.

The additional capacity requirement due to FGD is the result of two factors: (1) the increase in in-plant power consumption required to operate the FGD units (an "energy penalty") and (2) the increase in capacity needed to offset a decrease in system reliability. The increase in capacity to offset the energy penalty associated with FGD is approximately 28,000 megawatts for the 1985-2000 period; the increase associated with reliability ranges from approximately 9,000 megawatts to 77,000 megawatts. These estimates do not include the effects of any FGD systems on the additional capacity required. Total new coal capacity that is to go on-line between 1985 and 2000 was projected by Teknekron to be approximately 534,000 megawatts. It should be noted that the upper limit of the range of these estimates associated with reliability, 77,000 additional megawatts, assumes an FGD modular availability of 80%, no redundance in FGD modules to provide backup capability during FGD module outages, nor any other mitigating factors.

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SECTION 1

INTRODUCTION

This report presents the results of work performed by Radian Corporation of Austin, Texas, for the Office of Air Quality Planning and Standards, Emission Standards and Engineering Division, of the United States Environmental Protection Agency. This project assessed the impact of flue gas desulfurization (FGD) systems on the overall reliability and expected generation requirements of electric power generating systems in the United States through the year 2000.

Power system reliability is directly affected by the availability of generating units. Since FGD affects this unit availability, it also affects system reliability. For the purposes of this report, the following definitions of reliability and availability will be used:

> Reliability - the ability of a power system to provide continuity of service[19]. For generating units alone (neglecting the effects of the transmission and distribution networks), reliability can be measured as the probability that demand exceeds available capacity*. In this context, this probability can be described by the loss-of-load probability (LOLP), which is a well-known and accepted index of reliability in the utility industry.
>
> Availability - the amount of time a generating unit is capable of operating at a particular power output (also called operating availability). Numerically, availability is expressed as the ratio of the number of hours the unit is available to the number of hours in

* Technically, this particular measure of reliability as given is equivalent to (1.0- probability that service is continuous).

the period[7]. Reliability in terms of LOLP or (1.0 - LOLP) can be directly calculated from availability using probabilistic relationships (see Appendix A).

Consequently, the impact of FGD on power system reliability can be estimated by using probabilistic methods and by considering any other pertinent factors. The methodology to estimate this impact includes consideration of the following five items:

1. A determination of the projected generation types; quantities, and typical demand characteristics for new coal-fired generating units. (See Sections 4.1, 4.2, and 4.3.)

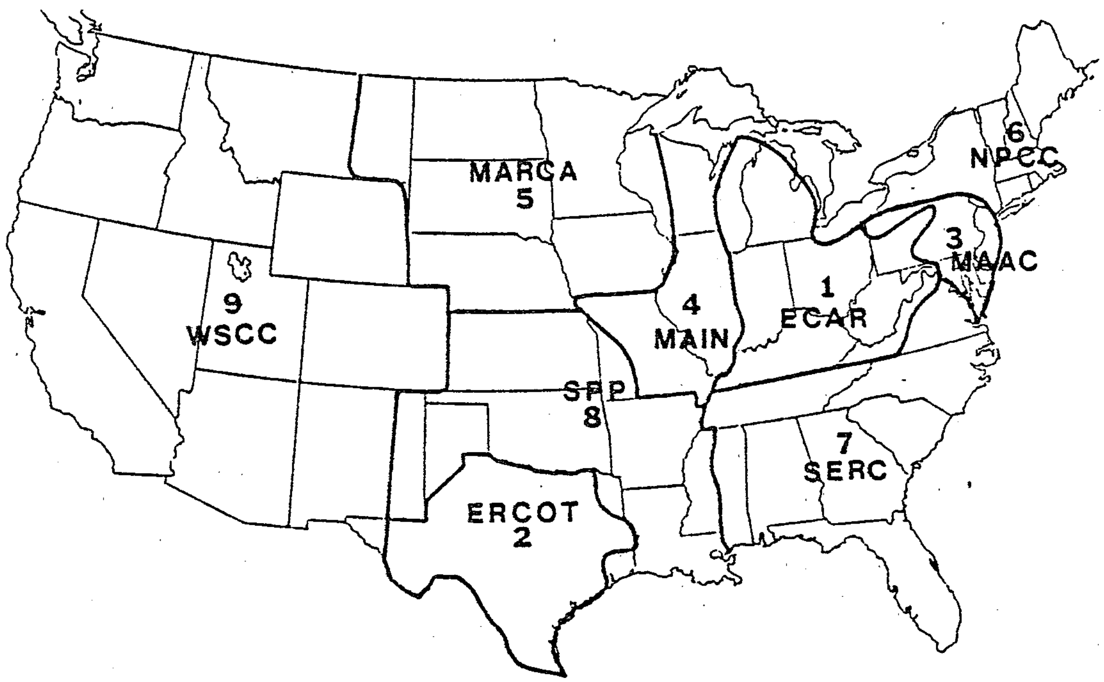
2. An assessment of the ability of each power pool (or reliability council) to meet power demands in 2000 with and without scrubbers through the calculation of LOLP. (Scrubber configurations and availabilities were assumed for this study.) (See Sections 4.6.4 and 4.6.5.)

3. A determination of the effects, if any, of scrubbers on the ability to maintain reasonable and typical reserves, and a calculation of the amount of any additional capacity which must be added to offset any scrubber impacts. (See Section 5.1 and 5.3.)

4. An investigation of nationwide reserves as to generation types and amounts. (See Section 5.3.)

5. An assessment of bulk interchange capabilities which might be used in the event of outages caused by FGD. (See Section 5.2.)

This study addressed the problem of large-scale implementation of FGD on both a regional and national basis. The wide-spread practice of interconnecting electric utilities ("power pooling") has led to the division of the country into nine major power pools. These pools and their respective service areas are shown in Figure 1. With the formation of the



1 - ECAR - East Central Area Reliability Coordination Agreement
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9 - WSCC - Western Systems Coordinating Council

Figure 1. Division of U.S. into NERC Reliability Regions

National Electric Reliability Council (NERC), these nine power pools became reliability regions which report to NERC on an individual basis. Each pool has its own particular mix of generation, load or demand characteristics, operating practices, reserve requirements, and interchange agreements. The effects of FGD considered in this study are thus addressed for each of the nine reliability regions and for the nation as a whole.

Almost all existing commercial applications of flue gas desulfurization on coal-fired boilers use either the lime process or the limestone process and almost all the data available at this time are for these processes. This study utilized estimates or assumptions of performance for limestone processes and it assumed that (1) all new FGD units, or scrubbers, are of the limestone type, and that (2) each scrubber would have an energy requirement necessary to achieve 90 percent removal efficiency.[9] The five scrubber configurations shown in Table 1 were studied. It was assumed that all new coal units for each case had FGD systems which were configured identically; i.e., only module throughput capacity varied depending on the size of the generating unit. While other modular configurations are certainly possible for various unit sizes, only these five were considered to allow for ease in computation. Furthermore, although smaller generating units (less than 600 megawatts) might require fewer scrubber modules, it was found that these units most probably will be a small portion of total generating capacity by the year 2000. Hence, it is expected that any variations in scrubber configurations among these smaller units would not significantly affect the results of this study. In addition, this study did not address either the validity of available data, the desirability of the limestone process, or the technical feasibility of achieving various removal efficiencies or various FGD module availability levels.

Table 1. FGD SYSTEM CONFIGURATIONS STUDIED

Case	Number Scrubbers per Generating Unit	Number Modules per Scrubber	Number Spares Modules	Availability per Module[a]
1 (Base Case)	0	---	---	---
2	1	5	0	90%
3	1	5	1	90%
4	1	5	0	80%
5	1	5	1	80%

[a] Outage rate = 100% - Availability

Power plant outage data (exclusive of scrubbers) were taken from Edison Electric Institute (EEI) data accumulated over the period 1972 - 1974 (3 years) for large mature units built before 1971. Only units which burned coal exclusively were considered, and total outage rates (forced plus scheduled full and partial outage) were considered. These data covered units which were grouped into two categories: 390-599 MWe* capacity and capacity greater than 600 MWe. Consequently, this study considered only those units in these two size ranges; however, the vast majority of planned generating facilities are in these two groups.

* Electric megawatt output at the bus bar; also called MW by the industry. In this report MWe will be used to avoid confusion with thermal boiler input megawatts (MWt).

These generating units were also grouped according to probable duty. Typical power system practice has been to use large new units for either intermediate (cycling) or base-load duty. Load duration curves were developed to reflect before-the-fact desired capacity factors of 70 percent for base-load units and 55 percent for intermediate-load units. Anticipated load duration coupled with expected additions by type and percent capacity (coal, oil, nuclear, hydro, etc.) were used to determine a reasonable expected mix of base-load and intermediate-load coal units for each reliability region. This mix was used to determine (1) overall ability to meet load and (2) expected reserve generation types. Sensitivity of this analysis was also estimated.

Because this study was done to provide data for the evaluation of a revised New Source Performance Standard for coal-fired power plants, two future time periods were considered. Because of the long lead times (7-10 years) required for the construction of new coal-fired power plants, all units scheduled for operation prior to 1986 were evaluated separately in terms of any existing and/or potential FGD equipment. It was found that any NSPS enacted today probably would not affect most of these units. However, it was assumed that all coal-fired units on-line between 1985 and 2000 would need FGD systems to meet the revised NSPS.

Because of the short time constraints under which this study was done, aggregate total reliability in terms of the sum of all types of generation which exist in each region (nuclear, hydro, gas turbines, etc.) could not be evaluated. The same demand curves for the two unit types considered were used for all nine geographical regions. Different curves were used, of course, for base and for intermediate units. The primary justification for using the same curves for all regions was that region-to-region differences in demand per generating unit were probably smaller than the uncertainty regarding the demand curves which would apply more than a decade in the future. Nevertheless, although the same unit demand curves were used for all regions, the total demand varied by region. This was accounted for in the analysis. Furthermore, it is felt that correlations exist between demand at the same time at different generating units in the same region. The demands at different units, for example, are affected simultaneously by diurnal variations and by area-wide weather changes. Treatment of these correlations, however, was beyond the scope of this study. The omission of the correlations affects the calculated incremental loss-of-load probabilities to some extent, as is discussed in Section 4.6.4 and Appendix A. It is believed, however, that omission of the correlations does not have a large effect on the decrease in power system reliability due to the use of scrubbers. Finally, in this study, only new coal units were analyzed, and only that portion of the total power load they were expected to carry was assessed. New coal units were the only type of unit which were considered to require FGD systems. While a more thorough analysis would certainly have been beneficial, it is believed that the results presented in this study are sufficient to estimate the effect of FGD systems on power system reliability and adequacy. The results can provide insight into the effects of FGD on different types of units with different duty cycles, and they provide estimates of additional generation required to offset the effects of implementing FGD systems on new coal units.

SECTION 2
CONCLUSIONS

A detailed description of the results of this study is contained in Section 5. From these results, the following conclusions concerning a revised NSPS requiring FGD for all new coal-fired electric generating units may be drawn:

1. Before 1985, the small numbers of committed FGD systems required by a revised NSPS will have very little effect on system reliability and adequacy. Any revised NSPS enacted at the present time will primarily affect new coal-fired units anticipated to come on-line after 1985.

2. It was found that (1) FGD unavailability and (2) energy penalties due to FGD cause reductions in available system capacity leading to additional capacity requirements. The mean percent reductions in capacity caused only by FGD unavailability for the four scrubber configurations in this study are shown in Table 2. These mean percent reductions were found to be virtually insensitive to changes in mix of intermediate-load or base-load units or load factors (Section 5.4). Estimated energy penalties caused by increased in-plant energy consumption for limestone scrubbers with 90 percent removal were reported to be on the order of 3.4 to 3.8 percent of generating unit capacity[9].

Table 2. MEAN ADDITIONAL CAPACITY REQUIREMENTS IN PERCENT OF NEW COAL CAPACITY TO OFFSET THE RELIABILITY EFFECTS OF FGD

Case	No. Modules	No. Spares	Availability Per Module	Mean Additional Generation Requirement[a]
1(Base)	0	---	---	0
2	5	0	90%	4.5%
3	5	1	90%	1.2% (Best)
4	5	0	80%	9.9% (Worst)
5	5	1	80%	4.4%

a Expressed as a percent of new coal capacity without FGD. Does not include boiler/turbine/generator availability effects.

3. The amount of additional capacity required due to FGD was found to be very sensitive to scrubber availability and modular configuration (i.e., number of modules, spares, etc.). Consequently, if the values assumed for module availability were too high or too low, the impact of FGD would either be amplified or mitigated. Similarly, if the number of modules and/or spares changed, or if bypass were allowed, the estimated additional capacity requirements would change.

4. It was found that the effects of FGD on reliability, system reserves, and in-plant energy consumption most probably would be offset by the addition of more new units rather than by oversizing units

which are already planned since system reliability is degraded, not enhanced, by enlarging individual sizes of a constant number of units. These new units will probably be new coal units.

5. Assuming no spare FGD modules and a module availability of 80 percent (the worst case studied), approximately 105,000 MWe would be required nationally in 2000 to offset reduced system reliability and increased in-plant power consumption caused by FGD. The best case studied (one spare module and 90 percent availability for each module) requires about 37,500 additional MWe. The other cases studied (90 percent, no spare; 80 percent, 1 spare) require about 63,000 MWe of additional capacity. Additional results for each reliability region are summarized in Tables 3, 4, and 5. As can be seen from these tables, the impact on individual regions varies considerably. These generation estimates include mean boiler/turbine/generator availability effects but do not include effects of any FGD on additional units.

6. It was found that, independent of any revised NSPS, the electric utilities may encounter problems in maintaining adequate reserves in the future due to delayed construction of new plants. If future reserves are marginal or inadequate, widespread implementation of FGD would tend to compound this problem. This impact results from boiler derating when the unit is without bypass or available spare scrubber modules and an FGD module or modules fail.

Table 3. TOTAL FGD-RELATED ADDITIONAL CAPACITY REQUIREMENT BY REGION IN 2000[a] (MWe)

Region	Case I (base)	Case 2 (5/0@90%)[d]	Case 3[b] (5/1@90%)	Case 4[c] (5/0@80%)	Case 5 (5/1@80%)
1-ECAR	0	13,815	8,320	22,805	13,650
2-ERCOT	0	7,540	4,390	12,690	7,440
3-MAAC	0	3,900	2,350	6,435	3,850
4-MAIN	0	6,070	3,660	10,025	6,000
5-MARCA	0	2,810	1,635	4,725	2,770
6-NPCC	0	3,400	2,050	5,615	3,360
7-SERC	0	9,440	5,685	15,580	9,325
8-SPP	0	8,120	4,730	13,665	8,015
9-WSCC	0	8,085	4,710	13,610	7,980
U.S. TOTAL	0	63,180	37,530	105,150	62,390

[a]Includes reliability effects and energy penalties

[b]Best Case

[c]Worst Case

[d](Number active modules/number spares @ % modular availability)

Table 4. TOTAL FGD-RELATED ADDITIONAL CAPACITY REQUIREMENTS BY REGION IN 2000[a] - 600 MWe COAL UNITS

Region	Case 1 (base)	Case 2 (5/0@90%)[c]	Case 3[a] (5/1@90%)	Case 4[b] (5/0@80%)	Case 5 (5/1@80%)
1-ECAR	0	23	14	38	23
2-ERCOT	0	13	7	21	13
3-MAAC	0	7	4	11	7
4-MAIN	0	10	6	17	10
5-MARCA	0	5	3	8	5
6-NPCC	0	6	4	10	6
7-SERC	0	16	10	26	16
8-SPP	0	14	8	23	14
9-WSCC	0	14	8	23	14
U.S. TOTAL	0	108	64	177	108

[a]Includes reliability effects and energy penalties.

[b]Best Case

[c]Worst Case

[d](Number active modules/number spares @ % modular availability)

Table 5. EXPECTED ADDITIONAL GENERATION REQUIREMENTS DUE ONLY TO FGD ENERGY PENALTIES BY REGION - 2000

Region	Maximum Additional Generation Requirements Due to FGD Penalty - MWe[a]
1-ECAR	6,325
2-ERCOT	3,245
3-MAAC	1,785
4-MAIN	2,780
5-MARCA	1,210
6-NPCC	1,555
7-SERC	4,320
8-SPP	3,495
9-WSCC	3,480
U.S. TOTAL	28,200

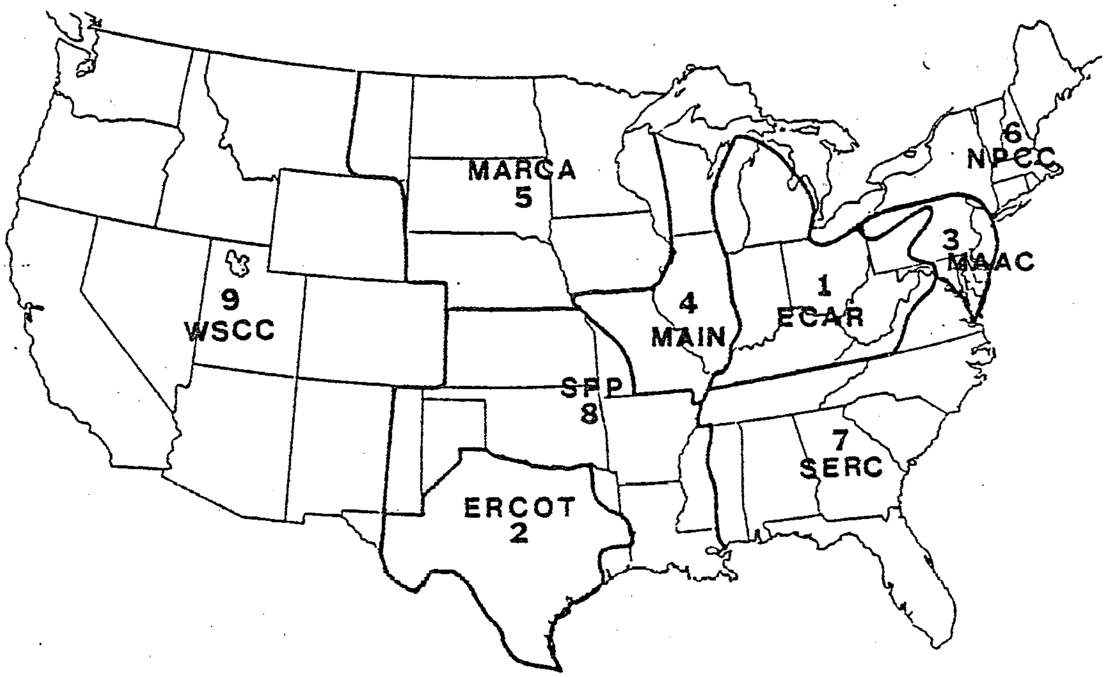
[a]Includes only effects of new coal unit boiler/turbine/generator availability. This assumes that the additional generation has an average availability equal to that of a new coal unit.

7. Because of a variety of technical and institutional constraints on the interchange of power among different regions, it was determined that bulk power shipments probably could not significantly reduce the additional capacity requirements caused by the widespread implementation of FGD.

8. It was found that these effects of FGD on system reliability and adequacy could be mitigated in a number of ways. For example, redundancy or maintaining spare modules can significantly reduce the need to increase capacity to offset reduced reliability. The use of alternative coal utilization technologies which avoid or reduce the need for flue gas cleanup is another obvious method for mitigating impacts. Finally, the adoption of a policy permitting the bypass of scrubber modules on outage status when reserve capacity is critically low or under other temporary emergency conditions could also reduce significantly the need to increase generating capacity.

SECTION 3
DESCRIPTION OF PROBLEM

The main objective of this study was to evaluate the effect of FGD systems on the reliability and adequacy of electric utility systems. The first step was to determine the incremental reduction in system reliability due solely to scrubbers on new coal plants on a regional basis. The nine NERC reliability regions considered are shown in Figure 2. Because of time constraints for this study, it was impossible to compute total system loss-of-load probability based on the interaction of all



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8 - SPP - Southwestern Power Pool
9 - WSCC - Western Systems Coordinating Council

Figure 2. Division of U.S. into NERC Reliability Regions

forms of generation (coal, oil, nuclear, hydro, etc.). Instead, this study assumed that the generation forecasts utilized represented that capacity necessary to assure an acceptable system loss-of-load probability without FGD on all new coal units, and that the generation which had been planned or forecasted left appropriate reserve margins. In this context, then, only new coal units were considered in the calculation of incremental loss-of-load probabilities (ILOLP) for new coal with and without FGD. For the cases including FGD, additional generating requirements necessary to maintain the same incremental loss-of-load probability as without FGD were computed for cases considering the various FGD modular availabilities and configurations. This calculation, therefore, assumed that none of the existing non-new-coal capacity could be used to offset any effects of FGD. It was also assumed that base and intermediate demand characteristics for the new coal units were similar in each power pool. The estimated mix of base- and intermediate-load new coal units was then used to determine the aggregate demand for each region used in the ILOLP calculations. The additional generating requirements for the cases with FGD, determined from these calculations, were then combined with expected additions in capacity required to offset energy penalties associated with FGD to give net additional generating requirements due to FGD in each region. Since these ILOLP calculations involved only new coal units on systems with other forms of generation, reserve policies were investigated to determine whether or not systems might be overbuilt or underbuilt in the future, i.e., whether the assumptions above might be influenced by other factors. Constraints on emergency interchange were also investigated. In addition, the effect of FGD on the reliability of a single generating unit was also assessed.

The remainder of this report addresses the above points. Section 4 discusses the determination of the effect of FGD on reliability, adequacy and capacity based on generation mix, outage rates, demand characteristics, and energy penalties. Section 5 evaluates the results on reliability from Section 4, and discusses the net effect of FGD on generation with respect to additional capacity required, constraints on interchange and reserve policies. The appendices contain a detailed mathematical description of the probability calculations, a determination of generation mix for each region, and test case incremental loss-of-load probabilities.

SECTION 4
DETERMINATION OF EFFECT OF FGD ON FUTURE GENERATION REQUIREMENTS

To estimate accurately the effect on FGD on reliability several intermediate calculations were made. The mix of power generation was first determined for each power pool. Evaluation of individual demand characteristics, outage rates, and energy penalties for each area was completed next. The overall effect of FGD was then evaluated for an individual unit and for all new coal in each region. The effect of FGD on utility reliability and adequacy was estimated separately for units put on-line before 1986 and for those on-line between 1985 and 2000.

4.1 Evaluation of Generation Forecasts

Because of differences in fuel resources, demand and operating policy, each of the nine power pools generates power using different proportions of various unit types. Since this study assumed that each pool or region operates in a somewhat autonomous fashion, it was decided that the effect of FGD could be best estimated on a regional basis. Data developed by Teknekron and supplied by EPA[1] provided estimates of the number and location of individual units planned for construction through 2010 and their expected or assumed* sizes in MWe. These data were analyzed and plants were grouped by reliability region served so that the expected mix of generation for each region could be determined. Tables 6 and 7 show the mix for each region determined from these Teknekron data for units put in service before 1986 and from 1985 to 2000.

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*Teknekron assumed sizes of 600 MWe for each new coal unit and 1200 MWe for each new nuclear unit if no other data were available.

Table 6. EXPECTED GENERATION TO BE ADDED (BY RELIABILITY REGION) PRIOR TO 1986

		Coal						Nuclear		Oil		Gas	
		0-390 MWe		390-599 MWe		600 + MWe							
Region	Total Additional Capacity (MWe)	No. Units	% Total MWe[a]	No. Units	% Total MWe	No. Units	% Total MWe	No. Units	% Total MWe	No. Units	% Total MWe	No. Units	% Total MWe
1-ECAR	48,879	19	7	13	13	27	41	20	37	2	1	0	0
2-ERCOT	14,316	0	0	10	35	4	20	4	33	0	0	7	12
3-MAAC	21,143	0	0	1	2	3	10	16	74	5	14	0	0
4-MAIN	23,083	7	6	14	32	0	0	11	50	8	12	0	0
5-MARCA	10,942	9	9	11	47	7	44	0	0	0	0	0	0
6-NPCC	17,898	2	<1	0	0	3	13	10	61	7	26	0	0
7-SERC	45,467	7	3	5	6	12	19	26	62	11	10	0	0
8-SPP	30,271	7	6	12	19	13	31	11	39	3	<1	5	4
9-WSCC	47,064	34	19	20	23	11	17	17	40	2	1	0	0

[a]For Region

Table 7. EXPECTED GENERATION TO BE ADDED (BY RELIABILITY REGION) 1986-2000

Region	Total Additional Capacity (MWe)	Coal 0-390 MWe No. Units	Coal 0-390 MWe % Total MWe[a]	Coal 390-599 MWe No. Units	Coal 390-599 MWe % Total MWe	Coal 600 + MWe No. Units	Coal 600 + MWe % Total MWe	Nuclear No. Units	Nuclear % Total MWe	Oil No. Units	Oil % Total MWe	Gas No. Units	Gas % Total MWe
1-ECAR	183,504	2	<1	4	1	185	61	60	38	0	0	0	0
2-ERCOT	75,309	4	1	7	5	103	83	7	11	0	0	0	0
3-MAAC	64,450	0	0	0	0	54	50	44	50	0	0	0	0
4-MAIN	59,450	2	<1	1	1	82	83	8	16	0	0	0	0
5-MARCA	27,886	4	4	1	2	40	86	2	8	0	0	0	0
6-NPCC	88,450	2	<1	1	<1	46	32	54	68	0	0	0	0
7-SERC	227,632	11	1	5	1	124	34	123	64	0	0	0	0
8-SPP	92,013	10	2	4	2	114	75	16	21	0	0	0	0
9-WSCC	172,805	13	2	8	2	111	39	86	57	0	0	0	0

[a] For Region

Several conclusions can be drawn from these forecasts. From the unit size data which were reported and not assumed, it was found that after 1985, utilities will probably concentrate on the construction of units which are more standardized in terms of size; this standardization process is presently underway in at least one region.[5] The types and sizes of these units are not uniformly distributed among regions. It can be seen, however, that the number of nuclear units is anticipated to increase. The power pools installing large numbers of nuclear units may use fewer coal-fired base load units unless demand is growing extremely fast. In the 1986-2000 analysis, small coal units ($\leq$600 MWe), as well as oil and gas units, show a sharp decline in their importance as prime movers. The maximum percentage of total MWe contributed by these smaller coal units is 19 percent after 1985, as opposed to 47 percent in earlier years. No oil or gas units are expected to be built after 1985.

These Teknekron data were compared to Federal Power Commission (FPC) estimates for 1990 as contained in the 1970 National Power Survey (NPS)[2] and as extrapolated to 2000 using NPS-derived growth rates. While some differences did exist between the Teknekron and NPS data, a combination of both was deemed sufficiently accurate for forecasting purposes and was thus used to compute the expected mix of generation in each area (Appendix B) in the following manner:

- All new generation estimates (1976-2000) for coal, oil, gas, and nuclear from Teknekron Data.
- Estimates for old units (pre-1976) remaining on each system, for other units (hydro, pumped storage, gas, turbine, diesel), and for old unit retirements from NPS
- Load factor data from NPS

Many of the units anticipated in this forecast are still in early planning stages, and thus, are subjected to operational and contractual delays. Should these delays occur, actual generation could vary from that used in this analysis.

4.2 Demand Characteristics

Generating unit duty can be assessed from operational and design viewpoints based upon expected demand as determined by the utility's dispatching policy. Figures 3 and 4 show typical weekly power system load (or demand) curves. An investigation of similar curves furnished by various utilities for this study showed that, while there are some seasonal and temporal variations, these figures can be viewed as being representative. Figure 3 has load divided as to type: base-load, intermediate-load, and peak-load. Figure 4 shows the same curve with a typical division of generation responsibility by type of prime mover. Economics dictate this division of responsibility; units with the lowest operating costs (with some exceptions, e.g., some hydro plants) are loaded to capacity (or, possibly, to their lowest individual heat rate points) first, and more expensive forms of generation remain in peaking or intermediate services. Also, as newer, more efficient steam units come on-line, older units which may have been base-loaded become peakers or intermediate-service units. Nuclear units are, almost without exception, base-loaded. Since new coal units are generally the most economical fossil-fueled steam units on most power systems, and since peaking capacity is and will be made up almost exclusively of old steam units, hydro units (including pumped storage) and internal combustion peakers, e.g., diesels and gas turbines, it remains that almost all new coal units will be designed for base-load and intermediate-load duty. An investigation of coal units under construction bears this point out - not a single unit was for peaking and only a few were for intermediate load.[3,4] It is expected that this situation will continue to exist in the future, although the relative percentage of new coal units for intermediate-load duty will increase as a greater proportion of nuclear units (base-load) come on-line. Therefore, based on these findings, this study has assumed that all new coal units will be designed for either base-load or intermediate-load duty.

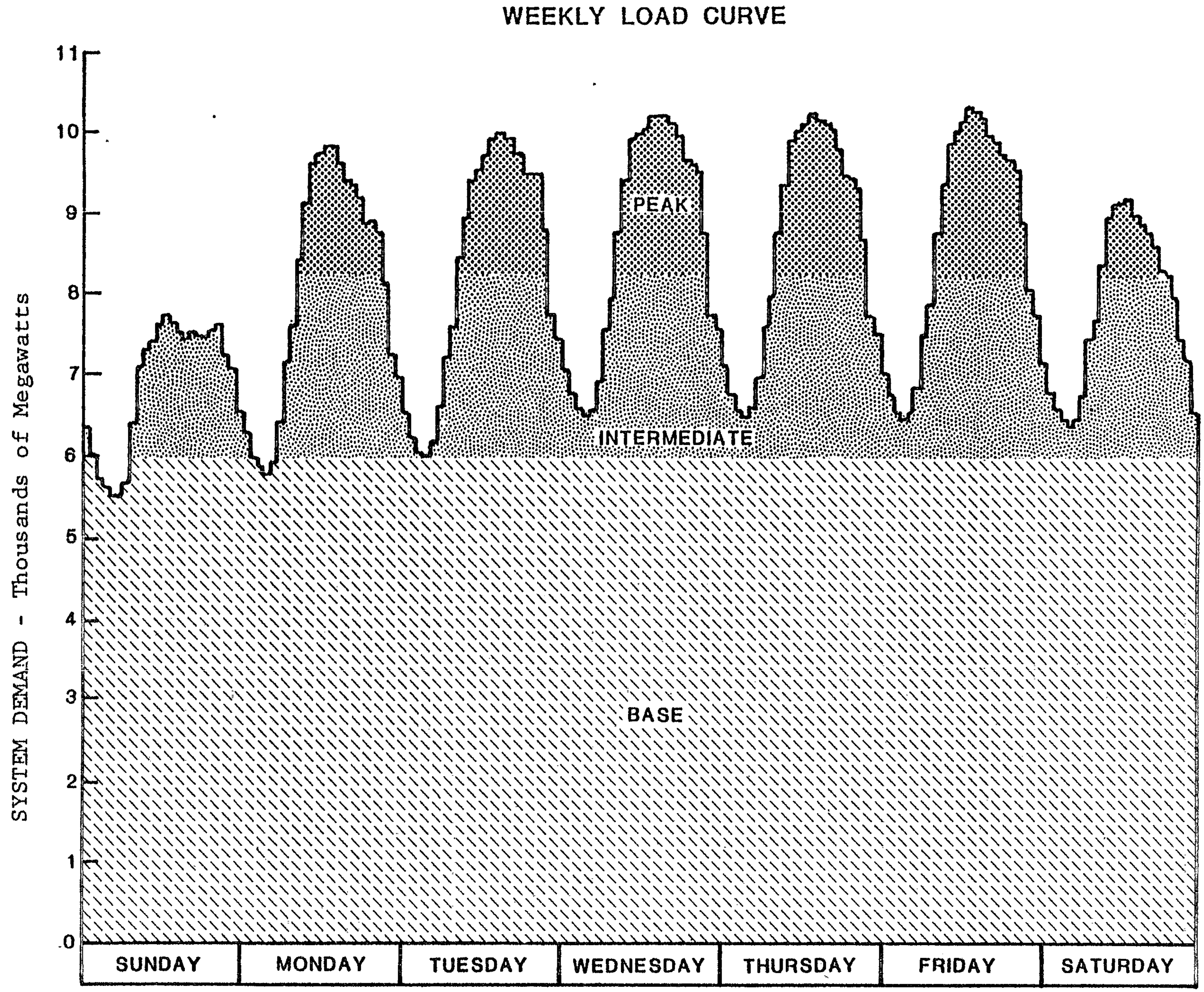

Figure 3. Typical weekly load curve.
(Adapted from 1970 NPS; no copyright)

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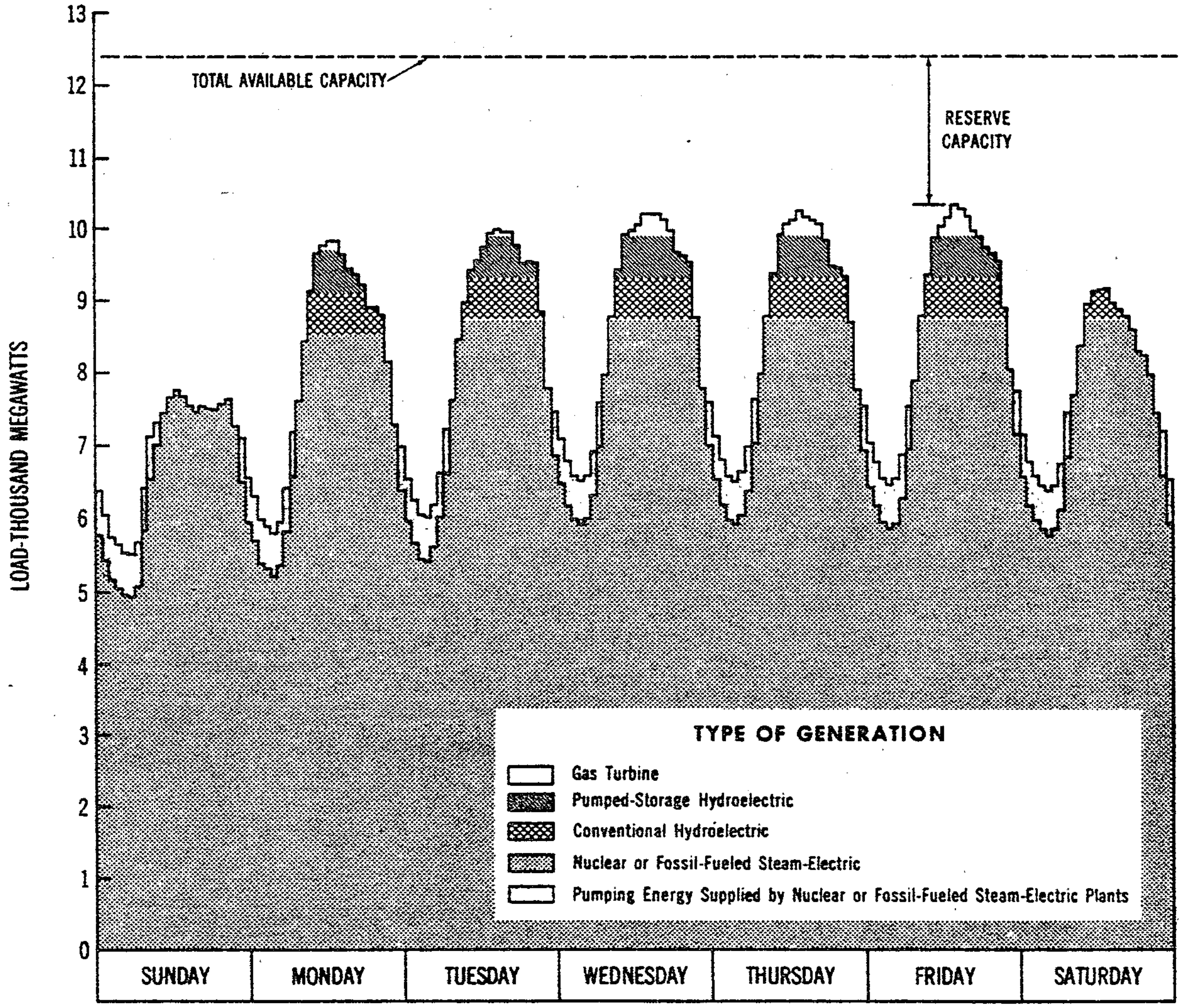

Figure 4. Typical weekly load curve apportioned by prime mover type.
(Reprinted from 1970 NPS; no copyright)

Since generating units of a single type, e.g., base-load, have similar controls and economies of operation, and since most utilities dispatch and commit their generation in similar fashion, it follows that hourly demands on units of the same type will be somewhat similar. This point is especially true with regard to base units, which are usually run at nearly constant power outputs except when economics of operation dictate that load be reduced to avoid shutting intermediate units down. Furthermore, new coal units will remain classified as base-load or intermediate-load for a large percentage of their lifetimes for two reasons. First, most base-load units require fairly extensive modifications to their steam flow and control systems to allow them to cycle (or follow load) more closely. Second, turbine shafts are designated for one application or the other; while intermediate units may be base-loaded at times, forcing a base unit to follow load or to be cycled on and off can reduce its lifetime and/or increase its maintenance requirements significantly.

In order to perform the reliability calculations in this study, it was necessary to estimate the desired loadings on each of the generating units, neglecting outages. The reliability calculations then determined whether or not the systems of new coal units could meet these desired loadings. To characterize desired loading on base-load and intermediate-load units, unit demand curves as functions of time were developed. These curves represent "typical" desired loadings which would be attempted for new coal units neglecting outages over the periods when those units are in either base or intermediate service. They, therefore, represent "before-the-fact" operating considerations (reasonably short-term) rather than "after-the-fact" considerations over the unit lifetimes. These curves, as used in this study, are probability distributions which can be expressed as cumulative probability distributions for ease in interpretation. These cumulative distributions, called "load duration curves" by the industry, are shown in Figure 5 for a base-load new coal unit and Figure 6 for an intermediate-load new coal unit. While these curves do not directly show exact diurnal variation in demand, they are derived directly from the diurnally varying curves and, therefore, can be considered as representative of unit loading which would be attempted for each unit type. These curves represent the percentage of time that demand on the unit equals or exceeds a certain value. They are obtained figuratively by placing each hourly demand value in descending order by magnitude and plotting the results. Mathmetically, these curves are computed from the probability densities of load versus probability of occurrence (load level versus number of hours at that level). This study has used the data in this latter form for computational purposes as in Appendix A. While the exact form of the actual desired unit loading curves may vary from day-to-day and unit-to-unit, the approximate curves used in this study represent what might be reasonably expected of these two different unit types.

These curves also can be described using capacity factors or load factors. Capacity factors represent the mean loading divided by capacity; load factors, mean loading divided by peak loading. The curves in Figures 5 and 6 thus represent capacity factors in the neighborhoods of 70 percent for base-load new coal units and 55 percent for intermediate-load new coal units. For the purposes of this study, it was assumed that peak unit loading would equal unit capacity at some point during the period under investigation and thus that capacity factor would be equal or nearly equal to load factor foreach unit. This assumption allowed for the approximation of total load on new coal units as a function of unit type (base or intermediate) only, and it eliminated the otherwise necessary requirement of considering each new coal unit individually. This approximation of total load on new coal units was, therefore, made by determining the expected mix of base-load and intermediate-load new coal units from existing load factor data, summing the demand densities in percent of capacity for all units,

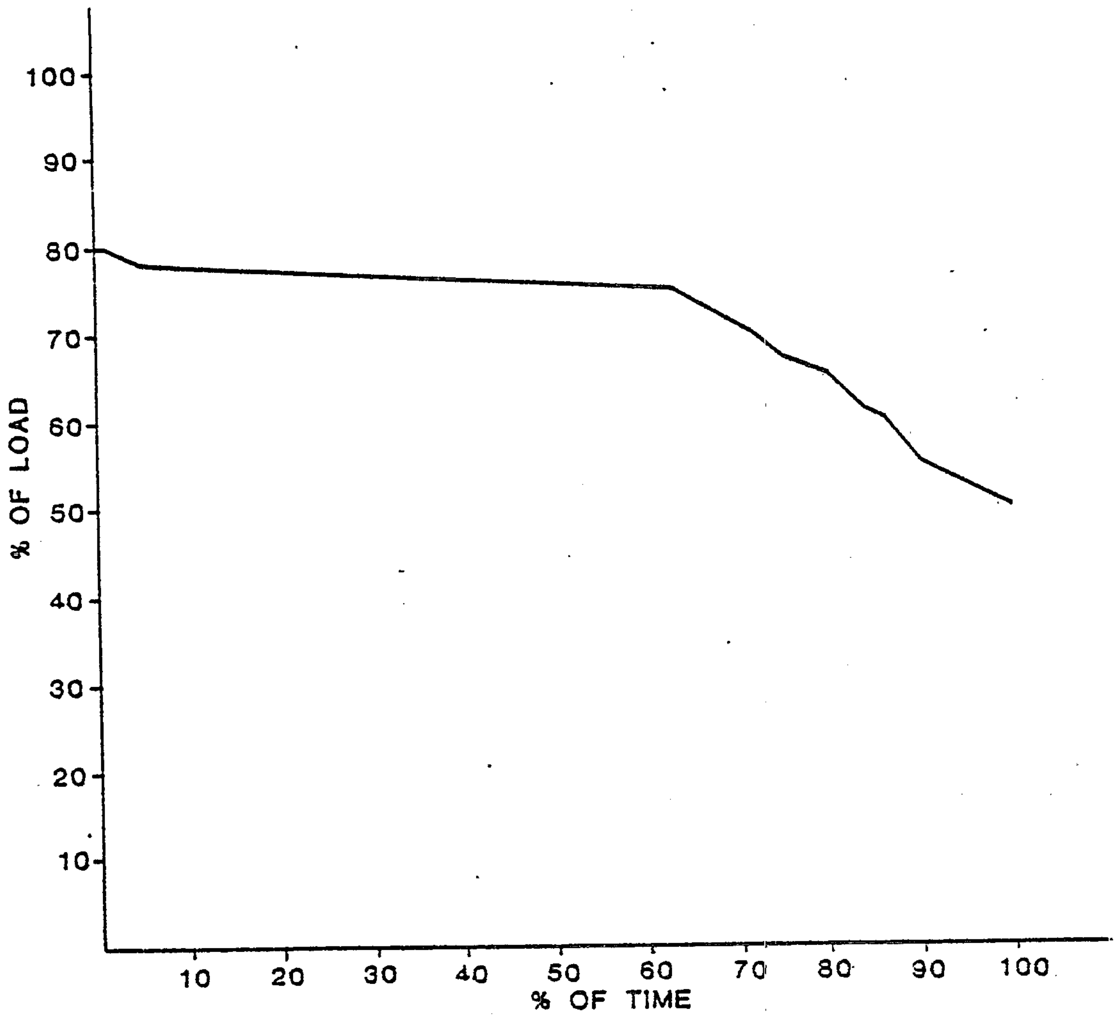

Figure 5. Expected load duration curve for new base-load coal unit.

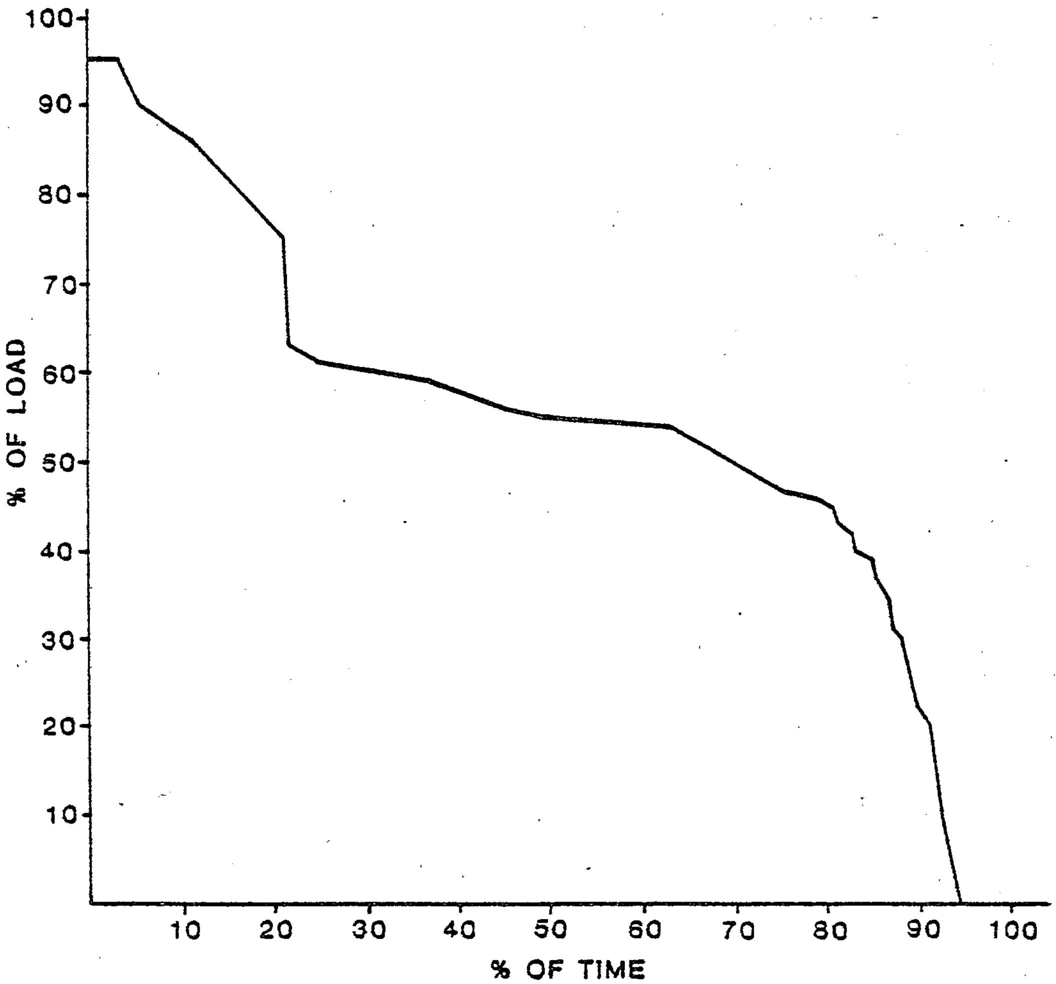

Figure 6. Expected load duration curve for new intermediate-load coal unit.

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and scaling by the sum of average unit sizes in MWe. The determination of the mix of base-load and intermediate-load new coal units for each region will now be discussed.

4.3 Determination of Mix of Base-Load and Intermediate-Load New Coal Units

As was outlined in the previous section, the mix of generating units by size and prime mover type was estimated for each region. It was assumed that the mix of duty types (base and intermediate) could be applied uniformily over new coal units in both size ranges studied (390-599 MWe and 600+ MWe). This mix was obtained by estimating the expected load factor for new coal units and assuming that it and the capacity factor were reasonably close in magnitude. Estimated system load factors for 1990 were obtained from the 1970 NPS and assumed to be the same, when rounded to the nearest integer, for 2000. Total system capacity was estimated using NPS and Teknekron data, and this capacity was grouped as old units existing in 1976, pre-1986 units by type and size, and post-1985 units by type and size. Peaking capacity (hydro, pumped, storage, gas turbine, etc.) was estimated from NPS data. System load duration allocation, as in Figure 7 for a portion of NPCC and Figure 8 for a portion of SERC, was used if available. Load factors were generally assigned in the following manner:

old units*	- system load factor
pre-1986 steam units	- system load factor or intermediate load factor, if estimated (e.g., NPCC)
all nuclear units	- 70% load factor (base-load)
all internal combustion	- 20% load factor (peaking)
all hydro and pumped storage	- 40% load factor (intermediate and peaking)

*Units in service prior to 1978. Does not include hydro, pumped storage, or internal combustion units.

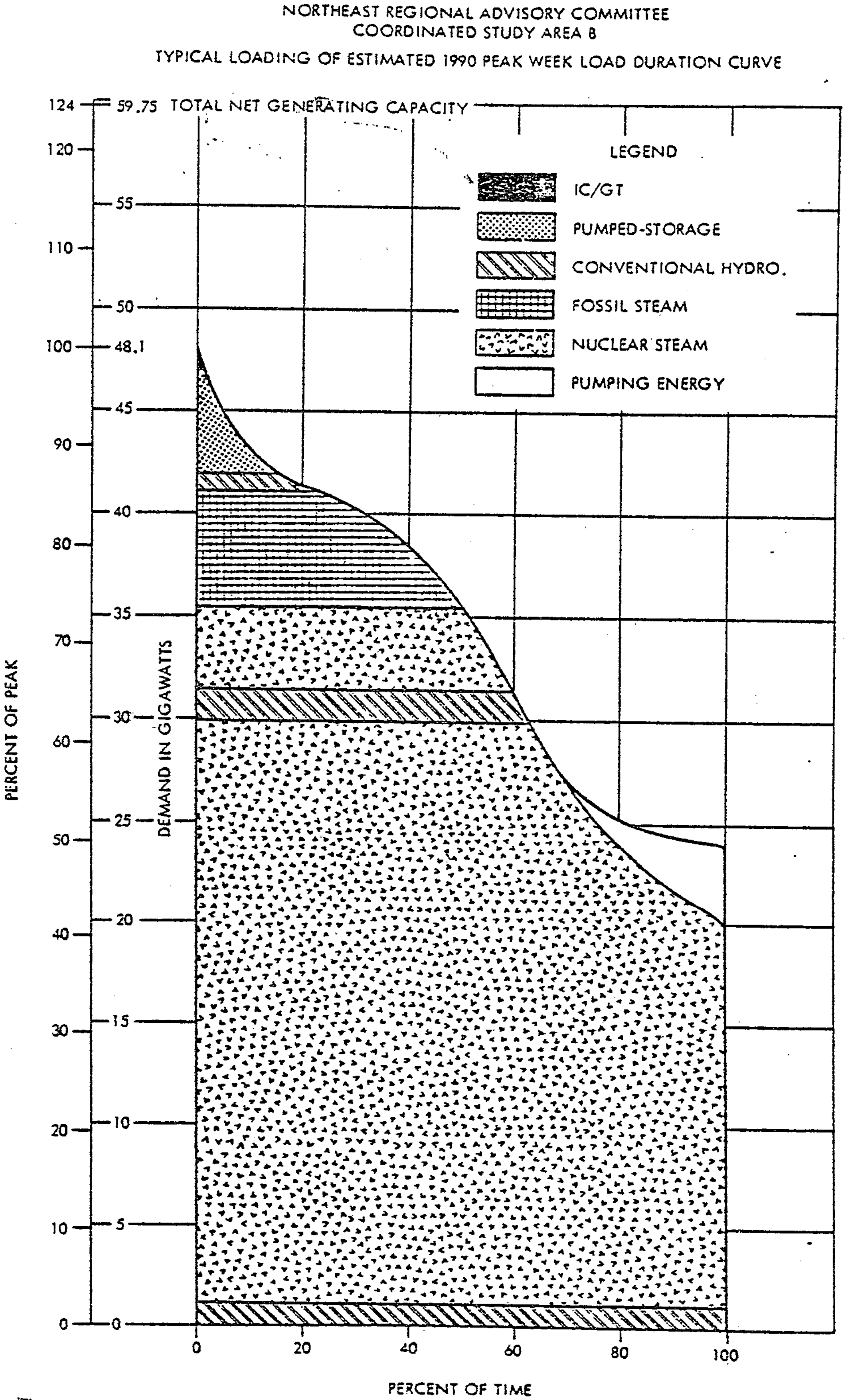


Figure 7. 1990 expected load duration curve with typical apportionment by prime mover type for a portion of NPCC (Region 6)
(Reprinted from 1970 NPS; no copyright)

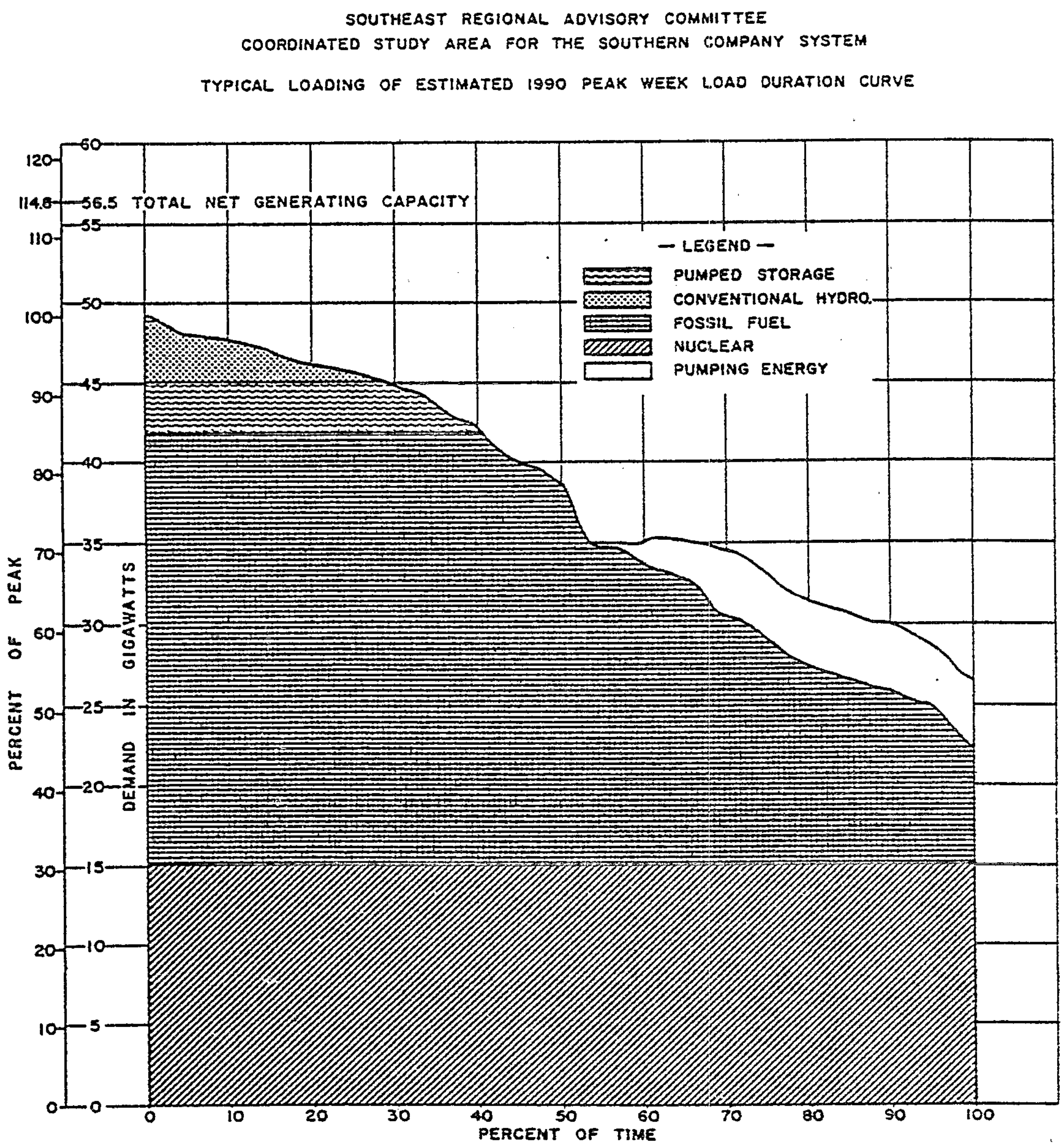


Figure 8. 1990 expected load duration curve with typical apportionment by prime mover type for a portion of SERC (Region 7)
(Reprinted from 1970 NPS; no copyright)

In the case of NPCC and WSCC, the last three items above were grouped together and given a net 50% load factor to account for significant amounts of base-load hydro available in those regions.

Net new coal load factors were then estimated by scaling each load factor by percentage of capacity, subtracting the sum from the expected system load factor, and rescaling by the ratio of system to new coal capacity, or

$$LF_{NC} \approx \frac{C_S}{C_{NC}} \left[LF_S - \sum_i \left(LF_i \quad \frac{C_i}{C_S} \right) \right] \tag{1}$$

where

LF_S = estimated system load factor

LF_{NC} = new coal estimated load factor

LF_i = estimated load factor for generation type i

C_S = expected total system capacity

C_{NC} = expected new coal (1985-2000) capacity

C_i = expected capacity of generation type i

The percent mix of base-load and intermediate-load new coal units was then estimated from the base-load and intermediate-load capacity factors

$$LF_{NC} \approx 0.55 \frac{C_{IL}}{C_{NC}} + 0.7 \frac{C_{BL}}{C_{NC}} \tag{2}$$

and from

$$\%IL = \frac{C_{IL}}{C_{NC}} \times 100 \qquad (3)$$

$$\%BL = \frac{C_{BL}}{C_{NC}} \times 100 \qquad (4)$$

where

C_{IL} = expected capacity, intermediate-load

C_{BL} = expected capacity, base-load

C_{NC} = expected new coal capacity

and where it was assumed that peak load on each unit equaled capacity at some time during that unit's lifetime. These results were then checked based on NPS system makeup data and general knowledge of regional problems and modified slightly if necessary. For example, base-load capacity was decreased slightly in WSCC to reflect uncertainties in water availability for hydro. In several other areas, slight corrections were made to account for expected uncertainties in nuclear plant construction. In general, no modifications in excess of 10 percent were made. The resulting expected mix of new base and intermediate load new coal units for each region is shown in Table 8; calculation results for each region are given in Appendix B.

These data were used as inputs for the determination of incremental loss-of-load probabilities (ILOLP). Each base unit was assumed to have the previously mentioned base-load demand characteristic; each intermediate unit; the intermediate-load demand characteristic. The percentage of base and intermediate units and the average unit size for each prime mover

Table 8. ESTIMATED MIX OF NEW BASE AND INTERMEDIATE LOAD COAL UNITS IN 2000

Region	% Base	% Intermediate
1 - ECAR	90	10
2 - ERCOT	10	90
3 - MAAC	10	90
4 - MAIN	70	30
5 - MARCA	70	30
6 - NPCC	0	100
7 - SERC	30	70
8 - SPP	0	100
9 - WSCC	90	10

size group (390-599 MWe and 600+ MWe) were given for each region as were the independent variables. Outage rate probability densities by prime mover size group, as discussed in the next section, were the only other variables needed for the calculation of ILOLP.

4.4 Outage Rates

The outage rates for coal-fired boilers that were used in this study are listed in Tables 9 and 10. These data were obtained from an Edison Electric Institute report[6] on trends of large mature fossil fuel units in operation prior to 1971. Planned and forced outages of coal-fired power plants were compiled for two size classifications: 390 to 599 MWe and 600+ MWe.

The outage rates presented in these tables were determined from the number of hours of operation at each electric production rate, and are averages for the years 1972 through 1974. They cover both partial and full outages. Other sources investigated[7,8] tended to uphold both the data used and the methods for collecting it.

The total amount of forced outage as reported in about twice that due to planned outage. Almost all the planned outage results in total outage while the forced outage is divided between total outage and partial outages of 60 to 99.9 percent of rated capacity.

The load factor (mean load scaled by dividing by the peak load) of the 300 to 599 MWe units is 67.9 percent. The 600+ MWe units have a load factor of 69.2 percent. This indicates that most of these units were probably base-load units, although some smaller units may have seen intermediate duty. These results compared favorably with the assumptions concerning unit

Table 9. NATIONAL OUTAGE RATES FOR LARGE, MATURE COAL-FIRED ELECTRIC GENERATING STATIONS - 390-599 MWe UNITS

Percent of Capacity	Probability of Planned Outage [a]	Probability of Forced Outage [b]
0	.1329	.1357
.1 to 19.9	.0010	.0016
20 to 29.9	0	.0091
30 to 39.9	.0001	.0041
40 to 49.9	.0001	.0038
50 to 59.9	.0001	.0176
60 to 69.9	.0007	.0153
70 to 79.9	.0015	.0389
80 to 89.9	.0050	.0774
90 to 99.9	.0097	.0480

Probability of 100% capacity is .4974

Mean availability = .6786. Standard deviation = .4305.

[a] Planned full or partial outage rate.

[b] Forced full or partial outage rate.

Table 10. NATIONAL OUTAGE RATES FOR LARGE, MATURE COAL-FIRED ELECTRIC GENERATING STATIONS - 600+ MWe UNITS

Percent of Capacity	Probability of Planned Outages[a]	Probability of Forced Outage[b]
0	.1633	.0971
.1 to 19.9	.0001	.0007
20 to 29.9	.0001	.0003
30 to 39.9	.0002	.0018
40 to 49.9	.0016	.0054
50 to 59.9	.0008	.0164
60 to 69.9	.0005	.0144
70 to 79.9	.0008	.0344
80 to 89.9	.0021	.1072
90 to 99.9	.0033	.0550

Probability of 100% capacity is .4945

Mean availability = .6924 Standard deviation = .4239

[a] Planned full or partial outage rate.

[b] Forced full or partial outage rate.

duty and load factor which were made in this study (Section 4.2). Since outage rate distribution depends somewhat on load factor, it is expected that future units will probably have outage rates which are somewhat similar to these.

4.5 FGD Energy Penalties

Power consumption of FGD systems results in the effective derating of coal-fired power plants, since power which could be used to meet load must be consumed in-plant to operate the FGD system. This power consumption is referred to as the FGD energy penalty and is reported as an additional generating capacity requirement necessary to provide rated unit power plus FGD requirements. Table 11 shows the energy penalties for each of the nine regions for 25, 100, 500, and 1000 MWe power plants. The energy penalties for the 500 MWe stations were used in this study since almost all of the new power plants are expected or assumed to be between 400 and 600 MWe.

The data in Table 11 are from an EPA study[9] on energy penalties for various FGD systems. They represent energy penalties resulting from 90 percent sulfur removal using limestone scrubbers. The energy penalties given represent the power requirements to produce 90 percent removal. The major types of coal that will probably be burned within each region in 2000 were also estimated to determine the energy penalties, since sulfur content affects FGD operation. It was assumed that ECAR (Region 1) and MAIN (Region 4) would use medium sulfur coal from the Midwest instead of the low sulfur coal from the West due to the effect of a revised NSPS. The remainder of the regions were assumed to use local coals or to adhere to present coal purchase practices. This assumption is based on estimated transportation requirements, historical use data from the 1970 NPS, and regional forecast data from several other reference.[10-13]

Table 11. EXPECTED ENERGY PENALTIES FROM FGD USE

Region	Expected Coal Type	% of Additional Generating Capacity Required to Operate the FGD System[a]			
		25 MWe	100 MWe	500 MWe	1000 MWe
1-ECAR	HV-MS local coal	3.7	3.7	3.8	3.5
2-ERCOT	MV-LS/LV-LS	3.3	3.3	3.4	---
3-MAAC	HV-MS	3.7	3.7	3.8	3.5
4-MAIN	HV-MS local coal	3.7	3.7	3.8	3.5
5-MARCA	HV-LS	3.3	3.3	3.4	---
6-NPCC	HV-MS	3.7	3.7	3.8	3.5
7-SERC	HV-MS	3.7	3.7	3.8	3.5
8-SPP	MV-LS/LV-LS	3.3	3.3	3.4	---
9-WSCC	MV-LS	3.3	3.3	3.4	---

HV - High Volatility

MV - Medium Volatility

LV - Low Volatility

MS - Medium Sulfur

LS - Low Sulfur

[a]Assumes 90% sulfur removal using a limestone scrubber. Data are grouped by size of the plant requiring the FGD unit.

4.6 Methodology for Calculation of Incremental Loss-of-Load Probabilities

In this section an overview of the analysis used to compute the incremental loss-of-load probabilities (ILOLP) is presented. The methods are discussed in detail in Appendix A. The presentation here is organized as follows in the subsections below:

(1) calculation of the probability distribution of capacity available at a given unit, taking into account both boiler and scrubber down-time,

(2) calculation of loss-of-load probability for a single unit, and

(3) calculation of incremental loss-of-load probability for a new coal only in a regional system in which the demand is distributed among the different generating units.

4.6.1 Calculation of Distribution of Available Power at a Particular Unit

It was assumed that a revised NSPS would require a generating unit to be derated upon FGD module failure if a spare module or bypass were unavailable. Therefore, for a given generating unit with FGD, the percent of total capacity which can be operational at a given time is limited by two factors. These factors are:

(1) the percent of total capacity at which the boiler is capable of operating,

(2) the number of scrubber modules which are available.

Suppose, for example, that the boiler, because of a partial outage, is capable of operating at 80 percent of capacity, but that only three of five scrubber modules are up. This means that the scrubber is capable of generating

$$\left(\frac{3}{5}\right) 100\%$$

or 60 percent of the output from a fully operational boiler. Thus, the boiler-scrubber system is limited to operating at only 60 percent of total capacity. Thus, both factors must be taken into account.

If r denotes the probability that a given scrubber module is up, and if there are K modules, the probability that exactly i modules are up is

$$P_i = \frac{K!}{i!\ (K-i)!}\ r^i\ (1.0-r)^{K-i} \tag{5}$$

This is the well-known binomial probability distribution.

The distribution of boiler outage for different sized plants was discussed in Section 4.3. The following is the primary equation used to combine the probabilities for the scrubber and for the boiler:

P(at least j% of capacity can be used) =

P(at least j% of boiler's capacity is available) x
P(enough scrubber modules are available to handle at least j% of the total capacity)

In this manner, the distribution of percent of total capacity available was obtained. The values $r = .8$ and $.9$ and $K=5$ and 6 were considered. When $K=6$, the sixth module was considered to be a spare; that is, each module was assumed to be able to handle up to 20 percent of the emissions from a fully operational boiler.

The mean and standard deviation of the percent of total capacity available were computed from the distribution. The use of the distribution to compute loss-of-load probability for a single unit is discussed in the following section and in Appendix A. The use of the distribution to compute the incremental loss-of-load probability for a regional system within which the demand is distributed among different generating units is discussed in Section 4.6.4.

4.6.2 Loss-of-Load Probability for a Single Generating Unit

The loss-of-load probability (LOLP) is simply the probability that not enough power is available to meet demand. If we define as random variables

Y = amount of power available,
X = power demand, and
$L = Y - X$,

then loss of load occurs if L is less than zero.

X, Y and L are random variables represented by probability distributions. The distribution of Y was obtained by using the analysis in the preceding section. The probability distribution of demand, X, was discussed in Section 4.2. A statistical method called convolution was used to obtain the distribution of L. Convolution as applied to this problem is discussed in some detail in Appendix A. The loss-of-load probability (LOLP) was obtained by summing the probabilities of values of L less than zero (demand exceeds available capacity).

4.6.3 Expected Effect of FGD on the Reliability of a Single Unit

Consequently, if LOLP with and without FGD can be computed as above, the effect of various scrubber configurations upon the reliability of an individual generating unit can be estimated. Table 12 shows the effect of a scrubber on the probability of meeting demand for each of the four unit sizes and types studied. It should be stressed that this table contains loss-of-load probabilities for individual new coal units and not absolute probabilities for meeting demand by all units in a system. Since individual units are typically part of an interacting system, this analysis is not exact and is meant only to provide qualitative information.

Table 12, then, shows the effect of the number of scrubber modules and the module availability on individual unit reliability. Module availabilities of 80 and 90 percent were considered. In addition, five modules were used with and without a spare module. The effect of these scrubber systems upon unit reliability is listed for 300 to 599 MWe units and 600+ MWe units in base- and intermediate-load service. The results expressed as (1.0 - LOLP) were computed by convolving* the demand probability distribution with the availability probability distribution for the boiler/scrubber system. Case 3 which used 90 percent module availability and one spare module was found to have the highest overall unit reliability while

* The statistical method of convolution as applied to this study is discussed in Appendix A.

Table 12. EFFECT OF FGD ON THE RELIABILITY OF A SINGLE GENERATING UNIT

				Probability of Meeting Demand			
				300-599 MWe Unit		600+ MWe Unit	
Case	Number of Modules	Number of Spares	Module Availability	Base Load Unit	Intermediate Load	Base Load	Intermediate Load
1(Base)	0	0	---	.676	.708	.693	.725
2	5	0	90%	.633	.684	.652	.700
3	5	1	90%	.665	.703	.685	.719(Best Case)
4	5	0	80%	.539	.642	.555	.657(Worst Case)
5	5	1	80%	.623	.682	.642	.698

Case 4, which used 80 percent module availability and no spare module, had the lowest unit reliability. It was found that a base-load unit had lower probability of meeting demand than an intermediate-load unit, as one might expect.

The facts that (1) groups of individual units interact and are committed, dispatched, and controlled simultaneously, and (2) groups of generating units can suffer concurrent full and/or partial outages, require that an entire power system be considered as a whole. In this case, the analysis of a single unit definitely cannot be applied to an entire system. Consequently, each region was studied as groups of generating units interacting simultaneously; the next subsections address this approach and its resulting estimates of changes in system reliability due to FGD.

4.6.4 Incremental Loss-of-Load Probability for a Power System

In this section, the calculation of the incremental loss-of-load probability (ILOLP) for a system of units* in a region is discussed. It was assumed that the system demand is distributed among all units such that the load duration curves of Section 4.2 were applicable to individual base-load and intermediate-load units.

In a given set of calculations, the incremental loss-of-load probability for new coal units was obtained for a particular region, assuming that all these units in the region had the same number of scrubber modules and that the probability that a particular module was up was the same for all modules. Separate calculations were made for the following cases:

*"System of units" in this case representing only a portion of total generating capacity.

(1) no scrubbers;

(2) five modules per unit and r = .9, where r is the probability a given module is up;

(3) six modules per unit and r = .9;

(4) five modules per unit and r = .8; and

(5) six modules per unit and r = .8.

These new coal generating units were classified as follows:

(1) large (600 megawatts or more) base units,

(2) small (390-599 megawatts) base units,

(3) large intermediate units, and

(4) small intermediate units.

The analysis presented in Section 4.6.1 was used to calculate the mean and standard deviation of the proportion of total power available for a given unit in each of the four categories. Then using properties of the mean and standard deviation along with other information, the mean and standard deviation of total power available for a given region were computed. The other information used was

(1) the mix of base- and intermediate-load new coal units and

(2) the average sizes of the large and of the small new coal units in the region.

Now define as a random variable:

Y = total power available at all units in the region.

The mean and standard deviation of Y are known, then, through the analysis discussed above. Also define as a random variable:

X = total power demand at all units in the region.

The mean and standard deviation of X can be obtained by using properties of the mean and standard deviation, the demand characteristics, and the generation mix. Then define as a random variable:

$$L = Y - X \tag{6}$$

As before, loss-of-load occurs if L is less than zero. The probability of this event occurring was calculated; details of the calculation are in Appendix A. Because of time considerations, this probability as used in this study is an incremental loss-of-load probability (ILOLP), since only that increment of system capacity composed of new coal units was considered in the calculation. ILOLP's were calculated for each region with and without FGD on all new coal units and for each of the four modular configuration/availability cases. THESE PROBABILITIES MUST NOT, IN ANY WAY, BE CONSTRUED TO REPRESENT ACTUAL EXPECTED <u>TOTAL</u> LOSS-OF-LOAD PROBABILITIES FOR THE REGIONS; <u>THEY</u> <u>ARE</u> <u>NOT</u>. However, if it is assumed that (1) the unit load duration curves given in Section 4.2 represent operation with interactions among all units (i.e., the total system is economically dispatched and/or operates under automatic generation control or load frequency control), and (2) expected mix of base- and intermediate-load new coal units without FGD represents operation at a reasonable system total loss-of-load probability with adequate reserves (i.e., the system is neither overbuilt nor underbuilt), then these values of ILOLP can be used to compute a percent additional generating requirement for the system with FGD. This requirement represents the amount of additional generating capacity necessary such that the computed ILOLP for the system with FGD is equal to the computed ILOLP for the same system without FGD. In other words, if the system studied is neither overbuilt nor underbuilt without FGD, it has a particular acceptable reliability level. If FGD is then required on all new coal units, reliability is reduced such that a mean amount of additional capacity equal to the mean additional generating requirement is required on the average to restore mean system reliability as measured by ILOLP to the previous level attained without FGD.

In mathematical terms, the above computation is as follows:

$$P(L<0.0)\Big|_{\substack{\text{no FGD} \\ \text{and } M_o \text{ MWe}}} = \rho_1 \tag{7}$$

and

$$P(L<0.0)\Big|_{\substack{FGD_i \\ \text{and } M_o \text{ MWe}}} = \rho_i < \rho_1 \tag{8}$$

where

FGD_i is a given FGD configuration and availability

and

M_o is the initial system capacity in MWe without FGD.

Therefore, if M_i is the additional generating requirement in MWe for FGD_i, then

$$P(L<0.0)\Big|_{\substack{FGD_i \\ \text{and } (M_o + M_i) \text{ MWe}}} = \rho_1 = P(L<0.0)\Big|_{\substack{\text{no FGD} \\ \text{and } M_o \text{ MWe}}} \tag{9}$$

This value of M_i was thus calculated for each region.

It should be noted that for a given region, L is the sum of the power available at each unit and the (negative of the) demand at each unit. Since each region contains at least 40 units, and in most cases, close to 100 units or more, it is evident that L is the sum of a large number of terms. Therefore, the calculation of M_i could be a very complicated and time-consuming process which might have been impossible given the time constraints of this study. However, it is reasonable to assume that L is normally distributed: the Central Limit Theorem in statistics states that under certain conditions, sums of large numbers of randomly varying quantities are approximately normally distributed, and the properties of normally distributed random variables are well-known and easily computed. The normality property, along with the means and standard deviations discussed above, then, were used to compute easily the incremental loss-of-load probabilities and, hence, the mean additional generating requirements $\overline{M}_i$. $\overline{M}_i$ is a mean value in MWe which was computed using the Central Limit Theorem and, thus, other mean values. In simplified terms, $\overline{M}_i$ was calculated from the relationship

$$\overline{L} = \overline{Y} - \overline{X} \tag{10}$$

where

$\overline{L}$, $\overline{Y}$, and $\overline{X}$ are mean values, and where

$$\overline{Y} = Y \cdot \overline{A} \qquad (11)$$

where

Y = total capacity available
$\overline{A}$ = mean new coal unit availability for the region without FGD.

Therefore, $\overline{M}_i$ must be scaled to represent the total capacity requirement M_i due to FGD. This scaling is accomplished by dividing $\overline{M}_i$ by the mean new coal unit availability without FGD for the region, $\overline{A}$. These results neglect the effects of FGD units on any additional operating capacity required.

In the calculations discussed above, correlations between demands at different units in the same region at the same time were not considered. Such correlations probably exist because of several factors; for example, all units would be affected by the same type of diurnal cycle. The result of this emission is to shift the incremental loss-of-load probability toward 0.5 to some extent. The investigation of these correlations was beyond the scope and limited timeframe of this study; it is felt, however, that the effect of the correlations is not drastic.

4.6.5 Expected Effect of FGD on System Reliability

This section considers the effect of FGD on the effective generating capacity of a power system. Listed in Table 13 are mean expected additional generation requirements

Table 13. MEAN ADDITIONAL CAPACITY REQUIREMENTS IN PERCENT OF NEW COAL CAPACITY TO OFFSET THE RELIABILITY EFFECTS OF FGD

Case	No. Modules	No. Spares	Availability Per Module	Mean Additional Generation Requirement $\overline{M}_i$ [a]
1(Base)	0	---	---	0
2	5	0	90%	4.5%
3	5	1	90%	1.2% (Best)
4	5	0	80%	9.9% (Worst)
5	5	1	80%	4.4%

[a]Expressed as a percentage of new coal capacity without FGD. Does not include boiler/turbine/generator availability effects.

$\overline{M}_i$ for the different scrubber module configurations and different module availabilities studied. As was previously mentioned, mean new coal unit availabilities for each region must be used with these mean additional requirements to determine the amount of actual total additional capacity required to compensate for the generating capacity lost due to lower FGD availability.

It can be seen from this table that the scrubber system of Case 3 had the least effect on the system performance, while Case 4 caused the largest decrease in system/mean available capacity. It must also be noted that Cases 2 and 5 had similar mean additional generation requirements indicating that adding a spare module compensated for the ten percent drop in module availability. These results may be sensitive to future statistical findings.

These calculations were made for the expected generation mixes in each reliability region and for other additional mixes and capacities. It was found that the mean percent additional requirements given in Table 13 were independent of either the mix of base and intermediate units or the total generating capacity in a region. The expected probability of excess demand* for new coal is sensitive to these considerations and is tabulated by region in Appendix C. This result is important because if the mean percent additional capacity requirement *per se* were independent of regional considerations, such as mix or load factor, then the results of this study could be easily applied to many different cases. Regional considerations would only be required to determine type and amount of total replacement capacity from the mean percent requirement expected. More detailed investigations should be made to verify and further clarify this relationship.

*Probability of excess demand = ILOLP

SECTION 5
EVALUATION AND INTERPRETATION OF RESULTS

The effect of FGD on reliability for units put on-line before 1986 was first evaluated and found to be only marginally important. Next, the effect on units put on-line between 1985 and 2000 was estimated for one individual unit and for an entire system. This study of the net effect of FGD on power generation led to several conclusions. First, significant amounts of additional capacity may be required to obtain the same ability to meet load as can be maintained without FGD. Second, constraints on power interchange among power pools may restrict necessary power flows to deficient utilities during FGD-induced outages such that interchange cannot significantly mitigate the impact of FGD. Finally, an analysis of reserves indicates that systems may be underbuilt by 1985 and thus may be unable to keep adequate reserves or, in some cases, to meet demand. It was found that further reductions in reliability caused by FGD would impact this problem. Measures to mitigate these impacts of FGD were also determined.

In this section the results leading to these conclusions will be evaluated. This evaluation considers the following subjects:

- Additional capacity requirements
- Constraints on interchange
- Reserve policies and requirements
- Uncertainty and sensitivity of study

5.1 Effect of FGD on Additional Capacity Requirements

The data and methodology presented in Section 4 were combined to provide estimates of the expected effect of FGD on individual unit and system reliability. This analysis assumed that any revised NSPS would require scrubbers on all new coal units not presently under construction. In this section, results are presented which reflect the effects of this implementation of FGD on the reliability of the nine regions of the U. S. before 1986 and between 1985 and 2000.

5.1.1 Effect of FGD on Reliability - Units On-line Prior to 1986

It was found that the proposed NSPS for coal-fired power plants will not drastically affect units which are on-line prior to 1986 because many of these units are already under construction. However, to subjectively determine the effect of any scrubbers on-line during this period, data furnished by EPA[14] for units and FGD systems presently either planned or under construction were collected and analyzed. These data are summarized in Table 14. As can be seen from the table, only about 20 percent of the new coal units on-line in 1985 are expected to have FGD systems.

Table 14. ESTIMATED SCRUBBER ADDITIONS BEFORE 1986

Region	New Coal MWe	New Coal % Total New Generation	No. Units [a]	No. Scrubbers [b]
1 - ECAR	30,122	62%	59	12
2 - ERCOT	7,798	54%	14	6
3 - MAAC	2,500	12%	4	0
4 - MAIN	8,752	38%	21	4
5 - MARCA	10,942	100%	27	7
6 - NPCC	2,278	13%	5	1
7 - SERC	12,862	28%	24	3
8 - SPP	17,097	56%	32	4
9 - WSCC	27,985	59%	65	17
U. S. TOTAL	120,336	46%	251	54

[a] Teknekron data
[b] EPA data cited in above text

From a more rigorous standpoint, NERC reports that 20 percent of the total additional generating capacity required in 1985 is presently not under construction.[17] If it were therefore assumed that 20 percent of new coal capacity on-line before 1986 were also not under construction, then from Table 13, a revised NSPS would only affect about 9 percent of the total new national generating capacity. For the worst case studied (5 modules/no spares at 80% availability) this effect can be estimated as requiring about 5100 additional MWe nationwide. This estimation was done using the methods described in Section 4.6.4 for new coal generation on-line between 1985 and 2000.

Therefore, because of the small number of scrubbers planned in each region prior to 1986 and the small percentage of total additional generation which might require FGD, it is expected that the implementation of a revised NSPS would have very little effect on overall regional system reliability prior to 1985. There are few possible exceptions to this statement: one is WSCC, where overall reliability will probably not be adversely affected, provided that another massive water shortage does not occur. These conclusions are, of course, subject to change if (1) more widespread use of FGD were required in this period, (2) construction of new units continues to be delayed (Section 5.3) such that systems are significantly underbuilt, (3) scrubbers are installed without spare modules and with lower modular availability (< 80%) than is presently assumed, or (4) another massive fuel shortage occurs at the wrong time of year and puts a large number of units out of service.

5.1.2 Effect of FGD on Reliability - Units On-line Between 1985 and 2000

Assuming that the forecasts and data in Section 4 (without scrubbers) are correct insofar as reserves are concerned, (i.e., future system reliability is within reasonable bounds and required reserves are maintained), then the effect of FGD would be to produce a deficit in available generation such that reliability standards and reserve requirements would no longer be met. The results in Section 4.6.5 were analyzed based on this assumption to give the additional generating capacities which must be planned for and added in order to make reliability as measured by ILOLP equal to the base case (no scrubbers) ILOLP values for each region. These mean additional capacity requirements $\overline{M}_i$ in percent (as in Section 4.6.5) were found to be virtually identical by case regardless of system configuration.

Total additional capacity in MWe thus required in each region with FGD was obtained by dividing the mean additional capacity requirement in percent by the mean new coal unit availability for each region and multiplying by the amount of new coal generation MWe, as in Section 4.6.4. Thus, this study has recognized that this additional capacity would operate at the same mean availability as new coal without FGD. Table 15 gives these expected additional requirements in MWe to offset FGD reliability only for the five cases studied by region and nationally. In addition, energy penalties associated with scrubber operation were determined; these total expected generation requirements to offset these penalties by region are shown in Table 16. As was the case for reliability results, operation at the same availability without FGD as other new coal was considered. Total additional capacity required to offset FGD (reliability plus energy) is seen in Table 17.

As will be discussed in Section 5.3, it was found that this additional capacity will most probably be made up of new units. If present trends continue, these new units will probably also be new coal units. The additional generating requirements due to FGD were therefore estimated in terms of equivalent 600 MWe coal units.* These estimates are summarized in Table 18.

It can be seen from Tables 15-18 that a large amount of additional generation will be required to offset the effects of the widespread implementation of FGD. Since the 1970 NPS estimates that demand during the period 1990-2010 will double about every 10-12 years, these additional requirements after 2000 will also increase in like manner. Therefore, it is important to consider measures which would mitigate the impact of FGD. If it is assumed that the United States will continue to develop its

* 600 MWe units were assumed in order to agree with assumptions in the Teknekron data.

Table 15. ADDITIONAL CAPACITY REQUIREMENTS IN MWe TO OFFSET FGD RELIABILITY ONLY IN 2000

Region	MWe Case 1 (Base)	MWe Case 2 (5/0@90%)	MWe Case 3[a] (5/1@90%)	MWe Case 4[b] (5/0@80%)	MWe Case 5 (5/1@80%)
1-ECAR	0	7,490	1,995	16,480	7,325
2-ERCOT	0	4,295	1,145	9.445	4,115
3-MAAC	0	2,115	565	4,650	2,065
4-MAIN	0	3,290	880	7,245	3,220
5-MARCA	0	1,600	425	3,515	1,560
6-NPCC	0	1,840	490	4,055	1,800
7-SERC	0	5,120	1,365	11,260	5,005
8-SPP	0	4,625	1,235	10,170	4,520
9-WSCC	0	4,605	1,230	10,130	4,500
U.S. TOTAL	0	34,980	9,330	76,950	34,190

[a] Best Case
[b] Worst Case

Table 16. EXPECTED ADDITIONAL GENERATION REQUIREMENTS DUE ONLY TO FGD ENERGY USE PENALTIES BY REGION IN 2000

Region	Maximum Additional Generation Requirements Due to FGD Energy Penalty - MWe[a]
1-ECAR	6,325
2-ERCOT	3,245
3-MAAC	1,785
4-MAIN	2,780
5-MARCA	1,210
6-NPCC	1,555
7-SERC	4,320
8-SPP	3,495
9-WSCC	3,480
U.S. TOTAL	28,200

[a] Includes only effects of new coal unit boiler/turbine/generator mean availability.

Table 17. TOTAL FGD-RELATED ADDITIONAL CAPACITY REQUIREMENT BY REGION IN 2000 - MWe

Region	Case 1	Case 2	Case 3[a]	Case 4[b]	Case 5
1-ECAR	0	13,815	8,320	22,805	13,650
2-ERCOT	0	7,540	4,390	12,690	7,440
3-MAAC	0	3,900	2,350	6,435	3,850
4-MAIN	0	6,070	3,660	10,025	6,000
5-MARCA	0	2,810	1,635	4,725	2,770
6-NPCC	0	3,400	2,050	5,615	3,360
7-SERC	0	9,440	5,685	15,580	9,325
8-SPP	0	8,120	4,730	13,665	8,015
9-WSCC	0	8,085	4,710	13,610	7,980
U.S. TOTAL	0 (base)	63,180	37,530	105,150	62,390

[a] Best Case

[b] Worst Case

Table 18. TOTAL FGD-RELATED ADDITIONAL CAPACITY REQUIREMENTS BY REGION IN 2000 - 600 MWe COAL UNITS

Region	Case 1	Case 2	Case 3 [a]	Case 4 [b]	Case 5
1-ECAR	0	23	14	38	23
2-ERCOT	0	13	7	21	13
3-MAAC	0	7	4	11	7
4-MAIN	0	10	6	17	10
5-MARCA	0	5	3	8	5
6-NPCC	0	6	4	10	6
7-SERC	0	16	10	26	16
8-SPP	0	14	8	23	14
9-WSCC	0	14	8	23	14
U.S. TOTAL	0 (base)	108	64	177	108

[a] Best Case

[b] Worst Case

coal resources as in the President's energy plan, then several alternative measures to mitigate the impact of FGD are possible. These alternative mitigation measures include:

1. Use of spare FGD modules
2. Allowance for bypass of scrubber modules on outage status with reasonable restrictions, such as when load cannot be met
3. Use of alternative technologies which meet a revised NSPS without FGD or with reduced FGD.

Other possible mitigating measures include the purchase of power from other utilities or the carrying of additional reserves on older units. However, the next two sections indicate that these latter two alternatives are too tightly constrained to be highly significant mitigation measures.

5.2 Evaluation of Interchange Constraints

In the event of an FGD-related outage on a single unit or a number of units, it is possible in some cases for a utility or power pool to purchase emergency power from another utility or pool. Hence, this study has included an investigation of the constraints on power interchange among utilities. Many of these constraints must be evaluated using classical electrical AC network theory, since the flow of power in a network is directly related to the state of the network at a given time. Such an evaluation was beyond the scope of this study. Furthermore, the explanation of network constraints given in this section is highly simplified. In addition, this section also evaluates reported non-simultaneous power transfer capabilities for the nine NERC reliability councils.

Power interchange among utilities is restricted by many different constraints. These constaints include excess generation in a given area, maximum tie line power flow capabilities, and contractual constraints. The capability to transfer power requires accessible, available power generation <u>and</u>, more importantly, accommodating tie line and supporting transmission networks. It should thus be noted that regardless of desires, contractual requirements, or net interchange capabilities, power transfer is, in the end, directly controlled by the instantaneous state of the generating system and the network. If generation is unavailable, power cannot be transferred. More importantly, if a network in a given instantaneous state (regardless of its design or available generation) cannot accommodate a desired power flow from point A to point B at a given moment when it is needed, very little can be done to alleviate the situation. Moreover, interconnection does not eliminate reserve requirements and thus cannot eliminate the additional generation requirements caused by FGD; it merely disperses them. In the case of highly constrained interchange, as exists in the U. S., it is doubtful that a reasonable dispersion of the large amounts of additional generation required by FGD could be achieved.

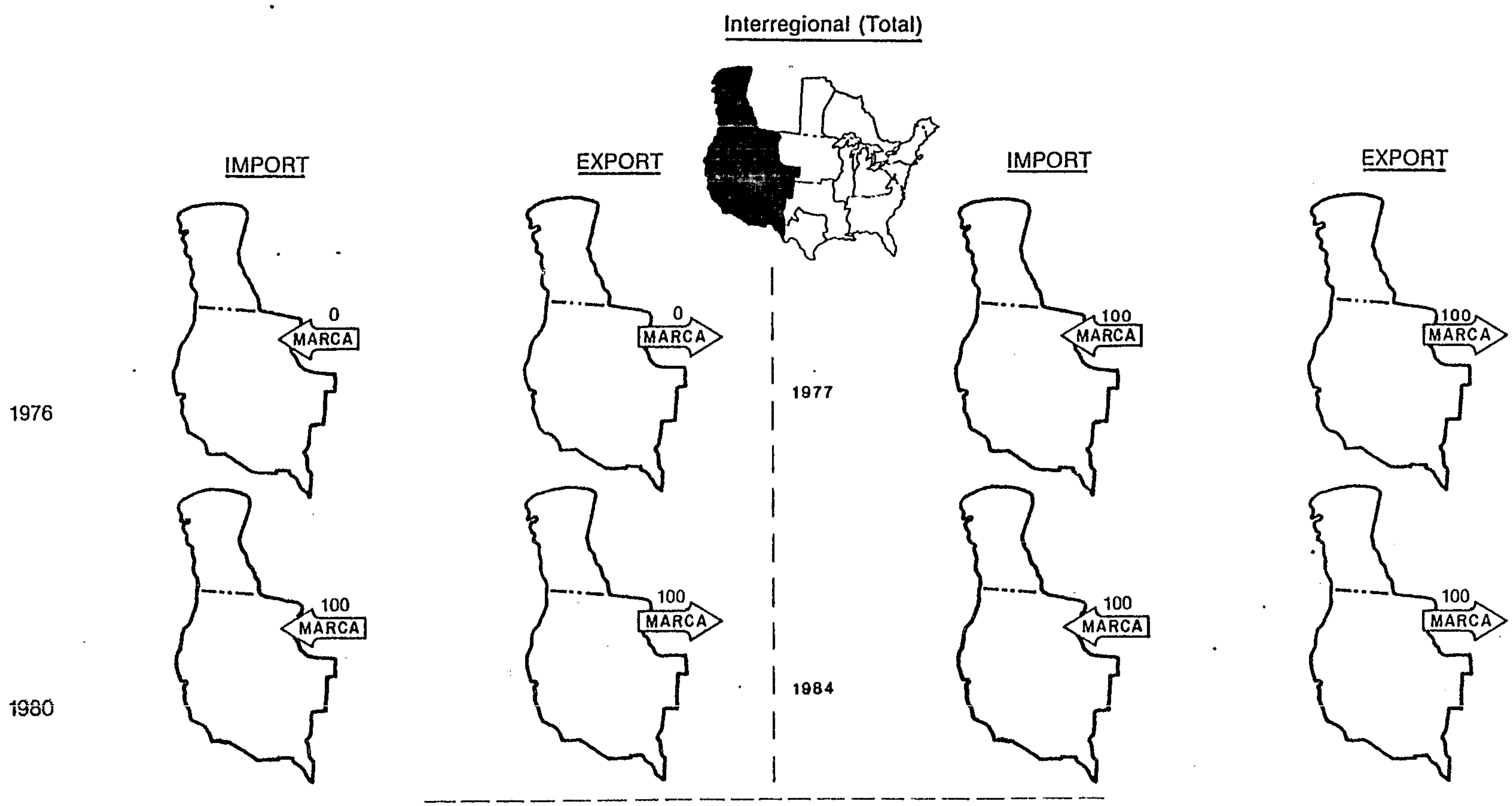
Several constraints resulting from system design and instantaneous network state may be encountered during the transfer of power.[15] Network and generation configurations including location of plants, generation type, transmission voltage, instantaneous plant power output, transformer tap settings, and so on, can strongly affect a utility's ability to interchange power. For example, nuclear units require an extended outage (one month) for refueling at predetermined intervals for optimum utilitization of the nuclear fuel. These scheduled outages can cause problems when forced outages occur coincidentally. Under certain normal network conditions, large generating plants which are electrically close to tie lines can impair tie line flows to values far below rated capacities. Furthermore, operating constraints can influence tie line capabilities. Utilities which rely on only one major fuel (usually at a uniform price) do not routinely interchange power with other utilities because it is not economical. For example, ERCOT, which traditionally has relied almost solely on natural gas at a uniform price has not engaged in significant amounts of economy power exchange among its members. Utilities of this type may be interconnected but generally do not have transmission networks which can accommodate massive power flows which might be necessary in the event of a large outage. Conversely, when a region does routinely interchange large amounts of power on an economy basis, emergency transfers may be severely restricted because tie line and supporting network flows are already near the capabilities of the transmission lines. Tie lines and network design (or network state) may affect connections in another way. One major impediment to efficient energy transactions in WSCC is loop flow. The western part of this region is a relatively low impedance network; the eastern part, high impedance. The result of this situation is that the actual flow of power through these interconnections may not match the scheduled transfer of power between control areas, and power may, in fact, loop completely around the system. Loop flow can overload essential tie lines so that in the event of an emergency, bulk power transfers become impossible. In fact, if loop flow should occur as a result of or in conjunction with power loss at a marginally stable location on a network whose state (or configuration) is also marginally stable, the flow of power can even reverse itself away from the areas where the need is greatest. This reversal generally has a cascading effect which can result in a massive blackout.

In addition to generation and transmission constraints contractual constraints on interchange also exist. In general, these contractual constraints are controlled by regulatory agencies. While most utilities have emergency short-term power exchange/payback agreements with their neighbors, utilities in many of the power pools and/or utility companies state in their interchange contracts that they are under no firm obligation to supply power in the event of forced outages of equipment, missed load forecasts, or fuel supply problems for any specific period of time. This practice is, in many cases, required by regulatory agencies in order to maintain adequate service to the supplying utility's own customers. This practice may thus inconvenience a receiving party should a power transfer be terminated; such termination can and probably will result in a severe power disruption. This type of disruption usually occurs when the supplying utility experiences a coincident outage. Obviously, the probability of this type of power cutoff increases with the widespread use of FGD systems since it has been shown that FGD reduces unit availability and system reliability. Also, in many cases, interchange transactions must be scheduled. For example, Middle South Utilities Company, located in SPP, has required in the past that the receiving party furnish a schedule twenty-four hours and, sometimes seventy-two hours, in advance of the interchange transaction. This scheduling delay, however, can be avoided through mutual agreement if it is to the advantage of both parties, as in an emergency. Middle South also burns cheaper fuel for their own system load and reserves the higher priced fuel for power transfers. This practice, generally regulated to assure their customers of a cheaper rate, can cause delays in emergency shipment to cover extended outages if the price of power is too high. In addition, political constraints, such as recent actions by some states to keep cheaper types of power at home, can influence the power interchange transactions from region to region.

While it has been shown above that interchange of power is strongly constrained by a number of factors, it is still important to evaluate any maximum interchange capabilities which might be required in the event of an outage. Present and expected future power interchange capabilities vary considerably from region to region. The following diagrams show the potential non-simultaneous energy transfer capabilities of each of the nine NERC reliability regions with neighboring regions and subregions.[16,17] Each of these capabilities represents the maximum possible power transfer capability which might be expected under ideal network conditions. Furthermore, each of these interchange capabilities represents a non-simultaneous interchange; i.e., not all transfer capabilities shown can be utilized at once. Actual transfer capabilities thus can be expected to be somewhat less than these values for reasons given previously.

Figure 9 shows that WSCC (Region 9), presently participates in no significant interregional power transfers; it is anticipated that the minor interconnections with MARCA (Region 5) which presently exist will not increase significantly in size due to stability considerations. WSCC does have strong subregional power transfer capabilities among member utilities; this subregional interchange capacity is expected to increase in the future. Figure 10 shows that ERCOT (Region 2), the most independent reliability region, still has no interconnections with any other regions. It is anticipated that this situation will probably not change in the future. However, ERCOT is divided into northern and southern subregions which can, and do, engage in limited emergency power exchange among member utilities.

MARCA, Figure 11, can engage in power interchange with MAIN (Region 4), SPP (Region 8), and WSCC. It appears that MARCA will gradually increase energy import capability and decrease export capability to MAIN over the next six years, while power interchange capability with SPP should remain relatively constant.



Intraregional (Total)

	1976	1980
WASH/ORE/IDAHO/MONT/UTAH to CAL/NEV	3400	4300
WASH/ORE/IDAHO/MONT/UTAH to ARIZ/COL/NM/WYO	1500	1580
CAL/NEV to WASH/ORE/IDAHO/MONT/UTAH	3400	4300
CAL/NEV to ARIZ/COL/NM/WYO	2300	2300
ARIZ/COL/NM/WYO to WASH/ORE/IDAHO/MONT/UTAH	1500	1580
ARIZ/COL/NM/WYO to CAL/NEV	2300	2300

Figure 9. Non-simultaneous emergency transfer capabilities (MWe) - WSCC.

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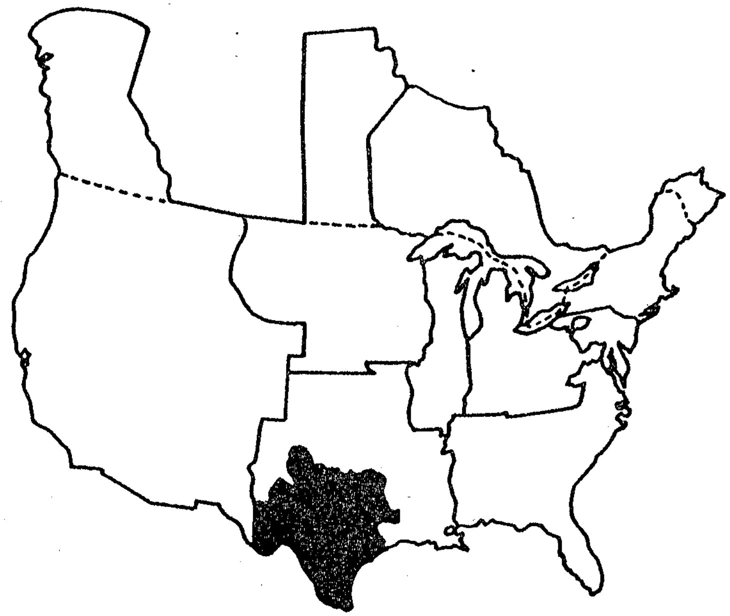

No permanent normally closed
interconnections with any other regions

Intraregional (Incremental)

	1976	1980
NORTH AREA to SOUTH AREA	900	1200
SOUTH AREA to NORTH AREA	900	1200

Figure 10. Non-simultaneous emergency transfer capabilities (MWe) - ERCOT.
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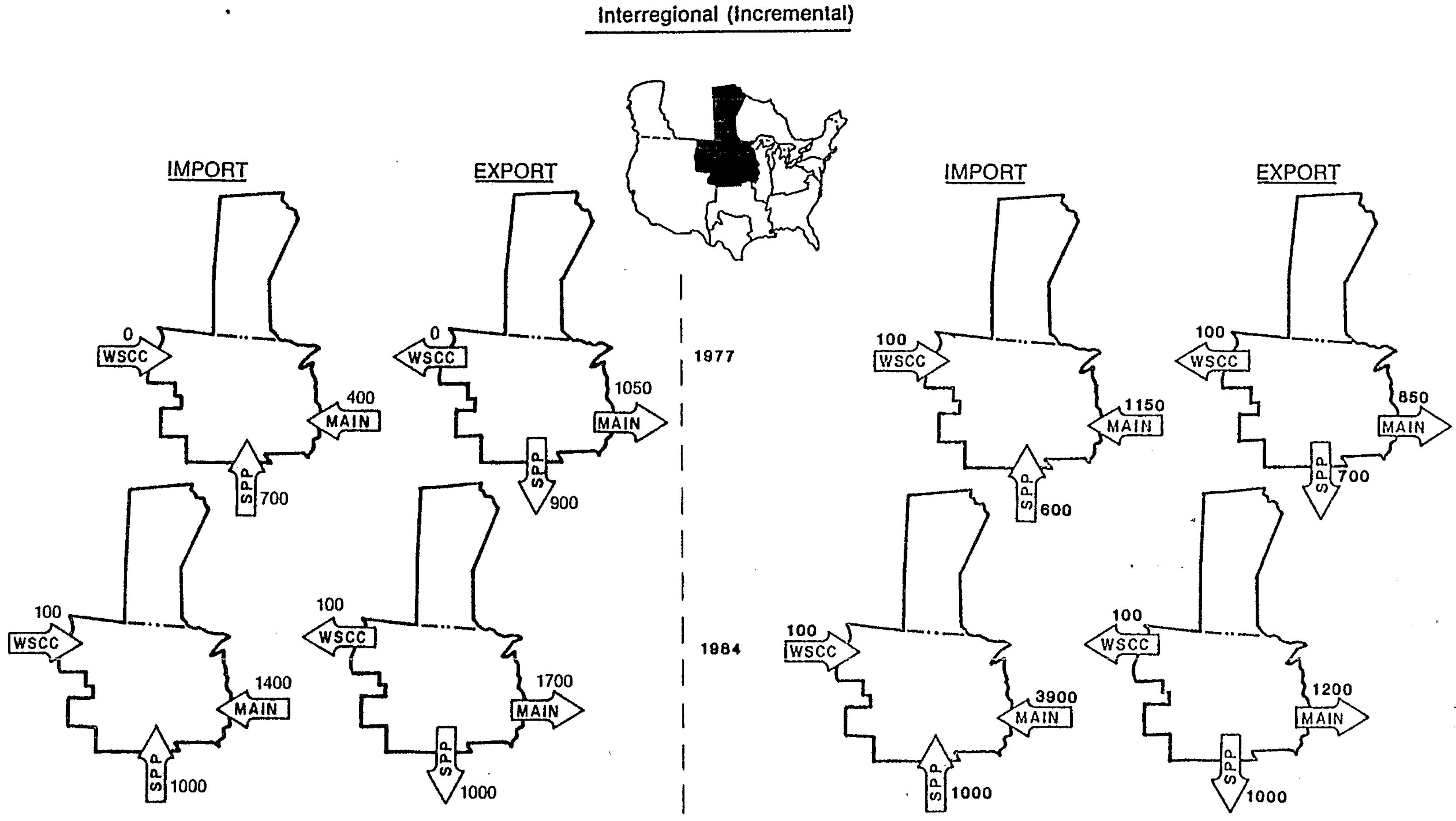

Intraregional (Incremental)	1976	1980
DAKOTAS to MINN	100	400
DAKOTAS to IOWA	500	400
DAKOTAS to NEBRASKA	300	400
IOWA to MINN	250	650
IOWA to NEBRASKA	350	—
MINN to IOWA	450	1000
MINN to NEBRASKA	350	900

Figure 11. Non-simultaneous emergency transfer capabilities (MWe) - MARCA.

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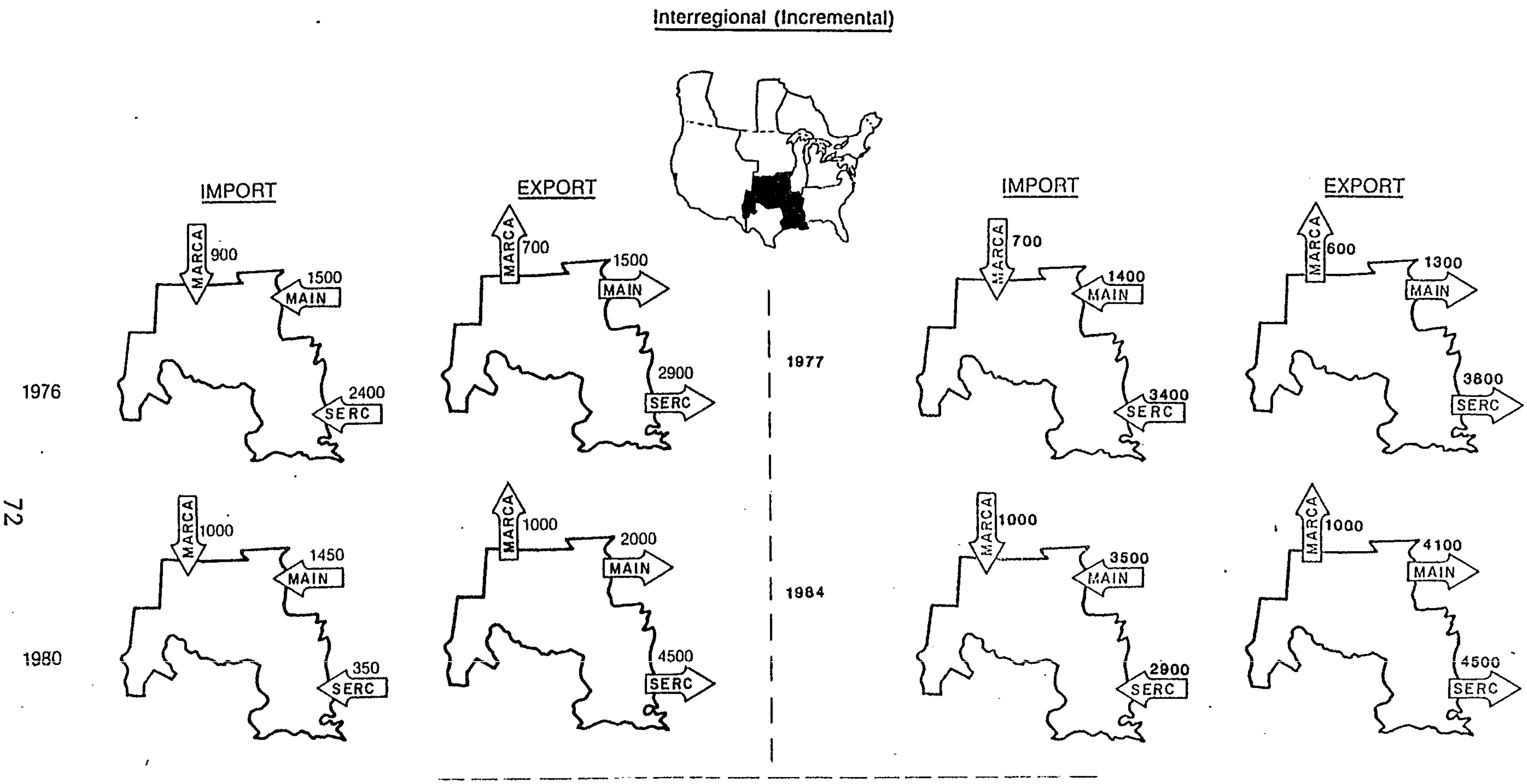
The seven subregions of MARCA can also transfer power among themselves. SPP, Figure 12, can exchange power with SERC (Region 7) and MAIN in addition to MARCA. SPP also can interchange heavily among its four subregions. Figure 13 shows that MAIN can engage in sizable power exchange with MARCA, SPP, ECAR (Region 1), and SERC. These exchange capabilities are expected to increase by 1984. MAIN is divided into six subregions which also can engage in heavy power transfer. SERC, Figure 14, is subdivided into eight subregions which are also involved in power interchange. SERC also can transfer power with SPP, MAIN, ECAR, and MACC (Region 3). These transfer capabilities are expected to increase, with one exception; by 1984, energy export capabilities to SPP should decrease considerably. This reduction could indicate the installation of a new large generating unit by a member of SERC in the area of that particular interconnection. NPCC, (Region 6), Figure 15, power pools with ECAR and MAAC, and is composed of six subregions which also can transfer large amounts of power among themselves.

Figures 16 and 17 show the interchange capabilities of ECAR and MAAC. These regions are not divided into subregions, and are generally dispatched as single systems without regard to individual member utilities. Therefore, their power interchange capabilities _per se_ are strictly interregional. ECAR has interchange capabilities with MAAC, MAIN, and SERC; and MAAC can interchange with SERC, ECAR, and NPCC.

From the above figures and text, it is apparent that the eastern power pools are more tightly interconnected than the western pools; however, no interconnections have been made between the east and the west. It is doubtful that any major east-west interties will be established before 2000, if at all.



Intraregional (Incremental)

	1980 Imports	1980 Exports
ARKANSAS/LA./MISS./E. TEXAS	2000	2000
OKLA./W. ARKANSAS	2000	2000
KANSAS/W. MISSOURI	1700	2100
MISSOURI	500	500

Figure 12. Non-simultaneous emergency transfer capabilities (MWe) - SPP.

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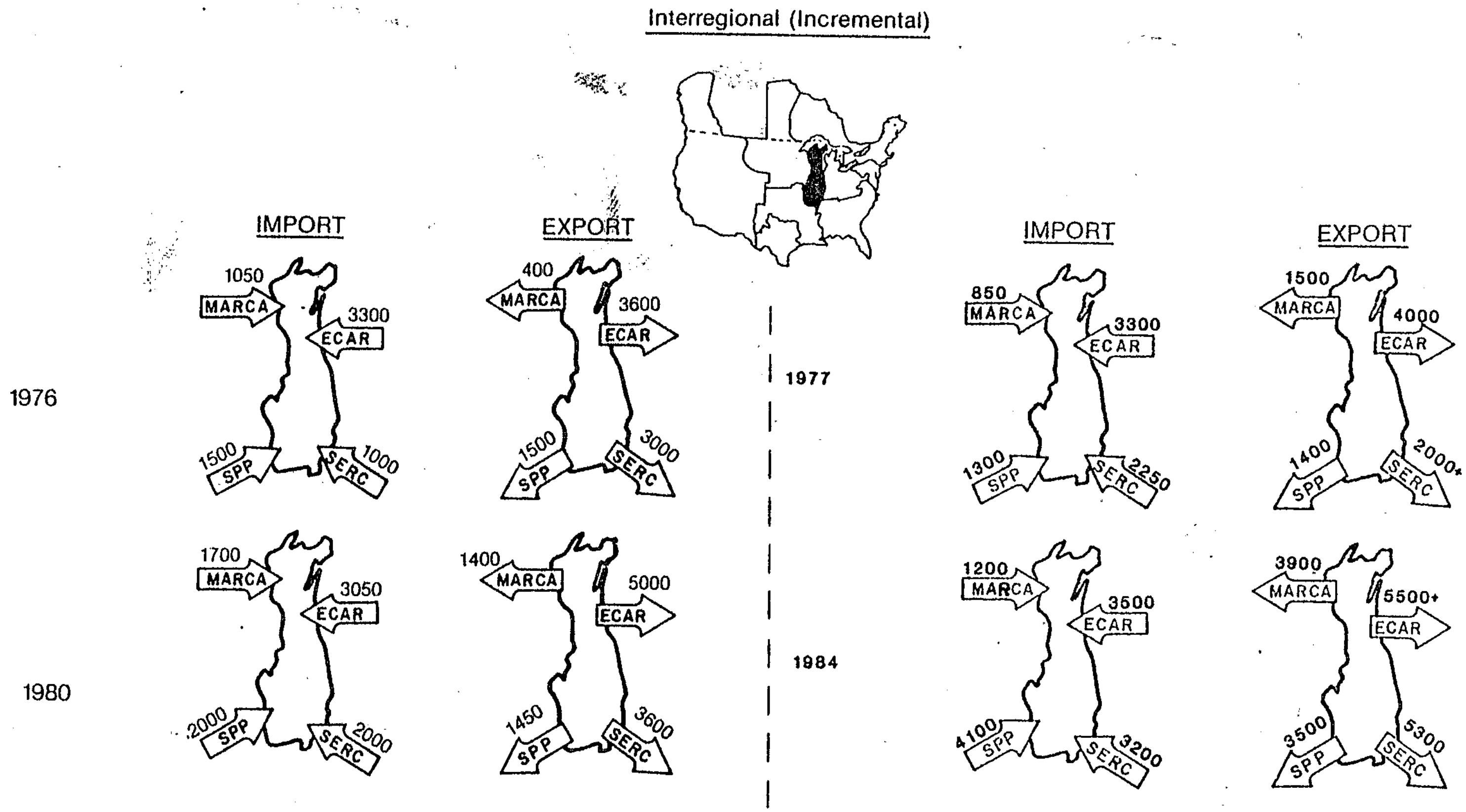

Intraregional (Incremental)

	1976	1980
COM ED (C.E.) to WIS.-UP. MICH. (WUMS)	1100	1600
CE to CENTRAL ILL.	1500	2000
WUMS to C.E.	800	750
CENTRAL ILL. to C.E.	600	2300
CENTRAL ILL. to MISSOURI	600	1700
MISSOURI to CENTRAL ILL.	1500	2400

Figure 13. Non-simultaneous emergency transfer capabilities (MWe) - MAIN.

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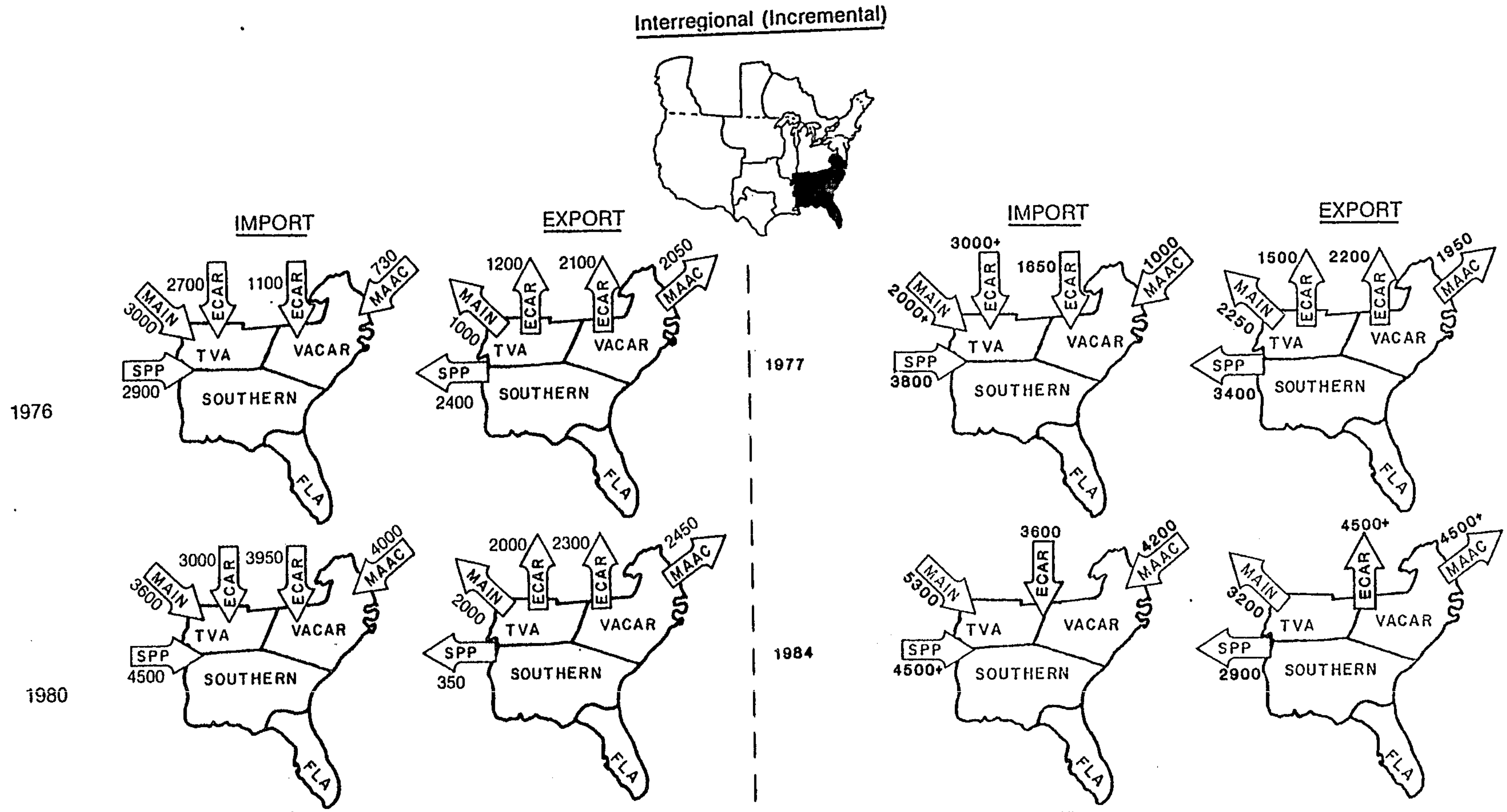
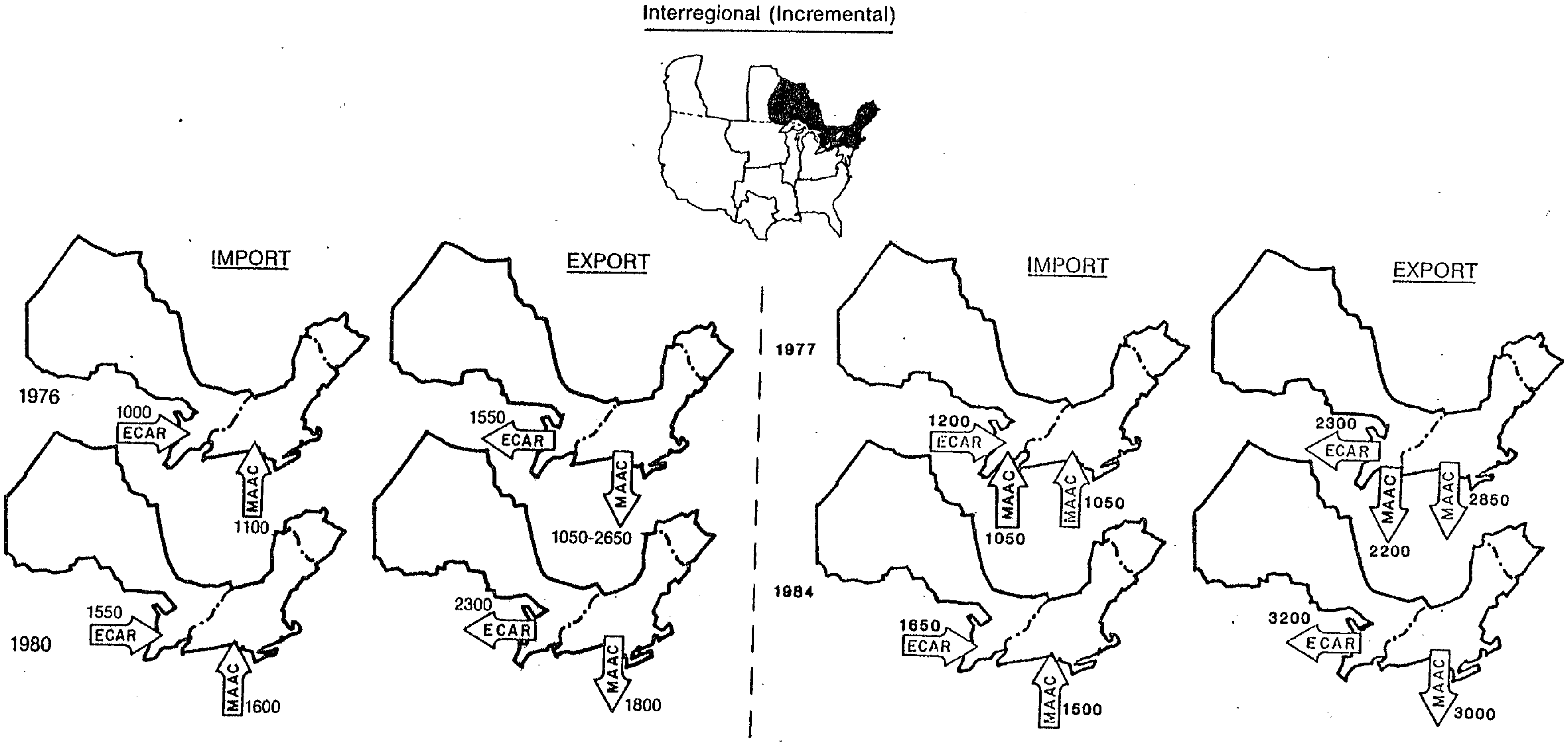


Intraregional (Incremental)

	1976	1980
FLORIDA to SOUTHERN	50	600
SOUTHERN to FLORIDA	75	400
SOUTHERN to TVA	2000	750
SOUTHERN to VA. & CAROLINAS (VACAR)	350	1500
TVA to SOUTHERN	1600	2100
TVA to VACAR	800	1100
VACAR to SOUTHERN	500	1400
VACAR to TVA	1300	1600

Figure 14. Non-simultaneous emergency transfer capabilities (MWe) - SERC.

Adapted from 6th Annual Review...(Ref. 16), 1976 and 7th Annual Review...(Ref. 17), 1977, by the National Electric Reliability Council with permission.



Intraregional (Total)

	1976	1980
NEW YORK to NEW ENGLAND	1075	1325
NEW YORK to ONTARIO*	1000	1225
NEW ENGLAND to NEW YORK	1150	1275
NEW ENGLAND to NEW BRUNSWICK	500	500
NEW BRUNSWICK to NEW ENGLAND	500	600
ONTARIO to NEW YORK*	1000	1225

*Direct ties only.

Figure 15. Non-simultaneous emergency transfer capabilities (MWe) - NPCC.

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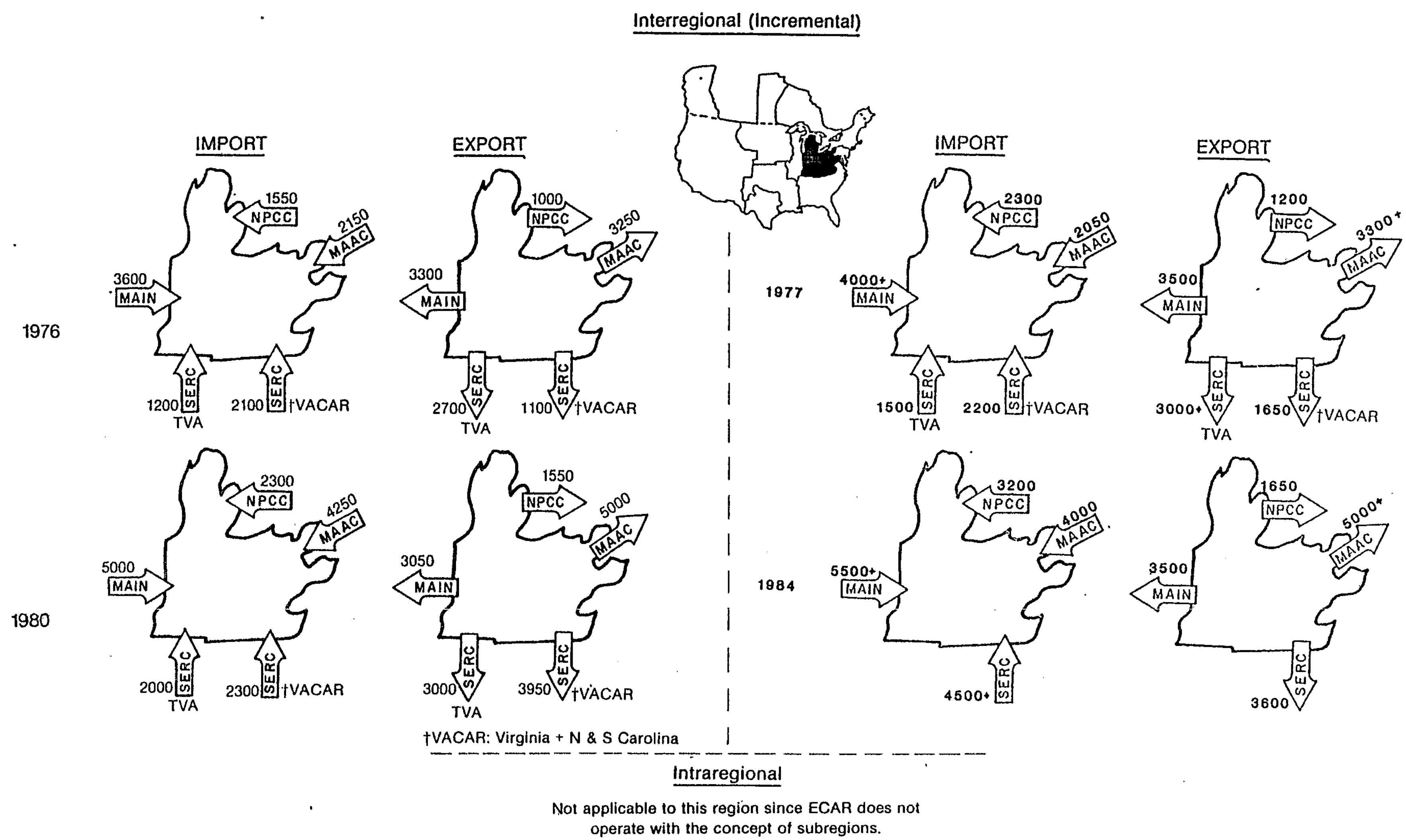

Figure 16. Non-simultaneous emergency transfer capabilities (MWe) - ECAR.

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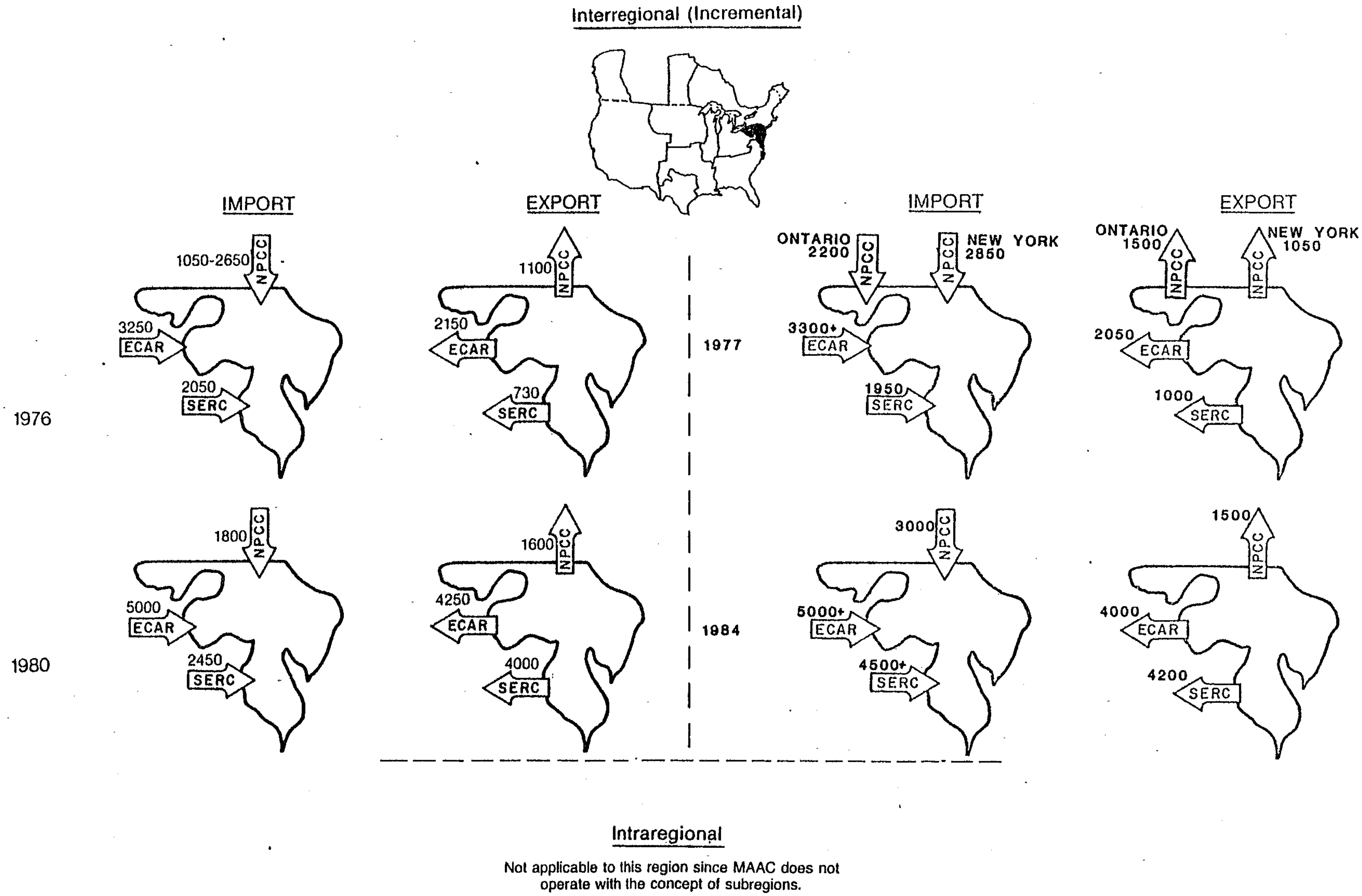

Figure 17. Non-simultaneous emergency transfer capabilities (MWe) - MAAC.

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Power pools with more efficient tie line networks coupled with increased reserves could alleviate some disruptions in power flow caused by FGD. However, because of fairly strong constraints on the interchange of power among different regions, it was determined that bulk power shipments most probably could not significantly reduce the additional capacity requirements caused by widespread implementation of FGD over long periods of time.

5.3 Evaluation of Utility Reserves

Generation reserves for utilities are essential in maintaining continuity of service. Shortages in power resulting from forced outages, delays or maintenance on new generating units, and fuel supply problems, require the use of reserve generation to maintain a given level of reliability. Reserves, therefore, must be maintained at levels sufficient to cover anticipated possible power losses. Such power losses include:

- an error in load forecast such that actual peak load exceeds forecast by 15-20 percent,
- the loss of the largest generating unit or plant on a system,
- the loss of the largest transmission line on a system, and
- the loss of the largest interconnection with imported power.

The amount of reserve generation utilized in each individual region ranges between 15 and 20 percent and is not uniform across the nation. This range of percent reserves is generally considered by the industry to be adequate, although 15 to 25 percent of capacity is preferred for the mean unit sizes in use today.

Since it has been shown in previous sections that use of FGD on all new coal units will reduce system reliability, it follows that FGD will increase system reserve requirements. Hence, if a revised NSPS were adopted, additional generating capacity would have to be added to the nation's utilities in order to maintain levels of reliability achieved without FGD; required amounts were seen in Section 5.1.2. Two factors regarding reserves, then, are relevant to a discussion of the impact of FGD on power system adequacy. These factors are:

(1) how the additional generating requirements imposed by widespread use of FGD will be met, and

(2) whether or not systems without FGD can be expected to contain adequate reserve capacity in 2000.

These factors will now be addressed.

System reserve requirements are affected by many different considerations. In order to increase generating capacity as required by the use of FGD, several strategies could be employed; these include the following:

- construction of larger or oversized generating units

- construction of additional generating units of average size

- utilization of interchange

- modification of load shape, i.e., load factor.

The effect of each of these strategies on system reserve requirements will not be discussed. First, as the average unit size increases on a system, the percent reserve requirements must also increase to maintain a constant loss-of-load probability. An example of this requirement is shown in Figure 18. In general, if all other variables are held constant, a unit larger than average will affect reliability in a negative fashion in proportion to the square of its size.[2] For example, a 600 MWe unit would have nine times the effect of a 200 MWe unit on reserve requirements. Hence, oversizing of units reduces system reliability and increases reserve requirements. On the other hand, reserve requirements are reduced as the number of units increases because the magnitude of a failure is reduced. A system with one unit with a capacity of X MWe would require at least 100 percent reserves but a system with four units, each with capacity X/4 MWe, would require only 25 percent reserves to obtain essentially the same level of reliability. A similar reduction in reserve requirements can be seen through the use of interconnections with other utilities. Load factor also influences the reliability of a system; in general, the higher the load factor, the greater the percent reserve requirement. This is because a high load factor generally indicates a fairly flat load shape with substantially equal loads throughout the

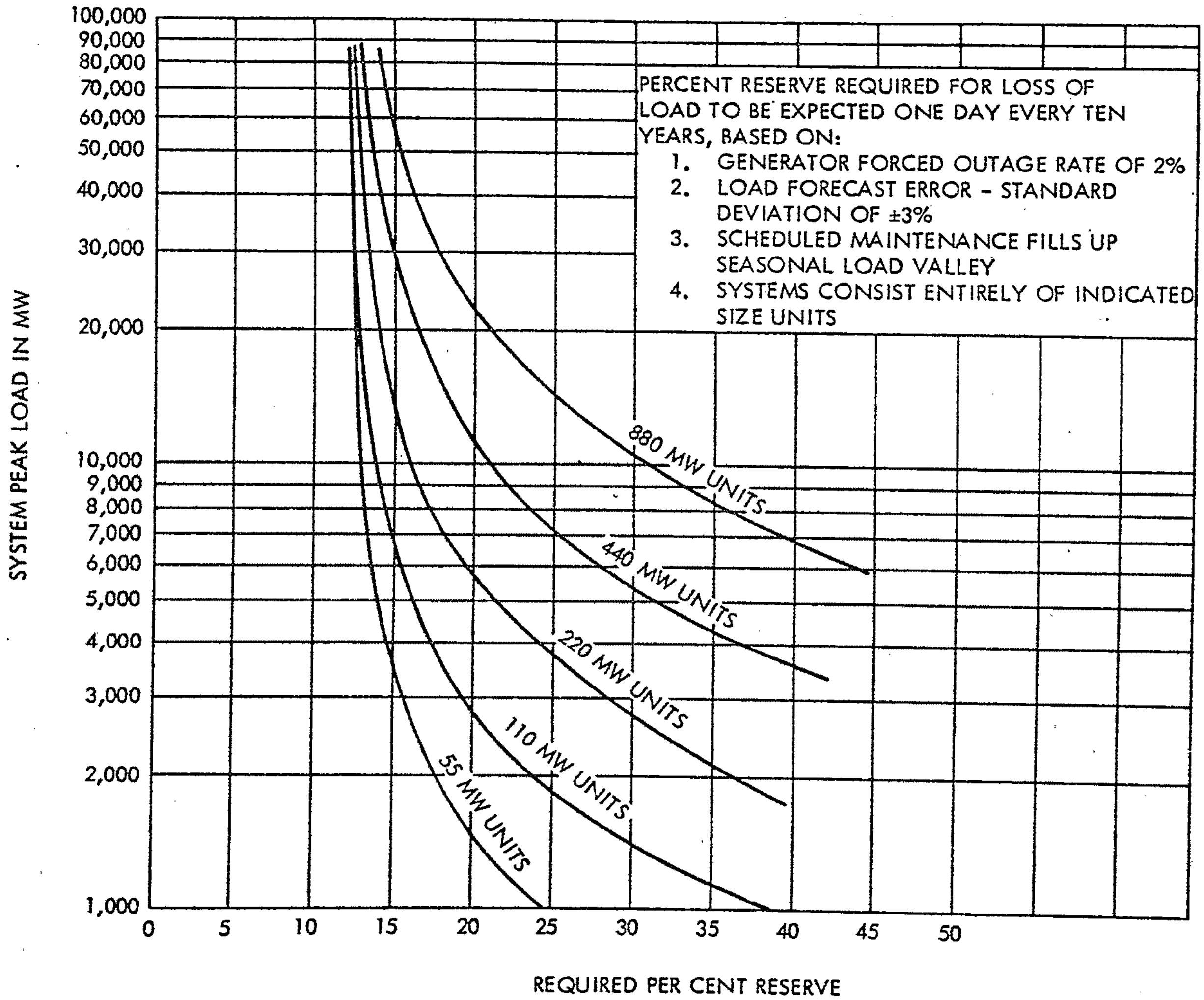

Figure 18. Reserve requirements as a function of unit size
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year. This type of load characteristic does not allow for maintenance which is usually done during extended periods of low load. Hence, the risk period is longer and additional reserves must be maintained to cover units on maintenance status. Energy conservation measures to increase base load and reduce peak load as evidenced, for example, in time-of-day metering would, thus, tend to increase percent reserve requirements from their present levels. Reductions in load factor, on the other hand, reduce percent reserve requirements at the expense of system economy. Furthermore, it is presently quite difficult to control load shape to the extent that the effect on reserve requirements is highly significant. Therefore, it can be readily seen that the feasible strategies for overcoming the effect of FGD are the following:

(1) construction of additional generating units of average size

(2) utilization of interchange

(3) modification of load shape

Since it is difficult to control load shape in order to reduce reserve requirements and since it has been shown in Section 5.2 that interchange may be strongly constrained in the future, the most feasible method of reducing reserve requirements or overcoming a decrease in reliability caused by FGD would be to build more generating units of average size. Since coal units are presently and probably will continue to be the most economical units to build and operate, it follows that decreases in reliability (and, thus, increases in system reserve requirements) caused by the widespread use of FGD, as called for in the revised NSPS, will be met in almost all cases by the construction of new, additional coal units of average size.

It is important to consider the probable future generation reserve situation in order to determine if any effects of FGD might be mitigated or possibly amplified. Nationwide reserve generation is expected to drop within the next few years as a result of insufficient power generation expansion.[17,18] According to NERC, this problem is a result of the long lead times required for the approval and construction of new plants.

Figure 19 depicts large unit generating capacity to be added nationally in the next ten years. Twenty percent of this capacity is not yet under construction. It can be projected that a certain amount of delay will be encountered with these generating units. NERC projects that coal-fired generating units which are not presently under construction will probably be delayed one year. Nuclear generating units which do not have construction permits will probably be delayed two years, and those units which are already under construction will be delayed one year because of difficulties in obtaining operating licenses. These delays do not reflect intentional delays caused by reduced growth in demand. Figure 20 shows a potential deficit in national operating reserves beginning in 1980 as a result of these delays in construction and operation. If this trend continues, the expected peak demand, as seen in this figure, could rise above generation capabilities as early as 1990. Since generation reserves are not uniform across the nation, each reliability council should be considered separately. The following paragraphs discuss projections of the probable ability of each reliability council to meet demand and maintain sufficient reserves. These projections are based on a future growth rate of 5.7 percent per year, as opposed to 7.0 - 7.5 percent per year used prior to 1977.

The individual reliability councils function according to their own unique conditions. Consequently, the system reserve policies and outlooks of these regions vary. Figure 21 shows

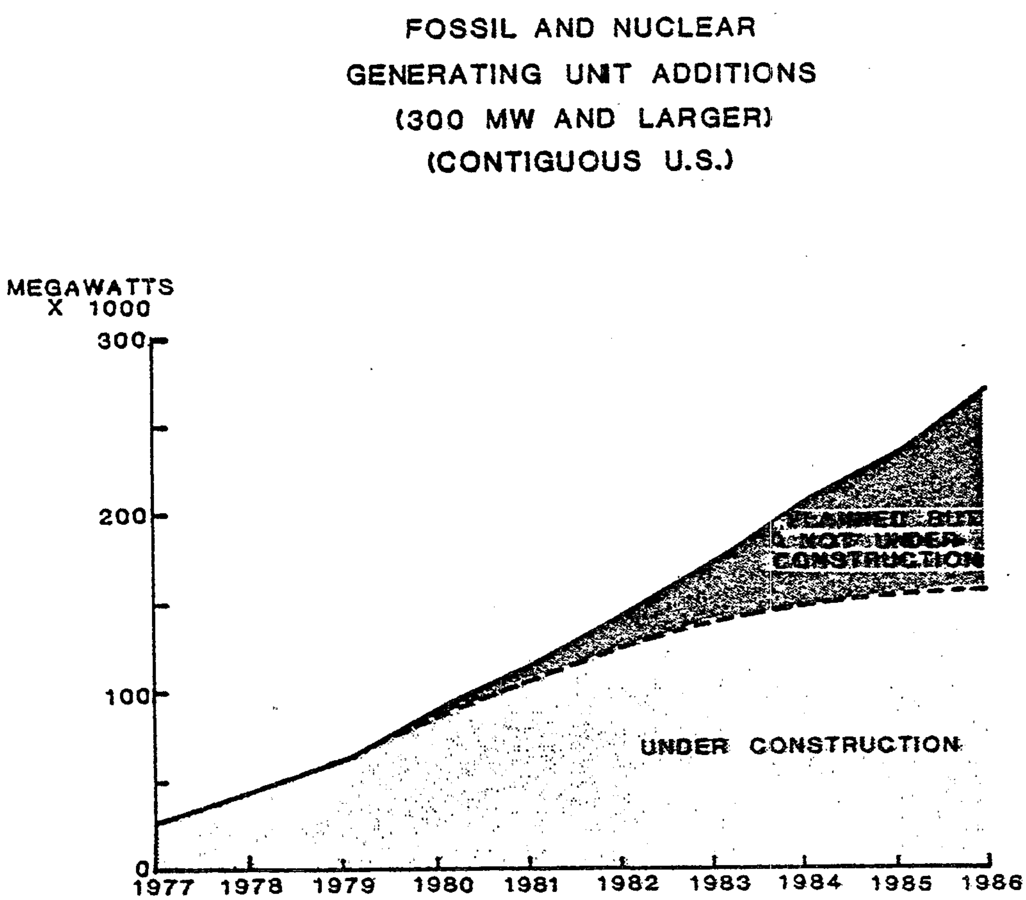

Figure 19. NERC large unit construction forecast - U. S. through 1986. Reprinted from "7th Annual Review..." (Ref. 17) by NERC, 1977, with permission.

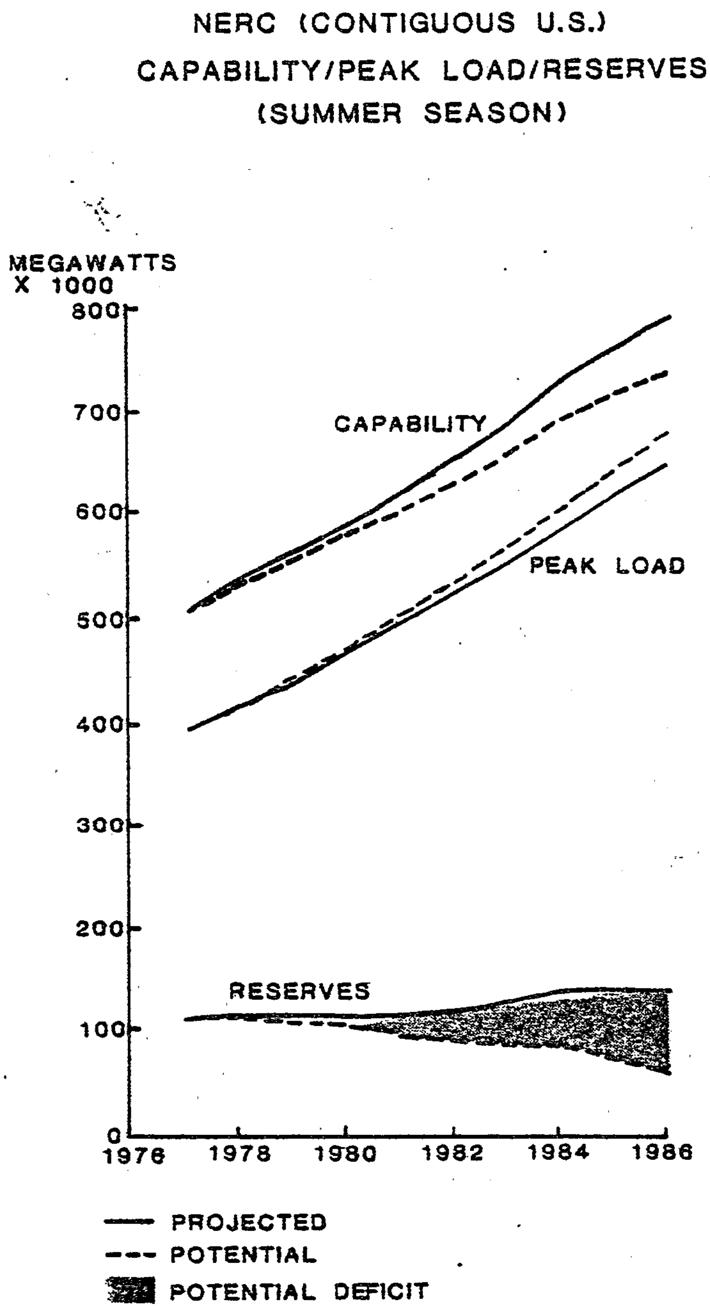

Figure 20. NERC reserve forecast for contiguous U. S. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

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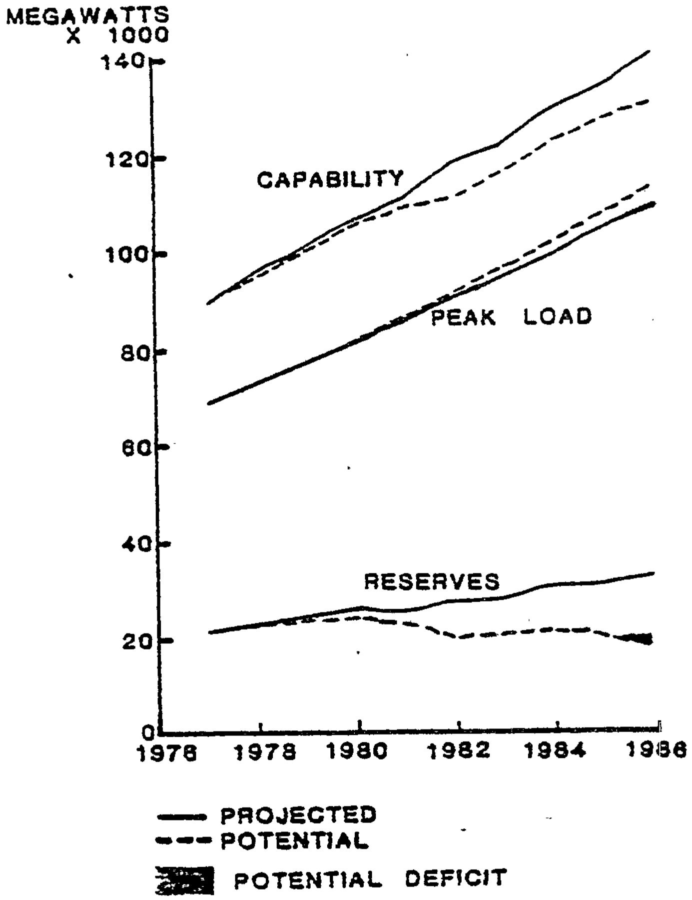

Figure 21. NERC reserve forecast for Region 9 - WSCC. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

the reserve requirement of WSCC (Region 9). It should be noted that a large portion of WSCC is supplied by hydroelectric generation where water availability is somewhat undependable. However, capability of supplying the peak load in this region does not appear to present a problem in the near future, provided no further water shortages are experienced.

MARCA (Region 5), Figure 22, could encounter a reserve deficit as early as 1982. This region's generation capabilities might not meet peak demand as early as 1986. Any further delays in construction past about 1985 could result in severe power shortages. Another similar situation is anticipated for SPP (Region 8); Figure 23. The potential deficit for this region could be as high as 10,000 MWe in 1986. SERC, (Region 7), Figure 24, may also experience a deficit in 1978; however, a downward trend in reserves might not actually develop until 1980. SERC does not appear to have any difficulty in meeting peak demand in the near future. Figure 25, MAIN (Region 4), follows a trend similar to SERC. A potential deficit could begin as early as 1979, but does not actually drop significantly until 1984. SERC may, however, have trouble meeting peak load before 1990 if construction of additional generation capability is further delayed. In the case of ERCOT, (Region 2), Figure 26, reserve generation will probably remain high until 1984, when a potential deficit could occur. Based on these NERC projections, it is expected that ERCOT will be capable of meeting peak loads through 2000. By 1990, ECAR (Region 1), could experience a power shortage if peak load indeed becomes greater than generation capabilities, Figure 27. ECAR's reserve generation may decline in 1980 with an increased deficit in 1984. MAAC (Region 3) and NPCC (Region 6), Figures 28 and 29, are the regions with the most favorable outlooks. No trouble in meeting demand is projected for either region through 2000. The reserve generation anticipated for both regions remains relatively sufficient; however, after 1982, some deficiencies could occur.

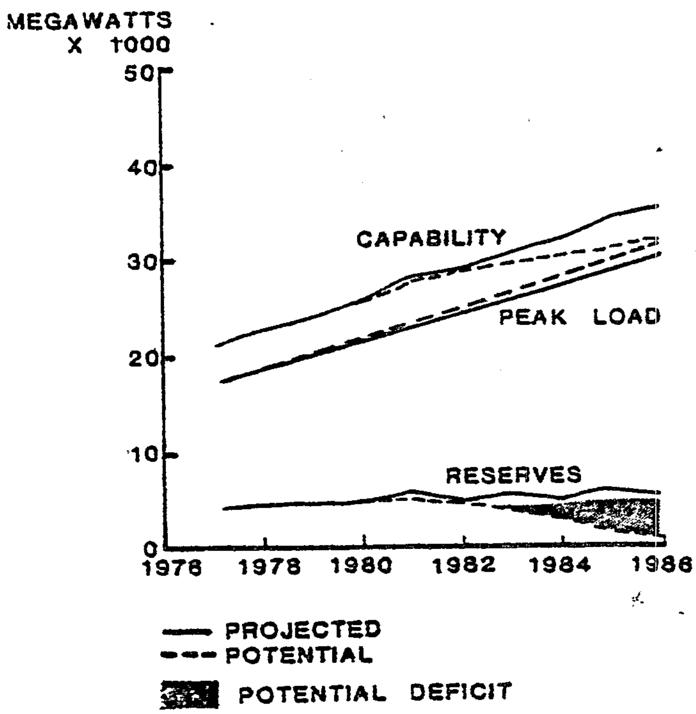

Figure 22. NERC reserve forecast for Region 5 - MARCA. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

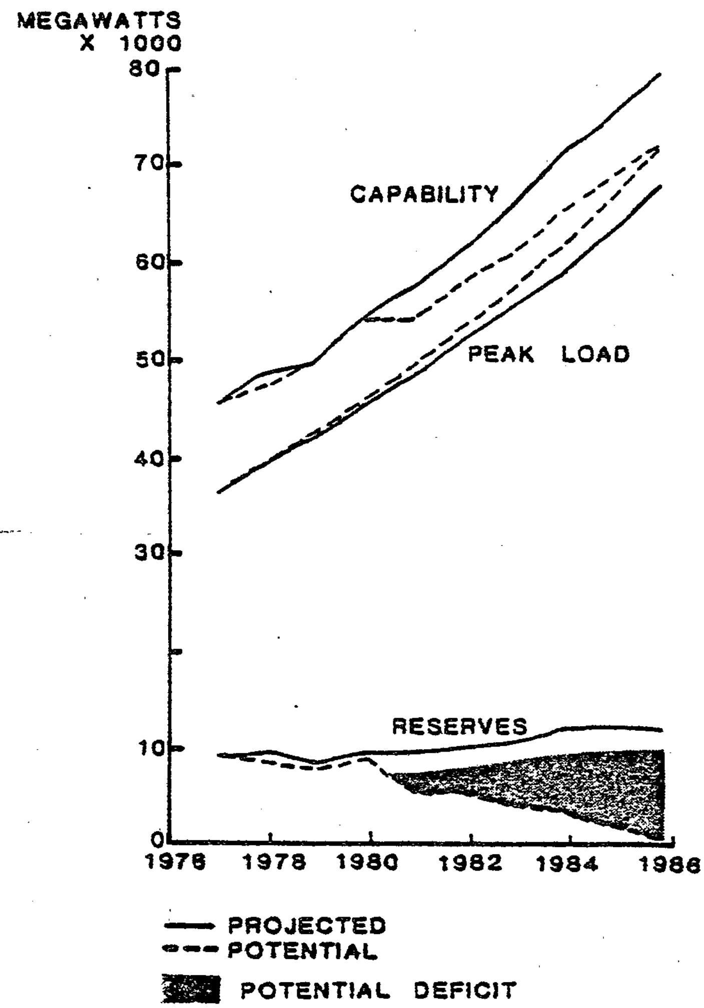

Figure 23. NERC reserve forecast for Region 8 - SPP. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

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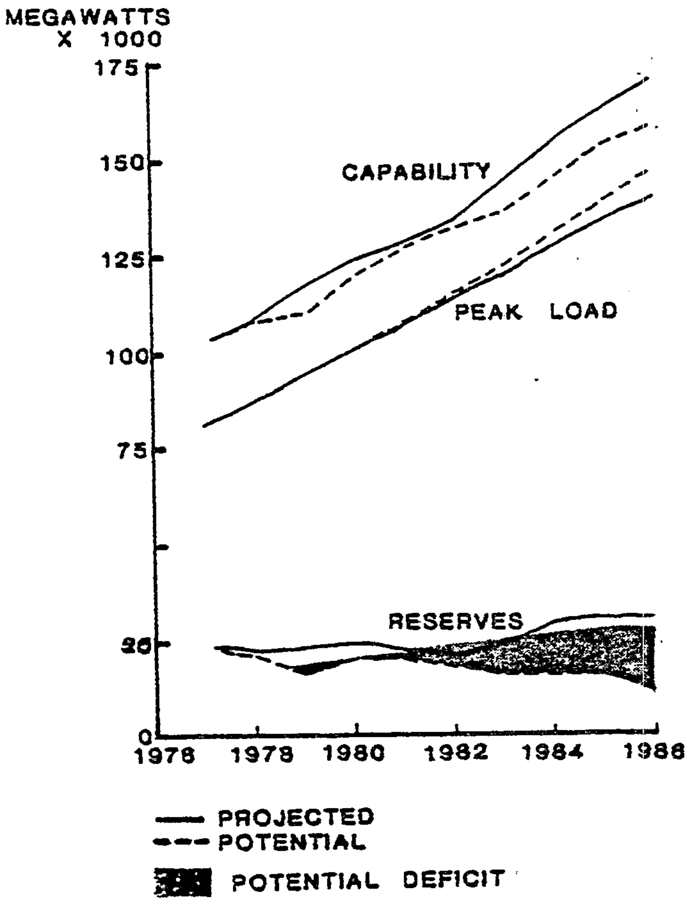

Figure 24. NERC reserve forecast for Region 7 - SERC. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

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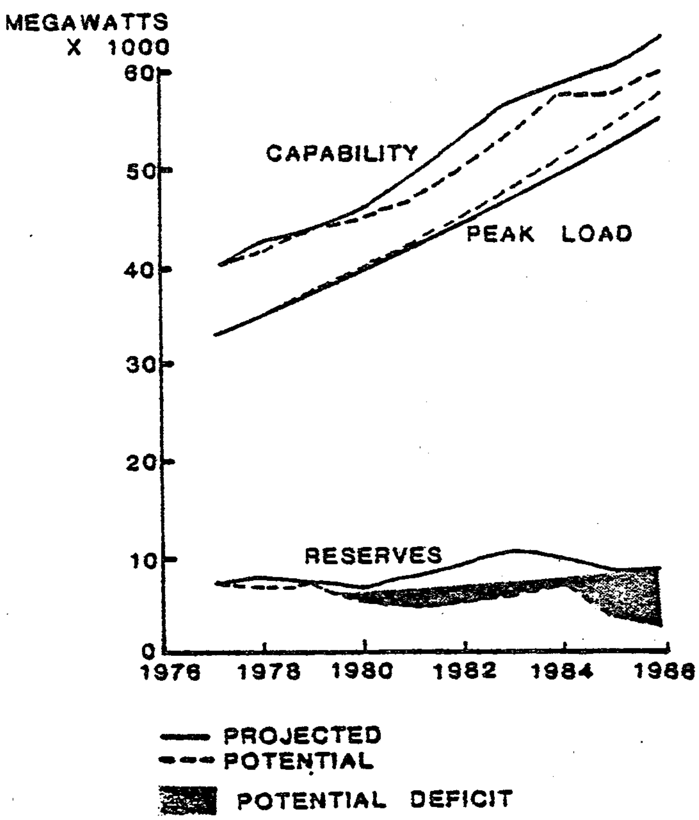

Figure 25. NERC reserve forecast for Region 4 - MAIN. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

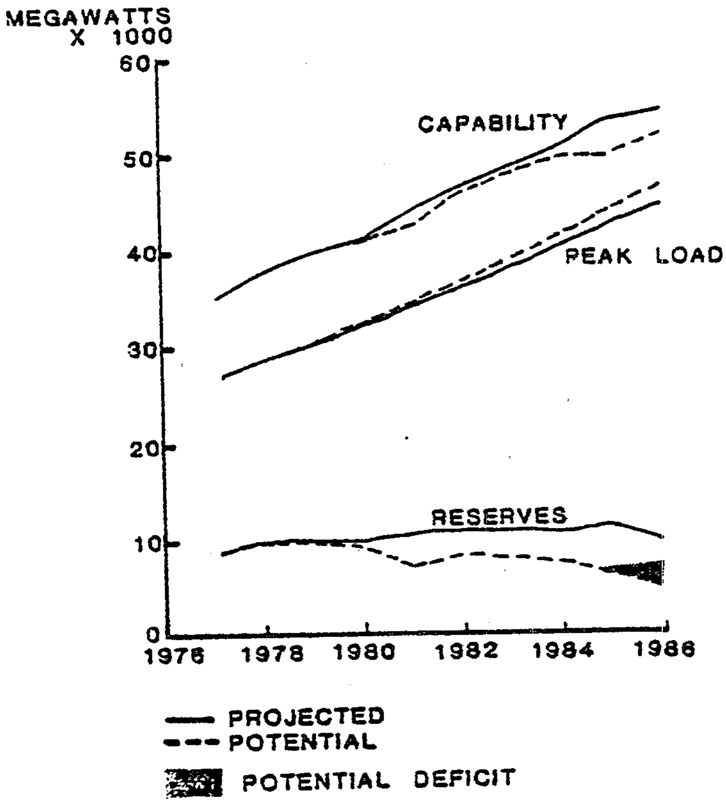

Figure 26. NERC reserve forecast for Region 2 - ERCOT. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

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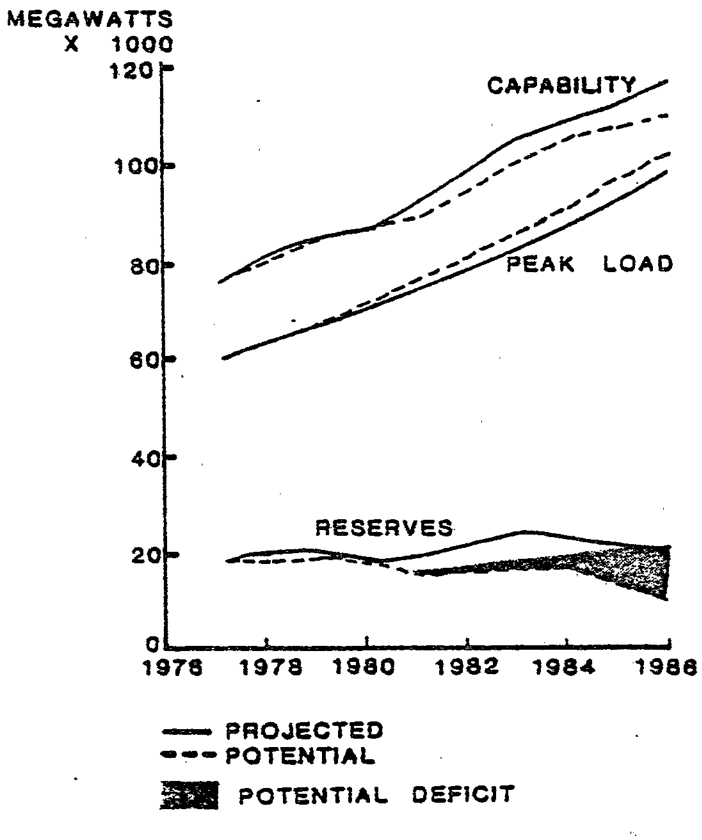

Figure 27. NERC reserve forecast for Region 1 - ECAR. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

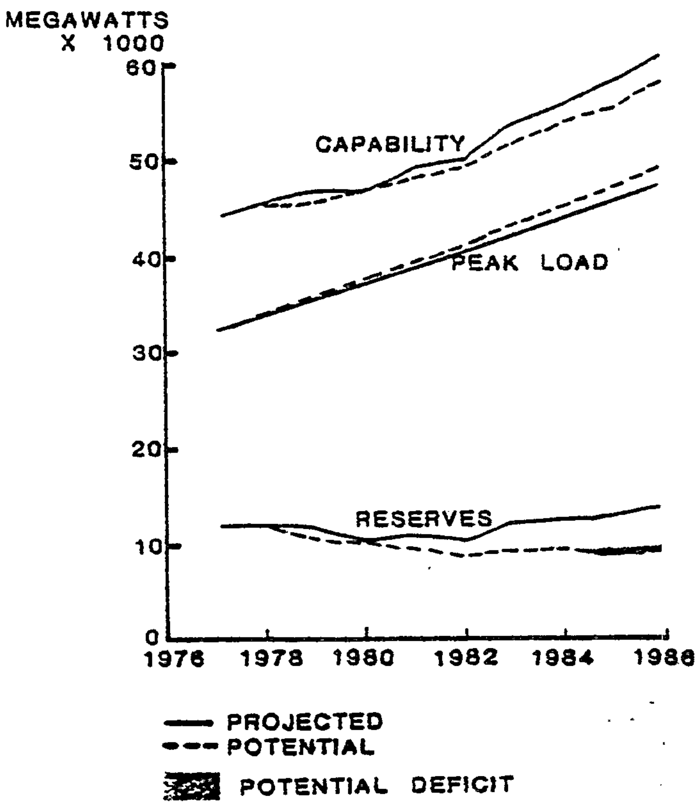

Figure 28. NERC reserve forecast for Region 3 - MAAC. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

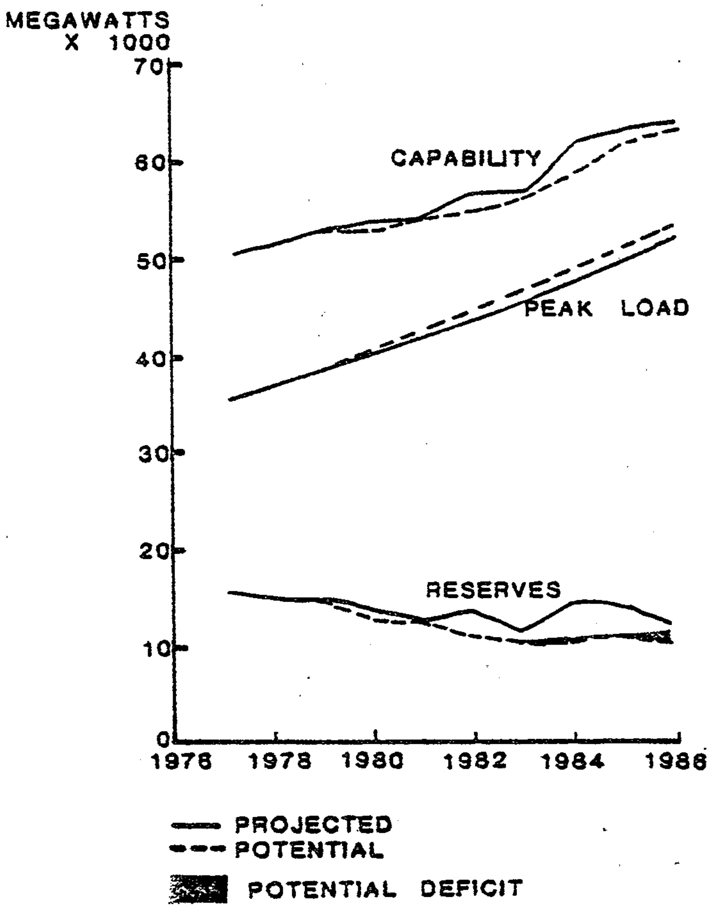

Figure 29. NERC reserve forecast for Region 6 - NPCC. Reprinted from "7th Annual Review..." (Ref. 17), by NERC, 1977, with permission.

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Should any further delays be encountered in new generating unit or major transmission line installation and operation, serious deficiencies in capacity could result. If these delays result in systems being underbuilt in terms of actual reserve capacity after 1985 as these projections indicate, the impact of FGD would be amplified, since FGD has been shown to reduce generating unit availability, and, hence, system reliability.

5.4 Sensitivity of Results to Projected Demand and Generation Mix Statistics

The analysis in this study considered only new coal units and their incremental contribution to system reliability. Due to many unpredictable factors, the exact number of new coal generating units which will be operational in the future and its percentage of total generation cannot be known. The number of units, moreover, affects the demand at any given plant and the mix of base- and intermediate-load new coal units. Thus, it is of interest to know how sensitive the results are to the demand distribution and the mix of unit duty types.

Calculations were performed for a wide variety of cases to investigate the sensitivity. These cases involved the following load factors:

(1) 70% for base units and 55% for intermediate units, and

(2) 60% for base units and 45% for intermediate units.

The mix of base- and intermediate-load new coal units was also varied. The fraction of new coal base units was varied from 0 to 100 percent in steps of ten percent. This set of runs was performed for the first set of load factors listed above. It was found that the following quantity Q was essentially invariant as the load factors and mix were changed:

$$Q = \frac{X_T - X_T'}{C_{NC}} \qquad (12)$$

where

X_T = available power minus power demand assuming no scrubbers are used,

X_T' = available power minus power demand assuming scrubbers are used, and

C_{NC} = total estimated new coal capacity.

The quantity Q is the decrease in excess capacity over demand when scrubbers are added as a proportion of total capacity. Since demand is the same whether scrubbers are used or not, however, Q can also be viewed as the decrease in total power available due to the use of scrubbers as a proportion of total capacity.

The invariance of Q is indicated by the fact that for all load factors, mixes, and regions considered, the values of Q were the same to three significant figures. The conclusion is that the proportional decrease in available power due to the use of scrubbers is insensitive to quantities which had to be projected into the future and which are therefore uncertain. The variable Q, then, is a reliable output of the study in this respect. The values of Q for various scrubber configurations are given in Table 19. As expected, Q does change as the number of scrubbers or the probability r changes (r has been previously defined as the expected availability of a scrubber module).

The reason why Q is insensitive is that as the mix or demand statistics are changed, the available capacity with scrubbers and the available capacity without scrubbers are affected in the same way, according to the assumptions in this study. Actually, these parameters might vary slightly because the FGD unit itself places a demand on the generating unit (energy penalty) which would not exist without FGD. From the above definitions,

$$X_T = C_{NC} - D(M) \tag{13}$$

and

$$X'_T = C'_{NC} - D(M) \tag{14}$$

where

C_{NC} = new coal capacity available without FGD
C'_{NC} = new coal capacity available with FGD
$D(M)$ = power demand (as formulated, $D(M)$ is function of the mix of base- and intermediate-load new coal units)

From Equation (12), then

$$Q = \frac{C_{NC} - D(M) - (C'_{NC} - D(M)}{C_{NC}} \tag{15}$$

and, thus

$$Q = \frac{C_{NC} - C'_{NC} - D(M) + D(M)}{C_{NC}} \tag{16}$$

From this equation, it can be seen that the power demand as a function of mix cancels out, leaving Q invariant in terms of load factor and mix of base-load and intermediate-load new coal units. The incremental loss-of-load probability for a given scrubber configuration, however, is very sensitive to such changes. The incremental loss-of-load probabilities sometimes change by several tenths as the mix or demand is varied. The incremental loss-of-load probabilities, then, are more sensitive to predictions of future conditions and, thus, are probably less reliable than is the quantity Q discussed above. However, these incremental loss-of-load probabilities do not reflect system loss-of-load probability; they only represent the effect on new coal units given the assumption that the system without FGD was designed in a reasonable manner for a reasonable total system loss-of-load probability.

The sensitivity of the incremental loss-of-load probability to load factor is demonstrated by Tables 20 and 21. It is seen that as the load factors are decreased by ten percent, the incremental loss-of-load probabilities sometimes decrease dramatically. However, it should be noted that the 60%/45% load factors vary considerably from the load factors associated with the EEI outage data (Section 4.4); it may well be that unit outage data used are invalid or nearly invalid for this case, since, in reality, these load factors tend to reflect more intermediate or peaking duty from an entirely different class of units whose outage rates were not examined. The 70%/55% load factors used as the basis for this study are more in line with the EEI data and are thus, considerably more reliable.

Table 19 . ADDITIONAL GENERATION REQUIRED FROM THE USE OF SCRUBBERS AS A PROPORTION OF TOTAL NEW COAL CAPACITY

Case	No. of Scrubber Modules[a]	Probability r	Proportional Deficit in Generation
1(base)	0/0	---	0.0%
2	5/0	.9	4.5%
3	5/1	.9	1.2%(Best)
4	5/0	.8	9.9%(Worst)
5	5/1	.8	4.4%

Note: These values apply for all regions and different generation mixes.

[a](Active modules/spares)

Table 20 . INCREMENTAL LOSS-OF-LOAD PROBABILITIES (ILOLP) FOR WORST CASE (5 ACTIVE MODULES/NO SPARES; r = 0.8) LOAD FACTOR SENSITIVITY TEST

Region	Generation Mix Used (% Base/% Inter.)	ILOLP Case 4a[a]	ILOLP Case 4b[b]
1-ECAR	25/75	.30	.00
2-ERCOT	50/50	.75	.04
3-MAAC	0/100	.17	.01
4-MAIN	60/40	.82	.12
5-MARCA	70/30	.82	.28
6-NPCC	10/90	.27	.02
7-SERC	10/90	.14	.00
8-SPP	50/50	.74	.04
9-WSCC	90/10	.99	.41

[a] Load Factors: Base = 70%, Intermediate = 55%

[b] Load Factors: Base = 60%, Intermediate = 45%

Table 21. INCREMENTAL LOSS-OF-LOAD PROBABILITIES (ILOLP) FOR BEST CASE (5 ACTIVE MODULES/1 SPARE; r = 0.9) LOAD FACTOR SENSITIVITY TEST

Region	Generation Mix Used (% Base/% Inter.)	ILOLP Case 3a [a]	ILOLP Case 3b [b]
1-ECAR	25/75	.00	.00
2-ERCOT	50/50	.08	.00
3-MAAC	0/100	.01	.00
4-MAIN	60/40	.17	.00
5-MARCA	70/30	.34	.03
6-NPCC	10/90	.00	.00
7-SERC	10/90	.00	.00
8-SPP	50/50	.07	.00
9-WSCC	90/10	.53	.00

[a] Load Factors: Base = 70%, Intermediate = 55%

[b] Load Factors: Base = 60%, Intermediate = 45%

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APPENDIX A

CALCULATION OF INCREMENTAL LOSS-OF-LOAD PROBABILITY FOR NEW COAL GENERATION IN A POWER SYSTEM

APPENDIX A

CALCULATION OF INCREMENTAL LOSS OF LOAD PROBABILITY FOR NEW COAL GENERATION IN A POWER SYSTEM

In this Appendix, the analysis which was used to calculate the incremental loss-of-load probability for new coal in each geographical region is presented. An understanding of the mathematics is not essential to understand the meaning of the results presented in the text of the report. The analysis is presented, however, for completeness of documentation and for the benefit of those who are interested.

The discussion in the sections below is organized as follows:

(1) calculation of the mean and standard deviation of capacity available at a given unit, taking into account both boiler and scrubber down-time,

(2) calculation of loss-of-load probability for a single unit, and

(3) calculation of loss-of-load probability for a system of units among which demand within a geographical region is distributed.

CALCULATION OF MEAN AND STANDARD DEVIATION OF AVAILABLE CAPACITY AT A PARTICULAR PLANT

In this section, the calculation of the mean and standard deviation of available capacity at a particular unit are discussed. The probabilities associated with scrubbers will be discussed first, then (briefly) the probabilities associated with the boiler, and finally, the probabilities of various levels of power availability for the scrubber-boiler system.

Suppose there are exactly k scrubber modules and each module has a probability r of being up at a given time. The values r = .8 or .9 and k = 5 or 6 were considered in this study.

Then, from the well-known binomial probability distribution,

$$P \text{ (exactly i modules are up)} = \binom{k}{i} r^i \ (1.0 - r)^{k-i}$$

where $\binom{k}{i}$ is the binomial coefficient:

$$\binom{k}{i} = \frac{k!}{i!(k-i)!}$$

But it has been assumed in this study that only five modules can be used at any given time. If there is a sixth, it serves as a spare. Thus, if we denote the probability that i modules are capable of being used by P_i, $0 \leq i \leq 5$, then when k = 5,

$$P_i = \binom{k}{i} r^i \ (1.0 - r)^{k-i}$$

and when k=6,

$$P_i = \binom{k}{i} r^i \ (1.0-r)^{k-i} \qquad 0 \le i \le 4$$

therefore, for five modules plus one spare module, it follows that

$$P_5 = \binom{k}{5} r^5 \ (1.0-r)^{k-5} + \binom{k}{6} r^6 \ (1.0-r)^{k-6}$$

$$= \binom{k}{5} r^5 \ (1.0-r)^{k-5} + r^6$$

Each scrubber module can handle at most 20% of the total capacity. Thus, when i scrubber modules are capable of being used, the plant can operate at no more than $\left(\frac{i}{5}\right)$ 100% of total capacity.

The probability functions for percent of boiler capacity available are discussed in Section 4.4. See Tables 9 and 10.

The probability functions for the boiler and the scrubbers were then combined as follows:

$$P \text{ (0 capacity can be employed)} = q_o + P_o - P_o \, q_o$$

where

q_o = probability 0% of the boiler is operational, and

P_o = probability no scrubber modules are available.

Moreover, inverse cumulative probabilities can also be computed

P (at least j% of capacity can be used) =

P (at least j% of boiler's capacity is available) $\times$

P (enough modules are available to handle at least j% of the total capacity)

where $j = 20, 30, \ldots, 100$.

These inverse cumulative probabilities were calculated because of computational convenience; the probability

P (at least j% of capacity is used)

is obtained by performing a single multiplication, given that the basic probabilities for the availability of the boiler and the scrubber individually are known.

For the purposes of further calculations, however, inverse cumulative probabilities cannot be used. It is necessary, therefore, to express the probabilities in the following form:

α_i = P (X_i % of capacity is available)

where X_i is a number between 0 and 100.

This is discussed in detail below.

The probabilities corresponding to intervals, such as 20 to 30% of the total capacity, can be obtained from the above:

P (% of available capacity in between 20 and 30) =

P (% is at least 20) - P (% is at least 30)

The following special case was noted:

P (0 <% of capacity available <20) =

1.0 - P (0 capacity is available) -
P (at least 20% of capacity is available)

This case represents operation at levels usually requiring manual control of the unit's boiler/turbine/generator system.

The result of the analysis above, then, is a table of probabilities of the following form:

Probability	Percent of Total Capacity	Proportion of Total Capacity	Midpoint of Interval of Proportions
α_1	0	0	$x_1 = 0$
α_2	.1-19.9	.001-.199	$x_2 = .15$*
α_3	20-29.9	.200-.299	$x_3 = .25$
.	.	.	.
.	.	.	.
.	.	.	.
α_{10}	90-99.9	.900-.999	$x_{10} = .95$
α_{11}	100	1.0	$x_{11} = 1.0$

*Because of physical limits of the boiler/turbine/generator's speed and voltage regulation control systems, it is felt that running at very low percentages of capacity, such as 5%, is unlikely. Thus, 0.15, rather than the interval midpoint, 0.10, was used for this case.

The mean and standard deviation of the proportion of total capacity available were then computed as follows:

$$\text{mean} = \sum_{i=1}^{11} x_i \alpha_i$$

$$\text{std. dev.} = \sqrt{\sum_{i=1}^{11} x_i^2 \alpha_i - (\text{mean})^2}$$

where α and x are defined by the table above.

CALCULATION OF LOSS-OF-LOAD PROBABILITY FOR A SINGLE UNIT

In this section, the calculation of the distribution of available capacity minus power demand for a single unit is discussed. From this distribution, the probability of not meeting demand follows immediately. The basic probabilistic technique used is called convolution; the mathematical solution requires solving an integral known as the convolution integral.

First, we assume that the distributions for demand and for available power are tabulated in terms of percent of total power in steps of ten percent. Thus, the following data will be used:

Percent of Total Capacity (%)	Probability of Demand	Probability of Power Availability
0	PD_1	PA_1
10	PD_2	PA_2
20	PD_3	PA_3
30	PD_4	PA_4
40	PD_5	PA_5
50	PD_6	PA_6
60	PD_7	PA_7
70	PD_8	PA_8
80	PD_9	PA_9
90	PD_{10}	PA_{10}
100	PD_{11}	PA_{11}

The probability of available capacity is obtained by using the analysis discussed in the preceeding section. Although, as calculated, this probability function is not tabulated in steps of ten percent, such a table can easily be approximated. The probability that available capacity is 40 percent, for example, can be approximated by

$$P\ (35\% \leq \text{available capacity} < 45\%) =$$
$$1/2\ P\ (30\% \leq \text{available capacity} < 40\%) +$$
$$1/2\ P\ (40\% \leq \text{available capacity} < 50\%)$$

The latter quantity is obtained directly from the results of the last section. A similar type of approximation was made with respect to the demand curves, which are discussed in Section 4.2.

Now, we are interested in the characteristics of available capacity minus power demand, which we will call L. It is desired to compute the probability of different values of L. We will let X denote demand and Y denote available capacity. Then

$$L = Y-X$$

The random variable L, then, equals a particular value T if Y equals a value Y_o and X equals Y_o-T, since

$$L = Y-X = Y_o - (Y_o-T) = T$$

To compute the probability that L equals T, then, we will sum the probabilities of occurrence of the different ways L can equal T. Consider the case L = 80, for example. The following is a complete list of ways this can occur, given that X and Y are tabulated in steps of 10:

(1) $X=0$ and $Y=80$, which has probability $(PD_1)(PA_9)$;
(2) $X=10$ and $Y=90$, which has probability $(PD_2)(PA_{10})$; and
(3) $X=20$ and $Y=100$, which has probability $(PD_3)(PA_{11})$.

The probability that $L=80$, then, is

$$(PD_1)(PA_9) + (PD_2)(PA_{10}) + (PD_3)(PA_{11}).$$

In general, the probability that L equals some value T is calculated from the approximation of the convolution integral as follows:

$$P(L=T) = \sum_{Y_o}\left[P(Y=Y_o) \cdot P(X=Y_o-T)\right]$$

where the sum is over the appropriate tabulated values of Yo. The loss-of-load probability, $P(L<o)$, is then easily calculated from the distribution of L:

$$P(L<o) = \sum_{T<o} P(L=T)$$

CALCULATION OF LOSS-OF-LOAD PROBABILITY FOR A SYSTEM OF POWER PLANTS

In this section, the calculation of the loss-of-load probability for a system of generating units within a geographical region is discussed. It is assumed that demand is distributed among all plants in the system. These calculations were used to determine the incremental loss-of-load probability (ILOLP) for only new coal units.

The demand probability functions for base and intermediate units are discussed in Section 4.2. The mean μ and standard deviation σ of proportion of capacity demanded at a particular site are computed as follows:

$$\mu = \Sigma B_i C_i$$

$$\sigma = \sqrt{\Sigma C_i^2 B_i - (\mu)^2}$$

where

C_i = i^{th} value of proportion of total capacity, and
B_i = probability that that amount of capacity will be required to meet demand.

In the manner indicated above, the following means and standard deviations were computed:

	Mean	Standard Deviation
Base Units	μ_B	σ_B
Intermediate Units	μ_I	σ_I

To convert the mean and standard deviation from proportion of capacity to capacity in megawatts (MWe), the following calculations are needed. The same equations apply for demand as for available capacity.

Suppose a plant has capacity C. In the calculations, one value of C was used to represent plants with capacity 390 to 599 MWe, and another value was used to represent plants with 600 MWe or above. The two specific values vary with region. If the mean and standard deviation (of either demand or available power) in terms of proportion of capacity are μ and σ, respectively, then the mean and standard deviation in mw are $C\mu$ and $C\sigma$.

Now, the mean of a sum is the sum of the means. Thus, if there are N plants, each with mean available capacity $C\mu$, the mean for the N plants combined is

$$\sum_{i=1}^{N} C\mu = NC\mu$$

The variance (standard deviation squared) of a sum is the sum of the variances. The standard deviation of the N plants is, therefore,

$$\sqrt{\sum_{i=1}^{N} (C\sigma)^2} = C\sigma\sqrt{N}$$

The above relationships, then, can be used to find the mean and standard deviation of the total available capacity or demand for a set of power plants with the same total capacity and demand curves. Suppose the following generation mix exists for a region of the country:

no. of small (390 - 599 MWe) base units = NSB
no. of large (600 MWe or over) base units = NLB
no. of small intermediate units = NSI
no. of large intermediate units = NLI

Then if C_s and C_L are the average capacities for the small and large units, respectively, the following are the means and standard deviations for the different classes of units.

Power Demand Statistics

	mean	standard deviation
large base units	$\overline{X}_{LB} = C_L(NLB)\mu_B$	$S_{LB} = C_L\sigma_B\sqrt{NLB}$
small base units	$\overline{X}_{SB} = C_S(NSB)\mu_B$	$S_{SB} = C_S\sigma_B\sqrt{NSB}$
large intermediate units	$\overline{X}_{LI} = C_L(NLI)\mu_I$	$S_{LI} = C_L\sigma_I\sqrt{NLI}$
small intermediate units	$\overline{X}_{SI} = C_S(NSI)\mu_I$	$S_{SI} = C_X\sigma_I\sqrt{NSI}$

The mean $\overline{X}_D$ and standard deviation S_D for total demand on the system, then, can be computed as follows:

$$\overline{X}_D = \overline{X}_{LB} + \overline{X}_{SB} + \overline{X}_{LI} + \overline{X}_{SI}$$

$$S_D = \sqrt{S_{LB}^2 + S_{SB}^2 + S_{LI}^2 + S_{SI}^2}$$

Technically, if the random demands being added are correlated, the variance of the sum is the sum of the variances plus a set of covariance terms. It is clear, moreover, that the demands at two power plants in the same region are positively correlated. Both demands would reflect the same general type of diurnal cycle, and thus, for example, a cold front could increase demand throughout the region.

An investigation of correlations among demands at different plants is beyond the scope of this study. It is evident, however, that inclusion of positive convariance terms would increase the value of S_D. The loss-of-load probabilities which are reported in the text, and which are discussed below, are influenced somewhat toward .5 due to the omission of the covariance terms. While it is believed that the resulting error is not excessive, further study of the effects of demand correlations would be beneficial.

For a given case, all units in a region were assumed to have the same number of scrubber modules (5 or 6) and the same value of r (.8 or .9). The variable r is defined earlier in this Appendix to be the probability that a given scrubber module is up. For a given case, then, suppose the following statistics regarding proportion of total capacity which is available have been computed:

	mean	standard deviation
small units	μ_{AS}	σ_{AS}
large units	μ_{AL}	σ_{AL}

Then the mean and standard deviation of total power available in MWe for the different classes of plants can be computed as follows:

Power Availability Statistics

	mean	standard deviation
large base units	$\overline{X}_{ALB}=C_L(NLB)\mu_{AL}$	$S_{ALB}=C_L\sigma_{AL}\sqrt{NLB}$
small base units	$\overline{X}_{ASB}=C_S(NSB)\mu_{AS}$	$S_{ASB}=C_S\sigma_{AS}\sqrt{NSB}$
large intermediate units	$\overline{X}_{ALI}=C_L(NLI)\mu_{AL}$	$S_{ALI}=C_L\sigma_{AL}\sqrt{NLI}$
small intermediate units	$\overline{X}_{ASI}=C_S(NSI)\mu_{AS}$	$S_{ASI}=C_S\sigma_{AS}\sqrt{NSI}$

The mean $\overline{X}_A$ and standard deviation S_A of power available for the system, then, can be computed as follows:

$$\overline{X}_A = \overline{X}_{ALB} + \overline{X}_{ASB} + \overline{X}_{ALI} + \overline{X}_{ASI}$$

$$S_A = \sqrt{S_{ALB}^2 + S_{ASB}^2 + S_{ALI}^2 + S_{ASI}^2}$$

We are interested in the random properties of the available power minus the power demanded. This difference L has the mean value

$$\overline{X}_L = \overline{X}_A - \overline{X}_D$$

and the standard deviation

$$S_L = \sqrt{S_A^2 + S_D^2}$$

The probability that demand will not be met is the probability that L is less than zero. The next question to address, then, is how to compute that probability.

Each region considered will have at leat 40, and, in most cases close to 100 new coal units or more, and L is the sum of

(1) the power available at each of the units, and

(2) the (negatives of the) power demanded at each of the units.

Thus, L is the sum of approximately 200 terms or more. Since sums of large numbers of random variables are generally very nearly normally distributed, it is reasonable to assume that L is normally distributed. (The Central Limit Theorem in statistics is a rigorous statement of the normality property of certain sums of random variables.)

The probability that L is less than zero, then, can be expressed as follows:

$$P(L<0) = P\left(\frac{L - \bar{X}_L}{S_L} < \frac{-\bar{X}_L}{S_L}\right) = P\left(Z < \frac{-\bar{X}_L}{S_L}\right)$$

where Z is a normally distributed random variable with mean zero and variance one. The desired probability, then can be found by standard methods. For new coal units only, this probability, expressed as ILOLP, is given by region and by scrubber configuration in Appendix C.

APPENDIX B

ESTIMATED LOAD FACTOR CALCULATIONS BY REGION

REGION 1 - ECAR

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	36,810	67%
Pre-1986†		
Coal	30,122	67%
Oil	723	67%
Nuclear	18,034	70%
Post-1985÷		
Coal		
0-390 MWe	60	50%
390-599 MWe	1,990	70%
600+ MWe	111,200	
Nuclear	70,254	70%
Other*	18,357	33%
Regional Total	287,550	67%

Conclusions - 100% base
Used - 90% base/10% intermediate to reflect uncertainties in load

*Estimated from 1970 NPS
÷Estimated from Teknekron

REGION 2 - ERCOT

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	12,038	57%
Pre-1986†		
Coal	7,798	57%
Gas (/Oil)	1,718	57%
Nuclear	4,800	70%
Post-1985†		
Coal		
0-390 MWe	990	57%
390-599 MWe	3,679	54-56%
600+ MWe	62,140	
Nuclear	8,500	70%
Region Total	93,163	57%

Conclusions - 100% intermediate
Used - 10% base/90% intermediate to reflect uncertainties in nuclear

*Estimated from 1970 NPS
†Estimated from Teknekron

REGION 3 - MAAC

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	22,590	62%
Pre-1986†		
Coal	2,500†	55%*
Oil	3,020†	55%*
Nuclear†	15,923	70%
Post-1985†		
Coal		
600+ MWe	32,400	57.8%
Nuclear	32,050	70%
Other*	12,592	33%
Region Total	121,075	62%

Conclusion - 10% base/90% intermediate

*Estimated from 1970 NPS
†Estimated from Teknekron

REGION 4 - MAIN

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	27,536	61%
Pre-1986†		
Coal	8,752	61%
Oil	2,755	61%
Nuclear	11,576	70%
Post-1985†		
Coal		
0-390 MWe	350	61%
390-599 MWe	550	65.7%
600+ MWE	49,200	
Nuclear	9,350	70%
Other* (mostly peakers)	10,886	22%
Region Total	120,955	61%

Conclusion - 70% base/30% intermediate

*Estimated from 1970 NPS
†Estimated from Teknekron

REGION 5 - MARCA

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	14,529	61%
Pre-1986†		
Coal		
0-390 MWe	948	61%
390-599 MWe	5,109	62%**
600+ MWe	4,885	65%**
Post-1985†		
Coal		
0-390 MWe	1,050	61%
390-599 MWe	500	66.6%
600+ MWe	24,000	
Nuclear	2,336	70%
Other* (peakers/pumped storage)	5,929	30%
Region Total	59,286	61%

Conclusion - 70% base/30% intermediate

*Estimated from 1970 NPS
†Estimated from Teknekron
**Reflects large base-load Western coal units

REGION 6 - NPCC

Unit Type	Expected Total Capacity MWe		Estimated Load Factor
Old*	20,933		61%
Pre-1986†			
Coal			
0-390 MWe	32	(probable peaker/ cycling)	50%
600+ MWe	2,246		61%
Oil	4,721		61%
Nuclear	10,899		70%
Post-1985†			
Coal			
0-390 MWe	400		61%
390-599 MWe	400		54.1%
600+ MWe	27,850		
Nuclear	59,800		70%
Other* (mostly hydro/ pumped storage)	40,194		50%**
Region Total	167,475		61%

Conclusion - 100% intermediate

*Estimated from 1970 NPS
†Estimated from Teknekron
**Reflects base-load hydro

REGION 7 - SERC

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	30,640	65%
Pre-1986†		
Coal	12,862	65%
Oil	4,659	65%
Nuclear	27,946	70%
Post-1985†		
Coal		
0-390 MWe	2,789	65%
390-599 MWe	2,273	59.1%
600+ MWe	76,209	
Nuclear	146,361	70%
Other*	12,656	33%
Region Total	316,395	65%

Conclusion - 30% base/70% intermediate

*Estimated from 1970 NPS
†Estimated from Teknekron

REGION 8 - SPP

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	17,712	58%
Pre-1986†		
Coal	17,097	58%
Oil	225	58%
Nuclear	11,774	70%
Post-1985†		
Coal		
0-390 MWe	1,975	58%
390-599 MWe	2,068	54.2%
600+ MWe	68,820	
Nuclear	19,150	70%
Other* (hydro/pumped storage)	5,784	40%
Region Total	144,605	58%

Conclusion - 100% intermediate

*Estimated from 1970 NPS
†Estimated from Teknekron

REGION 9 - WSCC

Unit Type	Expected Total Capacity MWe	Estimated Load Factor
Old*	48,585	63%
Pre-1986†		
Coal	27,985	63%
Oil	309	63%
Nuclear	18,770	70%
Post-1985†		
Coal		
0-390 MWe	3,579	63%
390-599 MWe	3,900	75.7%
600+ MWe	66,700	
Nuclear	98,626	70%
Other* (hydro)	132,224	50%**
Region Total	400,678	63%

Conclusion - 100% base
Estimated - 90% base/10% intermediate due to uncertainties in hydro

*Estimated from 1970 NPS
†Estimated from Teknekron
**Reflects base-load hydro

APPENDIX C

INCREMENTAL LOSS-OF-LOAD PROBABILITIES FOR NEW COAL ONLY BY REGION IN 2000 - TEST CASE RESULTS

APPENDIX C

INCREMENTAL LOSS-OF-LOAD PROBABILITIES FOR NEW COAL ONLY BY REGION IN 2000 - TEST CASE RESULTS

This Appendix presents the incremental loss-of-load probabilities (ILOLP) for new coal only by region for different scrubber configurations and for different module availabilities. Also, the base case (with no scrubbers) is given for each region as a means of comparing the incremental ability of new coal units in each region to meet demands placed upon them with and without FGD.

Region	% of New Coal Capacity Used in Base Service	Scrubber Configuration	Availability of Each Module	Incremental Loss-of-Load Probability (ILOLP)-New Coal Only in 2000
1-ECAR	90	5/0*	.8	.999
		5/0	.9	.885
		5/1	.8	.874
		5/1	.9	.535
		0	-	.392
2-ERCOT	10	5/0	.8	.165
		5/0	.9	.015
		5/1	.8	.014
		5/1	.9	.0022
		0	-	.0011
3-MAAC	10	5/0	.8	.238
		5/0	.9	.0608
		5/1	.8	.0593
		5/1	.9	.0215
		0	-	.0146
4-MAIN	70	5/0	.8	.900
		5/0	.9	.528
		5/1	.8	.516
		5/1	.9	.267
		0	-	.198
5-MARCA	70	5/0	.8	.822
		5/0	.9	.528
		5/1	.8	.519
		5/1	.9	.338
		0	-	.282
6-NPCC	0	5/0	.8	.186
		5/0	.9	.0493
		5/1	.8	.0483
		5/1	.9	.0185
		0	-	.0129

*(No. active scrubber modules/spares) - one scrubber of the given configuration per each new coal generating unit.

Region	% of New Coal Capacity Used in Base Service	Scrubber Configuration	Availability of Each Module	Incremental Loss-of-Load Probability (ILOLP)-New Coal Only in 2000
7-SERC	30	5/0	.8	.407
		5/0	.9	.0562
		5/1	.8	.0534
		5/1	.9	.0091
		0	-	.0045
8-SPP	0	5/0	.8	.0795
		5/0	.9	.0045
		5/1	.8	.0043
		5/1	.9	.00048
		0	-	.00021
9-WSCC	90	5/0	.8	.994
		5/0	.9	.833
		5/1	.8	.822
		5/1	.9	.534
		0	-	.419

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16. Abstracts

Impacts of FGD on U.S. electric reliability and adequacy through 2000 were evaluated. Coal-fired units on-line before 1986 and between 1985 and 2000 were considered for the nine National Electric Reliability Council (NERC) regions. Each region's ability to meet power demand (with reasonable and typical reserves) as a power pool with and without FGD was assessed. Different FGD module configurations and assumed availabilities were considered. Power interchange capabilities which might be used during FGD-induced outages were also evaluated, as were reserves.

It was concluded that a revised NSPS would have little effect on system adequacy before 1985. By 2000, however, the NSPS would have a significant impact on reliability and adequacy, requiring large amounts of additional generation to offset the effects of FGD. Sensitivity of these results was analyzed and mitigating measures were determined.

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