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ELECTRICAL LOAD FORECASTING

A REVIEW

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ELECTRICAL LOAD FORECASTING - A REVIEW

by

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ELECTRICAL LOAD FORECASTING METHODOLOGY

I. INTRODUCTION

All capacity planning by electric utilities must begin with a forecast of sales of electric energy. The perceived need then forms the basis of system planning. The purpose of this study is to examine the various methods of load forecasting used by electric utilities. A rather extensive survey of this sort was carried out by a panel assembled by the Federal Power Commission.⁽¹⁾ This study, rather than repeat all that work, was devoted to determining if the methods had changed, determining what research is being carried out in the area, and looking into the factors which a utility considers when a capacity addition is to be made. These extensions carry into such areas as system reliability, reserve margins, uncertainties, etc. The economic factors of financial arrangements and corporate strategy are beyond the scope of this study.

Forecasting the future is, of course, always fraught with uncertainty, and much effort has gone into reducing the uncertainty. Research is continuing in several places on new methods of forecasting. The nature of a forecast changes as the time scale or planning horizon changes. In this study, we shall be concerned only with the medium- to long-range forecasts, i.e., 5 to 10 years and 10 years "plus". This range is about the lead time for new large additions to capacity. The short-term forecasts, however, must be considered in their influence on the longer-range forecasts. Unfortunately, the farther one tries to see into the future, the cloudier becomes the crystal ball. This is a troublesome fact.

A philosophical point or two about the nature of electric utilities has to be made to help understand their position in regard to expansion. The private utilities are profit-making enterprises in the manner of other businesses and, thus, their motives for expansion of sales are only those of other businesses. Their product is in great popular demand. All utilities

(1) The Methodology of Load Forecasting, Report to the Federal Power Commission, Technical Advisory Committee for Load Forecasting Methodology, 1969, (hereafter referred to as MLF).

are regulated bodies (being controlled monopolies) and by charter, must supply power to any customer who applies since there is generally no alternative source. The terms of the hookup will vary with the size of required load.

The utilities have an incentive to forecast as accurately as possible because an overestimate results in unused capacity and reduced profits, while an underestimate results in loss of potential profits; frequently, customer irritation; and very possibly, a danger to health and safety due to failure of some of the many devices which depend on their product.

In appraising present practice, vis-a-vis the results of MLF, it is found that (a) not much has changed insofar as load forecasting methodology by individual utilities is concerned, (b) there is a good deal of attention, showing up in the literature, being given to system security (or stability, etc. = reserve margins), (c) as the systems get bigger, more and more attention is being given to accurate estimates of reserve margins, (d) the coordinating councils and the various power pools are taking a larger part in system planning, and (e) there is a slow evolution of method of management control taking place, principally in the power pools, whose aim is to improve planning and systems stability.

II. LOAD CHARACTERISTICS

The load, or energy flow, of an electric utility is a continuously varying quantity. While the minute-to-minute or second-to-second variations are quite irregular, the time-averaged value shows certain regularities as the interval of averaging increases. To look at the load variation of one day's time, the recorders at generators and substations can be assembled and analyzed. The daily variation may typically appear as in Figure 1. In Figure 1, the components of load have been estimated and summed to compare with the actual system load. It is thus seen that there is a daily peak, the size and shape of which will vary from region to region and season to season.

The daily variation can be further assembled on a weekly basis to yield data such as that shown in Figure 2. The variation of the daily peaks with day of the week is thus evident. This pattern is also subject to variation by season and by region. The classification of the weekly loads into their principal components (peak, intermediate, and base load) yields information necessary for short-term scheduling of generating capacity. The integral or area under the curve represents total energy delivered.

When the highest peak of each month is plotted for a year, variations in demand such as those in Figure 3 are obtained. Here, two regions are shown to indicate the kind of variations to be expected under varying climates. The West Region has a summer peak due to air conditioning and also a winter peak corresponding to a relatively high electrical heating load. The peak-to-valley ratio is not extreme. The South Central Region, by contrast, is a region rich in oil and natural gas and as a consequence, does not have a large winter heat load. This region does, however, have a large summer peak due largely to the air conditioning load.

To indicate the extent of variability of the weekly loads, the data for three years from the Edison Electric Institute⁽²⁾ is shown in Figure 4. The principal features are the large fluctuations due to summer and winter peaking.

The integration of over a year smooths the result a great deal. Figure 5 shows the total energy delivered by year.⁽²⁾ The exponential character of

FIGURE 1
PENNSYLVANIA POWER AND LIGHT COMPANY
MAJOR COMPONENTS OF SYSTEM LOAD

SOURCE: MLF

FIGURE 2
WEEKLY LOAD CURVE

SOURCE: National Power Survey, 1970.

FIGURE 3
ESTIMATED 1970 MONTHLY PEAK DEMANDS

SOURCE: National Power Survey, 1970.

FIGURE 4 WEEKLY ELECTRIC OUTPUT

Total Electric Utility Industry
(Excluding Alaska and Hawaii) • 1967-1969

SOURCE: Edison Electric Institute.

FIGURE 5 GENERATION

Total Electric Utility Industry
(Including Alaska and Hawaii Since 1963)
By Type of Prime Mover - 1920-1969

SOURCE: Edison Electric Institute.

the growth is apparent. The growth of generating capacity is equally apparent in Figure 6.

A different way of representing data such as that presented in Figure 2 is in the form of a "Load Duration Curve" for a given period. Such a typical curve is shown in Figure 7. This curve is formed by plotting each demand level against the duration of time that it existed; thus, the very highest levels exist for only a short time, while the base load is demanded 100% of the time. Along with the "Load Duration Curve" is a typical "Capacity Duration Curve". Since no plant operates 100% of the time, the curve intersects the abscissa at some time short of 100%. If the "Load Duration Curve" is plotted as a percent of peak load instead, the energy units represented by a dashed line on Figure 7 (which represents the average of the load duration) are also a "System Load Factor". This quantity is typically 50-60%.

So far, the figures have represented the data somewhat as a meter would record it; that is, nothing is said of where the energy went nor what happened to it. At this point, however, the problem of forecasting by the utilities has achieved some definition.

The utility, if it is to supply all the demands, must supply the peak demand when demanded and also must supply the total energy or the integral under the "Load Duration Curve". Obviously, some effort is made to optimize the choice of plants to meet this demand. A look at Figure 4 shows the forecasters' problems are to be: The long-term forecaster needs to predict the annual peak load, the total generation, and their annual rate of growth.

FIGURE 6 INSTALLED GENERATING CAPACITY

(Including Alaska and Hawaii Since 1963)
Based on Name Plate Ratings at December 31, 1920-1969

SOURCE: Edison Electric Institute.

FIGURE 7.
PLANT AND LOAD DURATION CURVES

III. REVIEW OF PREVIOUS WORK

The state-of-the-art up to 1969 is well summarized in the "Methodology of Load Forecasting" (also reproduced in Vol. IV of the "1970 National Power Survey"). The pertinent parts of that report are appended to or liberally quoted in this report. A summary of the pertinent points follows.

A. Summary of Load Forecast Methodology

All load forecasting methods appear to include the same fundamental steps:

1. Collect historical data (seasonal, etc.) and adjust them to achieve reasonable consistency over the historical and forecast period;
2. Analyze the data to determine the significant economic, demographic, and climatic factors which have affected load growth in the past;
3. Extrapolate the significant causal factors into the future and determine the degree of uncertainty in each extrapolation;
4. Derive forecasts by considering the effect that these causal factors are expected to have during the time period chosen;
5. Determine the relative degree of uncertainty in the forecast;
6. Periodically compare recorded performance with previous forecasts and make adjustments in techniques and assumptions.

While the essential steps are summarized here, not all utilities use all the steps or the same data. The quantity forecast differs, the techniques differ, and the degree of sophistication differs. The differences are generally advisable, reflecting the differences in needs of the utilities because of their differing geographic and economic conditions. It is apparent also that there is no single best method, but rather that each utility must evolve a method that is most appropriate to its situation and requirements.

B. The Need for Load Forecasts

Electric utilities plan the capacity of their systems to meet the expected peak demand requirements. These forecasts are part of the basis for planning additions to generating capacity, as well as transmission and distribution equipment. The combination of demand and energy forecasts forms the basis for planning fuel requirements. Energy and demand forecasts are also the starting points of financial planning. Since the outlays for equipment, land, and fuel are very large and growing, the need for careful planning for revenues is apparent.

The load forecasts of the utilities are collectively important to regulatory bodies as policy planning bases and to equipment suppliers for their manufacturing and inventory planning. As plants get larger and more expensive and the time between decision and operation lengthens, the need for good forecasts becomes more crucial.

C. The Need for Accuracy in Forecasting

The consequences of inaccuracies in forecasts by electric utilities is neatly summed up in "The Methodology of Load Forecasting, (MLF)" and is quoted below.

1. Significance

Reliance on a dependable supply of electricity has been an important element in the evolution of the living habits of Americans as well as the country's industrial operations. The reliability of service demanded by the American people requires that power be available for use whenever the demand occurs and whatever its magnitude. The fact that there may be equipment failure or natural disturbances that render certain equipment inoperative is seldom considered as an acceptable reason for the interruption of the bulk supply of electric power. As a result, the industry must plan reserve and standby systems to meet such contingencies. Accurate demand forecasts play an essential part in providing effective reserve and standby arrangements.

The needs for additions to generation, transmission, and distribution facilities, the carrying costs of which represent such a major portion of the total annual cost of a utility system, are

largely determined from demand and energy forecasts. Provision for adequate service to the consumer at the lowest cost, compatible with maintaining an adequate net income for the utility system, depends heavily on accurate demand and energy forecasts. Substantial variances from forecasts, therefore, can lead to inadequate service, unduly high costs to the consumer, and/or inadequate income for the system.

2. Consequence of Errors

The degree of accuracy needed cannot be neatly categorized but is dictated by the probable consequences of error (where "error" is used in this text, it is used in the statistical sense of variance between predicted and recorded results). The impact and duration of the consequence of errors in demand and energy forecasts will vary among systems. Such differences will depend upon the alternatives available to the system and upon the time period for which the forecast is made. Some of the key consequences are as follows:

a. Immediate Future and Short-Term

Since the primary use of these forecasts is to permit operation at the lowest incremental energy cost, the main consequence of error is the non-optimum use of resources. Consequences might be that fuel would have to be purchased at a premium price or conversely held in inventory; distribution plants might have to be built with overtime labor or conversely labor might be used in projects which could be delayed a year; nuclear or hydro resources might go unused or conversely be used up and substituted for with higher priced fuel.

However, gross inaccuracies in such forecasts could lead to a shortage in available capacity. Because distribution facilities have a minimum planning period of about one year, errors in the short-term forecasts could result in inappropriate distribution construction schedules.

b. Intermediate-Term

Because of the critical role intermediate-term forecasts play, as discussed above, the consequences of error of such forecasts are the most serious.

Forecasts which are too low could result in the use of high-cost resources, heavily loaded transmission and distribution facilities with associated higher losses and reduced reliability. Low forecasts could also reduce the opportunity for power and energy sales with neighboring utilities and could even result in curtailment of load. Forecasts which are too high, on the other hand, cause problems of equal severity. This could lead to the construction of unneeded generation, transmission, and distribution facilities and thus to higher cost electric service.

To convey an impression of the magnitude of the effect of an intermediate-term forecast error and of its ramifications, it is perhaps useful to give a rough estimate of the effects of a specific error - a 10% forecast error in 10 million kilowatt system.

Such an error could result in the demand being one million kilowatts lower than expected with one million kilowatts of generating facilities in operation one year or more ahead of the time required. Assuming for purposes of illustration a plant investment range of \$100-\$150 per KW,* and total fixed charges at an annual rate of 15%, the cost due to the forecast error could be \$15 million to \$22.5 million per year. Meanwhile, if the energy forecast were equally in error, the increase expected in revenue would not materialize. Assuming an annual revenue of \$20-\$40 per KW, this could represent an unrealized growth in annual gross revenues of \$20 million to \$40 million.

Of course, there would be some offsetting savings, such as revenue from possible sales of excess power to neighboring utilities, lower system fuel costs resulting from lower energy requirements and from the use of new, more efficient generating facilities to carry the system load and increased flexibility in the maintenance schedule.

An error of such magnitude in the opposite direction could create a severe risk as to the reliability of the system. To compensate for this, a system may have several alternatives. For example, if feasible, construction schedules could be speeded at a premium cost, relatively

* These costs are currently more than doubled and the capital cost is more nearly \$400/KW; the cost due to a forecast error is, therefore, of the order of 30 to 50 million per year.

expensive firm power purchased from neighbors or higher operating cost peaking type capacity could be ordered. The full economic cost of any of these alternatives to the consumer, the stockholder, or the local economy is difficult to quantify.

c. Long-Term

The consequences of error in long-term forecasts are broad in scope and vary widely in accordance with the specific programs developed. While errors could lead to management decisions that in retrospect would appear faulty and take years to correct, some errors may be such that the utility would be able to recover from them with little or no consequence when studying intermediate-term forecasts. For example, long-term contracts or the establishment of special rates commit the utility and thus would preclude any recovery action for the term of the commitment. On the other hand, construction programs that do not require full commitment until the intermediate-term forecasts are made can be adjusted in the intervening years.

D. The Approach to Forecasting

Given the variability of the load, as illustrated in the several preceding figures, the task is to identify, to the extent possible, the cause and effect relationships implied by the observed variations. The effort usually begins with the classification of loads. An excellent discussion of the load classification from MLF follows.

The nature of the classification depends upon the need of the forecaster and availability of data. Some of the more typical groupings are by type of customer, by type of use, by level of use, by geographic location, by rate schedule, and by supply voltage.

1. F.P.C. Classes

The Uniform System of Accounts prescribed for Public Utilities and Licensees by the Federal Power Commission designates the several series of operating revenue accounts as follows:

a. Residential

Residential Sales - "...for electricity supplied for residential or domestic purposes. Records shall be maintained so that the quantity of electricity sold and the revenue received under each rate schedule shall be readily available."

b. Commercial and Industrial

Commercial and Industrial Sales - "...for electricity supplied to customers for commercial and industrial purposes...Records shall be maintained also so as to show separately the revenues from commercial and industrial customers (a) which have demands generally of 1,000 kw or more, and (b) those which have demands generally less than 1,000 kw...If the utility classifies large commercial and industrial customers and related revenues on a lesser basis than 1,000 kilowatts of demand, or segregates industrial customers and related revenues according to a recognized definition of an industrial customer, such classifications are acceptable..."

c. Other

Public Street and Highway Lighting - "...for the purposes of lighting streets, highways, parks and other public places, or for traffic or other signal system service, for municipalities or other divisions or agencies of state or federal governments."

Other Sales to Public Authorities - "...for electricity supplied to municipalities or divisions or agencies of federal or state governments, under special contracts or agreements or service classifications applicable only to public authorities..."

Sales to Railroads and Railways - "...for electricity supplied to railroads and interurban and street railways for general railroad use, including the propulsion of cars, or locomotives, where such electricity is supplied under separate and distinct rate schedules."

Sales for Resale - "...for electricity supplied to other electric utilities or to public authorities for resale purposes."

Interdepartmental Sales - "...for electricity supplied to other utility departments."

d. Problems of Classification

While such classifications appear clear and uncompromising, there are significant differences in reporting among utilities. For example, some utilities treat apartment and mobile home park dwellers as individual residential customers and report all usage as such. Others master-meter the building or park and count it as a commercial account. Some utilities classify all farms as residential customers. Others separate the larger farms and group them with commercial customers.

There have been continuing efforts to further standardize such reporting within the industry. However, significant differences remain, largely because the way in which individual systems use classifications reflects their rate categories and service philosophies.

2. Supplementary Groupings

The preceding classifications, while fairly broad, may suffice in forecast analysis for certain systems. However, variations and subdivisions within this series are as many as the imagination of the forecaster deems useful, but care must be taken to match the benefit with the cost of establishing and maintaining the data base. Table I is a specific example of customer classification by type of use employed by one system.

TABLE I

SAMPLE CUSTOMER CLASSIFICATION

Domestic	Industrial
Residential	Industrial - space heating
Farm Service	
Residential - rural	Public street & highway lighting
	Other sales to public authorities
Residential - space heating	
Farm Service - space heating	Sales for resale
Residential - rural - space heating	Rural electric cooperatives
	Other electric utilities
Commercial	
Commercial - space heating	
Commercial - rural	
Commercial - rural - space heating	

Such detailing of classifications may enable the forecaster not only to view the growth trends of particular segments of the market in more detail for load forecasting but also to develop a sales forecast with more precision than afforded through working with the class aggregate.

a. Type of Use

i. Location or Type of Dwelling Unit

Within the residential class customers can be coded on the basis of the location of their residence, that is, in an urban, suburban or rural area. This might be particularly appropriate if farms are generally classified as residential and sales to that group are of sufficient magnitude to be set out separately. Residences might also be classified by type such as single-family dwelling, duplex, apartment, mobile home or seasonal dwelling.

ii. Devices

Another method would be to classify residential customers on the basis of the types of appliances used, such as homes with electric ranges, or with electric water heaters, or electric space heating, or air conditioning or some combination of such appliances.

A similar breakdown might be made for commercial and industrial customers. This might be by those having electric air conditioning, electric heating, process heating, large motor loads, electric cooking, etc.

iii. Standard Industrial Classification (SIC)

Some systems group commercial and industrial customers by SIC codes as established by the Bureau of the Census. This provides detailed categories of electric use by homogeneous groups. Other systems elect to classify these customers only by the broadest categories such as metal related industries, extractive industries, service industries, etc.

Still other systems study in detail only a small number of commercial and industrial customers. These might be the 50 or 100 largest. Their load is then forecast separately from the remaining commercial and industrial accounts.

b. Level of Use

Another possible method of subdividing load for analytical purposes is the separation of customers or groups of customers by volume of use alone. Such subdivision could utilize as size criteria such items as billing demand, amount of energy used or, in some cases, load factor groupings.

One advantage of this type of classification is that the larger units or groups have the greatest impact upon the trend of total demand and analytical effort can be more effectively utilized by concentrating on these groups.

c. Rate Schedules

A further classification of customer loads used in forecasting is by rate schedules. This method can provide more detailed variations than the minimum grouping of customers prescribed by the Uniform System of Accounts. Rates are usually designed to be applicable to particular kinds of groupings of customers and therefore lend themselves well to workable classifications for forecasting purposes. The energy data is usually readily available in the regular course of business of a utility. But for forecasting for more than one utility system, care must be taken, since rate classifications frequently differ among utility systems.

d. Geographic Areas

Although it is widespread practice among utility load forecasters to segment their service territories into several subdivisions, there is little uniformity of method. Some select areas by geographic boundaries or municipal subdivisions; others segregate by operating areas or sales areas, or by regions served from major substations; still others specifically define areas by known or expected sales growth rates which may be much higher or lower than the system average.

The selection of sub-areas is usually governed by the availability of historical sales, demand or other data for each area, and by the likelihood of perpetuating and expanding such data.

There are at least two methods by which this can be accomplished. One is to select appropriate feeders or substations supplying the area and measure the power input into the area. Another is to identify the accounts served in the area and periodically summarize billing information.

Subdividing the system geographically facilitates analysis if the sub-areas so selected have unique attributes. Also, specific economic or environmental conditions which influence energy and demand characteristics can, in many instances, be identified and correlated with load changes in each area. Patterns of electrical use in an urban area are in sharp contrast with those in rural areas where hours of activity, seasonal patterns and equipment uses are likely to be quite different. Certain sub-areas may be oriented directly toward tourism or a specific recreational activity which will require different amounts of energy at different times as compared with any other sub-area. Geographic areas frequently have their own level of economic strength and potential. Even weather, particularly in extensive systems, may frequently be more severe in one geographic area than another and its effect on load requirements recognized and evaluated locally rather than on a system average basis.

The size of the forecasting system itself may be a factor for consideration in developing a load forecast, depending in part upon the techniques used to prepare the estimate. Placing a given large customer on a small system has a completely different relative effect from placing him on a large one. In the extreme a small system's load might be doubled while the effect on a large system load would be barely noticeable.

Area size is a major consideration in developing load estimates for large interconnected systems (power pools). As has been previously discussed, many factors affect system demand and the influence

of each factor varies over a wide range of values. Those most aware of these effects are the member utilities who have gained a more intimate knowledge of the different characteristics of the area and the effect each has on its own system. They have the statistics and the general knowledge of the area to make the best estimate. Thus, for the more extensive interconnected systems, demand forecasts are usually the resultant sum of independent forecasts made by each participating utility for its own system corrected for the historical diversity that has existed among the various member systems.

e. Other

Another method of classification now used by a number of utilities is to break the total load into two segments, the base load and the weather-sensitive load. Base load is treated as a function of the general state of the economy while the weather-sensitive load is considered to vary with weather conditions. This breakdown differs from the others in that statistical analysis is used to derive the two segments.

E. Load Class Patterns

The patterns of consumption by the various consumer classes is covered in detail in MLF. The principal thrust of the discussion is to demonstrate the difference in load patterns of consumer classes among themselves by region, by size, and by season. The differences in load patterns between consumer classes with the above factors is demonstrated as well. These differences are all important to the individual utilities serving the loads and make for diversity in the methods applied to the forecasting effort.

The factors affecting the use of electric power are also addressed. These are summarized in the following:

1. Residential

The residential component of load, while having the most constant annual growth rate, has become probably the most seasonally volatile load of the three. Its influence on the seasonality of a system peak can be very great, dependent on its proportion of total load, and the promotion and acceptance of air conditioning and space heating.

On many systems, residential loads are becoming an increasing percentage of total system loads. Their characteristics have changed substantially in the past decade and will continue to undergo changes as the mix of domestic load devices and their usage change. Not long ago, lighting played an important role in both the daily and annual load curve, but this is no longer true today when higher energy consuming devices have taken the lead. These are air conditioners, space heating devices, ranges and water heaters.

The refrigerator is one of the most widely used domestic appliances. Since it operates in an area of almost level temperature and its use is controlled by a thermostat, its diversified use is almost a constant load. Usage of an electric range is generally limited to three periods a day, with the greatest coincidence during the evening period.

Other than space heating and cooling devices, electric water heaters are the largest users of kilowatt hours of any domestic appliance today. While their usage characteristics are determined by size of the family, the number of appliances in the home which use hot water, and the groundwater temperature, they too are thermostatically controlled and have a highly diversified consumption.

Generally, there has been an increased demand for more home comforts and conveniences. Millions of room air conditioners have been installed in areas of the country subject to hot weather. Large number of medium- and higher-priced homes are being constructed today with central air conditioning. Electric space heating has similarly begun to obtain acceptance, changing the shape of load patterns throughout the country. The trends indicate load patterns in the future will reflect a much greater sensitivity to weather and temperature variations than has been experienced in the past.

2. Commercial and Industrial

a. Commercial

Commercial loads have very definite seasonal patterns although they are sometimes treated as a base load due to the historic importance of lighting. Specific applications producing seasonal

variations in this class are again air conditioning and space heating. In areas of high saturation, the seasonal effect of air conditioning on load patterns has already been felt. In the remaining areas, small stores, filling stations and many schools will either rapidly adopt air conditioning or will become a small portion of the total commercial load.

Electric space heating is beginning to be accepted in commercial applications. The effect of "heat-with-light" applications on seasonal load patterns may be slight, since the load is dominated by high level lighting which can substitute in part or in whole as the heat source. Other electric heating applications, however, will have a substantial effect on seasonal load patterns.

b. Industrial

Industrial loads are classified frequently as base loads subject primarily to economic variations. The very large industrial loads, particularly in the chemical and metal reduction categories, are usually in this group. These loads have little variation in seasonal load patterns and vary only slightly from hour to hour. It can be assumed that they lift an entire load curve uniformly.

Most other industrial loads may be usefully classified into groups having 1-, 2- or 3-shift operations. The load pattern of each is distinctively related to the hours of operation. A certain amount of service-type load, which generally includes some air conditioning and, in some instances, space heating, is supplemental to the production portion of the load. Where investment in machinery and other facilities is quite high, the tendency is to have a multi-shift operation. Where labor costs are a major component, the number of shifts tends to be more dependent upon economic conditions. Some industries such as mining and cement manufacturing or certain industrial practices such as retooling of facilities and vacation schedules have a seasonal impact on load patterns. In some industrial establishments a portion of the load may be interrupted by the supplier under special terms of an interruptible power supply contract.

Treatment of interruptible loads, load reductions due to strikes, plant shutdowns, etc., for forecasting purposes differs among systems. Some systems record load as experienced with no adjustments for any of the above. Others record the experienced load and adjust it to reflect what the load would have been if such occurrences had not taken place. Forecasts can similarly include or exclude the possibility of coincident strikes, vacations or reductions by voluntarily interrupted loads.

3. Other

Other load classifications include railroads, street railways, agricultural, street and traffic lighting, public authorities including military installations related to government programs, resale to other distributing utilities, losses and company use. For specific systems these can be significant and have seasonal patterns. For the nation as a whole, these classifications are relatively minor, and their growth trends tend to be quite stable.

F. Data Requirements

The data required for load forecasting fall into three general categories: utility load data, weather data, and economic data.

The utility data are those which the utilities collect for themselves. These load data are obtained from several sources but are most commonly obtained from meters at the substation level. The number and kind of customers are an important basis from which the utilities' planning starts.

Weather data are most generally limited to temperature and humidity. Geographical location provides significant differences in data needs. In some regions, high temperature is invariably accompanied by low humidity (e.g., South Central and Southwest); hence, the humidity index is of no particular concern. In others, high humidity may accompany a high temperature and a special index, the THI, or Temperature-Humidity Index, is used. There exist a great many local historical series of weather data extending over long periods.

There exists also a large array of economic data for both regional and national application. Studies have shown the importance of the condition of the economy for determining the demand for electric power.

A more detailed discussion of these factors is given in Appendix A.

G. Forecasting Methods

There are two basic forecasting methods: extrapolation and correlation.

1. Extrapolation. In using extrapolation, it is assumed that the pattern of the future is the same as that of the past. This method involves the fitting by least-squares or by inspection of a group of pertinent data from the past and extending it to the future. The form of the pattern may be straight-line (constant annual increments) or exponential (constant annual growth rate). Approximations of the exponential form by quadratic or cubic curves are also used.

The principal difficulty with extrapolation is that the underlying causative factors may not be identified. On the other hand, the growth of electric power demand has been relatively smooth for many years, and simple extrapolation is adequate for some utilities, if the extrapolation is not too far into the future.

2. Correlation. In applying correlation to the growth of electric power demand, one attempts to relate the growth to various causative factors. An assumption inherent in this method is that once the correlation is made, the causative factors can be predicted at least as well as the demand itself by extrapolation. In some cases, the correlations give important information even though the causative factor cannot be reliably predicted; for instance, the correlation of temperature (or THI) and the weather-sensitive component of the load. The correlation method's virtues lie in understanding the fluctuations and deviations from the extrapolated values.

Frequently, both methods are used to supplement each other and together will yield a more accurate forecast.

Both methods have many variations in statistical treatment, and no single method is best - or even adequate - for all cases. Both of the two basic methods are subject to modification by special information and judgment.

Special information may come from many sources: vacation schedules from industrial customers, strikes in a major industry, new housing development plans, etc. The extent to which these pieces of information effect a forecast depends a great deal upon the size and diversity of a particular utility.

Good or informed judgment is an essential ingredient to any forecasting method. It is essential in selecting factors to be analyzed, the methods employed, and the weight to be given to each of the factors and methods. In the case of missing or incomplete data, informed judgment will frequently bridge the gap.

A more detailed look at these factors, together with a summary of what was learned by the Technical Advisory Committee on Load Forecasting Methodology (MLF), is given in Appendix B. We note here that in the survey carried out by the author, not much has changed and the summary of the methods as determined by MLF is still representative of industry practice.

There is some research into methods going on with the objective of improving the forecasts. The inherent conservatism of the utility industry mitigates against any rapid, substantial change in methods. A survey of the accuracy of the forecasts indicates that "five year and up" forecasts predict within about 5% the observed loads (see Tables in Appendix B).

IV. RESERVE MARGINS

The question of how much reserve capacity should a utility have is an old one and one which has received increasing attention in recent years. As each utilities' system gets larger and more complex the need for interties with other systems and better arrangements within their own system has required an ever-more sophisticated analysis. In the not too distant past, reserves were taken as "the largest unit", "one and one-half time the largest unit", or some other such rule of thumb. When units were relatively small, this sort of rule wasn't too bad but as unit sizes have grown steadily larger and systems more complex, such methods are no longer adequate. The extent of the interest in the problem is indicated in the bibliography. Reserves are typically to meet some expected as well as unexpected events. The expected events are scheduled maintenance but because it is scheduled, it usually is treated as additional load and not subject to fluctuations. It must nevertheless be accounted for in system planning. In systems with large seasonal peaks most scheduled maintenance will be during the off-peak season and cause little disruption.

As with most things, mechanical boilers, turbine-generators, transmission lines, etc., are subject to failure for any of a nearly infinite variety of causes from lightning strikes to simple mechanical breakage. The means of coping with these unscheduled events is in the amount of reserves maintained. Since the losses are stochastic in nature, the method of attacking the problem are largely stochastic. A committee of the American Institute of Electrical Engineers published a review of the situation along with some history in 1961.⁽¹⁾ In this paper there is discussed the three basic measures of system reliability:

1. Loss of load probability.
2. Loss of energy probability.
3. Interval between outages.

The results of method (1) are stated as the probable number of days per year that the system load is expected to exceed the available generating capacity. A "Loss of Load Probability" of 0.2 days/yr is usually expressed as "one day in five years." Each occurrence of a daily peak which exceeds the

(1) Application of Probability Methods to Generating Capacity Problems, AIEE Committee Report, Paper 60-1185, February 1961.

generating capacity is given equal weight regardless of the length or amount of deficiency in capacity. In method (2) the outage probability is combined with the percentage of load interrupted to yield the probability of not supplying a certain amount of energy. Method (3) measures the system reliability in terms of the interval between outages and the corresponding average outage duration. There are a number of variants in terminology and application. In this section, an attempt will be made to show equivalence when it exists and interpret the terminology. In the AIEE Committee Report the comparisons are carried out in terms of a hypothetical problem, the terms of which are to compute the reliability index by each method, given a load duration curve, a set of generators with known forced outage rates and other pertinent data. The effect on the indices of many possible variations are then calculated. It is shown that although the results of each sort of calculation are not identical, the effects are generally similar and decisions based upon the results would not be substantially different. Planners however would do well to use more than one method, e.g., method (3) and either method (1) or method (2). A topic not covered directly in the AIEE Committee Report but covered a bit in the discussion is the matter of cost to achieve a given reliability. The topic is naturally and closely connected to a discussion of required reserves but beyond the scope of this report.

Several other measures of system reliability, variants of those discussed above are in use. One of these is the "Probability of Positive Margin" or POPM.⁽¹⁾ The relationship of POPM to the loss-of-load probability may be illustrated as follows: Assuming 250 working days per year, a loss-of-load probability of one day in 10 years is equivalent to the loss of load of one day in 2500 days. If all days have equal probability of loss, then each day has about $1/2500$ or 0.0004 chance of sustaining a loss of load. The probability of not losing the load or having a positive reserve margin is simply $1 - .0004$ or 0.9996.

(1) Mabuice, E. M., Wilks, R. L. and Boxerman, S. G., Generation Reserve Requirements - Sensitivity to System Parameters, private communication from Mr. Mabuice.

Mabuce, et. al., using POPM have analyzed the sensitivity of the system reliability to changes in the system parameters. The context of the work was the setting of reserve margins for the Mid-American Integrated Network. From an assumed number of units of specified size, maturity, and forced outage rate, the authors compute the reserve requirement versus the POPM level (see Figure 8); reserve requirement versus the size of connected system for a given POPM (Figure 9); reserve requirement versus the makeup of the most recently added 30% of installed capacity for different unit sizes and assumed forced outage rates (Figure 10); the effective load carrying capacity versus unit size for various forced outage rates and an assumed POPM level (Figure 11); the reserve requirement versus maturation time for a fixed POPM level (Figure 12); and of most importance to this study, the effect of load forecasting uncertainty upon reserve requirements (Figure 13). The load forecasting uncertainty is represented by a normal distribution and a standard deviation in the load forecast at constant POPM. It is clear that for uncertainties above three percent, the reserve requirement rises rapidly (at about 3% reserves/percent uncertainty). The importance of improving the accuracy of load forecasts is therefore apparent.

For the details of the probability calculations, reference should be made to the original papers as the details are too long and tedious to be included here.

FIGURE 8.
RESERVE REQUIREMENT VERSUS POPM
LEVEL DESIRED

FIGURE 9.
RESERVE REQUIREMENT VERSUS SIZE
OF CONNECTED SYSTEM

FIGURE 10.
RESERVE REQUIREMENT VERSUS MAKEUP
OF MOST RECENTLY ADDED 30%
OF INSTALLED CAPACITY

FIGURE 11.
EFFECTIVE LOAD CARRYING CAPABILITIES
VERSUS UNIT SIZE AND
FORCED OUTAGE RATE

FIGURE 12.
RESERVE REQUIREMENT VERSUS
ASSUMED MATURATION TIME

FIGURE 13.
PERCENT RESERVE REQUIREMENT VERSUS
ASSUMED STANDARD DEVIATION
OF LOAD FORECAST

V. BIBLIOGRAPHY

This bibliography represents a sampling of the literature on subjects related to the topic at hand. It is not to be considered complete but only representative of the work going on in the community concerned with the problems of load forecasting and system reserve requirements. The bibliography is divided into three parts, one directed mostly to load forecasting and load forecast uncertainty effects, one directed mainly to system reserve requirements, and one concerned primarily with economics of power systems. A common abbreviation to be used is: IEEE-PAS for IEEE, Power Apparatus and Systems.

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APPENDIX A

STANDARD DATA REQUIREMENTS

APPENDIX A*

STANDARD DATA REQUIREMENTS

I. TYPES OF DATA NEEDED

Data used in load forecasting may be grouped into three broad categories: utility data, weather data and economic data, both national and regional. Each of these is important in load forecasting.

Utility data are defined as those data which originate in the utility itself but which also may be collected and presented by other agencies. Each system's particular data are the primary materials for forecasting. Load and customer data collection and treatment are important prerequisites for the preparation of load forecasts. As can be seen in Appendix B, the trend of historical data is an important element in considering the future, especially when interpreted in the light of other information such as weather and economic data.

Weather data reflect meteorological factors and these affect load in an important way. The predominant weather factor for most systems appears to be temperature. Fortunately, considerable historical temperature data are available for analysis. Other forms of data are available for only limited periods.

Economic data comprise a large body of information measuring the status and performance of the economy. These measures are available on both a national and a regional basis. These are important because customer growth and increasing power consumption depend ultimately on economic development.

The text below reviews some of the data in general use by electric utilities in load forecasting.

* This appendix is basically Chapter IV of MFL.

II. UTILITY DATA

A. Load Data

Load data (both demand and energy) are usually available or can be collected from log sheets and billing data. They consist of historical data on generation; hourly demands; sales by classes of service; losses; and peak demands for daily, weekly, monthly, seasonal, and annual periods.

It is important to have clear definitions of these data because the series should be consistent over time and be related logically to other parameters. For example, confusion may arise in considering demand when some data are on an hourly basis while others are based on shorter periods. Or commercial and industrial loads, which may follow different trends, may be included in a single business and industry series. Industrial loads are usually responsive to the business cycle, while commercial loads are less responsive to business conditions but are usually responsive to weather conditions.

As has been mentioned earlier, there can be substantial differences among systems and over time within the same system in the method of classifying energy data. For example, the distinction between commercial and industrial may not be used but rather the total of the group may be divided between large and small customers. Similarly, residential load in rural areas may include considerable farm equipment, or it may be separately recorded, or the whole load may be reported as commercial. Apartment loads, which appear basically residential in nature, are frequently classified as commercial when master-metered.

B. Number of Customers by Classes of Service

The differences in definition of class of service discussed above generally apply here, too. Customer and sales data are frequently used to compute average use by classes of customers. Changes in such averages must be carefully interpreted in the light of classification practices and changes in such practices.

C. Special Metered Data

Loads may be metered to determine more accurately the components of total load. For example, cooling and heating loads may be metered in sample areas as a means of learning their magnitude and characteristics. New loads appearing on the system, such as mobile homes, selected farm equipment, or a specific type of industrial load, may also be metered.

D. Marketing Data

Marketing data are helpful in appraising opportunities for future growth and the probable effect of competition. Major categories of such data are appliance saturations, public preferences and opinions, and price of electricity relative to competing energy sources.

1. Appliance Saturations

Such data are commonly cast in terms of ownership or use of a specific appliance per customer or per household. They may be supplemented by reports of shipments of appliances by manufacturers. Care must be taken in the use of these statistics, since they may be based upon sample surveys and, therefore, incorporate shortcomings inherent in surveys, such as bias, false response, non-randomness, etc.

Also, saturation is usually considered as having a ceiling of 100%. Several appliances - television, refrigerators, room air conditioners, for example - may be represented more than once in a growing number of households. Failure to account for multiple ownership leads to improper energy or market potential estimates.

2. Preference and Opinions

These are always based upon surveys and the same sample limitations noted under "Appliance Saturations". In addition, preference surveys must be handled with caution because subsequent actions may differ from expressed opinions.

3. Price of Electricity Relative to Competing Energy Sources

The relative price of electricity to a competing energy source, for example gas, may be useful in showing growth relationships which are dependent on price elasticity. However, it must be kept in mind that the relative price per million Btu received by the consumer does not necessarily reflect the cost of operating his devices. Efficiency of conversion of the two sources may be different. Comparisons over time may not be valid if there have been changes in relative conversion efficiency.

E. Special Considerations

Some considerations which may be important include examination of the effects on the load data of wheeling arrangements, interconnection commitments, special contracts with large industrial accounts, and municipal and REA resale accounts.

These data tend to be a discontinuous series and can affect the total system data in a significant way. These effects may be direct, such as the addition or cancellation of a large sales contract, or indirect, such as the influence on losses of a large wheeling agreement.

III. WEATHER DATA

Weather data are varied and extensive. They include temperature, humidity, degree days, wind velocity and direction, precipitation, and sky cover. Much data, especially temperature, are available in published form over several decades for most locations. Within the past decade, the Weather Bureau (Environmental Science Services Administration) has developed other measures of personal comfort, such as heating and cooling degree days, chill factor, and temperature-humidity index. During the development stages, many different ways were used to calculate these measures. Care must be taken not to mix these.

Special note should be taken that several different weather measures of heating or cooling needs may be pertinent to utility data. For example, in relation to cooling, energy may be needed to cool commercial buildings when the ambient temperature rises to 50 to 60 degrees. For residences, energy for cooling may not be needed until temperatures reach 75 to 85 degrees. Therefore, different bases of cooling degree days would be appropriate for each of these loads. Similarly, separate measures of heating degree days would be required in relation to heating effects.

Analysis of weather and its effect upon weather-sensitive loads should include probabilities of occurrence of weather phenomena in the future. Identification of probabilities of extreme temperatures is helpful because loads can be studied more precisely.* Future temperature may be predicted with precision only in terms of probability. These, however, must be developed by each system to meet its requirements from basic Weather Bureau data.

* Annual peaks in one region, which has a high saturation of electric heating, have occurred at temperatures ranging from as high as 20 degrees to as low as -10 degrees. This is a 30-degree temperature swing in a region where winter loads currently vary about 100 MW per degree temperature change. If temperatures are 10 degrees colder than normal minimum temperatures, the load will be 1,000 MW more than would be expected at normal minimum temperatures and, conversely, loads would be 1,000 MW less if temperatures were 10 degrees warmer than normal.

IV. ECONOMIC DATA

A variety of economic factors influence loads. These include population and households, employment, income, industrial production, gross national product, construction, and many others. These data can be helpful in explaining historical load behavior and thus suggest important considerations for forecasting in a given utility area.

It is important that the applicability of the data, as well as the concept and construction of the series, be well understood before being utilized. For example, in analyzing the volume of new customers, it is important that the conclusions take into account not only the standard single-family and apartment units, but also mobile homes. Or, data expressed in dollars must be examined for the effect of changing price levels, and it is often desirable to convert them to constant dollars to eliminate the effect of general price changes. Many of the series are periodically revised, sometimes in substance and coverage and sometimes only in terms of the precision of the measurement. Breaks in continuity are a factor for which the forecaster must be alert. In general, the use of these data as related to the consumption of electricity must be established through careful analysis of the past record by each forecaster.

There is a lack of reliable business indicators at the local political subdivision level, but several items of information, such as census data, housing inventory statistics, labor market surveys, bank deposits, and the like, are frequently available and may be sufficient to prepare adequate analyses.

V. ADJUSTMENT OF DATA

Historical utility data may be adjusted to make them uniform in definition and coverage in order to increase their usefulness in forecasting. Significant changes in load resulting from strikes, plant shutdowns, or other load interruptions can be added back to load to determine what the full potential load might have been. Such factors as leap year, changes in billing cycles, and metering errors may require adjustments to eliminate distortion in the true growth of a data series. In general, historical data are more useful in forecasting when they are uniform by class and coverage and when any change of definition of the data is clearly recognized.

Heating, cooling, and to some extent lighting and irrigation loads vary with weather factors. Calculation of the degree to which load varies with these factors is important because this allows adjustment of historical data to evaluate or eliminate the effects of weather extremes. Adjusted data can also be used advantageously in computing weather adjusted relationships for use in forecasting, such as load factors and coincidence factors.

VI. FORECASTS OF ECONOMIC DATA

A number of organizations publish forecasts of various segments of the national economy. Some utilities use such forecasts in preparing load forecasts. Perhaps the most widely used source in the electric utility industry is the McGraw-Hill, Inc., publication Electrical World in which forecasts of a group of related indicators are presented each September. These indicators are: FRB Index of Industrial Production, GNP, population, households, new dwelling units, consumer disposable income, total employment, manufacturing production workers, and business capital investment. Forecasts are given by years for the next five years and at five-year intervals for the next 15 years.

VII. ASSUMPTIONS

A forecast is no better than the assumptions upon which it is based. Preparation of assumptions frequently involves some analysis and adjustment of historic data. There is an interrelationship between the assumptions made for the load forecast and those made for economic forecasts. Electric utility loads are largely dependent upon factors which are outside the utility's control, such as demographic and economic conditions. Therefore, a forecast must include, implicitly or explicitly, assumptions about these factors. To the extent reasonable, it is usually helpful to examine factors affecting load and to make explicit assumptions about their future behavior.

Although some assumptions may be stated in general terms, they are more useful when stated specifically and in as much detail as reasonable. It is useful to arrange them in a form suitable for convenient review so that others may follow the reasoning and be able to ask questions and suggest changes. This facilitates review and periodic revision of the forecast. The making and recording of assumptions is properly an integral step in the forecasting procedure.

VIII. CURRENT RESEARCH IN LOAD FORECASTING

Given the variability of the observed loads, some ways have been and continue to be sought to reduce the uncertainty in load forecasting. The current techniques which yield long-range uncertainties of about 5% will be difficult to improve upon, but because of the dynamic nature of the growth of the economy and the electric load patterns, it behooves the forecaster to be constantly alert to changes which will render his methods obsolete. The trends in research are in the directions of trying to better understand the fluctuations in terms of their explanatory variables and trying new approaches to living with the fluctuations. The description of current research in load forecasting is not exhaustive but more indicative of the trends. There is increasing activity within the utilities occasioned by the need to justify new capacity, such as a nuclear reactor up to eight years in advance of startup. The forecasts have to be convincing to the various regulatory and licensing bodies. There has been some lagging in the utilities because they lack specialist personnel and data. The costs of hiring an adequate specialist staff and obtaining the data are the principal inhibitions. The chief methods of communication with other forecasters have been occasional papers in the trade and technical journals and some exchange within the coordinating groups. The research listed will be outlined by organization performing the research.

- RAND Corp.

Under funding by the National Science Foundation, with contributions from the State of California and Rockefeller Foundation, the RAND Corp. is carrying out a detailed study of the need for energy. This includes electric power generation. Under this program, they have been and are continuing to explore electric power use in the U. S. and the State of California. They have produced several studies of the various facets of the problem, to wit:

1. Residential Electrical Energy Consumption in California: A Conceptual Forecasting Model. Mow, C. C., Mooz, W. E., and Anderson, S. K., R-995-NSF/CSRA. (Draft)

In this study, the objectives are to identify the pattern of residential electrical consumption and the driving forces behind the uses, and to develop a residential energy forecast model for the State.

The methods used are a mixture of traditional extrapolation, end-use analysis, and econometric projection.

2. Manufacturing Sector Electrical Energy Use in California: A Conceptual Methodology. Mooz, W. E., and Mow, C. C., R-991-NSF/CSRA. (Draft)

In this study, the estimating methodology relies on the projection of individual trends in electrical energy use, as observed, as a function of time for each of 20 manufacturing industries. Lack of time and data prevented complete quantification, but reasonable projections are made and the roles of the principal determinants discussed.

3. Residential Demand for Electricity: Econometric Estimates for California and the United States. Anderson, K. P., R-905-NSF, January 1972.

Least-squares regression techniques are applied to the U. S. for 1969 (cross-section analysis) and to California for 1947-1969 (time series analysis). The U. S. Analysis indicates statistically significant influence of electricity cost, average household income, average number of persons per household, fraction of population living in non-metropolitan areas, average July temperature, and as a special case, the percent all electric customers of the utilities.

4. A Probabalistic Forecasting Methodology Applied to Electrical Energy Consumption. Salter, R. G., R-993-NSF (Draft), February 1972.

In this study, the traditional forecasting techniques are supplemented by probability concepts to attempt to quantify areas of high uncertainty; for instance, the future transitions between income classes. The probabilities are assigned in the form of beta-functions and the convolution performed by a Monte-Carlo technique.

5. Building an Energy Demand Signed Digraph II; Choosing Edges and Signs and Calculating Stability. Roberts, F. S., RN-927/s-NSF. (Draft)

This study examines a rather unique approach to the energy demand problem, although still in a formative stage, and has not been applied to the problem of load forecasting as yet. The method

is an outgrowth of graph theory and appears to be particularly useful in policy areas.

- Oak Ridge National Laboratory - Cornell University

These studies are another group funded under the NSF-RANN program. Though directed primarily toward energy/environment interactions, an important part of the work is directed to consumption of electric energy and, thus, relevant to the problem of load forecasting. There are two principal publications bearing on the problem:

1. Electricity and the Environment. Chapman, Duane, Tyrrell, T. J., and Mount, T. D., paper presented to the AAAS Meeting, December 1971.

The part of this study involving consumption of electricity is a rather thorough look at the problems of applying econometric methods to the factors of consumption. The pertinent variables are taken to be the price of electricity, total personal income, and population. Many problems are identified and some solutions proposed. The problem of conflicting earlier work on the elasticity of demand for electricity with the price is in principal resolved by introducing a lag factor. They then observe a short-term and a long-term elasticity; the long-term elasticity being realized in two to three years.

2. Predicting the Past and Future in Electricity Demand. Chapman, Duane, Mount, Timothy, and Tyrrell, Timothy, paper prepared for the NSF workshop on Energy and the Environment, February 1972.

A conclusion of this study is that the growth behavior of electricity demand will not be as well behaved as in the past. This is based on the observed facts that the population, income, electricity prices, prices of competitive goods (to electricity), and appliances and machinery (using electricity) have all changed in directions which result in higher electricity demand and in a generally smooth manner. The future, on the other hand, holds the promise of rising prices (for environmental control, health and safety, etc.), leveling or decreasing growth rate of population, and changes in per capita income. The uncertainty in the projection of any of the explanatory variables is reflected in the uncertainty in load forecast.

- Technical Advisory Committee on Load Forecasting Methodology for the National Power Survey

After completing the study of load forecasting for the FPC, MLF produced the study abstracted below. While not properly a research effort in load forecasting methodology, it is an assessment of some changes which have occurred since the original load forecasts for the 1970 National Power Survey were produced.

1. Changed Underlying Factors Influencing Electric Load Growth. Report to the Federal Power Commission, Technical Advisory Committee on Load Forecasting Methodology for the National Power Survey, 1971.

Here, it is surmised that the major factors influencing load forecasts which are new or changed since 1968 are:

- a. Environmental conservation;
- b. Changes in population growth;
- c. Resource conservation;
- d. Inflation may be higher;
- e. Increased capital requirements;
- f. Fuel shortages.

The direction of the change in demand which some of these changes will occasion is, at the moment, mostly undetermined. A complete discussion is in the cited document.

An earlier effort at relating load growth to generating capacity additions was published by C. W. Watchorn in 1963.⁽¹⁾ The principal conclusions are that the timing of capacity additions can be calculated within a narrow range by determining the long-term trend for the annual energy requirements based on the relative growth characteristics of industrial and nonindustrial loads and the frequency distribution of the deviations of the normalized annual peak loads.

A later attempt to further refine the forecasting by separating the weather-sensitive load from the base load is given by Heineman, Nordman and Plant.⁽²⁾ After examining a number of variables, the authors deduce that

(1) Watchorn, C. W., Load Growth Characteristics as Related to Generating Capacity Additions, IEEE.

(2) Heineman, G. T., Nordman, D. A., and Plant, E. C., The Relationship Between Summer Weather and Summer Loads, IEEE, Vol. PAS-85, November 1966.

the daily peak load can be forecast using a base load plus the product of a cooling demand factor and a single weather variable or:

$$DPL = B + CDF \times WV.$$

The base load factor (B) and the cooling demand factor (CDF; related to air conditioner saturation) are forecast separately.

An innovative approach to forecasting loads is given by Turner.⁽¹⁾ A comprehensive land use study of an 800 sq mile area around Memphis, Tennessee has been used to project demands. The virtues of the system for the utility are that not only is the forecast correlated with development of the area but correlated by location as well which aids immeasurably in planning.

Another paper on application of probability methods to load forecasting was published by Pleines and Zajir.⁽²⁾ A method of producing an average demand and a probability of exceeding the average plus some increment is derived. The basic data are appliance numbers and their ratings and use factors. The methods may be extended to other aspects of demand forecasting.

A description of a probability methods applied to load forecasting is described by Kind.⁽³⁾ In the analysis the baseload and weather-sensitive load are separated and the components analyzed and forecast. A weather model is derived and convoluted with the weather-sensitive load forecasts. The combination then with the base load yields a forecast with a mean and variance.

An effort toward more orderly planning by monitoring load forecasts for substations is given by Hubbard.⁽⁴⁾ A program for comparison of load forecasts with the experienced load leads to a more accurate estimation of timing for changing equipment to meet load growth.

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- (1) Turner, H. D., Land-Use Study Used to Forecast Systems Peak, Electrical World, August 11, 1969.
 - (2) Pleines, W. W. and Zajir, K. U., A Method of Estimating Demand, IEEE, PAS, February 1963.
 - (3) Kind, Carl G., Probability Technique Adds New Meaning to Demand Forecasting, Electric Light and Power, January 1969.
 - (4) Hubbard, J. C. Monitoring Load Forecasts, IEEE Trans., Vol. PAS-88, June 1969.

There is probably other current research going on or preparations being made to pursue some new courses. The Purdue University program is an on-going program of the Purdue Energy Research and Education Center and is described in detail in the MLF document. The Purdue efforts are given in detail in a paper by Stanton and Gupta.⁽¹⁾ The effort is concentrated on probabilistic monthly and weekly peak demand forecasting and the derivation of annual peak demands. Some efforts at getting started are evidenced at Washington State University in a document proposing some regional centralized forecasting efforts to improve the forecasts of the individual utilities.

The need for improvement in forecasting is recognized by the Electric Research Council⁽²⁾ by its proposal to spend about \$100,000 per year on load prediction and another like amount of the supply on fuel aspects of this problem.

(1) Stanton, K. N. and Gupta, P. C., Forecasting Annual and Seasonal Peak Demand in Electric Utility Systems, IEEE Trans., Vol. PAS-89, May/June 1970.

(2) The Electric Utilities Industry Research and Development Goals through the Year 2000, Report of the Research and Development Goals Task Force to the Electric Research Council, ERC-1-71, June 1971.

APPENDIX B
CURRENT FORECASTING METHODS

APPENDIX B*CURRENT FORECASTING METHODS

Forecasting techniques are tools. No single method or group of techniques in itself assures success in forecasting. Knowledge and judgment of the forecaster in applying selected techniques in a given utility load situation are essential. So is final judgment of the elements used in arriving at the ultimate load forecast.

The number and kinds of forecasting methods used vary considerably from utility to utility. Use of several methods is common. Differences in methods result in part from variations in economic and geographic conditions, system characteristics, and mix of loads in the utility areas. For example, population may change rapidly in one utility area and be stable in another. Utilities with large cooling loads have an interest in developing estimates of historical cooling loads and load-weather relationships and using these in forecasting cooling loads. Utilities serving industrial loads which are highly responsive to the business cycle and which constitute a large proportion of total load usually put more emphasis upon analysis of industrial loads than do utilities serving a stable and small industrial load.

I. BASIC FORECASTING METHODS

Forecasting methods can be grouped into two categories: extrapolation and correlation.

A. Extrapolation

Extrapolation is based upon the assumption that future growth will be a continuation of a discernible pattern of past growth. Specific methods include compound rates of growth, annual increments, fitting of mathematical growth curves, and use of graphs of treated or untreated historical data.

Extrapolation often produces acceptable results because electric loads exhibit stable growth over rather long periods. Residential, outdoor lighting, and service loads appear to be largely insulated from the business cycle.

* This appendix is basically Chapter V of MLF.

However, forecasters relying predominantly upon this method may fail to recognize underlying changes which eventually will affect future growth. For example, a succession of very hot summers might mask declining growth in non-air-conditioning loads.

B. Correlation

Correlation relates electric power loads to selected associated factors. Correlation methods include scatter diagrams, simple correlation, multiple correlation, and simple or complex models. While results from these techniques, especially the more sophisticated methods, cannot be accepted at face value but must be evaluated in terms of the theories underlying the techniques, including their limitations, they provide insight into the causes of past growth and its variation and quantify relationships between load and factors which affect load. This leads to a clearer understanding of the factors which cause growth and of their relative importance. Further, when forecasts deviate from actual loads, the correlation approach is helpful in identifying causes of deviation.

One problem associated with correlation methods is the need to obtain and select forecasts of these associated factors, i.e., independent variables, such as population, income, appliance saturation, etc. There is no assurance that this can be done with any greater accuracy than forecasting electric loads directly. Despite this difficulty, correlation is useful because it forces the forecaster to consider and analyze future load in a context of other factors rather than as a completely independent phenomenon.

It is important, however, that the analyst/forecaster avoid the mistake of drawing conclusions from spurious correlations which have a high degree of statistical significance but no logical relationship.

II. SPECIAL INFORMATION AND JUDGMENT

Although extrapolation and correlation are fundamental to the art of load forecasting, they are not generally sufficient to assure the best results. Two additional ingredients that are often important to the development of a sound load forecast are the use of special information and the exercise of informed judgment.

A. Special Information

Special information is used to modify or reinforce the forecast. Examples include opinions of industrial plant managers as to probable future loads, planned utility promotion programs, the results of appliance surveys to determine present saturations and buying intentions, predictions of business activity, and area and national electric power forecasts. Such information is not only an important indication of definite future planning for electric consumption by others, but also is a stimulant to the forecaster in thinking about the possibility of new trends.

B. Informed Judgment

In forecasting, informed judgment is necessary in the selection of the factors to be analyzed and in the selection of the forecasting methods to be employed. It is also essential in determining the weight to be given to differing forecasts derived from use of several techniques. In uncertain situations when information is incomplete or when forces affecting load are not quantified, the informed judgment of the analyst is of particular importance. For example, he must decide whether forces favorable and unfavorable to growth of a new type of load are such that the new load is likely to become significant over the relevant planning period.

Finally, informed judgment plays a major if not decisive role in identifying likely future changes in trends, in selecting among competing forecasts of external forces such as economic activity and housing starts, in evaluating market penetration in such areas as air conditioning and heating, and in identifying areas and degree of competition from alternate energy sources.

III. SURVEY OF INDUSTRY FORECASTING METHODS

In order to determine the present state-of-the-art of load forecasting in the industry, a survey was made of the current practices. Survey respondents were selected with the objective of including all types of systems, all areas of the country, and all types of forecasting methodology rather than on a random basis. The survey questionnaire was prepared and distributed through the FPC Regional Advisory Committees. Thirty organizations responded. The techniques used by the respondents for short-term, intermediate-term, and long-term load forecasting are discussed below.

The survey results reflect the dynamic nature of forecasting methodology in use during the period 1961-1967. Forecasting methods have evolved to meet the particular needs and individual characteristics of the various electric utility systems. Several respondents adopted changes in methods during the seven-year period; others mentioned changes that are being considered. This evolutionary process is found to be common in systems represented on the Committee as well as in the experience of those responding to the survey.

The wider daily and seasonal swings in loads experienced in the last few years and growth of new kinds of loads or changing patterns of growth of existing loads have been among the reasons for the search for new forecasting techniques. Another reason has been the increasing need for improved accuracy and more detailed forecasts to enable economic planning for greater use of energy interchange and larger generating units. Finally, improved forecasting methodology developed outside the industry along with the development and availability of greater computational capability also have been responsible for changes in load forecasting methodology.

A. Short-Term

Most utilities reported that hour-to-hour and day-to-day load forecasts are prepared by adding expected load changes to current or recent past loads. Nearly all reporting utilities indicated that expected weather conditions are considered in preparing forecasts 24 hours in advance. Half specifically report use of temperatures, while only five refer to humidity or wind velocity. Nearly all indicated that historical hourly load patterns and

day-of-week patterns are considered. Ten utilities report that changes in large industrial loads, strikes, and other abnormal events are recognized in making the forecast.

Few of the reporting utilities use complex forecasting methods for short-term forecasting. However, a small number report developmental work to computerize hour-to-hour and day-to-day load forecasting, presumably to permit analysis of more variables. One utility reports it is engaged in developing empirical formulae to automate short-term forecasting of hourly loads based on expected temperatures, previous temperatures, and previous loads.

B. Intermediate-Term

In the survey questionnaire, intermediate-term forecasting is defined as covering a period of four to six years. The survey indicates that the most intensive use of statistical techniques is in intermediate-term forecasting.

1. Adjustment of Data

All utilities report adjusting historical data in some manner, i.e., making some form of preliminary analysis to eliminate the effects of cyclical, seasonal, or irregular factors prior to analysis of trend factor. More than half specifically report adjusting for the effect of weather, while others take weather into account through judgment or historical relationships. Five report adjusting for specific events, such as plant shutdowns.

A quarter of the utilities specifically report use of formal statistical treatment. These include time series analysis, correlation analysis, analysis of variance, and other such techniques. The remaining three-quarters report calculations based upon historical relationships; it is not clear from the survey responses whether these systems determine the historical relationships through formal statistical analysis.

2. Approaches

In the forecasting of loads, utility systems are using a variety of approaches. Four sets of approaches to various phases of load forecasting are set forth below.

a. Energy vs Peak Demand

About half of the reporting utilities prepare an energy forecast as the primary forecast, with a peak demand obtained by use of load factor relationships. The other half prepare peak demand forecasts directly. Several report less detailed forecasting of the secondary data to serve as a check on other methods. For example, one utility prepares energy forecasts in detail by classes of service and geographic areas and calculates peaks by use of load factor projections. As a check on these figures, weather-adjusted peaks are extrapolated on the basis of past trends.

Advantages claimed for emphasizing peak forecasts are that it is the most direct way to obtain what most systems consider the most important forecast; that load factors are frequently erratic and difficult to project; and that demand data can be related more directly to such variables as temperature.

Advantages claimed for emphasizing energy forecasts are that energy data are usually less erratic over time than peak data and are, therefore, a better indicator of underlying growth trends; that load factors are no more erratic than peaks in the short run and in many cases tend to be rather stable over long periods despite year-to-year variation; and that detailed data are available by classes of services, areas, or other subdivisions and can be readily related to appropriate variables, such as weather, national economic indicators, and population.

b. Total Load vs Components

About one-third of the reporting utilities prepare forecasts of system loads in total. The other two-thirds assemble peak forecasts either by geographic areas, by types of customers, or by some other subdivision of load. Forecasts of the individual parts are combined and adjusted for losses and diversity to obtain a total system load forecast. Loss and diversity adjustments are based on historical relationships.

Proponents of the total load approach argue that it is difficult to perceive changes in trends in each load component, e.g., the sudden surge in residential air conditioning, the rebuilding of one area, a new industrial development. In addition, their experience has shown that the overall growth of demand and energy has been smooth in the past, rapid growth in one component offset by slower growth in another. Rather than trying to foresee each new application or change in use of existing applications for each component, they feel more confident in predicting the overall continuing rate of growth of their system.

Proponents of the components approach argue that one part, e.g., a portion of the service area, a class of service, or a type of load, may be growing much more rapidly than the remainder. If this part is substantial and its rate of growth differs significantly from that of the total, failure to segregate it can result in misleading conclusions. Further, they argue that a great deal more detailed information can be more meaningfully correlated to the parts than the total.

c. Average Weather vs Extrêmes

Most utilities prepare forecasts designed to reflect normal weather conditions. Historical seasonal or monthly peaks are usually adjusted for weather using weather models or other computational methods to provide the basis for peak projections. Other utilities construct graphs of historical peaks, correlate

them with temperatures at the time of peaks, fit a curve through the historical data, and extrapolate. Both of these methods are designed to provide a normal peak forecast or the peak which is most likely to occur if historical, average extreme conditions occur in the future. That is, it is equally likely that actual peaks will exceed or be less than the forecast.

Utilities experiencing greater variability in loads either from irregular weather or economic patterns are forced to consider loads under other than average conditions. This may take the form of stating forecasts in probabilistic terms or just a simple statement of the possible extremes associated with the forecast.

To obtain extreme forecasts, four utilities report that extreme peaks are calculated from normal peak forecasts either on the basis of historical differences between normal and extreme weather peaks or by adjusting of normal peak forecasts to low probability weather conditions using extrapolated load-weather relationships or models. Two utilities report that extreme weather peaks are forecast directly.

d. Simple vs Formal Statistical Methods

About a third of the reporting utilities indicate use of simple methods of forecasting which include graphic projections and use of historical growth rates. Their forecasts are usually tempered with judgment and influenced by considerations of the business cycle and other economic factors. Depending on the load and growth characteristics of the system, such methods often can be effective.

Another third of the utilities report use of mathematical methods involving least-squares, logarithmic curves, and modified exponential growth curves. In some cases, these are simply mechanical methods of extrapolation with the ultimate results being tempered by judgment. Other companies select the type of curve based on the relationship of its mathematical characteristic

to the growth characteristic of the system. Four utilities report use of correlation or models through which customers and loads are related to demographic and economic factors.

C. Long-Term

Long-term forecasting is generally defined as being in the order of 10 to 30 years in the future. One-fourth of the utilities surveyed report that they do not prepare long-term forecasts.

Half of the remaining utilities report that long-term forecasts are extrapolations of intermediate-term forecasts based on judgment, compound rates of growth, fitted curves, or some combination of these. The other half use a variety of methods.

One utility states that historical information, its intermediate-term forecasts, and trend projections of economic indicators, such as GNP and the FRB Index of Industrial Production, are taken into account in its long-term forecasting.

Another utility reports that long-term forecasts are prepared by projecting energy requirements by rate classes using trends and marketing information. Historical relationships are used to obtain demand contributions of the various rate classes to the system peak demand. Typical demands for each class of customers are derived from sample demand metering of a statistically selected group of customers.

A utility with large in-migration of population reports that long-term forecasts are based on land use and land-use trends. Land uses are analyzed and divided into 12 categories. Relationships between land-use categories and related demands are established by load surveys.

A detailed method of long-term forecasting by classes of service is reported by one utility. The method includes trend projections and correlations, such as residential customers per commercial customer, correlation of annual changes in industrial sales with changes in GNP and correlation of agricultural sales with rainfall conditions.

IV. STATISTICAL ANALYSIS OF SURVEY RESULTS

A. Description of Data

Tables B-I and B-II summarize the data reported in the survey and analyzed below. These data represent two different kinds of measures. The first is either a trait of the forecasting method or a characteristic of the system which might influence accuracy of forecasting. The second is a measure of relative success in forecasting and is used here as the dependent variable of the analysis.

1. Dependent Variables

Data from the survey questionnaire provide percentage deviation of forecasts from actual data for each year, 1961 through 1967. To reduce the volume of data in the analysis, the Committee used forecasting deviations on only three bases: (1) The average absolute forecast deviation for the years 1965, 1966, and 1967 of the forecasts made 5, 4, and 3 years in advance; (2) The average absolute forecast deviation for the years 1965, 1966, and 1967 made 2 years and 1 year in advance; and (3) The average absolute forecast deviation for the years 1965, 1966, and 1967 made 1 year in advance. Separate measures are shown for the peak demand forecasts and the energy forecasts. Individual values for each system and the mean value for all reporting systems are shown in Table B-II.

Several alternative measures have been calculated to test whether these three sets of values are representative. While different calculations of deviations result in slightly different values, no statistically significant differences have been found.

As would be expected, forecasts prepared 1 or 2 years in advance are more accurate than those prepared 5, 4, and 3 years in advance. The table below compares average differences for all companies.

<u>Time of Forecast</u>	<u>Average Difference</u> <u>Mean of Reporting Companies</u>	
	<u>Demand</u>	<u>Energy</u>
5, 4, and 3 yrs. in advance	5.2%	4.8
2 and 1 yr. in advance	3.8	3.2
1 yr. in advance	3.5	2.7

TABLE B-I

SUMMARY OF LOAD FORECASTING, SURVEY RETURNS, SYSTEM CHARACTERISTICS, AND FORECASTING METHODS

Company	Size of System	% Residential Sales	% Industrial Sales	1967 Ratio of Summer to Winter Peak Demand	Peak Demand (1) vs Energy (2) Both (3)	Total (0) vs Component (1)	Simple (0) vs Complex (1) Analysis
	1: 0-1500 MW 2: 1500-5000 MW 3: Over 5000 MW						
1	1	NA	NA	.63	2	1	0
2	3	24	41	.76	2	1	1
3	1	37	36	1.25	1	0	1
4	2	24	44	1.20	2	1	0
5	2	36	43	1.01	1	1	0
6	3	25	34	.98	2	1	1
7	1	33	30	.83	1	0	0
8	2	48	25	.64	2	1	0
9	2	22	48	.93	2	0	1
10	2	25	37	.90	1	1	0
11	1	22	41	.96	1	0	0
12	2	NA	NA	.83	-	-	-
13	NA	25	43	1.15	2	1	0
14	3	29	25	1.00	2	1	1
15	2	33	41	.84	2	1	0
16	2	28	20	1.01	3	0	1
17	3	24	37	1.11	1	1	1
18	1	27	28	.89	-	1	1
19	2	47	13	.94	1	1	0
20	2	25	35	1.54	1	0	0
21	1	NA	NA	.70	1	0	1
22	NA	NA	NA	NA	2	1	0
23	2	26	37	1.04	2	1	0
24	2	32	33	.84	-	1	1
25	NA	24	NA	1.16	2	1	0
26	2	24	52	1.05	1	1	1
27	2	24	51	.91	2	1	1
28	2	21	49	.91	2	1	0
29	2	15	57	1.27	1	1	1
30	1	4	NA	1.28	3	0	0

B-11

* NA denotes not available.

TABLE B-II

SUMMARY OF LOAD FORECASTING SURVEY RETURNS - AVERAGE DIFFERENCE BETWEEN ACTUAL AND FORECAST

Company	Forecasts Prepared ⁽¹⁾ 5, 4, & 3 Yrs. in Advance		Forecasts Prepared ⁽²⁾ 2 & 1 Yr. in Advance		Forecasts Prepared ⁽³⁾ 1 Yr. in Advance	
	Demand Average Difference	Energy Average Difference	Demand Average Difference	Energy Average Difference	Demand Average Difference	Energy Average Difference
	%	%	%	%	%	%
1	5.6	NA	6.7	NA	6.9	NA
2	3.2	4.3	2.2	1.1	1.9	0.9
3	5.5	NA	5.1	NA	5.5	NA
4	1.8	7.7	1.6	6.3	1.5	5.6
5	2.2	2.7	5.1	1.7	5.4	1.2
6	4.5	6.9	3.1	2.2	1.5	0.5
7	13.7	4.6	5.9	1.0	5.6	1.1
8	3.7	1.7	3.3	1.1	2.4	1.3
9	5.1	10.5	3.5	4.2	3.5	2.5
10	10.7	9.7	4.7	4.1	3.1	2.7
11	NA	NA	NA	NA	NA	NA
12	15.1	7.5	10.4	11.0	9.8	12.1
13	2.4	1.6	2.6	1.2	3.3	1.4
14	2.7	2.5	1.8	1.2	2.0	1.0
15	10.7	9.7	4.7	4.1	3.1	2.7
16	3.2	2.0	2.5	2.3	1.7	2.5
17	2.7	4.0	3.4	3.1	3.7	2.7
18	6.8	8.2	4.1	4.3	3.7	3.1
19	7.7	1.4	6.0	1.4	6.0	1.4
20	3.5	NA	3.5	NA	3.5	NA
21	2.8	NA	1.2	NA	0.6	NA
22	NA	NA	NA	NA	NA	NA
23	1.8	4.1	2.0	4.1	1.6	2.6
24	5.7	4.2	3.8	4.7	2.7	2.7
25	3.8	0.6	4.7	0.6	4.8	0.7
26	4.4	7.5	3.0	4.8	2.9	4.0
27	1.9	6.7	2.0	4.8	2.0	3.1
28	10.8	5.8	4.0	4.7	3.4	4.6
29	3.0	2.0	1.6	2.0	1.5	2.0
30	7.4	3.7	6.0	3.6	4.7	3.4
Average	5.2%	4.8%	3.8%	3.3%	3.5%	2.7%

B-12

* Percent average difference for the years 1965, 1966, and 1967.

While the above reflects averages, inspection of individual system responses in Table B-II shows some notable exceptions. These probably result from unusual conditions for the year forecast. Since very few systems provide adjusted data, it is impossible to determine with certainty whether this is true.

Inspection of the data also reveals very large variations in differences among systems, running from a high of 15.1% to a low of 0.6% on peak and 12.1% to 0.5% on energy. Large variations are frequently caused by unusual problems for the system. For example, in one case, rapid growth in industrial load stopped abruptly for causes completely beyond the system's ability to foresee. In another case, forecast increases in air conditioning installations occurred, but the summers were cooler than normal in the years examined by the survey.

Table B-II shows that on the average, the differences between forecast and actual results are smaller for energy forecasts than for demand. Individual system results, however, vary significantly from this generalization. As mentioned earlier, energy series tend to be more regular in that they are the integral of the instantaneous conditions over a period of time - in this case, one year. Demands reflect conditions over a short span of time - in this case, a one-hour period.

2. Independent Variables

Three of the independent variables represent differences in forecasting techniques reported in the survey. These are peak demand vs energy forecast, total vs components forecast, and simple vs statistical methods.

Other extraneous causes for variations, such as extremes in weather or variations due to business cycles, cannot be isolated as well due to lack of sufficient data. However, by grouping systems by characteristics, the effects of such variables might be discernible. The following variables are used to pool like systems: relative size of system, residential sales as a proportion of total sales, industrial sales as a proportion of total sales, and summer vs winter peaking.

B. Description of Analysis

Statistical tests have been employed to determine whether the variations in forecasting results are traceable either to the methods employed in forecasting or to the intrinsic character of the system doing the forecasting. A simplified analysis of variance does not show any significant relationships among the variables because there was not enough variety among respondents.

Also, a simple statistical comparison, T-test, is applied. The results are shown in Table B-III and indicate some reasons for variation in forecasting. These are discussed in greater detail below. It should be remembered that a T-test may not reveal significant differences if there is significant covariance or an absence of randomness.

C. Results of Analysis

Table B-III shows the results of the series of statistical comparisons between various pairs of data. The first two columns indicate the groups being compared. The third column shows whether the demand (KW) or energy (KWH) forecasting deviation was analyzed. The columns headed "Mean A" and "Mean B" show the mean deviation of each forecasting group. The column headed "T" is the statistical result, namely Mean A less Mean B divided by the standard error of the sample-mean differences. The heading "°F" means degrees of freedom. The final column indicates whether differences between Mean A and Mean B are statistically significant.

Other than two cases described below, no comparison has statistically significant differences. While there are some large differences among the means, the variation of the data making up a given mean is also very large. As indicated by the T-test, pure chance is as likely a cause of differences between means as variation in characteristic.

This is especially true among the variables representing variations in forecasting technique. These results are shown in the first ten lines of the table. One may infer that the significant variations are hidden within other factors not isolated in the analysis or that different techniques are appropriate for different system situations.

TABLE B-III

RESULTS OF T-TEST LOAD FORECASTING SURVEY

Comparison			Forecast	Mean A	Mean B	T	°F	Significant to .05 Level
Item A		Item B						
Forecasting Methods								
Prediction:	Energy	vs Peak Demand	KW	4.71	4.86	- .1	18	-
Prediction:	Peak Demand	vs Both	KW	4.86	4.30	.3	13	-
Prediction:	Both	vs Energy	KW	4.30	4.71	- .2	13	-
Prediction:	Energy	vs Peak Demand	KWH	5.40	3.84	1.1	14	-
Prediction:	Peak Demand	vs Both	KWH	3.84	3.84	.0	10	-
Prediction:	Both	vs Energy	KWH	3.84	5.40	- .9	12	-
Prediction:	Component	vs Total	KW	4.42	5.89	-1.1	25	-
Prediction:	Component	vs Total	KWH	4.54	5.20	- .4	21	-
Complex		vs Simple Analysis	KW	3.96	5.59	1.4	25	-
Complex		vs Simple Analysis	KWH	5.35	4.02	1.1	21	-
System Characteristics								
Res. Sales 0-30%		vs Res. Sales 30-100%	KW	4.01	6.85	-2.4	24	Yes*
Res. Sales 0-30%		vs Res. Sales 30-100%	KWH	4.87	4.05	.6	21	-
Indust. Sales 0-30%		vs 30-40%	KW	6.35	3.83	1.7	13	-
Indust. Sales 30-40%		vs 40-100%	KW	3.83	4.55	- .5	15	-
Indust. Sales 40-100%		vs 0-30%	KW	4.55	6.35	-1.1	16	-
Indust. Sales 0-30%		vs 30-40%	KWH	3.44	4.78	-1.1	10	-
Indust. Sales 30-40%		vs 40-100%	KWH	4.78	5.85	- .7	13	-
Indust. Sales 40-100%		vs 0-30%	KWH	4.85	3.44	1.7	15	-
0-1500 MW		vs 1500-5000 MW	KW	7.02	5.81	.5	13	-
1500-5000 MW		vs Over 5000 MW	KW	5.81	3.55	.9	12	-
Over 5000 MW		vs 0-1500 MW	KW	3.55	7.02	-1.7	7	-
0-1500 MW		vs 1500-5000 MW	KWH	6.40	5.00	.6	10	-
1500-5000 MW		vs Over 5000 MW	KWH	5.00	3.95	.6	12	-
Over 5000 MW		vs 0-1500 MW	KWH	3.95	6.40	-1.1	4	-
Summer Peak Demand		vs Winter Peak Demand	KW	3.42	6.69	-2.7	26	Yes*
Summer Peak Demand		vs Winter Peak Demand	KWH	3.49	5.86	-2.3	22	Yes*

* Not significant at the .01 level.

The T-test indicates that winter peaking systems have significantly greater forecasting deviations than summer peaking systems in both demand and energy. This appears reasonable since variability of winter temperature is generally greater than for summer temperature and since 4 of the 16 winter peaking systems in the survey clearly have large electric heating loads.* However, summer peaking systems with substantially larger summer weather-sensitive loads than winter weather-sensitive loads generally experience greater forecast deviations in the summer.

The test also indicates that systems with a higher proportion of residential sales have significantly greater deviation in demand forecasts than systems with a low proportion of residential sales. The reason for this may be that most of the former also have winter peaks.** It is interesting to note that the difference is not significant in the energy forecasts. In general, this is consistent with the observation that energy forecast deviations are generally less than peak demand forecast deviations.

Tables B-IV through B-VII summarize data collected in the Committee's survey. Table B-IV shows the average differences between the forecast and actual loads for various time periods grouped by size of systems. Tables B-V, B-VI, and B-VII show similar information with systems grouped in accordance with the forecasting methods employed: Table B-V, whether demand or energy is the basic forecasting series; Table B-VI, whether total load or components of load are utilized; and Table B-VII, whether the type of statistical analysis used is simple or complex. It must be emphasized that the average differences between forecast and actual loads set forth in these tables are not statistically significant at the 5% level. Consequently, the material contained in these tables must be handled with considerable care in reaching any conclusions based upon them.

* For example, one such system has winter peaks because 3 out of 10 homes are electrically heated. Both heating and cooling loads vary about 100 MW per degree temperature change on this system. However, there is a one in ten probability that summer maximum temperatures will be 5 degrees hotter than normal. By contrast, there is a one in ten probability that minimum winter temperatures will be 14 degrees colder than normal.

** Of the above 7 systems with residential sales 30-100%, 4 also had pronounced winter peaks in 1967. These 4 systems had large electric heating loads. Thus, most systems in the survey with a large percentage of residential sales had large electric heating loads which, together with the greater variability of winter weather, may explain why they had greater deviations in demand forecasts.

TABLE B-IV

DIFFERENCES BY SIZE OF SYSTEM

Years in Advance	Size of System in MW		
	<u>0-1500</u>	<u>1500-5000</u>	<u>Over 5000</u>
5-4-3			
Demand	7.0%	5.2%	3.3%
Energy	5.5	5.2	4.4
2-1			
Demand	4.8	3.7	2.6
Energy	3.0	4.0	1.9
1			
Demand	4.5	3.3	2.3
Energy	2.5	3.4	1.3

TABLE B-V

DIFFERENCES BY DEMAND VS ENERGY

Years in Advance	Forecast Emphasis	
	<u>Demand</u>	<u>Energy</u>
5-4-3		
Demand	4.9%	4.5%
Energy	3.8	5.2
2-1		
Demand	3.7	3.3
Energy	2.5	3.0
1		
Demand	3.7	2.9
Energy	2.1	2.2

TABLE B-VI

DIFFERENCES BY
TOTAL VS COMPONENTS

Years in Advance	Forecast Method	
	<u>Total</u>	<u>Components</u>
5-4-3		
Demand	5.9%	4.4%
Energy	5.2	4.5
2-1		
Demand	4.0	3.4
Energy	2.8	3.0
1		
Demand	3.6	3.1
Energy	2.4	2.3

TABLE B-VII

DIFFERENCES BY
SIMPLE VS COMPLEX ANALYSIS

Years in Advance	Type of Analysis	
	<u>Simple</u>	<u>Complex</u>
5-4-3		
Demand	5.6%	4.0%
Energy	4.0	5.4
2-1		
Demand	4.2	2.9
Energy	2.8	3.2
1		
Demand	3.9	2.6
Energy	2.4	2.3

Note: Data are indicative only; and as shown in Table B-III, the differences are not statistically significant. Further, since the groupings in these tables are slightly different from those in Tables B-II and B-III, it is not possible to compare means directly.

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