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Demand Forecasting in the electric Utility industry

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DEMAND FORECASTING IN THE ELECTRIC
UTILITY INDUSTRY

by

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INTRODUCTION

> There would be . . . a reduction in the nationwide average price per kilowatt hour from 1.7 cents today to about 1.2 cents in 1980 (Federal Power Commission, Oct 1964, 277).

An actual forecast made by the Federal Power Commission in 1964. But instead of decreasing as predicted, the average cost per kilowatt hour rose to 4.49 cents by January 1, 1980.

Changes in the Electric Utilities Business Environment

In the last 15 years, the electric utility industry has been subject to some of the most volatile and controversial business conditions since the great depression. Until 1973 electricity demand grew at a stable rate that allowed for relatively accurate demand forecasts and minimized the risk of planning for the future.

The sudden rise in fuel costs resulting from the Arab oil embargo upset the electric industry's stable world. America rebelled at the high prices and immediately began conserving energy, causing the energy intensity of the economy to decline every year between 1977 and 1987 (EIA/DOE-0384(87), 1988, 3). As the price of oil rose, so did the cost of producing and suppling electricity, causing both demand growth and profits to decline at the same time. Even with increasing prices, total yearly consumption of electricity continued to increase, but at a much slower pace. The only exceptions were between 1973 to 1974, and 1980 to 1981, when total electricity consumption actually decreased (EIA/DOE-0384(87), 1988, 2).

Adding to the industry's already existing problems, recent regulatory decisions have penalized some electric utilities for overbuilding by not allowing redundant plants into the ratebase (Holman, 5 September 1985). But, at the same time, regulatory commissions demand utilities to provide the country with an adequate and reliable electricity supply.

Considering that it takes anywhere from 7 to 12 years to order, design, and build a new coal base-load plant, the question arises as to who is responsible for the cost burden of a forecast that overstates future electric demand. In the case of an underforecast that causes a capacity shortage, there is no question where the cost would fall, upon the consumers. They will be hit with increasing costs, brownouts, and possibly even blackouts as capacity-short utilities scramble to install more plants, or attempt to purchase expensive power from neighboring utilities.

How realistic is the forementioned power shortage scenario? According to Charles M. Studness, it is highly unrealistic:

> During the decade before the energy crisis in 1973, the industry's reserve margin averaged 20 percent, and it was never higher than 23 percent. At the time, a peak reserve margin of 20 percent, equivalent to a capacity factor of 16 percent, was considered optimal. During that decade, capacity grew 7.3 percent per year.
>
> During the 13 summers from 1975 through 1987, the industry's reserve margin averaged 33.8 percent, and excess capacity averaged 12 percent, the same as in 1975. Peak demand grew 2.7

percent per year during 1975-79 and also 2.7 percent per year since 1979. Yet, as late as 1979 . . . utilities in aggregate were still maintaining a ten-year forecast of peak demand growth of 4.7 percent per year, only one point below the ten-year forecast in 1977 of 5.7 percent per year . . . utilities increased their capacity 35 percent between 1975 and 1987, while all the time maintaining excess capacity of 12 percent (Studness, March 1988).

Studness goes on to say so much over capacity made regulators adopt "regulatory methods never widely used before . . . phase-ins and disallowances." To him, the need to build more plants is a fallacy created by utilities through the use of bookkeeping games. The constant 12 percent excess capacity, along with continual overforecasting, gives strength to Studness's point of view. However, this is only one point of view.

In firm disagreement with Studness, there is Peter Navarro, a researcher at the John F. Kennedy School of Government's Energy and Environmental Policy Center and author of the grimly titled book The Dimming of America, in which he asserts:

> As a result of conservation and the pressures of recession, the pre-1970's average rate of growth in electricity demand has been cut almost in half to the rate of 3.6 percent. Moreover, this average rate is the product of very erratic growth rates in individual years. In some years, such as 1972, 1973, and 1976, electricity demand growth has been as high as 6.3 to 8.4 percent. But in recession-plagued years such as 1974 and 1980, it has been close to zero and in 1980-1981 even negative.
>
> In thinking about the reliability penalty, one important question to consider is to what extent conservation will continue to hold down the growth rate in electricity demand. These analysts see the low growth rates in electricity demand during the 1970s and early 1980s as being attributable as much to economic recession as to conservation, and they point to the rebound of demand growth . . . marked by the higher growth rates such as the 6.3 and 4.6 rates in 1975-76 and 1976-1977 and the latest case in point, the improved 3.6 percent annual growth rate observed in the later stages of Reagan's "economic recovery". (in the second half of 1983, in fact, electricity demand grew at a rate of about 8.5 percent over that experienced

in the second half of 1982.)

> Accordingly, most analysts predict that demand for electricity will continue to grow at a rate of at least 3 percent per year and, if the economy continues to recover over the next few years, perhaps even higher. (Navarro, 1984, 53).

Navarro obviously believes an increased demand in electricity, the need for greater capacity, and possible power shortages are not just bookkeeping fantasies, but very real problems which need to be dealt with immediately.

These two opposing points of view provide the fundamental attitudes for a highly controversial issue. But before trying to decide which situation is more correct, it is important to understand why there is such a fight over a simple forecast.

First, let's observe how the different growth rates will affect electricity supply and the reserve margin by comparing need with capacity in each situation.

The 2.2 Percent Low-Growth-Rate Scenario

Both the National Electric Reliability Council (NERC) and the Department of Energy (DOE) agree with a 2.2 percent electric demand growth rate through the year 2000. (Williamson, 30 April 1987). Federal support of an issue, whether it is correct or not, will often lead to its adoption by state and local organizations, resulting in a greater impact than other views. Such is the case for the 2.2 percent growth rate. Because of its use by commissions, it has been more of an influence on capacity planning than the high growth forecast.

To apply the 2.2 percent growth rate, assume all capacity increases were put on hold at Studness's request. Based on the 1986 summer generating capability of 633,291 megawatts, and a peak 1986 demand of 476,320 megawatts, electric utilities would have less than a 20 percent reserve margin in three years, but, it would still take 14 years for peak demand to meet current summer capacity (DeCampo, 1987, 14).

If electric utilities were allowed to finish construction on all additions planned by the year 1996, the results would be somewhat different. Total summer capability would increase by 7.87 percent to 685,582 MW, leaving the U. S. with a 13.6 percent reserve margin by 1996. However, these numbers also represent a 372 plant, 12,638 megawatt summer capacity retirement by the electric utilities before 1996 (DOE/EIA-0348(86), 1987, 245). By keeping these plants on line, the United states would boost its reserve margin to 15.2 percent, further reducing the need for new plants.

With the preceding results in mind, consider what would happen if electricity producers were allowed to increase capacity at whatever rate they deemed necessary, possibly at a 4.4 percent per year rate. The result would be an increased capacity to 975,268 megawatts by 1996. Assuming Studness's forecasts are correct, and allowing for a 20 percent reserve margin, a 266,504 MW excess capacity would exist.

Capital in excess of $280,612,721,000 would be required just for the construction of enough plants to supply that much electricity (Hanson, 1987, p.a26)! Without any new consumers to pay for such an extravagant bill, the responsibility would fall on the old consumers in the form of increased rates.

Even though this is an extreme example, it gives some indication of what could possibly happen (it also shows why Studness's argument is so appealing). At a 13 percent annual interest rate, the interest on one $10 billion dollar nuclear power plant is 1.3 billion dollars a year. When such a small overbuilding adds such a tremendous cost to consumers, imagine what a hundred billion dollars of overcapacity will do. This definitely creates a "why build it now if we don't need it now" attitude and adds still more problems to an already difficult situation.

Effects of the 4.4 Percent High-Growth-Rate Scenario

Although there is great support for growth rates higher than those used by the NERC and DOE, there is not a specific rate that has been accepted as a correct rate. Most high growth forecasts are either unspecified, i. e. "at least 3 percent", or are not in agreement with any other forecasts. The general consensus of a high growth forecast appears to be in the 4 to 5 percent range.

Use of a 4.4 percent growth rate was adopted from the NERC, who believes there is an 80 percent chance of demand being between negative .2 and positive 4.4 percent through the rest of the twentieth century (Williamson, 30 April 1987). Since the NERC was the only source to state a specific high growth rate within the 4 to 5 percent forecast range, their rate was adopted for the sake of comparison.

If electricity demand grows at 4.4 percent per year, the current supply capability of electrical utilities would not be able to meet electric demand within 7 years. Even if the industry utilized all planned summer capability additions, 52,291 MW, and did not retire any plants, the electric utilities would not be able to meet peak demand in 1995 when it reached 732,662 MW and there would only be a 685,582 MW supply (DOE/EIA-0095(86), 1987, 11).

It has been said that increased capacity is not a case of "will we need it", but "when will we need it". This situation is clearly visible even with a low demand growth; eventually the need for more capacity will arrive.

Under current industry situations, capacity shortages can be solved by purchasing excess power from other electric utilities. This solution works only as long as the electricity industry continues to expand its capacity. With each additional electric utility that uses another electric producers reserve capacity to meet power shortages, reliability decreases. Eventually, there will not be any electric producers with excess capacity, eliminating one of our current solutions to electric power shortage.

Regulators Response

Electric utilities believe their actions are in the best interest of their customers. They have been trying to maintain reliability, while still keeping a low price. In an attempt to meet these goals, the industry has relied heavily upon both technological and economic knowledge for planning purposes.

The result of rational planning has led the industry to build increasingly larger plants, allowing them to benefit from economies of scale and to minimize cost. While the larger plants allowed electricity producers to benefit from economies of scale, they also created a problem - the need for more lead time. Since the larger plants take more time to build and test, the demand for their output must be seen sooner (Williamson, 30 April 1987).

Larger plant sizes should not be completely blamed for the increased lead time. Technological changes were another major contributor. Together these villains doubled the time needed to build a plant: in 1960 it took a three to five year lead time for the construction of a new coal-fired base-load plant, now it takes anywhere from seven to twelve years for a utility to put up a new coal fired plant. With the longer lead time, electric utilities have needed long-term and accurate forecasts of demand growth.

But how can a long-range forecast be accurate in a rapidly changing environment? Clearly shown by the quote at the beginning of this chapter, unforeseeable events can and do prove embarrassing to those engaged in the risky business of forecasting electric demand.

So, how should the problem be dealt with? Many electric utilities have voted in favor of construction, taking a chance of overproduction rather than being caught shorthanded (DOE/EIA-0095(86), 1987, 236).

Unfortunately for electric utilities, regulatory commissions have become less tolerant of unnecessary plant production or over capacity. Recent decisions by the public service commissions of New Mexico, and Pennsylvania have punished electric utilities for excess capacity by not allowing them to enter investments for overcapacity into the ratebase on the grounds "customers should not have to pay for capacity they don't need" (Holman, 5 September 1987). In one extreme case, the Public Service Co. of New Hampshire was forced to file bankruptcy after it was not allowed to enter its costs associated with the Seabrook nuclear power plant into the rate base (Chipello, 29 January 1988).

After the Three Mile Island accident (1979), plans for the construction of any Nuclear plants beyond those already underway have been scrapped, eliminating any new starts since 1979. Even so, the industry will be completing construction on nine new nuclear plants and have them ready to be put on-line between the years 1987 and 1997. If regulatory commissions allow these plants to operate, they will account for 44.5 percent of the new generating capacity (DOE/EIA-0095(85), 1986, 235).

Although construction is continuing as planned on most nuclear units, what will be done with them is still a mystery. As we have seen, the Seabrook plant has been completed, but has not been allowed to start-up. Shoreham, a New York nuclear plant, already running and in the rate base, has now been ordered to shut down (Paul, 27 May 1988).

In the first case, the Seabrook nuclear plant was never allowed into ratebase, forcing the stockholders to pay for all the costs, keeping the electrical rates lower. The decision concerning the Shoreham plant is completely opposite. Here the ratepayers are responsible for the costs of the nuclear plant and any construction expenses incurred by building replacement plants.

What can the utilities do in this situation; what message is being sent to them? The commissions are demanding prudent investments while keeping the costs of generation low, without indicating which is more important or what is considered prudent and low. All that can be assimilated from the actions of regulatory agencies is undoubtedly confusing to some electric utilities.

To the utility industry, these radical decisions by public commissions have left them with very few solutions to maintain financial security: 1. Build a greater number of power plants with a smaller capacity; 2. Modernize already existing but retired plants; 3. encourage conservation; and 4. rely on purchased power.

Certainly, all four options are being given serious consideration today, due, in part, to the inability of forecasting models to produce accurate long-range forecasts. In fact, the inexact "art" of forecasting may prove to be the final nail in the coffin of dinosaur-sized, nuclear and coal baseload plants.

Other Considerations

As a whole, consumers should naturally love Studness and his proposition; greater utilization of current plant capacity and the use, rather than early retirement, of all workable plants. The theory behind this idea is that without the construction of extra plants, combined with a higher utilization level of those already existing, the average cost per kwh should decrease, providing the consumer with a cheaper source of electricity.

In theory it may sound great, but is it really? There are many other variables to consider:

1) 29.5 percent of the United States' generating capacity comes from either oil or gas burning units (DOE/EIA-0348(87), 1988, 8). While oil and gas burning generators are useful in the sense that they can still produce electricity, they have become economically obsolete. In simple terms, consumers would be better off if the utility industry put these units into retirement.

According to Northeast Utilities, Millstone 1 and 2, the two nuclear plants it used to replace several of its existing oil and gas guzzlers, save over $300 million per year. Shutdown of the inefficient plants has reduced the nation's annual oil consumption by 18 million barrels a year, lessening our dependance on foreign countries (Navarro, 1987).

By direct comparison, it is possible to see how early retirement can save money. The average kwh produced by oil costs 4.51 cents to generate, while gas generators produce electricity at a slightly less 3.43 cents per kwh. Next to the price of coal generated electricity, these units look like black holes! Oil generated kwhs cost 2.6 times more to generate than those generated by coal. Even gas pales with a price 1.9 times greater coal generators (Hanson, 1987, p.a31).

Full utilization of these units would result in a 2 million barrel per day increase (or 3 percent) in oil consumption. Because of the high cost, most of our excess capacity is in the form of underutilized gas and oil units (Mills, 2 April 1987).

2) The majority of plants being retired are these oil and gas peaking units used primarily to meet short-run high demands. If these

plants were to be used more intensively, it would increase the average cost of electricity.

3) 13.4 percent of the nations total electric capacity is from hydroelectric power. Including this in the total summer capability assumes the generator is fully under water and has enough pressure to spin the generator. In a drought stricken year, output may by severely reduced.

By mid-July, 1988, an Union Electric Co. plant located in Keokuk Iowa had to close 11 of its 15 generating units when the water flow from the Mississippi and Des Moines rivers fell below average. Shut-down of those units amounted to a two-thirds loss of it normal 135 MW generating capacity (Byrne, 24 July 1988, 3).

4) Of the plants that are expected to be needed (put on line) in the next 10 years, only 50 percent are over one-half completed, and of those, three-quarters of them are nuclear plants (Williams, 30 April 1987). If a hard-line is taken on the use of nuclear power plants, and none of those under construction are allowed to be used, the United states will face an even more critical power shortage.

5) Electricity demand does not have a simple linear growth pattern that is easy to predict. It is both price and income sensitive with respective short-run elasticities of and -.2 and .5, and long-run elasticities of -1.1 and .8 (Hyman, 1983, 44).

If real gnp were to increase by 2 percent, we could expect the income elasticity to increase the demand for electricity by 1 percent in one year and could expect demand to increase by 1.6 percent in the future.

At the same time, if real electricity rates were to decline by 1.7 percent, we could expect yet another .34 percent increase in demand in one year and a possible 1.8 percent within a couple of years. The combined elasticities result in a total 1.34 percent increase in the first year and a final effect of 3.4 percent on electricity demand. All this change is a result of a modest 2 percent growth in gnp (Studness, 14 November 1985).

A briskly growing economy could make meeting electricity demand, without a counterbalancing large price hike, a fantasy.

Importance of Demand Forecasting

As late as 1976, several years after the oil embargo, the national government itself was predicting a 5.4 percent annual electricity demand growth over the next 10 years, down by only 1.6 percent. To meet estimated demand growth, investments of $272.6 billion would have to be made.

In all, forecasting of electric demand is vital not only to the utilities producing electricity, but to the consumer as well. In the most recent years, 1987-88, electric utilities have not only reduced future building projects, but have also emphasized both the need and desire to build gas and oil powered plants. It is amazing to see the changes that are occurring, even though utility owners have wanted to retire these types of plants because of excessive costs. Utilities now plan to build them in an attempt to maintain the companies existence and maintain a reasonable rate of return.

As one representative from a electric utility has said:

> It is unrealistic and unfair for some regulator to disallow utility rate base treatment of facilities due to short-term excess capacity, when that excess is largely or completely the result of a downturn in the national economy (Sandbulte, 1983).

Outline of this Study

The next chapter, Chapter 2, will examine forecasting methods used by the electric utility industry and regulatory commissions, and will evaluate them according to criteria relevent to the industry.

Chapter 3 will examine how state commissions have treated electrical demand forecasts in recent years.

The final chapter, Chapter 4, will provide a summary of the forecasting problems and alternatives facing the electric industry today.

Chapter 2

METHODS OF FORECASTING

ELECTRICITY DEMAND

Introduction

> This prolonged period of steady growth of demand enabled most utilities to make accurate forecasts based on simple techniques. In most cases, a trend extrapolation or expert opinion served the purpose (Pachauri, 1975, 3).

But that was before the first Organization of Petroleum Exporting Countries oil Crises (Grunau, 1985, 15). The stable prices and steady economic growth preceding 1973 were so predictable that more complex methods of forecasting were not required.

The wide swings in economic activity that followed the OPEC meeting caught electric utilities completely unaware. They were forced to face risk and uncertainty like any other business. But the electric utility industry is not like any other business. Its product has come to be viewed as a necessity with one slightly unique twist, total output capacity cannot be suddenly increased from one year to the next like housing or food. Instead, an increase requires both time and large capital outlays.

If investors are truly risk adverse, they are not willing to invest in a high risk industry, unless they receive just compensation (the market rate of return). Ultimately, the oil embargo increased the cost of capital for the electric industry. So while the rest of society was reducing energy consumption to compensate for high oil prices, electric utilities, in an attempt to reduce the recent surge of growth uncertainty, were searching for a "crystal ball" to tell the future. To date, the closest thing the electrical utility industry has to a crystal ball is economic forecasting.

Forecasting Methodology

History of Forecasting Methods

Until 1978, the primarily forecasting techniques used by the electric industry were trend extrapolations. In 1976, econometric techniques entered the business, and by 1980, took-over as the predominant technique. It is important to note that econometric techniques were not the only newly developed techniques in the late 1970s. At that same time, end-use techniques were introduced. Since their weak start immediately following introduction, end-used techniques have been increasingly accepted and used as a primary forecasting technique. As of 1988, electric utilities employ end-use methods to a greater degree than econometric methods for forecasting residential demand.

In the twenty years following World War II, there were no significant changes in either demand growth for electricity or the cost or electricity production. Most electricity generation came from fossil fuel dependent plants. The relatively short production time (3-5 years) did not require extremely accurate or long-range forecasts. Mistakes could easily be corrected by relatively quick installation and commissioning of additional capacity.

The sudden increase of oil prices that occurred in the 1970s changed all of that. Prices of oil-generated and gas-generated electricity reached extreme heights, eliminating its use as an economically feasible method of supplying electricity.

Attempts to reduce the cost of electricity led to an increasing share of electricity being generated from large coal fired plants and nuclear reactors; which required more time to construct than smaller coal, oil or gas units.

As plant sizes and lead times grew, electric demand growth slumped, making accurate forecasting a paramount objective for the industry. Trend techniques were almost completely abandoned for econometric methods that captured the economic influences behind electric demand. These models improved accuracy, but they also increased the size of necessary data sets, and required greater computer time (Pachauri, 1975, 4).

Direct costs, however, are of minor importance for forecasters of electric demand. A greatest cost would come from forecasting errors which could lead to rate base disallowances and power shortages. To understand why electric demand forecasting is difficult and has errors, it is imperative to review forecasting techniques as well as to review the business environment the forecaster of electric demand must consider.

Non-Econometric Models

Non-econometric forecasting models do not always use scientific or mathematical methodology when estimating future values of electricity demand. These methods often appear magical in nature and always attract skepticism regarding their validity. They have a distinct advantage over econometric models in areas of cost and data availability. These techniques can be categorized into five general models:

Expert Judgement

Expert judgement includes interviews with utility personnel, consultants, and government experts to gather opinions of future sales and peak demand. Once again, there is no scientific bases for the estimate. The result is subject to hunches, guesses and bets of human beings.

Customer Survey

This method includes mail, telephone, and in-person interviews with customers to obtain future expectations of electricity consumption for their household, plant or establishment.

Load Factor Analysis

This method is used extensively in forecasting peak load. it is based on forecasting a load factor from historical data and anticipated building schedules and then applying this load factor to the forecasted energy.

The general model:

equation 1) LF = AE / PH * 8,760

equation 2) PHF = AEF / LFF * 8,760

where:

LF = load factor, the average electricity demand per hour as a percent of peak electricity demand

AE = total annual electricity demand

PH = peak hour electricity demand

PHF = peak hour electricity demand forecast

AEF = total electricity demand forecast

LFF = load factor forecast.

This model uses actual data to calculate the load forecast, a number which represents average electricity demand as a percent of peak hour electricity demand. By dividing both sides by the load factor, then multiplying both sides by peak hour demand, equation 2 is derived. Assuming a constant load factor, equation 2 allows a forecaster to estimate future peak electric demand based on total future demand.

For example, if we assume total electricity demand for 1988 was 100,000 kilowatt hours, and the peak hour demand was 20 kilowatt hours, then the load factor would be 57.02 percent (LF=100,000/ 20 * 8,760). Assuming a 10 percent increase in total electricity demand, and a constant load factor, we could enter these numbers into equation 2 and get a forecasted peak hour electricity demand of 22.02 kilowatt hours (LFF = 110 / 57.02 * 8760). As can be seen, even though this is considered a forecasting method, it requires the use of an already forecasted variable in order to work.

Trend Extrapolation

Trend extrapolation can be a simple straight-line, polynomial, or log-arithmic extrapolation where the best fit of historical data is obtained and used for forecasting. Even though trend extrapolations are mathematical, there is no economic or scientific basis for future values. The forecast is based only on past activities and does not even consider future variables: it is assumed the past will repeat itself.

The general formula:

y=b0+b1x

where:

y = electricity demand in time period t

b0 = is a constant

b1 = a parameter

x = historical demand for electricity (Bails, 1982, 127).

The relationship between y and x is determined by measuring the mean squared error terms between the actual and forecasted values for each model used. Then the model with the lowest error terms is adopted for use.

Time Series

Time series models are often referred to as naive forecasts. They are qualitative forecasting techniques that base predictions entirely on historical values and patterns of the variable. As a result, time series models are useful when economic conditions are stable, but lose accuracy when changes occur.

These models often incorporate weighted averages, exponential smoothing, or adaptive estimating procedures, all three of which use the same basic estimating procedure. In the case of a moving average, the next period's electricity demand value is forecasted as an average of the last n time periods.

The General formula:

$$ED = (edt + ed(t-1) + ed(t-2) + . . . + ed(t-n+1)) / n$$

where:

ED = electricity demand in time period t

edt = historic electricity demand in the last n time periods

n = number of terms included in the moving average (Bails, 1982, 336).

Weighted moving averages attempt to correct insensitivity problems of a simple moving average by assigning weights to the observations. The weighted observations are then divided by the sum of the weights. The advantage of a weighted moving average is its ability to account for seasonality, cycles and respond more quickly to changing patterns (Bails, 1982, 337).

Exponential smoothing is the most widely used time-series model. Its primary advantage over moving averages is the inclusion of preceeding error terms in the forecast and it responds more quickly to changing conditions.

The general formula:

$$St = aYt + (1-a)St-1$$

where:

St = the smoothing statistic

Y = the actual value of electric consumption in time period t

a = the smoothing constant, greater than 0 and less than 1

St-1 = estimate in time period t-1 (Bails, 1982, 340).

Econometric Models

Econometric models are mathematical equations that attempt to capture and explain the relationship between the dependent variable and economic factors that influence the dependent variable. Econometric models require the forecasters of electricity to obtain data (typically on a time-series basis) for the dependent variable and a host of independent variables. As a result, the cost of econometric forecasting will typically be greater that extrapolations or time series models.

The types of econometric models being used by forecasters of electricity demand today can be grouped into five classifications:

Aggregate Single Equation Econometric

Aggregate single equation models usually consist of a linear, log-linear, or a log-log formulation of sales or peak load determined by independent variables such as an income measure, a price variable for electricity, a price variable for substitutes, a weather variable, and a monthly variable. Forecasting techniques using this method can be identified by one equation representing total electricity demand or usage.

Even though single equations are simple, they can be extremely accurate. By using only GNP, first differences, and lags, it is possible to explain 99.85 percent of the variation in electricity from 1947 to 1985 (Searl, 1986, 31).

The general model is:

$$Yi=C+b1X1+b2X2+bnXi + \cdot \cdot \cdot$$

where:

Yi = electricity demand in time period i

C = a constant

bn = a parameter for each variable, the slope of Y with respect to X

Xi = variable number n in time period i.

A specific model of this type that is used by the Department of Energy (DOE) for its comparative forecasts uses six independent variables:

EGEN=Ebo (EPRICt bl) (GNP72t b2) (HDDt b3)
(CDDt b4) (NGPRICt b5) (HPRICt b6)

where:

EGEN = total electricity generation in month t

EPRIC = real residential electricity price in month t

GNP72 = real GNP in month t

HDD = Population-weighted heating degree days in month t

CDD = population-weighted cooling degree days in month t

NGPRIC = real residential natural gas price in month t

HPRICE = real residential heating oil price in time t.

bi = the exponential factor of each variable i, i=1 to 6.

The DOE then assumes a multiplicative relationship that allows bi to estimate the elasticity for each variable (DOE/EIA 0202(85/3q)2, 1985, 58).

Disaggregate Single Equation Econometric

This method can be identified by the use of a number of equations, each one representing an individual sector such as commercial, residential or industrial. The sector demands are then summed to get a total electrical demand.

Model:

Ed = RD + ID + CD

RD = A1+a2Xi+a3Xi+ . . .

ID = B1+b2Yi+b3Yi+ . . .

CD = C1+c2Zi+c3Zi+ . . .

where:

ED = total electricity demand

RD = electrical demand for the residential sector

ID = electrical demand for the industrial sector

CD = electrical demand for the commercial sector

Xi, Yi, and Zi are independent variables

A1, B1, and C1 are constant parameters (Pachauri, 1975, 8-11)

The outstanding model of this type was done in the early 1950s by Fisher and Kaysen. Their work focused more specifically on the industrial and residential sectors, but set the standard for sector specific models (Taylor, 1975, 85).

Multiequation Econometric

A multiequation econometric model usually includes fuel share and flexible functions for models. They generally involve several equations per sector which are solved simultaneously or in sequence where the results of one equation are fed into another creating a complex formula.

The general model is of the sort:

$$Ed = f(\text{all variables } Di)$$

$$Di = b1+binXin+ \ldots$$

$$Xin= c+ anIn + \ldots$$

where:

Ed = total electricity demand

Di = electrical demand for sector i; i=1 to x

Xin= independent variable n of sector i; n = 1 to y.

Although a model of this type is subject to the creativity of the forecaster, it possesses an increased sensitivity to economic determinants of electric demand, and bases final demand forecasts over all demand variables rather than just one.

A major problem with these models is the time factor. To get a final result, a forecaster may have to build a GNP growth model, a population growth model, and a model to explain any other variable deemed significant rather than building only one formula. For example, in the case of the energy technology assessment model, total energy consumption is estimated, prices for electricity and nonelectric energy are estimated, and then both supply and demand models are built and solved simultaneously subject to utility maximization and cost minimization (Manne, 1976, 380).

When econometric methods are utilized, forecasts are no-longer based on past electric demands alone. Instead, electricity demand is based on future values of an income measure, population, number of customers, appliance saturation, electricity price, price of substitutes population, and heating and cooling days. However, these values are not necessarily known any better than the future values of electricity demand. By increasing the complexity of the forecast, emphasis has simply substituted one set of unknowns for another.

End-use Models

In the simplest terms, the demand for electricity is a function of the total stock of electrical appliances (white goods). Naturally, the most logical method of finding total demand would be to find out where, by what, and how much electricity is being used: an end-use model.

The classical end-use model, after which all other end-use models were fabricated, was developed by Fisher and Kaysen in the early 1960s. Their model is usually used to target the residential sector but can be used in the commercial and industrial sectors. It is characterized by a forecast based on appliance use where the number of households, appliance saturation, and the use per appliance are all multiplied to determine total electrical consumption by households. In the commercial or industrial sector, these forecasts are generally done by equipment type such as heaters, boilers, and furnaces, (figure 1).

The general model:

Dt = the summation of KitWit, all white goods

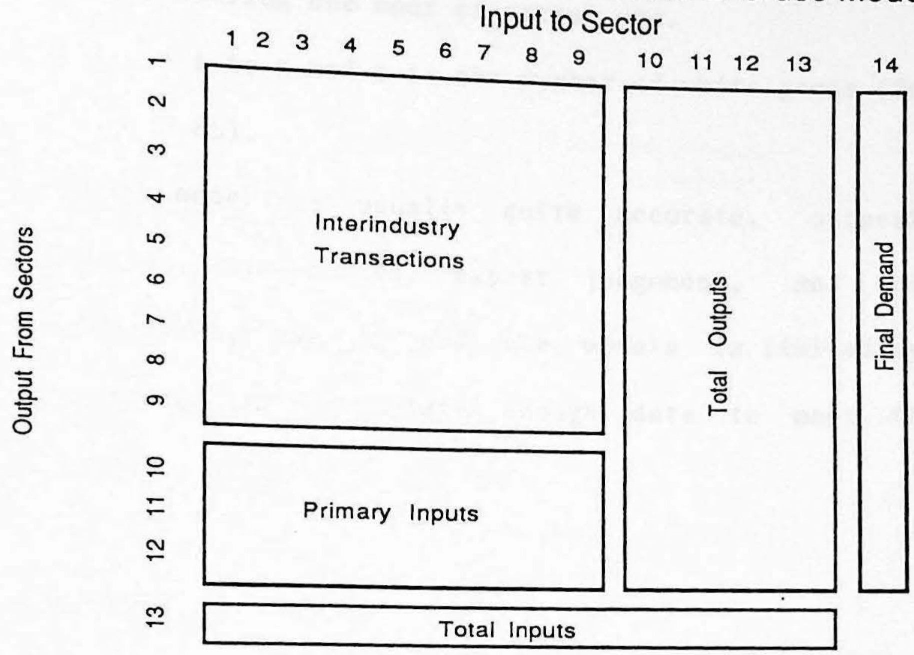
where:

Dt = the total metered use of electricity in KWh's by all households in the community during time period t.

Kit = the average intensity of use of the ith white good during time period t (kwh/t/unit of white good).

Figure 1

Interindustry Transactions in the End-use Model



Industry Sectors:

1. Agriculture, nonfuel, mining, and construction.
2. Manufacturing, excluding petroleum refining.
3. Transportation.
4. Communications, trade, and services.
5. Coal mining.
6. Crude petroleum and natural gas.
7. Petroleum refining.
8. Electric utilities.
9. Gas utilities.

Primary Inputs:

10. Imports.
11. Capital services.
12. Labor services.

Final Demands:

10. Personal consumptions expenditures.
11. Gross private domestic investment.
12. Government purchases of goods and services.
13. Exports.

Source: Hoffman, Kenneth C., and Jorgenson, Dale W. "Economic and Technological Models for Evaluation of Energy Policy", The Bell Journal of Economics, 8. no. 2 (Autumn, 1977): 448.

Lit = the average stock during period t of the ith white good measured in kwh's of electricity consumed during one hour of normal use.

i = 1 to n and n is the number of white goods (Taylor, 1975, 85).

This model is usually quite accurate, outperforming trend extrapolation, time-series, expert judgement, and customer survey models. However, use of end use models is limited by the time and expense needed to accumulate enough data to meet the necessary requirements.

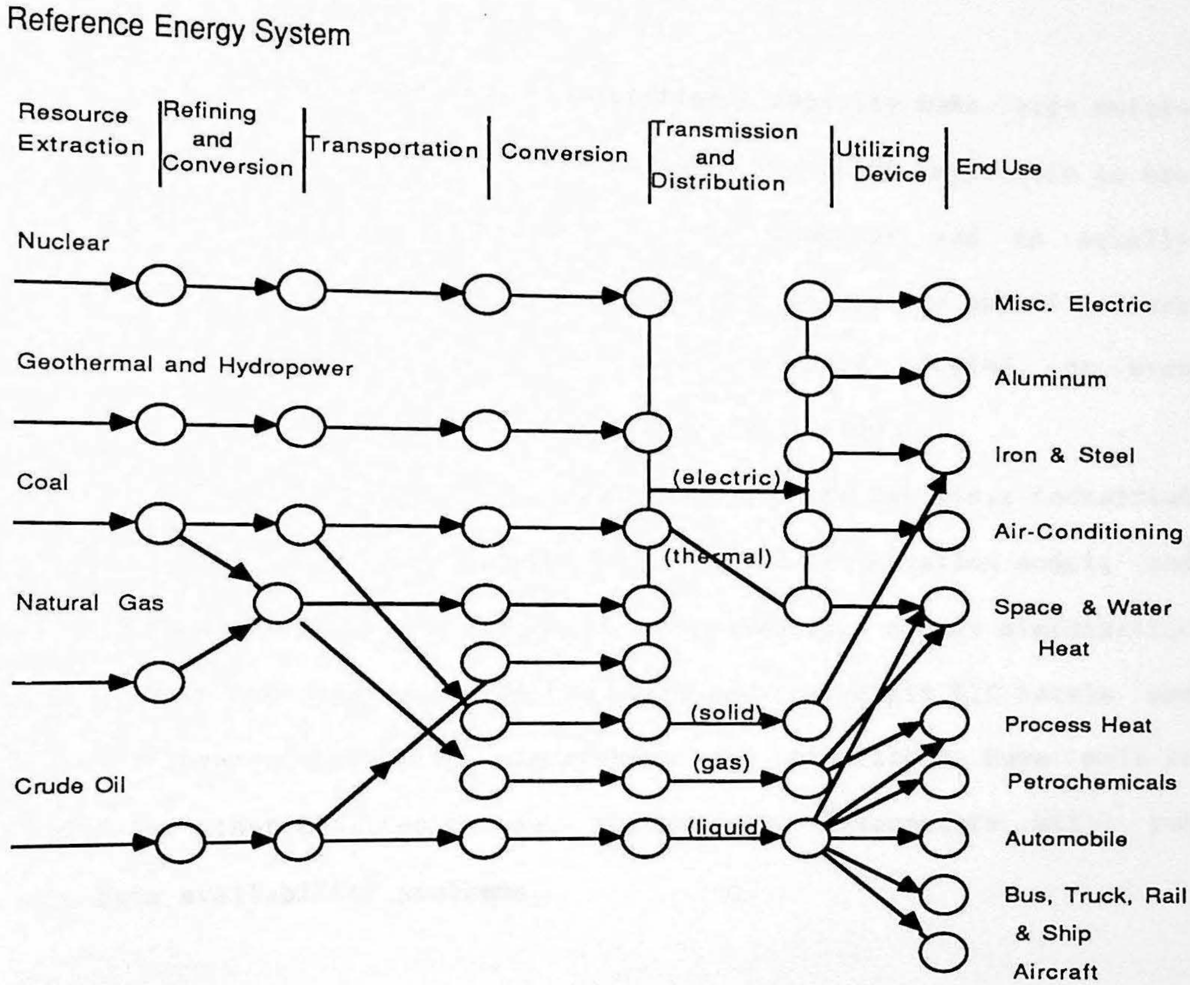
Process Model

Process models are large input-output models which assign energy supplies to energy demand by following energy conversion processes determined by the model. The costs of energy conversion in both physical and financial forms are measured at each step: from oil to steam, steam to electricity, and to final use,(figure 2).

These models are used almost exclusively for the industrial customers of an electric utility or the national industrial electric demand. They are aggregate "energy" approaches that estimate total energy demand based on total economic production. By analyzing total output of from the economy, this model determines which type of fuel would provide the most cost effective source of energy for each stage of production based on prices calculated from the actual process flows of products as they are manufactured. At each stage of production, choices are made as to what equipment and fuel to use based on cost minimization

Figure 2

Process Model



Source: Hoffman, Keneth C., and Jorgenson, Dale W. "Economic and Technological Models for Evaluation of Energy Policy", The Bell Journal of Economics, 8 no. 2 (Autumn, 1977): 450.

or consumer utility maximization.

There is not a general formula for a process model. Instead, it is up to the forecaster to either develop a completely new model or use one already in use.

Necessary data bases and computational capacity make large multi-variable multi-equation models such as these virtually impossible to use unless an organization is armed with a large computer and an equally large budget. The extravagant costs that accompany the use of process models have restricted the number of firms that have adopted, or even attempted to use, process models (Hoffman, 1977, 445).

The two most common process models are the Oak Ridge industrial model, an industrial sector technology use and optimization model, and the Brookhaven National Laboratory process model, a cost minimization model. Both are constructed at the three and four-digit SIC levels and employ linear programming algorithms. The algorithms have made it easier for other entities to use, but even so, forecasters still run into data availability problems.

Northwest Conservation and Electric Power Plan

Introduction

After having seen the general forecasting models used by the electric industry, it is time to look at a specific case. The model used by the Northwest Power Planing Council provides an excellent subject to use for an illustrative purpose.

First, a look at the Northwest Power Planning Council itself. This council was created in April 1981 under the Pacific Northwest Electric Power Planning and Conservation Act of December of 1980. Its' purpose is to make judgements about future electrical energy demand and resources to be developed to meet the regional needs of Idaho, Montana, Oregon and Washington.

The council's principal duties are to: 1) develop a 20-year regional power plan to ensure the Northwest an adequate and reliable electrical power supply at the lowest cost; 2) develop a fish and wildlife program to "protect, mitigate, and enhance" the fish and wildlife affected by the hydroelectric development in the Columbia River Basin; and 3) provide for broad public participation in these processes (Northwest Power Planing Council (NWPPC), 1986, p.1-5).

Since we are dealing with forecasting, only the first duty is of immediate concern to us. Due to the Northwest Power Planning Councils' size, it was able to implement a wide variety of techniques which are not within the budget constraints of an average firm. They implemented the use of process models, end-use models, disaggregate econometric models, time-series models, and even expert judgement models to some extent.

In order to ensure an adequate capacity to meet electricity demand in case of rapid economic expansion yet not have an unreasonable amount of excess capacity, the Council made four separate economic expansion forecasts: high, medium-high, medium-low, and low electricity demand growth forecasts. The high and low electricity growth rates are highly unlikely extremes, but are still possible, while the realistic expectations fall somewhere within the midrange.

To get these results, the council disaggregated the Northwest economy into four different sectors: residential, industrial, commercial, and irrigation. They then built a forecasting model for each individual sector, changing the independent variables and assumptions to forecast each of the four senarios (high, medium-high, medium-low, low).

Assumptions

Each of the four regional forecasts was made within the context of a corresponding national model with certain basic assumptions required for each specific scenario. However, due to the size of the entire model, only the most critical assumptions will be evaluated. For all of the models, it was assumed that construction cost would grow at .4 percent per year and inflation would be 5 percent.

The high growth scenario assumes an employment rate growth of 3.2 percent per year, a population increase of 2 percent per year, and household growth of 2.8 percent per year, all for the years 1985 to 2005, and the industrial sector would be 100 percent utilized.

Growth rate assumptions for variables affecting the medium-high growth rates were 2.4 percent for employment, 1.5 percent for population, and 2 percent for households, with the industrial sector producing at 80 percent capacity. These estimates are twice as high as the forecast of national growth rates in the medium case.

Assumptions for the medium-low electricity demand growth rate included: employment growth of 1.5 percent per year, population growth of .8 percent per year, and household increases of 1.3 percent per year, with the industrial sector being 60 percent employed. These growth rate assumptions were 25 percent faster than the medium for the national level.

The last growth rate scenario, the low growth rate, was estimated based on the assumptions of only a .5 percent growth in employment per year, a population growth rate of .2 percent per year, a .3 percent household growth rate and a 40% employed industrial sector. This resulted in a forecasted growth rate that was 40% lower than the national low growth forecast (NWPPC 1986, p. 4-6).

To finalize the assumptions of growth rates, each scenario combines realistic relationships between economic factors. For example, a robust economy should increase the cost of capital, and increase fuel costs, while a sluggish economy should result in a slower fuel price increase, and lower capital cost.

Model

Since the Council disaggregates electricity demand into four sectors, the model for total electricity demand is:

Model:

ED= Edr+Edi+Edc+Edg

Where:

ED = total electricity demand

Edr= residential electricity demand

Edc= commercial electricity demand

Edi= industrial electricity demand

Edg= irrigation electricity demand.

In turn, electricity demand fror each sector is a function of several variables whose values vary dependant upon assumptions behind the independant variables.

Residential Sector Demand Model

Model for the residential sector:

Edr= f(h,a,e,f,i)

Where:

h= number of households

a= number of energy-using appliances in an average household

e= the efficiencies of these appliances

f= the fuel used by each appliance

i= the intensity of use of each appliance (NWPPC 1986, 4-9).

The estimates each of the independent variables for the four different scenarios based on the assumptions for each scenario.

Commercial Sector Demand Model

Model for the commercial sector:

Edc= f(fs,e,f,eq)

Where:

fs= floor space

e = efficiencies of the equipment used

f = fuel used by equipment

eq= the equipment necessary for the floor space (NWPPC 1986, 4-12).

These input factors are estimated according to investment factors, fuel prices, and available technology for each of the four scenarios.

Irrigation Sector Demand Model

The model for electricity demand for irrigation assumes an average of 700 megawatts, the average for the years 1976 to 1983. The Council then assumed a rate of growth in irrigated acres and simply applied a range of price responsiveness for each growth scenario: -.6 price elasticity for the low forecast, -.4 for both medium forecasts; and -.2 for the high forecast (NWPPC 1986, 4-14).

Industrial Sector Demand Model

The model for the industrial sector uses four different forecasting methods: 1) key industry model; 2) econometric models; 3) simple relationships; and 4) assumptions.

The key industry models are detailed approaches to electricity demand for lumber and wood products, pulp and paper, and chemicals. This is actually an end-use model which divides the industry into energy intensive activities according to uses such as motors, electrolysis, or lighting. The amount of electricity used at each process is then estimated for an average plant, with adjustments made for projected price changes.

For the remainder of the industrial sector for which data are available, econometric models are used with forecasts made from historical data. These equations attempt to measure the effect of industry production and energy process on the demands for different types of energy including electricity. For parts of the industrial sector that do not have enough data to produce satisfactory results using econometric equations, simple relationships are formed between output and electricity use to obtain forecasts. When no valid relationships can be formed, the council assumes certain values for the variables.

Forecast Results

In an attempt to arrive at the best possible forecast, the Northwest Power Council started with the accepted as the most accurate forecasting techniques (end-use and process models) for residential, commercial, and industrial sectors. After doing all estimations that were possible with these incredibly complex models, the Council began to supplement their model with other forecasting methods, using the most accurate method possible for each step, and finally using expert judgement for the situations and assumptions that did not have enough data to make any other form of forecast.

The results of this model estimated that by 1990 there would be 18,044 average megawatts of electricity sales for the high growth scenario and 13,697 average megawatts of electricity sales in the low growth scenario. By the year 2005, they forecast 26,101 average megawatts of electricity sold in the high growth rate scenario, and 15,121 average megawatts of electricity sold in the low growth scenario.

As a result of the exponential nature of growth, uncertainty increases as forecasts are extended further into the future. As uncertainty increases, the difference between high and low forecasts also increases with each year a forecast is extended, creating what has come to be known as the "alligator jaws."

Model Evaluation

Criteria

In 1985, William Huss sampled electrical utilities and public commissions to find what criteria they used for rating economic forecasts, what their ratings of various forecasting techniques was, and what economic factors they considered significant for electricity demand.

To begin with, Huss submitted a list of 18 different criteria definitions, Appendix A, to the 75 largest utilities, a random sample of 25 small utilities, and 38 commissions. Each subject was asked to pick and rank the top eight criteria, using 8 as the most important criteria and 1 as the least important of the eight. The results were then compiled into a weighted scale based on the number of times each ranking was given to a specific criteria. For example, if a criteria was ranked 8 four times, and 2 three times, its weight would be 38 (4(8)+3(2)=38). This scale is assumed to represent the industry as a whole, Appendix B.

The survey showed that utilities and commissions alike felt a forecast should, first and foremost, make sense. All three groups also included historical performance, and data availability in the top five criteria. When allowed to expand the list to the top ten evaluation criteria, all three groups valued prices-elasticities and statistical tests important.

After initial agreements, opinions differed widely. Large and small electrical utilities considered explainability as a highly significant factor, while commissions did not. Development and implementation costs were rated highly by both commissions and small utilities but not by large utilities. The most interesting discovery was that, as a whole, neither utilities nor public service commissions considered the price of electricity to be a major factor in electric demand forecasts.

By aggregating the results of all three sample sectors, Huss found the top eight criteria to be: 1) historical performance, 2) explainability, 3) cost, 4) data requirements, 5) reproducibility, 6) sensitivity analysis, 7) statistically sound and 8) acceptance in the literature. These criteria were then used for relative comparison among the various forecasting methods.

Evaluation

Huss then asked utility analysts and regulators to evaluate the forecasting methods according to the top eight criteria. The summed results show how the electrical industry feels about each model type:

Trend extrapolations are cost effective, and have data requirements which are easily met. But because of their historical inability to explain or account for changes in the economy, these methods are not accepted by electric utilities or public service commissions as a valid method for electricity demand forecasting.

It turns out that aggregate single equation econometric, disaggregate single equation econometric and multiequation econometric models all score highly with both electric utilities and commissions. All three techniques perform well historically, are easily explainable, give reproducible results, are statistically sound, and are capable of being used for sensitivity analysis.

The decision of which of the three forementioned techniques to use is often limited by the data sources and funding available. Aggregate single equation econometric models appear to be the most cost effective and have the smallest data requirement. Multiequation econometric models, requiring extensive data bases, turn out to be the most expensive of the three.

Also highly rated is the end-use equipment model. Huss believes it is the forecasting technique of the future. Its greatest strength is its explainability. End-use models account for all electricity use giving it the unique ability to explain any and all changes in total consumption.

The other techniques, process models, advanced time series, expert judgement, customer survey and load factor analysis, scored horribly with both groups. Process models are too new, complex, and expensive to be taken seriously by the electrical industry as a whole, and are only used by experiment stations (Hoffman, 1977, 445). The other four are all cost effective but have not performed well historically, are not sensitive to economic change, and are not explainable.

Advanced time series models are statistically sound and relatively inexpensive. However, this type of model is poor in evaluating or predicting the probable change in sales resulting from a new variable or a change in the variables. Like trend extrapolations, it only reflects past, not future economic activities. Since the mid 1970s, forecasts from time series models have been inaccurate to the point of being outperformed by trend extrapolations.

Expert judgement is cost effective and easily acquired, but the validity of the results varies greatly and any attempts at long range forecasting are educated guesses at best.

In summary, it can be said that electric utilities and commissions value simple econometric techniques over any other. As of 1987, econometric models are the predominant forecasting techniques used for determining electricity consumption in commercial and industrial sectors. In the residential sector, econometric techniques account for 40 percent of electricity demand forecasting. End-use models are the primary techniques used in residential electricity demand forecasting, and process models have found a niche only within the industrial sector.

Chapter 3

ELECTRIC DEMAND FORECASTING AND REGULATION

Introduction

> The 84 sample utilities recorded write-offs of $1.57 billion in the first quarter, which brings the total write-offs since 1984 to $8.51 billion. . . . These write-offs have reduced shareholder equity by 6 percent . . . have also reduced the industry's actual (unadjusted) return on equity to . . . 11.3 percent in 1987, and 11.2 percent for the 12 months ending with March (Studness, July 21, 1988, 34).

The three years from 1985 to 1988 have proven to be detrimental to many electric utilities. Decisions of regulatory agencies have made rate and ratebase reductions almost as common as rate increases: 1988 earnings per share have dropped to a level 4.5 percent below that of the 1985 level (Studness, 1988) and as of October 1987, 15.9 percent worth of construction costs from 12 plants had been disallowed from the ratebase (Haubold, 1987).

While investment losses have always been cause for concern in any industry, in the case of electric producers, they have caused near panic. Spokespersons for many electrical utilities have accused regulatory agencies of changing the standard of prudence, and allowing only consfiscatory rates.

The stage was set in 1923 when U. S. Supreme Court Justice Brandeis stated that every investment may be assumed to have been made in the exercise of reasonable judgement unless the contrary is shown (Phillips, 132). Since then, the burden of proof has been transferred to the shoulders of the electrical utility, requiring the company in question to prove the reasonableness of every investment before regulatory agencies allow it to be included in the ratebase.

To say that the burden of proof has changed does not mean the criteria for evaluating prudence has changed as claimed by unhappy utility managers. In fact, commissions still hold that the reasonableness of a managerial decision must be judged on the basis of all that an electric utility knew or should have known, and the circumstances which existed at the time the decision was made (80 PUR4th 479, 480 (Mass. 1987)). Any time a regulatory agency follows this path when evaluating the reasonableness of a managerial decision, the electric utility in question should not have to fear unreasonable ratebase disallowances.

If the standards of prudence have not changed, are all of the recent ratebase disallowances justified? In order to answer this question, one must first understand what the goals of electric utilities and regulatory commissions are.

Goals of Electric Utilities and Regulatory Commissions

In the U.S., regulation is mainly concerned with the evaluation of rates, service, safety, and the efficient operation of public utilities. On the other hand, the goal of a public utility is to:

> provide the public with as much and as good service as the public wants and is willing to pay for. The goal of regulation . . . .

is to translate this task into operating terms, and see to it that it is carried out (Phillips 1984, 152).

Although this description is a simplified version of the duties of both commissions and utilities, it introduces a critical point: electric utilities are required to provide safe, adequate, continuous and efficient service (68 PUR4th 473 (WYO. 1985)). This duty requires an electrical utility to act like a business in a perfectly competitive market, but at the same time, prevents a utility from leaving the market or changing its product like any other business in a perfectly competitive market.

A regulatory agency attempts to achieve five goals or objectives: 1) to prevent excessive profits and unreasonable price discrimination among customers; 2) to assure adequate earnings so that the public utility sector can continue to meet consumer demand; 3) to ensure service is provided to the maximum number of customers; 4) to promote and develop the industry; and 5) to ensure maximum public safety and management efficiency (Phillips, 1984, 152). As an economic force substituting for competition, emphasis has recently been place on the assurance of proper resource allocation and the maximization of the economic performance of electric utilities by providing explicit incentives to reward efficiency and penalize inefficiency (Phillips, 1984, 153).

A glance at the relationship between the goals and activities of these two entities reveals a serious problem: while much of an electric utility's current building activities are based on decisions made several years ago, a commission has the opportunity to subject those activities to judgement in the current time period and with the supreme advantage of evaluating with ex post data. Even though the prudence review does not use current economic activities, such as the load factor and cost of fuel, to evaluate past decisions, there are other tests which may use current or past data.

The Three-Tiered Test

Originated by the California Public Utilities Commission the three-tiered test first differentiates between the prudence review and the used and useful criteria, then introduces a new criteria to be used in determining ratebase allowances, the risk-sharing principal. As a result, the three tiers of the test are: 1) the prudence review; 2) the used and useful criteria; and 3) the risk-sharing principal (69 PUR4th 206 (CA. 1986)).

At the same time that they developed the three tiered test, the California Commission established policy that requires any power plant construction costs to pass through all three tiers of the test before it is either entered or disallowed from the ratebase.

The Prudence Review

The prudence review is a look at the investment decisions made by a public utility. In order to pass the prudence review, a regulating agency determine whether the investment was wise and made in good faith. Exclusion of an investment from the ratebase due to imprudence can be justified in the cases of fraudulent, unwise, or extravagant expenditures that should not be a burden on the public (Phillips, 1984, 292).

Upon initial interpretation, a reader might be led to believe excess capacity should be classified as an unwise expenditure. However, the California Public Utilities Commission clearly pointed out that if the decision to build was the best choice when made, it was still a prudent investment and had to be passed on to see if it could be considered used and useful.

Used and Useful

In the early cases, commissions appeared to use the used and useful criterion as a tool to assist in the determination of prudence. As time went on, some commissions began selectivly implementing the used and useful criterion as a separate test. Until finaly, the California Public Utilities Commission wrote the used and useful criterion into its' three tiered test as a specific test seperate from the prudent review.

According to the new definition, prudence must still be determined based on knowledge and information existing at the time the decision was made, but used and useful would be determined with respect to current information. When the test was being used for the purpose of prudence, there was a limited range of unnecessary items that would be excluded from the ratebase:

> (1) Duplicate and unnecessary property; (2) obsolete and inadequate property; (3) property to be abandoned; (4) abandoned and superseded property; (5) overdeveloped property and facilities for future needs; (6) real estate: buildings, leaseholds, and water rights; (7) incomplete and contemplated construction; (8) property used for nonutility purposes; (9) property of other utility departments (as in the case of a combination gas and electric utility company); (10) property not

owned; (11) property donations-voluntary or involuntary; (12) deposits and moneys advanced by customers (Phillips, 282).

Few would dispute the reasonableness of these 12 general guidelines which were used to assist in the development of logical conclusions regarding whether an investment was prudent. Instead, complaints from electric utilities are directed at the additions to guidelines. While the original 12 were simply guidelines used to determine logical conclusions, the new criteria have been developed with a specific end in mind, and are merely means used to justify the end.

By 1985 the used and useful criterion in California had been expanded to include: 13) successful completion of the startup program, an uninterrupted run of at least 100 hours during which time power is furnished to the grid at between 95 and 100 percent of thermal output capacity; 14) successful completion of the preoperational test program; 15) successful testing of capability to supply full share of rated power to intrastate customers with the single most critical transmission line out of service; 16) issuance of or receipt of commitments for the issuance of all necessary operating licenses upon the effective date of a commission order granting rate recognition for the plant; 17) evidence of competence in the plants operation and nuclear regulatory commission compliance history; 18) the granting of an exemption from criteria 13-17 upon good cause and upon condition that the plant is fully operational at a power level less than rated full power; 19) the supplying of electricity to intrastate customers which output scheduled by the lead dispatcher, subject to plant availability (68 PUR4th 326 (MO. 1985)).

The combination of time and additional criteria have allowed public utility commissions to attack the accuracy of electricity demand forecasting. The new used and useful criterion has been the tool used for ratebase disallowances in the last decade. While the prudence test would allow ratebase status for the excess capacity and numerous partly completed electric generating plants owned by electric producers, the new used and useful criterion disallows many plants because they are currently idle.

It would not be correct to say all commissions have adopted, used, or contributed to this list in order to disallow as many costs as possible. In some cases, as long as the decision was made prudently, and the forecast was consistent with other forecasts in the region, reasonable excess capacity is allowed into the ratebase. One such decision was made by the Pennsylvania Public Utility Commissions finding:

> it is no longer necessary to interpret the phrase reasonable reserve margin as a projected actual reserve to take account of the issues of large quantum changes in capacity, imperfectly predictable load growth, and long lead-time of certain construction projects; interpretation of reasonable reserve margin in the sense of the optimal, just and reasonable margin, consistent with prior usage in excess capacity decisions in virtually all other previous rate cases (84 PUR4th 198, 199 (PA. 1987)).

The Pennsylvania Public Utility Commission also stated a plant held for future use that will be utilized within ten years should be included in the ratebase.

While many state commissions have adopted the ten year utilization criterion to include excess capacity into the rate base, interstate electric suppliers have to fight to get the same expense allowed in each state they supply power to. In a radical decision, the California

Commission did not allow the Pacific Power and Light Company to recover costs associated with an out-of-state construction project even though Pacific Power and Light had a forty year contract to supply the excess capacity to an out-of-state utility. The California commission found the length of the contract prevented the plant from being either "used and useful" or excess capacity for electric consumers in the state of California. Therefore those costs associated with the new plant could not be entered into the ratebase (69 PUR4th 189 (CA. 1985)).

The Risk Sharing Principal

The risk sharing principal was placed into effect to counteract the Used and Useful criterion. Too many utilities were suffering financial difficulties from the bloodletting being allowed under the disguise of the used and useful criterion. Anytime a commission, or population did not want to pay for some cost incurred by an electrical utility, and that cost wasn't currently producing electricity, it was possible to get the cost kicked out of the ratebase on some technicality.

The merciless commissions were hiding behind such terms as "possible rate shock" and the perversions of other statements such as "The absence of imprudence does not dictate the total recovery of revenues associated with excess plant" to justify their actions (75 PUR4th 363 (MO. 1987)).

The risk sharing principal then came into being under claims that unforeseeable changes in the economy were risk related, and should not be accepted as justification for ratebase disallowances. This principle suggested that instead, these costs should be shared equally between ratepayers and electric utility owners (69 PUR4th 189, 192 (CA. 1985)).

Under the risk-sharing principal, as determined by the California Public Utilities Commission, a utility should not have to bare the cost of a prudent decision to abandon a partially constructed plant, nor should it receive a rate of return on the investment. In simple terms, risk sharing forces the public and an electrical utility to share the burdens caused by unforeseeable changes in consumption patterns, costs, or political activities.

Applied Used and Useful

A quick review of the used and useful criterion shows that it largely deals with excess capacity. What has caused the excess capacity? Excess capacity could not be caused by prudent investments, or could it? The key factor involved here is nothing other than forecasting. Even though an investment decision is declared prudent based on the forecasts, the expenses incurred in association with that decision do not have to be allowed if the forecast was not accurate.

For example, if electric utility company x invested $10 million to meet a forecasted 10% increase in demand over the next 5 years, but demand growth suddenly dropped to 0, none of the $10 million would have to be included in the rate base. Even though the initial decision was prudent, the forecast was inaccurate, forcing electrical utility x to absorb the loss. However, this is just a hypothetical situation. To really understand what is happening, it is necessary to look at recent commission decisions.

Forecasting Decisions

Since each electric utility ratebase case has unique twists with no two being exactly alike, it is impossible to do justice to each case, nor is it critical to this discussion. Instead, three specific cases are presented representing commission actions which: 1) dictate the forecasting method to the electric utility; 2) guide the utilities direction of forecasting methodology; and 3) accept the forecasting methodology used by the electric utility but subject the results to the used and useful criteria.

Case One: Illinois Public Utilities Commission vs Edison Electric Power Company (77 PUR4th 433 (ILL. 1986))

This case is an excellent example of the increasing role of public utility commissions in determining appropriate electric demand forecasting models.

In a ratebase hearing, the Illinois Public Service Commission stated explicitly which methods were acceptable for peak electric demand load forecasts for both individual sectors and aggregate peak electric demand. The accepted models were: 1) the disaggregate econometric approach (to determine indivivual sector demand); and 2) the end-use approach (to determine electric demand for the residential sector).

After conducting an investigation into Edison Electric's load forecasting methods and procedures, the Illinois commission found the methodology "not reasonable." The Commission then proceeded to outline exactly what should be included in the end-use model for the residential sector, and how Edison Electric should implement the specified variables into their forecasts (77 PUR4th 433 (ILL. 1986)).

Edison Electric was ordered to:

> 1) analyze whether the development of separate explanatory variables for room air condition saturation and central air condition saturation would improve the projection of air condition saturation over time; 2) account for changes in the sizes and efficiencies of air conditioners over time; 3) measure the equivalence of room and central air conditioners based upon comparable power requirements; 4) use a quadratic specification to extrapolate air conditioning saturation in addition to comparing model results with the Gompertz method; 5) explain, change, or justify year by year, its projection of declining prices in electricity over its ten year forecast; 6) develop an end use model for the residential customer class; 7) prepare a description of the uncertainty contained in its load forecasts; and 8) prepare a comprehensive report of the prices and availability of time of day meters including meters that measure kilowatt demand as well as kilowatt hour use, meters that combine load control functions with time of day functions, and meters in the developmental stage.

Although the preceding order seems explicit enough, the Illinois Public Utilities Commission was not yet satisfied, and also directed Edison Electric to include: 1) a cost function that explicitly linked the size of load forecasting errors to their impacts on present value revenue requirements; 2) a documented range of forecasts along with the associated optimal construction program for each case, giving consideration to nongeneration alternatives such as cogeneration and mandatory residential time-of day rates for meeting projected increases in peak load; and 3) an analysis considering the appropriateness of implementing a mandatory residential time of day rate during the 20 year period covered in the energy plan to avoid future capacity additions (77 PUR4th 434 (ILL. 1986)).

This case presents a situation where the regulating agency played a major role in formulating the electric demand forecasting model, even to the point of emphasizing their preference for cogeneration to meet additional demand. Although cases such as this are not overly common, they have gained publicity as a result of the controversy surrounding them.

Case Two: New Hampshire Commission
RE Public Service Company of New
Hampshire (66 PUR 4th 349
(N.H. 1985)

Unlike the preceding case, the New Hampshire Commission did not meddle with the forecasting techniques of an electric utility. Instead, they simply demanded that the electric utility provide validation to account for the values of key assumptions entered into the forecast model.

Specifically, the New Hampshire Commission wanted verification for four assumptions: 1) the price elasticity of demand; 2) the correlation between economic growth and growth in electricity consumption; 3) the impact that switchovers from conventional to alternate fuel sources would have on electric demand and prices; and 4) the impacts that conservation and new technologies would have on electric demand, prices, and the electric industry (66 PUR4th 349, 380 (N.H. 1985)).

In addition, the New Hampshire Commission developed a list of elements which could not be included in electricity supply planing, including Canadian hydropower and cogeneration. The New Hampshire Commission determined that Canadian hydropower should be used as a supplemental rather than a primary source of power as its supply was uncertain. They found cogeneration to be an ineffective source of electric power because of a shortage of necessary technologies needed to utilize the programs (66 PUR4th 349, 350 (N.H. 1985)).

The importance of this case lies in that last statement. If cogeneration is not used in supply forecasts but is developed anyway, it will result in excess capacity that could possibly be disallowed from the ratebase with the used and useful criterion. Even though the forecasting error may be caused by the commission, an electric utility may be forced to bear the excess capacity cost because the outcome of the used and useful test will not be found until after the plant is completed.

It is common for state commissions to first scrutinize the forecasting technique used, then offer their own various slight alterations to the forecasting technique. Two other examples, whose demands were not quite so harsh are the North Dakota Public Service Commission and the New York Commission. North Dakota simply ordered the use of a least cost strategy to match the energy supply to demand, in an attempt to minimize the cost of service (81 PUR4th 90, 108 (N.D. 1987)). New York has ordered that an electric demand forecast should include all estimated consumers in the forecasted years but did not specify how to implement it.

Independant of a commission's willingness to admit it, each and every case that subjects an electric utility to the used and useful criterion is evaluating the forecasting techniques used by that electric utility. Simple logic will reveal excess capacity to be the result of an inaccurate forecast. If the forecast was accurate, there would be no excess capacity.

Case three: Indiana Public Service Commission

RE Northern Indiana Public Service Company

(67 PUR4th 396 (IND. 1985))

The Indiana Public Service Commission is a good representation for commissions that accept the electric utilities forecast methodology without question. The Commission still subjects the forecast to scrutiny, but at a later date. In an attempt to determine the reasonableness of excess capacity and the forecasting error, the Indiana Public Service Commission cited eight factors as relevant for determining excess capacity:

> 1) prudence of management decisions in construction the units which leads to excess capacity; 2) the reasonableness of the utility's demand forecasts at the time of construction began; 3) whether changed circumstances have occurred and whether the utility re-evaluated its construction program in light of those changed circumstances; 4) the lead time required to construct the generating facility in question; 5) whether it is necessary to operate the facility to provide adequate and reliable service; 6) any unique circumstances which might affect reserve margins; 7) the financial effects that a rate base exclusion would have and what long term effect are exerted upon the utility's ratepayers and; 8) the effect of changes in demand forecasts upon the adequacy of the utility's reserve capacity and its ability to serve its customers (67 PUR4th 396, 401 (IND. 1985)).

The criteria implemented by the Indiana Public Service Commission admits forecasting errors are not always directly related to forecasting techniques. It accepts the fact that there are other phenomena in the world which cannot be accounted for, (i.e., droughts, depressed economic conditions, high oil prices, decrease in population growth, ect.). In the same spirit of the cost sharing principle of the California Public Utility Commission, the Indiana Public Service Commission decided that an electric utility should not have to the sole bearer of excessive costs resulting from unforeseen phenomena.

The Indiana Public Service Commission still subjects the final capacity to a margin analysis; distinguishing between reserve margin, capacity margin, and operating margin. However, it rejects the use of any of these measures of excess capacity and refers to an economic analysis of the case (67 PUR4th 396, 402 (IND. 1985)). Although the Indiana Public Service Commission does not claim to be scrutinizing forecasting methodology, it is doing so indirectly by reserving the right to disallow costs associated with excess capacity.

Non-Prudent States

In recent years, another breed of state commissions has evolved, non-prudent commissions. Non-prudent commissions do not even subject electric utility investments to a prudence review. Instead, these commissions automatically accept an electric utility's demand forecasts and allow costs into the ratebase until construction is finished. Once the construction is completed, the new plants are subjected to the used and useful criterion to determine whether or not the cost will stay in the ratebase.

As one can see, an electric utility has no idea of how its investment will be treated until after it is completed. Under the title of a non "prudent investment" state, Arizona requires property to be either used and useful or under construction to be considered for inclusion in ratebase. Any plant that is that is classified as excess capacity or held for future use will be disallowed (1987 Annual PUR4th 356 1986). In this particular state, an electric utility may find construction costs of a specific plant included in the ratebase until completion of the plant, at which time the construction costs could be disallowed on the bases of excess capacity.

Decision Implications

Once a public service commission sets direct policies and orders like those above, they become guides for other regulatory agencies. It is common for other commissions to adopt the policies and orders as their own, increasing the strength and effect of those orders over time. The Texas Commission provides an excellent example. They do not have many of their own findings, instead, their entire orders are filled with quotes from other agencies. In one case, they implemented the least cost order of North Dakota, the Indiana excess capacity findings, and the Pennsylvania excess capacity order (1987 Annual PUR4th 124 1987).

Electric utilities believe they have been been burned by inflation, environmental regulations, and unjust disallowance of full recovery of construction costs by state utility regulators. They are now reluctant to build more power plants, believing a stance of non expansion is the most prudent investment of all (Paul 1988, 3).

Summary

While representatives of electric producers like Laros (vice president of Theodore Barry and Associates), Sandbuilt (vice president of Minnesota Power and Light), and Haubold (Partner of Kirkland and Ellis) are screaming at the supposed injustice being dealt out to electric utilities because of changes in the standards of prudence (Haubold, 1987), these persons, and others like them, are overlooking one simple fact: the standards have not changed. Evaluations to decide if investments were prudent or not are still being conducted as they were twenty years ago. Commissions still inspect the costs in question and determine, based on knowledge available at the time, if the decision was the best one possible. Even a large percent of the criteria for the "used and useful" test are over twenty years old.

What has changed then? The trends have. Excess capacity may have been disallowed twenty years ago, if it had existed. The main difference is how long it takes demand to grow to meet the excess supply. On one hand, if current electric demand growths continue, it may take the U.S. until 2003 to utilize all of the excess capacity existing today. On the other hand, if it would only take 3 years to exhaust that excess supply if demand suddenly began to grow at a 7 percent annual rate.

Chapter 4

SUMMARY AND CONCLUSIONS

> Although surprises such as a natural calamity or an international political incident can overwhelm a well-thought-out projection, the forecaster's task remains one of analyzing historical data and institutional trends, studying the information needs of management, and generating detailed reports that focus on the decisions management must make (Bails, 1984 4).

Although forecasters do not know what electricity demand will be in the future, they can work to reduce the range of uncertainty facing electric utility decisions. However, greater forecasting accuracy generally necessitates larger, more expansive models capable of explaining complex interrelations in the economy. Milton Friedman best summarized this problem when he wrote:

> The gains from greater accuracy, which depends on the purpose in mind, must then be balanced against the costs of achieving it (Friedman, 1935, 17).

Summary

The problem of excess capacity in the electric utility industry cannot be attributed to any single phenomenon. However, there are three major factors that can be identified as contributing to the problem: 1) the long lead times needed for an electric utility to construct a power plant; 2) the oil price shocks in the 1970s; and 3) the sudden downturn in electric demand resulting from a faltering economy and higher electric prices.

In an attempt to solve the excess capacity problem, the electric industry embarked on a quest for the prefect electric demand forecast, enabling the electric industry to witness the evolution of forecasting methodology from simple trend extrapolation, to the most recently developed process and end-use models. But developing and implementing a forecasting model are two different things. On one hand, trend extrapolation models were retired from active use due to an inability to forecast accurately in a volatile market. However, the retirement of trend extrapolation models did not lead to the immediate adoption and implementation of end-use and process models by most electric utilities. Independent of the forecasting accuracy achieved with these models, the high cost of implementation has priced them out of the market except for the larger electric utilities. As a result, the industry has continued to emphasize disaggregate models that enable cost efficient results within an acceptable range of accuracy.

Unfortunately, the focus of developing these new forecasting models may be placing emphasis in the wrong area. Even if the industry had implemented the most accurate forecasting techniques, it could not have forecasted the previously mentioned supply and demand shocks. These complex models ultimately require estimates and best guesses, supporting the belief that forecasting is an art, not a perfect science.

If the electric industry wants to avoid future shocks, it cannot rely solely on improving forecasting techniques while continuing to use planning schedules that take from 7 to 15 years to implement. The electric industry must seriously investigate sources of electric generation that can be quickly implemented, such as cogeneration and conservation. Both of these sources of energy can often be implemented in less than a year, reducing the necessary lead time to increase electric capacity. In many cases, potential cogeneration sources already have basic equipment and energy source available, and are just waiting to be tapped.

The electric industry is already moving in the right direction, but ultimate success will require the support of both state and federal regulating agencies. As it stands now, electric power producers do not know what to expect from state regulatory commissions. Ratebase treatments vary from state to state, year to year, and case to case. The uncertainty of commission decisions has made capital attraction an increasingly difficult task for power producers.

Conclusion

Economic volatility and the liberal use of the used and useful criterion since the mid 1970s have persuaded the majority of electric producers that it is in their best interest to increase the amounts of resources allocated to forecasting in order to achieve a higher degree of accuracy.

But more accurate electric demand forecasting alone will not solve the electric industries financial problems. As long as state regulatory agencies continue to act unilaterally and inconsistently in each individual rate case, regulation will continue to be another source of volatility increasing uncertainty in an already uncertain process.

APPENDIX A

Criteria Definitions

A. Historical Performance of Model
For well-developed modeling approaches, this includes the model's ability to forecast accurately as measured by mean absolute percentage of error, mean square error, or other error measures. For new models, it means a validity test where the forecaster uses the model structure as having been formulated several years in the past and measurers the difference between model forecasts and actual conditions or peak load.

B. Consistencey Between Forecast Assumptions and Reality
The variables such as price, income, employment, that drive the model should reflect the assumptions which the forecaster intuitively believes about the forecast environment.

C. Statistical Tests
Includes various values of fit tests such as R squared, Chi-squared, t-tests, and F-tests.

D. Does the Final Forecast Make Sense Given Input Assumptions.
Does the forecast seem within reasonable bounds and the forecaster's intuitive judgement of the future? Does the approach seem logical and account for all key factor influences?

E. Explainability to Regulators and Managers
Can the forecasting approach be described to management, and regulators in a simple, logical, and intuitive fashion which does not require extensive familiarity with statistics, computer programming, or the associated jargon?

F. Cost to Design and Update
Includes time spent to collect data, design, and implement the approach, purchase or write appropriate softwear and produce model updates. Cost should be considered relative to the magnitude of the decision affected so that more money would be spent on a forecast to influence a more significant decision.

G. Availability of Data
Can the proper data be obtained in a simple, cons-effective manner and will it continue to be available throughout the lifetime of the model?

H. Reproducibility
Can the approach, and data sources be described in such a manner so that an independent individual or organization can reproduce and understand the forecast? Is the forecasting approach well documented?

I. Ability to Evaluate Fundamental Structural Change
Can the model capture fundamental changes such as increased conservation ethic, the decline of heavy manufacturing industries, and the growth in service and information industries? Can the model help evaluate market environments.

J. Clearly Stated Forecast
Has the forecaster described why a forecast is needed and how it is to be used? Is the approach consistent with the purpose?

K. Acceptability of Method in Published Literature and from Peer Reviews
Do the academic and professional journals support the technique used? Is the approach consistent with what is employed by other utilities or by EPRI.

L. Consistent Inclusion of Both Local and National Economic Variables
The model must reflect both national and local economic conditions as well as the relationship between the two. Both the national and local forecasts of economic conditions must be based on the same set of assumptions.

M. Stability of Method-Results Over Time
If the forecast results undergo drastic changes from year to year or even from month to month, confidence in the forecast suffers. The same can be said for a forecast model or approach which shows no consistency over time.

N. Reasonable Sensitivity Analysis Using Alternative Input Assumptions and Alternate Techniques
Is the forecast relatively stable regardless of the technique used? Have the forecasters tested the effect of errors or changes in the input variables? Have these sensitivities included the development of a "scenario" or consistent set of alternative input assumptions (rather than taking the extreme of all input assumptions)?

O. Inclusion of Fuel Prices and Price Elasticities
How well does the model incorporate the effect of price or other key variables into the process?

P. Ability to Analyze Marketing Strategies
Can the model measure the effect on load of utility demand side management activities including load management, time-of-day rates, electrification, advertising, conservation, or home energy audit programs, et cetera?

Q. Acceptability to Commission, Administration, and Other Political Organizations
Will the approach and resulting forecast meet the requirements of the various public organizations who will not only scrutinize the forecast technically but reflect public perceptions or political motivations as well?

R. Level of Disaggregation
Does the model have the proper level of disaggregation? Models which are not adequately detailed to not permit managers to address individual customer classes. Models which are too disaggregated are expensive and cannot be adequately supported by available data.

(Huss, 1985, 28,29)

Appendix B

Top Ten Criteria by Client Group Using Weighted Score

Large Utility Analysts	Commissions	Small Utility Analysts
Does the Forecast Make Sense?	Does the Forecast Make Sense?	Does the Forecast Make Sense?
Data Availability	Data availability	Data Availability
Historical performance of model	Historical performance of model	Historical performance of model
Statistical tests	Evaluates structural change	Acceptability to commissions
Explainability	Sensitivity analyses	Consistency between Assumptions-drivers
Stability over time	Clear statement of purpose	Explainability
Evaluates structural change	Cost	Cost
Consistency between assumptions-drivers	Statistical tests	Statistical tests
Acceptability to commission	Inclusions of prices elasticities	Stability over time
Inclusion of prices elasticities	Level of disaggregation	Clear Statement of purpose.

(Huss, 1985, 29,30)

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