CHANGING NEEDS IN ELECTRICITY DEMAND FORECASTING: A CALIFORNIA PERSPECTIVE

Joseph Eto, Lawrence Berkeley Laboratory,
Carl Blumstein, University of California, and
Michael Jaske, California Energy Commission

ABSTRACT

The forces of deregulation and integrated resource planning are causing changes in the role of electricity demand forecasts. The experience of California since the early 1970's provides a background for a discussion of these changes. The traditional utility planning paradigm, in which forecasting and generation planning are sequential steps, is being replaced. Integrated resource planning leads toward a process in which the sequence becomes an iteration. Deregulation leaves the sequence intact, but replaces the generation planners with a market. These changes in the planning process have been accompanied by some dramatic upheavals in rate design. Taken together, these have changes created some difficult challenges for electricity demand forecasters. We identify load shapes, the effects of rate structure, consumer behavior, and customer data as areas about which we need to know more. A renewed commitment to forecasting research and development appears to be required.

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TIMES HAVE CHANGED

When the California Energy Commission (CEC) was established in 1975, the role of electricity demand forecasts was clear. The early seventies had been marked by growing controversy over the siting of nuclear and coal power plants. Multiple and overlapping state and local jurisdictions made the siting process slow and contentious. Utilities believed that dozens of additional plants would need to be built before the end of the century and that a streamlined siting process was therefore imperative. Environmental interests were also alarmed by these projections and sought verification. The Warren-Alquist Act, which established the CEC, was the state's response. This legislation was backed by the state's utilities and signed by Governor Ronald Reagan at the end of his term [CEC, 1975]. The CEC was to act as a "one-stop" power-plant siting authority with the power to override local and other state jurisdictions. An important part of the siting process was the development of a biennial forecast of electricity demand. The forecast, along with an agreed upon set of supply planning assumptions, would be used to determine how many power plants needed to be sited.

The Warren-Alquist Act brought the state into the utility planning process, but did not change the traditional utility planning paradigm, in which demand forecasting and generation planning are sequential steps. The generation planner's problem remained: *given the demand,* find the optimum means of supplying it.

The past 13 years have seen this paradigm seriously eroded. Two developments in the utility industry caused this erosion. The first is the emergence of integrated supply and demand planning (or, for short, integrated resource planning). The second is the trend toward deregulation and independent power production. As we will see, these two developments have quite different implications for forecasting; taken to extremes, they have consequences that may be mutually exclusive.

Integrated Resource Planning

The Warren-Alquist Act gave the CEC, not only the authority to site power plants, but also authority and a timetable for establishing energy-performance standards for buildings and appliances. The first CEC staff attempts to forecast relied on econometric models; however, it was quickly observed that these models could provide little information about the effects of standards, which led the CEC staff to develop end-use models for their biennial forecasts. The early biennial forecasts were marked by intense debate among the CEC staff and the utilities about the merits of different modeling approaches and the accuracy of sales forecasts. All of the sound and fury of that debate may have obscured a change that was more fundamental than the changes in modeling methods that were occurring. In retrospect, we can see that the CEC had started down the path of integrated resource planning. They were mandated to take steps (i.e., implement standards) that we might today call demand-side management. They needed methods to evaluate the likely effects of their actions, so they began to develop the necessary tools.

Integrated resource planning cannot yet be described as a routine process, but in California it is accepted that the utilities should treat conservation as a resource that will be substituted for generation. From the integrated resource planning perspective, the problem is to meet the demand for energy services such as heating, cooling, and lighting, in the most efficient manner. Because alternative means of providing energy services may require different amounts of electricity, the demand for electricity is determined by the resource plan chosen. Currently, methods for integrated resource planning are rudimentary, but they appear to be evolving toward an iterative process of comparing the results of different patterns of investment in the demand and supply sides. For this process, several forecasts must be produced, each describing one component of many potential integrated resource plans. Forecasting models will get a real workout.

Iterative use of forecasting models requires that models accurately reflect the structure of energy use in two dimensions: consumer's energy service choices and the load shape impacts of these choices (see, for example, Eto, et al., 1987). First, in order to represent consumer demand accurately, the forecast must include both the performance of conservation equipment in the field and consumer behavioral responses to demand-side opportunities. Second, the level of detail required of forecasts is also increased. Because demand-side programs will reshape utility loads, we need hourly detail on future loads, in order to predict the effects on utility's future production costs.

Increasing centralization of the provision of energy services is implicit in the integrated resource planning process. The utility's area of responsibility is enlarged to include all of the means by which consumers provide themselves with energy services, not just the power. Integrated resource planning does not require that the utilities actually own generation or end-use equipment, but it does require that they exercise some control, either directly or indirectly, over how and when energy services will be provided. With integrated resource planning, the rationale for centralization is the achievement of economies of coordination.

Deregulation and Independent Power Production

Integrated resource planning takes us toward centralization, but deregulation takes us in the opposite direction. In the extreme, the utilities divest themselves of all generation capacity and operate their transmission and distribution systems as common carriers. There is no "obligation to serve." A host of producers compete for the consumer's dollar. In these circumstances, the role of demand forecasting would be greatly reduced. Bottom-line forecasts would be made by each individual producer who would be concerned primarily with whether he could sell the power he planned to produce. Total demand would be a secondary concern. That is, the individual producer would be concerned about his competitive position (will his costs be low enough?, will his marketing be good enough?, etc.). Of course, he would be interested, to some extent, in the overall size of the market, but he would be much more interested in his competitors' costs and marketing strategies.

In California, things have not gone so far and probably won't, at least in the near future. California's experience with deregulation began with a program for utility purchase of independently produced power through standard offers. The standard offers were a series of agreements offered to any prospective power producer. One of these offers, Standard Offer number 4 (S.O.4) provided guaranteed prices to producers for 10 years. As it turned out, the offered prices were too high. The response to S.O.4 was overwhelming, the offer was not suspended quickly enough, and the state soon found itself with a potentially serious overcapacity problem. (The seriousness of the problem will depend on how much of the capacity under contract actually comes on line.)

After S.O.4 was withdrawn, the California Public Utilities Commission (CPUC) began to develop new procedures for utility acquisition of independently produced power. The CPUC now proposes qualifying facility solicitations for a fixed amount of capacity, paid at administratively determined avoided costs, using second price bids to resolve over-subscription [CPUC, 1986]. A competing method proposed by the Federal Energy Regulatory Commission (FERC) would involve some kind of auction. In either method, demand forecasts would play a central role. To implement an auction, for example, planners must first determine how much new capacity is needed. Then this amount will be placed out for bid in a process that will probably involve competition among independent producers and the utility.

The CPUC and FERC proposals may actually increase the seriousness of an inaccurate forecast because it may be more difficult to make mid-course corrections. Independent producers are not likely to be willing or able to scrap a project in its early phases or to stretch out construction because expected growth in demand does not materialize. A recent CPUC/CEC joint report emphatically repudiates contract abrogation [CEC/CPUC, 1988]. (As one sign of the changing times, the most recent hearings on the CEC staff's biennial forecast were marked by arguments made by the independent power producers that the CEC staff's forecast was too low. This used to be the position of the utilities, but they are now producing forecasts that are often lower than the CEC staff's.)

UPHEAVAL IN RATE DESIGN

In California, integrated resource planning and deregulation have led to dramatic changes in rate design. Beginning in late 1986, the CPUC began a major investigation into many facets of electric utility regulation. Among the motivations for this investigation was the growing threat of current customers "bypassing" the system by installing self-generation equipment.

The CPUC determined that revenue requirements would have to be allocated so that charges to customers would have to more closely reflect the cost of service, especially where reductions coincided with potential for substantial bypass*. First, in each investor-owned utility general rate case, the rate design adopted would move toward the cost-of-service goal. Second, so utilities could have greater flexibility to combat bypass, they would be allowed to negotiate lower rates with customers threatening bypass.

Utilities are modifying rates to reflect cost of service in three specific ways. First, average cost per kWh charged to each class much more closely matches cost of service. Utilities are trying to use marginal costs to allocate revenue responsibility at a customer class level and, thus, signal the true costs of providing electricity to consumers. Second, individual tariff components are being revised to reflect more accurately the relationships between fixed and variable costs. In general, fixed charges are being increased, and variable charges are being reduced commensurate with today's low marginal fuel costs. The most striking expression of this trend can be seen in recent experiments with the real-time communication and updating of prices. Third, for tariffs with

* It is ironic to note that the use of cost-of-service principles, in particular those based on marginal cost, had long been a policy of CPUC. The current, wide-reaching implementation of these principles, however, waited until the threat of bypass xxxxx appeared to make it imperative.

demand charges, the fixed and on-peak components are being increased, and the off-peak and energy components are being decreased. These changes in rate design philosophy suggest increased emphasis on the ability of prices to influence consumer behavior.

In addition to rate design changes that shift revenue requirements among classes, and within classes through tariff construction, the CPUC will grant utilities the authority to negotiate rates with any customer having peak demand of 1,000 kW or larger [CPUC, 1987]. This so called "less-restricted" class will also no longer be covered by the usual adjustment mechanisms to protect against forecast error or inflation, so that the utility has an incentive to maximize revenues through tough but sensible negotiation of special contracts. These anti-bypass special contracts will be used by utilities to keep customers who would otherwise have left the system and self-generated their own electricity. The only control the CPUC will exercise over these contracts is to assure that a minimum rate is charged that covers marginal fuel costs, incremental transmission and distribution costs, and capacity costs, if reserve margins are not being met. The particular rate resulting from these negotiations for any one customer will depend solely upon the negotiating skill of the two parties and the credibility of the customer's self-generation threat. Also, the CPUC will allow utilities to enter into incremental sales contracts with customers at rates below tariff levels as long as the same minimum threshold that applies to anti-bypass contracts is met, and as long as the contract is for purchases beyond those which would have been made by the customer anyway.

CHALLENGES FOR DEMAND FORECASTING

What will be the impact of these changes in rate design on energy demand forecasts and forecasting models? To begin, we must acknowledge that models may not be fully capable of handling certain challenges. For example, analysis of the potential for incremental sales contracts may be possible, but predicting the actions of a few dozen major industrial customers with highly individualized contracts may be impossible in any model. (Those who have been involved in electricity forecasting for a few years have their old forecasts to keep them humble.) As discussed below, there are some formidable challenges, but we are not yet ready to abandon the field to astrologists.

The Effects of Rate Structure

One challenge for forecasting that is a direct result of recent regulatory activities is the recognition that rate structure may, in some circumstances, be as important as rate level in modifying consumer behavior. Treatment of rate structure in long-run demand forecasting models is an old problem that has never been satisfactorily resolved. Initial attempts to grapple with rate structures were unsuccessful and the issue gradually faded away as other priorities took over model development energies. Currently, most end-use forecasting models cannot begin to address the impact of tariff structure on consumer behavior because they are predicated upon average rates, or prices.

Changes that tend to shift the allocation of revenue requirements among fixed versus variable components of the tariff (in some cases, dramatically) are not accommodated in most forecasting models. Similarly, the effects of multiple, time-differentiated, and sometimes non-linear (i.e., block rate) electricity tariffs on demand are also poorly understood. Yet, for large consumers (who are the primary candidates for self-generation), time-of-day rates are mandatory and demand charges are standard components of electricity bills. Finally, real time pricing, which is the logical extension of time-differentiated pricing, presents a completely unique modeling challenge.

Multi-component and non-linear rate structures mean that the concept of an annual average electricity rate, which is central to most price elasticity and life-cycle cost formulations, is no longer meaningful. Rather, for any given rate schedule, there is a continuum of average annual rates that is uniquely determined by the load characteristics of each consumer. Moreover, having determined this rate, its usefulness in evaluating the benefits of changes to the consumer's electrical demands can not be made *a priori*. Some measures will not save peak demand, and others may save only on-peak energy. In each case, use of an average annual rate may seriously misrepresent the true economic impact of a measure for the consumer.

The Link Between Energy and Peak Demand

We must tighten the the link between energy and peak demand forecasts. Currently most end-use forecasts are performed in two sequential steps. First, annual energy use is forecast for the planning period. Second, annual energy use is spread over the hours of the year to produce hourly load shapes. This latter step is typically a mechanical allocation of energy use to the hours of the year based on fixed seasonal, weekly, hourly and, for weather sensitive end uses, climatic factors (see, for example, CEC, 1987). In this process, a given change in electricity consumption for an end use is spread in constant proportion to load over the hours of the year.

For most end uses, this approach is satisfactory. We tend to believe, for example, that highly efficient lighting technologies do not change the load shape for lighting; they simply reduce the overall level of the load shape. (An exception is daylighting.) However, the list of promising demand-side options for which the sequential approach is no longer appropriate is expanding. The list includes all load-shifting technologies and pricing strategies, such as thermal energy storage, utility- or customer-dispatched load management, and time-differentiated electricity tariffs whose goal is to move load from one time period to another. It can also include certain high-efficiency measures where the increases in efficiency come at the expense of shifting load disproportionately toward on-peak periods (e.g., adjustable speed drives or two-speed compressors for air conditioners).

The list, moreover, is not limited to technologies. Changing features of the population pose equally challenging problems for forecasting behavioral influences on energy use and load shape. For example, two-worker household appliance usage schedules can be dramatically different from the traditional single-worker household schedule. At one extreme, energy use may be shifted away from on-peak to off-peak hours.

Behavioral Issues

Despite substantial improvements in forecasts, considerable uncertainty remains about the mechanisms and determinants of consumer price response. Better understanding these mechanisms is essential for incorporating demand-side activities into resource portfolios.

In the residential sector, two choices are mediated by price: choices about the amounts of energy services to consume and choices about the means used to provide energy services. The first type is purely a decision about consumption; the second type is at least partly a decision about investment.

A simple model for the first kind of choice is that consumers act to satisfy their preferences, subject to the constraint of having only a limited amount of money to spend. The preference structure is revealed by consumer responses to price changes. This model is fine, as far as it goes, but forecasters must also ask themselves whether and how the preference structure might change in the future. There is evidence that preference structures are influenced by social norms, household composition (family size, age distribution), ethnicity, and other non-economic factors [Stern, 1984 and Lutzenhiser, et al., 1987].

A simple model for the second kind of choice is that consumers act to minimize life-cycle costs. In choosing among alternative means (e.g. different refrigerator models) of providing an energy service, they weigh the present cost of more efficiency against future savings, using discount rates that are implicit in their choices. If one does not require that, 1., consumers are actually aware that they are choosing in this way or that, 2., the implicit discount rates have any relationship to the cost of credit, this model is tautological. Given any relationship between cost and efficiency, an implicit discount rate can always be computed. However, implicit discount rates may be just as subject to change as revealed preferences.

Recent analyses of residential appliance efficiency choice suggest that appliance holdings, taken together, have significant influence on individual appliance choices. In these studies, having gas space heating is linked to the likelihood of having gas water heat (see, for example, Goett, 1984). In other words, decisions on individual end-use technologies do not take place in a vacuum; they are affected by the presence of other technologies in the household.

Price response in the commercial and industrial sectors has received less attention from electricity demand forecasters than price response in the residential sector. This is partly because models for forecasting commercial and industrial sector energy use are more primitive than residential models at forecasting choices about the purchase and use of energy-using durables. Also, it has been presumed that decisions in the commercial and industrial sectors are more nearly "economically rational" than those in the residential sector. Evidence for this presumption is lacking. Indeed, anecdotal evidence suggests that decisions in these sectors are confounded by such factors as bureaucratic inertia and misplaced incentives for decision makers [Blumstein, et al., 1980].

DATA NEEDS AND OPPORTUNITIES

In order to respond to concerns about how rate structures affect demand, how energy and load shape impacts are related, and how consumers demand energy services, forecasters will need data in addition to what is currently available. At this time, a new generation of demand forecasting models should be evolving, but this evolution cannot proceed without better data. We briefly note three areas in which we believe additional efforts will be most useful: improving survey data, collecting data on self-generators, and analysis of short-interval (e.g., 15-minute), whole-building load data.

The first- and second-generation disaggregate forecasting models relied principally upon utility customer survey data, and to some extent the US Census, for information about appliance holdings. These so-called saturation surveys emphasized the physical enumeration of appliance holdings and the basic features of the structural shell of the building, with little detail on the attributes of the residential household, or of the way a particular commercial enterprise makes its decisions. New forms of end-use models, which improve upon existing models in their realistic simulation of decision-making, require better data. Recent research into contemporary residential survey techniques finds that improved reliability can be obtained at no greater than current cost [Pettigrew, et al., 1988]; however, additional confirmation is required.

In California, self-generation has already become a significant force in the supply mix. Accordingly, resource planning should focus upon total electricity consumption, rather than just on utility sales [Jaske, 1988]. To prepare such forecasts, sources of data beyond those readily available are necessary. For example, information about self-generator electricity production and contractual arrangements is needed in order to describe aggregate electricity consumption, rather than just utility sales. The CEC is engaged in a rule-making proceeding in order to ensure that all electricity producers and consumers contribute to the information base used by the state for energy planning.

Understanding customer response to changes in rate design is complicated. Tariff components have shifted to emphasize on-peak and standby charges rather than energy charges, and demand-metered customers are being exposed to price signals quite different from what they have experienced in the last decade. To date, few utilities have performed the end-use oriented load research metering needed to understand how customers currently use energy and might respond to, among other things, new rate designs. The primary reason is the high cost of metering individual end uses and obtaining detailed information on customer equipment holdings.

Currently, the most readily available data consist of short-interval, whole-building load data, which are routinely collected for billing purposes or for load research in support of cost-of-service studies. Analytic techniques for whole-building or end-use data are still primitive. Very little analysis has gone beyond extracting seasonal load profiles, as is typically done for end-use model development purposes.

We are encouraged by recent research on decomposition of whole-building load research data into constituent end uses [Akbari, et al., 1988 and Schick, et al., 1988]. We believe that, if these these decomposition techniques can be validated, analyses can proceed at reduced cost compared to the traditional metering of individual end uses. While this promising research continues, forecasting model developers will have to be content with the data presently available.

NEXT STEPS

More decentralization on the supply side, more centralization on the demand side, radical changes in rate design, and difficult methodological challenges -- all of this leaves the field of electricity demand forecasting uncertain. Workers in the field should be re-evaluating strategies and planning new initiatives. Part of our purpose in preparing this paper was to present some ideas to stimulate this process.

A second purpose in preparing the paper was to propose some initiatives of our own. In particular, we see a need for renewed commitment to forecasting research and development. The late '70s and early '80s were years of vigorous research and development activity. State and Federal agencies and many utilities were busy with the development of new forecasting tools. Much of this activity has subsided as model development has given way to forecast production. The nation's electricity systems will be ill-served, if this trend is allowed to continue.

We have identified the load shapes, effects of rate structure, consumer behavior, and a variety of data as areas about which we need to know more. A number of other topics also deserve attention. Examples include:

- better methods for quantifying forecast uncertainty;
- models that are more flexible and easier to use;
- better methods for forecasting self-generation;
- improved understanding of industrial technology choice;
- definitive methods to determine total commercial floor space; and
- information about prospects for future energy services.

This is, of course, only a partial list (see, for example, Jaske 1985).

The foregoing can be read as a plea for more money to be devoted to forecasting research and development. We make this plea without apology. The stakes involved in electric utility planning decisions are enormous. Relatively small investments to make better informed planning decisions will almost certainly yield high returns (see, for example, Gellings and Swift, 1988).

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