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Proceedings of the Workshop on Electricity Demand Forecasting by State Agencies

Robert B. Shelton
Colleen G. Rizy
Ruth J. Maddigan
Darrel Nash

Prepared for the
U.S. Nuclear Regulatory Commission
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PROCEEDINGS OF THE WORKSHOP ON ELECTRICITY DEMAND FORECASTING BY STATE AGENCIES

February 23, 1982
Washington, D.C.

Robert B. Shelton
Moderator of the Workshop

Colleen G. Rizy
Editor of the Proceedings

Ruth J. Maddigan
Darrel Nash
Workshop Coordinators

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ABSTRACT

This report documents the proceedings of the Workshop on Forecasting Electricity Demand by State Agencies. The workshop was organized by Oak Ridge National Laboratory in cooperation with the Nuclear Regulatory Commission. It was held in Washington, D.C., on February 23, 1982.

The workshop was intended to bring together representatives of state energy offices and public utility (or service) commissions to discuss electricity demand forecasting methodologies. As the proceedings of the workshop, this report is a valuable source of information for forecasters of electricity or energy demand in general. The insights into many of the problems, solutions, and experiences of demand forecasters are found in this report.

MR. SHELTON: Good morning. My name is Bob Shelton. I am head of the Economic Analysis Section at Oak Ridge National Laboratory.

On behalf of Oak Ridge National Laboratory and the NRC, I would like to welcome you to this workshop on Forecasting Electricity Demand by State Agencies. It's our goal this morning to bring together forecasting practitioners in order to facilitate a discussion of forecasting methodologies currently being used by public utility commissions, state energy offices and other state agencies.

As many of you know, both the Lab and the NRC have a continuing interest in the objectives of this workshop. Economists at the Laboratory have been involved in modeling energy demand for over 10 years, and we have worked extensively with the NRC in the development of state-level and service area-specific models of electricity demand, and this will be presented to you in a few moments. Our work has become much more closely tied to state agencies over the past year.

NRC's interest in the subject has grown out of its mandate to assure that independent need-for-power assessments are included in the evaluation of nuclear power facilities' construction licenses. We hope that the workshop will highlight, not only the strengths of current approaches, but also the areas which require further research.

Basically, we have the session divided into two parts. This morning's session will focus on econometric modeling; we will include presentations by the Lab, Colorado, Maryland, New Mexico and West Virginia.

This afternoon's session will focus on end-use modeling. We will have presentations from New Hampshire, Wisconsin and Oak Ridge. Unfortunately, our California representative will not be with us due to illness, but we will try to perhaps pick up some of the issues that Mike Jaske was going to talk about in some of the other discussions.

Our presentations unfortunately are going to have to be short. What we would like to do during these presentations, though, is convey to you general information which will permit you to discuss during the discussion session some of the issues brought up during the presentations in greater depth, recognize the individuals involved in particular activities that interest you and follow this up either on a personal basis or in writing at a future date. Because we have a very tight schedule, I will ask you to please hold your questions and comments to the discussion period.

Certainly in our region of the country right now, where TVA is making various forecasts, and several nuclear power plants rest on those forecasts, involving billions of dollars, you can understand the feeling of risk involved in making these projections.

Our first speaker this morning will be Darrel Nash. Darrel is the leader of the License Relations Section of the Office of State Programs of the Nuclear Regulatory Commission. Darrel has been with the NRC since 1973, and has been involved with the analysis of topics related to environmental impacts of nuclear power plants.

Darrel has authored numerous publications in the area of cost analysis of energy alternatives. Darrel will lead off the presentations this morning by discussing NRC's interest in state preparation of need-for-power assessments for NEPA purposes.

MR. NASH: I would like to welcome you this morning, and I'm very pleased to see you here. We have a rather tight schedule, as Bob said. We want to cover a lot today, but hopefully this tight schedule will bring forth our best efforts, and we won't be wasting time.

We weren't sure, when we really got this thing off the ground a couple of months ago, that we could succeed. We were not sure we could get people interested in being speakers at the workshop, and we wondered if anyone would come if we held a workshop. As plans progressed, we were very pleasantly surprised that we were able to get a good group of speakers, and we were overwhelmed by the number of responses to our inquiries as to whether people would be interested in attending. So we're very pleased to have all of you here.

So we have somewhat of a common basis for proceeding with the workshop today, I am going to start by giving you some of the background of where NRC has been on the need-for-power issue and where we are now.

The NRC does its need-for-power assessments as the result of the National Environmental Policy Act, which was passed more than a decade ago. Everyone probably knows it as NEPA. This Act requires that agencies determine that there is a need for the project. In the language of NEPA, there is a requirement that alternatives to the proposed action be considered. One of the alternatives is not to proceed with the proposed project; therefore, we have to show that the project is needed, and that's where forecasting comes in.

As an aside, all the Federal agencies that do NEPA reviews are required to make a finding of need for the project, and they all do this. There's a variety of different ways of doing the review, and there is substantial latitude among agencies as to how they approach this, but in each case, ultimately, the agency itself is responsible for finding that there is a need for the project.

When NEPA came along, NRC—or, AEC in those days—didn't have any formal means of forecasting electricity demand. So we relied on the assessment by the Federal Power Commission, which is now the Federal Energy Regulatory Commission. We got started developing some capabilities in the early 1970's. I think more than anything else, the Arab oil embargo in 1973 and 1974, along with the subsequent substantial increase in oil prices, created a lot of concern in general for energy-need forecasting. For the NRC, this was expressed by two or three Atomic Safety and Licensing Board decisions which, in effect, required a more systematic and economically based review. NRC responded basically by using the results of major studies, particularly the Project Independence studies. After a time, we contracted with Oak Ridge National Laboratory to develop an economic model to do electricity demand forecasting.

Basically, the geographic unit of their model is state level, thus the name "SLED," as you'll hear about more in a few minutes. There are several variations on SLED as it has been further developed through the years. The capability is essentially developed to service-area forecasting. There are many other capabilities of the model, which you'll hear about shortly.

I think it's quite important to understand the approach that NRC takes in our need for power assessment. We essentially take the forecast of the applicant (the utility that's requesting a license to construct a nuclear power project), as a point of departure. Next, we obtain a forecast from the Oak Ridge SLED model. Then we evaluate results from other models that may be applicable for that general region of the country. Finally, we assess the applicant's forecast in light of the independent forecasting that we've studied.

We don't in any sense try to replace the applicant's forecast with the Oak Ridge model, or other independent forecasts, but use the Oak Ridge model as a basis for review to help us understand whether the applicant's forecast is reasonable—not necessarily all of his assumptions—but where it comes out. We review the applicant's forecast and determine whether the Oak Ridge model essentially verifies or calls into question certain aspects of it. If we have disagreements as part of the licensing process, we go back to the applicant and ask him for verifications of his conclusions until we reach a point where we decide that the applicant's forecast, or the modifications made, are reasonable. So, it's not: "Here's our forecast, here's your forecast, and we like ours, so you're going to have to conform to ours."

Next, I will discuss the issues which have caused us to look for ways of more directly involving the states. Throughout the time that NRC has been involved with need-for-power forecasting, or "assessment," there have always been substantial questions with regard to how far we should go in reviewing utility planning. Also, there has been concern as to whether we are duplicating efforts by states and regional bodies in forecasting, and whether we should be relying more on state or FERC forecasts rather than getting this closely involved with the assessment as we do.

As early as 1975, there was a paper presented to our Commissioners outlining some of the problems and questions that the staff had with regard to how far our agency should be going in need-for-power assessment. There's been a number of formal papers presented since that time. So, throughout the last six or seven years, there's been a lot of interest in placing greater reliance on states. The question has been: how do we go about this? We've looked briefly at a number of different alternatives.

Various formalized cooperative arrangements were considered. One approach that we were taking a few years ago was to establish agreements with states, without reference to whether or not there were any licensing cases pending. The effort started with states which had assessment capability and were interested in working with NRC. We completed a formal agreement developed with the State of New York. They were to essentially do the forecast, prepare a write-up for our Environmental Impact Statement, and testify in the hearing. They would have been acting on behalf of the NRC as a contractor. But about the time that the agreement was finalized, New York stopped licensing nuclear power plants, so the agreement has never been used.

We talked with some other states, but nothing got as far as with New York, so that avenue hasn't been pursued any further.

A major question in placing more reliance on states is their capabilities to do the assessment. In 1977 and '78, NRC did a survey of state capabilities in doing need-for-power forecasts, as well as some other areas of NEPA reviews. Since that time, DOE has done at least two surveys that I know of, and has published their findings of state capabilities. Furthermore, several states, albeit fewer as time goes on, adopt applicants' need assessments largely without review. Thus, if we were to use such assessments by themselves, we would not have an independent review such as NEPA requires.

As I was telling someone this morning, I'm not sure at least of the current validity of these surveys, because in the past few months, particularly in preparing for this workshop, we've found that there's more capability in the states than the published surveys show; at least that's my impression. So the surveys are of substantial value, but aren't necessarily up to date.

This essentially brings us up to why we called together a workshop such as this. The approach we're now pursuing with regard to state involvement is not in the area of getting any kind of a formal agreement with the state beforehand, but when an application is in the pipeline, to work on a case by case basis to place substantial reliance on state forecasts, if the states have such capability. This would, depending on the dollars worked out with the state agencies involved, be something like we had planned for New York; in other words, doing the assessment, preparing the Environmental Impact Statement and testifying at the hearing. It would essentially be the state's project.

That doesn't end the story, however, because in the NRC's legal interpretation of the NEPA requirements, the NRC is ultimately responsible for the need-for-power assessment. We can place substantial reliance on states, but our staff has to be in the position of saying: "Yes, this is a valid model, and we can testify that the approach taken is acceptable in the trade, and this should give you a valid forecast." So, in a technical sense, we plan to place a lot of reliance on states, but, in a legal sense, it's still the NRC's final responsibility.

Getting to the specific purposes of the workshop, then, what we want to have is a basis for characterizing the models in terms of what kind of information we can get from them. So we're looking for primarily the panel members here, but also members of the audience to—after hearing the various presentations today—take a good hard look at them, not from the expectation that we'll say that this one is acceptable, this one is not, and here's the one we're going to use, and discard the rest. Rather, we want to see what the capabilities of the models are, how well can they responsd to or take into account changes in economic, demographic and social conditions. How do the models perform in responding to changes in technology mixes, technology of electricity-using devices? How they perform in terms of looking at alternative futures, for example, various growths in demand. One of the concerns in forecasting is that we never are going to get a "right" forecast; so the models should be able to evaluate the impact of error.

Finally, and this may be a sensitive issue for the practitioners themselves: what's the track record of these models as used in forecasting? It's great as long as you can talk about something in the future, but what has been the success in correctly forecasting based on using the models in the past? If they were good forecasts, were they right for the right reasons?

So this is what we at NRC would like to get out of this workshop, and we'll proceed with the presentation of the various models.

MR. SHELTON: Thank you, Darrel.

Our next speaker will be Ruth Maddigan. from Oak Ridge. Ruth has directed a project analyzing the demand of the rural electric cooperatives, and is currently involved in updating the State-Level Electricity Demand (SLED) forecasting model developed at Oak Ridge National Laboratory for the NRC.

Ruth originally came to the Laboratory as one of the Lab's Wigner post-doctoral fellows. Her presentation will focus on the use of the Oak Ridge SLED integrated forecasting system in need-for-power assessments.

MS. MADDIGAN: It's a real pleasure to be here and to see so many faces out there. As Darrel said, we were a little unsure as to what kind of response we'd get on the workshop, and we're so glad to have you here. We want to share with you some of our experiences with modeling, and to hear about your experiences at the state level in modeling. We hope to exchange information about the difficulties and the challenges and the excitement involved with forecasting electricity demand.

Today, I want to talk about what Oak Ridge is doing in econometric modeling of electricity demand. This afternoon, a colleague of mine, Dan Hamblin, will focus on the engineering-economic models that have also been developed in the Laboratory for forecasting energy demand.

One thing that makes economics so intriguing is that we don't approach problems in just one way; we manage to be able to look at problems in a lot of different ways and learn something different from each approach.

What I want to talk about in the presentation this morning can be organized into essentially four different topics. First, I will give a short description of the forecasting models and their interactions. I will not attempt to go into details about the methodological approaches, but we have several publications available that will give you everything you ever wanted to know about the SLED models. Those of you who would be interested in more detail can leave your name and address with me, and I will be happy to send you some of the publications on the models.

Second, I want to talk a little bit about the sample results from a case study that was performed at the Lab last year for a utility in Indiana. This simple example will show how the models link themselves together and how we use the state-level forecasts to develop a service area-specific forecast.

Then, a very short part of the talk will be on the weaknesses of the SLED system, and then I will highlight the strengths of the approach. I will end the talk with a description of some of the work Oak Ridge is doing this year to provide technical support in the transfer of the models to the states.

Slide 1 is a schematic that's one of my favorites; it gives a picture—a general overall view—of how the SLED model works to forecast state-level electricity demand.

Essentially, demand and price are endogenous in the model, so there are equations for sectoral demand and sectoral price. The model forecasts by sector; that means we have equations set up for the residential, commerical and industrial sectors.

To be able to simulate the forecasting model, one must input exogenous demand determinants—things like the growth rates in population, income, and manufacturing activity—and then electricity costs are also put into the SLED integrated system. Electricity costs are forecast in the Total Operating Cost (TOC) submodel, which I will get into in more detail in just a moment.

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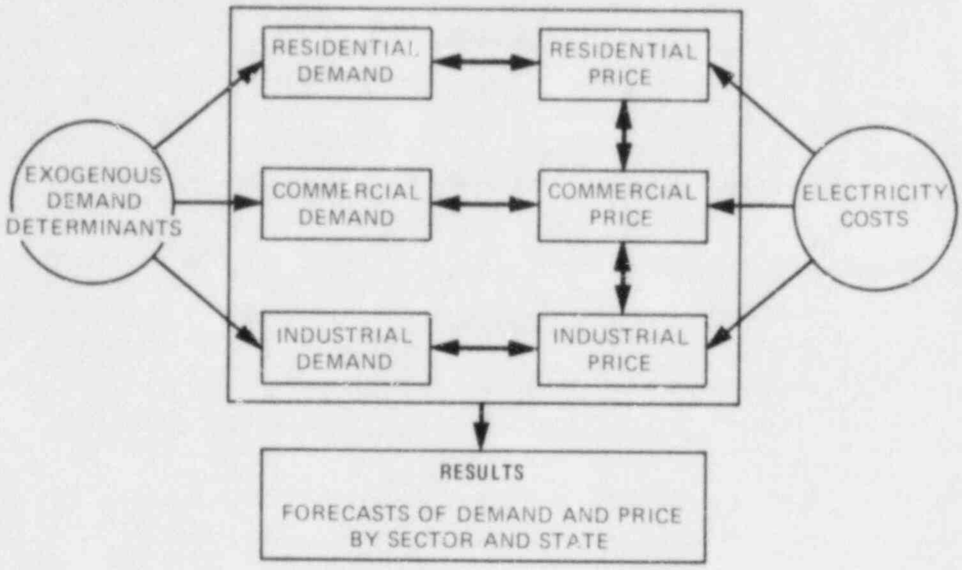
STRUCTURE OF ORNL REGIONAL ELECTRICITY DEMAND FORECASTING MODEL



SLIDE 1

This system of equations then results in forecasts of demand and price by sector and state; that's essentially what the SLED model will do for you.

As Darrel and Bob mentioned, we have been involved in this project for quite some time, and as all of you recognize, as you get more into the analysis of a problem, you realize that there are additional aspects of it that need to be examined.

This SLED forecasting model was originally developed in the mid-1970s, and it's a partial-adjustment model. Most of us, I believe, are familiar with partial-adjustment models, and familiar also with some of the hazards of using the partial-adjustment approach. As the saturation of electricity-using appliances in particular areas reaches its peak, using a lag-dependent variable may not be appropriate. But the model has performed very, very well in model validation exercises in which we calculate the mean square percent error. The model also does well in tracking post-sample-period demand when we have the actual values of the exogenous variables. One of the problems, of course, with forecasting is that when one forecasts, one uses projected values of population, income and the other input variables. This use is definitely another source of error in predicting electricity demand, and a hazard involved in forecasting.

As I mentioned earlier, demand and price are endogenous for the three sectors. The six equations are estimated using three-stage least squares with annual state-level data. Under the SLED framework, we estimate regional coefficients; these are estimated for the nine Census regions.

Now, recognizing that the partial-adjustment approach may be inappropriate in periods where the past historical development and movement in the saturation of electricity-using appliances are not expected in the future, the Lab has just recently developed the Varying Elasticity Model. This is affectionately referred to as "SLED-VEM." This version of SLED is still econometric, but appliance saturations are explicit. So we've developed a series of historical data: the percentage of households which use electric space heat and/or air conditioning and the percentage of homes, by state, which use electric water heaters and other appliances.

Then the model provides for the estimation of state-specific (rather than region specific) price and income elasticities. We essentially estimate a reduced form in which the own-price elasticity is in itself endogenous. States and the utilities which cover sub-state regions will have different price elasticities than the region as a whole. As with SLED, SLED-VEM provides estimates of demand and price.

These two models are essentially demand models, and they run with assumptions about the growth rates of the activity variables and the cost of electricity.

Because cost is such an important element of the SLED forecasts, it is necessary to analyze what total operating costs are going to be doing. The TOC submodel—the Total Operating Cost submodel—provides forecasts of average system costs consistent with the fuel price projections that we use with SLED. It's essentially an accounting model; it combines the shares of states' generation by fuel type with projected growth rates of fuel prices and capital costs to make a projection of electricity-generating costs. It's a simple model, but manages to capture the changes in cost that have been led by rising fuel prices.

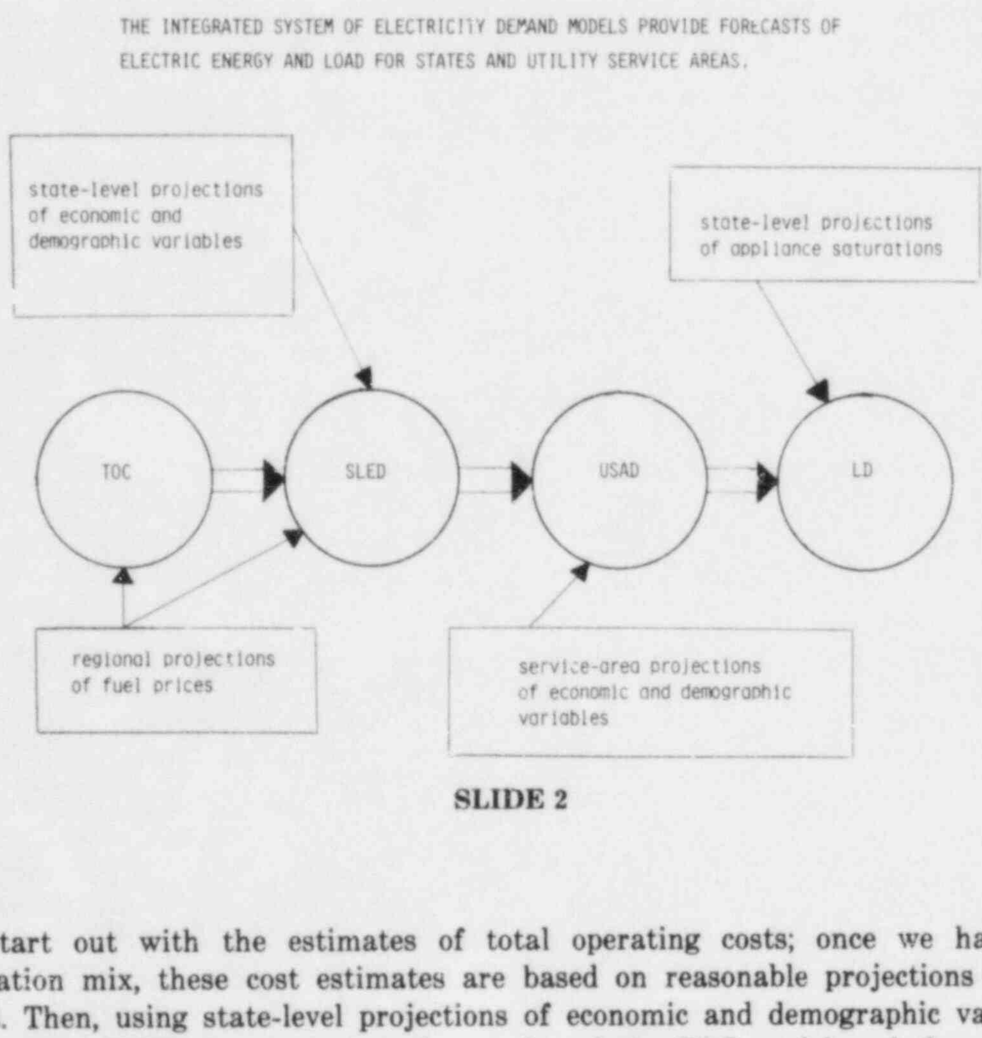
The model also reflects cost changes which are the result of changes in the state's generation mix. If states move more toward coal generation, TOC allows us to examine the effects that will have on their average system costs.

Now, I have presented how forecasts have been developed at the state level. That's what the three models I have just described focus upon. It was realized that there should be service area-specific forecasts also because a specific utility in the state does not necessarily grow at the average value of the state as a whole. A model developed by Rich Tepel, at the Lab, is the Utility Service Area Disaggregation (USAD) model. USAD is linked with SLED; we estimate parameters using the time series data from the service area in comparison with the rest of the state. So we use the information that we have developed from SLED to be able to enhance the information from the Utility Service Area Disaggregation model.

To forecast using USAD, we must estimate service area-specific economic and demographic variables. Now, those of you who have been involved in forecasting at the state level recognize that this is an extremely difficult task. One must use accounting data to make estimates as to which proportion of a county is served by the particular utility, and use these shares to develop population and income estimates for that particular service area.

USAD then provides forecasts of electricity demand and price by sector. Then, recognizing that, occasionally, what we really need to do is look at capacity needs, we turn to another approach that goes beyond kilowatt hour demand. We just happen to have a Load Duration model. It is linked with the Utility Service Area Disaggregation model. To be able to run this model, we have to have access to tapes of hourly load data; we estimate maximum and minimum load, and then provide a forecast of the load duration curve.

Now, that went by pretty quickly, but I happen to have this picture of the model's interactions (Slide 2), and I'll show you exactly how it works.



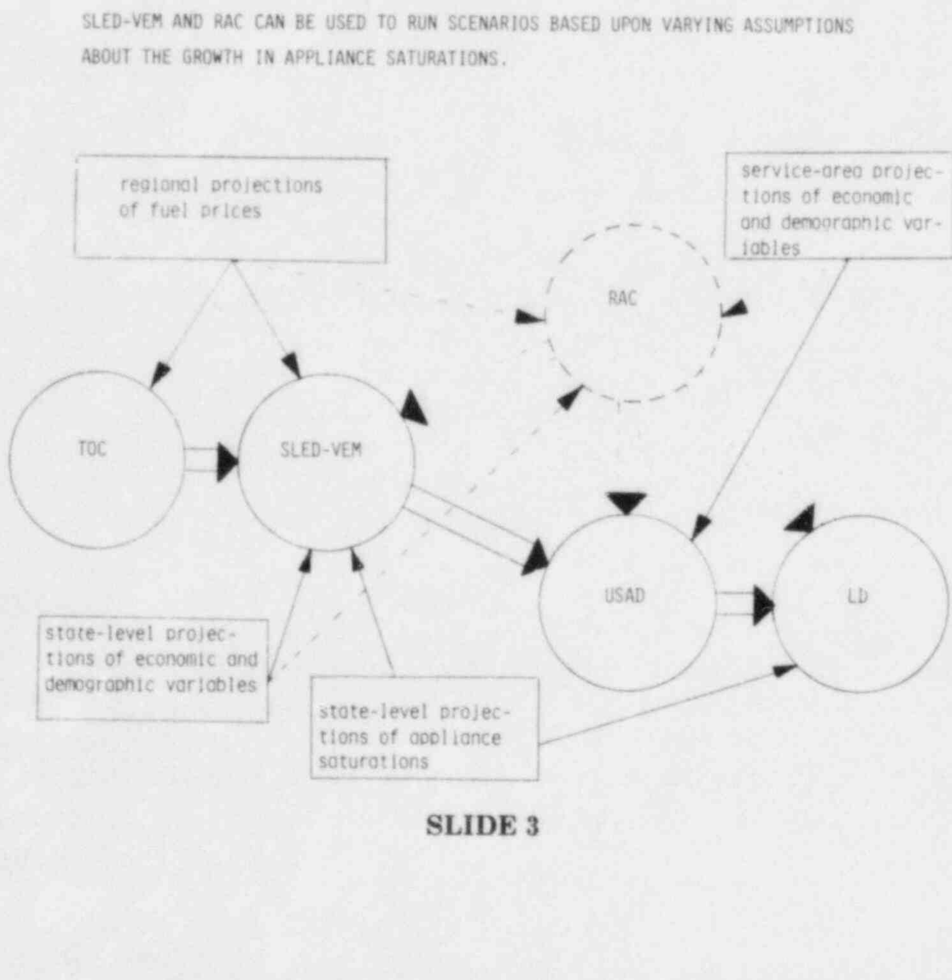
SLIDE 2

We start out with the estimates of total operating costs; once we have the generation mix, these cost estimates are based on reasonable projections of fuel prices. Then, using state-level projections of economic and demographic variables, we can run SLED, incorporating the results of the TOC model and the regional projections of fuel prices. Then SLED feeds into the Utility Service Area

Disaggregation model. Again, to be able to run USAD, we must have service area projections of economic and demographic variables.

Lots of times, it is interesting to be able to run alternative scenarios. For example, even though national growth trends in population may be something that demographers can project with some reliability, regional projections are very difficult to project. It is difficult to anticipate the movement of population among the states. Then USAD feeds into the Load Duration model, and here we need state-level projections of appliance saturations. Now, we are currently involved in this area as we update our modeling efforts.

Slide 3 shows that model development efforts have been directed toward the estimation of the Residential Appliance Choice (RAC) forecasting model. This model could be used to forecast what those appliance saturations are going to be. These forecasts can be input to the SLED-VEM model. Remember, the appliances we are concerned with are space heating, water heating, and air conditioning. The estimation of RAC has been based on the 1979 DOE customer survey data; it's estimated using a multinomial logit approach, and forecasts from a simulation of this model, once it has been completed, can be used as an input to SLED-VEM and USAD.



SLIDE 3

The RAC model has been estimated, but we do not have it ready yet to make forecast simulations. That's why RAC is surrounded by dotted lines in Slide 3.

You can see how many linkages RAC manages to add to the modeling system to complicate our lives. The TOC model will still be input into SLED-VEM, state-level projections of economic and demographic variables, and regional projections of fuel prices will be used consistently across TOC and SLED-VEM.

Then the RAC model will be able to produce for SLED-VEM the state-level forecasts of appliance saturations. This is something that is very crucial to the consistency of the estimation of SLED-VEM.

Notice that the RAC model is also consistent with state-level projections of the economic and demographic variables. Then SLED-VEM can be input into USAD.

Now, I have a double dotted line here between RAC and USAD because we anticipate that the forecasts of appliance saturations that we can get from the RAC model can be used in the specification of USAD. We have not done that yet, but it makes a lot of sense. Research into this area is going to be part of our modeling development.

The SLED system is becoming increasingly complicated, but we believe it is focusing on important issues that should be examined in the analysis of electricity demand.

Now, I want to change gears and talk a little bit about the recent case study performed about a year ago. Larry Hill and Colleen Gallagher worked on this particular case study, and it highlights the very simple fact that state and service area-specific forecasts can be different.

This analysis was based on NIPSCO—the Northern Indiana Public Service Company. This utility provides electricity service to 19 counties in Northern Indiana; it also sells natural gas in Indiana. The majority of its sales are in the industrial sector; this makes it really intriguing and very, very different from the state. NIPSCO's percentage of industrial sales has been growing; it was 66% in 1965 and 73% in 1978. For Indiana as a whole, the industrial sector accounts for less than 50% of the total sales. These differences made the analysis even more fun.

Hill and Gallagher were able to look specifically at the industrial sector, and bring to bear more detail on this sector than we would in another case.

Now, NIPSCO shows higher overall growth under the three fuel-price scenarios due to the high growth in industrial sales. This was relatively interesting.

For the state of Indiana, the historical growth rates between 1965 and 1978 were 7% annual growth in the residential sector; commercial was 6.7%; and industrial was

6.2%. The total growth rate for the 14 year period, which is the historical period we used to estimate USAD, is 6.5%.

NIPSCO had been growing faster overall than had the rest of the state over the same period, at 7.5%. NIPSCO's industrial sector was distinguished by a very high growth of over 8%. Our forecasts for NIPSCO are lower in the residential sector than for the state, less in the commercial sector also, but higher in the industrial sector.

The range of forecasts for NIPSCO, for the period 1978 to 1990, are between 4.5 and 6.2%, depending on the fuel-price scenarios. We ran fuel-price scenarios here, but of course, if we got carried away we could run scenarios on demographic variables or on other ranges of the exogenous variables.

The NIPSCO example highlights the importance of the interpretation of the model's results. It is very important that the analyst who is working with the model have some sort of feel for what's going on in the state, and for what the future of that state is, because numbers can only tell you so much. This is one of the problems that I find extremely intriguing, in that the projections are definitely based on the input assumptions. At the Lab, we develop our projections using information from BEA and other sources.

It is crucial to examine different scenarios to see what the sensitivity of the model's results can be to different input assumptions and how far off you think some of those input assumptions might be.

One must highlight another caveat that arises with the use of econometric models with stationary coefficients. One must recognize that there is potential for structural change over the forecasting period, so that the coefficients which were appropriate over the historical period may not be the ones that reflect future relationships. That is one of the reasons why it is so important to continually update econometric models, to provide additional information as it becomes available.

Also, there is the problem of error in variables where historical data is estimated. For example, for the utility service area, one can not go out and get an absolutely, 100% correct count of the population in the service area, so even in the historical data we make some estimations as to what that population actually is.

Now, the major strength of the integrated system—I told you I'd get to the strengths—is that it incorporates the interactions of the important demand determinants to estimate kilowatt hour and kilowatt sales growth. Perhaps this is what's most valuable about a model. A model helps us see linkages, to examine the interactions of all of the variables considered to be important, and to estimate the forecast in electricity demand based on these interactions.

Very importantly, modeling facilitates the analysis of alternative scenarios. It allows us to ask the "what if" kind of questions, and it highlights those variables which have the greatest impact on electricity demand. This is especially valuable at the service area level; for example, in the study of NIPSCO, there was a very strong emphasis on the modeling of the industrial sector. Another advantage of the SLED system is that it provides a perspective on the regional differences in growth.

Now, as Darrel mentioned, there is an interest in working with the states in the area of forecasting electricity demand, and currently, ORNL is working with NRC in the transfer of the SLED models to interested state agencies.

We've been working with several states already. Joe White has been working with us in the transfer of the SLED models to New Mexico. We've also been working with Arizona and Oklahoma.

Now, the transfer process, as we are currently developing it, as our experience increases, includes the provision of computer tapes which have the models and data on them, the documentation of the methodology, and user's manuals. Oak Ridge has numerous Technical Memoranda and other types of material that explain the methodology, and it would be possible to replicate the models from these. But it's much easier if you have a user's manual and a computer tape, believe me.

Oak Ridge is also going to be providing technical assistance to those states who need some help getting the tapes on their system, and in running the first case studies to make sure that the states can work with the models.

The Laboratory is continuing to update the models, and we will be providing those updates as they become available.

MR. SHELTON: Thank you very much, Ruth.

Our next speaker this morning will be Carl Hunt, from Colorado. The title of his paper is: "Data Base Development and Econometric Forecasting."

Carl is the chief economist of the Colorado Public Utilities Commission (CPUC). Carl has had published articles dealing with a wide range of issues, including an analysis of the welfare impacts of changes in residential telephone prices and an investigation of the short-term economic consequences of the Mt. St. Helen's volcanic eruptions.

He's currently involved in the development of econometric approaches to modeling the demand for electricity and natural gas.

As I say, Carl's presentation is entitled: "Data Base Development and Econometric Forecasting."

Carl?

MR. HUNT: The forecasting effort in Colorado actually has just started. It began the latter part of 1980 in response to a legislative mandate and subsequent allocation of funds to fulfill that mandate. Colorado law now requires that the CPUC prepare an energy forecast for the state and that the forecasts be presented to the legislature every two years.

The first report, which forecasted energy demand from 1981 to 1990 for each utility, was presented to the legislature in December, 1981. A reasonably good job was done for a first effort. But more importantly, the approach to energy forecasting will permit improvement in the forecasts and our forecasting techniques with minimal effort.

Before describing the approach, I would like to take a moment to describe some salient features of Colorado and the utilities under the jurisdiction of the CPUC. These are important because the environment in which the CPUC operates may influence the approach and may result in problems peculiar to Colorado.

Colorado is a large state, covering 103,000 square miles. The eastern part of the state is high plains. The western part is rugged mountains. Two million of the state's three million people live in the front range, a 150 mile area just east of the mountains between Fort Collins and Pueblo (this includes the Denver metropolitan area). The other major population center is the Grand Junction area with a population of approximately 100,000. Most of the vast land area of the state is sparsely populated. Some counties with over 1,200 square miles of land area are inhabited by less than 1,000 people.

The CPUC has jurisdiction over 44 electric utilities. These range in size from 14 megawatts to 2,000 megawatts. Included in the 44 utilities are investor owned utilities, rural electric cooperative distribution utilities, a rural electric cooperative generation and transmission utility, and municipal utilities. Public Service Company of Colorado (PSCo), which serves the Denver area and other front range loads, accounts for 57% of the load in Colorado. The rural electric cooperatives account for 22% of the load in the state. The two largest rural electric cooperatives are Tri-State, which has 10 members, and Colorado-Ute, which has 14 members. Tri-State's generation is outside the state of Colorado and consequently outside the jurisdiction of the CPUC. Colorado-Ute's generation is within the state of Colorado and consequently within the jurisdiction of the CPUC.

Among the first decisions made by the CPUC in estimating the demand for energy, was the type of analysis to be employed. Econometric analysis was chosen because econometric techniques, in our opinion, would provide the greatest amount of information and richness per dollar invested. Given a different level of resource commitment, a different methodology may well have been chosen. Numerous other methodologies could be acceptable depending upon resources available, time frame of the analysis and information desired.

Once the methodology was established, it was determined that a data base should be created without regard to any particular specification of equations. A list of all of the data that would be required for virtually any specification using econometric techniques which could be imagined was made. This approach would not tie the estimates to any particular specification or technique and would allow the flexibility to experiment with different specifications. The specification and technique which best modeled a particular utility could then be chosen.

The data were broken down into two parts, socio-economic data and utility-specific data. After listing each piece of data that was thought to be useful, a process of culling the data series based on availability, completeness and quality was begun. In the process of culling the data, it was determined that any series used would go back to at least 1963. That did not present a serious problem for socio-economic data series, but numerous difficulties were encountered in developing utility specific data back to 1963.

Socioeconomic data was developed by county for each of the 63 counties in the state. The counties also were aggregated into utility service areas. In some cases, utility service areas are not precise because more than one utility is certified in a single county. Any aggregation error should be small, however, as major population centers are generally served by a single utility. Errors in aggregation will occur generally in the sparsely populated regions. The socio-economic data developed for each of the 63 counties are: population, personal income, per capita income, retail sales, gross sales, employment and number of households.

In addition, data from the various weather stations in the state on heating degree-days and cooling degree-days were gathered and included in the data series. The data series collected in dollar terms can be accessed in either real or nominal dollars. The data also can be accessed by either county or utility service area.

Utility-specific data were developed for each utility by major customer classes. The major classes are: residential, residential heating, commerical, industrial, large industrial, irrigation, street lighting and public authority.

Under each of these customer classes data were gathered on: total kWh, kW per customer, revenue, electricity price, price of gas, number of customers and average bill per customer. Again, all dollar information can be accessed in real or nominal terms.

The greatest difficulties were encountered in developing the utility-specific data. With the wide diversity of utilities in the state of Colorado and varying degrees of sophistication and accuracy in data collection by the various utilities, data collection priorities needed to be established. Efforts were concentrated on the three largest utilities and ordered by size. By modeling the three largest utilities in the state, 80% of the energy consumption can be captured. Some of the problems encountered in data collection were common to almost all the utilities, and some of the problems were common to certain types of utilities.

One problem that was common to all utilities was determination of price. The question of what price to use, marginal, average, if average how defined, is an extremely difficult question. The arguments are a thesis in themselves and will not be delved into here. The CPUC ended up using a crude measure of average price. Average price was used instead of the more correct marginal price because recent evidence indicates that results derived using marginal and average price are not significantly different and average price is much easier to determine.

Another problem common to all utilities was movement of customers between commercial and industrial classes. In one fairly small utility a movement of over 2,000 customers was noticed in a period of one year. Commercial and industrial classes have been combined as a short-run solution. While estimates on commercial and industrial class were generally unsatisfactory, estimates on a new category, business, were more acceptable. A longer run and more desirable solution for the major utilities is to find out which firms have switched and place them in the proper category.

Residential demand and residential heating customers were combined in many instances. The number of customers in each category was too small in many cases, particularly with the smaller utilities, to achieve satisfactory statistical results. Where possible, these categories should be estimated separately because of the large difference in average use per customer and differences in demand characteristics.

Another problem common to small utilities is missing data. Various pieces of data do not exist for one reason or another. In cases where a reasonable series is present before and after the missing data, the missing piece often can be estimated. In some cases, the data were so bad that certain series could not be used.

Analogous to the problem of missing data is the problem of glitches. Glitches are sudden aberrations in the data. These points were usually thrown out or estimated using the series.

A major problem encountered in estimating demand for generation and transmission cooperatives is the addition or deletion of distribution cooperatives. Where additions or deletions occurred, the data were adjusted so that the change would appear as if that were the case during the entire series. To date, the rural electric cooperatives have not been estimated individually. Only aggregations of the cooperatives have been modeled. Data on the distribution cooperatives are too spurious to obtain statistically reasonable results. Continued work needs to be done to smooth the data.

The econometric techniques used in the legislative report were simple and straight forward. The most common form of estimating total kilowatt hours was to estimate use per customer and number of customers. These two estimates were then multiplied together to obtain total kilowatt hours for each class of customer. Where satisfactory results were not obtained for these specifications, total kilowatts were estimated directly. Many different specifications were run for each customer for each utility. The specification for which the best statistical results were obtained was chosen for each customer class and utility. Thus, no single example of the equations estimated can be given. An example of some common specifications for residential classes would include: use per customer as a function of electricity price and per capita income; number of customers as a function of the ratio of electricity price to the price of natural gas and the number of households; and total kWh as a function of past consumption, electricity price and per capita income.

Those are merely examples of specifications used to estimate the demand for energy. A variety of specifications and techniques were applied to each customer class for each utility. The equation with the best fit and statistical significance was then selected to use in the forecasting effort. With a good data base and any one of a number of standard statistical packages, estimating a large number of equations is not an onerous task. Estimating a large number of equations can be beneficial in terms of increasing confidence in the estimations and increasing understanding of the econometric relationships.

Without going into great detail, some of the results obtained from estimations that were both retained and discarded may be of interest. Also of interest may be some unsuccessful techniques that may bear fruit with further analysis.

For example, price elasticities for most customer classes tended to be slightly higher than expected (still substantially less than one). Heating degree-days were not significant when residential and residential heating customers were combined. The majority of the households use gas for space heat, but even in areas where gas is not available, heating degree days tended not to be a significant variable. Dummy variables were used for pre and post 1973-74 embargo period. Little difference in coefficients was noticed. (Colorado primarily has coal-fired base load plants. Thus, the embargo did not have the immediate and severe cost disturbance as states with predominantly oil-fired base load plants.) In estimating the number of residential customers, a ratio of the price of natural gas to the price of electricity was used as an exogenous variable in some of the residential space heating equations. Where a choice between gas and electricity is available for space heating, the decision on which to use will be based in part upon the marginal cost or expected marginal cost of each. Once a decision is made, the consumer is locked in and not likely to switch unless a very large, sudden change occurs in the relative marginal price of gas and electricity. Some attempt was made to estimate demand based on total bill. The results were disappointing but should be pursued, particularly, where consumers receive one bill for gas and electricity.

The approach of developing a good data base has provided a number of advantages. It enhances confidence in the results when the estimations are statistically significant. It provides room for flexibility and experimentation in estimation techniques and specification of equations. While the CPUC has made considerable strides in estimating energy demand in the state of Colorado, continued effort is required if we are to take full advantage of what has already been done.

Data for the individual rural electric distribution cooperatives of Colorado-Ute and Tri-State need to be improved. For most purposes, modeling these cooperatives in the aggregate is adequate. However, for certain rate making functions such as issuing a Certificate of Public Convenience and Necessity (CPCN), estimates for the individual cooperatives would be beneficial. Recently a utility applied for a CPCN to build a transmission line. The hearing process showed that the line was larger than necessary. Without some estimates of load in the area in which the line was to be built, rate payers in many areas of the state may have had to pay for unneeded investment.

The CPUC has prepared peak-load forecasts for each utility in the state. The results of these forecasts have not been as satisfactory as the energy forecasts. The capacity forecasts have employed techniques using annual load factors. Peak-load forecasts will require additional efforts but are a secondary priority.

The quality of the forecasts depend upon both the estimation of coefficients in the econometric model and the forecasted independent variables. Thus, a priority project in the future will be to develop, in conjunction with other state agencies, a regional econometric model. The primary purpose of the model for the CPUC will be to aid the energy forecasting effort by improving the quality of forecasted economic and demographic data.

The CPUC also is in the process of developing a number of other models to tie into the energy forecasting models. Work is being completed on an optimal capacity planning model, an optimal transmission and distribution model and a regulatory accounting model for the major utilities in the state. For each major utility under its jurisdiction, the CPUC can estimate the amount and type of capacity and transmission and distribution requirements based on the utilities current configuration and estimated future energy requirements, and the CPUC can estimate the financial impact of the future load requirements on the utilities.

When looking to improve our state forecasting of socio-economic data—I don't know exactly what we can do there. We're trying to develop or purchase some regional economic models so that we will have better data, as Ruth said, to put into our forecasting models.

MR. SHELTON: If anyone in the audience wants to get in touch with someone else in the audience with similar interests, we'll have a list of names and affiliations of everybody who signed up. We will be happy to provide that information to anybody who would like to have it; they can write to us or just ask for it after the session.

Also everyone was supposed to pre-register. We understand that that was not always possible, but we can provide a list of everyone who pre-registered.

Our next speaker is Matt Kahal. He is a principal with Exeter Associates Incorporated, and has served as a consultant to the Maryland Power Plant Siting Program on load forecasting for the last four years. In addition to forecasting, he has been involved in the analysis of PURPA rate-making standards and the choice of alternative generation technologies.

Matt will present a review of the Maryland Power Plant Siting Program's econometric load forecasting methodology.

MR. KAHAL: Good morning. Before I get started, I'd like to correct one misstatement that was made by Darrel Nash earlier this this morning. Darrel indicated that load forecasts will never be right. I was right once. I forecasted correctly the peak load for the Allegheny Power System for 1981. One of my partners described that as purely dumb luck, but there's hope for all of us forecasters. Actually, it's embarrassing being right, because no one will believe you.

I'm here today to represent the Maryland Power Plant Siting Program (MPPSP). Many of you probably have never heard of the Power Plant Siting Program. It's an office of the Maryland Department of Natural Resources, and it has responsibilities for the power plant siting and licensing, and coordinating the interests of the various agencies in the State of Maryland on power plant licensing applications. One of its duties is to perform need-for-power analyses, which brings us to our topic for today.

The Power Plant Siting Program has been involved in econometric load forecasting since the early 1970's, which makes it one of the oldest state load forecasting programs in the country, and it's been, I think, a pretty successful program. I've been fortunate enough to have been involved with it since 1977.

The first study that Power Plant Siting did in this area was, interestingly enough, a forecast of PEPCO, the utility that serves the Washington area; and coincidentally, PEPCO at the time was attempting to license a nuclear power plant at Douglas Point.

Up until the 1970's, PEPCO had been one of the most rapidly-growing utilities in the country, and Power Plant Siting came up with the radical forecast, as a result of this econometric study, of about 4-1/2% load growth for PEPCO. I use the word "radical," because before the time of this forecast, PEPCO's annual load growth had been 9-10%. It was later concluded that PEPCO did not need the proposed nuclear plant at Douglas Point.

PEPCO shortly after that came to agree with PPSP's assessment, and today PEPCO is forecasting a load growth around 1% a year, which makes it one of the slowest growing systems in the country. So right off the bat, the Power Plant Siting found the econometric forecasting program that it had set up to be extremely useful, and it's been very useful ever since.

Two forecasts that I've been recently involved with—one with Delmarva Power and Light, which I'm going to talk about this morning, and the Allegheny Power System—have been used in power plant licensing and planning proceedings.

One of the very successful aspects of the program has been our ability to work closely with the utilities' forecasting personnel. We have been able to exchange information and ideas on methodology. In the mid-1970's, the Power Plant Siting Program and the utilities were very, very far apart, both on how one goes about the forecasting and on the actual results. Over the last few years there's really been quite a convergence, a convergence between the growth rates that we have been forecasting and the growth rates the utilities are forecasting.

We used to be substantially below what the utilities were forecasting. Our forecasts haven't been coming up; they've actually been coming down a little bit, but the utilities' forecasts have been coming down dramatically.

The utilities have come to adopt a lot of the methods that we've been using, and we've been able to play something of an educational role. I think that is perhaps the most useful role that a state program can play.

Let me turn now to the Delmarva Power and Light study. I listened with great interest to Carl Hunt's talk this morning as he talked about his data problems, because I encountered much the same thing that he did in the Delmarva study.

Delmarva serves, or provides about 95% of the power on the Delmarva Peninsula, but it only serves at retail about two-thirds of the Peninsula. The rest is served by a whole group of co-ops and municipals, and other very, very small, privately-owned utilities.

The Delmarva Peninsula is, you might say, "Balkanized" with respect to the structure of the electric utility industry, at least in retail. We decided that the only way we could model the Delmarva Peninsula was to ignore service territories and go out and collect both the energy data and the economic data for the entire Peninsula, since from a bulk power planning and supply standpoint, it really is one integrated unit.

We were not entirely successful. It was extremely difficult to gather all of these data, correct the definitional inconsistencies with the data, and so forth, for these smaller utilities. We succeeded with the larger of these small utilities, but some of these very small utilities were so small that they weren't reporting their data to anyone. Municipals in Delaware are not regulated, and therefore do not report to the State Utility Commission. They're even too small to report to FERC. I felt a little bit like James Michener doing research for *Chesapeake*, over there on the Eastern Shore.

Let me describe, in a little more detail, the methodology that we used. The DP&U study used about 20 or 30 equations to forecast electricity and peak-demand usage. The guts of the model were approximately 10 structural econometric equations.

Residential usage equations were estimated using pooled data, with the three states on the Peninsula as the cross-section units. The commercial and industrial models were estimated purely from time-series data, with separate models for each state. There are also models—really more statistical than econometric in nature—of other sales and energy losses. In addition to the econometric models themselves, there is also a demographic model which is a mathematical rather than an econometric model. There are saturation equations for air conditioning and space heating; weather adjustment equations; and summer and winter peak-demand equations. There are also some other minor equations that make up the forecasting system.

The econometric models which I described as being the guts of this model contain the usual kinds of determinants of demand that you might expect, factors such as income, wages, employment, population, electricity price, and so forth. Alternate fuels are not too important on the Delmarva Peninsula since there isn't much natural gas available, except perhaps in northern Delaware, around Wilmingston.

The models are dynamic; we used a lagged dependent variable, the partial adjustment type of model, which allows us to estimate both short-run and long-run elasticities. The elasticities that we obtained were approximately in the minus .3 to minus .5 range, which is, I'm sure, a bit lower than the folks at Oak Ridge have obtained for price elasticities. The wage rate cross-elasticity was slightly under 1.0, which I think is consistent with the literature on electricity demand. Thus, the wage rate cross-elasticities were found to be higher than price elasticities.

Generally, we obtained good statistical results from our models, measured by the R-squares and T statistics. However, the good statistical results that we obtained were never relied on very heavily to determine whether or not the forecasting equations are good equations. The criterion which should be used is whether or not the results make sense. You can obtain a .99 R-squared, but if your model is not intuitively pleasing, it should not be relied on for long-run forecasting purposes.

Well, I don't want to belabor too much the details of our methodology. If you are interested, you can get in touch with me; and I would be glad to send you copies of the studies that we've done, which document pretty carefully our models and methodology.

Instead, I'd like to turn, for just about five minutes—and that's probably about all I have—to some of the major problems and issues that are involved with econometric forecasting over the years that I've run into.

A frequent criticism that's made of the work that we do is that we rely heavily on pre-Arab Oil Embargo data. There's a belief on the part of many people that the world suddenly changed in October 1973, when the Arab Oil Embargo occurred, and that somehow, all of our history before 1973 is irrelevant and should be ignored.

In fact, the data base that we have been using in our studies has gone from approximately the mid-1960s through 1977. The reason for terminating in 1977 is that there's a couple of years time-lag involved in getting a county-level data, which is what we rely on. The result is that slightly less than half the data that we've been using are from the post-embargo periods, and the criticism that's raised is: how can your models possibly be used to forecast the future when you're relying so heavily on that old era, which does not represent how people behave today?

I have found that that criticism is just simply not valid. In fact, the models that we've been using explain behavior during the pre-embargo period and the post-embargo period with approximately equal accuracy. In other words, what's happened is not so much that human behavior has changed since 1973; it's the external forces that affect human behavior since 1973 that have changed. The underlying propensity of people to respond to changes in income, changes in prices, for businesses to respond to the cost pressures they face—that hasn't changed. From doing an analysis of the residual patterns in the models, we have found it works just about equally well for the pre-embargo and post-embargo periods. There has been no tendency for the model to systematically underestimate usage, perhaps, in the early period and overestimate usage, perhaps, in the later period. That gives me a lot of confidence in the use of the models for forecasting.

Although the models are sound, we would like to update them periodically. Our plans now are for doing a complete overhaul of each one of our system forecasts approximately every four years, and we intend to perform updates at least every two years.

If Power Plant Siting Program faces a licensing proceeding or something like that, then the forecast revision or update has to be made at that time. But the notion that you have to estimate your models from the most recent data is, in my opinion, not correct and is impractical. If you're going to use a model to forecast out 15 or 20 years, it makes no sense to say that your forecast isn't valid because you haven't incorporated 1981 data. If your forecast depends upon incorporating data that's less than a year old, then what good is it for forecasting out 15 or 20 years?

I've also found that our models, even though now they're based on a data base that only extends through 1977, work pretty well.

Let me move on to another problem that Ruth talked about. Econometric models, by their very nature, are models of unconstrained choice; in other words, they attempt to describe the way people will behave, given the choices and the incentives that they face in a free-market context. Energy markets are not entirely, from the energy users' point of view, free unconstrained markets. In the future, we can expect that energy usage will be affected by conservation programs that are independent of energy prices. It will be affected by time-of-use pricing, for which we have virtually no historical experience, and other policies such as the growth of cogeneration and other decentralized generation sources.

How do we incorporate this into an econometric forecast? We have tried to do it by just taking our results and performing some external stimulations on them, but I don't have any final answers.

There's one final problem that I want to talk about in regard to the accuracy of load forecasts. Our forecasts involve assumptions about the behavior of the economy, and the economy simply does not always behave as expected.

If an econometric forecast requires assumptions about economic growth out into the future, and if we can't forecast economic growth accurately, then what good is an econometric forecast? I don't really have an answer to that question; our experience in relying upon the Bureau of Economic Analysis's local projections has not been completely satisfactory.

I don't want to use this as an opportunity to criticize BEA. No one has been able to forecast very well, and I think one of the reasons why is that most economists tend to concentrate their forecasting efforts on the short run. There has been very little effort and very few resources expended on long-range forecasting. It is important that those of you working in the policy area and thinking about your needs impress this upon those responsible for long-range economic forecasting, whether it's state agencies or Federal agencies. A more intensive effort to understand the long-run factors that will affect economic growth is needed, because the econometric load forecasts have a clear need for reliable long-run economic projections.

Well, unlike Ruth, all I've talked about here are the disadvantages rather than the advantages of econometric methods. There are other people here today, perhaps, who can speak to the advantages. I'm more concerned these days about the problems than I am about informing everyone how well our methodology works.

MR. SHELTON: Thank you very much, Matt. Our next speaker is Joe White, from the New Mexico Public Service Commission. Joe has been with the Commission nearly two years and has been involved in the analysis of of rate design, the study of costs of service issues, and the forecasting of demand and supply. His duties have also included testifying before the Utility Regulatory Commission concerning rate designs and PURPA standards.

Joe will discuss the planning for the development of electricity demand modeling capabilities.

MR. WHITE: Good morning, my fellow crystal-ball gazers. The purpose of my remarks is to review the issues and concepts related to development of load forecasting capability at the New Mexico Public Service Commission.

In keeping with Bob Shelton's comment on the dangers of modeling, let me be clear that the following comments are the sole responsibility of the author and do not necessarily reflect the positions of the Public Service Commission or its Staff.

Over the last four to five years, load forecasting and related issues have received increasing attention from the Commission, New Mexico utilities, and other interested parties. For our purposes, load forecasting may be defined as the intelligent estimation of utility load requirements for a given level of plant. To date, all formal load forecasts have been performed by the utilities. Specifically, the Commission has used four vehicles to achieve this purpose: (1) the Commission's Capital Expansion Case; (2) the Commission's General Order concerning conservation efforts of gas and electric utilities; (3) plant certification cases; and (4) the traditional rate case.

With this dependency on utility load forecasting models, there has developed an increased awareness of the need for independent load research. This awareness is due to several forces. First, it became obvious that the initial analytical assumptions play a key role in the results of any analysis. Secondly, it became apparent that some major New Mexico utilities had poor or non-existent load forecast studies.

But load forecasts have increased in significance for other more important reasons. First and foremost has been the increase in costs, especially plant costs, which are passed on to the New Mexico ratepayer. Some of these costs have been environmentally related while others have had a financial history. Regardless of these reasons, these costs have increased and therefore are of concern to the Commission.

Second has been the recognition that the State, and hence utility service areas, are undergoing noticeable population growth. Many feel that this growth is due to New Mexico's excellent climate and wealth of natural resources. For example, the State is the nation's leading producer of the refined uranium ore used by the nuclear power industry. In 1978, New Mexico produced 47% of the nation's total output. Today, while that output has dropped to 35%, the State is still the leading producer of yellow cake in the United States. New Mexico also produces copper, oil, agricultural products and molybdenum. Historically, these resources have substantially impacted load requirements of the New Mexico utilities.

Finally, many utilities that serve New Mexico have increased both their power pooling agreements and FERC jurisdictional sales. Some feel that this trend will not only continue, but increase. The interplay of these power agreements and domestic energy needs has given rise to questions concerning the availability and cost of power to New Mexico.

Given this background, many analysts see a large number of potential load forecasting applications. These applications include the analyses of utility market structures. Such analyses will help determine responses to changes in price and the potential impacts of natural gas deregulation.

Second, load forecasting can assist in the analysis of potential demand and energy needs. These issues have vital roles in the certification of new utility plants as well as the development of billing determinant information for both the traditional and innovative rate designs. Billing determinants include such things as the number of customers by class, the kWh sales by class and the level of demand placed on the system by each class.

Third, models may help the policy maker when deciding on such issues as interstate sale of power or the merger of utilities and utility systems.

Finally, load forecasting may be used to determine exogenous variables for other analytical needs.

Once these broad uses of forecasting were evident, it was necessary to clearly define and prioritize such uses in light of the Commission's limited resources.

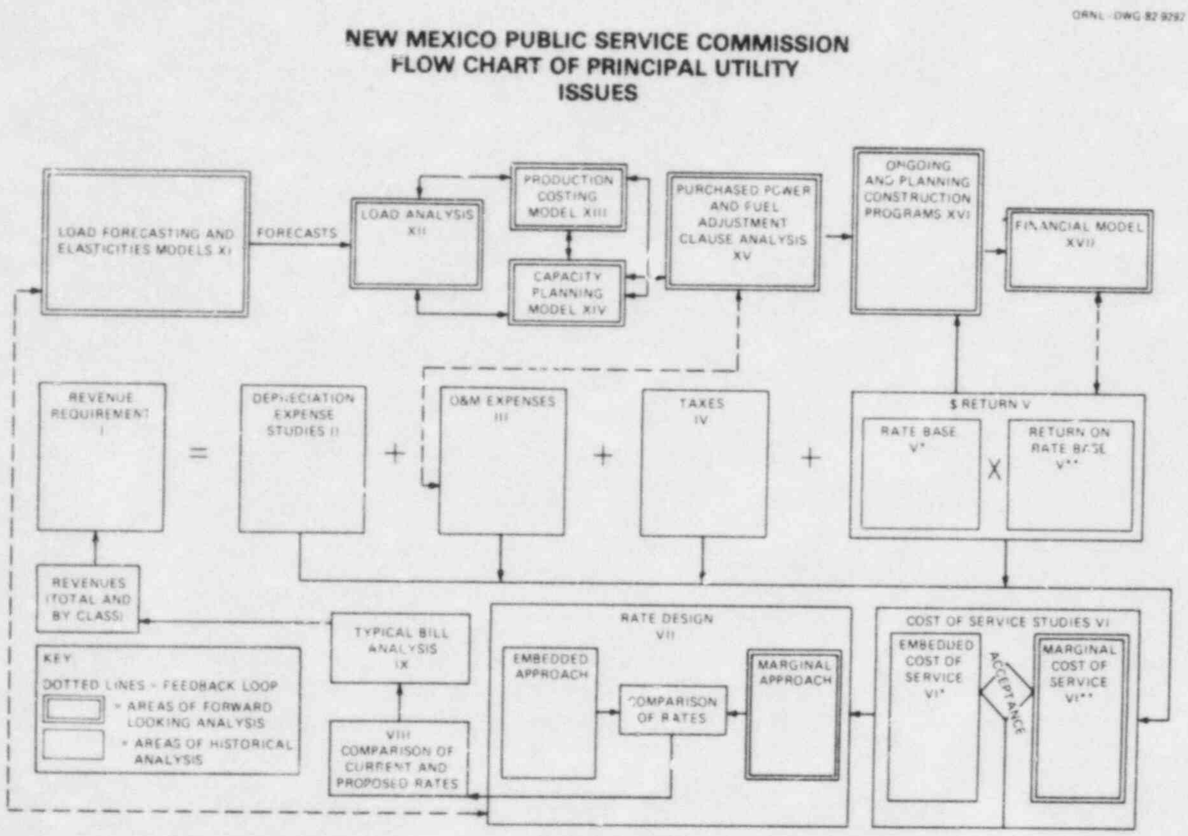
At present, an apparent, though informal, consensus has been reached. First, the staff will analyze those forecasts submitted by the utilities. These forecasts are used to analyze and verify the various conservation activities of the utilities, their plant certification requests, and to develop billing determinants, if possible.

Second, the staff will develop independent load forecasting models to better match the policy and technical needs of the Commission and staff.

Finally, after the staff agrees on certain technical concerns, it is hoped that the use of such a model can be used in conjunction with other analytical tools used by the staff.

Returning to the second point above, with the use of load forecasting analysis in conjunction with other models, the Commission has recently started an ambitious data-processing program. The goal of this program is the automation of those tasks now considered too time-consuming to be normally attempted, as well as the less exciting but all important day to day needs of the staff.

The result of this effort has been the acquisition of a family of models which may be organized as shown in Slide 1, a diagram of principal utility issues. Hopefully, over time, one or more load forecasting model can be integrated into this framework. Let us now turn to this framework.



SLIDE 1

The principal components of the revenue requirements of a typical utility are shown at the center of the diagram. These components include the total revenue requirements of the utility. This value is set equal to the total of taxes, O&M expenses (less depreciation), depreciation expense, and the product of the rate base and the return on rate base. These costs can then be analyzed through an embedded and/or marginal cost of service study. The results of these studies are then used to design tariffs for the utility in question. These tariffs are actually prices and therefore impact the amount of electricity sold by the utility. These consumption patterns, in turn, impact the capacity expansion plans of the company. The capacity expansion plan in turn affects the financial conditions of the utility. The financial condition then impacts the return requirements mentioned earlier, thus returning us to the revenue requirements issue.

Under this framework, load forecasts can be used with marginal or embedded cost of service studies. Forecasts of detailed demand and energy requirements could be used in the design of rates, the study of current and future production costs and, if necessary, in association with future test years cost of service studies.

While the acknowledgement and assessment of modeling needs may sound like a logical, step-wise process, we have found the process to be long, at times seemingly illogical, and full of stumbling blocks.

Stumbling Block 1: the parties using the models, for either policy or technical purpose, must clearly establish their needs and goals.

Stumbling Block 2: second and most importantly, the technical and policy users must combine their needs and establish a realistic set of priorities and time frames.

Stumbling Block 3: administrators must realize the resource requirements necessary to conduct and verify model studies. These requirements include: adequate staffing; acknowledgement of the time required to conduct such analyses; proper funding and support for computer tools; education of other staff members; establishment of the legal or regulatory procedures necessary to develop and analyze load forecasting and other models; and finally, acknowledgement of documentation needs.

Stumbling Block 4: the staff must integrate all modeling needs into a cohesive package. This integration process means many things.

First, staff must agree on the uses and applications of the models to insure that the analysis in any one is not jeopardized by the analytical treatment accorded other issues. For the load forecaster, this involves the determination of which type of forecasting methodology is most appropriate for a given analysis.

Next, the model users must insure that those data used by the models are of the proper magnitudes and that the minimum number of observations necessary for each model or application is available.

Finally, the staff must develop an array of load forecasting models which adequately address the technical and policy concerns of the Commission without (hopefully) necessitating the need of models specific to each of the State's 28 electric utilities.

Stumbling Block 5: finally, the staff will have to combat those reservations which have arisen due to the actual or perceived misuse of forecasting and simulation models.

Given these observations, I believe useful conclusions can be drawn from the New Mexico experience. First, administrators must recognize the resource needs associated with load forecasting and both the technical and policy concerns that must be logically integrated in such an analysis.

Second, the policymaker should recognize the consequences of inaccurate load forecasting or the lack of such forecasting and attempt to gain a complete understanding of the issues involved.

Third, the technical analyst must insure that all models, including load forecasting models, are accurately documented.

Finally, for those interested in the transfer of models, such models should be applicable to a wide variety of analytical concerns. New Mexico examples of these concerns include those of the policy maker and technical analysts as they relate to such topics as mining loads, oil field loads and irrigation loads. These models should also be compatible to a variety of resource constraints experienced by those wishing to acquire such models. These constraints include limited staff, funding, and short lead time for model implementation.

MR. SHELTON: Thank you very much, Joe. The continuous adjustments that you make as you go around the circle, in terms of the models and the output of the data, and making it compatible with the input to the next data or the next model—let me make the observation that after you've gone through this process for a while, the data become endogenous to the research.

The next speaker is Mark Wilson. Mark is a staff economist with the West Virginia Public Service Commission. As a staff economist, Mark's responsibilities include forecasting rate design and financial analysis.

Mark's talk this morning will be "Electricity Demand Forecasting Needs in West Virginia."

MR. WILSON: Good morning. The title of my talk is "Needs in West Virginia for Electric Forecasting." Our Commission has only been doing independent demand forecasts for two or three years, and I'll talk about three areas of those forecasts.

First, I'm going to discuss a few reasons why we feel accurate demand forecasting is important. Then I'm going to talk about our current capacity for forecasting, and a technique we've been using. Finally, I'll close up by talking a little bit about our needs and the outlook for fulfilling these needs in the future.

First, then: Why we feel demand forecasting is important.

The main reason we feel forecasting is important is that electric demand has been so erratic over the last few years, particularly over the last five years. In fact, in the 1960s, you could put a ruler to electric demand forecasting in West Virginia. You would have had a slope of 7% rate of increase in load growth every year, and that slope would fit your observations very well.

Since the oil embargo, that linear trend line has not worked nearly so well. In fact, now modern forecasts project a 3 to 4% growth rate. It's no coincidence that most of the people on the panel here are just recently out of graduate school and that, I think, demonstrates that forecasting is a new art, and something that hasn't historically been undertaken with the rigor that it has been just recently.

So the 1960s were basically an engineer's dream: build and build and build, and if they overbuilt, that was no problem either, because you could anticipate the load growth and grow right into increased expansion.

Moreover, the relative price of electricity was falling through most of the 1960s.
The 1970s, on the other hand, have been considerably different, particularly in West Virginia. As the economy in general has seen, there's been an increase in service-type jobs, and these jobs have a very low productivity growth, at least compared with historical growth in the manufacturing and extractive sectors. So real incomes since 1975 have stopped growing appreciably.

In fact, as most of you economic historians know, through every generation in the history of this country there's been a twofold increase in the standard of living. This pretty much stopped in 1975, and over the past 5 to 7 years, the real growth rate in Gross National Product was 1%, or something around there.

So the 1970s have been different.

Second, the relative price of electricity has changed dramatically in the 1970s. All energy-intensive industries have found that relative prices have gone up for energy resources. This has been because of inflation; not primarily, but that's been a major contributor.

We've found that in regulated industries, it's easy to pass on these increases of inflation; if your workers are asking for a cost-of-living adjustment, those are easily passed on to the ratepayer. That causes the relative price of electricity to go up.

The energy-intensive industries have also undergone the external shock of OPEC prices. We haven't been affected too much by that in West Virginia because we have predominantly coal-fired generation. But we've noticed it because the cost of coal has been driven up by the price of oil.

Finally, the rapid surge in demand in the mid-1970s has contributed to a tempestuous decade. We've found that the rapid surge in demand was also caused by an energy-related phenomenon, and that was the moratorium on natural gas hookups in much of the mid-1970s.

So the combination of this inflation, the moratoria on natural gas, and the changing relative price of electricity, has caused the 1970s to be a tempestuous decade.

At the end of the 1970s, our Legislature in West Virginia recognized that we were having a problem confronting the electrical utilities. We didn't seem to have adequate demand forecasts, while the utilities were continually overshooting their demand forecasts. So we needed some way to examine their forecasts and their expansion plans.

In 1973, the Legislature gave us a statutory obligation to do independent forecasts, and to address the Legislature annually and give them a supply and demand balance profile. So that's what we've been doing for the last three years.

Now to the next issue: current forecasting capabilities and techniques.

Well, we don't have a SLED or FRED or a RAM. I guess if I had to give it a name, I'd call it LINE; it's just a linear extrapolation of historical data, and we project that into the future.

Again, as you econometricians know, there are some problems with the trend line. The major problem is that it only considers two variables; it looks at time and it looks at the real demand, or demand changes in load growth.

So the biggest problem is that you're only considering two things and you're assuming what you project in the future is going to be the same as the historical experience. The way we come up with this trend-line approach is, first we scrutinize the electric utility's model, and this will give us some idea if what we project is anywhere close to the ballpark.

Currently we're considerably outstaffed by the utilities. Ninety-six percent of the electricity in West Virginia is served by three major companies. That's the Allegheny Power System, the American Electric Power System, and VEPCO. Of course, these companies have computers and models and staffs and everything else. All our Commission has is me.

Clearly they outstaff us considerably. I'm always impressed when I see 20 or 30 people doing the same thing I've done in half an hour. Of course this will change, and I'll talk about this shortly.

So we examine, in good faith, their models, and we assume that their projections are correct, and then we go one level further and do a complete cross-verification of all their input values. We get our economic information primarily from state agencies as opposed to county and lower disaggregated agencies. We engage in on-site visits to the utility, and this is primarily to talk to the people in forecasting and let them know that we're not in an adversarial posture. We just want to understand what they're doing, because often times, unless you show that you're non-adversarial, they will go over your head in a hurry, because they've got sophisticated, multi-equation models.

Okay. So we engage in these on-site visits and independent cross-verification of economic and demographic variables. After all this is done, we go ahead and do our trend-line analysis. Our trend-line analysis is both short-run and long-run, because we have to somehow account for the change in relative prices in the late 1970s. The way we do this is by taking a short-run, five years, and assme that that's the post-embargo shift to the new relative prices of electricity. We project that out into the future, a ten-year projection; that's the first step of the procedure.

The second step is to take the historical data of the past ten years. It's been mentioned earlier this morning that there hasn't been much change in the pre-embargo and the post-embargo response to electric prices. Of course this is true for an econometric model; however, it's not true for a trend-line analysis, because we can't incorporate relative prices in trend-line analysis.

We have to go back and take a broad historical view, and we find that the broad view gives us about a 5% growth rate increase. The narrow post-embargo years give us about a 3.1% growth rate.

What we do then, after the visits and after looking at the model and cross-verifying the inputs, and projecting our own values, is to see if these are radically different than what the utilities have estimated. And if they're radically different, of course, we try to make some reconciliations. In general, our estimates have been pretty close.

The final thing I'd like to talk about is our forecasting needs and the outlook for fulfillment of these needs. First of all, as I see it, we need a larger data base. So far, we don't have any regional economic information. We've looked at Wharton's model; we're thinking about bringing that on line, but there is, of course, a resource constraint there.

We would also like a bigger demographic modeling base. So far we get data at the state level, but that's usually not enough, because most of our utilities serve multi-state regions.

We recently increased our word-processing and computer activity by acquiring time-sharing basis on an IBM 370 computer. That's going to enhance our efforts considerably; we can stop punching things out on our TI55 calculators, and punch them in on a CRT screen. This will provide more sophisticated capacity; in fact, the capacity that we need to get the forecasting job done.

The outlook for this is very good. Like I said, in 1978 our State Legislature embraced the idea that our Commission needed this capacity, and they've appropriated the funds, and in fact, the staff for better forecasting.

Moreover, our Commission has a very favorable view of forecasting; they recognize the need for economists, most of them fresh out of graduate school, and they're going to continue to pursue that—hiring on bigger staff, increasing our data base and committing the resources that we need to do it.

So the outlook for West Virginia forecasting is favorable.

Thanks.

MR. SHELTON: Thank you very much, Mark. The next part of the the agenda will involve questions from the audience, and from the participants. The audience has been remarkably quiet, so I would like to open it up now for either A, questions, or B, comments.

We've seen this morning a wide range of activities in the states in terms of forecasting capabilities, and I think that was one of the things we wanted to highlight.

When you ask questions or have comments, I would appreciate very much if you would state your name and your affiliation, for our recording of the session this morning.

MR. KELLY: I'm Kevin Kelly, from the National Regulatory Research Institute. My apologies for coming in late, so this question may have been answered before I got here, and it's addressed to any of the speakers. How do you handle the difference in jurisdictions?

What I mean is that you may have a utility, for example, that covers more than one state, or several states, or you may have a holding company like AP, that services part of West Virginia, but may build more plants than apparently are needed in West Virginia, because presumably they're needed in some other portion of the AP system. That's one facet of the problem.

Another facet is that you may have a utility that is not under the jurisdiction of the state commission totally, and part of its sales go to municipal or cooperative utilities.

Do you state people then want to include those demands in your forecast, or only the demands for the jurisdictional area?

An addendum to it: how does SLED treat that? Does SLED look at some natural geographic area, or is it geared to look at a particular jurisdictional area?

MR. SHELTON: Why don't we start with Matt?

MR. KAHAL: Matt Kahal, the Power Plant Siting Program.

This has been a very serious problem in Maryland, because there are four major utilities serving the state, three of which are multi-jurisdictional.

We ran into this problem particularly in 1978, when we were going to do a forecast of Potomac Edison Company, which operates in Western Maryland. In our contract with the Power Plant Siting Program, it was listed in the work plan, and we weren't doing much thinking about it. Then when we actually looked at it, we realized that Potomac Edison was part of the Allegheny Power System, which also contains Monongahela Power, and West Penn Power.

Since planning is done at the system level for all multi-state utilities that I know of, we realized that we had to do a forecast at the system level, which tripled our work effort, and played havoc with our work plan.

So what we did was, we constructed forecasts for each of those three utilities: Monongahela Power, Potomac Edison and West Penn., and in each of the five states in which they operate—Maryland, Pennsylvania, West Virginia, Virginia, and Ohio. Forecasting has to be done that way; there's absolutely no point in doing only the part of the system that's within your state. And as a result, it creates a tremendous increase in the amount of work, and I must add that it's a compelling reason for states to cooperate. We've been trying to cooperate with the surrounding states, which also have jurisdiction over the Maryland utilities, and there are tremendous opportunities for sharing of resources, for sharing of information, and I think it's absolutely essential that that happen, if everyone is going to get maximum benefit out of the work that's done.

MR. SHELTON: Ruth, do you want to comment on SLED?

MS. MADDIGAN: Yes, that's a very, very important issue, as to the disaggregation of the utility service area data, to be able to look specifically at different states. It's definitely an issue that we recognize. It's important to recognize whether or not the data are available.

We did a service area forecast for Dairyland Power Cooperative, and Dairyland serves four states—Minnesota, Wisconsin, Iowa, and Illinois.

We were able to disaggregate the sales data, the distribution cooperatives, to get then state-specific disaggregations. The Utility Service Area Disaggregation model works with linkages with the SLED model, which provides forecasts by state, so when this is possible, we can make those kinds of separations.

The key is whether or not the utility can provide that kind of information; that is, state-specific. If not, when we have to work with sub-region areas, and then look at the utility as a whole, still aggregating, then, population and income information across states.

So it depends on whether or not the utility can provide us with information that is separated by state; if not, we have to look at the complete, for example, four-state region; look at, then aggregate the population-income-demographic type of variables, weather variables, to be able to encompass, then, the total region area. We definitely do not put our heads in the sand and say: well, this particular utility is approximately—mostly in Wisconsin, so it's all right if we forget the rest. Because you can't forget the rest.

The growth patterns are very definitely different by state, and those must be considered.

MR. SHELTON: Thank you, Ruth.

The climate certainly differs from region to region with regard to cooperation. I might ask Joe to comment on the West and California.

One of the big issues, of course, with the Western states has to do with the demand for electricity in California, and where that generation is going to come from.

MR. WHITE: Bob, you're right. Currently, the cooperation of western states, to my knowledge, has not been extensive, although I think there's a lot of interest in it.

Part of the problem, as I tried to address earlier, is the limited resources that we do have. However, that's not to say we don't think it's important.

For example, four of the five major industrial utilities in New Mexico have a large volume of either FERC jurisdictional sales, or other formal power-purchasing agreements between themselves and the utilities. We have found that the information can be critical in analyzing various issues that come up.

Recently, about a year and a half ago, the issue of a sales tax on power to California came up, for a variety of reasons—pollution, costs, political leverage by certain personalities in the state government. The result of that was a somewhat scanty but informative review of certain of these contracts, and yes, we do know we can play a role, and we'd like to find out more.

MR. SHELTON: Would any of the panelists—or participants—like to comment on the issue?

MR. LEE: My name is S. B. Lee; I'm with the Maryland Public Service Commission. To respond to to Mr. Kelly's questions: I just recently performed a generation expansion planning cost survey for the Allegheny Power System, which is the same system that you mentioned, which serves West Virginia, Maryland, Pennsylvania, and Ohio.

Now, I would like to separate the issue into two sides. Number 1 is the engineering issue. The second one is the financial issue.

From the engineering standpoint, when you're doing a capacity analysis and generation expansion planning, you have to look into the whole system. Therefore, you're required to make an econometric model of forecasting from the system standpoint.

Now, when you get into the financial standpoint, that means you want to allocate. Let's say APS is going to build a new power plant, and you have to allocate how many percentages to what state. Then the requirement would be: which state is going to need demand on what electricity? So therefore, the jurisdictional forecasts are company-wide forecasts. The parts serving Maryland or the parts serving West Virginia would come into the picture, because that would be useful to see how to allocate the costs to the different states and different jurisdictions.

MR. GRAHAM: I'm Frank Graham, Atomic Industrial Forum, and I would like to introduce another thought into the proceedings.

That is, long-range electricity forecasting is self-fulfilling. If you underestimate, then it means that the jobs and the increased productivity are going to move to an area of increased or excess capacity.

I think some people have called electricity the locomotive of economic development, and it's that thought that would indicate that you should have an excess capacity, if you're going to have economic growth.

MR. SHELTON: You sound vaguely like TVA.

MR. GRAHAM: It worked in TVA. We'd never have built Boulder Dam, or perhaps Bonneville Dam, on economic projections.

MR. SHELTON: I think what you say is very true, in a regional concept. I think that has been the experience in the Tennessee Valley. However, I would argue that's not true nationally; that what's true for a particular region in a particular time period is not true nationally.

We're talking about redistribution of basically income in the United States. If all regions have excess capacity, then obviously that's not going to hold true.

MR. SCHOENGOLD: David Schoengold, from the Wisconsin Public Service Commission, and I would like to comment with regard to that.

To some extent, if you underforecast and you underbuild, you may find yourself in a situation where you just cannot have the economic growth that you might otherwise like to have.

But conversely, if you do overforecast and overbuild, you are likely to find yourself in a situation where you've got to pay for that overcapacity. That drives your rates up, which makes it difficult for the economic growth which you might expect to have come in to make use of that excess capacity to develop.

The situation might have been different at times in the past, where you were facing declining costs with increasing production, and as you then overbuilt, you would then have declining costs; that would cause the increased economic growth. But when you've had the situation we're faced with now, where increasing growth, increasing production tends to drive costs up, it's not at all clear that the same mechanism that worked in the past will continue to work in the future.

MR. GRAHAM: But isn't excess capacity the cheapest capacity that you have? It's certainly cheaper than building new capacity, from what we can see in the future now, so having it there may attract the jobs and industry that you would be concerned with having.

MR. SCHOENGOLD: Not necessarily. If somebody else has—shall I call it an appropriate amount of capacity, as opposed to an excess amount, and they can therefore charge a more reasonable rate for their electricity.

MR. SHELTON: I think we're back to this general equilibrium problem. You know, what's good for one region may not be good for the country.

Yes?

MR. HUNT: Can I make a comment on that?

Part of what you're talking about goes back to, I suppose—as an economist, you have the same problem: what are the microunderpinnings of macroeconomics? Or what is the difference between short-run and long-run?

We know that there are differences. We know that there are microunderpinnings of macroeconomics, but we don't know how to get from microeconomics to macro, and it just confuses us.

In the short-run, we know there are qualitative differences between the short-run and the long-run. The long-run is not like the short-run, but how do you get from the short-run to the long-run? We don't know that.

We don't know where those switches take place, and what those switches are, and to some extent, I think what you're talking about is: how do you move from short-run to long-run? At this point, what you're talking about is probably true in the short-run, but maybe not in the long-run.

If you look at the United States in terms of energy consumption per unit of output, we're extremely high, much higher, for instance, than Japan and European countries. Part of the reason has been that our energy costs have been low.

Now our energy costs seem to be increasing, and we may see changes in our technique, so that we are conserving. We create capacity now not by building new generating capacity, but through conservation, and that's going to be a long-term process. Exactly how that's going to occur, where we get the switch from generating capacity through building, in the short run, and through conservation in the long run, is really anybody's guess. But I suspect that it will happen.

If you look at foreign countries, you can say that we can be much more efficient, and with increasing energy prices, it will happen. But how, I don't think we know.

MR. WOOD: I'm Anton Wood; I'm from the District of Columbia Energy Office, and we're just beginning the process that many of you have already undertaken. so I would like to get some sort of basic information which we hopefully can impart to our legislature, which relates to how much of a budget do you have in some of your states to operate these programs, and what are your staffing levels?

I'd be particularly interested in hearing from Mr. Wilson and Mr. White, and Mr. Hunt and Mr. Kahal, on the specifics of their programs in that area.

MR. SHELTON: Shall we just go around the table? This should be interesting.

MR. WILSON: I'm Mark Wilson, from West Virginia.

We just have two people who are fully engaged in forecasting activities. That includes both gas and electric forecasting, so we have one person per industry, really.

Like I said, the appropriations are increasing. We've got time-sharing computer access now, and we've gotten the appropriations to go attend conferences and spend the resources to shore this effort up.

UNIDENTIFIED VOICE: How much?

MR. WILSON: I'm sorry, I don't know the dollar figure.

MR. WHITE: My name is Joe White, from the New Mexico PSC.

In terms of load-forecasting, specifically, we're much like Mark and his outfit. We have lumped all of this under a model computer application, that unfortunately is extensive. I would suggest that you look at the computer CPU rates that your commission will have to work with, make a generous estimate of what you think it would be, and double that.

In terms of staffing for load-forecasting specific applications, we split it up between an engineer and myself; we have responsibility for all of the forecasts of gas, electric and, in a couple of cases, water utilities in our jurisdiction. The total number of utilities there is roughly 80.

Going back to the budgeting process, for load-forecasting analysis, we feel that the ideal situation would preferably be one person per type of utility—maybe more, depending on the number of utilities you have, the number of models. I can't think of the exact figures, but it seems like our computer budget, for the overall effort that I tried to explain in that diagram, is estimated at roughly $300,000 a year over the next couple of years.

MR. HUNT: Before we got all of our data out and were able to make some estimations based on the data—Mark's story kind of tickled me, where he was working with the calculator. That happened to us.

We were in a future test year that the Public Service Company had filed, and like I said before, they had this 180 some-odd equation model, 1000 some-odd variables, and were presenting this in stacks and reams of paper, and I was there with my HP41-CV calculator. Right? And you feel at a real disadvantage.

But I'll begin by stating what our budget was last year for our forecasting effort. It was $100,000; this year it's $65,000. That's been appropriated by the legislature.

We have one person—me—who is responsible for all of that, and a computer programmer who works part-time on our forecasting effort. We do the rest of the work through hiring consultants, and we have had varying numbers of people working as consultants.

I should say this is both for electric and gas forecasting, because we do both, and we have had as many as—at one time we've had as many as eight consultants working. We have one full-time—or, I shouldn't say full-time, three-quarter time contract employee— who is an economist, who works almost exclusively—has worked in the past almost exclusively—on forecasting of electric demand.

We have relied on the gas side on the energy consulting firm Energy Research Consultants, and they vary from having one to two people working on the gas forecasting part.

MR. KAHAL: Currently, we're doing a number of economic studies in addition to the forecasting for power plant siting, and we don't literally have a separate line item in our budget for forecasting, but I can give you an estimate.

Over the years we have generally spent something in the area of about $60 to $80,000 a year. That's not adjusted for inflation; that's a historical figure for forecasting.

But you have to take a couple of things into consideration there. One is that we've been doing it for a long time and we're very much up to speed on doing this. For someone, or an agency, who's in more of a developmental mode, and has a learning curve to deal with, it might cost them a good deal more than that.

Second, unlike a regulatory commission, which has needs for the use of a forecast in its regulatory proceedings, rate-making proceedings, power plant siting, since its purpose is only to deal with the certification and licensing situations, can go at a somewhat more leisurely pace, I think, than a regulatory commission, and as I indicated before, we try to do one major forecasting project a year.

Let me emphasize something else. I had talked of this a little bit earlier. All of this—the resource problem—underscores again the need for states with multijurisdictional utilities to cooperate, and I'm explicitly directing this to both Mark and Anton; let's talk about this, let's try to share our informational resources.

MR. SHELTON: Before we go on to any other questions, I would like anybody else who would like to talk about the activities, the level of effort in your states, to have that opportunity to so mention it now.

Is yours a question? Can you hold it just a second. Yes.

MR. SCHOENGOLD: Dave Shoengold from the Wisconsin Public Service Commission. We actually do something a little bit differently than some of the other people who have been talking. We actually do not specifically get into forecasting of electric demand of the Wisconsin utilities, but our role is more one of reviewing and critiquing utility forecasts. To some degree that, I guess, is a much less intensive role in terms of projects than the actual forecasting, but for informational purposes we, at the moment, have on the order of approximately 1-1/2 persons working on critiquing of what are, I guess, about five electric utility forecasts. We put in a request to our legislature for an additional person, and it was denied.

So of those five forecasts, we typically do a fairly good review, on about maybe three of them, the ones that are most critical, and the others that are either less controversial or more straightforward get sort of a cursory review.

MR. KANECH: I am Ron Kanech, with the Nebraska Energy Office. I'm the Manager of Research and Statistics, and we do forecasting. Last year we received a gracious budget from the Legislature and a ton of laws. I had two Ph.D.'s, two people with their master's and a programmer. We had a large staff, plus another guy and myself. We had one year to have everything done. Now we've lost our two Ph.D.'s. When you're given such a short time constraint and a lot of money for the whole agency to exist—our agency does many other things besides forecasting—it's tough to get data.

I hope that you can start small. Start with people who can collect data and know what your goals are. Then, hire the staff to begin to manipulate this stuff. You need a staff to know what to collect. I don't have an answer for it, but a lot of staff and a lot of money aren't the answers. It's time.

MR. SHELTON: One of the ways that some states I know have overcome some of these problems in staffing, and I'm not sure it would be appropriate for the district, and that's cooperation with universities, state universities. You receive funds from the state. For example, most state universities have bureaus of business and economic research that go under various titles, various names, and quite often these receive state appropriations which can be used to assist state agencies, and that is also sometimes helpful, also sometimes harmful.

MR. NASH: In listening to the various experiences of where people are at this time and getting some evaluation from them, particularly the ones who feel very resource-constrained, what you feel you need to get to is a situation where you can more fully interact with the utilities when they come in with their forecasts. Not that you're going to do a forecast which replaces theirs and then go with yours, but to have a capability, so that you can evaluate the forecast and make a determination as to whether this is something you should go with or work with further.

So is that enough of a question to get some response?

MR. HUNT: I'll respond to that. In our utilities, most of the people have several functions. One is what they call the litigation function. We testify, and the other is a research and advisory function. And the same thing happens, I think, in the forecasting effort. The forecasting efforts that we're making now are basically an advisory effort. We would use it in rate cases, but primarily what we've developed for use in rate cases is that the utility has to present a forecast that is auditable and that we will be willing to take the utility's forecast, provided that we can examine it and verify the methodology and see that it is a reasonable forecast. We don't want to get into rate cases. In the battle of forecasts, "Our forecast is better than your forecast; our R-squareds are higher than your R-squareds; our T statistics are better than your T statistics." We want to avoid that.

In forecasting, there's only one person I know who's made an accurate forecast.

So I wouldn't want to claim that my forecast was, in fact, better than anybody else's forecast.

So we want to look at, for ratemaking forecasts, the utility's forecast and examine that and use that as the basis for making our decision.

MR. SHELTON: Anyone else? Yes.

MR. KAHAL: I've worked extensively with the major utilities in Maryland on light forecasting over the last couple of years, and I've heard a lot of talk this morning about what utilities do. People feel a little intimidated, apparently, by the size of the staffs and resources that utilities have available to them by their 300 or 400 equation models that they have. You have to realize something, though. Yo can do the utilities a lot of good by doing an independent forecast. One of the problems that utility people have is that they're a little too close to what they're doing. They have a problem stepping back and taking a close look at it, and you can offer them some fresh perspective. So don't be intimidated by what they do.

What we have found in Maryland is that we've been able to teach them something about modeling. They've been able to teach us something about how their systems work, and we sit down and we listen to each other, and a lot of good has come of it. As a result, we have avoided the adversarial kind of situation, which I think is basically destructive. On the other hand, don't use the company's forecast as a benchmark for your own work. Don't take the attitude that "Well, I think what I'm doing is okay, because it looks like it's close to what the utility is doing." That assumes the utility is right to begin with, which defeats the entire purpose of what you're supposed to be doing.

So, work with the utility. I think states and utilities can learn from each other, but be skeptical of the work that they do. Unless you're skeptical of it, you're not doing either your state or the utility any good.

MR. WILLIAMS: I'm Gary Williams with the Mississippi Department of Energy and Transportation. In North Mississippi right now, we've got a situation where TVA is trying to decide whether to continue construction on the Yellow Creek Nuclear Power Plant. I'm just curious. I was wondering if there are any experiences in a situation like this where you've got a decision that has been made, and now you're trying to rethink that capability. I realize it's complex from the utility's point of view, in terms of their capital costs versus their future demand.

But I guess my question revolves around what is the process for updating your models and your projections and how often is it done, and how does it relate to a decision such as this, when you're trying to go back and reconsider a prior decision on future demand?

MR. SHELTON: I think that's a good question. Anybody want to tackle that one?

MR. WHITE: I guess I'll start. In New Mexico, we use those four vehicles I mentioned earlier, in terms of a continual effort, a conservation plan called a GO-33 is a biennial filing, which includes further detailed glove forecasting information which is filed by the staff. We critique that. If we find anything questionable in it, we notify the Commission and the authority, informing them if those aren't solved the plan is objected and they have to try again.

In terms of a case such as you're mentioning, we have no problem at all, with either the Commission, intervenors or the utility or some other party, entering in an independent load forecast in the process of reconsidering something. I think there is some evidence of that in a recent case involving a geothermal plant in New Mexico. I can't think of a case number. If you need a legal precedent, there it is.

MR. SHELTON: I think one of the interesting things is, there's sort of a phenomenon independent of the economics of the situation, that once you get these things going, given all of the uncertainties in any forecast, there seems to be a tendency not to shut down, not to close them down. I mean that's just the sense that I get.

But how about Colorado?

MR. HUNT: We are legally mandated to do a forecast every two years, which means by legislation we have to update it every two years. We plan on doing that annually, since it's almost as easy to do it annually as it is every two years. We don't currently have the problem of having overcapacity. We're a growing state. We have an adequate amount of capacity. We've improved the power pool adequately. So I can't really address the problem that once you have a plant and then the forecast changes, what would you do? We haven't run into that.

MR. SHELTON: Do we have anybody from a PUC that's currently undergoing the agonies of that decision?

MR. HOWELL: We might have. Keith Howell, Mississippi Public Service Commission. We don't have exactly the subject that has been suggested might exist,

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we have something very similar. And I'd rather not get into it right now. For many reasons, but we could be faced with similar problems.

MS. ALEXANDER: Barbara Alexander from the Texas PUC. We do have that problem. And I also wanted to add a question too. We came up with that problem in connection with the Palo Verde Nuclear Power Plant. That was when a group of us in economic research were first charged with evaluating the load forecasts just last year. My question is, the only people I heard mention three-staged least squares was the Oak Ridge group, and it seems—I don't know whether you all are the only ones that get into reduced form or simultaneous equations systems or more advanced forms of modeling. It seems like one person can do a trend analysis really easily, and I'm kind of wondering what it takes to get up to that level in terms of resource commitments. Everyone else seems to have two or three people, and I'm just wondering if that's the same for you all.

MS. MADDIGAN: Well, at Oak Ridge, we have a considerable number of people working in the forecasting area, including a computer programmer, but one of the key elements of being able to do two-stage, three-stage least squares is having a software package that will allow you to set up the structure and be able to make your estimation and to examine the residuals and look at what kind of tests you need to do.

So, you need to have competent econometric people involved in it, but you also need to have that companion capability of the software with computer system. So then, we've just been working with the multinomial logit approach to the estimation of the appliance saturation, and that has, again, been dependent upon increased capability of our computer software to be able to move in that direction to make consistent estimation in that direction.

Then we work with computer programmers to be able to develop the simulation programs which use the coefficients the economists estimate. Then we have graphs that give the details of forecasts of price and demand. And that kind of interaction with the computer scientists is extremely valuable.

MR. SHELTON: Basically, I guess there are two issues. One is the model development which is really the business we're in as opposed to model operation which requires much less in terms of the particular state involved. If you want to go out and develop your own model, you're in for a big effort, I guarantee you.

We kind of drifted off of the main question, and I want to make sure everyone has an opportunity who would like to comment on plant delays. Actually, we have a project that's not very far along now for the NRC, in which we're looking at the cost delays of nuclear power plants which, after it's completed and with NRC's blessing, we will be happy to supply then to anyone who would like to read it.

MR. HUNT: I'd like to comment on using some of these more sophisticated techniques. We've done some of that, and like Ruth says, primarily it depends on you don't have to have a large staff, you have to have at least somebody with some expertise in the computer programs, which are available in packages. I would suspect that for any state that has a major university, those programs are easily available. I think most states have. Our experience has been that using many of these sophisticated techniques did not give you any better results.

So what we end up doing is taking the simplest thing that gives us good results, and we are going to lose, particularly for gas, some sophisticated pooling techniques. I cannot describe to you the problems that we have with gas data. Electricity is wonderful compared to what we have in gas. And the polling programs, I think, are necessary, but we didn't do that if we had the data in the form that we had it on the electric side. We just haven't gotten much benefit out of sophisticated techniques, so we tend to use the simplest we can.

MR. ANDERSON: You asked if other people had the same problem as people in northern Mississippi. We do in Georgia.

My name is Tom Anderson, with the Georgia Public Service Commission. We deal with Georgia Power, which supplies a major part of the state. Integrated in the Georgia system is Oglethorpe, and some municipals as well, so we have the problem with dealing how we separate that out.

Of course, Georgia Power is owned by the Southern Company, which is the Southern Pool, so we have problems in integrating everything from Mississippi, Alabama and Georgia, and also in Florida.

The problem Georgia Power has is that in a few years they'll have nuclear plants coming on line, which started back before the oil embargo, so its primary question is: how does it dispose of its excess capacity?

That's sort of the question we're looking at, and people are responding to a proposal, or offering a proposal where we're going to examine that issue. But maybe the people in Mississippi, and I think there are some people here from Alabama, ought to let us know what you want to know. We're having a consultant do it.

Basically, what the staff does, in the past—and it has been done by the economists— but it's simply been some simple linear progression. Then we compare that with what Georgia Power does. Of course, as in the past, the staff has been amazed with what Georgia Power does.

We don't have econometric models, and we haven't had that kind of capability, and so my question is: what's the best approach, if you're starting from scratch, have a little bit of money you can spend, but not very much staff?

We do have access to university people: we do use them, will probably use them more extensively, but do we go the West Virginia route, or the Colorado route, or what sort of recommendations do people have?

Specifically, what things do you look at when you examine the utilities, the companies' approach? What biases should we look for? What recommendations can you give us where we can give them enough expertise, or something that would help them in improving their models?

MR. SHELTON: Maybe we should start—since this was partially directed to you, Matt, I'll let you take the first crack.

MR. KAHAL: First of all, I think that the answer to your question, Tom, depends in part upon the amount of resources that you have available, and that you anticipate having available. Fortunately, in Georgia you have an easier problem than some of the other states, in that you are dealing with fewer utilities.

For all practical purposes, you're only really dealing with one very large utility, which means that if you can satisfy yourself that the company is doing a good job with forecasting, then you might be satisfied with a program which only involves monitoring the activities of the company, evaluating their work and so forth.

In the case of Maryland, the legislature mandated that the Power Plant Siting Program prepare independent forecasts, because that clearly wasn't the case. The utilities were not up to snuff, and they weren't even serious about doing a good job.

That was back five or six years ago, and now that's changed greatly, and maybe within a few years I can work myself out of a job now. I don't know.

But if you do have a situation where the utility is doing solid work and you don't have a lot of resources to devote to your own program, it may make sense to limit yourself to a kind of monitoring program.

In states where the utilities are not doing a really trustworthy job, then I think it's very important to develop a program. The reason I say that is because even though we seem to be talking about a lot of dollars, in relationship to the cost of a power plant, or even the cost of bringing on a plant one year before it's needed, the cost of a good demand-forecasting program is miniscule. It's an extremely cost-effective way to spend money.

MR. SHELTON: You know, one of the divisions we made—tried to make—in our workshop is the difference between econometric forecasting models and end-use or, "engineering economic models," and hopefully, by this afternoon, that dichotomy, in terms of choices that one might make from the utilities' perspective, will become more clear. Hopefully in the afternoon session, I would like to encourage us to get into a discussion of the pros and cons of each modeling technique.

Oak Ridge happens to be on the left hand, and on the right hand we're heavily involved in both types, and there's not even agreement within the Laboratory as to which is the most appropriate. But I think after this afternoon's sessions, perhaps, we can get a little better handle on that question.

MR. LINDER: I'm Herb Linder, with the American Public Power Association. Our members, of course, represent a great number of very small municipal electric systems, who, up until the time that the ruler on a piece of semi-log paper failed, didn't have any problems in load forecasting, but they do now.

It appeared to us—at least to me, and I'd like to get some understanding from the panel—that, when you go into programs of forecasting that are primarily econometric, then you're dependent on county, state and Federal establishments for developing the data base that's going to be used, as against maybe other methods, which are generated by the utility record themselves.

And in that connection, I'm concerned a little bit about what your estimates are, not so much of your own office costs in preparing and maintaining your data base, but the agencies that develop the basic data that you so highly depend upon.

MR. SHELTON: Anyone else? We have a representative of one of the premier data agencies in the Federal government, the Energy Information Administration. I wonder if Bob Wynand has any observations?

MR. WYNAND: EIA is currently engaged in an electric power data requirements review, where we are soliciting comments from data users in the Federal government and elsewhere, to make known to us the kinds of data collection efforts that they need to support their programs that may or may not currently be done. It provides you with an opportunity to let us know what it is you need that you're not getting, and among those things that are currently being collected—issues of timeliness, completeness and any other issues that you might raise are welcomed.

In terms of budgets, EIA currently is in the mode of re-evaluating its contribution to the overall burden in collecting electric power information, or attempting to consolidate forms, to reduce duplication of effort, and provide the same quality and detailed level of information that is currently provided.

So the notion is that whatever we do in our data requirements, things should be better for those people who have to provide that information, and that users will have as much if not more information than they currently do.

So we have sort of a crazy-quilt collection effort currently in place. Because of the historical nature of the way things have evolved, we're trying to systematically review what the requirements are and come to grips with them.

MR. SHELTON: Thank you. Other comments on that? Any other comments on this data issue? It's come up time and again during the presentations.

MR. HUNT: I can make just a very quick comment. When we were looking at data—what data sources we were going to use, among the criteria that we used was: does it have a history? We wanted to at least build the data base back to 1963, and any of the data that didn't go back that far, we didn't even consider.

We also discussed with a number of different people in state government and at the universities who were familiar with the quality—at least they sound like they're familiar with the quality of much of the regional data, and tried to take series that they considered to be quality for particular things.

For instance, we did not use any single data source, and we took suggestions on where to go, for instance, for personal income, or for population and so forth, from different sources, according to what people who have worked in the field considered to be the best and most reliable data for that series.

MR. SHELTON: Thank you, Carl. Yes, Matt?

MR. KAHAL: It's frequently mentioned that the data requests that are made of utilities for agencies that are doing econometric forecasts are burdensome, and it's certainly true that it does require utilities to provide a lot of information.
But there's another way of looking at it. In our experience, we've been able to improve upon the process and improve upon the data that the utilities have provided to us, and then we make that freely available to them. The utilities can derive a lot of benefit from the data series that we put together for them.

Although there are costs to the utility in providing it, there are potential benefits to the work that states do if utilities are smart enough to take advantage of it, the spadework that the state agency is doing in independent econometric forecasting, so it's a two-way street.

MR. SHELTON: As part of our transfer process of the SLED model, we transferred an incredibly large data base with the transfer of the model. So I think many states have jumped with glee when they found out about the data base.

Is this related?

MR. FOLKES: Ken Folkes, with the Federal Energy Regulatory Commission.

In line with the comment upon electrical power system data, the Commission is currently undergoing an evaluation of which data we will continue to collect in the electric power area, and there's an on-going rule-making.

So if in fact you're interested in this particular area, I would encourage you to respond. Unfortunately, I don't recall the exact number, but it was just issued in January.

We, about a year or so ago, eliminated much of the universe that we previously had in the case of the Annual Power Systems Statement, which gives historical operating data both in terms of energy, peak loads and energy, and also generation system characteristics. We eliminated what was then called the 12B and the 12A, which were generally smaller utilities, and we have now kept the larger utilities.

However, our current evaluation would probably reduce that universe. The previous universe, as selected by the older former Federal Power Commission, was around 3600 utilities. When we eliminated the 12A and the 12B, that reduced the universe down to around 650, and some of the proposed universe-selection limits would now reduce that universe down to maybe 300 or 400.

It's a matter of dollars; we just don't have the money or the staff to pursue these activities in a somewhat quote-unquote "public interest basis."

However, I think our approach tends to move in the direction of when we have a case—and we don't have cases with all utilities, and there are roughly 205 jurisdictional utilities in the United States, all of whom are, of course, investor-owned—we would then collect the data we need at that time, so if they don't all come in, why have them submit the data annually?

So it's a matter of cost-benefit, as I see it as an engineer, anyway.

MR. SHELTON: Thank you. Is there another data issue?

MR. SALOMON: Steve Salomon, NRC Office of State Programs.

In 1977 we did a survey of the states and the various issues citing demand-for-power as part of the Federal-state siting action study. Today, I'm learning from Mark Wilson that, in '78, West Virginia has new laws, and Carl Hunt says Colorado has new enabling legislation that requires the state to have the forecasting capability in this area.

In fact, in '77, when we did the study, there were a number of other states that did have no capability.

I'd just like to open this question up to the full panel, as well as the people in the audience, and find out how many other states have entered into this area.

MR. SHELTON: Thank you. Anybody like to respond to that? Yes?

MR. COYNE: Jim Coyne, from the State of Maine.

We have just drafted a bill which would require the State Energy Office to present electricity demand forecasts on an annual basis. I'm the economist for the Energy Office, and I have just prepared the first series of econometric demand forecasts for the state as a whole, in preparation of taking on that duty, whether we are required to do so or not.

I guess at this point I feel as though I have a couple of questions.

Having addressed this issue, I have a couple of questions as well about the SLED model, because I spent an awful lot of time developing my own econometric forecast. Listening to Ruth earlier, I wonder if I shouldn't have just called Oak Ridge and had them ship me the SLED model.

I could have accomplished in a couple of days what took me many, many months, and when you talk about transferring that model, are you talking about transferring a model and data from which I then could estimate my own Maine-specific coefficients, or are you talking about transferring a model which already has coefficients in it, which I would have to take as they were?

Second of all, I think we're all concerned about the costs of these kinds of efforts. Is there a price tag attached to SLED?

And when I talked to DRI, they talked about very nice models and information, but then when I find out the price, it's prohibitive.

Is this the case also with Oak Ridge?

MR. SHELTON: I'll answer the general issue; then I'll let you take on the specific one, Ruth.

First of all, the transfer—the price is right in that it is costless to a state, in the sense that the model is transferred to the state free of charge. We are working with the states to make sure that the appropriate entity in the state can operate the model, and go through the mechanics and understand the system.

We can, with NRC's blessings, help the state make minor modifications in the model. Obviously we can not tailor-make—remake this model for every state in the Union. However, we can work with you to either: A, show you how to work the modifications easily, or more easily than perhaps you would be able to do if you went into this thing alone, or, B, make some minor modifications at the Lab.

It's very efficient for us to re-estimate some of the equations. For example, different regions of the country have different issues in electricity demand. The one we encountered in the West, of course, was the mining sector; we had to make modifications, some small modifications, in the model to reflect those.

Ruth's been involved in this process, and I'll let her talk about some of the specifics of the transfer.

MS. MADDIGAN: The interesting part of it is, fortunately, what exactly you want the model to do, and what issues you want the model to examine.

What we are transferring is the simulation model for SLED and for the Utility Service Area Disaggregation model, and the data bases.

So if you felt an alternative specification was appropriate, for perhaps the state level model, or the region of which Maine is a part, you could use the data base. Lord knows there are a lot of alternative specifications that one could possibly consider, that would be consistent with economic theory.

One could re-estimate that regionally, especially if, for example, you wanted to regionalize—not like the Census regions, but by power pools or something like that, just make the coefficient specific to some sort of a jurisdictional type of approach. Re-estimate that, change the coefficients in the simulation model, and run it.

So that simulation model is a nice package that prints out all the nice tables and everything. That can be adjusted, according to if you're still using either the SLED-VEM or the SLED approach. You just adjust those coefficients.

Another thing is that the data base is available lots of times by state. People will collect information and then realize that what they need to look at is perhaps a larger regional area, and the SLED data base provides the kind of consistent data across different states that could be useful for that kind of analysis.

Also, the Utility Service Area Disaggregation model needs to have coefficients input that are specific to utility service area. Essentially, what's done is, a separate set of regressions are run for each utility, because it was determined not to be cost-effective to be able to have the capability of, by default, running every single utility. It was felt that when a utility would come up, that was the time to put that data up on the data base, because we are dealing with an examination of the whole country, and we never know when we might be looking at one specific state.

But these kinds of interactions are something that Oak Ridge would be very, very happy to help you with, and we just tell you, the tape is full; it's just wonderful to be able to transfer all that information.

The one thing we have not had a problem with so far is that we have only made the transfer to systems that work with IBM. We have not tried to do the kind of adjustments that would be necessary if it had to go on a Honeywell or a CDC, or something like that. That's a problem we will face as it comes up.

MR. SHELTON: The Lab, as you might guess, has an extremely strong support area in computers and software packages, and conversions. So we realize there are going to be problems when we start switching systems, but I'm reasonably confident that our Computer Science Division programmers can make the transfers.

MR. ANDERSON: Is this a FORTRAN source program?

MS. MADDIGAN: Yes.

MR. SHELTON: Any further on this comment?

MR. WOOD: Just for informational purposes, again, Anton Wood, from the District of Columbia Energy Office.

In relation to your question about state agencies being required to issue annual reports forecasting various energy sources, the District of Columbia now has that requirement, through the Energy Office Act enabling legislation.

Not only are we to provide those types of scenarios for electricity, but also for gasoline and natural gas, and whatever else you can think of.

MR. SALOMON: What year was that passed, please?

MR. WOOD: It became effective March, '81.

MR. SALOMON: Thank you.

MR. NASH: I was glad, Jim, that you asked your question, because it was part of my talk that I had to cut out. I was going to mention this availability of the Oak Ridge model.

I was wondering if any of the rest of the panel—maybe particularly—are you also interested in transferring your model to other jurisdictions?

MR. KAHAL: Absolutely. We have in the past, with Pennsylvania—we've provided our material—Power Plant Siting—has provided the work that's been done to the Office of the Consumer Advocate of Pennsylvania. We've also worked with people in Delaware.

No one in the other states has worked with us on a formal basis. We've simply provided the results.

But I think I can speak for Power Plant Siting, that they would be very happy to sit down and share anything that's been done, to the extent that other jurisdictions are interested. There's absolutely no point in reinventing the wheel.

One of the things that we have emphasized is simulation with our models, so that other jurisdictions—and that's one of the advantages of econometric modeling—other jurisdictions, if they like other sets of assumptions better, can simply take our models—and it's a computerized system—stick in different assumptions and crank out different scenarios, and we're very anxious to work with other jurisdictions.

MR. GREEN: I'm Julian Green, with the Federal Energy Regulatory Commission's Regulatory Analysis Office.

This is, I guess, a sort of bottom-line question. I would direct it first to Darrel Nash.

Historically, since any sort of demand forecasting has been done, has the Nuclear Regulatory Commission indeed denied licensing for a plant based on that sort of reason?

MR. NASH: Sid Feld might be able to help me out on this, but in terms of denial, I'm quite sure the answer is no. But we do talk about the timing of the power plant, as to whether we think the utility is too optimistic in terms of their forecast, and perhaps it should be some years later, this type of thing.

But outright denial—that hasn't happened.

Sid, can you add anything?

MR. FELD: The closest we came to it was an application for Green County, in New York State, where it appears as if the need for power assessment was going negatively, but the application was withdrawn for other reasons as well.

MR. GREEN: Okay. And to any of the other states, although most of you sound as if you're new in the area, have you seen similar instances, or would you project that this is going to happen, so that these kind of analyses are actually going to have any impacts on regulatory decisions?

MR. SCHOENGOLD: The Wisconsin Commission denied an application to build a nuclear plant on the basis of a lack of need. Two years back, I think it was; the Tyrone Nuclear Power Plant.

MS. ALEXANDER: Barbara Alexander, from Texas.

In relation to the Paloverde plant I mentioned earlier, I believe that was originally scheduled to go to hearing last spring or summer, and we haven't gone to hearing yet because—I think one reason might be—I hate to speculate—the staff filed some testimony that was critical of the forecast that the company had filed, and that the City of El Paso had filed. Various parties started delaying the hearing, and the next thing we heard, the company was negotiating to sell a good portion of the plant, and all that is still just up in the air.

The plant is being delayed; I think it definitely had some impact.

MR. HUNT: We haven't denied building the plant in Colorado as a result of forecasting. We have denied at least one CPCN at least partially as a result of the forecast of demand.

Another thing we notice is that since we've gotten into the business of forecasting ourselves, the forecast of the utilities has decreased somewhat—in two cases, rather significantly.

MR. KANECH: Ron Kanech, from the Nebraska Energy Office.

A little bit about Nebraska. We were interested in Jerry Jackson's commercial model. We went through the model a couple of years ago, and he made a nice assumption that Nebraska behaved like the rest of the Mid-West. Nebraska is the great American desert; we have 17,000 square miles of sand dunes, the largest amount of sand dunes in the Northern Hemisphere. We're desert covered with grass.

We irrigate like crazy, out of the Oglalla aquifer, and we have a peak-load problem. We are a major exporter of electricity; we export electricity like crazy, but we have a peak-load problem. We don't need to build capacity; we need somehow to arrange our peaks. We have a night-peak problem; they irrigate at night.

So we're different. We want to build what's called the Mandan Transmission Line, from Manitoba, Canada through the Dakotas into Nebraska. Our office, in a sense, loves the idea. It's cheap, nice to the ecology, and doesn't ruin our land.

But we have that problem, and it hasn't been addressed. Peak load is major, and our electric demand forecasts for the year we've been in operation look beautiful. We haven't had time to go off.

But the peak problem! The rates are different from one municipality to the next, and we have about 90-some municipalities. They're all publicly-owned utilities, we have no rate control in Nebraska. We have a big problem, and I'd like to hear some comment how that's handled, and if somebody really is concerned about that, because we are. That's why I'm here.

MR. WILSON: How did your Commission view the PURPA hearings? Did you have PURPA hearings, and have they been resolved yet?

MR. KANECH: We don't regulate any rates. We don't have a public utilities commission.

MR. WILSON: That would give you a peak-load problem, all right.

MR. SHELTON: Comments from others? Yes?

MR. ANDERSON: I'll make a comment. Why not do some projections and see what would happen to some of those if they charged a higher price during the day? I mean, they say: what if we did this? What would be the result? They'll have to decide whether they do it or not.

MR. KANECH: They do. That's why they irrigate at night, because they charge higher in the day, to force them to night, so the shift went from day to night.

It's a nicer peak, because they won't compete with air-conditioning, but you know, it's still there.

MR. SCHOENGOLD: Direct load-control and interruptible rates is the best way of dealing with the peaking problem.

MR. KANECH: Can I comment again on that?

There's a million different methods; some have rate-control, and they shut off their irrigation pumps, and some say you can irrigate between July 2nd and 3rd, and if it's raining, you irrigate.

There's such a variety of methods, load factors and everything, from each place to another, and they all think they're doing a great job, and we don't need to comment on it, we just need to forecast it somehow and say if the Mandan Line needs to be built or not.

Mandan was built because we have a peak in the summer and Canada has a peak in the winter, and we want to share. Export in the winter and import in the summer.

MR. SHELTON: Is the nature of your question for people to specify some unique capabilities of their forecasting methods with regard to peak? Is that what I understand?

MR. KANECH: Yes. To see if they've taken into account peak-load forecasting.

MR. SHELTON: If you're doing forecasting—well, I would not say impossible, but it would be difficult not to do peak, and maybe we can go around, if anybody has some comments on their success or lack of success in forecasting peak.

Ruth, do you want to take an effort?

MS. MADDIGAN: Well, you're definitely right, that the examination of peak-load demand is a very crucial one in the determination of capacity needs.

What we have focused on at Oak Ridge is a kilowatt hour demand modeling capability, and then we also forecast then an annual load duration curve.

So we have not attempted to model anything specifically, but examining minimum and maximum peak and load duration curve. The forecasts, then, have essentially been derivations from that.

The California Energy Commission has done considerable work in the examination of peak load. There are models, not from the Economic Analysis Section, but from some of the engineering groups in the Laboratory, that have examined peak load and examined the sort of downtime to generation unit reliability type issues.

There are an awful lot of issues dealing with reliability and with the peak that have been examined, but not by us, and not within the SLED forecasting system.

I could send you some copies of some publications that have been done by some of the people at Oak Ridge who have examined some of these issues, and look at some of the models they have developed. I do not know whether or not they would be something that you could adapt specifically to some of your needs, but that may be true.

I know that Dan had also been considering the possibility of how the building sector models could be used, and some of the information derived from the building sector models could be used in the development of a peak-load model.

MR. SHELTON: Dan?

MR. HAMBLIN: Yes, I just wanted to say that for the building sector model and the industrial model, we have been looking to integrate with Michael Jaske's California Energy Commission peak-load forecasting model. It seems like it's good enough that we don't have to reinvent the wheel in that area.

MR. SHELTON: Matt, did you want to comment?

MR. KAHAL: Yes. I haven't seen too many successful direct econometric models of peak demand, and by direct econometric, I mean models that attempt to explain peak-demand in terms of its true underlying determinants. And we haven't tried to do that either.

One of the reasons why you can't do that—or, I think one of the reasons why it has not been successfully done—is simply because you don't have data available on loads at the time of peak by class on a historical basis that go back very far.

There are some load-survey data around; I suppose you could do a few things with that and make some assumptions about it, but the peak-load data by class are vastly inferior to energy data by class.

That's why I think the way to go is to do some fairly disaggregated detailed modeling of energy usage, and then use the energy forecasts to build up to the peak-demand forecast, and that's what we've tried to do.

We have tried to model peak demand in terms of, first of all, total energy output on the system, and the customer-class mix on the system, and of course, weather. Those are going to be the primary determinants when you take an indirect approach, and as I said, the data force you to do that.

What it does point out is that there is a real need, when you're doing your energy modeling, to be fairly disaggregated by customer class, and by season as well. Annual models of energy usage just won't do. It's desirable to have seasonal models.

We have done our own modeling using either quarterly data or monthly data. This is something that we're very concerned about in Maryland, because some of the utilities in Maryland have very low annual load factors. PEPCO's load factor, from time to time, has been below 50%, which makes it one of the lowest in the country, and the reason for that is obvious. There is no industrial sector that PEPCO serves.

So, clearly, generation planning—the planning of the system in the long run does depend on what you think will happen to the system annual load factor, and in fact, the entire load-duration curve, over a very long period of time.

So my only advice is: given the lack of a detailed class-load data—and by that I mean demand at the time of peak—on a historical basis, the way to go is to do a historical detailed model of energy, and then build up to peak demand. The attempts to do it directly just haven't been very good in my opinion.

MR. SALOMON: Yes. Dave Salomon, NRC. I would like to suggest that you might change your focus away from econometric forecasting to end-use forecasting. It is my understanding that windmills, for example, are coming in really strong in the Midwest, especially for irrigation, similar to what the problem is for light peaking. Have you investigated to see how rapidly maybe windmills might substitute for electric pumping?

MR. KANECH: That is just pump water for cattle. Irrigation takes huge pumps and high pressure. You would have to have a windmill the size of the farm to do anything like that. But we have a very detailed end-use model, and we do it monthly. We have monthly peaks. That is not, you know, our daily peak, when we are hitting close to the maximum. I was wondering about that type of detail, because we have a lot of data. I just don't know how to go about it. I am lost.

MR. LEE: My name is S. V. Lee, with the Maryland Commission. Before I joined the Maryland Commission, I was with a major Midwest utility company. And when I was there, I was trying to develop two econometric models. One is an energy econometric model, which is dealing with the forecasting of class, of particular class of customer. The econometric model will deal with peak load. We basically use it for checking. We use it to forecast the total system peak and the checking, the other models, the way that you are describing, using energy relating to peak forecast. We evaluate the load factor in the future to see what the increase in the future is.

MR. SHELTON: Well, seeing no further hands, and I am exhausted, and I am sure the panelists are equally tired, we will reconvene promptly at 1:30, and we will take up end-use modeling and then, hopefully in the discussion session, we can come to grips with these different modeling techniques.

As I understand it, there is no cafeteria in this building, so it is every person for him or herself. There are a number of restaurants on H Street, and this is actually a pretty good place to find restaurants, although you don't have much time.

We will reconvene at 1:30.

AFTERNOON SESSION
(1.45 p.m.)

MR. SHELTON: I think it is time to get the afternoon session underway. For those of you who may not have been here this morning, my name is Bob Shelton, from Oak Ridge National Laboratory.

This afternoon we will follow the same pattern that we followed this morning. As I have already mentioned, Mike Jaske is unable to attend. He evidently has an infection that prevented him from flying. We regret that, because, as many of you working with state issues know, California has been in the forefront in many of these areas.

However, perhaps in the course of this afternoon's discussion on end-use models we will be able to pick up some of those issues that Mike would have discussed had he been here.

Our first speaker this afternoon will be Robert Camfield. Bob is Director of the Economics Department at the New Hampshire Public Utilities Commission, where he has been the chief economist for four years. He is responsible for load forecasting research, technical analysis of major policy issues before the Commission, the economic assessment of conservation technologies and techniques of energy use and the estimation of the cost of capital for rate-making purposes.

Bob has analyzed a wide range of energy issues, including natural gas and the impacts of the Three Mile Island accident on financial markets. This afternoon Bob will discuss modeling electricity demand and supply at the state level.

MR. CAMFIELD: Hello. My comments today will be presented within a very short four-part discussion.

First, I will discuss briefly the history of the electric power industry in regard to growth in energy sales.

With that as a foundation, the discussion moves on to demand forecasting generally and the role that can be played by demand forecasting in the process of price regulation.

Third, I will discuss what we are currently doing in New Hampshire.

Fourth, I will proceed to use the overhead projector to outline the analytical mechanisms that we are using in New Hampshire, as incorporated in an analytical supply-demand system.

The post-World War period in America evidenced unprecedented growth in energy demand. The United States emerged in the aftermath of the great war as a world leader in both military and economic strength. The U.S. domestic and foreign policy was aimed at maximizing the local production of goods and services, technological advance, and maintenance of our position of dominance in the economic affairs of the free world.

What did this mean for the electric power industry? Well, as you might expect, the electric power industry experienced robust growth in sales. It takes increased energy to fuel advancement in economic activity. At least it does if the efficiency of the capital stock of energy-using appliances and equipment remains unchanged.

Increases in real per capita income could not have been realized without a steady advancement in productivity. Productivity changes, in turn, were made predominantly through an increase in the size of the capital stock, using more capital per unit of labor. In similar fashion, the commercial and services sector experienced increases in the saturation of air conditioning, of office appliances, and of lighting and refrigeration equipment. Households, with steady advances in income, experienced growth in appliance saturation.

But with the increase in sales, prices fell. Essentially a declining cost industry—at least in accounting terms—prices steadily declined with advancing demand.

These matters are common knowledge, and I suppose that I need not dwell on them any further. But I think it is important to recognize the extraordinary changes in our attitude with regard to energy consumption and its price that has occurred in recent years, for, as the nation was more or less indifferent to the use of energy in the decades of the 1950s and 1960s, energy now is a salient topic of concern and discussion.

Facetiously I suppose, I view this simply as a response to changes in relative prices. Whereas, energy, and particularly electric energy prices, was falling in real terms, at least through the early 1970s, that all came to an end during the 1973-1975 period, of course, with the sudden and sharp increases in imported foreign oil prices, having both primary and secondary impact upon our economy.

For those of us in New England, the crude oil prices increased dramatically as well, obviously causing our electric energy prices to rise very dramatically, due to the region being so dependent upon foreign oil for electric power generation.

For sure, the 1973-75 period ushered in a new era, an era of concern for conservation and renewable resources. For regulators and perhaps electric power planners too, the 1950s and 1960s formed an era of complacency, of steady robust growth coupled with falling nominal and real prices. The only discussion for the regulators was whether or not the industry was exceeding its authorized return. Can we decrease the rates fast enough in response to the decreasing unit costs?

A steady growth in demand due to a decrease in prices and significant advances in economic activity implied a world where the discussion about optimization of resources was absent.

Commensurate with the changes of the 1973-75 period, there has been a significant change in the subject of the discussion; the discussion now is about the appropriate rate design and, importantly, a discussion about optimization—optimizing the generating mix among competing alternatives, including conservation and renewable resources.

As an economist might intuitively expect, a rise in real prices implies a reduction in the growth and demand. And, indeed, the recent historic period, 1975-1981, discloses a significant, if not dramatic, fall in the ratio of energy use per unit of real economic activity in the country.

The fall in growth of demand, not to be confused with a fall in absolute demand, has been true not only of energy generally, but for electric energy too. And I note that a recent long-term forecast by a major forecasting service has, through the year 2000, the ratio of electric energy to real GNP remaining relatively constant. My personal view, however, is that the ratio could in fact fall dramatically.

But getting directly to the area of demand forecasting, the question which begs to be asked is: why does one want to forecast electric energy demand at all? I respond by going back to the issue of optimization.

It is in the interest of us all to attempt to minimize energy costs; and, insofar as the planning process suggests responses to future conditions of demand and supply costs, it seems to me that the assessment of prospective demand is at the cornerstone of planning; if you please, demand planning.

We will proceed to plan on a level trajectory of demand, or alternate trajectories of demand. Given that, we will choose a strategy of selected supply options which minimize system prices for at least some period of time horizon. And supply options should include overt conservation plans and renewable resources.

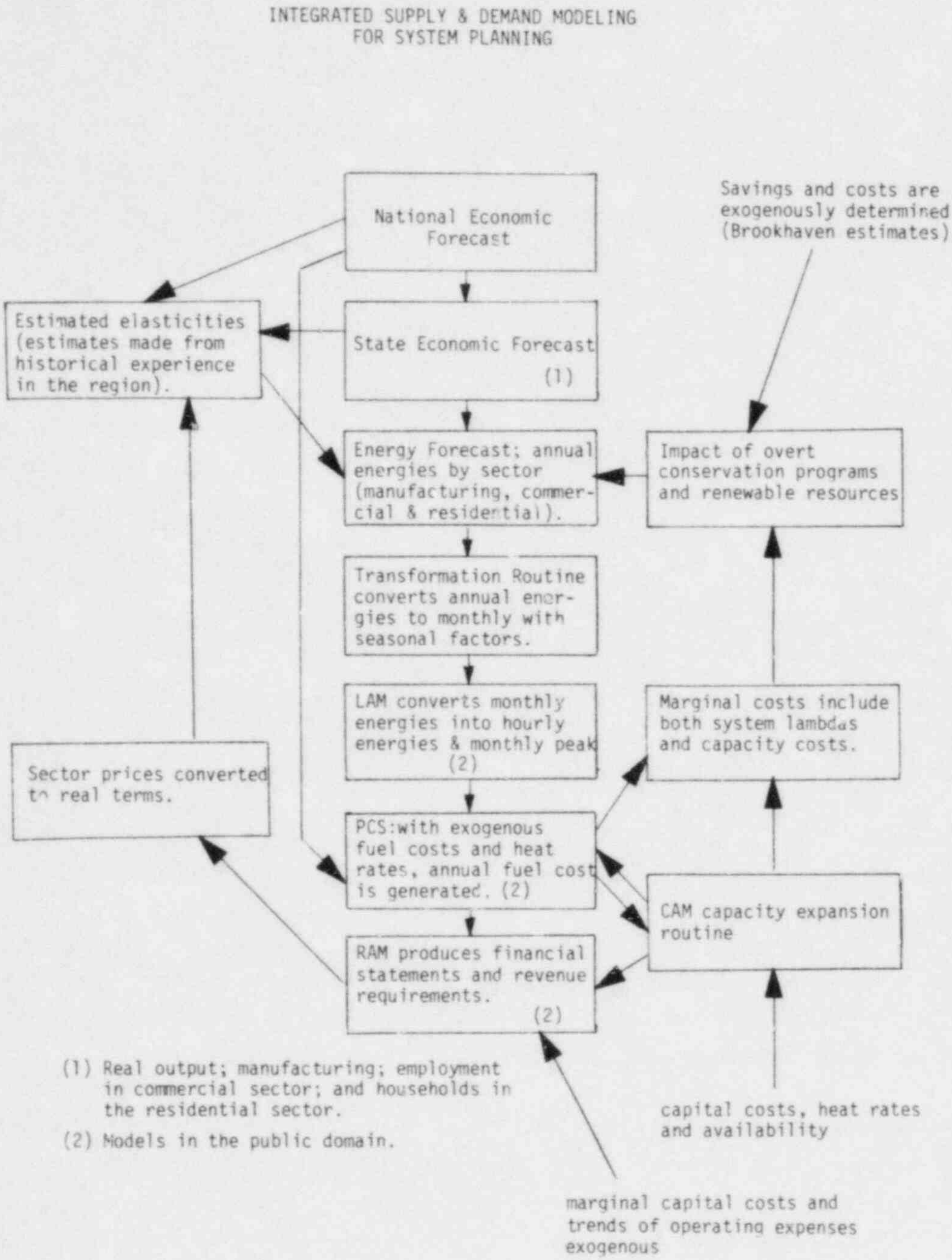
Let me now proceed to use the overhead projector here and show you what we are doing in New Hampshire.

Here, in Slide 1, is the national economic forecast. On the demand side we are relating energy to units of economic activity. And to deal with economic activity in the future in any regional area, in this case New Hampshire, you have to somehow relate that to a forecast or a trajectory of national economic activity.

So, here we are using a major forecasting service which provides us with units of economic activity. And through a relatively simple algorithm, we relate that national economic forecast to a state economic activity. That, in turn, as you might expect, drives energy demand. And these groups represent essentially the core of our demand side system.

Now, getting on to the supply side system—I guess I will label this "demand"—the trajectories of energy demand through the year 2000 are used to drive a Production Cost Simulator (PCS). This, in turn, given a loading order of the generation mix of the electric system, will give us, along with certain other fixed costs, a forecast, of financial requirements of the electric system. This, in turn, is used through another algorithm to generate prices. The real prices go through a vector of price elasticities to feed back to the energy demand.

Out of PCS, too, we get system lambda prices, or with capacity costs, "marginal costs." They in turn, are used to assess conservation and renewable resources which



SLIDE 1

enter here and therefore represent a decrement to energy demand from what it would otherwise be. This is the essence of the system that we are currently in the process of putting in place.

Below this line, of course, is the supply side module, and above this line is the demand side. Given the time span that we have to work with here, I cannot get into the details of these various algorithms, but this is the essence of the system that we are attempting to put up for New Hampshire.

I have taken less time than I expected. Are there any questions?

MR. SCIORTINO: Steve Sciortino, and I am with the Virginia State Corporation Commission. When you are running a PCS, are you assuming you have already got an optimal mix of generation out there to run the model? Or, if you are using this for a forecasting basis, you are of course working with the existing system. What about alternatives with respect to your expansion?

MR. CAMFIELD: We are, in addition, putting up a capacity expansion loop which, as you know, feeds into the forecast of financial requirements and also, of course, alters the loading order of PCS. So that is considered, but in the model that we are using right now, and that we have up right now, capacity expansion alternatives are not included. In New Hampshire, capacity mix is more or less fixed; and I think that is realistic for 1990. That may be a unique case for New Hampshire. Obviously, larger systems have more flexibility in terms of an evolving the generation mix than we have in New Hampshire.

So to complete my response, yes, in terms of dealing with the optimization of supply alternatives, at least going beyond conservation and conservation technologies, certainly one would want to include a capacity expansion loop on the supply side.

MR. SHELTON: The next speaker is Jerry Mendl. Jerry has held a variety of positions with the Wisconsin Public Service Commission since 1974. Jerry is currently the administrator of the Division of Systems Planning, Environmental Review and Consumer Analysis. As such, he is responsible for reviewing and critiquing the long-range expansion plans of electric utilities and for the development of any alternate plans. Extensive use is made of generating system simulation models and forecasts analysis methods in this process.

Jerry's talk today is entitled "A Regulator's Perspective of Electricity Demand Models: Planning Response to Uncertainty."

MR. MENDL: Thank you. I got here just in time, it looks like. I was out giving another session earlier in the morning.

Dave Schoengold, also from the Wisconsin PSC and one of the bureau directors that reports to me, is going to hopefully fill in some of the things that may not have been covered, or may need to be covered a little bit more, because I was unfortunately not able to be in attendance at the earlier presentations. Dave is also going to speak with authority—more authority on the second aspect of my presentation—so he will be coming up a little later on.

I thought what I would do is very briefly mention the Public Service Commission's role with regard to energy and capacity planning. The Wisconsin PSC has a fairly extensive set of statutes that deal both with the obvious ratemaking types of proceedings, but also get into capacity planning and capacity approval. Capacity planning and capacity approval are actually two separate functions.

We have a normal certification process by which various proposed plant construction is reviewed and must be authorized prior to construction, but we also have what is called in our state a power plant siting law which gets into long-range capacity planning. It takes a 20-year look at capacity expansion and needs and reliability types of questions both for generation and transmission. And it's in that review that guidance is initially given to the utilities for their ultimate plans.

In the conduct of those types of reviews the PSC's role has evolved over the years. Initially the PSC's role was envisioned to include a lot of forecasting to be prepared by staff, that is, staff do their own energy and demand forecasts and ultimately present them as one of the alternative sets of information that the Commission would be basing its final determination on. That has evolved due to budget shortages and also the expertise in other segments of state government, particularly our Division of State Energy (of which there are some representatives here), who are doing some independent demand forecasting.

Therefore, the current role of the Wisconsin commission and the Wisconsin Commission staff is to review, critique and analyze the forecasts and the subsequent expansion plans. I don't want to mislead you. As part of this role the Commission staff does do independent alternative plan generation, so we identify and develop alternative plans that might be considered. But essentially the forecast function is largely that of critiquing and reviewing, and I think that provides an interesting perspective at a discussion such as this, in that we can perhaps share some of the insights that we have encountered through our review process.

One of the basic contentions that we have developed is that there is a tremendous amount of uncertainty involved in capacity planning for forecasting areas. We have identified two basic approaches to that uncertainty and planning in light of that uncertainty.

First of all is to attempt to reduce that uncertainty as much as possible by understanding and improving forecasts. The second, which Mr. Schoengold will be discussing in more depth, is methods which reduce the effect of that uncertainty, i.e., a cost minimization planning to reduce the amount of consequence that might result from having what we believe are the unavoidable errors in forecasting. So with that introduction, I'll proceed with a very brief discussion.

We have had several types of models that were presented to us by the various utilities, the other state agencies and other interested parties that the Commission has considered. I've lumped them into three general categories. Now, I know that there are many subcategories. I'm sure there are specifications that could be identified. I'll just identify the three major ones. Those basically are trending, econometric, and end use.

We clearly recognize that there are various combination or hybrid models that may use elements from various of these basic types to form, perhaps, a more responsive overall model. Just so that we're clear on definitions, trending basically is an extrapolation of historical consumption trends through various statistical or perhaps more simplistic methods. There is essentially a recognition in those models that the dependent variable, i.e., the desired consumption forecast of peak demand or energy, is solely a function of time, and one looks for trends through time and then attempts to extrapolate them in one way or another.

I will just summarize what we have identified as some of the strengths and weaknesses of trending. First, by its nature, it's a model that's relatively easy to develop and use. The data are largely available, take very little effort to compile. The analysis of the data is possible through such things as standardly available statistical packages from the various computing centers. It may be, in its worst case, and I swear to you some of the utilities were doing this at one point not too terribly long ago, a graphical extrapolation, and that was all fine when things were fairly stable in terms of the amount of annual growth.

The model, as indicated there, has minimal data requirements. Data are readily available. There is only one data point per period, and it's a matter of extrapolating or looking for the trend or the tendency that exists in that time series.

It's major weakness—now, that simplicity is there for its advantage—is that it assumes a continuation of the past. It really does not provide any responsiveness to changes in the basic structure of the electric utility system or the consumption patterns in that system, or population growth within the service territory. It's not particularly responsive to any of those. It lacks any type of causality.

The theory is basically a statistical theory and it doesn't really have a good, strong, technical underpinning to reflect the causes of increased energy consumption. So that, in a nutshell, methods.

The second type of model, as I mentioned earlier, was the econometric. Now, the econometric model is somewhat different. The consumption is predicted as a response to various economic and demographic variables. That would include, I think as the previous speaker that I had the opportunity to listen to said, population, price, economic activity, things of that nature.

The dependent variable in that instance is a function of those types of explanatory variables expressed in an equation that essentially becomes a driving equation.

What it attempts to do, really, is provide some causal explanation for the projected demand levels. Again, in a purely econometric model, these tend to be very much oriented towards economic types of information.

On to its relative strengths and weaknesses. Basically, it reflects causality, and that seems like a big improvement over the simple trending method. A weakness that I pick up a little later, but I might as well mention now, is that causality is defined by the nature of the driving equation that is somehow established by using past data, so essentially you are still limited to some degree to the historic information that you've used. It's somewhat difficult to predict whether the trends that have occurred in developing that driving equation are going to remain the same through time.

Yet, it does provide for an increased understanding of why consumption changes. It's a behavioral model in that it assumes that people are responding, or consumers in aggregate are responding in a certain way, to changes in the explanatory variables.

Given that the model is responsive to these various demographic and economic variables, it is particularly suited to evaluating scenarios and could contemplate different levels of growth in those variables. It has been our observation that it's particularly well suited to an evaluation of types of pricing policies, the effect of price.

I've already mentioned the weakness—that it's limited by historical relationships between variables. Another weakness, and it's a very important one, is that the elasticities are ostensibly response coefficients in the equation and are largely indeterminate. It's very difficult to get data, particularly for certain types of forecasts. If one looks at peak demand forecasts, for example, that type of data is very sketchy and very nontransferrable, in many cases, between regions where there are some data available. The models essentially need forecasts to be developed for each of those independent variables, in order to produce a final forecast. Your forecasting effort is now to forecast a multiplicity of variables using statistical or trending techniques and then combine them through a driving equation into a final result.

Typically we found that the method is not particularly well suited for dealing with peak demand, although there are some models available, nor for the load shape. Again, from our observations, the limitations tend to be the result of the lack of clear elasticity or response coefficients for the driving equation.

I would like to draw an analogy, a fishing analogy, if I may, between the statistical model, the trending model, and the econometric, and to some degree the same analogy applies as well to the end-use model, except perhaps in even more detail. The analogy is a fishing one. Looking at, for example, a mono-filament line versus a braided line, the strength of the line in the mono-filament line is essentially determined by the strength of the single fiber that's involved, and that is much the same as in the trending type of model. You're taking that single element and the strength of the forecast is really determined by the single element.

In the case of a braided line, in the sense of the econometric or ultimately end-use models, the strength is determined essentially by multiple fibers that are interacting with one another to produce the final line, i.e., the final forecast.

As I mentioned earlier, the third class of models are the end-use models. An end-use model basically predicts on the premise that you can sum the usages of individual end uses. These individual end uses are essentially the product of some usage function, some usage amount, some number of such items or end uses or appliances that are being used, and the duration of their use. The products for each of the end uses which are then summed to formulate the final forecast.

Again, summarizing some of the strengths and weaknesses of the end use model, in a sense it is perhaps the best of the models in that it provides the most understanding of what may be occurring. This is particularly true when it's used in the hybrid case with an ecometric component of some nature to get a price function in there as well.

Another strength is that the model is very capable and very flexible for modeling structural changes. For example, if there is an improvement in the efficiency usage, if there is some conservation effect that can be specifically quantified in terms of usage change or envelope efficiency or appliance efficiency of some sort, it can be modeled. You can model the population and some of the demographic variables, such as housing size, very specifically. In that sense it provides a very competent tool for evaluating alternate policies regarding those particular types of changes.

If there is a policy that may affect conservation, that's a very appropriate model in which to evaluate specifically what types of effects would have to occur and what the specific end result of those effects would be.

As a weakness, the method is very data intensive. It's necessary to collect data on such things as how long usage duration is, how many people have them. Whereas it provides a lot of detail, a lot of the detail is assumed and inferred from data that are presently not available to the degree that one might like the data to be available. That comment applies particularly to sectors which are highly heterogeneous. For example, the commercial energy use cannot be typified into a simple pattern as, say, a residential sector might be.

One is looking for a least common denominator between all commercial establishments, and it might be something that only relates to floor space and not in much detail with regard to process or your final product of manufacture. In many cases, such as a shopping center or something of that nature, there may not even be a product of manufacture.

Our observation, although the method is usable for other types of information, is that the best suitability of this model is for forecasting energy. It can be used to do a peak forecast, but similar to the econometric model, is somewhat limited by lack of data relating specifically to peak usage.

I guess with that, I'd like to summarize what I think some of our pitches, if you will, would be regarding the forecasting.

In general, based initially on our early involvement in attempting to do some forecasting and secondly, in our subsequent critique and review of forecasts, we've observed that the role of models is to provide understanding, not necessarily numbers. I think a lot of people get hung up with looking at specific numbers and saying this is it, this is the forecast, this is what I'll build my planning on. Whereas that may be necessary, it's dangerous if you accept that on blind faith without really recognizing that what the model should really attempt to do is identify information and knowledge and understanding of what the potential situation might be.

Second is our observation that multiple modeling methods increase the decision maker's ultimate understanding; that is, having a forecast which is based, let's say, on an end-use model which is then compared to a forecast based on a statistical or econometric model. And having those somehow match very closely provides a little bit more information, a little bit more certainty and confidence than something which does not check out against one another.

Thirdly, no single method is always best. The Commission has taken up this question of modeling and whether to establish a standard for modeling that all utilities would have to follow. And in reviewing the accuracy of the various utilities' forecasts and the methods that were used, and finding that there is a tremendous amount of error involved in any type of model, specifically declined to select a single model, again reflecting on the need for understanding related to using multiple modeling methods.

That is not to say that improvements, as they are discovered, cannot or should not be incorporated into the models; but to define very narrowly exactly what the model should contain and how it should be done, we firmly believe would be a mistake. It would limit the amount of information and knowledge one might be getting from the effort.

Fourth: increased complexity doesn't automatically mean a better model. There are models that are available which I think decision makers in particular sometimes tend to look at and say: "Ah, this is a computer model, as opposed to straight line extrapolation," and this somehow means something, that the output is sacred or unchallengeable.

Similarly, we found that someone who used the Box-Jenkins method or a trending method of some nature, who has then put it against an econometric method, there's a tendency to say: well, econometrics is going to be more accurate.

It may provide more information, but it doesn't necessarily mean it's more accurate.

So, to decision makers and to staff who are going to be providing information to decision makers, I strongly caution the assumption that sophistication means a better model necessarily—better results, necessarily.

Fifth: I think it should be obvious by now: expect to be wrong. One thing that we have been able to say conclusively about forecasting is that we've never had one that's right on.

Incidentally, I can't resist the temptation to point out that the early independent modeling efforts that Commission staff were originally involved in doing have had a good track record. Oddly enough, those were essentially a form of extrapolation model, using the Box-Jenkins technique. Those forecasts, five years later, have been the closest on average of any of the forecasts that we have before us. A lot of hindsight there, and maybe pure luck.

I'm not saying that Box-Jenkins is the best approach, but I'm saying: expect to be wrong, regardless of what you try.

Lastly—is the need to identify what the variables, the models, whatever model was used, may be sensitive to. So the idea was to prepare sensitivity analyses for two purposes: one, to identify the critical variables and see how much the output of the model responds to variations in the input, and two, to start thinking of forecasts as truly being a range of possible numbers rather than a single specific number.

If you've going to be wrong, you might as well be wrong in a range, rather than wrong in a specific number.

With the little flippant comment, I'll turn it over to Dave, who is going to discuss what to do when you're wrong.

MR. SCHOENGOLD: I guess what I'm going to talk about is, basically, what the Commission staff and what the Commission can do about the problem, that you don't really know what the forecasts are going to be. You know you're going to be wrong, and you know you're going to be uncertain. How do you deal with it?

The way we perceive that you have to deal with it is, you have to try to minimize the risk that's at stake by your being wrong, and there are three basic things that we see you can do to minimize this risk. One of them is the last thing that Jerry mentioned—a sensitivity analysis you do in your forecasts.

You see what the likelihood of your forecasts being off by certain amounts is, if certain projections happen differently than you expect.

Another is that you try to plan as flexibly as possible. You don't want to lock yourself into a situation where, if something goes differently than you expect it to, you're in real trouble.

And the third area that you can make use of for minimizing the risk is use of load management at the load control on your system. And if you go into a little more detail, particularly in sensitivity analysis, you want to look at what the most likely forecasts are, see what the optimal system that you can develop to meet those forecasts would be, and then see how invariant this optimal system is with a forecast range.

If you're projecting a certain forecast, and instead, it's a little bit higher, is the optimal system that you come up with under that forecast very different from the one under the most likely forecast? Or, if the forecast is a little bit lower, is the optimal system going to be very different?

You want to look at the optimal system and how that varies with fluctuations of fuel costs, interest rates, inflation rate—all the various uncertainties that can go into the planning process, and you want to actually try and determine how much your risk is, what risks you are facing, if you plan for more than one set of circumstances, and the circumstances come out differently than you expect.

And one of the ways that you deal with that, and one thing that you may look at, is the fact that the best decision to make may not necessarily be the one that gives you the lowest-cost system under what you think is the most likely future occurrence.

You can look at the expected costs of a system at various ranges, and try to factor into it what the likelihood of different occurrences being is, and then try to factor these in to the extent possible with the probability of them happening, and come up with what may be your prediction for what may be the most likely least-cost system, which is not the same thing as the cost—the lowest cost for the most likely system.

You may end up going for a system that, if everything comes out exactly as you project, will be a little more expensive than the least-cost, but is more resilient to changes.

You also may want to do some things like plan your capacity to build in smaller increments than you might otherwise think of. If you have a utility that you expect to grow 1000 megawatts a year, and you're planning on building a 1000-megawatt plant, it may not be that critical if you're off by a year or so in the need for a plant. But if your growth drops off to a few hundred megawatts a year, and you're thinking of 1000-megawatt plants, you can be in real trouble when you get a year or two's change in the most optimal timing.

If you're talking about plants in the couple of hundred megawatt range, and you're faced with that particular problem, it's much less of a problem. You've got more pieces of the system you can move around, you can juggle with, you can change the timing of.

You would like to, if possible, investigate the cost-effectiveness of smaller scale, short-term actions which may defer high cost commitments. The use of smaller increments of capacity is related to that. If you're talking about something—if you're going to do transmission planning, you may try to, if possible, put off your commitments to the bigger, higher voltage lines that you think you may need but you may not, and you may be able to get by with building something smaller and reinforcing lower voltage lines for a while, and put off the decision to build something bigger until you have a better idea of whether it's really needed or not.

It's the same kind of thing as dealing with smaller units of capacity.

Another thing that you might want to do is give additional weight to alternatives which have shorter pay-back and you can put on line quicker. Some of the alternative generation sources that are being talked about have shorter times to put into play than major large generating stations. You have again more chance to adjust things to recognize changes in your system, because you don't have to commit so early and so much money so soon that may lock you into a situation that you may find yourself in a position where it's difficult to get out of it.

And as I said, the third way that we see that's very important for dealing with uncertainty in load growth—other uncertainties—is the use of load-control, load management.

When a utility puts in direct load-control on its system, they can actually have some control over the loads that they have to meet, instead of just having to predict what the customers are going to do to meet it; they actually have some control. If loads grow faster than they expect, well, you can, if necessary, control some of those loads. You can shut things off, and not serve at the time of peak.

If loads don't grow as fast as you were expecting them to, well, you may not make use of this load control, but you still may be able to make use of it if you have plants unexpectedly go down for maintenance, if you have some kind of weather conditions that throw you a loop you didn't expect; if you have a sudden opportunity where maybe one of your neighbor utilities is in real trouble and they need some assistance from one of the utilities that you're looking at. They may be able to make use of their load control, and use some of their plants to help this other utility.

It gives the utility more control over the conditions that they have to face.

One of the problems that they have in this uncertain time is the uncertainty of what they're going to have to face.

A third important thing that load management does is to decrease the importance of peak forecasts relative to energy forecasts.

A number of people have made the point today that energy forecasts are a lot more reasonable to develop than peak forecasts are. They seem to be more—I'll call them rational in the sense of being responsive to changes and to underlying causes. They're less affected by weather conditions, and freak occurrences.

By using load control, if you have the equipment available to serve the energy, you're more likely to be able to shut off various loads, serve peak if you get unusually high peak, and still be able to serve basically the energy needs, which are the major underlying things that the utility is trying to serve.

And with those various kinds of things that you can do, you're better able to deal with the uncertainty that you know has to exist when you're forecasting the need for electricity.

MR. SHELTON: Thank you very much.

Our next speaker is Dan Hamblin. Dan is in the Economic Analysis Section at the Lab. Dan has been involved in the maintenance, revision and application of the Lab's building sector end-use models of residential and commercial energy demand. He has also worked on the development of an economics model suitable for analysis of innovative building designs situated in various tax and utility pricing environments. Before coming to the Lab, Dan taught economics at the University of Wisconsin at Parkside.

Dan will wrap up the formal presentations this afternoon with a discussion of further developments in end-use modeling.

MR. HAMBLIN: This is intended to be the second half of Mike Jaske's presentation, so—it looks like it will have to be the first and the second half.

I've divided my presentation into the following four components (Slide 1): since I'm associated with the Oak Ridge building sector models, I'll talk a little bit about

FURTHER DEVELOPMENTS IN END-USE MODELING

I. What are the ORNL buildings sector models?

II. What has motivated improvements in the models?

III. What improvements have been made and are being made?

IV. What are significant end-use modeling concerns for need-for-power assessments?

SLIDE 1

what they are, what has motivated improvements in the models, further developments that are in process, what improvements in the models, further developments that are in process, what improvements have been made and are being made, and what are significant end-use modeling concerns for need-for-power assessments.

As the second half of the missing presentation, I'm probably lacking a little detail in the explanation of what these basic models are, so I hope this is not too summary in nature. Perhaps if there are further questions, I can address them in the discussion part.

We have end-use models for commercial and residential buildings. We also have an industrial sector model that I am not directly associated with.

These models are so-called engineering economic predictors. They forecast annual energy use and policy impacts by building type, end-use and fuel.

The drivers for these models are both from inside and outside the Laboratory. They operate from exogenous forecasts of overall macroeconomic variables: GNP, disposable income, demographic variables such as population, fuel prices, equipment prices, and the like.

We also have drivers that are developed inside the Laboratory, and constitute the basic parameterization of the model. These have to do with the four basic components of the building sector models.

There's a building stock growth component, for which we estimate econometric coefficients in the residential sector, both for the numbers of the stock and for the size of the individual components of the stock—the average size of single-family houses, for example.

In the commercial sector, the basic building stock unit is per square foot of floor space, so stock is captured in one dimension.

Then we have the second basic component—usage. We estimate coefficients for predicting intensity of usage adjustments, such as desired changes in average thermostat settings.

The third basic component, which really makes an end-use model an end-use model, is technology assessment.

Our model operates on the basis of a production paradigm. We look at isoamenity curves, which are like isoquants to economists, and we look for tangencies between those and iso-life-cycle cost curves. We have to parameterize these isoamenity representations of shell and equipment technical options, according to the results of engineering process analysis.

Or we look at advanced technologies in things like heat-pumps, solar options, and various kinds of other end-use technologies.

Finally, we have a basic econometric component model dealing with fuel and equipment choice, for which we estimate coefficients.

Slide 2 summarizes the points I have made in defining the end-use models: the last bullet in this figure is something that I intimated in the context of discussing the isoamenity representations, and that is, that really, the underlying paradigm of our models is the minimum life-cycle cost paradigm. The decision-makers minimize the life-cycle cost of owning and operating the end-use equipment.

There are three things that have motivated improvements in these models; one, the change in the territory for the analysis, has a couple of dimensions.

One dimension is in the way we ordinarily think of a territory. That is, that we developed these models primarily for regional analysis and national analysis, and there's been, I guess I would say in pure economic terms, a lack of sponsorship interest in the use of the models at this level, as much as we previously had. On the other hand, there's been more interest shown at state levels and service area levels. A model which is suitable for aggregate analysis is certainly not suited for a more disaggregate level of analysis. So that's motivated interest in getting at the characteristics that would improve the models for alternative levels of analysis.

A second aspect in the territory for analysis is what do we use the model for? What do we focus upon? We used to be very reluctant to advertise the energy demand forecasting properties of our end-use models. We really didn't want to use them for forecasting energy demand. What we wanted to use them for was forecasting the

What are the ORNL buildings sector models?

- End-use models for commercial and residential buildings

- Engineering-economic predictors of energy use and policy impacts by building type, end use, and fuel

- Driven by exogenous forecasts of
    - GNP/Disposable Income
    - Population
    - Fuel Prices
    - Equipment Prices

  (typically) from outside ORNL

- and
    - Coefficients for predicting building stock growth
    - Coefficients for predicting usage adjustments
    - Parameters for isoamenity representations of shell and equipment technical options
    - Coefficients for fuel-and-equipment choice developed at ORNL

- With an underlying paradigm that decision makers minimize the life cycle cost of owning and operating energy using equipment -- by their efficiency choices for equipment and shell

SLIDE 2

deltas where deltas were conservation program impacts—the change in demand that you would get if you instituted some particular program. Now, however, with the change in the other sort of territory for analysis, we are looking at the properties of the model that might make it better at forecasting energy demand as well as conservation program impacts.

The second stimulus for improvement is that the model is not doing very well. We haven't done so well at modeling some policy impacts, particularly in the area of those things which have information components—that are somehow related to implicit discount rates at which choices are made.

A first kind of impact that we have modeled poorly at the national level has to do with predicting the penetration of advanced end-use technologies, that DOE is spending money on developing.

A second kind of policy that we haven't done so well on falls under the category of home audit retrofit, and that plays on two underlying weaknesses in the model. One is the information implicit discount rate kind of thing. The other is the aggregation problems with these models—a topic I will get into in a little more detail later.

But, basically, we started out in the residential sector with a model that looked at new houses and the existing stock of houses as a lump. Okay. Well, you can't very well look at retrofit with an amorphous lump of existing houses. And so we had to do something in that area. Finally, the model reviewers have recently had their say about our model. I think we have been fortunate, in one sense, that our residential model in the last year has been under fire. It has taken the heat of a couple of sponsored reviews, and the consequence of that is its weaknesses have been exposed and we have had to do some work on those weaknesses. And I think that we have benefited from that process, which leads me to a discussion of Slide 3 which summarizes the heat the residential model has been in.

This is what you really call "warts and all." I have divided these criticisms into three types, by source of criticism. The first type of criticism we have gotten is part of the formalized model evaluation process. Here, we have been reviewed by Daniel McFadden, who is an economist at the Massachusetts Institute of Technology, and also associated with the MIT Energy Lab; David Freedman, who is a statistician at the University of California at Berkeley; and by the "et al." who were two economists from the Economics Department at Berkeley.

So the first type of criticism was professional criticism by economists and statisticians and others.

The second type of criticism is by those who use our models and other models that are like ours. I call these individuals residential model practitioners; I should call them residential end-use model practitioners. If they are using our model, they say, "Well, this is what is wrong with it; this is what you ought to do to improve it." Some of these practitioners have made improvements in our model on their own behalf, and we have benefited from some of these improvements.

The third type of criticism comes from sponsors and conservation program practitioners. And, as you may have already noted, in some instances the program practitioners don't like the impacts that our models show for their programs. Hence, they argue either that the program is weak and not a good program, or that there is something wrong with the model. And the model is generally the first target.

Now, rather than going through each criticism in detail, I may hit on them as we go along. But I would note that there are some criticisms that occur more than once.

TYPES OF CRITICISM/RESIDENTIAL MODEL

1. Formalized "model evaluation" criticism by Daniel McFadden, David Freedman, et al.

   PRIMARY CRITICISMS

   - Aggregation bias (& vintage deficiencies)
   - Poor documentation
   - Poor validation
   - No feedback loop from energy prices and policies to housing numbers and size
   - Usage and fuel-and-equipment switching coefficients/ inconsistent and *ad hoc*
   - Lack of usage consideration in LCC optimization

2. Residential Model Practitioners - Bob Weatherwax, Mark Levine, Jim McMahon, et. al.

   PRIMARY CRITICISMS

   - Fuel and equipment switching coefficients/gas availability
   - Technology curves
   - Lack of vintage structure and consequences
   - Poor documentation of modifications
   - Theory bound and data short -- Intrinsic model structure
   - Insufficient end-use detail (18 versus 29)
   - Lack of household size influence on usage
   - Not very good at service area forecasting

3. Sponsors and Conservation Program Practitioners

   PRIMARY CRITICISMS

   - Lack of impacts for "their" programs
   - Poor documentation
   - Poor validation
   - Fuel-and-equipment-switching coefficients
   - Lack of vintage structure
   - Technology curves

SLIDE 3

I guess there is one other thing about model criticism I would like to say. End-use models, while simple in concept, are complex in structure. And they are deserving of criticism in some ways. They need to be opened up and the various components looked at, and a hit list like this made up relative to them. Oftentimes you get this kind of gospel faith in the numbers that come out, without recognizing how many different parts of the models are associated in producing those numbers—each part of which may have some kind of weakness.

The third part of my presentation, which follows directly from the second part, is what we are doing about the problems—what improvements have been made and are being made. Slide 4 delineates model improvements. The process isoquants, What Improvements Have Been Made and are Being Made?

- Improvements in engineering technology curves
- Improvements documented in the formal response to the McFadden evaluation
- Restructuring usage and fuel choice

SLIDE 4

which are engineering technology curves by another name, have been worked on in the last year or two—to improve the representation, particularly of advanced technologies. What happens with the development of these curves is that oftentimes in trying to fit the cost and performance of various technology options, we run into problems. Maybe I should explain this a little more. What our model basically says is: suppose I want to produce 72 degrees space heating in a certain area, like 1600 square feet of floor space in a single family residence. Okay, how can I do that with the various kinds of space-heating technologies? Well, there is a spectrum of space-heating technologies, for example, electric space-heating technologies, that have different associated capital costs and performances and efficiences.

What we do is produce an optimal frontier of the cost and performance of these technologies. You may have 15 or 16 technologies for electric space-heating, for example. And what we have to do is to try and parameterize these technologies in some simple way, such as a three-parameter curve fit. Of course, you find you can't do it very well in some cases. And what we do is sit down at an interactive computer terminal and use a lot of artistic techniques to get the best fit. We have found that some of the fits that were made quickly in the past were not made nearly so well as ones that we spent two or three days on. So we have gone back and have redone a lot of the work that has been done in the past to improve the engineering technology curves just from the artistic "fit" standpoint.

The other standpoint of improvement addresses the question, "Do the costs and performances that are reflected in these curves represent our current thinking?" We are involved in upgrading that aspect of the models right now.

I might emphasize that I am focusing my talk on improvements that we have made in our residential end-use model, because it is the one that has been in the review process. And, frankly, our resources over the past year have been focused in that area.

The second type of improvements are those improvements documented in the formal response to the McFadden evaluation. And then, I will also talk a little bit about restructuring usage and fuel choice in these models. Slide 5 summarizes our responses to to recommendations made by Daniel McFadden.

Responses to McFadden Recommendations

- The data are not sufficient to the task.
- The suggestion may not be sensible or practical to implement.
- The suggested model improvements have been made, or are being made.

SLIDE 5

You can't agree with everything a reviewer says. Therefore, we have three kinds of responses to Daniel McFadden's recommendations. There were a few instances in which we believed that the data were not sufficient to the task that he wanted us to accomplish with our model. There were also a couple of instances in which we thought the suggestion was not sensible or practical when you got right down to implementing it. In some cases, the cost of implementing it was just way beyond what we thought the additional gain would be.

But then, most of the time we thought the model improvements that McFadden suggested were worthwhile. In some cases, we had already started making them, because other people had complained about the same thing.

Slide 6 describes "McFadden inspired" improvements. I won't go through these model improvements one by one But again, if you look at the list of criticisms in Slide 3, these improvements address those criticisms in some sense. We haven't responded to every one yet, but we have responded to quite a few of them in upgrading the quality of our residential end-use model.

I would like to separate these in terms of what is being done. The Improvements No. 2 and 8 are improvements that have to do with the aggregation properties of the model, and I will talk about that in just a little bit. But Improvement 2, which is an addition of the housing vintage structure endogenous retrofit consideration and the energy data by income class, is at the stage of having the vintage structure code completed and pretty much checked out. But the behavioral characterization of endogenous retrofit consideration has not been completed yet. So that is where we are there.

All of the other improvements have already been implemented, although we would like to make some extensions on them. The elasticity corrections in the direction of logical consistency had to do with some problems that existed in going from an exercise in estimating fuel choice coefficients using those coefficients in simulating

Model Improvements Related to McFadden Recommendations

(1) Elasticity corrections "in the direction of logical consistency",

(2) Addition of housing vintage structure/endogenous retrofit consideration/energy data by income class,

(3) Associating housing-size-growth-induced increases in equipment capacity with concomitant increases in equipment prices,

(4) Considering usage in efficiency choice,

(5) Correcting interest rates employed in fuel-and-equipment switching,

(6) Elimination of duplicative lags in LCC optimum efficiency choices,

(7) Employing fuel price expectations in present value of energy cost calculations for determining LCC optima, and

(8) Simultaneous optimization with equipment replacements over the life of the structure/elimination of fractional-ownership-aggregation-error.

SLIDE 6

energy use over time. We resolved some of the logical consistency problems that were associated with that exercise. However, because we are reestimating the fuel switching, this will be replaced by something better.

No. 8 is the simultaneous optimization and has to do with new structure, equipment and shell choice.

Slide 7 summarizes salient aspects of our current residential fuel choice work. Fuel choice is the primary econometric component of our end-use model. What we are trying to do here is to make it more amenable to the forecasting environment of a service area. And to do so, we have tried to develop a methodology that is internally consistent with the underlying paradigm of the model, of the minimum life-cycle-cost technology choice paradigm. At the same time, it has a kind of black box generality associated with it. It allows us to take any particular survey area of analysis, and take that data, run it through a black box, produce some of these fuel choice coefficients, and use them to simulate fuel choice in the end-use model.

Slide 8 is a menu of new structure configurations for which life-cycle-cost minimizing technology choices might be made, and consequent fuel- and equipment choices might follow.

RESTRUCTURING USAGE AND FUEL CHOICE

- Nested logit discrete choice methodology
- Internally consistent with the minimum LCC technology choice paradigm
  - simultaneous for space conditioning and water heating in new structures
  - sequential for "portable" appliances and equipment replacements
- "Black box" generality in ability to generate coefficients from survey data representing differing size regions (e.g., nation or service area)
- Does NOT entail the Axiom of Independence of Irrelevant Alternatives

SLIDE 7

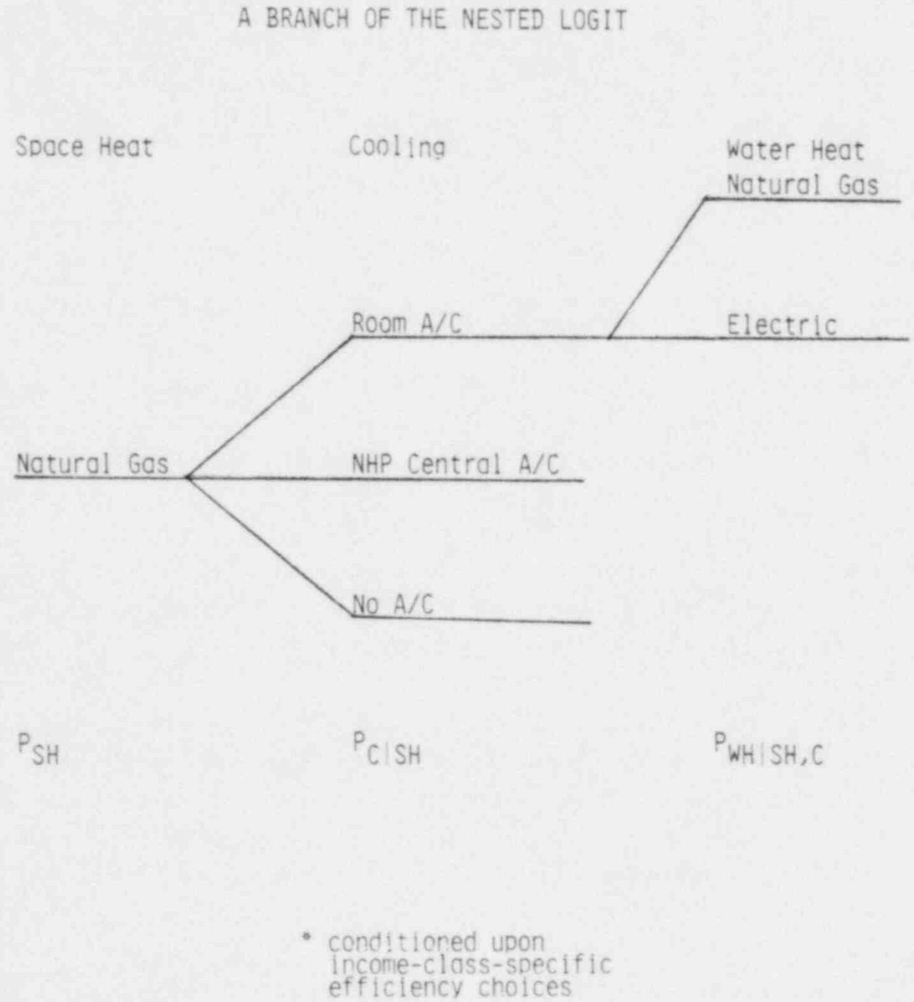
NEW STRUCTURE CONFIGURATIONS FOR WHICH LIFE CYCLE COST
COULD BE MINIMIZED

	Space Heat	Room A/C	HP Central A/C	NHP Central A/C	No A/C	Water Heat
1	Electric Heat Pump		x			Electric
2	Electric Resistance	x				Electric
3	Electric Resistance			x		Electric
4	Electric Resistance				x	Electric
5	Natural Gas	x				Gas
6	Natural Gas	x				Electric
7	Natural Gas			x		Gas
8	Natural Gas			x		Electric
9	Natural Gas				x	Gas
10	Natural Gas				x	Electric
11	Oil	x				Oil
12	Oil	x				Electric
13	Oil	x				Gas
14	Oil			x		Oil
15	Oil			x		Electric
16	Oil			x		Gas
17	Oil				x	Oil
18	Oil				x	Electric
19	Oil				x	Gas
20	Wood/Back-up	x				Electric
21	Wood/Back-up	x				Gas
22	Wood/Back-up	x				Oil
23	Wood/Back-up		x			Electric
24	Wood/Back-up			x		Electric
25	Wood/Back-up			x		Gas
26	Wood/Back-up			x		Oil
27	Wood/Back-up				x	Electric
28	Wood/Back-up				x	Gas
29	Wood/Back-up				x	Oil
30	Other	x				Other
31	Other	x				Electric
32	Other			x		Other
33	Other			x		Electric
34	Other				x	Other
35	Other				x	Electric

SLIDE 8

Slide 9 is a diagramatic explanation of the nested logit which underlies configurations of Slide 8.

Without further ado, I think it would be best if I proceeded to the last part of my talk.



SLIDE 9

Slide 10 lists the significant end-use modeling concerns for need-for-power assessments. When I look at these models and I ask how good they are for need-for-power assessments, the things that come to mind are the level of aggregation error, what I call the model soundness for the purpose at hand, the cost effectiveness of the model, and their potential for integratability with some kind of peak load forecasting methodology.

Significant End-Use Modeling Concerns for
Need-for-Power Assessments

- Level of aggregation error
- Model soundness for purpose at hand
- Cost effectiveness
- Integratability with load forecasting methodology

SLIDE 10

Slide 11 describes levels of sinfulness on the commission of aggregation error. What aggregation error has to do with is the way you combine results from a bunch of structural components. You use each structural component, such as a usage equation of some type, to forecast some average level based on some kind of econometric estimating equation. You also forecast some average equipment energy use intensity from some kind of technology component, like we have, that operates on the principle minimum life cycle cost. Similarly, you forcast an average shell energy use intensity. Again, you get some incremental improvements in the shell, such as addition of storm windows and so on. And finally also based upon economic and demographic factors, you forecast housing size.

Then, you take those averages and you multiply them times the market share employing the fuel end-use combination at which you are looking, and times the housing stock for that particular category. You get a quantity that is all just loaded with what is called aggregation bias, because it is not necessarily the case that the multiplication of these averages will result in the same answer you would get if you looked at the sum of the energy uses in individual households that comprise the aggregate. And this is the problem with most end-use models that have been developed. A lot of them use the same basic kind of equation.

Now, what we are involved in doing in our model is reducing the level of aggregation. We have divided the Q_t energy total into a whole bunch of components. For the existing stock, we have divided it into vintages representing buildings of different age. And for new structures, we have divided it into the configurations already depicted in Slide 9.

What we have done here is made a frontal attack on the inherent aggregation error in these models. The ideal, of course, would be to be able to sum up the whole housing stock and get an aggregate figure.

LEVEL OF AGGREGATION ERROR

Energy use for a particular building type, end use, and fuel

- Before

$$Q_t = \underbrace{HT_t}_{\text{housing stock}} \cdot \underbrace{HS_t}_{\text{housing size}} \cdot \underbrace{C_t}_{\substack{\text{market share employing}\\ \text{fuel/end-use combination}}} \cdot \underbrace{TI_t}_{\substack{\text{shell energy use}\\ \text{intensity}}} \cdot \underbrace{EU_t}_{\substack{\text{equipment energy}\\ \text{use intensity}}} \cdot \underbrace{U_t}_{\substack{\text{Average}\\ \text{usage level}}}$$

- After

$$Q_t = \underbrace{\sum_{v=1}^{V} Q_v}_{\text{vintage representatives}} + \underbrace{\sum_{c=1}^{35} Q_c}_{\text{new-structure configuration representatives}}$$

- Ideal

$$Q_t = \sum_{h=1}^{H} Q_h$$

or

Monte Carlo/Micro-simulation of individual household behavior

SLIDE 11

Slide 12 addresses the issue of model soundness for the purpose at hand. There are three model candidates, two of which are in wide use.

The California Energy Commission type of model is essentially an accounting base model. It adds up reality. It is much more data intensive and end-use detail intensive than ours is. Because of that, it has very high short-term accuracy. Its longer term difficulty is the absence of cause and effect that is based upon some kind of economic theory or engineering process analysis or what have you.

The engineering-economic models, which I represent, have much lower short-term accuracy. They are more theory intensive. They basically operate by simplifying

MODEL SOUNDNESS FOR THE PURPOSE AT HAND

Wants

- Mid-term forecasting credibility
- Ability to predict conservation program impacts

Tools	Method
• Accounting-base models	Add up reality
• data intensive	
• end-use-detail intensive	
• high short-term accuracy	
• validate well	
• longer term difficulty is absence of theory-based cause and effect	
• good for "add-up" conservation programs	
• Engineering-economic models	Simplify reality
• theory intensive	
• lower short-term accuracy	
• validate less well	
• longer term strength is presence of cause and effect	
• good for "prescriptive' and incentive-based conservation programs	
• essential to calibrate and validate thoroughly	
• Micro-simulation models	Sample reality
• theory and data intensive	

SLIDE 12

reality. Their longer term strength is the presence of cause and effect, but because they are not so data intensive, it is essential for these models to have a thoroughgoing calibration and validation exercise associated with their use.

And there are actually two of the micro simulation models—Jerry Jackson's in the commercial sector and Goett Cambridge Systematics model for the residential sector. These models employ Monte Carlo techniques to sample reality.

Slide 13 speculates on the cost-effectiveness of these model candidates. I shall speak a little bit on cost effectiveness, because I think that is an important issue with relationship to end-use models.

On the cost side, the California Energy Commission constructed a kind of relative run-time comparison. You can look at computer cost per unit of run time and use that to compare these models.

COST EFFECTIVENESS

- Cost
  - Relative run-time

Old ORNL Residential Model	1
CEC Residential Model	10
Goett Micro-Simulation	100
Current ORNL Residential Model	2
Discrete Choice/Vintaged ORNL Model	10

- Effectiveness
  - ?
  - How good are data?
  - Might use disaggregate/complex to unbias aggregate/simple

SLIDE 13

The original Oak Ridge residential model was a factor of 1, by which the data intensive California Energy Commission model came in at 10 and the micro simulation approach, which looks at individual households, came in at 100. Our current model, which has its simultaneous optimization in for new structures but does not have the vintage component for the existing stock, comes in at about a 2. And we anticipate that the full-blown model that we will have at the end of the year will come in with the same run time, and the same cost for running as the current CEC residential model.

The effectiveness is an open question. There really has not been a thoroughgoing comparison of these models. Moreover, effectiveness depends on how good the data are. And we are becoming more data intensive in our model as we try to make it more appropriate for service area analysis. There is every reason to believe that we will have a lot more problems with the data for service areas.

What we think, however, is that in some sense we might be able to use the disaggregate complex model that we are developing to see how good what we started with was—the aggregate simple model. You might almost say, from an economist's viewpoint, that the aggregate simple is kind of a reduced form of the disaggregate complex, and that we might use one to adjust the other.

MR. SHELTON: Thank you very much, Dan. We will take a coffee break here in a second, but before we do Bob Camfield has some information on some data that he would like to give. It will take a few minutes, and then we will take a break.

MR. CAMFIELD: As I was listening to others that followed me this afternoon, I became acutely aware that I didn't tell you one of the really serious things I wanted to tell you. That is, if you were to proceed in an endeavor, where might you start to get information. I can't tell you about the entire universe of information out there, but what I can tell you, however, is about some of the things that we're using, and the documents that we reference for the purpose of information. Oak Ridge National Laboratory, the work of Jackson, I think, is a very good introduction into how you might proceed with a combination of sort of theory-based econometric and end-use forecasting.

For elasticities, the work of Chern is very good. In addition, of course, the work of Anderson at Rand Corporation. These are not organized. Third, the Buildings Handbook of Oak Ridge National Laboratory is very useful for background.

Getting down to the end use and conservation penetration, that is to say, the penetration of conservation in the residential and commercial sectors, the Brookhaven building optimization model, BESOM and BECON, is a good place to start, I think. It deals both with the energy saved, that is, the accounting of the energy saved, as well as the dollars invested.

The NEPOOL-Battelle forecasting documentation would be another one that would be worth keeping in sight, if you were starting an endeavor. NEPOOL is the New England Power Pool located in Springfield, Massachusetts. One area that is particularly difficult, of course, is the commercial and services sector, as everybody knows, and in New Hampshire we're hoping to carry out some surveys of what's been going on in terms of how commercial establishments use their energy. In this regard we're relying on the Xenergy, Inc., group of Boston, Massachusetts. At least we're hopefully going to do some work with them. You might want to contact them with regard to surveys in the commercial sector. They've done a very extensive survey of the commercial sector for the New England Electric system, most recently. The documentation of this work is available as of December 1981.

MR. ANDERSON: You talked about a Rand study?

MR. CAMFIELD: Yes, the elasticity work done by Anderson of the Rand Corporation, and I'm sure in the residential sector. I think he did work in the commercial sector as well.

Again, I don't represent this as being the universe of information. EPRI, the Taylor Elasticity Studies, are very good, and how he treats the intramarginal price and the specification of price for estimation of price elasticity is a technique that has a terrific insight, I think. A state economic forecast is important because you have to somehow, I think, deal with the issue of economic activity. Here, the work of George Treyz at the University of Massachusetts is outstanding. Carl Hunt and I were recently talking to Treyz. I'm sure that Carl would agree with me, that Treyz has done some extraordinary work in the area of state economic forecasting, and he has a model now up and available for, as he indicates, every state in the union.

Going to building construction data, one thing that seems to have occurred is that after the 1975 period new building construction in the commercial sectors is much more energy-efficient than previous constructions. So what we're doing in New Hampshire is bifurcating the building stock, the basic building stock, into two different trajectories, using a decay function with the existing, or should I say, retrofit market, as it's sometimes called, and how that would proceed out in time, as well as new construction. Dealing with the construction of flow space data, you can go to the well-known F. W. Dodge McGraw-Hill subsidiary for construction data within the states.

Appliance prices. Any major forecasting service. Appliance prices, of course, relate to appliance saturation and income, and so that's very useful.

Finally, the intensity of use coefficients in manufacturing. How do we deal with that? I'm relying on the national data here: Survey of Manufacturers and the Census of Manufacturing Data. The energy sector is very useful. That data will take you through 1979 for the estimation of price elasticities.

In the commercial sector, it seems that the trend is toward evaluating energy consumption per unit of floor space, and the floor space trajectories are generated through the floor space employee ratio. This would essentially represent the unit of economic activity in the commercial and services sector. A good place to start for that data is the Ide Survey, done for the Department of Transportation, I believe. It's available through NTIS. In that regard, of course the Btu per square foot, which is converted to electricity on an annual basis, can be assessed through the A. D. Little project, the consulting project done for DOE/FEA.

And units of real output in manufacturing, which are the units of activity in the manufacturing sector. In New Hampshire, we're using Wharton econometrics for real output in 1972 dollars.

That's all I have to say Bob, but I thought that might be useful.

MR. SHELTON: Thank you very much Bob. That kind of continues some of the issues that were raised, particularly this morning.

Why don't we take a coffee break and we can reconvene at 25 minutes to 4:00. We will continue with general discussions.

(Recess.)

MR. SHELTON: We've covered the spectrum of models and modeling techniques, and we think it would perhaps be a good chance to open up discussion by asking our participants sitting around the table if there are any particular types of criticisms or information that they might provide us on the presentations by others and critiques of particular modeling techniques and basically any disagreements they've had. There have been some opinions cast out without much response. I've bitten my tongue a couple of times, and I'm sure some others have bitten their tongues a few times. So, we could open it up first to the participants to see if there's anything that they would like to comment on before we get audience participation.

MR. CAMFIELD: I have a question of Dave in regard to the minimization of risk in dealing with uncertain demand. One of your suggestions was to keep, as best you can, the increments to capacity small. If there are scale economies in the generation process, would that not be a loss therefore of those scale economies? Would that not be the price that you would bear for minimizing the risk?

MR. SCHOENGOLD: To some degree, there might be. It's been our experience that once you get beyond the 300 to 400 megawatt size in the last few years, those scale economies seem to have disappeared. In any case, even if they may still be there, you don't gain anything by getting yourself locked into a 1000 megawatt plant that's supposed to give you scale economies, only to get half way through building it and find that you can't decide whether to go ahead and build it and have to pay for it when you don't really need it, or to stop it in the middle and maybe go back and start it again and face whatever costs you have for doing that.

So there are some countervailing trends there. Depending somewhat on the size of the systems that you're dealing with, I think you can get into—now I'm talking from the Wisconsin experience—the situation where the system state peak demand is on the order of 5000 or 6000 megawatts with a few hundred megawatts growth per year. You can get to real problems if you start to try to put in, say, 1000-MW plants. The risks that you're facing just aren't worth any possible benefits that you may get from economies of scale, which in the last few years don't seem to have been occurring.

MR SHELTON: Yes?

MR. KAHAL: I'd like to address this question to anyone who feels they can answer it, although it was stimulated by Bob Camfield's presentation, and that is the double counting problem that occurs when you try to incorporate conservation programs or anticipated conservation programs into a load forecast. The problem is that when one tries to calculate the decrement to future energy demand from conservation, one has to take into consideration that market forces would have accomplished some of that so-called "conservation" anyway. Let me give you an example.

Suppose you have an attic insulation program in your utility service territory, and you estimate that 50,000 people are going to participate in that attic insulation program, let's say, by 1990. Now, it may well be the case that given the market forces that exist of those 50,000, 40,000 would have added attic insulation anyway. Does anyone have a decent method of dealing with the double-counting problem, when trying to take into consideration conservation programs?

MR. CAMFIELD: No. You're absolutely right. When I talk about conservation technologies and techniques, what we're dealing with here is a conservation that would occur beyond that that would be in response to prices. I don't treat conservation as something that is in response to price. When I'm talking about conservation, I'm talking about the results of an overt conservation plan, but for sure you've got to separate the two, so that you do not incorporate the responses to price that would otherwise have occurred. No question about it.

MR. HAMBLIN: We've done things with our end-use models to look at impacts of things like plant standards and building and performance standards of running an exercise of implementing the conservation program in the characterization of the technology choice and then holding prices constant—as against that, run a market pricing area, to see if we can get a relative handle on what the incremental impact of the conservation program would be over and above the market price.

MR. KAHAL: I've seen some of that. In fact, I've used some of your results in my own work, because that's all I can do. The things that Oak Ridge was doing looked conceptually reasonable, and in kind of a gross way, I tried to wrap that onto some of our own work, but I just haven't seen it really done well and, of course, I had to make assumptions that whatever you had embedded in your model was consistent with what I had embedded in mine. And that, of course, requires a leap of faith, but I've never really seen it done very well at the utility system level.

MR. SHELTON: I think that's the issue we have. Eric Hirst, some of you may know. Eric is at Oak Ridge and has a fairly sizable project now, in fact, measuring the effectiveness at the utility level of various conservation programs. Eric has what we call a "TM." It's a report coming out. I haven't seen it. I've only seen a summary of the results in which he, in fact, does this nationally. Of the conservation that has taken place nationally, he estimates that roughly one-third of this is the result of various federal conservation programs. As I say, that report should be coming out momentarily. I've just seen the preliminary summary of the report.

There was a hand back here. Yes?

MR. KANECH: One thing that I've done working for the Nebraska Energy Office involves verifying to the Feds how much energy Nebraska is saving through their education program. We would use factor analysis and principal component analysis, same thing, put in our data series from the factors of influence and identify one as price, one as seasonal trends, and also one as conservation efforts, which is high, and we take all the credit. I don't know how valid it is, DOE may shake their heads and say, "Boy, that's really neat." I don't know if they know what I'm doing, but we're taking credit in that way. Logically, it makes sense to me because we're able to isolate the variation, price induced and seasonally induced, and other things. Maybe we might take a dive in that way. I don't know how valid that is.

MR. KAHAL: Right, but that's if you have historical data on it. It's something else again to go into the future and try to figure out that we think these such-and-such programs are going to occur in the future and will attribute so much energy savings to them. It almost ends up being an arbitrary exercise, or it's an arbitrary exercise at best, and at worst, it results in double counting of energy savings and will result in a systematic downward bias in the forecast. That's where it becomes dangerous.

MR. HAMBLIN: I think there's another dangerous aspect to it, and that is, there's a kind of engineering mentality that works its way into these models, and by engineering mentality—

MR. SHELTON: Careful. We're not all economists here.

MR. HAMBLIN: At the expense of any economical reasoning that says, "Hey, look, I've got all these technologies. I know that they're technically feasible, and I can run a potentials analysis, using these models and see that there are all kinds of possible conservation, and if times are tough, we'll just think of some program to force the conservation," and I think that is kind of perverse use, a good aspect of the models.

MR. MENDL: I'd just like to add a comment to that, because one can also go the next step and figure out what's economically the potential and not have the foggiest idea whether it actually will be implemented. The same logic goes one step further. It seems to me, the bottom line, in discussing conservation, in trying to identify it as being price induced versus altruistic in some ways, is really an arbitrary distinction which may not be necessary, depending upon the type of model and what purposes you are trying to address it to.

In Wisconsin we've had several efforts to specifically quantify conservation, the conservation effect. They've produced, I think, some rather arbitrary numbers that look nice in the forecasts, but I don't think they have very much meaning in fact. We have just undertaken an analysis on, really, I guess it's sort of an end-use support approach, pretty much a pure end-use approach, in which the conservation has been blocked off and segregated into separate, specific programs and activities, identifying which is going to be cost-effective. That brings the problem I mentioned earlier. It isn't going to be implemented. What kind of policies ultimately are going to be involved in going ahead with implementation.

So I think it's more significant for some types of methods than for others.

MR. SCHOENGOLD: But that's not a forecast.

MR. MENDL: That's not a forecast. It's a scenario.

MR. KAHAL: I quite honestly think that this is an important area of research. If you are research oriented, you ought to think about this problem. I'm not.

MR. SHELTON: Questions from the floor. Yes?

MR. KELLY: Kevin Kelly, NRRI.

I have a question about what it is you try to forecast—demand retail or demand wholesale?

It may seem like there's a simple answer, but I'm not sure there is, because there are all kinds of close-out sales, ranging from what I call very firm, for want of a more accurate term right now, down through just economy purchased. Some of those perhaps you'd want to include in the forecast, some not. Some might be associated with very long-term contracts, some with 9-month contracts.

I won't be long-winded about it; I can maybe describe the problem more exactly, but any replies? Are the panelists about of one mind?

MR KAHAL: I'd like to address that, because it's an overlooked area.

To give you a simple answer to your question, Kevin, we've done nothing about non-firm wholesale sales. On the other hand, I've been involved in a couple of planning studies, and it struck me that the way utilities have gone about planning is fairly parochial. Utilities plan their systems in order to meet their "native firm" requirements. Period. Utilities do not look at markets, they do not look at power markets, generally. An exception to this, I think, is New England, where the New England Power Pool does not plan on a regional basis. That's virtually unique.

That's not done elsewhere, and it's certainly not done in this region of the country. It may well be that a unit which is uneconomic in terms of serving its own load might be very economic when you take into consideration opportunities for off-system sales. The only way you can assess that is to not just forecast your own requirements, but look at what's going on with the supply-demand relationships in the future on other systems.

It's definitely something that's worth doing. Believe me, other industries that are out there in the free market certainly look at the entire market, not just their own customers.

MR. KELLY: If I could add to that, if you do a demand forecast, and it includes firm wholesale sales, say for contracts six months or greater, and you find that, sure enough, when the plant is built, all of the power is being sold, and the system is just right about at capacity plus reserve margin, because it has the right amount of wholesale sales, you say: well, by golly, we needed that plant, and we're selling just the right amount of power, and everything dovetails. How do you check your demand forecast if you include wholesale sales at whatever price is appropriate in the future in the forecast?

In other words, can you ever be wrong in your demand forecast in that case?

MR. HUNT: I might add a little comment there, Kevin, to that argument. One of the real problems that I think commissions have in this whole area is that sales—resale, but in the uniform system accounts go below the line—get to be a real major issue in some rate cases.

This is particularly true with one of our utilities, whom we suspect may be building to sell outside the state, as opposed to building to sell inside the state.

We've attempted to forecast both with and without resale. You were right about the self-fulfilling prophecy in the resale, particularly in the system that you suspect of building to serve load outside the state.

MR. SHELTON: Certainly this is an issue in the Tennessee Valley, because waiting for that, as one gentleman this morning discussed about planning for that growth that's going to take place, because of, quote: "cheap electricity," and in fact it's not there. How do you make those charges when you're in fact selling to other utilities. Do you have full cost recovery or do you in fact sort of dump the power, and give others bargain rates?

And certainly, right now,

Mr. KREIMAN: My name is Greg Kreiman; I'm with the Wisconsin Energy Office. I'd like to comment on this concept of economically justified conservation.

I think we use that term with at least two definitions; the conventional notion of what economics is all about—at least the way I was trained to think about economics—is that it describes consumer choice in response to relative price changes and income changes, as the consumer actually behaves, not as external observers would like the consumer to behave.

And a lot of times we see conservation actions described as being economic, in terms of some extrinsically imposed standard of what economically justified means.

The principal area where this comes to fruition is in this choice of discount rates. In a lot of cases, we see some technologies being labelled as uneconomic, with unrealistically low discount rates. I think a lot of us would be shocked to use analyses with realistic discount rates—that is to say, discount rates that actually reflect how we behave as consumers.

McFadden and other people have estimated consumer discount rates for durables to be 20 to 25% a year, which seems absurd. Why would we as consumers have such high discount rates?

Well, I don't know. As a scientific economist, I don't know why, but that seems to be the fact. So if we plugged in those kinds of discount rates, a lot of things we'd label as economically justified would no longer be economically justified.

MR. SHELTON: That's the problem with life cycle. You know, people don't make decisions on the basis of life-cycle costs.

I'm about to get Dan's ire up, but in some of our estimates on this decision-making, 20% is low in some cases. It's like 80 or 90% in implied discount rates.

MR. KREIMAN: But my point is that the scientific economist—it's outside of the realm of science to say that a discount rate is wrong or right or low or high. It's just what is. If you used "what is the discount rate?" you'll get very different answers than what you would get if you used "what ought to be the discount rate?" I'm not saying that this is necessarily a defect of the Oak Ridge model, but some of the discount rates that were in earlier versions of the Oak Ridge model and other models—the Brookhaven work, for example—the discount rates were very low for both commerical and residential activities, and naturally you'll get some choices that wouldn't occur if you used very much higher discount rates.

MR. SHELTON: Dan, did you want to respond that?

MR. HAMBLIN: We started out in the Oak Ridge model with a kind of duplicative lag structure in the model, and we quite correctly did start out with low discount rates. Once the efficiency choice decision was made, Eric Hirst developed this little thing to get away from what he called the "optimum" to what he believed was the actual, which was, in a sense, trying to reflect the fact that consumers have shorter paybacks than the discount rate that was being employed would imply.

Since that time we've tried to take out that lag, partially in response to McFadden's evaluation of our model, and to start out the model with what we believe to be our discount rates that do reflect consumer choices. We've gotten some of this information from a study that was done on consumer discount rates involving choices of shell options, a study done at the Laboratory by Ken Corum and Dennis O'Neill, and also the discount rate work that was done by Jerry Hausman, at MIT, which is actual discount rate.

MR. SIDELL: I'm Mark Sidell, with the Pennsylvania Governor's Energy Council, and I'd like to ask a hard question about the validity you ascribe to your various models.

I happen to be working on the issue of utility deregulation, and I just wondered whether anybody has a model yet, or when you think you might have a model that would enable you to advise an entrepreneur that demand is going to be out there to start a baseload power plant, to go on line in year X under some prescribed deregulation framework, but with all the rest of the world's uncertainties about price.

MR. KAHAL: The work that we're doing in Maryland would not be useful. I don't think, for that, simply because we're interested in individual service territories which are the size of SMSA's or larger.

If one were to go into the power production business and was contemplating building a power plant, one would be interested in a lot wider market than just that. One would be interested in, I would think, at least regional supply and demand imbalances, rather than what was going on at the level of one individual utility system.

MR. SIDELL: Well, you are basically looking at a PJM system lambda, which defines how much one's going to pay for the power in the future, and what effect this will have on that extended to a whole subset of numbers in PJM.

MR. KAHAL: That would be true if you happened to have projections for each of the PJM members. Maryland is not an insignificant part of PJM, it's true. I don't even think that knowing PJM lambdas is enough, because right now there are very, very active power exchanges going on between ECON and PJM.

The question is: how wide does your world have to be? What ought to be your economic considerations if you are thinking of going into the power production business on a deregulated basis?

And knowing what's going on in Maryland, or knowing what's going on at the level of an individual Maryland utility is hardly enough.

So my conclusion is that the work we're doing certainly would not be adequate to give anyone a good assessment of what you're talking about.

MR. SCHOENGOLD: It occurs to me that if you were going to go into the deregulated power business, you'd have to sell your power at full marginal cost, plus appropriate markups, and it's my guess, based on no data, that there's no way that you could sell any new power beyond what you could generate with the present existing capacity, if you were selling it to the ultimate customers at that new marginal price plus markups.

I think that at those kind of prices, the market would be saturated.

MR. SIDELL: Forever?

MR. SCHOENGOLD: For a long time.

MR. SIDELL: If demand keeps growing, I would think sooner or later, system lambdas would be dominated 24 hours a day by oil-fire-power. I mean, it's imaginable eventually, maybe even more by wind-power costs, but the point is, I would think sooner or later, system lambdas would get up to the level where Art could recommission an old coal plant, or even build a new coal plant if I were in some environmentally sound place. If I could collect oil running rates 24 hours a day from a coal plant, I'd be happy.

Can you tell me when that day might come, so I can start getting my bankers together? That's the question.

MR. SCHOENGOLD: I would say a long time in the future is the most likely answer.

Time? I don't think anybody can give you, other than just saying: I think a long time.

MR. CAMFIELD: Mark, if I may comment on that, in regard to the penetration of renewable resources, Tim Glidden, at the Dartmouth Resources Policy Center, has done a lot of work in that area, and has some interesting models to deal with the economics of Section 210 power.

MR. WILSON: I'd like to just make one short comment.

I kind of disagree with these people who suggest that it's out of the near future. I think what you're talking about is cogeneration, or something like that, right, that could be done on a relatively small scale and could in fact realize economies of scale at 50 megawatts or something like that.

MR. KAHAL: I don't think that he's talking about cogeneration at all. That's a completely different story.

With cogeneration there's a guaranteed market for the power under the 210 rules. Moreover, what's normally going on now in sizable cogenerators is that they're signing up for long-term contracts with the utilities, so the cogenerators are in a much more protected position than in a truly deregulated market.

That's what Mark's talking about, isn't it?

MR. SIDELL: Not exclusively. To put it both ways, I agree that you've got a lot of cogeneration that comes in before you want to build a new baseload plant, especially in Pennsylvania.

But for instance, I know in the 1960s, a 100-megawatt coal plant that's presently out of commission, that might be worth bringing back into commission some day, with or without cogeneration, you'd have to run a steam line at least three miles to get rid of waste heat.

Does it fit in? Actually, our question is: is our modeling of demand such that it could give somebody now or some day in the future a reasonable estimate of whether or not it paid?

MR. CANFIELD: I think the models are available. I think you have to deal with them in terms of a scenario rather than in terms of forecasting specific—rather than a point forecast.

MR. SIDELL: Do scenarios get higher bond ratings? I'm sorry; I'm not trying to be sarcastic. I don't know the difference with respect to the investment decision.

MR. CANFIELD: I'm just saying, when you go out to ten years, the future gets a bit hazy, and it's only reasonable to deal with it in terms of ultimate scenarios, instead of dealing with it in a point forecast.

MR. HUNT: I might respond a little bit to that.

What you're asking, to me is: am I or any other economist a soothsayer? Of course we're not. Do models predict accurately. Do we have any models that predict accurately?

No, we don't. Models, if you're talking about what is going to happen in the future, are simply one tool that one uses to try and make reasonable assessments about what might happen, not what's going to happen.

I don't think anybody can claim to know what is going to happen, and can guarantee it. I mean, if you know somebody that'll guarantee it, I'd like to talk to them, because, I mean, I'd be happy to invest my money in them.

I don't think anybody is going to guarantee a return on any investment, and I don't think that anybody who has a model that attempts to say what is going to happen, what might happen in the future, is going to guarantee it.

Now, I would take my models, and I would take mine and several other people's assessment of of what might happen in the future; I'd be willing to bet my money on it. I can't because of the conflict of interest, but I would be willing, yes, to do that. But not simply based upon any single model. Models are non-responsive, and the user of the model is really more important than the model itself.

MS. MADDIGAN: This is a really interesting question, and the possibility of deregulation and generation is something that is extremely intriguing and could reform the electric utility industry dramatically over the next 20 years. The problem with the use of econometric models that we have right now is that the historical data have been collected, first of all, during a period of regulation. Whether or not we really believe that the historical period could reflect the new order of deregulation of generation is hard to figure at this point. It would be, again, another leap of faith.

MR. SIDELL: Someone said that that isn't valid if you're talking about models that span the OPEC price increase, and I tend to agree more with them.

MS. MADDIGAN: The other problem is that we're talking also about wholesale sales rather than retail sales. The models we've developed at Oak Ridge are looking at retail sales in a particular state, whereas what you want to look at is the purchase of power by utilities who, in turn, will then sell it to particular residential, commerical or industrial users.

Really, right now we have an empirical base in the cooperatives, in that many of the cooperatives are distribution systems which purchase power wholesale from federal agencies, from individual investor owned utilities and from other sources, and have historically had this kind of choice on wholesale purchase. And I believe that because the sort of structure would be different, that it would be probably inappropriate to use the models like, for example, the SLED model to be able to forecast demand under a deregulation scenario, unless you could make some adjustments as to what the differences in prices would be in wholesale power, what the differences would be in people purchasing from perhaps different states instead of proximity, and things like that.

MR. SIDELL: That's really helpful, Ruth. I appreciate it. I agree with a lot of that, but I would point out that you are jumping to the conclusion. I'm only talking deregulation of generation, and some of what you've said is indeed relevant to whether or not one wishes to go all the way and deregulate down to the distribution company. That, of course, bounces back to whether or not we can use Mel's model, which I didn't mention in the question originally.

It is interesting. I guess I am trying to find out how confident one feels. Are you saying, for example, that you don't think you have the confidence in these demand forecasts that say an econometric model of any of the three or four major consolidated firms might have when they give advice to a corporation that might use that as an important input in making a billion dollar investment in an automobile factory.

MR. HUNT: These people are selling their models and I think they project a lot more confidence in them than they actually have.

Second, I'd go back that the user of any model is more important than the model itself. That model is only a point of departure. It is a tool to use in analysis. Most models that I've used and I'm intimately familiar with, I can almost tell you what the results are going to be before I use them, run the model, and models have biases, they have assumptions. When you're using the model, you have to know that.

If you know those, you should know what the most probable outcomes are going to be, and a model is no better and no more worthwhile than the person using it. And they are not a substitute for intelligent analysis.

MR. KANECH. I agree exactly. Models are effectived tools. One thing that would put more fear in our beings would be if we were to add up all the standard errors and have our proper distributions coming out at the end—nobody does that. No model, when you say this is the answer, says this is the range and I am this confident. I tried it once, and the range turned out to be huge. It's unbelievable.

With just a few simple equations, you know, when you pull the variances together and write down the line that it's asking, that's the questions we always get. How confident are we. I want to build this plant, how confident are you? We're sitting back hedging, and yet, we have the tool.

I think another tool that we need is to carry along our distributions. The problem with this is we're only getting to end-use models. We don't have any distribution. We just pulled this number out of somebody's book on elasticity and it has nothing with it, no distribution.

So I agree with that and we get those questions, and we do need to be sensitive to that. Maybe we could get some feedback about what the PUCs are doing with respect to time horizons.

Do you have a legislative mandate, as to coming in with particular horizons, or are there rules of thumb? Are there PUCs that you know for what period of time your feet are going to be held to the fire, to make promises that may not exist with, for example, regard to construction and other issues?

Yes?

MR. KAHAL: In Maryland, the utilities are required to report their plans and forecasts out 10 years. That's clearly inadequate and everyone in the state knows it, and hopefully that will be changed. In power plant siting, we don't have any requirement as to how far we have to forecast out, but as a matter of practice, we do forecast out 15 years. You can quarrel with that figure, but 15 years appears to be adequate as a planning horizon for Maryland utilities.

MR. HUNT: The Colorado utilities have to submit capacity plans for 10 years, any major construction plan for 10 years in advance. Our forecasting has to be for a 10-year period. I mean, I guess in some sense I might disagree in the sense of 10 years as inadequate. If you get further out, the more speculative you get. Fifteen years we'll maybe be alive, I hope, so the further out you get the more chance of just pure speculation you have. Ten years seems adequate to me.

MR. BIGGERSTAFF: But you can't even build a nuclear plant in 10 years.

MR. KAHAL: That's right. Lead times are longer than 10 years.

MR. HUNT: That's right, lead times for nuclear plants. Now, if you're looking at capacity—you see, I'm not too concerned, in some sense, about whether they build coal, oil, or nuclear. I mean, that's no concern of mine. It's whether or not they have the capacity and whether or not they're making plans to meet that capacity, based upon some reasonable assessment of cost and the cost of alternatives. And if, for some reason, one is more expensive than another, there may be a regulatory reason because of the lack of ability to get the process done in 10 years. I mean, that's really not a specific concern that I would have in terms of doing my job. Now, maybe as a citizen, but not in my present job.

MR. BIGGERSTAFF: My name is Gene Biggerstaff. I'm with FERC.

The utility, in doing its long-range generation planning, I would say in most cases their 10-year plan is already fixed. You may be able to put in some coal-fired plants possibly in the next 10 years. Certainly under the present conditions you can't put in any nuclear plants, yet if you don't—we assume that the political climate changes, or whatever, and nuclear does become an option again at some point in time—I mean, you have to go out far enough so that you can assume that the utility may be coming to you as a Commission and say, "today I want approval to build this nuclear plant which I am thinking about 15 years down the road." Yet, if you only want to look 10 years in the future, you'll never get that.

MR. HUNT: I think that's a recent problem. The time that it takes between planning and completion of the plant has been increasing. I think that's a problem that's being recognized by utilities, by commissions, by regulators and it's, I think, beginning to be addressed. And I would suspect in the future that we're going to see a shortening of the time between planning and completion.

MR. BIGGERSTAFF: But you can't determine what the optimum generation mix is by the next 10 years. You've got to look out 20 years.

MR. HUNT: Oh, yes. To some extent I agree with you. But by the time 20 or 30 years come around, conditions are going to be so changed—or you know, within the next 10 years, conditions are going to be so changed that what you've done, planned on, is obsolete.

I think forecasting is an ongoing thing. It's ongoing and a 20-year forecast is nice, but I would discount anything I would say that was going to happen in 20 years. But I would want to have an ongoing forecast and pay more and more attention to what's happening the closer and closer I got. And It's a process. It's not you do it now and that's it. It's a process, a process that you continually go through, and there are always changes.

MR. MENDL: I'd like to echo my support for Carl's comments. In Wisconsin there is essentially a 20-year forecasting horizon, roughly, that the utilities are required to file. In practice, when the Commission reviews it, it will probably make some determinations over roughly a 10-year period, or the period during which the next plant decision has to be made. In other words, it basically uses the information but discounts or reduces the weight attached to the very distant portions of the future, and just tries to get a rough idea of how the distant parts restate to the shorter range planning, and at the same time, tries to assure sufficient capacity to build for shorter range.

So in practice, perhaps, the 10 to 15 year horizon is the one that's practically being used in Wisconsin, although there's a 20-year forecast being filed.

MR. HUNT: I'd like to add one other thing. We have requested information from some of our utilities. As a matter of fact, it's now required by law for 10 years. But one of the responses we got was, "ten years! We don't know what we're doing 10 years from now."

MR. BIGGERSTAFF: I know what you're saying. They've been reporting 10-year forecasts for 14 years.

MR. HUNT: You get sort of different answers, depending upon who you're talking to. Another thing that we get is "that's proprietary information; we don't want people to discuss that."

You see, those are the responses that you get, and they tend to be very reluctant, you know, and they have some legislative clout in the states. For instance, we recently lost the ability to suspend rural electric association rates. They can change the rates and put them into effect, and we can't suspend them. Why. Because they were unhappy with us for suspending their rates. They went to the legislature, pushed it through the legislature, a bill that keeps us from suspending their rates. So I mean, there are some practical political situations and utilities have agendas which may not follow what you want to do.

MR. SALOMON: Steve Salomon, NRC State Programs.

I might make a point that the Administration realizes that the lead time for nuclear power plants is rather long and there's a movement going on within NRC to construct legislation to be introduced into the Congress which will try to shorten the time by allowing the states to bank sites somewhat similar to what Maryland has been doing, and then to have standardized plants which are easy for the NRC to evaluate. So the end result would be that one could get into the nuclear power stations operating from the time the decision was made in the time frame of, say, 6 to 8 years instead of 12 years.

As to how that legislation will go in the Congress is another matter that I don't want to get into. The general counsel has been working with the task force within NRC to come up with that legislation.

MR. SHELTON: I believe Darrel, speaking of forecasting, would like to talk perhaps a little bit about the future, but before he does, just let me say how much I enjoyed this. I found it very educational. I think from our perspective that as model builders rather than appliers, certainly we need much more of this, and I think I can speak for all of us at Oak Ridge. We have found this very helpful and we certainly appreciate your attendance.

MR. NASH: Thank you. I just want to make a couple of points. The second one I'll make first, so that we don't all get up and leave before I make the first one.

I just wanted to thank several people from the workshop, basically at Oak Ridge, who did all the legwork to put the workshop together. Ruth Maddigan put a big effort into this. I really appreciate you, Bob, for chairing the session and keeping everyone in line, and so forth.

MR. SHELTON: You're kind.

MR. NASH: And all of the participants. As I said this morning, we weren't sure a couple months ago whether we could put something like this together, and you've all been a great help to us, and we really appreciate your participation, and also the audience. I'm very pleased with the participation you've made and the help you've given us. I also thank the 50 or so people who have already left for their participation.

Then the other point I want to make is to get some ideas from everyone here what you would like to see in terms of a follow-up for this, if anything. We have our general interest in getting the states into this need for power forecasting for use in our environmental impact work, and I can see there are some substantial capabilities for contributing to this and I would like to get some ideas from you while you're here.

Would you like to see workshops of any kind, first of all, or other conferences. Should there be something like this? It's technical in the sense that we talked about the models, but we didn't get into the econometric properties and so forth. Should there be workshops like this? Should we have workshops that are not basically economists talking to each other, but more interaction with administrators. Any ideas that you have along these lines. We'd want to get them while you're here.

MR. WILSON: It would be nice to have more time, maybe two days, if we could.

MS. MADDIGAN: To be able to go over in detail some of the models?

MR. WILSON: Right. And to reduce the unit costs of transportation, and so forth.

MR. CAMFIELD: That was my sentiment, exactly, Ruth. It was too short, that we needed two days.

MR. NASH. For the same number of speakers? More speakers?

MR. CAMFIELD. The same number.

MR. WILSON. Perhaps a question and answer period after each speaker's presentation so we could touch and not forget the points.

MR. SCHOENGOLD. I think that would have been valuable.

MR. WINDHAM. Gerry Windham from the Rural Electrification Administration. I think I noted earlier today before lunch, a lot of people were talking about resources needed for forecasting and talking about the TI55 approach versus the banks of computers and large software packages. I don't know how exactly to go about it, but it would seem to me that some sort of a program to talk to top administrators of different agencies about the resources that are needed for a good forecasting effort might be something to keep in mind.

I know we face some very similar problems that people were talking about today, where we really don't have the resources to do a thorough job of it. We're still back with the hand-held calculator, pencil and paper, and on rare occasions we can beg a little computer time. I think a lot of people seem to be in that same boat. We all have large software packages and computers to deal with, although I think most of us realize that to do a really thorough job of it we have to have more than just a hand-held calculator.

I don't know exactly how to go about making that point to the administrators of various organizations, but I think it is a point that needs to be made. We're making some decisions, in many cases, based on shreds of reasoning and information.

MR. KAHAL: Darrel, there are two separate kinds of needs that I see here. There are, first of all, a group of people here who have been in the modeling and forecasting area for a while, and would probably like to spend some time going over the nuts and bolts of these various models. I would. It's one of my few opportunities for cultural enrichment.

There are other people here who are dealing with specific regulatory problems that I've heard about, or are trying to get a program underway and need more general information about, in general, what's going on and how does one develops a load forecasting program. And so I think you have to recognize that there are two different kinds of needs.

This conference today, I think, has been fairly successful in doing that, although I would have liked to have sat down with some of the people who have been doing some sophisticated modeling and learned more about the details of what they're actually doing. and certainly from my own point of view, I would like to see more of the latter, of more roll-up-the-sleeves type of workshop session. At the same time, I'd like to be able to share some of my experiences with people who are trying to get a program started and who aren't ready, yet, to get into nuts and bolts.

MR. WHITE: On that same line, going back to the modeling program we're trying to do at the PSC, we haven't found another commission or entity that's tried this integrated package approach, if you want to call it that. We'd like to talk it over with anybody who's thought about it, or if we have any conceptual differences in approach like were outlined this morning. In that regard, I think agencies or groups, when they try to transfer a model or a technology, should seriously consider the size of some of the commissions and the constraints that are imposed on us and try to use something like SPSS or PMPP, where we don't have to rely so much on a computer person or computer facility. If you have someone familiar with those packages they can take them and use them very fast, instead of having to wait for the legislative session to complete so we can get back to playing games on the computer.

I really would like to see, and I'm sure our commission would like to see, a further effort and discussion held in that area, particularly the overall approach, because we have a lot of questions and concerns and no answers.

MS. ALEXANDER: It seems like a lot of the discussion has implicitly involved residential or commercial forecasts. We found, when we were trying just a couple of months ago to decide what we needed to do in the forecasting area overall, looking at various projections of load growth in the various service areas of Texas, that two or three utilities pretty much drove the answers to the question: are the lights going to go out in Texas?

And moreover, two of those utilities' own forecasts were driven by the assumptions they made about industrial demand, and that gets into some other questions. I don't know whether the group at Oak Ridge has really worked on very much or not, or maybe they've been talking about it and I didn't pick up on it or what, but that's a specific area of concern to us. We have the problem that if we just follow the company rules and say how much electricity you're going to need 20 years from now, if they knew they wouldn't tell us, because that would get us into plant expansion plans and so on, and the utilities have generally relied on the surveys of those customers. They've applied their own judgment that they have a much easier time getting data from those customers and evaluating it, and can't even really turn around and tell us the data because if they do it they have to take the name of the company off first, which is also proprietary. So any methods that people use to deal with that would be helpful for us.

MS. MADDIGAN: Yes, the industrial sector is something that would be interesting to focus on. There's the ORI model, the Oak Ridge Industrial model that we did not talk about specifically, but is essentially one of the family of engineering and economic approaches. It looks at that specifically, and the SLED model does incorporate the industrial sectors as one of the sectors for analysis. But specific examination, I think, of industrial load would also be an interesting type of approach for a workshop or seminar.

MR. SHELTON: Thank you all very much.

(Whereupon, at 4:40 p.m., the workshop was adjourned.)

Appendix A

DEMAND FORECASTING AND THE POWER PLANNING PROCESS IN CALIFORNIA

Michael R. Jaske
California Energy Commission

Appendix A

DEMAND FORECASTING AND THE POWER PLANNING PROCESS IN CALIFORNIA

Michael R. Jaske
California Energy Commission

Good morning. Thank you for the opportunity to speak about demand forecasting and the power planning process in California.

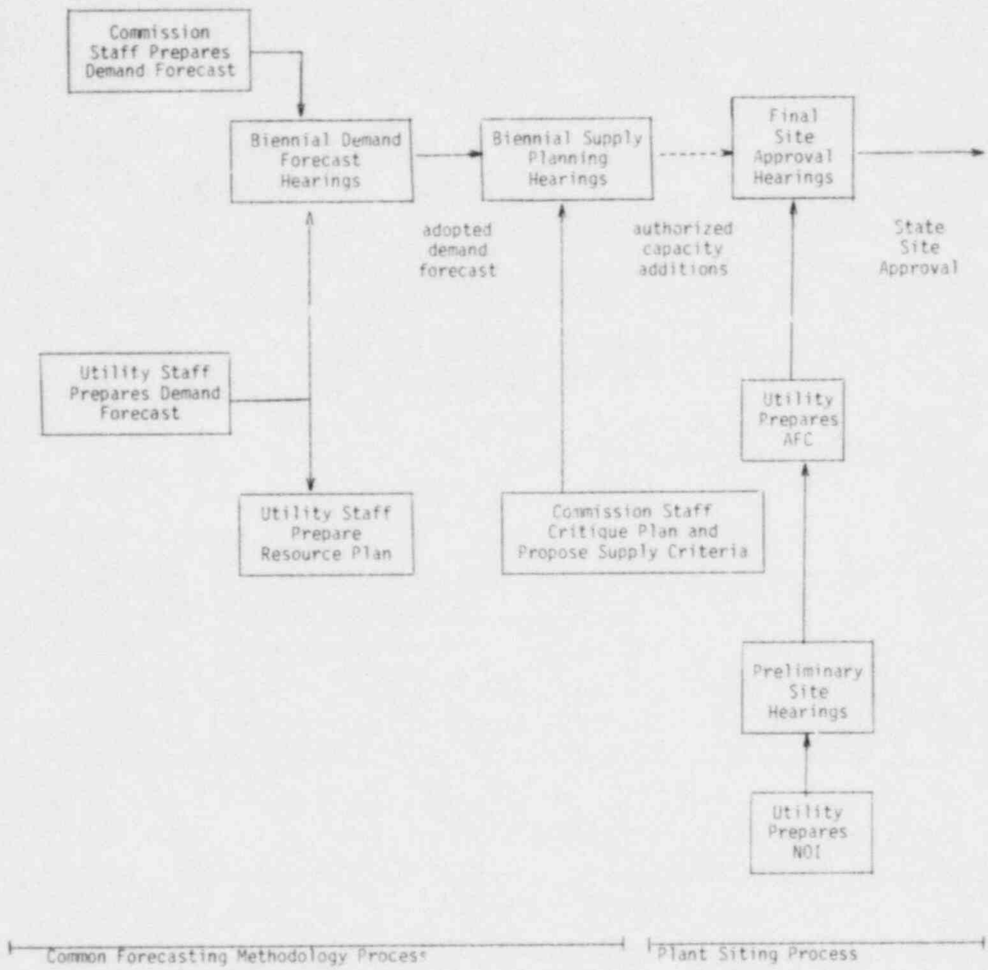
This morning I'm going to concentrate on three topics: a simple explanation of the overall power planning process as it exists in California; a discussion of current California Energy Commission (CEC) staff forecasting capabilities; and then finally the direction that CEC staff is headed in its developmental work for future forecasting capabilities.

Slide 1 is a schematic diagram of the essentially two-phase process for approval of power plants in California. The first phase is at the general policy level and the second phase is an explicit siting approval process for an individual plant. The first phase, is a general or generic process, where on a biennial basis the Energy Commission adopts a future level of energy demand. Through consideration of plant retirements and other adjustments, this results in an authorized level of capacity addition that each utility is allowed to add out into the long-run future. (And here we are spaking of principally the 12-year forecasting time horizon). The Commission has the technical backup to support such adopted demand forecasts and generating plant capacity additions from a long and involved process of forecast submittals by utility staffs and by independent Commission staff. All parties to these proceedings prepare demand forecasts and participate in an extended series of demand forecast hearings.

Utilities also submit detailed resource plans that are to be consistent with their demand forecast submittal. Commission staff critique these and propose revisions to the preferred supply resources that the Commission has established and continues to revise periodically. What this entire process means is, on a biennial basis, the Energy Commission establishes future demand levels and authorized capacity additions that control the amount of total utility capacity that is allowed. So this means, first of all, that a California regulatory agency has control over utility capacity. Second, as a matter of policy, California influences the type of generation plant utilities will construct in the future through its treatment of individual site applications. For example, geothermal plant applications are now, by regulation, on a fast track and are essentially approved only onsite criteria and without regard for need for power.

California Biennial Energy Policy Development Process and

California Power Plant Approval Process



SLIDE 1

The second phase of powerplant approval process is one which involves a specific plant application, and here there is really a two step process. First, the utility prepares what is known as a Notice Of Intent (NOI) which sets the stage for preliminary site hearings that describe capabilities of the site to handle the environmental burden of the plant, whatever type it may be. A lot of local input goes into the siting process. At the successful conclusion of a Notice of Intent, the utility actually prepares the Application For Certification (AFC) which brings us to the final site approval hearings. These hearings bring the need for power question in the form of the level of authorized capacity addition that is in control at that point for the utility in question. Provided that final approval for the AFC is given then the state approves the site, the Public Utilities Commission approves the construction of the plant, issues the Certificate of Pubiic Convenience and Necessity, and all permitting is concluded. This process essentially concludes all state and local approval of the plant itself. In fact, this was one of the fundamental reasons for the creation of the Energy Commission as a whole in 1975—to provide essentially one stop shopping in terms of permitting of powerplants.

There are some words on the first slide which refer to common forecasting methodology which was in the generic demand forecasting aspect of the powerplant approval process. Originally this was, in fact, thought to be a literally identical forecasting methodology used by each utility and by Commission staff. This soon proved to be impractical back in 1975 due to limitations of demand forecasting methodologies. What common forecasting methodology, or CFM, now means (Slide 2) is a very highly structured biennial process of submittal of independent forecasts by utilities and Commission staff and resource plan submittals by utilities and evaluation of these submittals on their merits. The content and format of utility submittals is highly regulated by what are referred to as Demand Forms and Instructions, Survey Forms and Instructions, and Supply Forms and Instructions. These constitute a specified format and content of material that is to be submitted that documents the utility's demand forecast, the input data that goes into its demand forecast and the resource plan that is consistent with the demand forecast. Another characteristic of the common forecasting methodology process is that it is

COMMON FORECASTING METHODOLOGY PROCESS

- ORIGINALLY ENVISIONED TO BE LITERALLY IDENTICAL FORECASTING METHODOLOGIES, BUT THIS WAS IMPRACTICAL
- CURRENTLY DENOTES A HIGHLY STRUCTURED BIENNIAL PROCESS OF INDEPENDENT FORECAST AND RESOURCE PLAN SUBMITTALS BY ALL PARTIES
- CONTENT AND FORMAT OF SUBMITTALS REGULATED BY DEMAND FORMS AND INSTRUCTIONS, SURVEY FORMS AND INSTRUCTIONS, AND SUPPLY FORMS AND INSTRUCTIONS
- PUBLIC AGENCIES, ENVIRONMENTAL INTERVENORS, AND THE GENERAL PUBLIC HAVE THE OPPORTUNITY TO PARTICIPATE IN THE PROCESS
- DECISION BY THE COMMISSION EMBODIED IN A BIENNIAL REPORT TO THE LEGISLATURE WHICH ALSO CONTAINS OVERALL ENERGY PROJECTIONS, AND RECOMMENDATIONS FOR LEGISLATIVE ACTION

SLIDE 2

very open, with public agencies, environmental intervenors and the general public allowed to participate in hearings.

A protracted series of demand forecast hearings exposes the methodology and assumptions used in each party's submittal. A legislative-type hearing process is used with informal presentation and interrogation of witnesses.

Finally, the Commission emerges from this hearing process with an adopted demand forecast level and through consideration of retirements and other adjustments, authorized capacity additions and a preference for specific generation technologies. These conclusions are embodied in the Biennial Report which goes to the Legislature. This report constitutes the blueprint for the energy future of the state as recommended by the Energy Commission.

The element of this whole process that is most relevant to demand forecasting, of course, the Demand Forms and Instructions (Slide 3) which specify the style and content of the demand forecast that is submitted by any of the participants in these proceedings, whether they are Commission staff or utilities, or independent intervenors. The Demand Forms and Instructions, as they now exist, do not restrict

DEMAND FORMS AND INSTRUCTIONS

o SPECIFY THE STYLE AND CONTENT OF A DEMAND FORECAST SUBMITTED BY A PARTICIPANT

o DO NOT DIRECTLY RESTRICT SELECTION OF INPUT ASSUMPTIONS OF FORECASTING METHODOLOGY

o MAJOR ELEMENTS ARE:

EXECUTIVE SUMMARY TECHNICAL APPENDIX

1. CUSTOMER SECTOR SALES FORECASTS
2. CUSTOMER SECTOR PEAK DEMAND FORECASTS
3. NUMBER OF CUSTOMERS
4. INPUT VARIABLE ASSUMPTIONS
5. SPECIAL DATA
6. METHODOLOGY DESCRIPTION
7. PLAUSIBILITY ASSESSMENT
8. SENSITIVITY ANALYSIS
9. CONSERVATION PROGRAM ANALYSIS
10. PRICE DOCUMENTATION

SLIDE 3

or constrain the selection of input assumptions or of forecasting methodologies, rather they are a means of documenting the set of assumptions and the methodology chosen by a participant. This allows a detailed understanding of the demand forecast submittal in a public review process. The Commission staff is the main body charged with review and summarizing these materials, so it wears two hats—as an independent participant and as service group to the Committee of Commissioners running the demand hearings.

There are eleven major elements within these forms and instructions and they cover the following items:

- Sales forecast by customer sector
- Peak demand forecast by customer sector
- Numbers of customers
- Various input variable assumptions
- Prices/Economics/Demographics/etc.
- Any kind of special data that might be necessary due to the particular methodology that a utility has used, or that any party has used
- A description of the methodology
- An assessment of the plausibility of the forecast results, preferably by sector
- A specified sensitivity analysis that gets the implicit elasticities of the forecast with reference to price or to economics or demographics
- A fairly detailed specification of the conservation program savings that are included price savings
- Documentation of the price forecasts that drive them all (that is, what resource plan are they based on, what are the various assumptions that go into prices used).

All of these elements go to further the goal of requiring the submittal to contain enough information to describe, in some detail, the entire process of developing the demand forecast of the participant in terms of input assumptions, methodology, and results.

Of course an element of interest to everyone here is "What is the methodology that is being used at this point in time? How does it compare to those that other forecasting groups in the nation are using?" Slide 4 very crudely summarizes the forecasting methods used and the type of conservation analysis used by each of the major entities forecasting in California. This slide describes the approaches used by: CEC staff, Pacific Gas and Electric (PG&E), Sacramento Municipal Utility District (SMUD), Southern California Edison (SCE), Los Angeles Department of

FORECASTING TECHNIQUES

USED BY

MAJOR CALIFORNIA UTILITIES

Entity	Forecasting Methods Used	Conservation Analysis
1. CEC Staff	end-use: residential commercial bldg.	end-use supplemented by off-line analysis
	econometric: industrial	
	engineering: ag & water other commercial peak	
2. PGandE	all sectors econometric	off-line program analysis supplemented by CEC end-use models
3. SMUD	all sectors econometric	off-line program analysis
4. SCE	all sectors econometric	off-line program analysis supplemented by end-use models
5. LADWP	end-use: residential all others econometric	end-use in residential off-line program based analysis
6. SDG&E	end-use: residential	end-use supplemented by off-line analysis
	econometric: commercial industrial	
	engineering: peak	
7. SCG	end-use: residential commercial bldg.	end-use "behavioral" for residential
	econometric: other commercial industrial	end-use for commercial bldgs., programs based for industrial

SLIDE 4

Water and Power (LADWP), San Diego Gas and Electric (SDG&E) and Southern California Gas Company (the largest retail gas utility in the nation).

You'll notice that in the twin columns there is rough parallel between the forecasting method and conservation analysis. Of course, conservation analysis is an extremely important dimension to demand forecasting in California. This is because one of the other dimensions of state energy policy that is far more prevalent in California than in other portions of the nation is to have explicit conservation program activity. Mandatory efficiency standards, incentive programs, information programs and utility sponsored conservation programs are all aimed at increasing the efficiency of the use of electricity, natural gas, and other forms of energy. This is an element that confounds demand forecasting in California, relative to other portions of the country, which makes the problem all that much more difficult.

We can see that there is a blend here of forecasting methods (end use, econometric and engineering simulation approaches). Commission staff has been a principal user and even a developer of end-use models. Utilities come out of econometric backgrounds and continue to use principally econometric techniques (That is, at this moment. Some work to change this is going on behind the scenes, but at this point, they are still principally econometric). San Diego Gas and Electric is the utility probably the closest to the Commission staff in use of detailed disaggregate models. In the conservation analysis column: you see that there is, principally, some kind of off-line analysis that supplements econometric projections and provides the adjustments needed to produce the baseline forecast that is plausible for the future. Since conservation is here and now and has an impact on the future, these adjustments are a necessary means of producing forecasts, not just policy tools and toys. Some utilities are using end-use moels to quantify conservation programs, and I am sure that this use of end-use models will increase in the future.

From this point on, I would like to concentrate on what is current California Energy Commission staff capabilities. Slide 5 essentially constitutes the rationale for our use of end-use models and our increasing use of them. First, they allow an ability to

RATIONALE FOR CALIFORNIA USING END-USE MODELS

GENERAL

1. ABILITY TO EXPLAIN HOW ENERGY USED
2. FACILITATE FUEL SWITCHING AND NEW ENERGY USING TECHNOLOGIES
3. NECESSARY FOR CONSERVATION SAVINGS ESTIMATION

CALIFORNIA SPECIFIC

1. LARGE QUANTITIES OF DETAILED END-USE DATA AVAILABLE THROUGH REQUIRED CUSTOMER SURVEYS
2. STATE REGULATORY POLICY HAS ESTABLISHED NUMEROUS CONSERVATION STANDARDS AND PROGRAMS

SLIDE 5

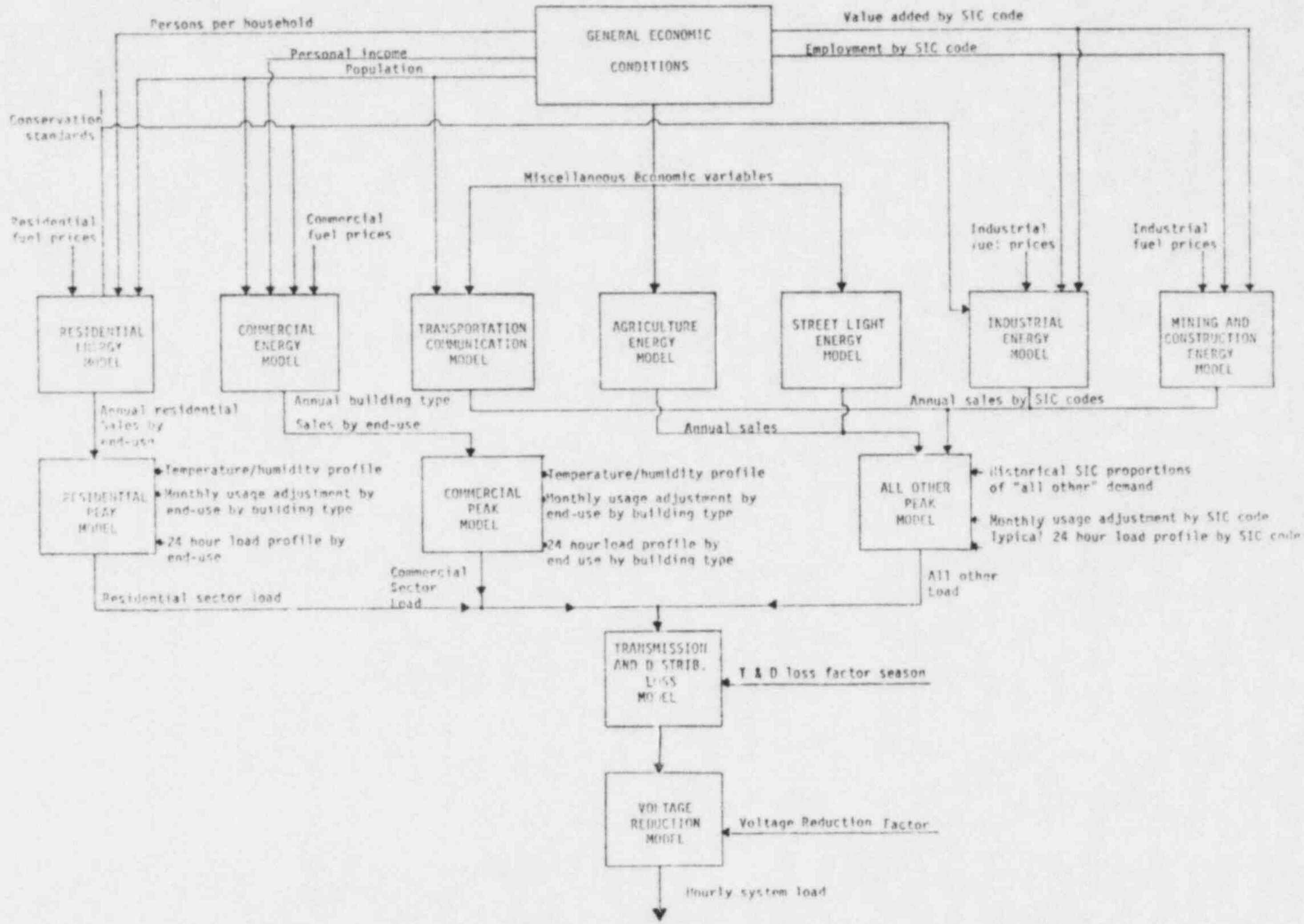
explain how energy is used. This is particularly important in determining the plausibility of the forecasts. Aggregate techniques, whether time series or econometric, have as a fundamental problem the inability to explain how energy is used. This greatly limits their ability to incorporate changes in energy efficiency. Further, end-use models facilitate a reasonable and realistic fuel switching and new technology introduction analysis. Much of econometric fuel switching is an artifact of the particular data used in estimation and is not rooted in an explicit understanding of how fuel switching is a option. Third, as explained earlier, these are vitally necessary for conservation savings quantification. This may be more important to California than other places, but is becoming a factor leading to their use everywhere.

More California-specific rationales are that we have very large quantities of detailed end-use data through surveys. Utilities are required to perform surveys of their customers through Energy Commission regulations, and this provides us with a wealth of information not available elsewhere in the country. We have now had three rounds of utility residential surveys; these are very large-scale mail surveys. We have completed one round of commercial building surveys, and are in the middle of another. We have had one Commission staff sponsored on-site commercial surveys. All of these data provide us with the means to surmount the main criticism of end-use models, that they are conceptually fine but cannot be implemented due to lack of data. Finally, the state has an overt regulatory policy of conservation standards and programs; more are under development and these require end-use analysis tools for their evaluation.

Slide 6 provides a very aggregate view of the Commission staff demand forecasting models. There are at the top a variety of economic and demographic variables that stem from a general economy projection, both nationwide as well as California and its subregions. There is a tier or forecasting models for residential, commercial buildings, transportation and communication industries that are still commercial, agriculture and water supply, street lighting and industrial and manufacturing customer sectors. Finally, the mining and construction sector. Each of these models produces simultaneous electricity and natural gas forecasts, and some of them produce other fuel forecasts. (Other fuel has been slighted quite strongly in our work, mainly because it is not very important. An example being that there is only about 1% of residential space heating with fuel types other than electricity and natural gas. The situation is far different than other portions of the country, particularly New England). Electricity forecasts from each of these models then flow through and are collected together in three components of the end-use electric load forecasting model, or peak forecasting model: the residential component, commercial building component and the all other component (principally industrial). Each of these components operates at the most disaggregate level that the corresponding sectoral sales forecast model operates.

The residential component is an end-use peak load forecasting model. The commercial building model is an end-use peak load forecasting model. The all other

SCHEMATIC OF CEC DEMAND FORECASTING MODELS



SLIDE 6

model is one which operates, not on end uses, but on individual industries or groupings of industries (for example, each of the two-digit SIC codes of the manufacturing sector). The result of each of these models is sectoral customer load, which requires that transmission and distribution losses be added. Finally, since we have a rather active voltage regulation program sponsored by our Public Utilities Commission and implemented by the utilities, there must be some adjustment for voltage regulation. These then result in an hourly system forecast from which we take peak demand values.

This collection of models has been put together over a number of years and has gradually evolved to the point where it is now. It continues to evolve. Work is under way right now on each of these sectoral models, most principally the industrial ones, but also residential and commercial. Because many of these are now or will soon be end-use forecasting models, a rather large amount of resources are devoted to this forecasting activity. I have a staff of ten working for me to produce long-run forecasts.

Each of these models produces forecasts on a utility service area basis or planning areas, and we divide California into seven planning areas. CEC staff are really producing seven geographically distinct forecasts with each of these models.

The next couple of slides will give some flavor for the characteristics of our various forecasting models. Let me just go through them rather quickly.

Slides 7 and 8 describe CEC demand forecasting moels. The residential sector model (Slide 7) was developed in-house and is disaggregated by end-use and by housing type; it essentially focuses on household stock of appliances and appliance usage, determined by a saturation model and an unit energy consumption model. Major inputs here are per capita income, fuel prices, persons per household, total number of households by housing type, and conservation standards.

The commercial buildings model we are using is a highly modified version of the ORNL commercial model. Commission staff have extended the number of building and end-uses and modified the structure rather extensively. We now have eleven building types and eight end uses for these fuel types. As many of you know, this model is principally a floor space accounting model which calculates energy use as the product of saturations of the various end uses, an efficiency factor (EUI) in kwh per square foot and a utilization factor. The main inputs to this model are: floorspace, fuel prices, and conservation standards.

Our other commercial sector model was developed in-house. It uses a disaggregation at the level of two and three digit SIC codes and is basically a simple summation of the product of an economic driver for the individual industry times a multi-component multiplier value (essentially a scaler use per unit of economic activity). Input values are industry economic activity levels.

CEC DEMAND FORECASTING MODELS

SECTOR	SOURCE	CHARACTERISTICS
RESIDENTIAL	DEVELOPED IN-HOUSE	DISAGGREGATION: END USE BY HOUSING TYPE FORMULA: $ENERGY = \sum_{K=1}^{3} [HOUSEHOLDS_K * \sum_{I=1}^{J} (SATURATION_{IK} * UEC_{IK})]$ INPUTS: PER CAPITA INCOME FUEL PRICES PERSONS PER HOUSEHOLD HOUSEHOLDS CONSERVATION STANDARDS
COMMERCIAL BUILDINGS	HIGHLY MODIFIED FROM ORIGINAL ORNL COMMERCIAL	DISAGGREGATION: BUILDING TYPE BY END USE FORMULA: $ENERGY: \sum_{K=1}^{11} [FLOORSPACE_K * \sum_{I=1}^{J} (SATURATION_{IK} * EUI_{IK} * U_{IK})]$ INPUTS: FLOORSPACE FUEL PRICES CONSERVATION STANDARDS
OTHER COMMERCIAL	DEVELOPED IN-HOUSE	DISAGGREGATION: 2 AND 3 DIGIT SIC CODES FORMULA: $ENERGY: = \sum_{K=1}^{K} [DRIVER_K * MULTIPHASE_K]$ INPUTS: ECONOMIC DRIVERS

SLIDE 7

INDUSTRIAL	DEVELOPED IN-HOUSE	DISAGGREGATION: 2 AND 3 DIGIT SIC CODES BY END USES FOR ALL MAJOR INDUSTRIES FORMULA: ENERGY: $\sum_{I=1}^{I}$ [PRODUCTION$_I$ * EFFICIENCY$_I$] INPUTS: PHYSICAL PRODUCTION RATE VALUE OF SHIPMENTS FUEL PRICES CONSERVATION STANDARDS
AGRICULTURE AND WATER SUPPLY	DEVELOPED IN-HOUSE	DISAGGREGATION: IRRIGATED CROPS BY HYDROLOGIC ZONE FORMULA: ENERGY: $\sum_{C=1}^{C}$ [IRRIGATED ACREAGE$_I$ * (WATER/ACRE)$_I$ * (ENERGY/WATER)$_I$] INPUTS: IRRIGATED ACREAGE WATER PUMPING EFFICIENCY WATER USE PER ACRE
PEAK/BASE LOAD	DEVELOPED IN HOUSE	DISAGGREGATION: AS DETAILED AS EACH SECTOR'S SALES MODEL FORMULA: LOAD$_I$ = $\sum_{N=1}^{M}$ [ANNUAL SALES$_N$ * ALLOCATION$_N$ * SHAPE$_{IN}$] INPUTS: END-USE ANNUAL ELECTRICITY SEASON HOURLY WEATHER DATA

SLIDE 8

The industrial model (Slide 8) that we are working on now has been developed in-house and is a disaggregation to two and three digit SIC codes by end uses for the major industries. It is essentially a model which computes consumption of energy as the product of physical production times the efficiency of production (or consumption per unit of production). It has as inputs physical production rate, value of shipments, fuel prices and conservation standards (to the extent they exist).

Our agricultural and water supply model was also developed in-house and is more important for us than for many areas because water pumping for agricultural or urban use is a major electricity use, perhaps seven or eight percent of total electricity use. This model basically works on the agricultural side by examining irrigated acreage in hydrologic zone, the consumption of water per acre, and the energy requirements per unit of water used. It uses irrigated acreage, water pumping efficiency, and water use per acre as inputs. On the urban water use side, the model calculates energy use as the product of use per person times population projections.

Finally the last major model is the peak or load forecasting model which was developed in-house and has as its level of disaggregation that which each of the sector sales forecast models use. It operates by projecting load at the individual end-use level as a translation of annual sales into load at any particular moment in time by allocating annual sales to the day of interest and then distributing those daily sales to hours of the day using load shapes. Inputs for all end uses are end-use annual electricity consumption and season; for weather sensitive end uses, hourly weather data is also used.

These models have a long way to go in various dimensions and are constantly being improved by our staff.

Slide 9 provides a simple summary of the developmental work we have under way for each of the major sectors. In the residential sector we are trying to improve our end-use saturation model, while incorporating the constraint of natural gas availability. We are trying to reestimate our UECs statistically, using conditional-demand analysis. We are trying to refine our characterization of various vintages of housing through heat load modeling.

In the commercial building area, we are trying to estimate short-run price elasticities using California data rather than national data. We are going to be further disaggregating the number of building types to give more precise and homogenous customer groups. We are going to be automating the computer procedures that we use to calculate EUIs from heat load results and survey data and from other information that we have available.

In our agriculture and water supply sector, we are going to refine our irrigated crop acreage projections, and we are going to be improving the split that we have made

MODEL DEVELOPMENT WORK IN PROGRESS

SECTOR	IMPROVEMENTS
RESIDENTIAL	o IMPROVED END-USE SATURATION MODEL INCORPORATING NATURAL GAS AVAILABILITY DATA o REESTIMATION OF STATISTICALLY BASED UECs USING CONDITIONAL DEMAND ANALYSIS TECHNIQUES o REFINEMENT OF HOUSING VINTAGES THROUGH HEAT LOAD MODELING
COMMERCIAL BUILDING	o ESTIMATE SHORT RUN PRICE ELASTICITIES USING CALIFORNIA DATA o FURTHER DISAGGREGATE BUILDING TYPES (FROM 11 TO 16) o COMPUTERIZE HEAT LOAD RESULTS AND SURVEY DATA
AGRICULTURE AND WATER SUPPLY	o REVISE IRRIGATED CROP ACREAGE PROJECTIONS o INCORPORATE RESULTS OF WATER AGENCY GIVING SPLIT BETWEEN SURFACE AND GROUND WATER
INDUSTRIAL	o IMPROVE FIELD SITE DATA IN EQUIPMENT INVENTORY FOR MAJOR ENERGY INTENSIVE INDUSTRIES o RECONCILE DIFFERENCES IN HISTORIC ENERGY CONSUMPTION BETWEEN ASM AND UTILITY BILLING DATA o DEVELOP SIMPLE END-USE MODELS FOR THE ASSEMBLY AND LIGHT MANUFACTURING INDUSTRIES o IMPROVE ELECTRIC MOTOR DRIVE INVENTORY DATA FOR MAJOR AND MINOR INDUSTRIES o PROJECT COGENERATION POTENTIAL BASED ON INDUSTRY USE OF ELECTRICITY AND STEAM
OTHER COMMERCIAL	o DEVELOP MORE COMPLEX MODELS BASED ON FLOOR SPACE AND PROCESS USE OF ENERGY
PEAK/BASE LOAD	o IMPROVE ALLOCATION PROCESS FOR RELATING ANNUAL ELECTRICITY USE TO THAT OF SPECIFIC DAYS o ACQUIRE AND INCORPORATE MORE DETAILED LOAD METERING DATA o DEVELOP A PROBABILISTIC LOAD FORECAST BASED ON WEATHER STATISTICS

SLIDE 9

between use of surface and groundwater water using results of a water agency survey.

Some of the most exciting things we are doing are in the industrial sector where we are trying to get these end-use models I have mentioned before up and running. We have preliminary versions now. We need to improve our current capital equipment inventory characterizations through more field data. We need to improve how we are reconciling the differences we have with historic energy consumption between Annual Survey of Manufacturers (ASM) and utility billing data, which are somewhat different. We need to develop a simple end-use model for the assembly and manufacturing industries. One thing we need to do, which is important to electricity forecasts, is characterize how electric motors constitute the stock of electricity using devices. These are very important elements in some industries; electric motors use 80% or 90% of total electricity in some process industries. Finally, we need to project cogeneration potentials which are based on a detailed examination of each the industry's use of electricity and its steam requirements.

In other commercial sectors, we are planning to develop a more complex model, something along the lines of the commercial building model, but which has a more sophisticated process use of energy, as these industries have in the real world.

Finally in our peak load forecasting model, we actually want to extend it away from peak load toward general load forecasting which will allow us to do better base load forecasting. We want to improve the allocation process that relates annual electricity use to that of specific days, whether they are summer peak days or winter second-peak days. We want to acquire and build in more detailed load metering data, something that the utilities have much more of than we do. In the future, we want to develop a means of projecting load in a probabilistic sense based on a detailed examination of weather data.

I would like to make a few closing remarks summarizing what I have said: We have had in California a very major commitment to end-use forecastings and to detailed examination of demand forecasting techniques. We have a fairly structured process. We have a fairly large scale of effort both as a regulatory body and from the utilities themselves. We have a very open and public process for examining demand forecasts, for coming to some resolution about a reasonable projection of the future. We have a lot of modeling techniques that some of you may be interested in pursuing; they are very resource and data intensive, but in our opinion are the way to go. I have a list of documents (Slide 10) available from us that can help you to become more familiar with our work.

Much of recent utility load forecasts for the future seem to be dropping relative to the old historic rates, but are probably still too high. In most cases the assumptions and methodologies which produce those forecasts are not well known nor brought out in public scrutiny. I urge you to consider processes for power planning that bring this more out into open examination.

Thank you for your attention.

References

The following documents have been prepared by CEC staff in the course of various forecasting exercises and contain mixtures of pure methodological description and specific demand forecasts. All are available from the CEC publications office, (916) 920-6216.

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2. Commercial Sales Forecasting Model--Electricity and Natural Gas, P102,79-020.

3. Peak Load Forecasting Model, P102-79-022.

4. Industrial Sector Forecasting Model--Electricity and Natural Gas, P102-79-024.

5. Economic/Demographic and Fuel Price Projections for Staff's Energy Demand Forecasts, P102-79-026.

6. Residential Sales Forecasting Model--Electricity and Natural Gas, P102-79-028.

7. Summary Models and Forecasts--Electricity Sales and Peak Load and Natural Gas Requirements, P102-79-030.

8. California Energy Demand 1978-2000. A Preliminary Assessment Staff Draft. CEC, August 1979, P102-79-004

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12. CFM IV Demand Forms and Instructions*

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* These two documents are available from the Demand Assessment Office of the California Energy Commission (916) 920-6971.

Appendix B

WORKSHOP REGISTRATION LIST

Appendix B

WORKSHOP REGISTRATION LIST

Panel Members:

Robert Camfield, New Hampshire Public Utilities Commission
Daniel Hamblin, Oak Ridge National Laboratory
Carl Hunt, Colorado Public Utilities Commission
Mathew Kahal, Exeter Associates, Inc.
Ruth Maddigan, Oak Ridge National Laboratory
Jerry Mendl, Wisconsin Public Service Commission
Darrel Nash, U.S. Nuclear Regulatory Commission
Robert Shelton, Oak Ridge National Laboratory
David Shoengold, Wisconsin Public Service Commission
Joe White, New Mexico Public Service Commission
Mark Wilson, West Virginia Public Service Commission

Preregistered:

Barbara Alexander, Texas Public Utilities Commission
Thomas C. Anderson, Georgia Public Service Commission
Vic Baird, Consumers' Utility Council
B. E. Biggerstaff, Federal Energy Regulatory Commission
Herbert Blinder, American Public Power Association
H. B. Bryant, Mississippi Department of Energy and Transportation
John F. Clark, South Carolina Governor's Division of Energy Resources
Jim Coyne, Maine Office of Energy Resources
Quentin Darmstadt, New Jersey Department of Energy
Ray DeLevie, Federal Energy Regulatory Commission
Robert T. Eynon, U.S. Department of Energy, Electric Power Division
Anthony Fest, Maryland Public Service Commission
E. J. Fowles, Federal Energy Regulatory Commission
Susan S. Gilmore, Virginia State Corp. Comm.—Economic Research Division
Julian Greene, Federal Energy Regulatory Commission
Ramesh Gurnani, New Jersey Department of Energy
Bruce Hagen, North Dakota Public Service Commission
Richard M. Hollis, Public Service Commission of Maryland
C. T. Howel, Mississippi Public Service Commission
Val Jensen, Illinois Department of Energy and Natural Resources
Peggy Jess, U.S. Department of Energy, Electric Power Division
Jeannie Kilmer, American Public Power Association
Hamg Kim, Alabama State University
Mary Kimbrough, U.S. Department of Agriculture
Ron Konecny, Nebraska Energy Office
Gregory Krohm, Wisconsin Department of Energy

David LaPlante, New Hampshire Governor's Council on Energy
Judith Lawrence, Rhode Island Energy Office
S. V. Le, Maryland Public Service Commission
T. S. Lee, Missouri Public Service Commission
Norman Leonard, Maine Public Utilities Commission
David M. Logema, South Carolina Governor's Division of Energy
John Makens, U.S. Department of Energy, Electric Power Division
James H. Mapp, Wisconsin Division of State Energy
Sue McBride, Pennsylvania Public Utility Commission
Jerry Price, U.S. Department of Energy, Electric Power Division
Jack E. Ravan, Alabama Department of Energy
Larry Schroeder, Oklahoma Corporation Commission
Steve Sciortion, Virginia St. Corp. Commission—Economic Research Division
Gail Scott, Oklahoma Energy Conservation Services Commission
Mark Seidel, Pennsylvania Governor's Energy Council
Bernard Tenenbauch, Federal Energy Regulatory Commission
Linda S. Tuck, Virginia St. Corp. Commission—Economic Research Division
W. I. Wheelock, Federal Energy Regulatory Commission
Gary Williams, Mississippi Dept. of Engineering and Transportation
John H. Williams, U.S. Department of Energy
Wayne Wright, Alabama Public Service Commission

Sign-ins:

Fred Hudspett, Alabama Department of Energy
K. H. Kim, Alabama Department of Energy
Norman M. Leonard, Maine Public Utilities Commission
C. Keith Howell, Mississippi Public Service Commisson
Val R. Jensen, Illinois Department of Energy
Ron Konecny, Nebraska Energy Office
Larry A. Schroeder, Oklahoma Corp. Commission
T. Gary Williams, Mississippi Dept. of Energy and Transportation
S. L. McBride, Pennsylvania Public Utilities Commission
T. S. Lee, Public Servive Commission, Missouri
Gregory Krohm, Wisconsin Energy Office
L. Don Lambert, REA—U.S. Department of Agriculture
B. E. Biggerstaff, Federal Energy Regulatory Commission
Anthony Foust, Maryland Public Service Commission
Jim Mapp, Wisconsin State Energy
Thomas C. Anderson, Georgia Public Service Commission
Frank Graham, AIF
Corie Brown, Public Utility Representative
Bernard W. Tenenbaum, Federal Energy Regulatory Commission
Herbert Blinder, American Public Power Association
Edward J. Fowlkes, Federal Energy Regulatory Commission

Barbara J. Alexander, Texas Public Utilities Commission
Quentin Darmstadt, New Jersey Department of Energy
Ramesh Gurani, New Jersey Department of Energy
Jeannie L. Kilmer, American Public Power Association
Steve Wilson, OCC
Richard M. Hollis, Public Service Commission of Maryland
David M. Logman, South Carolina Governor's Office
James Coyne, Maine Office of Energy Resources
Stephen Sciortino, Virginia SCC
Linda S. Tuck, Virginia SCC
Gerard R. Wenham, REA—U.S. Department of Agriculture
Mary D. Kimbrough, EIA—U.S. Department of Agriculture
John H. Williams, U.S. Department of Energy
H. B. Bryant, Oak Ridge National Laboratory
Diane Cowan, Hammon & Weiss
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Boyd L. Fjeldsted, University of Utah
Susan S. Gilman, Virginia State Corp. Commission
Antan V. Wood, U.S. Energy Office
E. David Hansard, AIF
Susanne B. Watkins, State of Maryland
Victor M. Baird, State of Georgia
M. R. Seidel, Pennsylvania E&C
S. V. Le, Maryland Public Service Commission
Robert T. Eynon, EIA—U.S. Department of Energy
L. N. Rib, LNR Associates
Kevin Kelly, NRRI
Michael C. Clark, DCEO
Andy Van Horn, TERA
William I. Wheelock, Federal Energy Regulatory Commission
Robert Lanford, Public Utilities Commission, New Hampshire
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52. Edwin G. Hudspeth, Deputy Director, Alabama Department of Energy, 25 Washington Avenue, Montgomery, Alabama 36130
53. Carl E. Hunt, Chief Economist, Colorado Public Utilities Commission, 500 State Services Bldg., 1525 Sherman Street, Denver, Colorado 80203
54. Stan Hvostik, Florida Public Service Commission, 101 East Gaines Street, Fletcher Bldg., Tallahassee, Florida 32301-8153

55. Michael Jaske, California Energy Commission, 1111 Howe Street, MS-23, Sacramento, California 95825
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58. Kevin Kelly, National Regulatory Research Institute, 2130 Neil Avenue, Columbus, Ohio 43210
59. Tom Kelly, California Energy Commission, 1111 Howe Street, Sacramento, California 95825
60. James Kennedy, Ohio Department of Energy, 30 E. Broad Street, 34th Floor, Columbus, Ohio 43215
61. Charles Komanoff, Komanoff Energy Association, 333 West End Avenue, New York, New York 10023
62. Steven Kraft, Nuclear Project Manager, Edison Electric Institute, 1111 19th Street, N.W., Washington, D.C. 20036
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67. Jane Ludwig, Operations Research Analyst, Virginia State Corporation Commission, P.O. Box 1197, Richmond Virginia 23209
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69. Maryland Power Plant Siting Program, Department of Natural Resources, Annapolis, Maryland 21401
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71. Robert Mellman, Charles River Associates, 200 Clarendon Street, Boston, Massachusetts 02116
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73. Bruce S. Mitchell, Engineering Analyst Colorado Public Utilities Commission, 1525 Sherman Street, Denver, Colorado 80203
74. Darrel Nash, Office of State Programs, Room AR 5037, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555
75. Dennis Nightingale, Public Staff, North Carolina Public Utilities Commission, 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina 27602
76. Sharon Norton, Westinghouse Corporation, Government Affairs Office, 1801 K Street, N.W., Washington, D.C. 20006

77. Emmanuel Ordon, Project Manager, Nuclear Fuel Cycle, Atomic Industrial Forum, 7101 Wisconsin Avenue, Washington, D.C. 20014
78. Laura Owens, Texas Public Utilities Commission, 7800 Shoal Creek Blvd., Suite 450N, Austin, Texas 78757
79. Gordon Plorin, Public Utility Statistical Analyst I, Minnesota Department of Public Service, American Center Building, 7th Floor, St. Paul, Minnesota 55101
80. Dorothy K. Powers, Energy Chairman, League of Women Voters, Voters Education Fund, 1730 M Street, N.W., Washington, D.C. 20002

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117 Robert Siller, Regulatory Engineer, Public Utilities Department, City of San Antonio, P.O. Box 9066, San Antonio, Texas 78285
118. Mrs. Lisa Steward, Atomic Industrial Forum, 7101 Wisconsin Avenue, Bethesda, Maryland 20814
119. Martha Stukas, Massachusetts Energy Facility Siting Council, 73 Tremont, Room 300, Boston, Massachusetts, 02108
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