THE WITNESS: I would like to respond, if I may

MR. HALL: Certainly.

THE WITNESS: Number one, the analysis performed by Mr. Komanoff is a very straightforward analysis. The data has been verified by myself. I have looked into the matter of nuclear plant performance on a number of occasions in the course of my academic research and have found that the data employed by Mr. Komanoff is an accurate representation of what he purports to find in his various sources. The methodologies employed here by Mr. Komanoff seem quite above board with regard to the standards applied in the econometric modeling and this is an area in which I have considerable expertise.

Therefore, his qualifications in other regards don't strike me as being germane in any way. He has assembled data of the record, has performed regressions in a way that is entirely above board. The summary statistics associated with these regressions validate very nicely and whether he is defective on some other account is really of no concern to me and is of no concern to my testimony.

MR. BURGRAFF: Could I ask counsel - -

MR. HALL: Do you have - -

MR. BURGRAFF: I don't mean to interrupt. I have just one more question. Can I have the date for the

decision you referred to?

MR. HALL: 28th day of March, 1977.

MR. BURGRAFF: Thank you.

BY MR. HALL:

Q Now, you have been able to determine all that, Dr. Shakow, despite the fact that you have not done a sufficient analysis of Mr. Komanoff's methodology to be able to tell me with assurance whether or not or how he had used the Handy Whitman Indices before I read the quotation, now, is that not correct?

A Well, yes, it is correct.

On the other hand, I have little doubt that this is the manner in which he employed the Handy Whitman Indices. I wanted to respond to your question as candidly as I could and it is true that I have not checked this particular facet of his analysis with him, so as to verify it firsthand, that this is in fact what he did.

However, judging from the other aspects of this particular work, there's very, very little doubt in my mind that he has deflated the current cost figures as reported in FERC form one in the matter that I indicated. I have very little doubt in that regard.

Q You also don't know whether Mr. Komanoff got the data from FERC form one or from an intermediate source, is that correct?

A That is correct. But given the fact that this intermediate source is presumably an accurate representation of the initial source, I see little problems with using an intermediate source.

Q You have used these equations to calculate the capital costs of Limerick, is that not correct?

A The direct capital costs. This would exclude the AFUDC.

Q And that is perhaps the most major of the plant cost differences between you and the company, is that not correct?

A I think the capacity factor assumptions are quite relevant, as well. Because - -

MR. HALL: Your Honor, I will make a motion to strike pages 44 through 52 of Dr. Shakow's testimony. Again, we have a very principal piece of data which is based upon a private communication, really, in this case nothing more than hearsay, as from an individual witness.

THE WITNESS: That is not - -

MR. HALL: I'm arguing at this point.

From an individual whose qualifications are not of record and do not appear and I don't think that the company is in the position to cross examine that. I don't think that there is - - this is certainly not the type of data which an expert can rely upon, in his testimony. It is

not a published source of data. It is not a recognized source of data. The individual who put it together is not a recognized authority and on that basis, I think a motion to strike should be granted.

MR. BURGRAFF: If I might respond, Your Honor, I think we are in the same position as we were before. Mr. Hall's real objection to this whole matter is really our expert's judgment that these figures are appropriate. I don't think it comes down to anything more than that. We clearly, at various times during the case, haven't felt that his expert's use of certain data was appropriate, either.

However, that's not any means to necessarily strike the opinion. Here we are faced with some type of decision that apparently is not even a final decision from New Mexico concerning Mr. Komanoff's abilities. It is stated early 1977, and Mr. Komanoff has made various alterations to his work since that time. We don't know the state of that, particularly that decision or what the case was about.

As I say, that seems to me to be evidence of simply Mr. Hall's concern with the fact that Mr. Komanoff's work was used. I think it is entirely appropriate as far as the use of the material is concerned. If he has qualms with our expert's reliance of using the data, I think that's one

thing. But it certainly isn't any means to strike the testimony.

MR. HALL: Your Honor, just in a brief response, I would note that Mr. Kommnoff is not here, so the company will obviously not have the opportunity to examine him either as to the manner in which he has put his data together or as to his qualifications to put the data together.

The only indication that we do have of record is the material that the company has been able to gather indicating some aspersions on these qualifications.

I would note that order is a final order.

(Transcript continues on next page)

MR. BURGRAFF: I would note once again, Your Honor, that Dr. Shaker has noted that he has made independent calculations for a means of testing this data and finds it appropriate. That is his expert opinion.

MR. HALL: Well, Your Honor, my motion to strike includes everything from Page 44 which begins with the coal equation and included through Page 52 which indeed includes the coal equation, the nuclear equation, both of which came from Mr. Komanoff and all of the total costs which are derived from these initial costs.

The motion would end at the bottom of Page 52 since the 5.65 per cent stated in that last line also comes from Mr. Komanoff.

MR. NOREN: I would like to add that Dr. Komanoff is especially recognized as an expert in the United States House of Representatives and wrote a report on power costs dated April 28, 1970 and also testified using this data to the House Subcommittee on Energy and Environment and at an Interior Committee hearing on economics, nuclear power in 1972.

THE ADMINISTRATIVE LAW JUDGE: I will take the motion in advisement.

MS. RUSH: I might add that Dr. Shaker has the study available. That is the study that Dr. Komanoff did that is not copyrighted and we can make inquiries to whether

that would be available to the company for their review.

MR. HALL: I would note, though, Dr. Shaker would have to return to stand cross on the study and even that would not entirely necessarily overcome the company's objection unless one could speak to Mr. Kennedy.

MS. BUSH: Well, Dr. Shaker has testified that he has done extensive studies in this area and the conclusions reached by Dr. Kennedy concur with his conclusion from his research and experience, so he is available for cross-examination.

MR. [illegible]: I am sure if necessary, we could arrange another telephone cross-examination as was done once before in this case.

THE ADMINISTRATIVE LAW JUDGE: I will take the matter under advisement. Let's take a ten minute break.

(Whereupon, at 4:35 o'clock p.m., the hearing recessed until 5:00 o'clock p.m.)

THE ADMINISTRATIVE LAW JUDGE: Back on the record.

BY MR. HALL:

Q Dr. Shaker, employing the Kennedy equation, you have calculated a dioxin per TEF cost of $1,002 per TEF for Limerick, is that correct?

A Yes, that is correct.

Q Doctor, I was wondering if you would be in a position to calculate for us how you derived that 61.002 at this point?

A Let's refer to Page 45 in my testimony. You will note a regression equation. The regression equation is developed in terms of a number of variables including nuclear capacity. That is total nuclear capacity. That is total nuclear up to that point in the United States. The capacity of the unit, the number of units designed by the architect engineer, a dummy, so-called dummy, variable indicating whether the location is a northeast location or not. That is indicated in the northeast section of the United States.

Tower indicates whether there is a cooling tower.

Common sited indicates whether there are two or more units sited for the same project and the term dragging refers to a situation where one unit has been completed but the second unit has not.

There are coefficients associated with each one of these variables. We calculated for the Limerick facilities the values of the variables associated with each of the seven variables.

Q Dr. Shalow, I didn't ask you for a discussion

of the question. I asked you to calculate the basis of the $1,002 per kW. Now we will be here quite a while if we are going to continue and go around the bush before answering the question.

MR. BUSH: I would object to the witness being interrupted in the middle of his answer.

MR. HALL: The witness was not answering the question to my scratch of the imagination.

MR. BUSH: That may be true, but I don't think it is proper to interrupt the witness in the middle of the sentence.

THE WITNESS: Okay. Let me proceed, please. The variable nuclear capacity --

MR. HALL: Your Honor, I would ask for a ruling on my request that the witness be asked to respond to the question.

THE ADMINISTRATIVE LAW JUDGE: Can you answer Counsel's question?

THE WITNESS: Yes, I am in the process of doing so.

MR. HALL: I haven't heard it yet.

THE WITNESS: I am trying to explain precisely what is being done. Should just, you know, do the calculations on my calculator. I am going to do that, but I thought it was relevant in answering the question to indicate precisely that

I am doing at each step.

BY MR. HALL:

Q Hector, all you were doing is reading what is in the text of your testimony. We only need the mathematical calculation.

A All right, I will proceed to undertake those calculations. The problem is indicating it is relevant because the cost of doing calculations at this hour, an arithmetical error may creep through, so I want to make it clear as to what I am doing.

70739 is multiplied by .57 and that yields a value of 45303. The size of the facility is 1015. That is in turn multiplied by minus .200. That yields a value of minus 219.44.

All is taken as 38 and this in turn is multiplied by minus .192. That yields a value of minus 3.376.

Northeast is applicable here since we are talking about a plant located in the northeast. Thus we enter the value plus 1.37.

The design of cooling towers, so the tower yield is 1.30.

There is a common steam facility, that is .91, and the additional variable was not applied and all this should be multiplied by 6.46. It is indicated in the equation.

Q Doctor, I must confess I have neglected to write

down the earlier figures you gave me.

A The MC is 73709, which I multiplied by the indicated coefficient and I got 45303.

MV is 1035 multiplied by minus .208 which yields 219.44.

AV was 58 times .182 minus yield minus 3.676.

To this we add 1.27, 1.20 and .91, which reflect the dangling and multiply it by 6.46. I will proceed to do this. When I add up everything prior to the final multiplication, I get 45093.88.

I am indicating all this subsidiary calculation to forestall the possibility of an arithmetic error which is a danger at this time.

Now we want to multiply that by 6.46.

Q Well, Doctor, perhaps I can shorten this a little. I note that you multiplied the MV and the MA by the minus .208, is that correct?

A That is correct.

Q There are zeros? They are not multiplication. The .0755 is also a zero.

A I misread that.

Q Our problem is, Doctor, we have calculated what we think the correct figure is and it is $150, which is a little less than your $1,662. Could you make your calculation again at some subsequent time and bring it to us?

A Yes. I will have to do that. I am sorry about this. Yes, I misread those years.

Q Doctor, what are the service dates and the AFUDC determination dates that you have assumed in your calculation for Limerick? What are your service dates and the AFUDC termination date that you have assumed in the calculation of your Limerick plant costs?

A Let's see. I guess I can refer you to Table E-4.

Q Table 4.

A Table E-4. Under that would be Sheets 5 of 7. That would indicate an in-service date of some time in 1987.

Q Have you chosen a specific month as an in-service date in your analysis?

A No, I don't believe so. What we did was we spread the known estimates to the construction budget as provided by the company and proportioned that construction budget relative to the Kennedy overall estimate.

Q And I take it your AFUDC on both units would continue through 1987, is that right?

A That is correct, as indicated on the exhibit.

Q Doctor, on Page 44, would you explain to me what an adjusted R square means?

A Yes, sure. An adjusted R square is an R square value which represents the sum of the squares of the deviation

of the initial dependent variables from defeated values of the regression relative to the deviations of the dependent variables from their meanings.

Let me state that again just to make certain I have it right.

An R square is one minus the ratio of the sum of the square deviations of the dependent variables and the defeated values of the regression divided by, that is the last term, divided by the sum of the squares of the deviations of the dependent variable from their meanings.

An adjusted R square divides each of the two elements of that latter quotient by the respective degrees of freedom associated with each element of the quotient.

Q Doctor, referring you to Page 52, would you call me how you have used the 8.65 per cent rate for nuclear plant capital cost of conversion?

A What page is that?

Q Page 51, which I believe you have taken from Mr. Kennedy.

A Okay. What would you like to know?

Q I would like to know how you used the 8.65 per cent shown in the last line that you have taken from Mr. Kennedy?

A I think that is a typo. That looks like a typo. I would say 2.65 is the correct value, there. If you

are referring to the 3.65 that is two lines above. May I correct that please?

Q Doctor, I will withdraw that last question. It is getting late.

Are you familiar, Doctor, with the term intermediate nuclear unit?

A Not really.

Q You are not?

A No.

Q Is it not true, Doctor, that during the earlier years of a nuclear plant's existence, that its capacity factor is lower than in later years?

A Well, I have done some work in this area and I have done also some collaborative work with some colleagues at Clark University who also have done some research in this area and our feeling is that while saturation appears to be consequential for units of relatively small size, that is between say four to 600 or 700 megawatts, for larger units, this alleged saturation has not been in evidence at least through the experience that we have noted so far.

Now I admit that your experience with smaller nuclear plants obviously more/extensive than our experience with the larger plants and the earlier plants were the ones that came on line earlier in the development of the nuclear energy.

Nevertheless, the work that I am referring to

seems to indicate very good correction for plants of this kind.

I believe I have some data to that effect. You will note on Page 39, the chart on top of that page, this is an attempt to track the performance of nuclear plants in terms of capacity factor and the sample is excluded to plants of relatively large size and I would say, except for the one data point associated with large 800 plus megawatts FWR's. There is the 60 per cent figure. All the other figures show, I would say, a fairly insignificant correction. This is particularly true for the PWR sample.

Q Referring to your Exhibit D, Doctor, can we deduce from that exhibit that you don't have much faith in President Carter's Wage Price Program?

A Which exhibit is this?

Q Exhibit D?

A Oh, yes.

Q Well, I was frankly very surprised at the faith which the company apparently placed in the same program.

The assumption that inflation rates are going to be maintained at a five per cent level starting in 1981 struck me as nothing short of imaginative on the part of the country from my standpoint. Even the most vigorous price control policy exercised by the government would be unlikely to maintain price increases at that variable level, but I

guess my answer to your question is yes, I was somewhat
dubious.

(Testimony continued on next page.)

Q In your inflation rate analysis, Doctor, have you employed the Consumer Price Index?

A Well, I don't see how one would employ the Consumer Price Index, given the volatility in this particular variable over the course of the past ten years. What we are doing, really, is we are speculating on inflation rates over the course of the next ten years and into the long term, and my feeling is that the Consumer Price Index is, given some rough indication of increasing instability in this variable, but is an accurate representation of what things are going to look like necessarily in the future.

Q Well, have you analyzed and based your estimate for the future on the Consumer Price Index, Doctor? That is the question.

A Well, as in the case of all these very, what speculative assumptions and my comment, no matter who is doing the analysis, when you are talking about inflation rates into 1990, 1991 and 1992, we are talking about a certain degree of speculation. We are not talking about hard and fast analysis.

We look at the Consumer Price Index and we see how it is treated over the course of the last three or four years. We note in that index an increasing degree of instability, as you are no doubt aware. I think one cannot be alive in this country today without being aware of that fact.

to have reflected the increase in instability of this measure by upgrading the company's assumptions by a substantial amount.

Q Dexter, the 300 MW coal plant that you propose in your optimum generation plant mix --

A You mean the two?

Q Well, the two or the three, depending upon the various load --

A Depending on load.

Q Those are baseloaded plants, aren't they?

A That is correct.

Q Now, at page 13, Dexter -- well, strike that. Dexter, there's shown in Exhibit 5 a discount rate, and the ESI low case that's shown to be 13.5 percent. How have you used this in your analysis?

A We have used that to discount the social cost calculated at the various years indicated in the analysis in order to get an aggregate social cost, stated down to 1979 dollar value. As I indicated earlier in this cross examination.

Q And wouldn't a larger discount rate, Dexter, result in a lower total social cost?

A Not necessarily. It depends upon what the cost-effective assumptions are like. If the escalation is at a rate that when you factor everything in factor that the discount rate, then this will not have not be in the case.

It is fairly complex, since we are talking

about a number of disparate escalation rates, associations with fuel, operation and maintenance, capital, purchasing in AFUDC. It is all so complicated that one cannot state with assurance that it is going to turn out one way or the other.

We are escalating on the one hand and then we are bringing things back on the other. The outcomes are likely to be fairly complicated.

Q The escalation rates between the FPC case and the FPC low case for fuels with the exception of natural gas, which I believe you will agree is not used by FPC to generate electricity, are the same, are they not?

A Could you repeat that, please?

Q The escalation rates for the fuels, nuclear through oil, are the same?

A Yes.

Q There is a difference in the inflation rate, is that not true?

A The escalation rates are the same and the effect of inflation rates are calibrated with respect to the different inflation rates. I think that's what you are alluding to. Or did I misunderstand it?

Q The inflation rates do differ between the two cases, do they not?

A That's correct, yes. 7.5, I believe and 9.

Q Yes, the inflation rates, though, are only

applied to certain operating and maintenance expenses, is that not correct?

A In the first row. But to some degree, the fuel costs are collinear with respect to the inflation rates. Not entirely. There's some exceptions, in particular cases, but the disparities in the inflation rates reflect, to some degree, differences in the various fuel costs.

Q Doctor, referring to page 13 of your prepared statement, you make the statement that it is correct that given rapidly rising oil prices, baseload oil-fired plants should not be assigned. Is that not correct?

A Let's see. Can you refer me to the line there?

Q It is line ten.

A Yes. I do indeed say that.

Q Referring to page 25, Doctor, table 8, if you know, what is the fuel source for Delaware 7, Delaware 8 and Schuylkill 2?

A Delaware 7, that would be oil. What's the next one?

Q Delaware 8.

A Delaware 8 would be oil and Schuylkill 2 would also be oil.

Q And what capacity factors have you assigned to these oil-fired units under your optimal expansion mix for 1995?

A They are listed baseload, which is, I assume, the point you are getting at. I would just say that relative to all the other options, I mean there are a lot of other things to be considered, including, obviously, the capital costs. Presumably, the inflation rate in all that we assumed in that scenario which is the EPA 1 scenario, the low scenario, so we are talking about an inflation rate of two percent.

If we account that relative to the capital cost inflation, associated with the Handy Whitman, given a projected capital cost inflation rate of what did we use? It's 2.65 percent or something of that order. That would yield an slightly higher inflation with capital cost associated with nuclear plants.

I agree that it is somewhat of an anomaly and a contradiction to that particular statement as a general matter, but as a particular matter in analyzing PSCO's generation mix and noting the presence of some already capitalized plants, presumably those plants were capitalized at a time when capital costs were much lower than they are now, it turns out that for these few exceptions, it is reasonable to include these in the mix.

As you will note, in looking at the other elements in that mix, oil-fired plants are generally not baseloaded, so this is not a very typical occurrence.

Q All right. Before, referring you to Sheet 8

of Schedule C, now, this is the 5300 load growth and 5300 optimum case. And for the year 1981 with the reserve margin of 15 percent. Would you know, Dexter?

A Can you color that to me again? I'm sorry.

Q Sheet 8.

A Sheet 8 of exhibit --

Q C.

A Okay. Thank you.

Q Do you know, Dexter, whether there is a Southmark bill shown on that page and on there's no suppose about 28, 15 is the 176 figure since the two 176 figures half-way down?

A I see it. It is option 73. Is that correct?

Q I don't have the numbers on mine.

A This is sheet 8, Exhibit 8?

Q Right.

A Okay. Yes.

Q Now, referring you to page 10 for the 22 percent reserve case, we also have the Southmark bill, don't we? It's line 73.

A What sheet is this, please?

Q Ten.

A Ten. Oh, we have two Southmark bills.

Q Only one big one. The other one is a peaking unit?

A Yes. Two Southmark bills.

Q Now, turning to pages 14 and 15 -- and this is the 1987 year, with reserve margin of 14 percent, and the 1992 year reserve margin of 22 percent.

A Yes.

Q Do we have any Seabrook units?

A No, we do not.

Q Now, referring to Sheets 20 and 22, which are at 14 percent, and also at 22 percent for the year 1992, are there any Seabrook units in that analysis, Dexter?

A Yes. There are.

Q Are there two Seabrook units?

A That's right.

Q Could you explain to me, Dexter, what has happened in that during 1991 to have one Seabrook Unit. In 1987 we have none and in 1992 we have two?

A Well, the model indicates that if we allow retirement and then if we assume that the firm can bring units back from, say, a state of some kind of cold storage, and similarly, some refinement is in order in this direction. What we are saying is that these units should be retired over a certain interval and then brought back.

Now, this, in fact, is an issue that's been of some concern to us in terms of a model, because what we are doing is we are optimizing from year to year and as a consequence, the possibility exists that a retirement would take

place only over a given interval. Now, I will submit that realistically, that probably is not that would occur in terms of company planning practices, and so I have assured myself, in reviewing the output from the model that the presence of anomalies of this sort is extremely rare. This happens only with respect to a small number of units.

I specifically checked this factor out. So while I admit that the optimization on a year-by-year basis as opposed to what I would call a forward-looking feature in the model is, it would be desirable to have that forward-looking feature in order to avoid this anomaly.

In my opinion, after reviewing the output from the model, I don't think that that greatly affects the testimony in a consequential way. I should also mention that a colleague of mine at EEI has analyzed some of the computer programs employed by utilities in the course of their own generation expansion procedures and the incorporation of a forward-look, as I have described it, is comparatively rare among models of this type. So this possibility exists for many such models.

I would suspect that what happens is that after going through the optimization, there is a second iteration at which this kind of analysis is carried out. Some kind of rationalization that goes out.

Q Doctor, do your models contain any costs

of retirement and then un-retirement of these units?

A To some degree. I would say the major way in which we incorporate this is through the imputation of the fixed, say, for the older units, of the fixed maintenance charges. So we don't, for example, and, in response to some of the interrogatories, you actually pursued an analysis, I forget, with respect to which mix of bringing a particular unit out of retirement and you noted that there would be some retrofitting that would be necessary in light of environmental considerations.

That kind of thing was not factored into the analysis, and in large part, because we were not provided with this information by the company. So to that degree, the analysis lacks this information, but -- and to the extent that it, in fact, the operation, the maintenance costs in and out, it does take account of it.

Q It takes account of them when the unit is in and does not when the unit is out?

A Precisely.

Q Now, Doctor, on Table 10, the two cases which you show there, there is shown to be a cost penalty of what is determined to be the FERC plant, and that cost penalty is stated to be 95.3 million dollars. Can you explain -- and this is 1981, can you explain to me the reason for that cost penalty?

A What are we referring to, specifically? The 95.3?

Q Yes.

A Well, I mean this is the difference between capital cost under the FEC plant mix, assuming FEC forecasts of load growth and plant costs and the ESE plant mix, assuming also the FEC forecast, but ESE low estimates of plant cost.

Q Would you agree with me, Dexter, that in 1981, there has been no change in plant mix between the FEC and ESE?

A No. There's some refinement indicated by the ESE model. That probably is what accounts for the difference. Also, don't forget there was accounting and also outage costs.

Q In other words, in the ESE model you have retired units to get down to a pre-arranged or pre-selected reserve ratio?

A Well, pre-selected, I think, is a little misleading in that we reviewed the costs associated with those four reserve margins and then chose optimal value? So it isn't as if it was pre-selected. It was selected on the basis of our observation procedure. That would be a more correct statement.

Q Turning to, Dexter, you address the assignment or non-assignment of the Units 2 facility. What do you refer

to as the full cost of generation as stated --

A What page is that, again?

Q Page 22. What do you refer to as the full cost of generation as stated in line 2 on that page?

A Full cost of generation would presumably be the estimate that was referred to in Exhibit DAS under 2B, under the column Fixed Cap. There is a capital cost indicated of $1,182.00 per kilowatt. The full cost of generation would factor that cost into the calculation.

Q In that on page 2 of 6?

A That is on page DAS, Sheet -- it doesn't really matter which one. This happens to be DAS high, but it really doesn't matter. It is true for all the scenarios. But for example, Sheet 6 of 6 under 2B refers to cap, fixed cap of $1,182.00 per kilowatt. And what I am stating is that the full cost factors in that particular fee.

Q And I take it are you saying that under the assumption that that cost is collected by the company through the GFC sale and then the sale should be permitted or would be economically desirable from Philadelphia Electric Company's point of view?

A Could you say that again, please?

Q Better, I am trying to determine the nature of your statement in that first paragraph that under the assumption that GFC pays for the assigned capacity on the basis of

the full costs of generation, the model indicates that Salem 2 should nevertheless be retained, you say?

A Should be retained?

Q Should be retained.

A Correct.

Q You go on to say where the price paid exceeds full generation cost, the assignment may be significant from the FERC standpoint.

A I haven't analyzed this. My understanding is that the financial factors in that case were very complex. And within the time constraints I did not wish, in this, as in other cases, to get involved in what was essentially a partisan analysis. So I assumed that we assigned it at full cost and netted my results for that particular assumption, but did not want to render judgment on the actual situation, which may be considerably more complex than this.

However, I have reviewed some of the materials submitted in regard to that sale, and I have some issues some statements, particularly in the statement made by the company to FERC, I believe it is a July statement, in which if I understand the materials correctly, it was claimed that under this assignment, the plant would be excluded from the rate base and all income and expenditures associated with the plant would likewise be excluded from the rate base.

this correctly, it suggests that the full cost assumption may be, in fact, a proper assumption. If I have understood this properly and if there aren't any factors of which I am presently unaware, it is possible that the analysis is somewhat more relevant than I have indicated in my testimony.

Q Doctor, are you recommending here that the company retain Salem 2 or are you making no recommendation? Which is it?

A In my testimony, I make no recommendation. I am merely indicating an observation that I have made after reviewing some of these materials. But I have not undertaken a full analysis. Because I have not undertaken a full analysis, I would not submit a yes or no recommendation. That would be a little too strong a statement on my part. I prefer not to make such statements without a more complete analysis.

Q Now, Doctor, you propose an alteration in the one day in ten year loss of load reliability standard which the company employs, is that not correct?

A Well, I propose a social cost criterion. I feel that one should not gear the choice of a reserve margin to a specific LOLP, but rather that the LOLP is, itself, an economically relevant variable that is to be assessed in terms of its social costs and benefits. That's the position I have taken here in my testimony.

Q And under your proposal, is it not true that

the company would routinely apply such devices as voltage reductions, public appeals for shedding and even local area service blackouts as a means of maintaining a generating capacity which equals its required load?

A I am altering those options. I am not recommending them. I don't think that they are necessarily desirable. What we are doing here is we are comparing the costs associated with these options to the costs of maintaining what I construe to be a very stringent reliability criterion and so then one compares the costs which are not desirable outcomes, to be sure, for what I term "not certainties options", to have as the costs incurred by the customers as a consequence of these options, is not so great as to warrant the inclusion of the additional reserve margin that would be necessitated under the company's reliability complement.

(Transcript continues on the next page.)

Q Well, in essence, you are recommending the Commission make an economic analysis if load blockage occurs, the cost of those load blockages, you allow the blockout, isn't that correct?

A Your question is a little unclear. I would appreciate a paraphrase.

Q You are recommending the Commission adopt a load reliability stand based on economic analysis which assigns class to load blockout and it is considered that the cost of a load blockout is less than the cost of a load blockout to allow the blockout, is that not correct?

A I would express it differently. Allow me, please. I would say that in the event that we apply a low reserve margin, for example, and as a consequence we incur at an infrequent rate, but at a rate perhaps more frequent than at a slow curtailment, one should cost that low curtailment at what we input to be a reasonable social cost and compare that to the benefits experienced by consumers as a consequence of the lower reserve margin.

If it came out on balance, the two are to an optimal figure then we should employ the lower reserve module.

Q Referring you to Page 8 of 24 of your Exhibit C, Doctor, you there show under load probabilities that blockouts under that case will occur in 1.8 days and ten

years, is that not correct?

A Yes, it is.

Q Now your 1.8 days there, Doctor, is not the same as one day in ten as calculated under the normal load for liability, is that not correct?

A That is correct.

Q Your calculation there, in fact, is 32. I guess it is more than that. It is close to 40 hours worth of blackouts in ten years, is it not?

A That's correct.

Q Whereas in one day in ten, it might be two hours or something of that nature?

A That is true. That is the whole purpose of this model to indicate that blackouts at a rate greater than those presently allowed for to the extent of say 30 hours in ten years, which is not a very appreciable figure and moreover, assuming that those blackouts are confined.

Don't forget, this includes the category partial blackouts, so we are not implying that the blackouts will be experienced by all customers within the service area, that this imposes cost to be sure, but it is made worthwhile by a very substantial reduction in the reserve requirement.

Q Now in your analysis, which has resulted in this figure, that we have just been discussing, the 1.8 days

in ten years, you have assumed in your computer program, have you not, Doctor, that the company will be able to flip the switch only when needed and only to the extent needed and to bring the load back whenever the load is there to be brought back?

In other words, you have assumed maximum flexibility on behalf of the company to make those judgments as to discarding load and picking up load with no limitations, is that not correct?

A It assumes, I grant you that point, as a general matter. However, more concretely what the program does assume is that there is a sequence of measures which are applied in sequence and we are really assuming that the company can proceed from one element in the sequence to the next element. What we are implying is that there is a certain degree of flexibility implied by that sequence but at the same time, I have reviewed for a number of companies planning documents which indicate the procedures in the event of deficient capacity and the range of options that I have described, I feel are well within the normal range of planning procedures in the event that these contingencies --

Q And Doctor, in your analysis on Page 2 of Exhibit C, you have not included any spinning reserve during this period of the blackout?

A No, the spinning reserve is not incorporated in

this model. That is correct.

Q If you knew, do utilities normally retain spinning reserve to prevent cascading system outages during curtailment?

A Yes.

Q That would increase the values that you show as curtailment there, wouldn't it?

A Yes, I agree. Clearly, I don't regard that as being a determinant, but that is what I would call a minor problem.

Q Now, Doctor, you have estimated the cost of curtailment for quantification in your social costs on Page 9 of your testimony, is that not correct?

A Yes.

Q And I believe one of the papers that you mentioned is that of Mr. Tolsma in 1975?

A That is correct.

Q Actually, Doctor, I wish to refer you to Mr. Kaufman's study done in 1975 and does not Mr. Kaufman say with respect to his study that incurring the results of the study, and I am quoting from him on Page 2, "One must keep in mind the fact of estimates of generation and liability and reserve planning techniques generally are at an early stage of development. That's despite the seeming accuracy of the computer-generated numbers, the results should be

viewed as an indicator rather than a guide. And the policy action, more work is required."

A Sir, can I respond to that?

Q Sure.

A I merely referred to this study for the record. As you will note, I indicate and I quote, "Very recent studies indicate that the cost of catastrophic accidents exceed these estimates by a factor of as much as two or three."

I cite a reference that coincidentally was referred to by interrogatories by the company itself. That is the Corvin Study of 1978. The Corvin Study indicates a value of $5.75 per kilowatt hour. I made this calculation just several days ago and we assumed in our study a value of $5.00 per kilowatt hour, so whatever the merits or deficiencies of the Kaufman Study, we are not taking that study very seriously in our analysis. We are using a factor five times as great. Therefore, the deficiencies in the Kaufman Study are very immaterial to this testimony.

Q I take it you would say the same with respect to the other studies?

A They are immaterial. I think they are interesting for the record. I cited them just to indicate the progression and the state of the art in this matter, but we did not want to open ourselves up to the criticism that we had employed

blackout cost estimates that were unfavorably biased on the low side.

Therefore, we considered and employed what we considered to be highly conservative estimates of $5.00 per kilowatt hour.

I should indicate that this 3.7% employed by the Corwin Study was most likely an older estimate for the PECO area in that New York City, as a highly concentrated urban area, probably more so than Philadelphia, would probably represent blackout costs on the extreme high side, so my estimate in the Corwin study is to any degree accurate, it has been supported by a large number of considerations, then the estimates for the PECO area should be somewhat below the 3.7% figure.

Q Now Page 31 of your statement, Doctor, you state and I quote, "A technical criteria such as the LLOP or the preferred modified LLOP constrains the possibility of blackouts with reference to a fixed probability criteria without considering economic consequences.

Implicitly, therefore, this method, assumes that economical desirable outcomes can be identified purely on the basis of a technical probabilistic analysis. Preliminary investigation suggests that this assumption is invalid."

Are you suggesting, Doctor, that this Commission

should alter the reserve liability standard for the Philadelphia Electric Company on the basis of the preliminary investigation?

A I am not making any recommendations with regard to the procedures to be employed by this Commission.

I am merely suggesting that in my opinion the use of the social cost criteria as a criteria without reference to a particular study is a criteria superior to the LOLP criteria and I would urge regulatory bodies in general to take this particular criteria very seriously in rendering its judgments.

I don't want to suggest that any decision be made on the basis of any kind of preliminary analysis, but the superiority of the social cost criteria relative to the LOLP criteria is very clear in my mind.

MR. HALL: Thank you. That is all I have, Your Honor.

THE ADMINISTRATIVE LAW JUDGE: Does any other party have any questions of this witness?

BY MR. HERSHEY:

Q Good afternoon, Dr. Shaker. I am Steven Hershey with Community Legal Services.

On Page 1 of your testimony, you indicate that in 1975, you directed a study for the City of Seattle. The study was entitled, "Energy 1990," is that correct?

A That is correct.

Q Was that study prompted by debate or as whether or not to build a nuclear generating plant for the City of Seattle?

A Yes, it was prompted precisely by that kind of consideration. Would you like me to elaborate?

Q Yes, please.

A The City of Seattle, on a preliminary basis, voted to participate in a very substantial way to a large and nuclear facility. That would be Wnoops 4 and 5 facilities. The extent of that participation was in excess of 10 per cent which represented a very substantial investment for the City of Seattle.

I should indicate that Seattle City Lights is a municipally-owned utility, so expenses by that utility are contained to the expenses by the city itself.

Upon the preliminary commitment by the city to that plant, there was a considerable amount of opposition developed and a settlement was reached between complainants and the city to hire an independent consultant to perform an independent load forecast in order to demonstrate whether the need for these facilities within the Seattle City Service area was established and it was my role as the principal in that study to perform this independent load forecast.

Q So you were hired by the city?

A Yes.

Q And the ultimate result of that study, am I correct, was that rather than building that nuclear generating plant, the city adopted those certain conservation measures which at the time the plant would have gone into effect would have saved equal in generating capacity?

A I don't know if the word equal is precisely accurate, but the Council was sufficiently persuaded that the implementation of the conservation program would work to the benefit of the city to a greater degree than participation in this facility and therefore, voted against this.

Q And the plan adopted was based on your recommendation?

A That is right, and approximately two months of testimony that I presented before the City Council virtually continuous debate.

MR. HERSHEY: Thank you, Doctor.

THE WITNESS: You are welcome.

BY MR. HOGAN

Q Doctor, in your testimony, did you figure in any way in your calculation of nuclear capital costs any redesign that may be required as a result of possibly the Three Mile Island incident?

A No, I did not.

Q So that would be a source of conservatism in your capital costs?

A To the extent those are adopted, the answer is yes. The equations are determined with reference to experienced outcomes from 1971 to 1978, as it is indicated, and this would predate the Three Mile Island incident.

Q Are you aware of any stream of capital cost increase that might be required as a result of that?

A I have only read casually on this matter and would not want to render a definitive judgment.

Q Did your calculation include any possible capital cost increases that might be required as a result of current nuclear regulatory investigation of modification that might be required for nuclear plant located in densely populated areas like the Limerick?

A No, I did not.

Q That would be another source of consideration?

A Yes.

Q In your figures of plant and site factors, are you familiar with the site of availability for water for the Limerick plant's cooling?

A I would not call myself sufficiently conversant in that matter for the purposes of this testimony.

Q If it were true that the Limerick plant might have to be shut down a certain number of days per year as

PECO claims in its construction license application to the NRC during the summer months because of lack of water, how would that affect the cost factor?

MR. HALL: Objection. I think the construction permit will speak for itself. I don't wish my silence to indicate that I agree with the contents of the question.

THE WITNESS: To the extent that plants are not permitted to ope the capacity factor going down. This is in no way suggesting this is a likely possibility. I am merely addressing the contingency asked by the question.

BY MR. ROSEN:

Q In your study, did you calculate the cost of your alternatives besides 300 megawatt coal plants?

A I indicated earlier in the cross-examination the various generic options that I have incorporated in my analysis.

Let me repeat them for your benefit. This includes generic nuclear plant, generic coal plant of 300 megawatts, a coal plant of 600 megawatts, an oil cycle plant and the combustion turbine. These are the only alternatives.

Q You did not calculate, for example, the cost of possible cogeneration or the company investment in conservation?

A No, I did not.

Q And if it were true that the cost of such conservation or wind generating programs were in effect less than the cost of building new coal plants, then presumably, such options would be even more economical in terms of their -- --

A Strictly speaking, the answer to your question is yes. I should indicate that wind is an energy-constrained option. It would be treated in analogy to run-of-the-river hydro which is the framework of this model. I think that energy constraint has to be borne in mind.

MR. NOGEE: Fine.

THE ADMINISTRATIVE LAW JUDGE: Is that all? Would you like some time?

MR. BURGRAFF: Yes. I don't think it would take very long. We would like to go over our notes.

THE ADMINISTRATIVE LAW JUDGE: All right. Let's have a brief recess.

(A brief recess was taken)

THE ADMINISTRATIVE LAW JUDGE: Let's go back on the record.

MR. BURGRAFF: Thank you, Your Honor. We have only three questions.

REDIRECT EXAMINATION

BY MR. BURGRAFF:

Q Dr. Shakow, you answered some cross examination earlier concerning case four on table one of your prepared statement, which is on page 7, and concerning various assumptions on where the company, as was noted, eats the cost or assigns it. Wouldn't that be consequential from the company's point of view?

A. It would be very consequential from the company's point of view. Obviously, the company would much prefer to assign rather than eat the cost. However, my model is calibrated from the standpoint of social, i.e. consumer costs, not company costs. Therefore, the important question is what kind of responsibility do the ratepayers assume under these various contingencies.

And in my judgment, relative to the overall assumptions of the model, it would not make any difference. That's what I indicated earlier in cross examination.

Q Could you please note, once again, the outcome of the model given the assumption of incremental costs for Limerick and ESNG cost assumptions?

A. Specifically, I would like to note that under those assumptions, the Limerick units do not enter the generation mix. Limerick unit enters the generation mix only on the assumption of incremental cost on one hand, but more importantly, the company cost assumptions including the assumption of a 5 percent inflation rate post 1981, which I have indicated

earlier that I feel is very grossly unrealistic.

Q Was the 1977 New Mexico decision which we haven't seen but which has been cited related to Mr. Komanoff's -- is it related to Mr. Komanoff's current work?

A No, it is not. The work of Mr. Komanoff, which I refer to in his testimony, was pursued in 1978 and 1979. Therefore, it could not have any bearing at all on the New Mexico decision.

MR. BURGRAFF: That's all we have on redirect.

MR. HALL: Your Honor, I have just two questions.

RECROSS EXAMINATION

BY MR. HALL:

Q Doctor, am I correct that you have made no analysis on what the financial impact on the Philadelphia Electric Company or its ability to render service would be of the necessity that it would, shall we say, "eat" $1 billion of costs related to Limerick?

A That is quite true. It is one of those many subsidiary analyses that I have not performed.

Q Now, Doctor, referring to the Komanoff regression equations, those equations depict, do they not, the rate of cost increase in nuclear plants during the period 1972 to 1978, is that not correct?

A They are estimated, based on an historical sample that spans this period during which time there was an

inflationary environment in that sector.

Q And in addition, was that not a period of major changes in NRC plant construction regulations which greatly inflated the costs of the nuclear plants?

A Well, the answer is yes. On the other hand, there is nothing to suggest that this pattern will not continue over the course of the next ten years, which is the period under consideration in my analysis, so while your observation that there is assumed to be an instability in this sector over the course of the historical period is correct, I would also contend that in all likelihood, this period of instability is not about to end in any abrupt way. It is likely to continue, at least over the immediate term.

MR. HALL: That's all I have.

THE ADMINISTRATIVE LAW JUDGE: No further questions? If not, Doctor, you are excused. This hearing will stand adjourned until 10:00 o'clock tomorrow morning.

(Whereupon at 6:33 p.m. the hearing was adjourned)

- - - - -

I hereby certify that the evidence and proceedings are contained fully and accurately in the notes taken by me during the hearing of the within cause, and that this is a true and correct transcript of the same.

MOHRBACH & MARSHAL, INC.

By Betty J. Marshal
Betty J. Marshal, CSR, RPR, CP

By Eugene W. Holbert
Eugene V. Holbert, CSR, RPR, CP

12-12-79

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(Exhibits JS-1, 2+4) R-79060865 C.A.Stmt. #3 Hrg. 12-10-79 2:00

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

VS.

PHILADELPHIA ELECTRIC COMPANY

R.I.D. R-79060865

*** *** ***

Direct Testimony of

John K. Stutz

as to

Long Range Load Forecasting

DOCKETED
DEC 13 1979

DOCUMENT FOLDER

November 2, 1979

E S R G

Q. Please state your name and business address.

A. My name is John K. Stutz. My business address is Energy Systems Research Group, Inc. (ESRG), 120 Milk Street, Boston, MA 02109.

Q. Please describe your background and qualifications.

A. I am currently a senior research scientist at Energy Systems Research Group. At ESRG I have specialized in the area of mathematical modeling and its application to energy related problems. I have had extensive experience in the areas of long range electric utility load forecasting. I have testified on matters related to load forecasting in the states of Massachusetts, Connecticut, New York, Pennsylvania and Michigan. A complete description of my background and qualifications is contained in the attached Vita, Exhibit ___ (JS-1).

Q. What is the purpose of your testimony in this case?

A. I will address three areas in this portion of my testimony:

1. I will present the results of an independent Base Case long range load forecast for the Philadelphia Electric Company system (PECO) prepared by ESRG. The Base Case modelling methodology, data sources, forecasting assumptions, and detailed results are described fully in Exhibit (JS-4);
2. The ESRG Base Case results are compared to PECO's long range load forecast, points of contrast identified, and a critique offered of aspects of the Company's forecast submission;

3. I will present the results of a Conservation Policy Forecast developed by ESRG. Again, detailed explication is summarized at the end of the testimony in Exhibit ___ (JS-5).

Finally, in a supplementary submission, I will discuss the aspects of the "essential human needs" question raised for consideration in this case by Chairman Goode in a memorandum to Judge Shane dated August 9, 1979.

Q. Why are you presenting a "Conservation Policy scenario analysis" in this case?

A. Currently, long range forecasts are prepared under "business-as-usual" assumptions. This characterizes both the Company's forecast and ESRG's Base Case forecast in this case. These assume only evolutionary changes in the economics and regulatory environment. Recent actions by the federal government and the state governments in New York and California suggest that there can be discontinuous shifts in regulatory policy--shifts which lead to a much more aggressive promotion of conservation than would normally be expected. The primary purpose of the Conservation scenario is to show the potential effects of such a shift in state policy upon the Base Case forecast of local growth in the PECO service area prepared by ESRG. Since the future direction of state policy is unknown at this time, the results of the Conservation Policy scenario analysis form a useful compliment to the Base Case forecast in describing the structure of peak demand and energy consumption which PECO may experience in the future.

Q. What are your major findings in this case?

A. Based upon the results of the long range Base Case load forecast prepared by ESRG I find that the estimates of growth in energy consumption and peak power developed in-house by PECO and contained in Exhibit ___ (WCH-1) are substantially in excess of what is likely to occur. A summary of the PECO and ESRG Base Case results appears in Table 1 below. Through a point-by-point comparison of the Company forecast with that prepared by ESRG, I find that the general overestimate of future electric load and energy growth can for the most part be traced to the following primary sources:

- Overestimates of likely residential customer growth,
- Inadequate treatment of certain residential end-uses,
- Overestimate of the addition of new loads in the commercial sector,
- Failure to adequately account for changes in energy intensity and self-generation within the industrial sector.

Based upon the results of the Conservation Policy scenario analysis in Exhibit ___ (JS-5), I find that if the State pursues a policy of vigorous promotion of conservation, the future load growth experienced by PECO may be substantially below that shown in the ESRG Base Case (see Table 1.1 of Exhibit ___ (JS-5)).

TABLE 1

Comparison of Annual Base Case Growth Rates:
1977-1988

	ESRG	PECO
Residential Energy[1]	1.6%	3.0%
Commercial Energy	.5	3.2[2]
Industrial Energy	1.9	2.7[3]
Total Energy[4]	1.4	2.9
Summer Peak	1.1	2.3

[1] Corrected for billing adjustments and 1977 weather normalization, and includes single point metered (SPM) apartments.

[2] Includes "Other Non-manufacturing" and 90% small "C & I" based on Exhibit ___ (WCH-1), Sec. 3.

[3] Includes manufacturing and 10% small "C & I."

[4] Excludes Sales for Resale.

Q. How are the results of the ESRG forecast related to the issues of capacity planning and utilization?

A. I share the view expressed by company witness Boyer that "Generation planning begins with the forecast of future annual sales and peak demand" (Exhibit ___(VSB-2), p. 1). Given that the forecast which I am sponsoring is significantly lower than that proposed by the Company, I would expect that it would lead to the need for substantially less additional capacity than currently planned. However, the issues involved in generation planning extend far beyond the area of load forecasting. For that reason I

will simply point out that the forecast which I am sponsoring has been used as one of the inputs for the analysis of the need for and economics of generation planning and system reliability presented by Dr. Don Shakow of our firm. One may consult Dr. Shakow's testimony to determine the impact of the ESRG forecast in the area of generation planning. The ESRG forecast is also relevant to certain of the financial issues in this case. Here one may consult the testimony of Mr. Robert Towers. Mr. Towers has utilized the ESRG forecast as one of the inputs in the preparation of his testimony.

Q. Before beginning your comparison of the ESRG and Company forecasts, please explain the relationship between your subsequent testimony and the information contained in Exhibit ___(JS-4).

A. Exhibit ___ (JS-4) contains a complete description of the assumptions, methodology, and results of the ESRG forecast. It is the primary source of information concerning my forecast. Below I will present a general discussion of the ESRG forecast with the aim of highlighting the points of difference between it and that prepared by the Company. For details concerning the latter forecast, the reader may refer to Mr. Hoch's Exhibit ___ (WCH-1).

Q. Please begin your comparative analysis of the ESRG and PECO forecasts by discussing the future number of residential customers.

A. The two forecasts are similar in methodology. Both first obtain estimates of future population growth, convert this to growth in the number of households (dwelling units), and then apportion the growth among different types of housing units. For 1988, ESRG forecasts 1.426 million households for the service area, while the Company forecasts 1.475 million households. ESRG divides new construction into 48% single family, 52% multifamily, while the Company has the split at 55% single family and 45% multifamily.

There are three major components to the forecasts of residential customer growth prepared by ESRG and the Company: population growth, trend in the number of persons per household, and split between single family and multifamily dwellings. On each point, PECO has taken a decidedly optimistic view. The PECO population growth rate is compared to the forecasts of the Census or the Pennsylvania Office of State Planning and Development in Exhibit ___ (JS-4), p. 66, and seen to be relatively high. However, this is offset by relatively high projections of the number of persons per household, which tends to decrease customer growth but raises the number of single family dwellings added. This latter point is significant because of lower consumption of multifamily units. Focusing on the single family/multifamily split for a moment, we note that the Company stresses what customers <u>may</u> want, not what they are likely to be able to afford. For example, the fact that the price of single family housing is expected to run 2 to 4% above inflation is seen as part of the "compelling case" for home ownership among young couples. (Exhibit ___ (WCH-1, p. 48). Nowhere in its discussion does PECO mention that real household income

has been stagnant since 1974, nor does it even suggest that escalating real housing prices, together with high mortgage rates and large down payments, may cut into the ability to afford "... the best single investment available to a young family or anyone else in this country." Based upon current and likely future economic conditions I regard the ESRG forecast as optimistic concerning both customer growth and addition of single family dwellings.

Q. Please discuss the difference between the ESRG and Company forecasts of residential consumption.

A. In my previous answer, I explained the difference between the two forecasts of the number of residential customers. Here I will focus on the difference in per customer usage. In order to facilitate the discussion I have prepared Schedule A of Exhibit ___ (JS-2). This schedule shows the difference between PECO and ESRG forecast 1987 per customer usage in four categories: refrigerators and freezers, heating, miscellaneous, and the remaining end-uses in the ESRG forecast. I have arranged the data in this way because it highlights the major difference in per customer consumption between the two forecasts. Notice that the first three categories cover the bulk of the difference. The end-uses lumped in the fourth category show small individual differences, the bulk of which cancel when added.

Q. Please explain the difference in refrigerator and freezer consumption.

A. This is due to much greater saturation assumptions in the Company forecast (unit usage is actually higher in the ESRG forecast). In the case of refrigerators, the base year (1977) saturation (average number of units per household) for single family dwellings is 1.2, while for multifamily dwellings it is 1.04. In both the ESRG and Company forecasts, the number of persons per household is falling and the share of multifamily dwellings is growing. It seems obvious that both these trends would argue for smaller saturation. In the ESRG forecast we have taken the very conservative assumption that the saturation of refrigerators in single family and multifamily units will remain at their current levels. This is also supported by the econometrically-based saturation growth analysis referred to in Exhibit ___ (JS-4), Sec. 8.1.2. The Company simply asserts , without explanation, that historic refrigerator saturation growth to 1.3 by 1988 averaged over single and multifamily units will continue. A similar set of comments apply to freezers. In addition to the demographic and housing type trends, the assumed penetration of larger refrigerators with their own freezer space point to a moderation in saturation growth for this appliance. Nevertheless, to be conservative I have allowed some saturation growth per the analysis in Exhibit ___ (JS-4) of about 25% overall between 1977 and 1987. The Company forecasts a 56% growth in freezer saturation growth between 1977 and 1987. I find that, given the underlying demographic and housing construction trends assumed by <u>both</u> ESRG and the Company, the refrigerator and freezer saturation forecasts made by the Company are unrealistically high.

Q. Please discuss the difference in electric space heating and heating auxiliary consumption.

A. Both forecasts assume rapid penetration of electric space heating among new customers. Historic penetration rates have been dependent on a complex mix of factors: construction practices, gas curtailment policy, economic promotion, etc. From 1970 to 1973, penetration rates in the PECO service area fluctuated, ranging from .13 to .34, then increased rapidly to over .50 in the gas curtailment years of 1974 and 1975. Given the recent rebound of the gas market, bans on new master-metered units, and the continuing economic inferiority of direct electric heating, the shared penetration rate assumptions of 30 to 70% over the forecast period (compare Exhibit ___ (JS-4), p. 69, and Exhibit ___ (WCH-1), p. 170) may be sources of over-estimation in both forecasts. The main source of divergence between the forecasts is traced to the differences of customer growth forecasts discussed earlier. Since penetration multiplied by new customers gives new electric space heated units, the resultant forecasts are sensitive to household growth assumptions. The difference in household forecasts accounts for over 70% of the 220 KWH/Year/Customer difference in Exhibit ___ (JS-2), Schedule A. The remainder of the difference is a composite effect. We assume a larger fraction of multi- to single family construction than does the Company with concommitant lower usage per household. Furthermore, based on our prototypical building shell analysis (Exhibit ___ (JS-4), Sec. 8.1.4 and Exhibit ___ (JS-5), Sec. 3.2, we have included thermal integrity improvements in new electric space heat construction reducing electricity requirements from

5 to 10 percent. For all of these reasons, but especially the differences in demographic assumptions and the shared high penetration projections, the ESRG electric heat estimate is, in my judgement, considerably more reliable.

Q. Please discuss the difference in miscellaneous consumption.

A. The Company miscellaneous forecast consists of three individually forecast components: dehumidifiers, supplementary heating, and transportation (electric vehicles), as well as general increases in the areas of cooking appliances, entertainment, and "personal comfort" uses. I will show that, for each of the categories the growth is highly speculative and where any applicable information exists it tends to suggest decreased rather than increased growth. I will deal with each end-use separately.

- Dehumidifiers. This is a curious case. The Company provides specific reasons why the use of this appliance should decline, related to the operating characteristics of central air-conditioning, and none whatever why it might increase. Yet saturation is assumed to increase from 15% in 1979 to 19% in 1988. A decrease here would be at least as plausible.
- Supplementary Heat. Here only the base year saturation is based upon hard data; usage is based upon an estimate of wattage and hours of use. Saturation is forecast to increase from .115 in 1977 to .195 in 1988 for rate R customers, with slightly smaller increases overall. Unit usage is expected to fall from 600 KWH to 575. No specific

explanation of either change is given. In fact, the pattern projected is extremely implausable. These units are equivalent to baseboard electric units, and as such are more expensive sources of heat than either the gas or oil units. The only logical reason for using them in a bathroom or bedroom, as PECO reports the majority are used, is to save money by heating only a limited area. If indeed this is the motive, then the use of such units for 1000 hours per year in both bedrooms and bathrooms as assumed by the Company in its forecast seems unlikely. Similarly, one might expect some decrease in the wattage of the average size of the units in use. The Company in making its forecast has assumed a large increase in the saturations of such units, 70% increase between 1978 and 1988, but only a 4.2% reduction in consumption. I feel this forecast to be extremely speculative, in view of the absence of data, as well as optimistic in its effect.

- Transportation (the "electric" car). This potential end-use has yet to come on line. Looking back over previous Company forecasts, we find that in 1976 it was expected in 1978, in 1977 it had slipped to 1979 and now, in the 1978-88 forecast, it makes its first appearance in 1982. In my view, this record is indicative of the actual state of affairs with the electric car: outside of DOE sponsored acquisition programs, no one knows if, when, or what numbers such vehicles will appear. Progress continues in such areas as battery design, but even if all technical obstacles

were overcome, there would still be the question of public acceptance of an electric vehicle with limited range and speed. In sum, I find its use extremely speculative.

Miscellaneous Cooking Appliances. Here we find mention of the microwave range. Microwave ovens, a closely-related appliance, have already been discussed in the section of the forecast dealing with the electric range, Exhibit ___ (WCH-1), p. 100. There it is assumed that a microwave oven will consume 190 KWH per year while reducing range consumption by 35%, or 245 KWH. This means in effect that microwave ovens consume 78% of the energy that would have been consumed by electric ranges to cook the equivalent items. This is simply false. In Exhibit ___ (JS-2), Schedule B, I have reproduced data showing the energy consumption in cooking a variety of foods using different appliances. As is clear from the data, microwave ovens use about 25% of the energy of ranges, depending on the food. Just as an illustration, let us accept the Company forecast assumption of 43% saturation for electric ranges in 1987. If <u>all</u> PECO customers used microwave ranges, forecast energy consumption would decrease. With respect to other cooking appliances, they too, as indicated in the exhibit, exhibit analogous "substitution" effects and will tend also to decrease overall usage, an effect which increases with increasing electric range saturation. In short, the likely effects of growing use of miscellaneous cooking appliances is to decrease overall use.

- Entertainment. Here, the Company discusses only variants of the television. Currently, they forecast two conventional televisions per customer in 1987. I find no reason to assume that these "new" end-uses would not simply supplant usage of one or more of the conventional sets. With the use of solid-state equipment, I see no reason to assume significant additional consumption for these devices.
- "Personal Comfort and Convenience." Here the only new load suggested by the Company is the home computer. Beyond the level of the hand-held calculator now in common use, I find this load extremely speculative. However, if it were to come into common use, it would presumably be a small solid-state unit with negligible usage. Any other assumption would fly in the face of current developments in computer technology.

Overall, the Company forecast usage in the miscellaneous category grows from 610 KWH per customer in 1978 to 1016 in 1987, an annual growth of 5.9% per year. As my discussion above has indicated, such a forecast of miscellaneous usage in 1987 is simply far beyond what one could reasonably expect.

Q. Please summarize your findings concerning the Company's residential forecast.

A. In most areas the Company residential forecast is reasonable. Population and single family housing growth potential are somewhat overstated. End-use consumption, due in part to the demographic

assumptions, for refrigeration, space heating, and miscellaneous consumption, is seriously overestimated. These problemmatic areas lead to a general overstatement of probable residential load growth over the forecast period.

Q. Please begin your discussion of the ESRG and the Company commercial forecasts.

A. The methods used by ESRG and the Company for its Base Case forecast are similar in approach. Both consider three basic factors as part of their forecasting methodology: changes in total commercial square footage to which service is provided, changes in the mix of end-uses serviced, and changes in the intensity of usage. The major difference between the two forecasts is in the degree of disaggregation. The ESRG forecast, as described in Section 4 of Exhibit ___ (JS-4), presents an extremely disaggregated approach to each of the three aspects of the forecast mentioned above. The Company forecast, on the other hand, as shown in Exhibit ___ (WCW-1), is aggregate in approach.

Q. Why does ESRG use such a disaggregated approach in forecasting commercial energy consumption?

A. We at ESRG find that to produce an adequate, accurate forecast, one must tie the forecasting methodology as closely as possible to the actual energy consuming end-uses. In the residential sector this leads to the end-use by end-use analysis both ESRG and the Company employ. We have continued this pattern of end-use analysis in our commercial forecast. For each of five building

types we identify four separate end-uses. Each building type/ end-use combination is forecast separately. For each such combination, the effects of growth in demand and changes in intensity of use are modeled separately, and then combined to provide the forecast for that combination. Based upon our knowledge and experience in this area, we believe that our forecasting approach represents the greatest degree of end-use disaggregation which can be achieved given the current availability of data in commercial sector consumption.

Q. Does the Company provide a comparable analysis?

A. No, it does not. As shown in Exhibit ___(WCH-2), pp. 220 and 221, with the exception of employment forecasts obtained from Wharton Econometric Forecasting Associates, all of the data is in aggregate form. Even the Wharton data is reduced to aggregate form before it is utilized. In the first paragraph on page 221, we find two key variables presented in an extremely aggregate form. These variables are square feet per commercial employee and electrical consumption per square foot in new commercial buildings. This second factor is in turn linked to other aggregate assumptions concerning conservation and the addition of new types of loads.

Q. How does the Company use of this aggregate data affect their forecast?

A. As I will show through a detailed analysis of each of the two items mentioned above, the Company's use of aggregate data accounts for the bulk of the difference with the ESRG commercial energy forecast.

Q. Please begin your discussion of the Company's use of its aggregate figure for square feet per commercial employee.

A. Wharton Econometric Forecasting Associates have supplied the Company with estimates of employment growth for the years 1975 to 1987. This information is disaggregated by type of business. From this information, PECO has derived an estimate of the total commercial square footage added in the 1978/88 period. This estimate was made by taking the total forecast employment growth and, assuming that there will be 465 square feet per employee, multiplying to obtain the square footage estimate. The PECO estimate is 121 million square feet. This represents a 22.3 percent increase over PECO's estimate of 1978 total commercial square footage.

The use of single estimates of the square footage per commercial employee represents a monumental simplification of the actual state of affairs. In Table 4.3 of Exhibit ___ (JS-4), I show detailed information concerning the number of square feet per employee. Because of the extreme variation shown in Table 4.3, the ESRG forecast of growth in commercial square footage is developed in the detail suggested by Table 4.3. The procedure is discussed in Exhibit ___ (JS-4). In Exhibit ___ (JS-2), Schedule C, I have developed an estimate of 1985 commercial floor space beginning with the disaggregated 1975 commercial floor space as developed by ESRG (and consistent with PECO total existing commercial floor space estimates) and applying the appropriate growth rates from the data developed by Wharton Associates. This computation makes exactly the same assumption of proportionality

between growth in employment and square footage as was made in the Company forecast, only the level of aggregation is different. Despite this similarity in method, the growth shown is strikingly different from that found by PECO. Instead of the addition of 121 million square feet in the 1978/88 period we find only 56 million in the 1975/85 period.

Q. Can you explain how such a difference is possible?

A. Yes, a simple example will make it clear. Suppose one had two types of business, the first with 200 square feet per employee and the second with 400. Then the average would be 300 square feet per employee. Now suppose the first business added 15 employees and the second 5. Using the average, one would expect $300 \times (15 + 5) = 6000$ square feet of additional floor space corresponding to these 20 employees. In fact, what we would find would be $200 \times 15 + 400 \times 5 = 3000 + 2000 = 5000$, or 20% less than the use of an average figure for square feet per employee would suggest.

Q. Can you estimate the effect of an overestimate of commercial square footage growth on the Company base forecast for the commercial sector?

A. Yes, I can. Using the growth rate in square feet per year developed in Schedule C of Exhibit ___ (JS-2) and the 1975 ESRG estimate of commercial floor space, I calculate that there would be 63 million square feet of commercial floor space added in the 1978/88 period. Following PECO's forecast procedure, I multiply by 34 KWH

per square foot and deduct 20% for conservation to obtain an additional 1850 million KWH of consumption in 1988. The corresponding figure in the PECO forecast is 3260 million KWH. The substitution of the estimate of floor space growth made on the basis of disaggregated input data thus reduces the Company's forecast of commercial energy consumption in 1988 from 12,320 to 10,754. This accounts for over half of the difference between the Company and ESRG forecasts.

Q. Is your use of ESRG data for 1975 commercial consumption consistent with PECO's commercial forecast assumptions?

A. Yes, it is. PECO presents its forecast of floor space growth from a base of 543 million square feet in 1978. Use of the above procedure produces an estimate of 541 million square feet for 1978.

Q. Please begin your discussion of the use by the Company of an aggregate figure for electrical consumption per square foot as a basis for forecasting the consumption in new commercial buildings.

A. It is simply not possible to reduce all of the information on the intensity of commercial energy consumption to a single number without collapsing a great number of essential distinctions and introducing the potential for substantial errors. In the ESRG forecast, the corresponding information is developed separately for each building and end-use as shown in Table 8.12 of Exhibit___ (JS-4). As explained in the text accompanying Table 8.12, the data on intensity of consumption per square foot is based upon an

updated version of the well-known information developed by A. D. Little, Inc. in its analysis of the ASHRAE 90-75 building standards. PECO has relied upon this A. D. Little analysis in determining its commercial conservation effects. The use of a single intensity figure is particularly troubling in light of the data presented by the Company on the extent of variation in the intensity of energy consumption in the commerical sector. As shown in Exhibit ___ (WCH-1), p. 210, among office buildings alone, the intensity of energy consumption differs by a factor of more than two. In addition to the single intensity figure itself, I have a great deal of difficulty with the Company's separation of basic intensity from conservation and saturation effects.

As I mentioned earlier, the question of intensity of energy consumption is interwoven with changes in the saturation of heating and cooling loads and the application of conservation. All of these factors are separated and treated as individual aggregate effects by the Company when in fact they are each specific to a particular building type/end-use combination and their results are inextricably linked.

Faced with all of these methodological shortcomings, I am forced to conclude that the treatment of the intensity of electric consumption in the Company base forecast of commercial energy consumption is so flawed that it places the adequacy and accuracy of the entire portion of the forecast in question.

Q. Above, you showed the approximate effect on the PECO forecast of a correction for the use of aggregate data on square footage per employee. Can you propose a similar correction for the use of aggregate intensity data?

A. No, I cannot. In my view the degree of over aggregation in the Company analysis of electric intensity and other related considerations is so great that, short of providing an entirely different procedure as I have done in Exhibit ___ (JS-4), I can provide no correction on this point. I should point out that I do regard the 34 KWH per square foot itself as extremely suspect. The data on which I have relied, shown in Table 8.12 of Exhibit ___ (JS-4), shows a maximum of 31.2 KWH per square foot with an average value far lower. These data are based upon the A. D. Little data, on which PECO has also relied. Their use beginning in 1975 produces good agreement with the average commercial consumption of 18 KWH per square foot reported by PECO in the base year 1977. Based upon an examination of the original data underlying the results in office building consumption reported by PECO in Exhibit ___(WCH-1), p. 210, I find that the 34 KWH per square foot figure is out of line with historic consumption levels. Since it is reflective of the 1974/77 period, I would expect that increased awareness of energy conservation as a goal in commercial building use would lead to a fall in the basic intensity of consumption toward the historic levels. This view is in accord with the energy intensity assumptions I have utilized in my forecast.

Q. In your comments thus far you have addressed the portion of the Company forecast dealing with new construction. Would the same comments hold for the Company analysis of usage in existing buildings?

A. Yes, they would. The same types of methodological difficulties involving over aggregation are present in both parts of the Company forecast.

Q. In its discussion of the base commercial forecast in Exhibit ___ (WCH-2), p. 221, the Company mentions certain "noncommercial" loads which are included in its commercial forecast. How have you dealt with these loads in your forecast?

A. These loads are included in my "other" building category as part of the light and power end-use. After completing my initial forecast for the commercial sector, I added to this building type/end-use combination an additional load to account for such "noncommercial" loads. This load is phased in linearly from 0 in 1978 to 740 million KWH in 1998.

Q. Might not this procedure involve double counting of growth in this category?

A. Yes, it might. For that reason the procedure is conservative and so consistent with my general forecasting approach.

Q. Thus far you have discussed only the approach used in the Company base case commercial forecast. Do you have any comments concerning the alternate procedures which they have developed?

A. Yes, I have a number of comments. First, from a methodological point of view, I note that all of the other approaches, as described in Exhibit ___ (WCH-1) p. 214-220, are at least as aggregate in approach as that developed by the Company for the base case. Thus none of these additional approaches addresses any of the methodological problems of over aggregation which I have raised. Second, concerning the results of the forecasts, I note that the approach used in the Company base case produced the lowest forecast of any of their methods. Given the substantial reduction which my correction for the use of aggregate square footage data produced in their base case, I am extremely skeptical concerning the usefulness of the other models. Finally I would like to make three comments concerning the regression models developed by PECO:

- Aggregate econometric models have a built-in assumption that the past will be similar to the future in its structural relationships. With respect to commercial energy consumption, I find this a dubious assumption.
- Good "model statistics" do not mean that a model will be a good predictor, they merely mean that you have put in enough variables to approximate the past.
- Even if we believe that a given model will reflect future relationships, there remains the question of the "explanatory variable." In the case of PECO's Model 2, this is real disposable income as forecast by Wharton Associates. This is a separate forecast, the construction of which one is largely ignorant. To understand it

completely, one would have to make a study of the Wharton model and its input assumptions. Referring to Figure 4 on p. 219 of Exhibit ___ (WCH-1), we see that the forecast produced by Model 2 increases much more sharply than was the case in the 1973/77 period, and in fact essentially parallels pre-1973 experience. Computations with the equation used in the model show that the type of growth exhibited in Figure 4 can only be the product of substantial increases in forecast disposable income. Given the current economic conditions, I find such growth suspect.

Q. Please begin your discussion of the Company forecast of industrial energy rates.

A. Sales to the large manufacturing class of customers (defined as SIC's 20-39 on PECO Rates PD and HT) account for most of PECO's sales to industry. In 1977, such sales accounted for 97%. The Company's basic forecast for the large manufacturing class is a time trending procedure: as explained in Exhibit ___ (WCH-1), p. 192, a time trend in sales per man hour of employment is developed using historic data for each 2-digit SIC. (The "SIC"'s, Standard Industrial Classifications, are standard groupings of industrial firms established by the federal government and used routinely for data gathering and analysis.) The yearly trended value of energy sales per man hour is multiplied by a forecast of man hours worked to obtain yearly forecast sales of 2-digit SIC. SIC's 29 and 33 are dominated by large petroleum and steel plants. For these categories the Company forecast is modified to take account

of information concerning the future plans of these large firms.

Q. Is this an appropriate forecasting approach?

A. There is a conceptual difficulty. In the analysis of industrial production, one usually distinguishes three factors of production: energy, labor, and capital. In a given industry, one does expect a stable relationship between these factors of production, and so the use of an historic trend involving the relationship between factors, such as energy and labor, or between total production and energy as is done in the ESRG industrial forecast, is indeed appropriate. What is inappropriate is the use of sales as opposed to total consumption. A trend involving the relationship between electrical consumption and man hours of employment expresses the historical relationship between energy and labor as utilized by industries in the Philadelphia area. The question of the relationship between sales and consumption is a separate question which, I believe, should be treated separately from any forecast of consumption. As is shown in Section 5 of Exhibit ___ (JS-4), the ESRG model does operate in the manner I have suggested. First, total industrial electrical consumption is forecast on the basis of a forecast of industrial production, and then a sales forecast is derived.

Q. Can you explain why the Company forecast combines the two steps you have proposed, the forecast of consumption and then the derivation of sales, into one step?

A. Yes, I believe I can. The difference between consumption and sales is due to industrial self-generation of electricity. This is the production of electricity by industries themselves. The term "cogeneration" is commonly applied to this process since the production of electricity is usually combined with the production of steam or hot water to meet industrial process requirements. In Exhibit ___ (WCH-1), p. 186, it is stated that "... no change in the ratio of self-generated to purchased power has been factored into this or previous forecasts." This means that the Company assumes that the ratio of total electricity to sales is constant. This being the case, it is not surprising that it has collapsed the two steps in forecasting of sales of electricity to industry into a single operation.

Q. Your forecast of industrial sales differs from that prepared by the Company. Does your treatment of self-generation account for the difference between the two forecasts?

A. Yes, it does. Using the year 1987 for purposes of illustration, I note that the Company forecasts industrial sales (Manufacturing sales plus 10% of sales to small C & I) of 10,515 million KWH. ESRG forecasts sales of 9860 million KWH in its Base Case. I have rerun the ESRG forecasting model to forecast industrial sales under the assumption that the fraction of electrical consumption satisfied by self-generation remains at 1976 levels. The result was a sales forecast of 10,535 million KWH in 1987, in virtual agreement with the Company.

Q. Do you accept the Company assumption that there will be no change in the fraction of energy supplied by cogeneration?

A. No, I do not. The Company itself has recently participated in a study by the Pennsylvania Electrical Association which documents the potential for increased cogeneration in its service territory. Other well-known national studies (see Exhibit ___ (JS-5), Sec. 5.2, for citations and discussion), also serve to establish this potential. The Company has assumed that, despite this acknowledged potential, there will be no change. In response to our interrogatory LF. 18d., the Company states with respect to growth in cogeneration, "...without government incentives not now known or effective, it is not highly probable that this growth will occur." "This growth" refers to the growth needed to keep up with total consumption as assumed in the Company forecast. What the Company is saying is that, absent additional government incentives, cogeneration may actually decline in importance. This directly contradicts, for example, the findings of the Thermo Electron Corporation, one of the reports cited above. They show growth in cogeneration without government incentives. Overall, I find the assumptions in the Company forecast of industrial energy sales unduly pessimistic concerning the future role of cogeneration.

Q. How is cogeneration treated in the ESRG forecast?

A. The ESRG forecast reflects the current uncertainty in this area. I find that some increase in cogeneration will take place but that it will be modest. As a high case assumption, I accept the Company assumption of no change. In the low case, I assume some increase

as shown in Table 8.19 of Exhibit ___ (JS-4). My Base Case is the average of the forecasts resulting from my high and low case assumptions. I note that even in the low case, I have used less optimistic assumptions than, for example, are given in the Thermo Electron study. Thus, my Base Case assumptions concerning increases in cogeneration are extremely modest and in my view are extremely likely to be met or exceeded.

Q. In addition to its forecast of manufacturing sales based upon man hours, the Company has presented a number of econometric models as a basis for forecasting such sales. Do you have any comments concerning these models?

A. Yes, I do. First I note that these models are extremely aggregate in nature. I would direct the same general criticism to them as I directed to the Company's aggregate models for the commercial sector. In addition, I note that these models have much poorer statistical properties than those proposed in the commercial sector and that, as shown in Exhibit ___ (WCH-1), pp. 196-197, that the actual sales do not lie entirely within the 95% confidence interval about the output of these models. While accurate reproduction of historic data is no guarantee of a model's predictive power, the failure of a model constructed by regression for historic data to fit the historic sales, is a reason for serious concern. In sum, I find that these models are not likely to prove useful in forecasting future industrial sales.

Q. Do you have any comments concerning the Company forecast of peak demand?

A. Both the Company and ESRG forecast peak growth as a function of energy growth. The methodologies and results both are quite similar. Both find a slight improvement in load factor over the forecast period. In general, the differences in the two forecasts of peak growth are due to differences in the underlying forecasts of growth in energy consumption.

Q. Please discuss briefly the Conservation Policy scenario described in your Exhibit ___ (JS-5).

A. Conservation Policy scenario assumptions and results differ from thosein the Base Case. These differences account for the differences between the Base Case and Conservation Policy Case forecasts. They assume that a fundamental change has taken place in the regulatory environment. The Base Case assumed the smooth continuation of current state-level conservation policy activity. The Conservation Policy Case, on the other hand, assumes a transition to the aggressive implementation of an integrated set of socially cost beneficial conservation policy measures as a result of action by the state. The measures are phased in by 1985. By posing such a conservation scenario, one can assess the implication (and desirability) of a conservation policy direction for the state. The broad policy areas addressed in the Conservation Policy scenario are listed in Table 2.1 of Exhibit ___ (JS-5). This is followed by a detailed specification and quantification of each policy measure. The constraints imposed on measure selection were technological

feasibility and decreasing social costs. The latter is construed to mean that the costs of achieving the improved energy efficiency implied by a given measure should not exceed the incremental costs of delivering the extra electrical (and other) energy that would be required in the absence of the measure. Indeed, the cost of saving a kilowatt-hour of electricity through these policies is generally considerably less than the cost of producing the energy equivalent. The Conservation Policy scenario results forecasts are presented alongside the Base Case results in the summary Tables 1.1 of Exhibit ___ (JS-4) and in more detail in Sec. 1.2 of Exhibit ___ (JS-5).

The Conservation Policy scenario shows that there is a great deal the state can do through implementing energy efficiency programs to manage long range electricity demand growth. The conservation results show energy consumption as essentially flat and peak demand falling, though no lessening in economic activity, decrease in end-use ownership levels, or decline in quality of life is assumed. Indeed, the Conservation scenario is designed to lower the overall costs of energy services in the state and, as we have shown earlier in a similar study for the State of New York, is likely to have the important additional benefit of creating a substantial number of jobs.

Q. Does this complete this portion of your testimony?

A. Yes, it does. As I indicated earlier, I will file supplementary testimony concerning the "essential human needs" rate.

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Hrg. 12-10-79

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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DOCKETED
DEC 13 1979

Direct Testimony of

Don M. Shakow

as to

Generation Planning and Reliability

November 13, 1979

E S R G

Q. Please state your name and your current position.

A. My name is Don M. Shakow. I am currently a Senior Economist for Energy Systems Research Group, Inc. of Boston, Massachusetts, and I am employed by Clark University, Worcester, Massachusetts, as an Assistant Professor of Economics.

Q. Would you please describe your educational background?

A. I graduated from the Massachusetts Institute of Technology with a Bachelor of Science degree in Humanities and Sciences. I hold a Ph.D. degree in Economics from the University of California, Berkeley.

Q. Please describe your relevant work experience.

A. Over the past five years I have done considerable research and have acted often in a consultive capacity in the areas of electric utility systems planning, energy usage and demand forecasting.

In 1975, as Senior Economist for Mathematical Sciences Northwest of Bellevue, Washington, I directed a loads and resources forecasting study for the City of Seattle entitled, "Energy 1990." This study involved the construction of an econometrically estimated load forecasting model coupled to a financial funds-flow model which determined future utility rates endogeneously. The study and a subsequent two months of oral testimony which I presented before the Seattle City Council was cited repeatedly as a decisive factor in a decision by this body regarding the municipal system's supply expansion program. The study was also cited and described at some length in a recent report by the House Committee on Government Operations entitled Nuclear Power Costs (Report No. 95-1090).

In 1976 I directed a regional all-energy demand study for the Northwest Energy Policy Project. This study involved the development of a large scale econometrically estimated model with major end-use components describing future regional demands for electricity, natural gas, petroleum products, and coal in the Pacific Northwest.

I have been called upon frequently to evaluate load forecasts and to provide estimates of the probable magnitude and direction of forecast error. Over the past three years I have undertaken evaluations for utility systems located in the Northeast, the Midwest, California, and the Pacific Northwest.

I have also conducted simulations of a number of forecasting models assessing the impact of conservation oriented scenarios on future loads.

Within the past year I have twice acted as expert witness and have submitted written testimony on the issue of load forecasting methodology for the Federal Energy Regulatory Commission.

I have also maintained an active interest in other aspects of electric utility system planning, most notably generation expansion and reliability analysis. In conjunction with Energy Systems Research Group, I have developed a prototype model which assesses the social cost associated with alternative reserve margins given a minimal cost, generation expansion scenario. This model has already been applied in rate proceedings. I have also prepared a study for the City of Seattle which compares the costs of underestimating versus the costs of overestimating loads, assuming alternative lead-times associated with the perception of forecasting error.

Q. What is the subject of your testimony today?

A. My testimony concerns an independent analysis of optimal generation expansion plans and reliability criteria for the Philadelphia Electric Company system, and an assessment of the current Company planning strategy and its probable impact on customer costs of electricity.

Q. Please summarize your major conclusions.

A. The Philadelphia Electric Company (PECO) has developed its construction program based on methodologies which exhibit palpable biases. In particular, outcomes are biased toward:

1. An excessive proportion of baseload relative to cycling and peaking facilities;
2. Within the baseload category, a preponderant emphasis on nuclear plants;
3. For the later years within its present planning horizon, excessive levels of reserve capacity.

These biases emerge when comparison is made between the PECO construction program and an optimal generation expansion program for PECO based on the criterion that the overall social cost of generation be minimized.

As a consequence of these planning biases:

1. Electric rates are likely to be excessive if the PECO construction program is implemented, relative to rates under an optimal program.
2. In particular, ratepayers are being asked to support the construction costs associated with Limerick units 1 and 2, neither of which would be built in a cost minimizing construction program. Under a range of cautious assumptions

on current and forecasted economic and technical parameters, I find that the Limerick units, totaling 2100 Mw, are not cost effective. Even assuming PECO's own forecast of demand growth rates, I find that by 1992 only three small 300 Mw coal-fired units totaling 900 Mw are required in the place of the two Limerick units, in addition to the 600 Mw of coal plants that PECO tentatively plans for 1992.

3. The reserve margins of 27-28% being advocated by the Company for the late 1980's are excessive, and are, moreover, not required to ensure reliable service. To achieve a partial blackout reliability of less than one day in ten years by 1987, reserve margins of 14-22% will likely be adequate.

Q. What is the basis for these conclusions?

A. These conclusions emerge on the basis of a model developed principally by myself in conjunction with staff from Energy Systems Research Group and Clark University.

Q. Could you please describe this model.

A. Exhibit A describes the structure, methodology, and assumptions of the model in detail. The ESRG Electrical Systems Generation Expansion Model (ESGEM) attempts to locate an optimal generation mix for an electrical supply system over a defined planning horizon. An annual social cost, representing the least cost plant expansion sequence, is calculated for a series of minimum reserve margins. The model selects that sequence where the overall expected levelized cost of generation is minimized under specified load conditions.

The calculation of total social costs as a function of reserve, once plants have been selected, is performed by the dispatch,

reliability, and production cost segments of the model. These consider all facilities currently in operation, plants under construction, "generic" supply options ranging from nuclear to combined cycle facilities, energy imports via existing interconnections, and alternatives for controlled, mandatory, and/or voluntary load curtailment. The model allows for present maintainance practices, the possibility of random forced outages, and the possibility of random variations in demand. In essence, the optimal sequence reflects a correct balancing among capital costs, fuels costs, curtailment costs, and purchased power costs. The model is, of course, similar in some respects to generation planning models used by many utilities. Unfortunately, I cannot compare it in detail to the generation planning model actually used by PECO and the PJM Power Pool to determine the PECO construction program, since the Company refused to provide me with a description of this model through discovery requests.

It should also be noted that for the purposes of this testimony, the model was run only for target reserves of 6, 14, 22, and 30 percent. The optimal levels referred to below are, therefore, only approximations to the actual optima. Some computer output from sample runs can be seen in Exhibit C.

Q. Is PECO's current generation expansion plan economically rational given its reliability criteria?

A. No, it is not. I have calculated the expected social cost* of generation for the years 1981, 1987, and 1992 under the present

*See definition under Table I

PECO expansion program and have compared them to costs implied by our own optimizations. Independently of the Company, I have selected two sets of economic assumptions regarding fuel inflation rates, interest rates, power plant costs, etc., which I believe bracket the plausible range that these variables will have for the next 15 years. I have labeled these two sets of assumptions the ESRG LOW and the ESRG HIGH scenarios, which stand, respectively, for the low and high extremes of the range of the ESRG inflation and cost assumptions.

Even the ESRG LOW set of assumptions involves higher fuel and power plant capital costs than the PECO assumptions, and are based on an inflation rate of 7.5% for the post-1981 period. The ESRG HIGH set of assumptions consists, then, of still higher prices, and is based on an inflation rate of 9% for the post-1981 period. All economic and technical parameters will be described in much greater detail below. In comparison to the ESRG assumptions, the Company's inflation forecast seems quite unrealistic, since they predict that the rate of inflation will drop suddenly to only 5% after 1981, for the remainder of the planning horizon.

When the ESRG model is run with either set of more realistic economic assumptions, I find that the PECO plant construction program is far from economically optimal, as can be seen in Table I. In all runs the full capital costs of all plants are included. In order to derive a single quantity as a basis for comparison, we have extrapolated costs for each year from 1981 to 1992 to get the total cost to the PECO customers of each scenario in 1979 dollars for the entire twelve-year period. The results are very clear and simple.

TABLE I

COMPARISON OF TOTAL SOCIAL COST[†]
UNDER ALTERNATIVE FORECAST ASSUMPTIONS AND SUPPLY EXPANSION PLANS

Forecast Assumption		Plant Construction		Real 1979 Cost	Mixed Current Dollars[††]
Demand	Cost	Plan	Year	(10^6 $)	(10^6 $)
PECO	PECO	PECO	1981	$ 739.7	$ 862.8
			1987	940.3	1,740.3
			1992	914.0	2,485.0
			Total*	10,515.8	19,674.1
ESRG**	ESRG-LOW	PECO	1981	669.6	817.7
			1987	1,077.6	2,395.4
			1992	831.1	3,043.3
			Total*	10,881.0	24,842.6
PECO	PECO	ESRG	1981	665.4	776.1
			1987	756.0	1,399.3
			1992	807.6	2,196.5
			Total*	8,883.9	16,603.4
ESRG	ESRG-LOW	ESRG	1981	595.1	726.7
			1987	577.7	1,284.0
			1992	542.9	1.988.2
			Total*	6906.3	15,218.0

† Defined as total production and curtailment costs plus capital cost of new plants (net of return and income taxes).

†† Based on yearly cost stream, unadjusted for inflation.

* Interpolated cumulative totals, 1981-1992.

** As presented in the testimony of John K. Stutz in this proceeding.

With the PECO plant construction program, using PECO's cost assumptions, the social costs (as defined in Table I) to customers could be about $10.5 billion 1979 dollars, even without considering income taxes and profits. (See row #1 of Table I.) In contrast, we see from row #4 that in the ESRG optimal construction program which excludes Limerick, the social costs to PECO customers would be only $6.9 billion 1979 dollars, even though the ESRG capital and fuel prices levels exceed Company forecasts, as we shall see in detail later in this testimony. In addition, from Row #3 we see that even with PECO's own demand forecast and cost assumptions, the ESRG construction program is considerably less expensive ($8.9 billion 1979 dollars) than that of PECO. Thus, the remarkable conclusion that emerges is that the ESRG construction program of only building small 300 Mw coal units after Salem #2 is cheaper for PECO customers under both ESRG cost and demand assumptions as well as under PECO cost and demand assumptions, as long as full capital costs for Limerick are included in the analysis.

Q. Is it not prudent to ensure against the possible incidence of unanticipated massive electrical supply shortfalls by the construction of what the Company proposes as sufficient generation capability?

A. The selection of a generation mix and an associated level of revenues can be likened to the purchase of an insurance policy. The rational consumer optimizes by balancing the cost of insurance in the form of premiums to the risks of casualty loss. Our calculations show that the economic risks in the form of social costs of curtailment associated with insufficient generation are relatively insubstantial as compared to the massive fixed obligations incurred as a consequence

of overexpansion. PECO is, in effect, vastly overinsuring the ratepaying public through its capacity expansion program. This is illustrated in Table II which shows the fuel, O & M, curtailment, and incremental capital costs for a sample scenario. This table shows that the dominating factors in the aggregation of total social cost are capital and fuel costs, respectively. Costs associated with curtailment reflecting the risks of under capacity are relatively minor, and in fact are probably overestimated, as will be discussed below.

Q. How sensitive are model outcomes with respect to blackout costs?

A. The generation mix which is optimal at a given reserve margin will be unaffected by changes in blackout costs because curtailment options are not included as supply options for generation planning in Module #1. Moreover, my computer analysis shows that the optimal reserve margin for PECO will be relatively insensitive to this parameter. This is shown in Table III where the total social cost of generation is calculated assuming a blackout cost of $5.00/Kwh and $2.50/Kwh, respectively. For each of the two test years, the optimal reserve margin remains approximately the same despite the decrease in the blackout cost parameter.

Q. How were the per Kwh costs of blackouts estimated?

A. I undertook a thorough review of recent studies in which the social costs of energy unserved was estimated. The results of these studies range from $1.23 Kwh (Telson, 1975) and $1.27 (1985 $) (Kaufman, 1975), to $1.00/Kwh (SRI, 1977; EPRI, 1978). However, very recent studies indicate that the costs of catastrophic blackouts exceed these estimates by a factor of as much as 2 or 3 (e.g., Corwin, 1978). For

TABLE II

A SAMPLE BREAKDOWN OF COSTS*
BASED ON ESRG LOAD AND PLANT COST ASSUMPTIONS

Cost Factor	1981	1987	1992
	(Costs in millions of levelized 1979 dollars)		
Fuel	314	277	263
Variable O & M	46	46	42
Carry Charges	69	81	73
Incremental Capital	-	61	37
Imports	143	95	120
Curtailment	4	3	4
Total	576	563	539

Source: ESRG Model

* Based on reserve margin of 14%.

TABLE III

SENSITIVITY OF MODEL RESULTS TO BLACKOUT COSTS
(SOCIAL COSTS* IN MILLIONS OF 1979 DOLLARS)

Reserve Margin	Blackout Cost	Years 1981	1987
6%	High	622.2	571.6
	Low	(603.2)	(563.0)
14%	High	576.4	563.2
	Low	(574.6)	(561.7)
22%	High	576.9	555.7
	Low	(576.4)	(555.6)
30%	High	587.0	575.0
	Low	(587.0)	(574.6)

* Estimates are based on ESRG load forecast and ESRG-LOW plant cost forecast.

this reason, we have chosen the highly conservative value of $5.00/Kwh in our base case. It should be noted that the incidence of catastrophic blackouts is extremely rare and is most often caused by inadequacies in transmission and distribution rather than generation plant.

Q. Apart from the issue of outage costs and reliability, aren't high reserve margins justified as a means of displacing high cost oil facilities with lower cost coal and nuclear plants?

A. This is a question over which there exists a great deal of confusion even among active professionals. Basically, it is incorrect to view the issue of oil displacement savings within a reliability context. This means that changing the reserve margin to improve reliability for an optimal set of generating plants, will generally not affect the economics and thus the desirability of building new plants for oil substitution purposes. These two goals are, in general, quite independent. The persistence of opinion to the contrary within the utility industry has led to much of this confusion.

Given a specific load configuration for some year in the future, results from the ESRG model indicate that there are no conceivable circumstances where it is economical to employ a baseload plant only for the purpose of achieving higher reserve margins. Instead, there exists an optimal configuration of baseload plants that will be employed at any target level of reliability. Higher reliabilitity target levels lead, in fact, to the introduction of increased numbers of peaking rather than baseload facilities. These results, of course, are quite logical since only the amount of baseload should determine the economic tradeoffs of baseload fuel switching.

Thus, more concretely, our model suggests that under most of the load and cost assumptions considered here, baseload demand is optimally served through the 1980's by the combination of the nearly completed Salem #2 facility and the introduction of several medium-sized coal burning facilities. At higher levels of reserve, the retirements of older oil-fired facilities are postponed and in later years some additional oil-fired combustion turbines are introduced.

These results (summarized in Table 4) show that the question of oil displacement is, indeed, independent of the issue of optimal reserve margins. It is correct that given rapidly rising oil prices (as well as national security consideration), baseload oil-fired plants should not be employed. This is demonstrated by the ESRG base case in 1990 for a 6% reserve margin, where large-size oil-fired facilities such as Eddystone units 3 & 4 show capacity factors of 4.8% and 6.9%, respectively, while coal-fired facilities -- e.g., Eddystone units 1 & 2, and the two new generic coal units are all baseloaded.

Thus, the imposition of higher reserve requirements in no way alters the optimal baseload configuration. It merely affects the retirement dates for oil-fired units. In fact, at 30% reserve, a host of older oil-fired units are re-introduced into the optimal supply configuration, whereas at lower reserve margins they would have been retired. The optimal reserve margin is thus determined on the basis of a tradeoff between the costs of curtailment on the one hand, and the capital costs and carrying charges of old oil units and new peaking plants on the other.

TABLE IV

INCLUSION OF SELECTED PLANTS IN THE 1990 OPTIMAL PLANT MIX* AS A FUNCTION OF RESERVE MARGIN

("YES" indicates that the plant enters the optimal mix at the specified reserve; "NO" indicates that the plant is excluded from that mix.)

	Plant	Rated Capacity (MW)	RESERVE MARGIN 6%	14%	22%	30%
PEAKERS	Cromby 2	183	NO	NO	NO	YES
	Salem 3	16	NO	NO	YES	YES
	Richmond 91	51	NO	YES	YES	YES
BASELOAD	Eddystone 1	381	YES	YES	YES	YES
	Eddystone 2	311	YES	YES	YES	YES
	Limerick 1	1055	NO	NO	NO	NO
	Limerick 2	1055	NO	NO	NO	NO
	Generic Coal	300	YES	YES	YES	YES
	Generic Nuclear	1200	NO	NO	NO	NO

* Based on ESRG load Forecast and ESRG-LOW plant cost Forecast.

Q. Please comment on responses that are available to PECO to alleviate situations of supply-demand imbalance, other than generation expansion.

A. A result demonstrated by our model is that optimal reliability levels are determined by a comparison between the costs of curtailment and the costs of facilities likely to be brought into service on peak. In analyzing curtailment costs, it is essential to distinguish between major loss-of-load events and episodes of shortfall which do not result in widespread blackouts. The model, for example, disaggregates eight distinct curtailment regimes other than blackouts (noted in exhibit A) ranging from emergency imports to voltage reductions. A majority of these involve some limited curtailment of service and/or a reduction in the quality of service.

While these options are decidedly inferior to that of continuous high quality service, their occasional use need not be uncritically avoided. In fact, the ultimate judgment concerning such "soft-curtailment" alternatives depends heavily on the costs imputed to these options. There is reason to believe that these costs fall considerably short of costs associated with massive blackouts. Costs of emergency power, for example, range about 10% above the operating costs of peaking plants. Controlled service loads for residential hot water heaters and interruptable contracts impose costs of a similar order of magnitude, insofar as the costs of transferring energy from on-peak to off-peak periods are minor.

In our model we have assumed that all curtailment options short of blackouts exhibit costs ranging from $.10 to $.20 per Kwh, as compared to $5.00/Kwh for blackouts. As a consequence, any increase in the availability of such "soft" curtailment options results in a

significant reduction in the overall costs of curtailment relative to blackouts, and hence, a reduction in the cost minimizing reserve margin. In Table V, for example, we show that an increase in the availability of emergency imports by 1000 Mw results in a significant reduction in outage costs and hence in the optimal reserve margin. At a 6% reserve margin, for example, the total social cost of the curtailment options only in 1987 (discounted to 1979 dollars) equals $27.7 million for the normal import situation as compared to $.53 million in 1990 in the presence of additional import availability. (All results assume ESRG-LOW cost escalation assumptions.) A similar result holds for increased availability of curtailment options other than emergency imports, but short of partial and rotating blackouts.

Q. In general, are there additional means of lowering reserve requirements aside from increasing the availability of curtailment options?

A. One promising approach is expansion in the range of centrally dispatched power pools. A study undertaken for the California Energy Resources Conservation and Development Commission showed that under full coordination of all California utilities within the framework of a power pooling arrangement and subject to the loss-of-load probability (LOLP) criterion of one day in ten years the necessary reserve margin dropped to 15%, as compared to target margins presently as high as 30.4% in absence of a power pool (Kahn, 1977).

PECO is a member of the PJM pool and thus benefits from enhanced system reliability at lower reserve margins as a result of this relationship. The possibility of additional benefits over present arrangements has not been explored in this study.

TABLE V

COMPARISON OF OUTAGE AND SOCIAL COSTS*
USING NORMAL AND HIGH IMPORT ASSUMPTIONS
(Millions of 1979 dollars)

Reserve Margin:	6%		14%		22%	
Year:	1987	1990	1987	1990	1987	1990
Import Assumption:	Normal	High	Normal	High	Normal	High
Outage Cost:	17.2	.4	3.0	.01	.8	-
Total Social Cost:	571.6	540.7	563.2	550.8	555.7	555.9

* Based on ESRG load Forecast and ESRG-LOW plant cost Forecast.

Q. Please summarize your position regarding the necessity of PECO's capacity expansion program from the standpoint of system reliability.

A. PECO's expansion program envisages expansion almost entirely in terms of baseload capacity. My results show that additional baseload capacity is not essential to ensure reliability. For all scenarios explored by the Model, baseload units are employed at capacity factors which are virtually unchanged under LOLP's ranging from zero to 50.8 days in ten years. These results obtained even for scenarios defined entirely on the basis of PECO planning assumptions.

The baseload mix indicated by the model at low target levels of reliability did not alter as reliability targets were increased.

I conclude that PECO's construction program will have no positive impact on reliability. Any possible justifications for this program must be evaluated solely on the basis of generation cost.

Q. Does the PECO capacity expansion program represent a Least Cost supply option?

A. No. In my opinion, based on the ESRG Forecast, the Least Cost plant configuration over the 1980's would warrant the introduction of two 300 Mw coal units, the retention of Salem unit #2, and the cancellation of Limerick units #'s 1 and 2. Under an LOLP constraint of .2 days in ten years this would imply no retirement among facilities presently in operation. Less stringent reliability (e.g., 6-8 days in ten years) would imply retirement of a limited number of existing peaking facilities. (If PECO's own forecast of demand growth had been assumed, an additional 900 Mw of baseload coal would be required, as we shall see.)

Q. How sensitive are these results to the underlying assumptions of the model?

A. The general tenor of these conclusions obtain for scenarios reflecting a wide range of assumptions. However, two exceptions to this assertion should be noted.

By ESRG "Base Case," we mean henceforth that PECO load growth occurs at a rate determined by the ESRG load forecasting model and that plant cost assumptions are derived from the ESRG LOW cost case.

Additional assumptions necessary for the application of the ESRG Base Case are as follows:

1. Load is assumed to grow at a constant rate with no change in the shape of the original (1978) PECO load curve.
2. Assignments of capacity are made on the basis of discrete plant units for periods of no less than one year.

For this Base Case, the optimal plant mix calculated by the model implies only two new facilities: two 300 Mw coal plants. Table VI summarizes outcomes under varying load growth and cost assumptions.

Load growth assumptions affect primarily the total capacity of coal units brought on line. Major qualitative differences in model outcomes lie in the cost assumptions. Where PECO cost-escalation rates are assumed and capital is valued only at the incremental (future) cost for plant construction, the model indicates the introduction of Limerick units #'s 1 and 2. This we shall term the PECO Planning Case. Otherwise, Limerick units are never introduced.

TABLE VI

OPTIMAL 1992 BASELOAD PLANT CONFIGURATION UNDER ALTERNATIVE ASSUMPTIONS

Case #	Load Growth	Plant Cost	Capital Cost	Optimal New Capacity	Optimal Reserve Margin (Approximate Rang
1	PECO	PECO	Full	2400 Mw, Coal*	14 - 22%
2†	PECO	PECO	Incremental	Limerick #1 Limerick #2 600 Mw, Coal	30%
3	PECO	ESRG-HIGH	Full	1500 Mw, Coal	14 - 22%
4	ESRG	ESRG-LOW	Full	600 Mw, Coal	14 - 22%
5	PECO	ESRG-LOW	Full	1500 Mw, Coal	14 - 22%
6	PECO	ESRG-LOW	Incremental	1500 Mw, Coal	14 - 22%
7††	ESRG	ESRG-LOW	Incremental	600 Mw, Coal	14 - 22%
8	ESRG	PECO	Incremental	Limerick #1 Limerick #2	30%

Source: ESRG Model

* All coal units listed in this column are 300 Mw units.

† PECO Planning Case

†† Base Case

Q. Does this suggest that the economic justification for the entire Limerick project hinges on the merits of using the incremental cost assumption?

A. No. Again, the model only outputs the Limerick facilities when it is assumed - both that incremental rather than total costs are the appropriate measure and that PECO's cost escalation assumptions are valid. In addition, all ESRG scenarios assume that a realistic capacity factor for new nuclear plants is .6, in contrast to the PECO assumption of .7.

Q. Could you comment further on the use of incremental versus total cost in assessing the cost-competitiveness of the Limerick units?

A. First of all, the use of incremental rather than full costs implies among other things that the assignment or cancellation of a plant under construction would not result in any credits applied to construction costs already expended. In the case of capacity assignments this is clearly untrue. The assignee would undoubtedly compensate PECO for part of or more likely all costs of construction. In addition, cancellations would imply book losses which could be applied against expenditures in the form of tax credits. Thus, for plants under construction, the application of full rather than incremental cost is a more realistic, more informative assumption in that it reflects the total cost of those plants to PECO customers.

The PECO plant cost assumptions are described in detail later. Here, I would like to stress that one of the primary differences with ESRG assumptions is in future nuclear capital costs. As I will indicate , the Company assumptions are, in my judgement, optimistic.

Q. How does the ESRG model deal with the possibility of limited term assignments of energy, that is, firm energy sales?

A. The ESRG model can accommodate a variety of specifications in regard to plant assignments. In the first place, it can assess the costs of a specific supply expansion plan, including assignments. For example, it can make a cost comparison between the case where a given assignment is made to the alternative case where it is not. This involves a decoupling of the optimal generation module (Module I, in Exhibit A) from the dispatching segment of the model.

Furthermore, the model can assess the status of assignments under conditions where a vigorous market for energy imports and exports is available. Under these circumstances, the optimal generation module selects for each year the optimal megawattage appropriate to a given technology within a continuous band bounded only by plant capacity. (This upper bound would reflect the case when PECO retained the entire capacity of the plant for its own use).

Finally, we can assess the desirability of "lumpy" assignments by assuming that capital costs include both incremental costs and costs expended plus a penalty for foregoing any potential profits that the utility can anticipate as a result of assignment. Under these assumptions, where the optimal generation module excludes such plants from the mix, the implication is that assignment is preferred to the retention of the plant for the year in question.

Q. Can the proposed assignment of Salem II to GPU for the years 1980-84 be assessed within this framework?

A. Yes. Under the assumption that GPU pays for the assigned capacity on the basis of the full cost of generation, the model indicates that Salem II should nevertheless be retained by PECO for the years 1981-85. Where the price payed exceeds full generation cost, the assignment may be expedient from the PECO standpoint.

We have also compared the social costs of generation under the current PECO supply plan to the alternative where the only change relative to the PECO plan is that the assignment of Salem II is excluded, i.e., all 474 Mw are retained by PECO. Table VII indicates a comparison of these two cases. Under these assumptions, the assignment of PECO cannot be recommended, as the social cost under assignment exceeds that of no assignment for each of the years 1981-85. It should be noted, however, that this table reflects a comparison of two sub-optimal cases.

Q. How would optimal social costs be affected by a moratorium on the completion of all nuclear plants under construction?

A. Under the ESRG Base Case, the optimal generation expansion plan excludes Limerick units I and II. Thus, a moratorium on nuclear construction would have no effect on optimal costs.

Q. Does the above conclusion apply to a moratorium on the operation of existing plants?

A. No. Salem units 1 and 2, for example, both enter the optimal mix. Their peremptory exclusion from the mix would raise generation costs. This is due to the presence of rapid escalation in the capital costs associated with any new (coal) plants as compared to the embedded cost of existing (nuclear) plants whose construction costs had not been as heavily inflated.

TABLE VII

A COMPARISON OF THE SOCIAL COSTS OF SALEM II ASSIGNMENT RELATIVE TO THE NO ASSIGNMENT OPTION UNDER THE ASSUMPTION OF COMPENSATION AT COST
(In Millions of 1979 Dollars)

Year	Assignment	No Assignment
1981	735.0	717.0
1982	810.4	750.2
1983	847.2	796.5
1948	891.9	846.1

Source: ESRG Model

Given PECO cost assumptions, for Salem II energy, the cost penalty of such a moratorium in 1987, say, would amount to roughly 36 mills/kwh and would incur additional expenses for PECO (and ultimately the PECO consumer) in the neighborhood of $100 million per year.

Q. Assuming that the ESRG rather than the PECO load forecasts are realized, would this imply a delay in the optimal on-line dates of Limerick units #1 and #2?

A. We have not identified any circumstances which would warrant a construction delay for Limerick units #1 and #2. As noted above, the introduction of the Limerick units is sensitive primarily to generation cost rather than to load growth assumptions. Under PECO cost assumptions the Limerick units are warranted at their earliest possible on-line dates. This applies to rates of load growth ranging from the ESRG base case to the PECO case. However, under the entire range of ESRG cost assumptions, a cancellation of the units, not a delay, is warranted as they do not enter the optimal mix at least through 1992.

Q. Please comment on the relative magnitude of baseload versus peaking facilities in the present PECO supply plan.

A. Our model suggests an unjustifiable preponderance of baseload plants in the PECO projected mix. Under the ESRG Base Case forecast and the ESRG LOW cost scenario, the optimal mix incorporates all existing baseload plants plus 600 megawatts of coal. The PECO mix by contrast includes 2110 Mw of additional (nuclear) baseload. The effect of this additional baseload is to force the operation of non-nuclear baseload plants at capacity factors which are inappropriately low.

This implies the presence of substantial idle baseload capacity. Since the fixed costs of baseload are high relative to those of peaking capacity, this situation implies that the utility incurs unnecessary costs. Table VIII illustrates the existence of idle non-nuclear baseload capacity in the PECO case, where costs are accounted in full. The 600 Mw of coal which are brought on line in 1992 to supplement Limerick units 1 and 2 are operated only 41.4% of the time. In no case do capacity factors exceed even 60% for these non-nuclear baseload plants.

Q. Can you estimate the cost impacts of this overemphasis on baseload by comparing expected costs for the PECO plan as compared to those of the optimal expansion plan?

A. Excessive baseload is likely to engender severe cost impacts. For example, estimated social costs for the PECO expansion case total $3043.3 million in 1992 (current dollars). In the optimal expansion case, at an equivalent level of reliability, costs total $2006.1 million, a discrepancy in current 1992 dollars of over one billion dollars. Idle baseload plant imposes costs of considerable magnitude indeed.

Q. Please comment on projected PECO reserve margins.

A. PECO anticipates reserve margins for the late 1980's of the order of 27-28%. Our model indicates that under the very unrealistic PECO Planning Case, 30% reserve margins are in fact optimal (note case #'s 2 and 8 in Table VI). In other words, given PECO's assumptions, including that of incremental capital costs, PECO's anticipated reserves are consistent with optimal reserves calculated by the ESGEM Model relative to a social cost minimizing objective. As noted,

TABLE VIII

1992 CAPACITY FACTORS: PECO SUPPLY EXPANSION VERSUS OPTIMAL EXPANSION*

		Plant	Capacity	Capacity Factor: Optimal Expansion (%)	Capacity Factor: PECO Expansion (%)
NUCLEAR	BASELOAD	Limerick 1	1055	N.A.	57.8
		Limerick 2	1055	N.A.	57.9
		Salem 1	468	68.8	67.7
		Salem 2	474	58.7	59.3
		Peach Bottom 2	447	69.4	68.3
		Peach Bottom 3	439	69.4	68.6
NON NUCLEAR	BASELOAD	Generic Coal	600	80.6	41.4
		Eddystone 1	301	58.7	44.2
		Eddystone 2	311	61.3	25.0
		Delaware 7	126	75.1	19.4
		Delaware 8	124	81.2	22.9
		Schuylkill 1	158	68.6	22.3
		Conemaugh 1	176	60.2	56.7
		Conemaugh 2	176	63.8	55.3
		Keystone 1	179	64.4	56.3
		Keystone 2	179	72.1	56.4

* The latter assumes ESRG load growth and ESRG cost scenario.

however, we believe PECO's assumptions lie outside the reasonable range of expectation, both in regard to load growth and in regard to plant cost and performance. If, instead of PECO's demand growth rates, we introduce the ESRG load forecast together with the PECO construction program, the reserve margin for 1992 would be 52.4%. This compares to an optimal target reserve level of 14% in the ESRG Base Case. In other words, there is likely to be a discrepancy of over 30% between the optimal reserve margin target and the realized margin.

Q. You have established that an increase in baseload capacity will not enhance the reliability of the system in a cost effective way. But what of reliability in general? An electric utility has a legal mandate to provide customers with service of a high and consistent quality. Does your model and the results it implies take sufficient account of this objective? Does it monitor reliability?

A. Most definitely. There exist a number of alternative methodologies current in the industry to ensure technical reliability in an electrical supply system: 1) the contingency outage, reserve criteria (e.g., a requirement that the system have sufficient reserve to meet load in the event that the largest unit in the system experiences outage), 2) the capacity reserve percentage, i.e., the prior specification of a reserve margin, and 3) the LOLP (Loss of Load Probability) method, which specifies a reserve margin, such that the probability of shortfall not exceed a given value (see Kaufmann, 1979).

There is a virtual consensus among workers in this area that among these alternatives only the LOLP method is analytically consistent. For example, consider a system with peak load of 1000 Mw

and a supply system consisting of a single facility, a baseload unit of 3000 Mw. The LOLP in this case is equal to the outage rate for this facility, say 1,000 days in ten years, well in excess of even the most lax of standards. However, the reserve margin is 200%, which would normally be considered very high. This example, while exaggerated, is not altogether fanciful as utilities become increasingly baseloaded and the size of individual units continues to increase. It shows, moreover, that the reserve margin is in itself not a reliable indicator of reliability. Some quantitative measure of the risk of shortfall must be imposed so as to imply a lower bound on the level of reserve. This will be dependent on the remaining supply configuration and its performance characteristics.

Recently, the LOLP method has been generalized (e.g., Shoengold, 1978) in the form of excess capacity analysis. This method specifies a continuous probability function which associates a probability with each level of capacity shortfall or excess. The traditional LOLP occurs as a single value of this function corresponding to a level of capacity excess equal to maximum import availability.

The ESRG model has been developed to calculate the probability function referred to above. This is necessary in light of ambiguity surrounding the LOLP concept. As noted, LOLP has been traditionally employed to monitor the probability of load in excess of capacity, plus imports, i.e., the probability of service interruptions, load control, voltage reduction and blackouts. In fact, though, we have determined that curtailment responses can be disaggregated into two very different categories: 1. "Soft" curtailment" regimes, with associated costs in the neighborhood of $.10-$.20/Kwh at most: and 2. blackouts, either

controlled or uncontrolled, with costs in excess of $.50/Kwh and in our very conservative Base Case assumptions, $5.00/Kwh.

From the economic standpoint, the objective of reliable service should focus on the probability of blackouts, rather than on the probability of curtailment in general.

For this reason, we have specified for each scenario in our model three different values of the excess capacity probability distribution.

I. The probability of curtailment overall.

II. The probability of blackouts.

III. The probability of system-wide blackouts.

In my view, the most appropriate single measure of technical reliability is II, rather than I.

The implications of this revised reliability parameter or index are very great. Table IX shows reserve levels implied by each of these two measures. The use of the revised criterion results in reserve levels approximately 8% less than those implied by the traditional "one-day-in-ten-years" LOLP criterion.

In summary, the ESRG model monitors reliability through the calculation of an excess capacity probability function. This enables it to explore alternative reliability criteria more suitable to the assessment of the genuine risks of system failure, as compared to traditional LOLP analysis.

Q. Can you recommend a particular reserve margin for PECO based on this modified LOLP procedure?

A. The procedure described above pertains exclusively to technical reliability. The major focus in our model is on economic rather than

TABLE IX

RESERVE LEVEL SUFFICIENT TO MEET DESIGNATED RELIABILITY LEVELS AT FULL COST

ESRG Base Case

	Traditional LOLP (Probability of curtailment) 1 day in ten years	Revised Criterion (Probability of Blackouts) 1 day in ten years	Social Cost Minimization Criterion
1981	30%	22%	14%
1987	22%	22%	22%
1992	22%	14%	14%

PECO Cost and Load Growth Assumptions

1981	30%	22%	30%*
1987	30%	14%	14%
1992	22%	14%	14%

* This is a consequence of historic overexpansion.

technical reliability. In other words, the objective in our model is to choose a level of reserve, so as to balance optimally the costs of curtailment and blackouts with the costs of additional capacity. Curtailment and blackouts are not considered negative per se in the Model, but are undesirable only insofar as they impose substantial costs on society at large.

A technical criterion such as LOLP, or the proposed modified LOLP, constrains the probability of blackout with reference to a fixed probability criterion, without considering economic consequences. Implicitly, therefore, this method assumes that socially desirable outcomes can be identified purely on the basis of a technical probabilistic analysis.

Preliminary investigation suggests that this assumption is invalid. Referring back to Table IX, it is clear that significant differences exist between outcomes using, say, traditional LOLP and cost minimization criteria. This demonstrates the inadequacy of purely technical solutions to this problem. Just as the designation of a reserve margin a priori is an inadequate characterization of the probability of system failure, the a priori specification of a probability constraint neglects to incorporate the social cost dimension and is, thus, in the last analysis just as arbitrary as the reserve margin criterion, albeit more analytically precise.

Q. What are the implications of this discussion in assessing operative and anticipated PECO reserve margins?

A. As noted above, PECO margins of 25-30% only appear justified from the standpoint of social cost minimization assuming:

1. that consideration is made only of incremental rather than full costs of capital for Salem unit #2 and for Limerick units #1 and #2,
2. that PECO forecasts are assured, and
3. that PECO cost and plant performance assumptions are employed.

The issue in regard to my conclusions about the PECO reserve margins is not one of methodology, however, since the results from our model largely support the PECO supply plan under the PECO Planning Case, including the choice of reserve margins. My disagreement is primarily with the adequacy of these assumptions. When the assumptions are altered, the optimal reserve margins are reduced substantially from the 25-30% range to 12-20%.

In other words, PECO reserve margins are excessive because of the inadequacy of the Company planning assumptions, not necessarily because of its analytical procedures. The biases introduced into the reserve margin analysis are a consequence of these faulty assumptions.

Q. What are the likely consequences of load control and load management procedures for reliability and social costs?

A. For a fixed reserve margin, both load management (i.e., policies designed to raise the load factor assuming a fixed energy constraint) and load control (i.e., measures to clip peaks above a specified level of load) are likely to have a favorable impact on costs. Both measures may result in a significant reduction in peak load. Insofar as required capacity is defined as (Peak Load) x (1+ reserve margin), the costs of fixed generation are reduced relative to the reduction in peak load.

However, these measures are, in fact, also likely to have an unfavorable impact on reserve margins. Consider, for instance, the case of a perfectly flat load (100.0% load factor). Note that any incidence of shortfall, at any hour of theyear, will require reserve capacity so as to forestall curtailment. For a more typical system, reserve is required in practice only during peak hours, which represent a relatively small proportion of total hours. Thus, the reserve requirements under a regime of load management and load control are likely to be greater than under a more typical load regime. This offsets to some degree the savings engendered by load management and/or control.

There is, moreover, a further circumstance whose effects may be still more unfavorable to these options. A flat load shape implies an optimal mix weighted heavily in favor of base load, relative to peaking capacity. This would imply the early retirement of many of PECO's existing generators and the construction of new baseload. However, given the cost of baseload under the escalation assumptions suggested by the ESRG cost scenarios, the overall generation costs associated with this modified load shape may be almost as high as would be the case with no change in the load shape. On balance, therefore, the net impact of load management/control is not certain to be cost effective, when account is taken of the costs of program implementation or the other social costs of load shifting. Thus, "peak-clip-valley fill" in particular might not result in a net decrease in social cost. But the key fact for the PECO system is that, as we have shown, the LOLP for blackouts under an optimal construction program is quite low. Thus, probably first consideration for improving reliability should

be given to implementing additional active load control technologies, e.g., ripple controlled commercial air-conditioning. (See Table IX.)

Q. Would you please explain the sources and bases for your selection of input assumptions and parameters for the generation expansion, dispatch reliability and social cost analyses you have performed with the ESGEN model in this case?

A. The general approach was to use Company data when this was made available to us. Where there were gaps in this data, I worked with the ESRG staff of scientists to perform calculations, review the industry literature, and make estimates of the relevant parameters.

For parameters associated with the future (e.g., costs, and technical and performance characteristics of new generation options) estimates were made based upon industry experience, industry and related literature, and ESRG staff expertise. Future trends (e.g. load growths, costs, inflation rates, cost escalation rates) were handled by establishing scenarios. The PECO scenario embodies all of the Company's assumptions. The ESRG LOW and ESRG HIGH scenarios embody ESRG estimates regarding future cost and load trends. Estimates of the magnitude and costs of the various curtailment regimes were based upon examination of the PECO system and review of the recent literature.

In general, my own estimates of various parameters were made conservatively. Various sensitivity analyses were performed.

Q. How was the load data used in your analyses obtained?

A. The detailed hourly loads on the PECO system for the year 1978 was obtained from the Company and used as the basis for my analyses.

Q. What were the ESRG load growth assumptions?

A. These were obtained from the detailed analyses performed by ESRG staff in this case (see Testimony of John Stutz, R.I.D.R-79060869. These

were approximately 1.3 percent per year from 1978 to 1992. During the same period PECO forecasts about 2.7 percent per year.

Q. Would you please provide more detail regarding your input assumptions?

A. Most of these are tabulated in the Table in Exhibit DS-B . It would probably be useful to explain the various sets of assumptions separately.

Q. Please describe your assumptions regarding the available supply options for the PECO System, their forced outage rates, and their capacity factors.

A. The supply options consist of all existing plants expected to be on-line by 1981 (including Salem 2, and excluding Cromby 5 and 6) according to Attachment I-B-4 of a Company document in this proceeding (Ref. 8) plus the Limerick 1 and 2 plants, and generic new supply options including 1200 Mw nuclear units, 300 Mw, 600 Mw and 1000 Mw coal units, 300 Mw oil cycling units, 400 Mw coal combined cycling units, and combustion turbines in sizes of multiples of 10 Mw.

The units' capacities have been obtained from various Company documents (including Company Exhibit VSB-1). For all units the capacity assigned was the summer rated capacity. This embodies conservatism since rated capacity can be expected to be higher during the rest of the year. Forced outage rates (FOUTR in Exhibit DS-B) were obtained from the Company (Attachment I-B-4 in Ref. 8). Forced outage rates for new units were developed by comparison with those of existing PECO units and by examination of the literature and industry experience (e.g., Refs. 9, 10, 11).

The variable CAPFAC in Exhibit DS-B is used in two ways in the ESGEN program, as discussed in Exhibit DS-A. In the capacity expansion module (Module I), CAPFAC is used as the expected annual capacity factor for each unit in order to compare expected costs for ranking. In the dispatch module (Module II) only the CAPFAC for hydro units is invoked, and there in order to conform to the Comapny's expected hydro operation. The expected capacity factor for all existing steam-electric units is obtained by subtracting the sum of forced and planned outage rates from 100 percent. For combustion turbines we have chosen 30 percent for CAPFAC based upon ESRG's discussions with various utilities in work for the Department of Energy (Ref. 12) and familiarity in previous work with utility operations. For hydro units (Muddy Run and Conowingo) CAPFAC was estima on the basis of actual usage of these facilities according to Company data. For new units (Salem 2, Limerick, and the generic supply options) CAPFAC was estimated based upon a review of the literature and industry experience. The large coal facilities were assumed to have CAPFAC's of 75 percent and 70 percent for 600 Mw and 1000 Mw units, respectively. EPRI (Ref. 9) has estimated 73 percent for 800 Mw coal units (with scrubbers). Our choice brackets this estimate, thus taking into account in a modest way the relative advantage of smaller units (see, e.g., Refs. 10, 13, 14). For 300 Mw coal units we assume an additional advantage in an 80 percent expected capacity factor. New combustion turbines were assumed to

have a CAPFAC of 30 percent. New oil cycling plants were assumed to have expected capacity factors of 85 percent (EPRI in Ref. 9 assumes 84 percent), and new coal combined cycle plants were assumed to have expected capacity factors of 80 percent (EPRI in Ref. 9 assumes 80 percent).

The remaining CAPFAC to be discussed is that assumed for new nuclear units (Salem 2, Limerick, and new generics). The Company has assumed 70 percent capacity factors for its new nuclear units. Recent research, including my own, in the area of nuclear power plant capacity factors leads me to conclude that this is an insupportably optimistic assumption for large nuclear plants, especially BWR's. I have chosen 60 percent to represent nuclear plant capacity factors. In my judgement, this is a reasonably conservative estimate, given my study of the experienced operating behavior of nuclear power plants as a function of size, type, manufacturer and other characterists (Ref. 15). In the research (Refs. 15, 16, 17, 18) I have found that large nuclear plants operating in the years 1968 through 1978 had the following capacity factor experience:

	Average Capacity Factor	Reactor Years in Sampl
Large (800+Mw) BWR's	54 $\pm$ 2 percent	46
Large (800+Mw) PWR's	57 $\pm$ 2 percent	78

On a yearly basis, beginning the first full year of operation, one finds:

Year	Large (800+MW) BWRs Capacity Factor (Percent)	Reactor Years	Large (800+Mw) PWRs Capacity Factor (Percent)	Reactor Years
1	51 ± 4	12	57 ± 3	23
2	49 ± 5	10	55 ± 4	19
3	53 ± 5	10	53 ± 4	16
4	58 ± 6	7	63 ± 5	11
5	59 ± 6	4	63 ± 5	6
6-7	69 ± 9	3	57 ± 9	3

For units over 1000 Mw the average experienced capacity factors have been 50 percent (14 reactor years) for BWRs, and 53 percent (16 reactor years) for PWRs. These are even lower than the 54 percent and 57 percent for 800+Mw BWR's and PWR's, respectively. While the experience with large (1000+ Mw) nuclear power plants is still limited, it certainly does not support the Company's assumption of 70 percent capacity factor for its new nuclear units. In fact, in choosing 60 percent for my present analyses, I am being conservative, even when this is compared with the results of the much larger (800+Mw) sample, which embodies capacity factor experience better than the 1000+ Mw units.

Q. How were economy imports, emergency imports, pumped storage hydro, and conventional hydro options taken into account?

A. Here, again, I will distinguish between the capacity expansion module (Module I) and the dispatch and costing modules (Modules II and III) of the ESRG ESGEN program.

The hydro options are included in the capacity expansion optimization model, where the least cost mix of supply options to meet expected load is developed. The import options are added (along with the curtailment options) only in the dispatch, reliability, and costing modules where economy purchases and the various insufficiency procedures are invoked based upon costing as well as supply and

demand fluctuation conditions.

The capacity factors (CAPFAC) for the hydro options were established on the basis of Company projected usage for 1981. Economy imports were also established on the basis of Company data. The Company's net purchases (after subtracting sales) in 1981 was used assuming an expected capacity factor of 50 percent to arrive at a reasonably conservative estimate of available economy import capacity for the future. A conservative estimate of available emergency import capacity (500 Mw) was established judgementally, based upon the magnitude of capacity and large number of units in the PJM system as well as the large number of transmission lines. Costs of emergency imports (listed in Exhibit DS-B under FUEL) were based upon the Company's interrogatory response, A.GLF.8.

Q. Please describe your assumptions regarding fuel costs.

A. Fuel costs for the 1979 base year, expressed in 1979 dollars, were obtained by examining mid-year (May-July) fuel prices. These prices, and their source are listed below.

nuclear	$ .35 per MMBTU	(Company Response A.GLF.4)
coal	$1.44 "	(Ref.19)
residual oil	$3.65 "	(Ref.20)
distillate oil	$4.14 "	(Ref.20)
natural gas	$1.91 "	(Ref.20)

We have increased base year oil prices over those estimated by the Company in order to adequately incorporate recent price increases.

Fuel costs for each unit in the PECO system were then calculated using the above prices and the plant-specific heat rates. Plant-specific heat rates were obtained primarily from 1977 Monthly Power Plant Reports (FERC Form 4) which give generation and fuel consumption data, and from FERC Form 12 reports. Fuel costs are given by:

$$\text{FUEL COST (\$ per Kwh)} = \text{HEAT RATE (MMBTU per Mwh)} \times \text{FUEL PRICE (\$ per MMBTU)} \div 1000$$

Q. How were fuel costs escalated for the years beyond 1979?

A. In order to describe my fuel cost escalations I must describe my inflation assumptions as well. Fuel costs were escalated by an annual rate which is the sum of the inflation rate and the real price escalation rate (specific to each fuel).

Exhibit DS-D summarizes the inflation rate, escalation rate, and discount (interest) rate assumptions for three sets of scenarios. We have developed three categories of cost related scenarios. The first (PECO) is designed to incorporate the Company's assumptions. The other two incorporate ESRG assumptions. These are designated as ESRG LOW and ESRG HIGH for low and high cost scenarios respectively.

I have pegged all cost escalation rates to the underlying rates of inflation in the ESRG scenarios; that is, all escalation rates are assumed to have a "real" (or constant dollar) component which is added to the inflation rate in the ESRG LOW and ESRG HIGH scenarios.

The Company has assumed annual inflation rates of 6.5 percent in 1980, 5.5 percent in 1981, and 5.0 percent thereafter. In my judgement, these assumptions are unreasonably low. The inflation rate for the last two years has averaged over 10 percent per year. I do not expect this to drop substantially or quickly over the next decade. The impact of the energy industry and energy prices alone within the overall economy is significant in sustaining high inflation rates.

I have therefore constructed two sets of escalation rate assumptions based upon inflation rates of 8.5 percent (1980), 7.5 percent (thereafter) in the ESRG LOW case, AND 10.0 percent (1980) and 9.0 percent (thereafter) in the ESRG HIGH case. I believe this range of inflation rates adequately represents the likely rate of inflation over the next ten years, given the uncertainties involved in making such forecasts. Having said this, I would like to note that the main results of my analysis are not very sensitive to the inflation rate assumptions since all cost estimates and comparisons are ultimately made in constant (1979) dollars, by applying a discount rate. Since both the ESRG and the PECO discount rates are 3% plus underlying inflation rate, the latter does not affect the comparisons to first order.

The Company has estimated annual cost escalation rates for nuclear, coal, and oil fuels. These are 8.2 percent, 8.0 percent, and 10.0 percent (8.0 percent after 1985) for these three fuels, respectively. The ESRG LOW scenarios embody these assumptions. In the case of natural gas the Company's implicit real price escalation rate is added to the ESRG LOW inflation rate.

In the ESRG HIGH case I have assumed real price escalation rates for oil to be 4 percent (1980), 5 percent (1981 through 1984), and 3 percent (thereafter). These are comparable with the Company's assumed real escalation rates 3.5 percent (1980), 4.5 percent (1981), 5 percent (1982 through 1984), and 3 percent (thereafter). Coal and nuclear fuel prices escalate at real rates of 2 percent (1980), and 3 percent (thereafter) similar to the Company's real price escalations for these fuels.

Q. What escalation rates have you assumed for other costs?

A. Operation and maintenance costs have been assumed to escalate at the prevailing rate of inflation. Non-generation options are assumed to escalate at the same rate as oil prices. Since the cost of this group of options is dominated by economy imports of electricity, this is a reasonable assumption. The discount rate or interest rate (expressing the time preference for money) is assumed to be 8 percent, 10.5 percent, and 12 percent for the PECO, ESRG LOW and ESRG HIGH cases, respectively, 3 percent above inflation.

Q. Please describe your estimates of the capital costs of new electric generation supply options.

A. The capital costs of coal and nuclear plants were made using regression equations developed by Charles Komanoff of Komanoff Energy Associates, Inc. in New York City. (Ref.) Mr. Komanoff has provided capital cost regression equations for direct construction costs in 1979 construction dollars for all coal fired units with capacity greater than 100 Mw installed by U.S. utilities from January 1972 through December 1978, and for all nuclear generating units installed from December 1971 through December 1978 (except for several "turnkey" plants supplied under fixed fee contracts). The data base for coal plants included 116 units with a total of 70,509 Mw, ranging from 114 Mw to 1300 Mw and averaging 608 Mw. The data base for nuclear plants consisted of 46 units with a total of 39,265 Mw, ranging from 514 Mw to 1130 Mw and averaging 854 Mw.

Mr. Komanoff's regression equation for coal plants is given by:

Cost ($/Kw in 1979 construction dollars) =

	t-ratios
0.303 ×	
(Coal Capacity)$^{0.588}$ ×	.686
1.26 if Scrubber ×	4.09
.90 if common-sited unit ×	4.84
1.26 if West ×	3.43
.77 if South Central ×	5.45
.74 if Southern ×	4.22
.85 if Southeast (but not Southern Company) ×	5.56
1.16 if Northeast ×	3.19
1.19 if American Electric Power ×	1.93
	2.37

R^2 = .670 F - value = 23.9

Adjusted R^2 = .642

where COAL CAPACITY is the total installed capacity of coal fired units in the U. S. at the time a unit is ordered.

Mr. Komanoff's regression equation for nuclear plants is given by:

Cost ($/Kw in 1979 construction dollars) =

	t - ratios
$6.46 \times$	
$(\text{Nuclear Capacity})^{0.575} \times$	2.69
	13.40
$(\text{MW})^{-0.208} \times$	2.63
$(\text{AE})^{-0.102} \times$	6.08
1.27 if Northeast $\times$	6.39
1.20 if Tower $\times$	5.24
.91 if Common-Sited $\times$	2.36
1.35 if "Dangling"	4.75

$R^2 = .921$ F - Value = 63.5

Adjusted $R^2 = .907$

where NUCLEAR CAPACITY is the total nuclear capacity operating or under construction at the date a unit's construction permit is issued,

MW is the capacity of the unit in megawatts

AE is the number of units designed by the architect-engineer (including the current plant) including any of the early commercial sized reactors excluded from the cost data base

"Dangling" is a description ascribed to four units in the data base whose duplicate partners had not been completed and therefore did not yet have final reported costs. Estimation of new unit costs does not include this variable.

All costs are in 1979 construction dollars, taking account of rates of inflation and construction cost escalation during the period when these units were built. Separate treatment of coal and nuclear units were developed from the Handy-Whitman Index of Public Utility Construction Costs. Furthermore, the regression equation gives direct construction costs only, excluding interest during construction.

These equations were used to obtain 1979 construction $ per Kw cost estimates for 300 Mw coal plants, 600 Mw coal plants, 1000 Mw coal plants and 1200 Mw nuclear plants.

The coal plants were assumed to have scrubbers, and, of course, northeast location. The 300 Mw units were assumed to be commonly sited in groups of three and the 600 Mw units in groups of two. The units were assumed to be ordered in 1980, and the size of the coal sector was estimated to be 356,565 Mw in that year. The results are:

300 Mw coal $757.6 per Kw in 1979 construction dollars
600 Mw coal 773.8 per Kw in 1979 construction dollars
1000 Mw coal 814.6 per Kw in 1979 construction dollars.

In estimating total unit costs, including construction cost escalation and interest during construction, it was assumed that the 300 Mw, 600 Mw, and 1000 Mw units would be constructed over 7, 8, and 9 year periods, respectively. The direct construction expenditures in 1979 construction dollars were spread out over these years in a typical pattern as shown below.

DIRECT CONSTRUCTION EXPENDITURES
IN MILLIONS OF 1979 CONSTRUCTION DOLLARS

	300 Mw Coal Unit	600 Mw Coal Unit	1000 Mw Coal Unit
Year 1980	18.2	15.5	16.3
1981	15.2	7.7	4.9
1982	36.4	10.8	4.9
1983	153.8	37.1	9.8
1984	267.4	157.1	39.1
1985	217.4	273.2	165.4
1986	49.2	222.1	287.5
1987	-	50.3	233.8
1988	-	-	53.0
Total	757.6	773.8	814.6

Construction cost escalation was taken to be 2.65 percent per year above the inflation rate, the same as was used for nuclear plant real construction escalation costs as reported by ESRG in previous studies (Refs. 22 and 23). Interest during construction was assumed to be 2 percent above inflation in the ESRG Low Case (10.5 percent in 1980, 9.5 percent thereafter), and 1.5 percent above inflation in 1980 (11.5 percent) and 3.0 percent above inflation thereafter (12.0 percent) in the ESRG High Case. The steps in the procedure for estimating the capital costs are summarized in Tables E-1 through E-3 in Exhibit ___(DS-E). Column 1 in these tables restates the yearly direct construction expenditures (in 1979 construction dollars per kilowatt) given above. Column 2 gives the yearly inflation rate. Columns 3 & 4 are obtained from column 1 by converting to current dollar construction expenditures by 2.65 percent plus the inflation rate in the Low and High cases, respectively. Column 5 gives the yearly AFDC rate. Columns 6 and 7 are obtained by applying the interest

rates (Low and High) to the total accumulated prior expenditures in a given year, and one-half the interest rate to the year's current expenditures. Columns 8 and 9 then take the total yearly expenditures for construction and interest (the boxed numbers in columns 3, and 8 and 4, and 7 and convert them to 1979 dollars according to the yearly inflation rate assumptions. The total estimated costs (including interest and escalation during construction) for the coal plants in 1979 dollars are:

COAL PLANT CAPITAL COSTS

	300 Mw Coal Units	600 Mw Coal Units	1000 Mw Coal Units
ESRG Low	$1058/Kw	$1103/Kw	$1197/Kw
ESRG High	$1111/Kw	$1164/Kw	$1257/Kw

Q. What capital cost escalation rate did you assume for these coal plants?

A. We assume that the earliest years these plants can come on line are 1985, 1986, and 1987 for the 300 Mw, 600 Mw, and 1000 Mw coal plants, respectively. Of course, the ESRG generation expansion optimization routine could choose to build these plants at later dates. The consequences would likely be that construction would be initiated later or delayed. In such instances, a yearly escalation rate which includes (1) the inflation rate, and (2) coal plant real construction cost escalation rates, must be applied. The Komanoff regression equation gives coal plant direct construction costs in 1979 construction dollars. Applying his equation to typical coal plants in the U. S., Komanoff

estimates a real construction cost escalation rate of 3.6 percent for plants completed between 1978 and 1988. I have conservatively taken 4.0 percent as the average annual real capital cost escalation rate for coal plants. This plus the ESRG Low or High annual inflation rates is applied to the above capital cost estimates (in 1979 dollars) to account for capital cost escalations during years of delay in initiating or completing construction.

Q. Would you please continue by describing your capital cost estimates for nuclear units.

A. I have developed capital cost estimates for the completion of Limerick Units 1 and 2 (earliest completion dates 1985 and 1987, respectively), and for generic new nuclear units coming on line 1990 and thereafter.

For Limerick 1 and 2 I have used the Komanoff regression equation with the following inputs: Since these units received construction permits in 1974, the variable NUCLEAR CAPACITY is given the value 78789, the size of the nuclear sector in megawatts in that year. The variable MW is taken to be 1055, the size of each Limerick unit. The variable AF is taken to be 38, the number of units designed by the architect-engineer, Bechtel, by the year 1974. Since the two units are commonly sited, in the northeast, and are designed to have cooling towers, these variables were also used in the regression equation. The result obtained was:

Limerick 1 and 2 Direct Construction Costs
in 1979 Construction Dollars
$1002 per Kw

I have not applied the 9 percent difference between the costs of Limerick 1 and 2 to express the economies achieved due to higher

first unit costs for common-sited units that is embodied in the Komanoff regression equation. The two units were, conservatively, assumed to share full station costs equally.

The generic nuclear unit was assumed to receive its construction license in 1982. At that time the size of the nuclear sector is estimated to be 169,171 Mw. The unit was assumed to have 1200 Mw capacity and to be built with cooling tower. The AE variable was taken at an intermediate value of 20 by inspection of estimated average experience of all major architect-engineer firms by 1982 (Ref. 24). The unit was not assumed to be common-sited. The result obtained was:

Generic 1200 Mw Nuclear Unit

Direct Construction Costs in 1979 Construction Dollars

$1683 per Kw

The total capital costs of the Limerick and generic nuclear plants were estimated using the same procedure as described for the coal plants. For the Limerick plants yearly direct construction expenditures were obtained from the Company. The Company's yearly direct current dollar construction expenditures from 1970 through 1979 and estimates through 1987 were converted to 1979 construction dollars using nuclear power plant construction cost escalation rates obtained from the Handy-Whitman index (see Ref. 25) for the years 1970 through 1977, and at 2.65 plus inflation thereafter (see Refs. 22 and 23). This allowed a yearly apportioning of fractions of the $1002/Kw 1979 dollar direct construction expenditures estimated by the Komanoff equation.

For generic units a typical yearly spread of direct constant (1979) dollar construction expenditures, assuming a twelve year schedule beginning in 1979 was estimated. The breakdowns for these units are given below:

NUCLEAR UNITS
DIRECT 1979 CONSTRUCTION DOLLAR
EXPENDITURES IN DOLLARS PER KW

	Limerick 1 and 2	Generic Nuclear Unit
1970	7.0	--
1971	33.1	--
1972	41.0	--
1973	63.1	--
1974	75.1	--
1975	77.1	--
1976	99.2	--
1977	100.2	--
1978	80.1	--
1979	55.1	11.3
1980	60.1	20.2
1981	64.1	16.9
1982	65.1	43.8
1983	61.1	106.2
1984	53.1	143.3
1985	42.0	217.5
1986	19.0	296.7
1987	7.0	338.9
1988	--	241.1
1989	--	118.0
1990	--	28.7
	1002	1683

These direct 1979 construction dollar expenditures were then used to develop total plant costs in the same manner as described for the coal plants. The details are given in Tables E-4 and E-5 in Exhibit ___ (DS-E). The historic interest rates during construction rates (1970-1978) were estimated using the Company's cost breakdowns (direct vs. IDC) during that period. Construction cost escalation rates were obtained from Ref. 25 for 1970-1977 period

and were taken to be 2.65 percent plus inflation thereafter. The results obtained were:

CAPITAL COSTS OF NUCLEAR UNITS IN 1979 DOLLARS

	Limerick 1 and 2	Generic 1200 Mw Nuclear Unit
ESRG LOW	$1764/Kw	$2913/Kw
ESRG HIGH	$1907/Kw	$3158/Kw

Using experienced 1970 through 1979 inflation rates and Company expenditure data, I estimate that the Company will have spent a total of $755/Kw in 1979 dollars for Limerick 1 and 2 through 1979.

Thus, the remaining (or marginal) costs of the Limerick units are $1009/Kw and $1152/Kw in the ESRG Low and ESRG High cases, respectively. As I shall describe later, in discussing the sensitivity analyses I have developed, I have constructed scenarios and obtained results with the ESRG Model assuming that (1) 100% and (2) 0% of the costs ($755/Kw) already incurred for the Limerick plants are included in the actual costs of these units for planning purposes.

Q. What capital cost escalation rate did you assume for nuclear units?

A. Based upon Komanoff results for 1978-1988 real cost (1979 construction dollar) escalations estimated for typical U.S. nuclear plants and an estimated 2.65 percent average annual construction cost escalation rate (Refs.22,23), I have represented the nuclear plant capital cost escalation as 8.65 percent plus inflation.

Q. What assumptions have you made regarding the costs of the Salem 2 nuclear unit?

A. Using Company data and annual inflation rates for the period 1968 through 1979, I have calculated Salem 2 total capital costs (including interest during construction) to be $1182/Kw in 1979 dollars. As with the Limerick units we have constructed sensitivity scenarios in which (1) 100% and (2) 0% of these costs are ascribed to this unit. Of course, no capital cost escalation is assumed.

Q. What capital costs have you assumed for other new generic generating capacity options?

A. By examination of the literature I have assigned costs (in 1979 dollars) of 225/Kw for new combustion turbines, 1460/Kw for new coal-fired combined cycle units, and 520/Kw for new oil-fired cycling plants. The capital cost escalation rates were estimated to be the inflation rate plus 4 percent and 2 percent, respectively, for coal and oil plants.

Q. How were these capital costs annualized?

A. The total capital cost of each plant was annualized on a levelized basis by applying a fixed charge rate. The fixed charge rate was calculated by applying the mortgage formula assuming a 30 year lifetime (L) or amortization period. The formula, embodied in the ESRG generation expansion program is:

$$FCR = \frac{d \times (1 + d)^{L}}{(1+d)^{L-1}}$$

This fixed charge rate does not include taxes and depreciation which were separately assigned to each new unit in the FIXCC variable in Exhibit DS-B.

The discount interest rate (d) is assumed to be 3 percent plus the long term inflation rate, that is, 8 percent in the PECO scenarios and 10.5 percent and 12 percent in the ESRG Low and ESRG High scenarios, respectively.

Q. What other fixed costs related to plant capital costs, have you assumed?

A. We have assigned fixed costs to nuclear plants, other steam-electric plants, and combustion turbines separately based upon average Company depreciation rates estimated by Tom Weiss . To each of these we have added 0.15 percent for real estate and property taxes estimated as a Company average over total investment by Tom Weiss . The resulting contributions to fixed carrying charges (FIXCC in Exhibit DS-B) are:

New Nuclear: 3.10 percent × Capital Cost (FIXCAP)

New Coal/Oil Steam: 3.36 percent × Capital Cost (FIXCAP)

New Combustion Turbines: 3.55 percent × Capital Cost (FIXCAP)

These costs are assigned only to new plants (Salem 2, Limerick, and the generic options) as are the plant capital costs. Furthermore, they are added to estimates of fixed operation and maintenance costs to obtain the fixed carrying charges (FIXCC in ExhibitDS-B).

Q. Please describe your assumptions regarding operation and maintenance costs.

A. These costs were estimated in 1979 dollars for fixed ($ per Kw) and variable ($ per Kwh) components separately. Recent Company data for total plant-specific O & M costs (Ref. 8)

were used. The breakdown between fixed and variable costs was made using estimates for each plant type provided in an EPRI study (Ref. 9), and using PECO plant-specific generation data. For the Cromby and Eddystone units, Company data (Interrogatory Response A.GLF.3) on estimated additional O & M costs, associated with environmentally related charges, were included. The variable and fixed O & M costs appear as VAROD and, respectively as FIXCC in Exhibit for all existing plants. For new units the fixed and variable O & M costs were assumed to be the same as Cromby 1 for coal, Eddystone 3 and 4 for oil, about the same as the Peachbottom units for nuclear. The fixed O & M costs for new units were added to the fixed costs for depreciation and taxes to obtain FIXCC for these units.

Q. You have argued for the existence of three major biases resulting from the PECO supply planning analysis, which you have identified as deriving from the cost assumptions employed in the PECO Planning Case, i.e.;

1. the bias toward baseload
2. the bias toward nuclear baseload, and
3. the bias toward high reserve margins.

Is it possible to provide some rough order of magnitude indication of the impact of these biases on utility costs, a proportion or all of which will no doubt be passed on to the PECO ratepayer?

A. In addition to my earlier discussion of the results that appear in Table I, one can address this issue further in the following way. (See Table X.) Beginning with the PECO Planning Case, except including full capital costs that appeared in row #1 of Table I (called "Initial Scenario" here), I have again identified the expected cost of generation for the years 1981, 1987 and 1992, as in Table I. I then examine a revision of row #4 in Table I, called the "Revised Scenario" here, assuming the ESRG construction program and prices. In this "Revised Scenario", I assume, however, that the PECO demand forecast comes true, in contrast to row #4 in Table I where the ESRG demand forecast was assumed. Again, we see that the cost penalty to the PECO customer of the PECO construction program exceeds $140 million 1979 dollars per year throughout the 1980's. This is further evidence that the PECO construction program cannot be justified on the basis of their demand forecast.

TABLE X

AN ASSESSMENT OF THE SOCIAL COST PENALTY DUE TO MISSPECIFICATION OF THE OPTIMAL SUPPLY EXPANSION PLAN
(Millions of 1979 dollars)

Year	Social Cost PECO PLANT MIX*	Social Cost ESRG PLANT MIX**	Cost Penalty of PECO Plan
1981	$739.7	$643.4	$ 96.3
1987	940.3	753.5	186.8
1992	914.0	798.3	116.7
Total ***	10,515.8	8,768.7	1,747.2

* Based on PECO Forecasts of load growth and plant costs.

** Based on PECO Forecast of load growth and ESRG-LOW estimates of plant costs.

*** Interpolated cumulative totals, 1981-1992.

Furthermore, I claim that this implies a lower bound on the cost penalty implied by using the PECO planning procedures and assumptions on the order of 1.4 billion levelized 1979 dollars per decade. This is because a true comparison at costs anticipated by ESRG would require that the estimates in the PECO case be inflated by the higher ESRG plant capital costs, thus increasing the discrepancy between the two cases considerably. Thus, even using the planning assumptions most favorable to PECO, including assuming their unrealistically high demand forecast, the cost penalty to their customers involved in building the Limerick plants rather than small coal plants is very large, and could potentially be several times this "lower bound" estimate, as can be seen in referring back to Table I.

Q. Does this conclude your testimony?

A. Yes. it does.

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PHILADELPHIA ELECTRIC COMPANY SYSTEM FORECAST

VOLUME II:

THE STATE BASE CASE FORECAST

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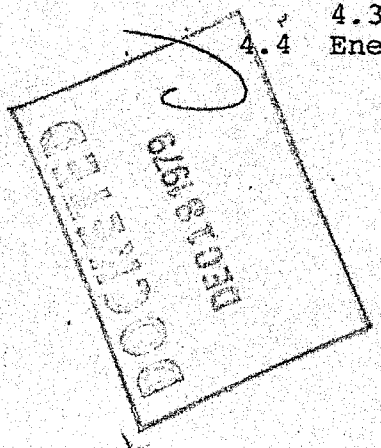
November, 1979

ENERGY SYSTEMS RESEARCH GROUP, INC.
Boston, Massachusetts 02109

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1. INTRODUCTION

1.1 Background

This volume summarizes the methodology, assumptions, and results of the ESRG Base Case long range forecast of electric energy and demand in the Philadelphia Electric Company (PECO) system. Along with the companion volume, Vol. II: The State Conservation Policy Case, it is presented as a contribution to the utility planning assessments being undertaken by the Pennsylvania Office of the Consumer Advocate.

The analysis offered in these documents focuses on electric demand growth issues for the PECO service area. The implications for such supply questions are addressed in complementary forthcoming ESRG studies and testimony. Specifically, corresponding to the sequence of the volumes, the following issues are treated:

- Base Case Forecast: long-range forecast of electricity demand by end-use and by utility service area under "business-as-usual" state policy and regulatory assumptions.

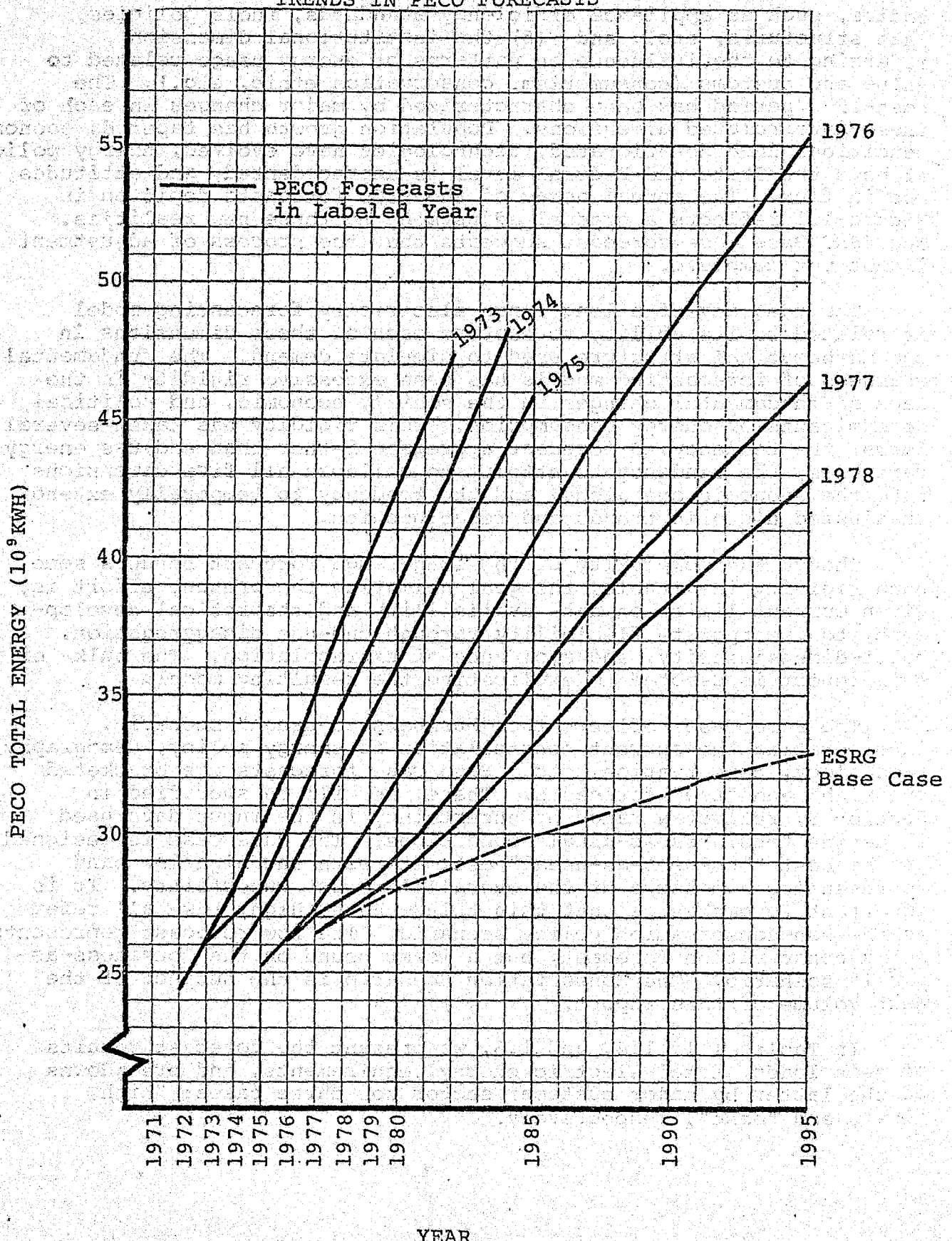
- Conservation Policy Case Forecast: interruption of base case growth with an array of concrete State conservation policy interventions designed to minimize electric energy growth consistent with the dual criteria of technological feasibility and favorable social costs.

After presenting a brief summary of the Base Case forecast results below, the remainder of the report describes in detail the conceptual basis and mathematical structure of the forecasting model, as well as the data and assumptions relied upon.

1.2 Forecast of Energy and Peak Load

The Company produced long range forecasts have declined dramatically over the past half dozen years. This is shown graphically in Figure 1.1. The steady decline of PECO forecasts reflects the Company's methodological and assumptive adjustments to some fundamental shifts in the five major dimensions affecting electrical energy consumption in the long run: (1) economic dimensions measuring the level of income, employment, prices, etc., (2) demographic dimension measuring population, households, age distribution, etc., (3) technological dimension identifying changes in conventional equipment (home appliances, building shell materials, etc.) and properties of emerging equipment, (4) policy dimension referring to the procedures and regulations promulgated by governmental

FIGURE 1.1
TRENDS IN PECO FORECASTS



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bodies, such as appliance efficiency standards, fuels policies, rate structures, etc., and (5) the institutional dimension referring to the influence on patterns of energy usage related to value and customs (consumerism, conservation ethic, etc.). The post-1973 period has been characterized by major changes in each of these interrelated dimensions. Population growth has tapered, economic conditions have deteriorated, technologies have evolved, energy policy at both the State and Federal level is unprecedented, and attitudes are in flux. The annual decay of the PECO forecasts depicted in Figure 1.1 reflects a gradual adjustment to these new realities. The ESRG Base Case forecast suggests that the process of adjustment is not yet complete.

The adequacy of a long-range electricity forecasting model is related to its ability to capture each of these dimensions in the mathematical structure used to simulate demand. The fundamental weakness of forecasting models has been excessive rigidity in the face of fundamental changes in the social, economic, and political determinants of energy consumption. This rigidity has taken several forms: the tendency to forecast aggregate rather than end-use energy variables, the tendency to attempt to collapse all five dimensions into the economic one alone, and the tendency to temporally extend unadjusted historic trends and relationships.

Though the complexity of the long-range forecast renders some such rigidity inevitable, the goal animating the present effort is, given current limits on data availability and theoretical development, to incorporate flexibility through end-use disaggregation, multi-dimensionality, and avoidance of extrapolation. The bulk of this report is devoted to explicating the resulting model.

The Base Case reflects the "business-as-usual" scenario, incorporating the current constellation of energy policy, demography, technology, conservation, etc. Base Case forecasts are bracketed by "High" and "Low" forecasts. These, as will be specified in Section 8, reflect a range of uncertainty in the input data used to define "business-as-usual" conditions. The Base Case is designed as the best "business-as-usual" estimate with the high/low band representing a measure of the overall forecast uncertainty. It is important to emphasize that this triad--Base, High, Low--<u>all</u> refer to the non-conservation policy scenario. The Low forecast represents, <u>not</u> a conservation forecast, but a lower bound on the "business-as-usual" scenario. The Conservation Scenario is the subject of the next volume of this report.

In Tables 1.1, 1.2, and 1.3, we present the forecast results of peak loads, total electric energy requirements, and breakdowns of the latter by major customer sector for three cases: "high, "low", and "base", respectively.

TABLE 1.1
ENERGY AND PEAK FORECAST: HIGH CASE

HIGH CASE
PEPCO

	ENERGY IN GWH					PEAK POWER LOAD IN MW	
	RESIDENT.	COMMER.	INDUSTR.	OTHER	TOTAL	SUMMER	WINTER
1977	9430.	8860.	8085.	2775.	29163.	5560.	4515.
1978	9760.	9010.	8400.	2840.	29010.	5720.	4710.
1979	9060.	9150.	8720.	2910.	29640.	5860.	4890.
1980	9350.	9280.	9030.	2970.	30640.	6000.	5060.
1981	9630.	9420.	9340.	3040.	31430.	6140.	5230.
1982	9900.	9550.	9660.	3100.	32200.	6270.	5380.
1983	10140.	9680.	9970.	3180.	32950.	6390.	5550.
1984	10370.	9800.	10280.	3220.	33570.	6510.	5710.
1985	10570.	9920.	10580.	3290.	34360.	6630.	5860.
1986	10780.	10000.	10780.	3330.	34690.	6720.	5980.
1987	10980.	10070.	10970.	3380.	35400.	6810.	6100.
1988	11180.	10150.	11160.	3510.	36000.	6910.	6230.
1989	11380.	10220.	11350.	3640.	36590.	7010.	6360.
1990	11590.	10290.	11540.	3770.	37180.	7110.	6490.
1991	11820.	10370.	11730.	3890.	37910.	7180.	6580.
1992	11850.	10440.	11920.	4010.	38030.	7250.	6640.
1993	11880.	10510.	12110.	4130.	38440.	7330.	6710.
1994	11710.	10590.	12300.	4260.	38850.	7410.	6790.
1995	11740.	10660.	12480.	4380.	39260.	7480.	6860.
1996	11760.	10730.	12670.	4500.	39660.	7550.	6930.
1997	11790.	10800.	12860.	4620.	40060.	7620.	7000.
1998	11810.	10870.	13040.	4740.	40470.	7680.	7080.
1999	11840.	10850.	13230.	4860.	40870.	7780.	7150.
2000	11870.	11020.	13410.	4980.	41280.	7830.	7220.

TABLE 1.2
ENERGY AND PEAK FORECAST: LOW CASE

LOW CASE
PEPCO

	ENERGY IN GWH					PEAK POWER LOAD IN MW	
	RESIDENT.	COMMER.	INDUSTR.	OTHER	TOTAL	SUMMER	WINTER
1977	8438.	8853.	8085.	2775.	26153.	5580.	4515.
1978	8580.	8810.	8190.	2810.	28370.	5610.	4580.
1979	8650.	8750.	8290.	2840.	28540.	5800.	4630.
1980	8720.	8710.	8370.	2860.	28570.	5830.	4650.
1981	8750.	8850.	8450.	2880.	29750.	5930.	4710.
1982	8790.	8610.	8510.	2910.	29920.	6030.	4740.
1983	8820.	8560.	8570.	2930.	29880.	5990.	4780.
1984	8850.	8510.	8610.	2950.	28920.	5820.	4800.
1985	8890.	8450.	8850.	2970.	28950.	5910.	4820.
1986	8900.	8470.	8700.	3000.	29070.	5810.	4850.
1987	8920.	8480.	8750.	3020.	29180.	5910.	4880.
1988	8930.	8510.	8790.	3130.	29370.	5930.	4920.
1989	8940.	8540.	8840.	3240.	29560.	5950.	4960.
1990	8950.	8560.	8890.	3350.	29740.	5960.	5000.
1991	8920.	8590.	8920.	3450.	29870.	5970.	5030.
1992	8980.	8600.	8980.	3560.	29990.	5980.	5050.
1993	8930.	8620.	8990.	3660.	30110.	5990.	5070.
1994	8790.	8640.	9030.	3770.	30230.	5990.	5090.
1995	8750.	8680.	9080.	3870.	30340.	5980.	5110.
1996	8700.	8620.	9090.	3980.	30450.	5700.	5130.
1997	8650.	8710.	9120.	4080.	30560.	5790.	5150.
1998	8610.	8730.	9150.	4180.	30670.	5710.	5170.
1999	8580.	8750.	9170.	4290.	30790.	5710.	5200.
2000	8580.	8770.	9200.	4390.	30920.	5720.	5220.

TABLE 1.3
ENERGY AND PEAK FORECAST: PROBABLE CASE

BASE CASE	ENERGY IN GWH					PEAK POWER LOAD IN MW	
	RESIDENT.	COMMER.	INDUSTR.	OTHER	TOTAL	SUMMER	WINTER
1977	8439.	9862.	8085.	2776.	29163.	5580.	4618.
1978	8660.	9910.	8300.	2830.	29580.	5670.	4650.
1979	8880.	9950.	8500.	2870.	29180.	5740.	4760.
1980	9030.	9000.	8700.	2920.	29650.	5820.	4870.
1981	9180.	9040.	8800.	2980.	30000.	5880.	4970.
1982	9340.	9080.	8980.	3000.	30510.	5950.	5070.
1983	9480.	9120.	9270.	3050.	30910.	6010.	5170.
1984	9610.	9150.	9450.	3080.	31290.	6070.	5250.
1985	9730.	9180.	9620.	3130.	31660.	6120.	5350.
1986	9840.	9240.	9740.	3150.	31980.	6170.	5430.
1987	9950.	9280.	9880.	3200.	32280.	6220.	5500.
1988	10060.	9330.	9980.	3320.	32690.	6280.	5580.
1989	10180.	9390.	10080.	3440.	33080.	6340.	5680.
1990	10270.	9420.	10210.	3560.	33460.	6400.	5770.
1991	10270.	9470.	10380.	3670.	33740.	6440.	5820.
1992	10280.	9520.	10440.	3780.	34010.	6480.	5870.
1993	10280.	9570.	10550.	3900.	34280.	6520.	5920.
1994	10250.	9610.	10660.	4010.	34540.	6560.	5980.
1995	10240.	9660.	10770.	4120.	34800.	6590.	6000.
1996	10230.	9710.	10880.	4240.	35060.	6630.	6050.
1997	10220.	9750.	10990.	4350.	35310.	6680.	6090.
1998	10210.	9800.	11100.	4460.	35570.	6690.	6130.
1999	10210.	9850.	11200.	4570.	35630.	6730.	6170.
2000	10210.	9900.	11310.	4680.	36100.	6780.	6210.

Table 1.4 recasts the forecast results in terms of average annual rates of growth for ten and twenty year periods. Note that growth rates are forecast to decrease somewhat in the second decade of the forecast period as equipment saturations are approached and the full effects of recently initiated conservation practices fully penetrate into the equipment stock. The rates of growth reported here lie below the most recent available forecasts reported by PECO (Ref. 19) of 2.3% average annual growth over the next ten years in system peak.

TABLE 1.4
AVERAGE ANNUAL GROWTH RATES (%/year)

	Peak Load			Energy		
	High	Base	Low	High	Base	Low
1977-1987	2.0	1.1	.1	2.3	1.4	.4
1977-1997	1.6	.9	.1	1.8	1.1	.4

1.3 Forecast by End-Use

The model, as we shall see, builds up system forecasts from a composite of end-use submodel forecasts. Such disaggregated forecasts are an intermediate output allowing for a more detailed understanding of the components of demand growth, the impacts of specific assumptions and the assessment of policy impacts. For completeness, these disaggregated energy forecasts are displayed in Tables 1.5, 1.6, and 1.7 for the residential, commercial, and industrial sectors, respectively.

1.4 Approach and Alternatives

Electricity consumption at the system level is a composite of the myriad end-use demands serviced by the given utility. The model employed here is based on the conviction that system requirements can best be understood and the impacts of the various factors driving growth best be computed if the model, itself, consistent with data constraints, is a composite of submodels for the major end-uses.

The approach--sometimes called engineering/end-use--identifies the actual physical energy-demanding stock and its energy requirement characteristics. In this way,the effects of definite changes in, say, equipment efficiencies, fuel mix, manufacturing processes, etc., are tracked at the point where they actually occur. Further, the disaggregated approach enables the user to flexibly and eclectically draw from the best subsidiary data sources available, be they optimization studies, market penetration analyses, or national and state economic and demographic projections. For example, the impact of a specific policy option, such as improved appliance efficiencies, can be accounted for directly where they impact (appliance submodels incorporating retirement schedules, vintages, and technology changes).

TABLE 1.5
DISAGGREGATED ENERGY FORECASTS: RESIDENTIAL SECTOR

PECO HIGH CASE - RESIDENTIAL SECTOR - ENERGY IN GWH

	1977	1982	1987	1992	1997
1: REFRIGERATORS	2555.	2713.	2728.	2554.	2491.
2: FREEZERS	446.	584.	661.	681.	683.
3: RANGES	342.	401.	449.	479.	490.
4: LIGHTING	645.	687.	728.	757.	762.
5: TELEVISIONS	592.	617.	650.	692.	733.
6: CLOTHES DRYERS	448.	555.	654.	733.	780.
7: CLOTHES WASHERS	106.	116.	125.	131.	133.
8: DISH WASHERS	184.	201.	230.	258.	275.
9: WATER HEATERS	868.	1088.	1236.	1338.	1348.
10: ROOM A/C	348.	358.	354.	352.	347.
11: CENTRAL A/C	430.	629.	794.	923.	995.
12: SPACE HEATERS	520.	684.	1208.	1382.	1428.
13: HEATINGAUXILIARY	544.	551.	558.	561.	559.
14: MISCELLANEOUS	428.	512.	604.	690.	758.

PECO LOW CASE - RESIDENTIAL SECTOR - ENERGY IN GWH

	1977	1982	1987	1992	1997
1: REFRIGERATORS	2555.	2594.	2546.	2448.	2296.
2: FREEZERS	446.	447.	440.	428.	414.
3: RANGES	342.	350.	357.	359.	359.
4: LIGHTING	646.	660.	657.	632.	583.
5: TELEVISIONS	434.	416.	405.	402.	401.
6: CLOTHES DRYERS	448.	514.	558.	587.	600.
7: CLOTHES WASHERS	106.	110.	113.	116.	116.
8: DISH WASHERS	164.	187.	204.	216.	229.
9: WATER HEATERS	868.	655.	828.	804.	770.
10: ROOM A/C	348.	334.	319.	311.	303.
11: CENTRAL A/C	430.	531.	581.	603.	604.
12: SPACE HEATERS	520.	646.	745.	798.	814.
13: HEATINGAUXILIARY	544.	540.	536.	530.	521.
14: MISCELLANEOUS	587.	606.	624.	637.	642.

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TABLE 1.6
DISAGGREGATED ENERGY FORECASTS: COMMERCIAL SECTOR

PECO HIGH CASE - COMMERCIAL SECTOR - ENERGY IN GWH

	1977	1982	1987	1992	1997
1: OFFICES					
1: HEATING	49.	108.	143.	171.	196.
2: COOLING	275.	311.	341.	365.	382.
3: LT & POWER	357.	389.	428.	446.	464.
4: AUXILIARIES	286.	264.	316.	330.	345.
2: RETAIL					
1: HEATING	38.	81.	108.	123.	138.
2: COOLING	629.	656.	680.	695.	709.
3: LT & POWER	1866.	1822.	1851.	1847.	1841.
4: AUXILIARIES	652.	648.	647.	648.	644.
3: HOSPITALS					
1: HEATING	26.	51.	70.	86.	101.
2: COOLING	272.	278.	281.	275.	271.
3: LT & POWER	683.	688.	689.	680.	671.
4: AUXILIARIES	364.	366.	362.	349.	338.
4: SCHOOLS					
1: HEATING	28.	46.	64.	85.	104.
2: COOLING	272.	244.	230.	237.	244.
3: LT & POWER	480.	401.	371.	382.	388.
4: AUXILIARIES	262.	219.	198.	201.	205.
5: OTHER					
1: HEATING	47.	102.	137.	160.	182.
2: COOLING	817.	864.	700.	718.	737.
3: LT & POWER	1034.	1323.	1563.	1738.	1915.
4: AUXILIARIES	965.	743.	781.	803.	814.

PECO LOW CASE - COMMERCIAL SECTOR - ENERGY IN GWH

	1977	1982	1987	1992	1997
1: OFFICES					
1: HEATING	27.	46.	64.	80.	94.
2: COOLING	269.	258.	246.	234.	224.
3: LT & POWER	345.	320.	299.	288.	278.
4: AUXILIARIES	261.	250.	240.	233.	227.
2: RETAIL					
1: HEATING	25.	44.	58.	67.	73.
2: COOLING	622.	563.	528.	527.	525.
3: LT & POWER	1851.	1663.	1562.	1584.	1604.
4: AUXILIARIES	641.	537.	481.	482.	501.
3: HOSPITALS					
1: HEATING	22.	39.	52.	62.	70.
2: COOLING	280.	276.	262.	238.	215.
3: LT & POWER	715.	720.	712.	688.	666.
4: AUXILIARIES	381.	382.	371.	343.	318.
4: SCHOOLS					
1: HEATING	25.	36.	47.	60.	72.
2: COOLING	275.	227.	190.	165.	141.
3: LT & POWER	476.	402.	352.	331.	313.
4: AUXILIARIES	287.	207.	170.	159.	147.
5: OTHER					
1: HEATING	29.	55.	75.	94.	113.
2: COOLING	627.	627.	623.	614.	607.
3: LT & POWER	1047.	1252.	1442.	1618.	1785.
4: AUXILIARIES	675.	704.	719.	721.	725.

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TABLE 1.7
DISAGGREGATED ENERGY FORECASTS: INDUSTRIAL SECTOR

PECO HIGH CASE - INDUSTRIAL SECTOR - ENERGY IN GWH

	1977	1982	1987	1992	1997
20: FOOD	658.	681.	782.	1012.	1253.
22: TEXTILES	120.	135.	150.	165.	179.
23: APPAREL	60.	75.	90.	105.	120.
24: LUMBER	15.	22.	30.	37.	45.
25: FURNITURE	11.	13.	16.	18.	21.
26: PAPER PRODUCTS	555.	667.	754.	806.	858.
27: PRINTING & PUBL.	196.	255.	317.	380.	446.
28: CHEMICALS	1024.	1127.	1158.	1119.	1031.
29: PETROLEUM & COAL	1198.	1288.	1331.	1303.	1275.
33: PRIMARY METALS	1728.	2279.	2780.	3150.	3543.
34: FABRICAT. METALS	324.	402.	479.	547.	621.
35: MACHINERY	361.	431.	491.	534.	576.
36: ELECTRIC EQUIP.	429.	537.	626.	687.	748.
37: TRANSPORTATION	328.	409.	483.	541.	603.
30: RUBBER & PLASTIC	435.	550.	623.	552.	664.
31: LEATHER	4.	5.	6.	7.	8.
32: STONE,CLAY,GLASS	176.	191.	201.	207.	212.
38: INSTRUMENTS	102.	170.	244.	314.	382.
39: MISC. MANUFACT.	358.	411.	402.	337.	258.

PECO LOW CASE - INDUSTRIAL SECTOR - ENERGY IN GWH

	1977	1982	1987	1992	1997
20: FOOD	658.	607.	616.	708.	789.
22: TEXTILES	120.	115.	110.	106.	102.
23: APPAREL	60.	62.	63.	63.	63.
24: LUMBER	15.	16.	16.	16.	16.
25: FURNITURE	11.	12.	13.	13.	13.
26: PAPER PRODUCTS	555.	516.	475.	467.	455.
27: PRINTING & PUBL.	196.	220.	238.	250.	260.
28: CHEMICALS	1024.	1053.	1043.	1032.	994.
29: PETROLEUM & COAL	1198.	995.	785.	606.	444.
33: PRIMARY METALS	1728.	1931.	2071.	2200.	2328.
34: FABRICAT. METALS	324.	358.	382.	382.	401.
35: MACHINERY	361.	414.	451.	470.	486.
36: ELECTRIC EQUIP.	429.	473.	491.	490.	481.
37: TRANSPORTATION	328.	409.	483.	541.	603.
30: RUBBER & PLASTIC	435.	552.	641.	708.	766.
31: LEATHER	4.	4.	3.	3.	3.
32: STONE,CLAY,GLASS	176.	180.	183.	186.	193.
38: INSTRUMENTS	102.	128.	146.	153.	158.
39: MISC. MANUFACT.	358.	456.	534.	552.	563.

2. OVERVIEW OF FORECASTING APPROACH

This section is restricted to a broad description of the forecast model characteristics. The conceptual basis and mathematical structures of the model are described in subsequent sections.

The model forecasts are based on the aggregation of separate forecasts for the major end-use components comprising system demand. This allows for explicit incorporation of the impacts of differential end-use growth, energy policy, new technology and specific conservation practices. For example, appliance efficiency improvements are integrated indirectly into the appliance submodel rather than as approximate adjustments on gross energy requirements.

The energy consumption for a given component is given by the expression:

$$\text{Energy Consumption in End-Use Category} = \text{End-Use Measure} \times \text{Energy Intensity}$$

In other words, the energy consumption by end-use is the product of the quantity of the end-use ("End-Use Measure") and the annual average energy consumed per unit of the end-use ("Energy Intensity"). The measure of an end-use activity will be in units appropriate to the sector being modelled. These are summarized in Figure 2.1.

The forecasting technique consists of three fundamental steps: (1) analysis of base year energy-consuming stock in terms of average measure levels and intensities, (2) specification of growth in the end-use measures and (3) simulation of the factors affecting the intensity of unit energy use. The actual mathematical analogs chosen for energy consumption in the end-use models must be wedded to the specific character of the end-use category. Further, they must be constrained by limitations in available data. The computational procedures selected are discussed in detail in Sections 3 through 7.

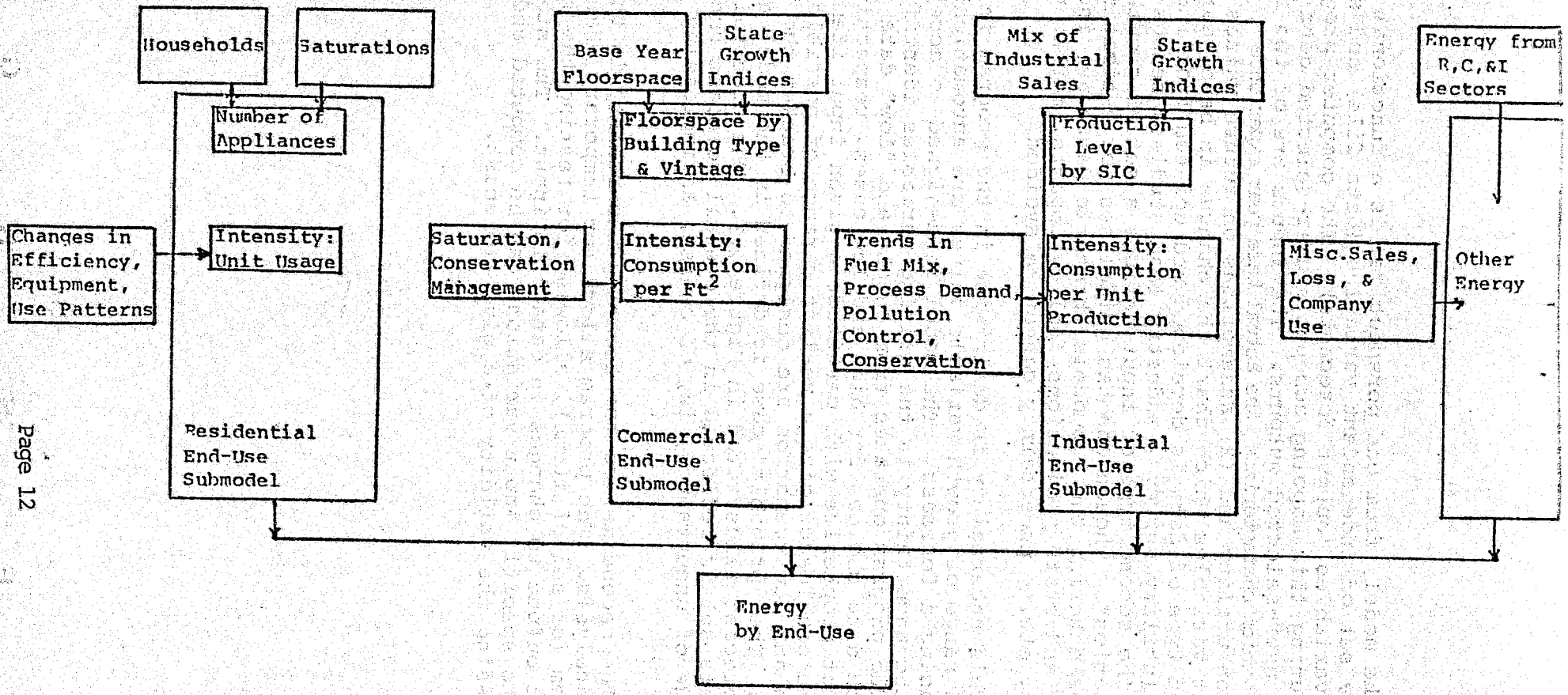
The energy forecast model is the heart of the system. It, in turn, is comprised of a series of submodels which produce forecasts of energy consumption disaggregated by end-use. These are summed to give annual energy and are input to the demand forecast model. The results for each utility are combined to output system energies and peaks. Additionally, the energy forecasts broken down by end-use category may be outputted allowing for a clearer understanding of the structure of total consumption and sensitivity to specific assumptions. The energy forecast model is schematized in Figure 2.2.

E S R G

FIGURE 2.1
MODEL COMPONENTS

SECTOR	END-USE ACTIVITY	END-USE MEASURE	ENERGY INTENSITY
Residential	14 Appliance Categories 2 housing types	number of units	average annual consumption per unit
Commercial	5 building types 4 end-use categories 2 vintages (new & existing)	floorspace square footage	average annual consumption per square foot
Industrial	19 manufacturing subsectors	production units	average annual consumption per unit production

FIGURE 2.2
ENERGY FORECAST MODEL SCHEMATIC



The model, from one perspective, is a functional relationship between a set of independent variables (data file) and selected dependent variables (output forecasts). The computer program designed for executing this mapping accepts a user-selected data file and produces user-selected outputs. The inputs are of two types: (1) data which characterizes the actual base year experience of a given utility and (2) assumptions on future values of the independent variables which chart the changes in base year values. The first type of data is developed and updated from independent sources (utility surveys, industry load studies, census information, etc.). The second type of input defines a set of growth assumptions or "scenarios". Though one has guidelines for estimating the growth variables entering the submodels (historic patterns, independent national and state projections, policy impacts, market penetration analysis, etc.), uncertainty cannot be avoided.

This uncertainty is dealt with in the program in two ways. First, a range of growth variable values are automatically required in producing a forecast. The model is designed to accept from the outset the uncertainty in the driving variables identified by the user. The program operates from "high" and "low" data files associated with data choices for high and low cases, respectively. Though one cannot prophesize with certitude a given input item, one can with some confidence give a realistic range of possible future values. The high and low scenarios are designed to bracket the set of possible futures. The "probable" case is defined in the model as the mid-range forecast illustrated in Figure 2.3. The uncertainty in the input data set is reflected in the overall forecast uncertainty. The range of uncertainty, is, of course, an increasing function of time.

The second method for treating uncertainty is through sensitivity analysis. The program allows for temporary changes of an input item (or set of items), allowing for testing the response in forecast output to changes in data file input. The stability of output to specific input variations can be computed and utilized in assessing the validity of a given forecast.

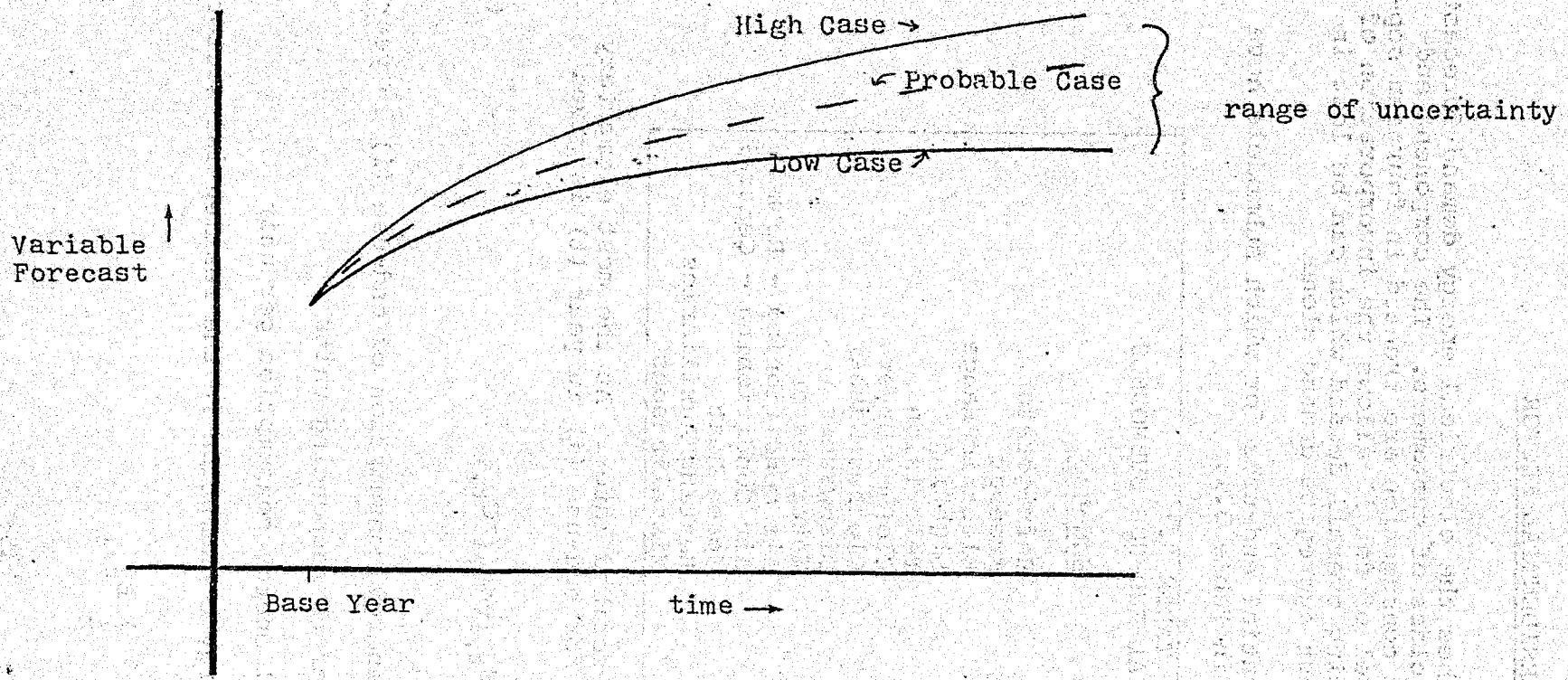


Figure 2.3. Forecast Scenarios.

3. RESIDENTIAL SECTOR

This section describes the electrical energy demand forecast model for the residential class of customers. The component end-uses of residential energy consumption are treated in fourteen separate submodels. This level of detail allows the incorporation of the central factors affecting overall demand which can be lost in methodologies which forecast aggregate demand alone.

The fourteen residential end-uses for which submodels have been developed are listed in Table 3.1.

TABLE 3.1
RESIDENTIAL END-USE SUBMODELS

Input	End-Use
1	Refrigerator
2	Freezer
3	Electric Range
4	Lighting
5	Television
6	Clothes Dryer
7	Clothes Washer
8	Dishwasher
9	Water Heater
10	Air Conditioning - Room
11	Air Conditioning - Central
12	Space Heat
13	Heating Auxiliaries
14	Miscellaneous

These submodels will be described later. At the most elementary level, annual consumption for end-use (i) in year (t) is given by the expression:

$$E_{t,i}=N_{t,i}\times C_{t,i} \tag{3.1}$$

where

$E_{t,i}$ = Total annual energy consumption of end-use (i) in year (t)

$N_{t,i}$ = Total number of corresponding units

$C_{t,i}$ = Average annual energy consumption per unit

Then the total energy consumption in the residential sector for year (t) becomes

$$\sum_i E_{t,i}$$

A glance at equation 3.1 will show that the residential forecast for each end-use can be viewed as a combined forecast of the total number of units, on the one hand, and the average consumption per unit, on the other hand.

3.1 Number of Units

The number of units for a given end-use is computed as the product of the number of households and the end-use saturation, defined here as the average number of units per household. The number of household units is further divided into single family units (SF) and multifamily units (MF). This breakdown is desirable since appliance ownership and usage patterns may vary significantly by housing type. A shift in the mix of SF and MF in the forecast period thus affects ultimate demand.

3.2 Saturation Curves

Saturations enter the end-use submodels via the logistic growth curve. This curve has the general form:

$$SAT_{t,i,k} = \frac{C_{i,k}}{1+B_{i,k} \times e^{-(A_{i,k} \cdot T)}} \qquad (3.2)$$

for the saturation (SAT) of a given end-use (i), and housing type (k), in year (t). The parameters are constrained by:

$$B>0,\ A>0,\ 0<C<1. \qquad (3.3)$$

(The indices are suppressed for notational convenience.) (3.3)

Parameter C is called the ceiling, representing the asymptotic limit of the dependent variable; the greater the value of A, the more rapid is the approach to the ceiling. From the derivative

$$\frac{d\ SAT_t}{dt} = \frac{A}{C} \cdot SAT_t \cdot (C-SAT_t) \qquad (3.4)$$

we see that the growth rate is proportional to both the level already achieved and the increment remaining to the ceiling.

Ideally, the parameters would be estimated by fits to historic saturation data. The data, however, is not sufficient to warrant such a complete determination. Instead, we have used base year saturations (SBY) to determine one parameter, chosen values for the ceiling or terminal saturation (STERM) according to scenario assumptions, and used historic data to fit the remaining variable A.

Rewriting equation 3.2 in terms of STERM and SBY and fixing the base year t=1 as we do throughout the model, we arrive at the form of the saturation curve as it enters the submodels:

$$SAT_t = \frac{STERM}{1+\left(\frac{STERM-SBY}{SBY}\right)\times e^{-A\cdot(t-1)}} \qquad (3.5)$$

3.3 End-use Submodels

The second term in Equation 3.1, the average annual energy consumption for each end-use, incorporates a great deal of complexity. Once the base year energies are established, the time dependence of average energy consumption must be computed. The major factors which can impact average energy use are:

- appliance efficiency increases
- thermal integrity improvements of building shells
- new technology market penetration
- population per household decreases
- energy conservation practices induced by electricity price increases

The end-use submodels are designed to allow sensitivity to assumptions on these trends. Consequently, overall forecasts based on a range of reasonable input assumptions allow for the development of a band of possible error within which lies the "probable" forecast.

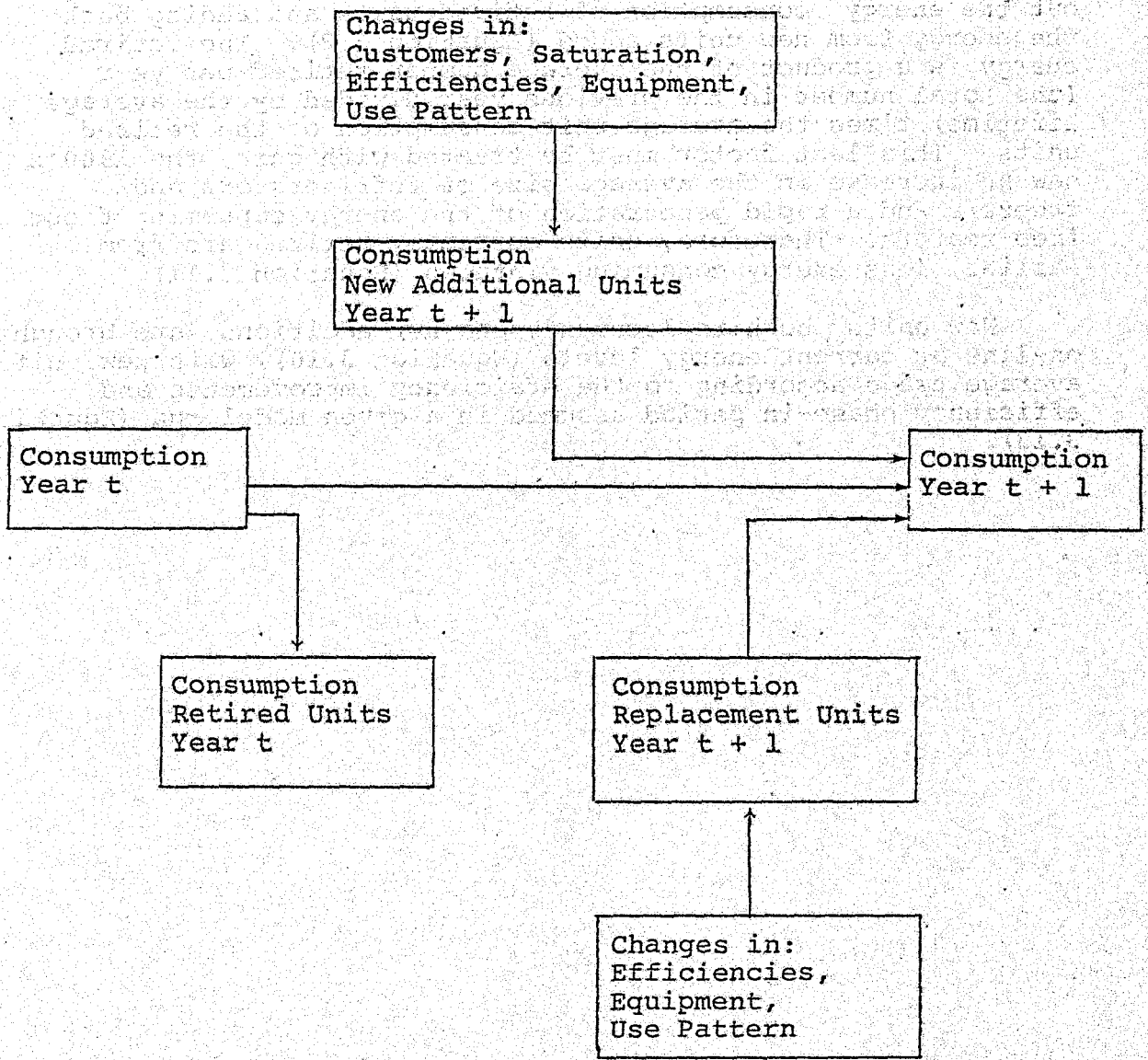
The submodels will be discussed in the sequence given in Table 3.1. In each case, we give a brief qualitative description in the text and the system of equations in an accompanying table. Although the end-uses have particular characteristics which require unique model elements, the overall strategy displayed schematically in Figure 3.1 is used throughout. The yearly increment in electrical energy consumption is calculated by (1) subtracting the energy consumption of retired units, (if any), (2) adding the energy consumption of replacements, and (3) adding the energy consumption of additonal new units due to customer and saturation growth. With this iteration technique, we can, once the base year breakdown is established, compute energy consumption for each year of the forecast under a given set of assumptions on changes in saturation, customer, technology mixes, efficiencies and use patterns.

3.3.1 Refrigerators and Freezers

The factors affecting demand for these two appliances are quite similar so that the same algorithm for modeling growth in energy consumption are employed. Variable definitions and dynamic equations are summarized in Table 3.2.

FIGURE 3.1

Schematic of Yearly Energy Increments by End-use



The total number of appliances by housing type is obtained by multiplication of saturation and households (Equation 3.6). The iteration procedure is initialized by computing base year consumption as the product of the number of appliances on-line in the base year and their average unit consumption (Equation 3.7). There is a great deal of variation in energy demand with brand, size and model. Therefore, average usage may vary as a function of regional appliance mix.

The iteration proceeds from year to year by subtracting out the energy consumption of retired units and adding back the energy from new units added (Equation 3.8). The retired energy is a product of the average number retired per year (the total number in the previous year divided by the average lifetime) times the average unit consumption of the retired units. This last factor must be treated with care; the 1960's saw an increase in the average size of refrigerators and freezers and a rapid penetration of the energy consuming frost-free feature. Therefore, units currently retired are from earlier, less energy consuming vintages (Equation 3.11).

New units, both replacements and net additions, are brought on-line at current energy levels (Equation 3.10), with new unit average usage according to the efficiency improvements and efficiency phase-in period assumed in a given model run (Equation 3.13).

TABLE 3.2
SUBMODEL FOR REFRIGERATORS AND FREEZERS

Variable Code

t	Year (base year = 1)
i	Appliance index (1=refrigerator and 2=freezer)
k	Housing type (SF=1 , MF=2)
TOTNUM	Total number of appliance
HSTOCK	Households
SAT	Saturation
UNNEW	Average unit usage of new appliance
UNAVBS	Average unit usage of base year stock
ALT	Average appliance lifetime
EFFIMP	Efficiency improvement over base year models
TEND	Final year of efficiency improvement phase-in
UNREP	Average unit usage of replaced units
UNOLD	UNREP for $t \leq ALT$
NEWENI	Energy use of new units
RETENI	Energy use of retired units
ENREU	Annual appliance energy demand

Equations

Stock stream:

$$TOTNUM_{t,k,i} = SAT_{t,k,i} \times HSTOCK_{t,k,i} \quad (3.6$$

Initialize:

$$ENREU_{1,k,i} = TOTNUM_{1,k,i} \times UNAVBS_{k,i} \quad (3.7$$

Iterate for t>1:

$$ENREU_{t,k,i} = ENREU_{t-1,k,i} - RETENI_{t,k,i} + NEWENI_{t,k,i} \quad (3.8$$

where

$$RETENI_{t,k,i} = UNREP_{t,k,i} \times TOTNUM_{t-1,k,i}/ALT_i \quad (3.9$$

$$NEWENI_{t,k,i} = (TOTNUM_{t,k,i} - TOTNUM_{t-1,k,i} + TOTNUM_{t-1,k,i}/ALT_i) \times UNNEW_{t,i} \quad (3.1$$

and

$$UNREP_{t,i} = \begin{cases} UNOLD_{t,i} & t \leq ALT_i \\ \text{for} & \\ UNNEW_{t-ALT_i} & t > ALT_i \end{cases} \quad (3.1$$

$$UNNEW_{t,i} = (1-EFFIMP_t) \times UNNEW_{1,i} \quad (3.1$$

$$EFFIMP_{t,i} = \begin{cases} \left[(t-1) / (TEND-1)\right] \times EFFIMT_i & 1 < t \leq TEND \\ \text{for} & \\ EFFIMT_i & t > TEND \end{cases} \quad (3.1$$

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3.3.2 Electric Ranges

The determinants of growth for electric ranges are straightforward: saturation and customer increases, efficiency improvements in new appliances, and market penetration of the microwave oven feature which can decrease overall energy demand.

The total stock is given, as usual, as the product of saturation and housing stock (Equation 3.14). Further disaggregation by housing type is not necessary for this end-use since available saturation and energy demand data does not distinguish between single and multi-family usage patterns. The iteration process is initialized with base year data (Equation 3.15) and proceeds with the characteristic subtraction of retired units and addition of new units (Equation 3.16). Units are retired at a rate equal to the inverse of the average life time (Equation 3.17). The two sources of new units, net additions and replacements, are represented by the first and second terms of Equation 3.18, respectively. Average usage of new units is decremented by a factor derived from assumed efficiency targets and phase-in times (Equations 3.19 and 3.20).

Finally, account is taken of the decreased energy usage associated with microwave ovens used in association with electric ranges. The total energy demand is a weighted factor of usage without and with microwave ovens, the first and second terms, respectively, in Equation 3.21.

TABLE 3.3
SUBMODEL FOR ELECTRIC RANGES

Variable Code

t	Year (base year = 1)
TOTNUM	Total number
HSTOCK	Households
SAT	Saturation
ENREU1	Annual electric range energy demand w/o microwaves
ENREU	Annual electric range energy demand with microwaves
UNAVBS	Average usage base year stock
UNNEW	Average unit usage of new units
EFFIMP	Efficiency improvement
TEND	Final year of efficiency improvement phase-in
RETENI	Energy use of retired units
NEWENI	Energy use of new units
ALT	Average lifetime
MSAT	Microwave oven saturation as a fraction of electric ranges
EDF	Energy demand factor: ratio energy demand with and without microwave oven

Equations

Stock stream:

$$TOTNUM_t = SAT_t \times HSTOCK_t \quad (3.14)$$

Initialize:

$$ENREU1_1 = TOTNUM_1 \times HSTOCK_1 \quad (3.15)$$

Iterate for t>1:

$$ENREU1_t = ENREU1_{t-1} - RETENI_t + NEWENI_t \quad (3.16)$$

where

$$RETENI_t = ENREU1_{t-1}/ALT \quad (3.17)$$

$$NEWENI_t = (TOTNUM_t - TOTNUM_{t-1}) \times UNNEW_t + \left(TOTNUM_{t-1/ALT}\right) \times UNNEW_t \quad (3.18)$$

and

$$UNNEW_t = (1-EFFIMP_t) \times UNAVBS \quad (3.19)$$

with

$$EFFIMP_t = \begin{cases} EFFIMT \times (t-1) / (TEND-1) & \text{for } t<TEND \\ EFFIMT & \text{for } t \geq TEND \end{cases} \quad (3.20)$$

Microwave oven adjustment:

$$ENREU_t = ENREU1_t \times (1-MSAT_t) + MSAT_t \times EDF \times ENREU1_t \quad (3.21)$$

3.3.3 Lighting

Lighting energy demand is represented as the product of average annual energy usage per household and the number of households (Equation 3.22). The household growth is developed outside the submodel and inputted to it. There remains the anticipated changes in lighting energy demand per household.

The model assumes that saturations are currently at 100%; i.e., all households have electric lighting and this shall remain true throughout the forecast period. However, the intensity of lighting use per household as well as the efficiency of conversion of electric to light energy has in the past, and may well in the future, vary with time. Future deviations from base year levels is taken into account by the usage factor (Equation 3.23).

In the past, several factors have contributed to increases in lighting energy demand per household: shift in housing mix toward larger SF residences, inexpensive electricity fostering purchase of decorative lighting and discouragement of household conservation practice. These trends have generally reversed: family size is gradually shrinking, MF dwellings are rising relative to SF, and rising electricity costs are encouraging conservation.

It appears likely that these shifting patterns will lead, at least to some extent, to the market penetration of energy efficient lightbulbs. These include improved incandescents and more fluorescents in the near term, followed possibly by commercialization of the screw-in fluorescent in the 1980's. Possible impacts of such technology shifts are incorporated in Equation 3.24.

TABLE 3.4
SUBMODEL FOR LIGHTING

Variable Code

t	Year (base year = 1)
HSTOCK	Households
UNAVBS	Average consumption per housing unit in the base year
UNAV	Average consumption per housing unit
UF	Usage factor
MF	Market fraction efficient bulbs
RELEFF	Efficiency improvement of nonconventional bulb
ENREU	Annual energy demand for lighting

Equations

$$ENREU_t = UNAV_t \times HSTOCK_t \quad (3.2$$

with

$$UNAV_t = UF_t \times UNAVBS \quad (3.2$$

with efficient bulb capturing market fraction:

$$UNAV_t = (1-MF_t) \times UNAVBS + MF_t \times (1-RELEFF_t) \times UNAVBS$$

or

$$UF_t = 1-MF_t \times RELEFF_t \quad (3.2$$

3.3.4 Television

The submodel for televison usage must contain sufficient complexity to allow for (1) saturation and customer growth, (2) changes in unit energy requirements, (3) changes in the mix of black and white and color televisions, and (4) decreased usage per unit in cases of multiple ownership. The last factor is due to the nonproportionality between the number of televisions and the viewing hours. That is, if, for instance, a family purchased a second television, the hours of use will not simply double since the redundant unit will be used to some extent in substitution for the first.

The dynamics of television energy demand growth are presented in Table 3.5. After defining the stock stream saturation and housing stock with inputs from outside the submodel (Equation 3.25), the iteration procedure is initialized with base year data (Equation 3.26) and proceeds from year-to-year in the usual way (Equations 3.27 to 3.31). Changing ratios of black and white to color are allowed in the weighted averages for new units in Equation 3.29. Finally, in the case of multiple average ownership, the total energy is decremented by a decreased use factor for second and third televisions (Equation 3.32).

TABLE 3.5
SUBMODEL FOR TELEVISIONS

Variable Code

t	Year (base year = 1)
k	Housing type
TOTNUM	Total number
HSTOCK	Housing units
SAT	Saturation
NEWCOL	Average unit usage of new color television
NEWBW	Average unit usage of new black and white television
EFIMCO	Efficiency improvement color units over base year
EFIMBW	Efficiency improvement black and white units over base year
TEND	Final year of efficiency improvement phase-in
FRBW	Fraction new units which are black and white
ALT	Average lifetime
RETENI	Energy use of retired units
NEWENI	Energy use of new units
UNAVBS	Average unit usage in base year
ENREU	Annual energy demand in (t,k)
DUF	Decreased use factor for multiple televisions

Equations

Stock stream:

$$TOTNUM_{t,k} = SAT_{t,k} \times HSTOCK_{t,k} \quad (3.25)$$

Initialize:

$$ENREU_{1,k} = TOTNUM_{1,k} \times UNAVBS \quad (3.26)$$

Iterate for t>1:

$$ENREU_{t,k} = ENREU_{t-1,k} - RETENI_{t,k} + NEWENI_{t,k} \quad (3.27)$$

where

$$RETENI_{t,k} = ENREU_{t-1,k} / ALT \quad (3.28)$$

$$NEWENI_{t,k} = (TOTNUM_{t,k} - TOTNUM_{t-1,k} + TOTNUM_{t-1,k}/ALT) \times ((1-FRBW_t) \times NEWCOL_t + FRBW_t \times NEWBW_t) \quad (3.29)$$

and

$$NEWCOL_t = (1-EFIMCO_t) \times NEWCOL_1 \quad (3.30)$$

$$NEWBW_t = (1-EFIMBW_t) \times NEWBW_1$$

with

$$EFIMCO_t = \begin{cases} (t-1 / (TEND-1)) \times EIMCOT & \text{for } t<TEND \\ EIMCOT & t>TEND \end{cases} \quad (3.31)$$

(similarly for $EFIMBW_t$)

Decrease usage for multiple ownership (for $SAT_{t,k}>1$):

$$ENREU \longrightarrow ENREU_{t,k} \times (1+DUF \times (SAT_{t,k}-1) / SAT_{t,k}) \quad (3.32)$$

3.3.5 Clothes Dryers

The submodel for clothes dryers is quite simple. Demand is primarily a function of saturation and customer growth since efficiency improvement possibilities are small and substitute technologies to conventional dryers are not on the horizon (increased use of solar drying would be reflected in lower saturations). Although predictions of changing unit usage intensity (such as loads per week) are unrealistic, qualitatively, the decreasing trend in population per household would suggest that current levels should safely overestimate demand. The equation set (Table 3.6) should by now be self-explanatory.

TABLE 3.6
SUBMODEL FOR CLOTHES DRYER

Variable Code

t	Year (base year = 1)
TOTNUM	Total number
HSTOCK	Households
SAT	Saturation
UNAVBS	Average unit usage of base year stock
ALT	Average lifetime
EFFIMP	Efficiency improvement over base year units
TEND	Final year of efficiency improvement phase-in
NEWENI	Energy demand of new units
RETENI	Energy demand of retired units
UNNEW	Average unit usage of new units year t
ENREU	Annual energy demand in year t

Equations

Stock stream:

$$TOTNUM_t = SAT_t \times HSTOCK_t \quad (3.33)$$

Initialize:

$$ENREU_1 = TOTNUM_1 \times UNAVBS \quad (3.34)$$

Iterate for t>1:

$$ENREU_t = ENREU_{t-1} + NEWENI_t - RETENI_t \quad (3.35)$$

where

$$RETENI_t = ENREU_{t-1} / ALT \quad (3.36)$$

$$NEWENI_t = (TOTNUM_t - TOTNUM_{t-1} + TOTNUM_{t-1} / ALT) \times UNNEW_t$$

and

$$UNNEW_t = (1-EFFIMP_t) \times UNAVBS \quad (3.37)$$

with

$$EFFIMP_t = \begin{cases} (t-1)/(TEND-1) \times EFFIMT & \text{for } t<TEND \\ EFFIMT & \text{for } t \geq TEND \end{cases} \quad (3.38)$$

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3.3.6 Clothes Washer and Dishwasher

Clothes washers and dishwashers are treated together since, as we shall see, the algorithm for modeling demand is identical. Each of these end-uses requires energy in two forms: (1) electric energy to drive motors and auxiliary equipment and (2) thermal energy in the form of hot water for process functions. Technology shifts are in the offing which would effect each of these.

For the case of thermal requirements, the impact on overall electrical energy is indirect. Specifically, changes in hot water demand will "flow through" to effect the electricity demand in the cases where hot water is produced in electric hot water heaters. The submodel allows for changes in both the electrical and thermal demands, saving the latter for input into the electric water heat submodel.

Therefore, after running the usual iteration to develop direct electrical energy demand (Equations 3.39 to 3.45), average forecast hot water demand for each appliance is calculated as a function both of overall saturation growths and unit demand changes. (Equation 3.46 to 3.47). These results are incorporated into the electric hot water heater submodel.

TABLE 3.7
SUBMODEL FOR CLOTHES WASHER AND DISHWASHER

Variable Code

t	Year (base year = 1)
i	Appliance index (CW = 7, DW = 8)
TOTNUM	Total number
HSTOCK	Households
SAT	Saturation
UNAVBS	Average base year unit electric energy usage
ALT	Average appliance lifetime
CWHW	Clothes washer average hot water demand per customer
DWHW	Dishwasher average hot water demand per customer
HWRECW	Hot water reduced demand -- clothes washer
HWREDW	Hot water reduced demand -- dishwasher
UNNEW	Average unit electrical energy usage of new appliance units
NEWENI	Energy demand of new units
RETENI	Energy demand of retired units
ENREU	Annual energy demand
EFFIMP	Efficiency improvement over base year
TEND	Final year of efficiency improvement phase-in

Equations

Stock stream:

$$TOTNUM_{t,i} = SAT_{t,1} \times HSTOCK_{t,i} \quad (3.39)$$

Initialize:

$$ENREU_{1,i} = TOTNUM_{1,i} \times UNAVBS_i \quad (3.40)$$

Iterate for t>1:

$$ENREU_{t,i} = ENREU_{t-1,i} + NEWENI_{t,i} - RETENI_{t,i} \quad (3.41)$$

where

$$RETENI_{t,i} = ENREU_{t-1,i}/ALT_i \quad (3.42)$$

$$NEWENI_{t,i} = (TOTNUM_{t,i} - TOTNUM_{t-1,i} + TOTNUM_{t-1,i}/ALT_i) \times UNNEW_{t,i} \quad (3.43)$$

and

$$UNNEW_{t,i} = (1 - EFFIMP_{t,i}) \times UNAVBS_i \quad (3.44)$$

with

$$EFFIMP_{t,i} = \begin{cases} (t-1/(TEND-1) \times EFFIMT & \text{for } t<TEND \\ EFFIMT & t \geq TEND \end{cases} \quad (3.45)$$

(Continued)

TABLE 3.7 (Continued)

Hot Water Demands:

New unit usage year t:

$$UCWHWI = 19 \times UNAVBS_7 \times (1-HWRECW_t)$$

$$UDWHWI = 4.6 \times UNAVBS_8 \times (1-HWREDW_t)$$

(factor 19 and 4.6 are ratios of hot water to electric energy requirements for clothes washer and dishwasher, respectively [Ref. 1])

with

$$HWRECW_t = \begin{cases} \left(\frac{(t-1)}{(TEND-1)}\right) \times HWRECT & \text{for } t<TEND \\ HWRECT & \text{for } t \geq TEND \end{cases}$$

Average unit usage:

$$UCWHW_t = (UCWHW_{t-1} \times REM_t + (TOTNUM_t - REM_t) \times UCWHWI_t)/TOTNUM_t$$

where REM_t = remaining units from previous year = $TOTNUM_{t-1} \times (1-1/ALT_i)$

Average usage per customer:

$$CWHW_t = SAT_{t,7} \times UCWHW_t$$

And similarly for dishwasher.

3.3.7 Electric Water Heaters

The electric water heater submodel is sensitive to a number of time dependent factors affecting overall energy demand:

- saturation
- efficiencies
- average residential hot water requirement
- solar technology penetration

The number of electric water heaters is computed in Equation 3.48. First, in Equation 3.48a, the base year units are computed from input data. For subsequent years, the total number is computed as the combination of the previous year's value (first term on the right of Equation 3.48a) plus additions from two new markets. First, all new electric space heaters are assumed to also have electric water heaters. (This will slightly overstate growth.) This is affected in the second line on the right of Equation 3.48b (penetrations of electric space heat also appear in the esh submodel, Section 3.3.9). Second, new non-electric space heated homes (Equation 3.48b, third line first bracket) are assumed to purchase electric water heaters according to base year electric water heaters saturations in base year non-electric space heated homes (Equation 3.48b, third line, second bracket).

The hot water energy demands of clothes washer and dishwasher have been developed earlier and are used in Equation 3.49 to define the demand from "other" uses. Possible reductions in this category, such as widespread adoption of slow-flow shower heads, etc., which are now on the market, are also allowed for in the last expression.

Average efficiencies of electric water heaters are expected to improve with time primarily due to minimizing stand-by losses through better insulation jackets. The iterative procedure in Equation 3.51 weights new units (first term) with existing units (second term). The unit electric energy demand is then given by the ratio of hot water output (measured in KWH's) and the average efficiency (Equation 3.52). If there is some penetration of solar equipment to assist in hot water production, this average must be properly corrected by weighting in the fraction solar assisted at reduced demand levels (Equation 3.52). The total electric energy required for this energy then follows immediately as the product of the total number on line and the average unit usage (Equation 3.53).

TABLE 3.8
SUBMODEL FOR ELECTRIC WATER HEATER

Variable Code

t	Year (base year = 1)
k	Housing type (1=SF, 2=MF)
TOTNUM	Total number
HSTOCK	Households
SBY	Base year electric water heater saturation
ESHSAT	Electric space heating saturation
UNAVBS	Average base year unit electric energy demand
UNAV	Average unit usage
ALT	Average lifetime
CWHW	Clothes washer hot water demand
DWHW	Dishwasher hot water demand
OTHW	Other hot water demand
HWREOT	Hot water reduced demand for "other"
AVEFF	Average electric water heater efficiency
NUNEFF	New unit average efficiency year t
FS	Fraction electric hot water heaters solar assisted
PCSOLW	Fraction supplied by solar in solar assisted units
ENREU	Total energy demand year t
PEN	Penetration of esh in new construction

Equations

Stock stream:

$$TOTNUM_{1,k} = SBY_k \times HSTOCK_{1,k} \quad (3.48a)$$

$$TOTNUM_{t,k} = TOTNUM_{t-1,k} + (HSTOCK_{t,k} - HSTOCK_{t-1,k}) \times PEN_{t,k} + [(HSTOCK_{t,k} - HSTOCK_{t-1,k}) \times (1-PEN_{t,k})] \times [(SBY-ESHSAT_{1,k})/(1-ESHSAT_{1,k}] \quad (3.48b)$$

"Other" water demand:

$$OTHW_t = (UNAVBS \times AVEFF_1 - DWHW_1 - CWHW_1) \times (1-HWREOT_t)$$

Where DWHW & CWHW are from previous submodel, the first term in parenthesis is the base year total hot water usage. (3.49)

By definition

$$NUNEFF_t = AVEFF_1/(1-EFFIMP_t)$$

where

$$EFFIMP_t = \begin{cases} (t-1)/(TEND-1) \times EFFIMT & \text{for } t<TEND \\ EFFIMT & t \geq TEND \end{cases} \quad (3.50)$$

Average efficiency from:

$$TOTNUM_t \times AVEFF_t = (TOTNUM_t - TOTNUM_{t-1} + TOTNUM_{t-1}/ALT) \times NUNEFF_t + (TOTNUM_{t-1} - TOTNUM_{t-1}/ALT) \times AVEFF_{t-1} \quad (3.51)$$

then,

$$UNAV_t = (DWHW_t + CWHW_t + OTHW_t)/AVEFF_t \text{ (w/o solar)} \quad (3.52)$$

$$\times (1-FS_t + FS_t \times (1-PCSOLW)) \text{ (w solar)}$$

Finally,

$$ENREU_t = TOTNUM_t \times UNAV_t \quad (3.53)$$

3.3.8 Air Conditioners

The two types of air conditioners -- room and central -- are treated as separate end-uses. For each, the final forecast is a co-mingling of saturation and customer growths, efficiency increases, and building shell-thermal integrity improvements. It is tacitly assumed that average unit size will not increase over the base year due to demographic trends toward smaller family size and the decreased cooling load requirement that accompanies improved insulation.

Energy demand is calculated by employing the usual iterative sequence (Equations 3.54 to 3.60). The model assumes that in cases of multiple room air-conditioner ownership, average energy usage is additive. This may lead to a slight overestimate of demand insofar as second and third window/wall units are used substitutively to some extent. Such an effect is, however, difficult to estimate.

The model allows for adjustments in the average thermal integrity of building shells in the housing stock (Equation 3.61). This is given as an average over changes in base year and new construction units as indicated in Equations 3.62 and 3.63. There are two likely sources for improvements here: reinsulation in the retrofit market and stricter conservation practices in new building designs relative to historic design standards. Consequently, the overall improvement over base year values depends on estimates of several factors such as current building stock average characteristics, the degree of future reinsulation, and the effects of anticipated building codes for new construction.

TABLE 3.9
SUBMODEL FOR AIR CONDITIONERS

Variable Code

t	Year (base year = 1)
k	Housing type (1 = SF, 2 - MF)
i	End use index (10 = Room A/C, 11 = Central A/C)
TOTNUM	Total number on-line
ALT	Average appliance lifetime
HSTOCK	Housing units
BYHSTK	Base year housing stock surviving
HRET	Housing unit removal rate
TIIMP	Average thermal integrity improvement
TIE	Thermal integrity improvement of base year housing units
TIN	Thermal integrity improvement of new construction units
EFFIMP	Efficiency improvement over base year
TEND	Final year of efficiency phase-in
SAT	Saturation
UNAVBS	Average base year unit consumption
UNNEW	Average unit usage of new units
NEWENI	Energy demand of new units
RETENI	Energy demand of retired units
ENEUIl	Annual energy demand w/o thermal integrity improvement
ENREU	Annual energy demand

Equations

Stock stream:

$$TOTNUM_{t,k,i} = SAT_{t,k,i} \times HSTOCK_{t,k} \quad (3.5$$

Initialize:

$$ENEUIl_{1,k,i} = TOTNUM_{1,k,i} \times UNAVBS_{k,i} \quad (3.5$$

Iterate for t>1:

$$ENEUIl_{t,k,i} = ENEUIl_{t-1,k,i} + NEWENI_{t,k,i} - RETENI_{t,k,i} \quad (3.5$$

where

$$RETENI_{t,k,i} = ENEUIl_{t-1,k,i}/ALT_i \quad (3.5$$

$$NEWENI_{t,k,i} = (TOTNUM_{t,k,i} - TOTNUM_{t-1,k,i} + TOTNUM_{t-1,k,i}/ALT_i) \times UNNEW_{t,k,i} \quad (3.5$$

and

$$UNNEW_{t,k,i} = (1 - EFFIMP_{t,i}) \times UNAVBS_{k,i} \quad (3.5$$

with

$$EFFIMP_{t,i} = \begin{cases} ((t-1)/TEND-1)) \times EFFIMT & \text{for } t<TEND \\ EFFIMT & \text{for } t \geq TEND \end{cases} \quad (3.6$$

Correct for changes in thermal integrity:

$$ENREU_{t,k,i} = (1-TIIMP_{t,k,i}) \times ENEUIl_{t,k,i} \quad (3.6$$

where

$$TIIMP_{t,k,i} = [TIIMP_{t-1,k,i} \times HSTOCK_{t-1,k} + TIE_{t,k,i} \times BYHSTK_{t,k} - TIE_{t-1,k,i} \times BYHSTK_{t-1,k} + TIN_{t,k,i} \times (HSTOCK_{t,k} - HSTOCK_{t-1,k} + BYHSTK_{t,k} - BYHSTK_{t-1,k})] / HSTOCK_{t,k} \quad \text{for } t>1 \quad (3.6$$

and

$$BYHSTK_{t,k} = HSTOCK_{1,k} \times (1-HRET_k)^{t-1} \quad (3.6$$

3.3.9 Electric Space Heating

The growth in the number of electric space heated (ESH) homes is closely related to the decision on fuel use in new construction markets or in converting existing households from fossil fuel heating to electric. Consequently, it is analytically useful to introduce the concept of "penetration" in developing the number of housing units with ESH. In the model, the following definition is used:

$$\text{penetration}_t = \frac{\Delta \text{ electric space heat customers}_t}{\Delta \text{ customers}_t}$$

where t is the year label and "Δ" signifies the change from the previous year. The historic values of the increments are readily available from utility records providing useful information in estimating future trends. With this definition, the yearly number of ESH units can be computed through the iteration procedure of Equation 3.63 of Table 3.10 with the initial number defined as the product of base year saturation and household for each housing type.

The ESH intensity (annual KWH consumption per unit) must be represented as the combination of three distinct heating systems: conventional resistance heating, electrically driven heat pump, and solar augmentation (with or without heat pumps). The key dynamic expression is the iteration formula, Equation 3.65, which increments the previous year's total ESH energy demand by the additional demand coming on-line. This additional demand is the sum of the contributions from the system options considered: conventional resistance ("direct"), heat pump and solar, respectively, in Equation 3.66. Each of these is in turn decomposed into the product of new units in the ESH subcategory and usage per unit Equations 3.67, 3.68, and 3.69. Adjustments are made for possible conservation oriented changes in building envelope designs ("thermal integrity factor") in new units relative to the base year mix of electrically heated units. Finally, the market share of each ESH option is given a broken linear time dependence over the forecast period.

TABLE 3.10
SUBMODEL FOR ELECTRIC SPACE HEATING

Variable Code

t	Year (base year = 1)
k	Building type (SF=1, MF=2)
TOTNUM	Total number
HSTOCK	Housing stock
PEN	Penetration
UNAVBS	Average usage base year stock
NESHDI	Energy demand of new direct ESH
NESHHP	Energy demand of new ESH with heat pump
NESHSA	Energy demand of new ESH with solar assist
FHP	Fraction of new ESH units with heat pump
TEHP	Time end of increasing heat pump fraction of new ESH
COP	Heat pump coefficient of performance
COPEI	COP efficiency improvement
TEFFI	End year COP efficiency improvement
FSA	Fraction of new ESH units with solar assist
TSSA	Time start of solar space heat penetration
PCSOL	Percent heating requirement due to solar in solar assisted ESH units
TIF	Thermal intergrity factor adjusting new unit demand from base year unit demand
ENREU	Annual energy demand

Equations

Stock stream:

$$TOTNUM_{t,k} = TOTNUM_{t-1,k} + PEN_{t,k} \times (HSTOCK_{t,k} - HSTOCK_{t-1,k}) \quad (3.63)$$

Initialize:

$$ENREU_{1,k} = TOTNUM_{1,k} \times UNAVBS_{k} \quad (3.64)$$

Iterate:

$$ENREU_{t,k} = ENREU_{t-1,k} + NEWENI_{t,k} \quad (3.65)$$

where

$$NEWENI_{t,k} = NESHDI_{t,k} + NESHHP_{t,k} + NESHSA_{t,k} \quad (3.66)$$

The subcomponents of new demand are given by:

$$NESHDI_{t,k} = (1-FHP_{t,k} - FSA_{t,k}) \times (TOTNUM_{t,k} - TOTNUM_{t-1,k}) \times (TIF_{k} \times UNAVBS_{k}) \quad (3.67)$$

$$NESHHP_{t,k} = (FHP_{t,k} \times (TOTNUM_{t,k} - TOTNUM_{t-1,k})) \times (TIF_{k} \times UNAVBS_{k}/COP_{k,t}) \quad (3.68)$$

(continued)

TABLE 3.10 (Continued)

where

$$COP_{t,k} = COP_k \times (1 + (t-1)/(TEFFI - 1) \times COPEI)$$

$$NESHSA_{t,k} = (FSA_{t,k} \times (TOTNUM_{t,k} - TOTNUM_{t-1,k})) \times TIF_k \times ((1-PCSOL_k/100) \times UNAVBS_k) \quad (3.69)$$

Phase in fractional breakdowns:

$$FHP_{t,k} = \begin{cases} ((TEHP-t)/(TEHP-1)) \times FHP_{1,k} \\ +((t-1)/(TEHP-1)) \times FHP_{TEHP,k} & \text{for } t<TEHP \\ FHP_{TEHP,k} & t \geq TEHP \end{cases} \quad (3.70)$$

$$FSA_{t,k} = \begin{cases} 0 & \text{for } t<TSSA \\ ((t-TSSA)/(21-TSSA)) \times FSA_{21,k} & t \geq TSSA \end{cases} \quad (3.71)$$

3.3.10 Heating Auxiliaries

Heating auxiliaries refers to the electrically driven equipment such as pumps and fans used in conjunction with oil and gas home heating systems. Energy demand is simply the number of fossil-fuel heating systems multiplied by the average unit electrical demand for auxiliaries. With the assumption that all customers have either fossil fuel or electric space heating, the heating auxiliary saturations is given simply by one minus the electric space heating saturations. This is used in developing the yearly number on-line (Equation 3.72). The expression for annual heating auxiliary energy consumption (Equation 3.76) is composed of contributions from surviving base year households (defined in Equation 3.74) and newly constructed units. Energy requirements for these are shown, respectively, in Equations 3.73 and 3.75 where possible decrements in average units usage due to improvements in the average thermal integrity of residential buildings is account for. On the other hand, the model does not explicitly include possible decreased energy requirements due to heating system or electric motor efficiency improvements.

TABLE 3.11
SUBMODEL FOR HEATING AUXILIARIES

Variable Code:

t	Year (base year = 1)
k	Housing type (1=SF, 2=MF)
ESHSAT	Electric space heat saturation
UNAVBS	Average unit usage in base year
TIIMP	Thermal integrity improvement over base year
TIE	Thermal integrity improvement of base year housing units
TIN	Thermal integrity improvement of new construction units
HSTOCK	Housing stock
BYHSTK	Base year non-ESH housing units surviving
HRET	Housing unit removal rate
TOTK	Total number of non-ESH housing units
ENEUI	Annual energy demand
ENEUI1	Annual energy demand from base year housing stock
ENEUI2	Annual energy demand from newly constructed units

Equations:

$$TOTK_{t,k} = (1 - ESHSAT_{t,k}) \times HSTOCK_{t,k} \quad (3.72)$$

$$ENEUI1_{t,k} = BYHSTK_{t,k} \times (1-TIE_{t,k}) \times UNAVBS_{k} \quad (3.73)$$

where:

$$BYHSTK_{t,k} = TOTK_{1,k} \times (1-HRET_{k})^{t-1} \quad (3.74)$$

$$ENEUI2_{t,k} = ENEUI2_{t-1,k} + (1-TIN_{t,k}) \times UNAVBS_{k} \times \left[TOTK_{t,k} - TOTK_{t-1,k} + BYHSTK_{t-1,k} - BYHSTK_{t,k}\right] \quad (3.75)$$

Finally,

$$ENEUI_{t,k} = ENEUI1_{t,k} + ENEUI2_{t,k} \quad (3.76)$$

3.3.11 Miscellaneous Appliances

This category includes an enormous array of small appliances used in the home for food preparation, entertainment, maintenance and personal care. Since energy demand in this category consists of use in a large variety of devices, each with low annual consumption, a disaggregated computational scheme is inappropriate. Consequently, forecast energy consumption is computed simply as the product of average demand per housing unit and the number of housing units (Equation 3.75). The average unit usage deviates from base year values by a factor which is phased in linearly over the forecast period (Equations 3.76 and 3.77).

Average use per customer of miscellaneous appliances had been generally increasing prior to 1973 as part of the overall growth in energy-intensive equipment fostered by a combination of rising real per capita income, declining real electricity prices, and an explosion of small convenience devices. Current trends can be expected to moderate growth. Major factors are:

- increasing electricity costs
- substitution effects (e.g., cooking devices for ranges)
- decreased growth in disposable income
- energy conservation awareness
- smaller families
- market saturation

On the other hand, unanticipated new devices may appear in the marketplace to refuel growth in average consumption. Consequently, there is a good deal of uncertainty in use per customer trends over the twenty year forecast. Actual scenario runs of the model encompass a range of values.

TABLE 3.12
SUBMODEL FOR MISCELLANEOUS APPLIANCES

Variable Codes

t	Year (base year = 1)
HSTOCK	Total number of housing units year t
UNAVBS	Annual average usage per housing unit in base year
UPCIN	Use per customer increase
UNAV	Annual average usage per household unit
ENREU	Total annual energy consumption

Equations:

$$ENREU_t = UNAV_t \times HSTOCK_t \quad (3.75)$$

where

$$UNAV_t = (1+UPCIN_t) \times UNAVBS_t \quad (3.76)$$

with

$$UPCIN_t = ((t-1)/20) \times UPCIN_{21} \quad (3.77)$$

4. COMMERCIAL SECTOR

In modeling electrical energy consumption for the commercial sector, the degree of analytic detail is constrained by the adequacy both of the data base and current understanding of energy flows in the commercial building sector. Over the past few years, however, substantial progress has been made in quantitatively characterizing the components of commercial demand which allows for considerably more refinement than has been traditionally employed (see e.g., Refs. 2-6).

The importance of avoiding aggregate historical trending or correlation analysis is underscored by the reversal or diminution of the underlying factors that drove U.S. commercial energy growth at over 5% per year in the twenty years preceding the oil embargo of 1973. These factors included: rapidly increasing population, per capita income, and proportion of employment in services, combined with decreasing energy costs.

The commercial model tracks energy demand for five building types (BT), four end-uses (EU), or twenty BT/EU combinations each for existing and new buildings. These are displayed in Table 4.1 along with the commercial category allocated to each building type. Both demarcations - "building type" and "commercial category" - will be useful in constructing the commercial model.

4.1 Model Structure

As discussed in Sec. 2, the underlying strategies in the commercial and residential sectors are analogous. In the commercial sector, the measure of energy using activity is the magnitude of floor space while the energy intensity is expressed in average annual KWH/square foot for each end-use, building type, and utility service territory. The elements of the model are displayed schematically in Figure 4.1. The specifications of base year floor space, average consumption per square foot of each end-use ("electrical use coefficients"), and saturations (fraction of floorspace with end-use) gives the base year breakdowns. Folding in the time dependences of floorspace, conservation, and saturations, one arrives at the yearly forecasts.

The commercial forecast model, therefore, divides conceptually into two separate submodels: one for floorspace and the other for electric intensity. These will be discussed in turn.

4.2 Commercial Floorspace

The floorspace computation is summarized in the first row of Figure 4.1. Note that the floorspace analysis is disaggregated by commercial category; these are then aggregated to building types according to the allocations of Table 4.1. The reason for this procedure is that while detailed growth forecasts are available for the 14 commercial categories (Reference 7), the latest intensity

TABLE 4.1
COMMERCIAL MODEL END-USES, BUILDING TYPES AND COMMERCIAL CATEGORY

Index i	End Use
1	Space-Heating
2	Cooling
3	Light & Power
4	Auxiliary

Index k	Building Type	Index j	Commercial Category
1	Office	1	Finance, Insurance and Real Estate
		2	Federal Government
		3	State & Local Government
		4	Professional Services
2	Retail	5	Retail and Wholesale
3	Hospitals	13	Hospitals and Health Related Establishments
4	Schools	14	Schools and Educational
5	Other	6	Trucking and Warehouse
		7	Other Transportation Services
		8	Communications
		9	Lodging & Personal Services
		10	Business & Repair Services
		11	Amusement & Recreation
		12	Railroad

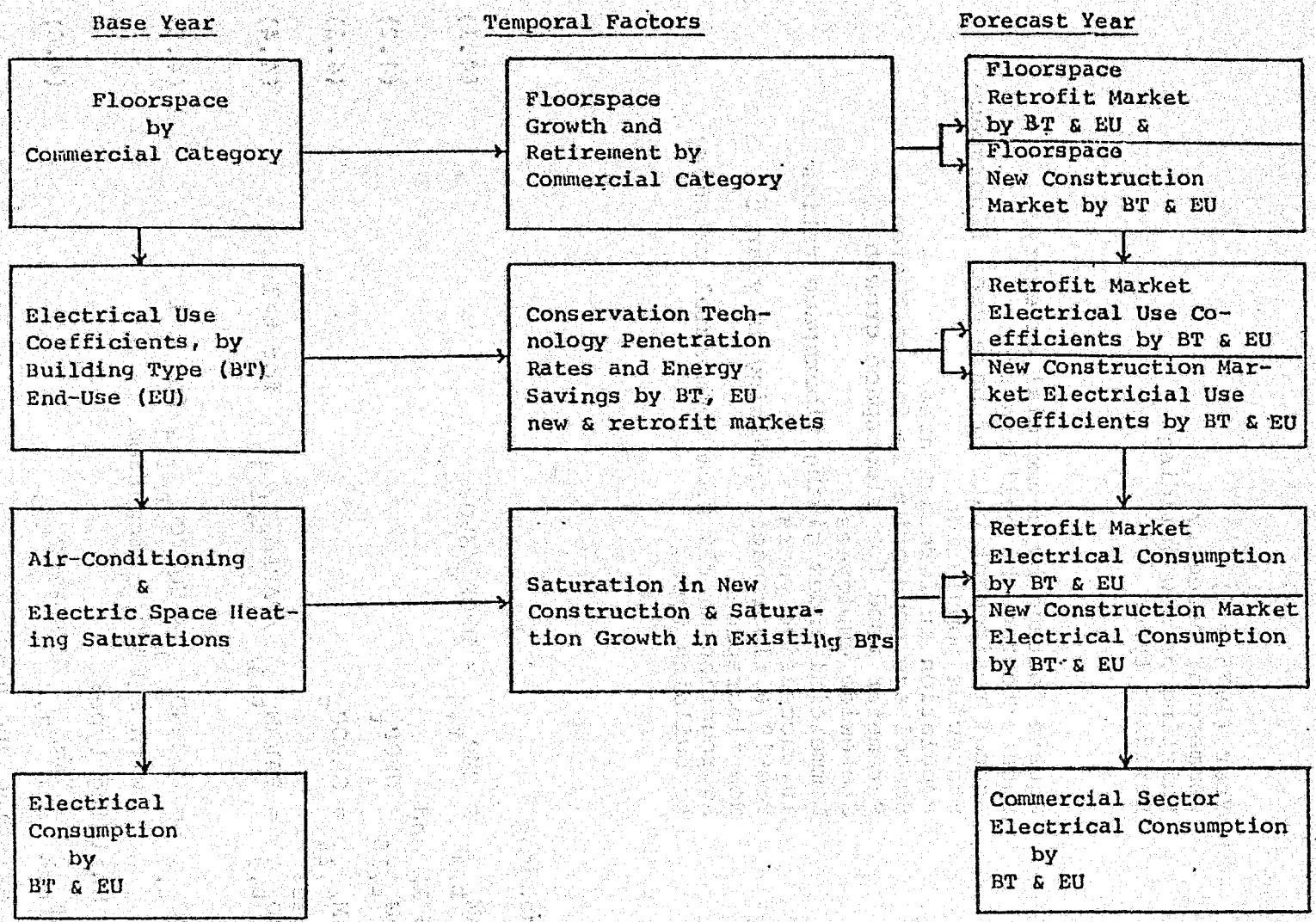


FIGURE 4.1
COMMERCIAL SECTOR MODEL SCHEMATIC

TABLE 4.2
COMMERCIAL MODEL - FLOORSPACE

Indices

t = 1,2,...	Year (1975 = 1)
j = 1 to 14	Commercial category
n = 1 to 2	Existing or new building
k = 1 to 5	Building types

Variables

SQFTCC	Square footage by commercial category
SQFTBT	Square footage by building type
RSQFT	Annual retirement rate of base year floorspace
SPOP	Statewide population
UPOP	Population in forecast area
SAPOP	School age population in forecast area
PARAM	Parameter used for floorspace growth
EMP	Statewide employees
COMIND	Commercial index giving floorspace ratios in successive years
OSQFT	Pre-1976 floorspace remaining in year t
NSQFT	New floorspace
AGG	Aggregation matrix from commercial category to building type

Equations:

Growth parameters:

$$PARAM_{t,j} = EMP_{t,j} \times UPOP_t/SPOP_t \quad (4.1)$$

for j = 1 to 12 and

$$PARAM_{t,13} = UPOP_t \quad (4.2)$$

$$PARAM_{t,14} = SAPOP_t \quad (4.3)$$

Growth indices:

$$COMIND_{t,j} = PARAM_{t,j} / PARAM_{t-1,j} \quad \text{for } t>1 \quad (4.4)$$

Iterate:

$$SQFTCC_{t,j} = COMIND_{t,j} \times SQFTCC_{t-1,j} \quad \text{for } t>1 \quad (4.5)$$

with $SQFTCC_{1,j}$ inputted.

Aggregate to building type:

$$SQFTBT_{t,k} = \sum_j AGG_{j,k} \times SQFTCC_{t,j} \quad (4.6)$$

Breakdown to existing and new:

$$SQFTBT_{t,k} = OSQFT_{t,k} + \sum_{t'=2}^{t} NSQFT_{t',k} \quad (4.7)$$

(continued)

E S R G

TABLE 4.2 (Continued)

where

$$OSQFT_{t,k} = \begin{cases} SQFTBT_{1,k} & \text{for } t = 1 \\ (1-RSQFT_k) \times OSQFT_{t-1,k} & \text{for } t > 1 \end{cases} \quad (4.8)$$

and

$$NSQFT_{t,k} = SQFTBT_{t,k} - SQFTBT_{t-1,k} + RSQFT_k \times SQFTBT_{t-1,k} \quad (4.9)$$

data and conservation penetration analysis are available on the basis of building type (References 6 and 8). Floorspace is thus treated on the basis of commercial category and then aggregated to the building type demarcation.

The system of equations for the floorspace component of the commercial model is given in Table 4.2. The model is based on a year-to-year iteration (Equation 4.5). Two factors are involved: 1975 floorspace data to initialize the iteration and an annual growth index.

4.2.1 1975 Floorspace

A separate computation was performed to generate the 1975 floorspace data. This was required due to the paucity of data on existing commercial building stock. Initial floorspace estimates were derived by multiplying Census employment data (Reference 9) by average floorspace per employee. School and hospital estimates were taken from national floorspace estimates (Reference 6) scaled to the forecast region by the ratio of state to national pupils and hospital beds, respectively (Reference 5). The square foot multipliers, giving average footage per employee by commercial category, are displayed in Table 4.3. They are based on average values by SIC given in the literature (References 5, 10), aggregated to commercial categories by using the groupings in the table (Reference 11) and taking weighted statewide averages over the SIC's within a group.

The 1975 floorspace results are used as data in the floorspace module of the main commercial program (see Equation 4.5). Total floorspace is ultimately calibrated to the specific utility by normalizing to base year energies as discussed later.

4.2.2 Floorspace Growth Indices

The growth indices ("COMIND") give floorspace ratios in successive year (Table 4.2, Equation 4.4). The gowth indices are equivalent to:

$$COMIND_{t,j} = (1 + GRSQFTCC_{t,j}) \qquad (4.10)$$

where

$GRSQFTCC_{t,j}$ = average annual growth rate of square footage in commercial category and year t.

For the case of hospital and health related establishments (j = 13), population growth is the proxy for floorspace growth (Equation 4.2). For the case of schools (j = 14), floorspace growth is equated to growth in school age population (Equation 4.3). For the other commercial categories, the level of employment was taken as the best measure of activity and, therefore, floorspace growth. Estimates of population and employment growth used in the current forecast are postponed to the data discussion below.

TABLE 4.3
SQUARE FOOTAGE MULTIPLIERS

Commercial Category	Corresponding SIC's	Average Square Feet Per Employee*
1. Finance, Insurance, Real Estate(FIRE)	60	155
	61	214
	62	176
	63	149
	64	149
	65	390
	66	187
	67	156
2. Federal Government	91	189
3. State and Local Government	92	183
	93	393
4. Professional Service	81	211
	83	216
	89	312
5. Retail & Wholesale	50,51	682
	52	987
	53	271
	54	509
	55	502
	56	532
	57	878
	58	270
	59	444
6. Trucking & Warehouse	42	3162
7. Other Transportation	41	280
	44	139
	45	809
	46	8050
	47	780
8. Communication	48	177
9. Lodging and Personal Service	70	837
	72	304
10. Business and Repair Service	73	275
	75	1422
	76	270
11. Amusement & Recreation Service	78	777
	79	871
	84	2000
	86	860
12. Railroad	40	187
County Business Patterns Admin. & Auxiliary Services		200

* Source: References 5 and 10

4.3 Electric Energy Intensities

With floorspace estimates generated with the methodology just described, there remains the second element of the commercial forecast: average electric energy consumption per square foot. As shown in the lower two rows of boxes of Figure 4.1, the evaluation of intensities again involves two phases: first, a specification of initial values of electrical demand coefficients (defined as average annual electrical consumption of a given BT/EU/service territory combination) and end-use saturations; second, an estimation of conservation penetration and saturation growth. We shall discuss these two phases sequentially.

4.3.1 1975 Intensities

Average electrical demands by end-use and building types have been adapted from the "theoretical building loads" developed for the Department of Energy by Arthur D. Little, Inc. (Reference 8). The study combined engineering design parameters and survey research to arrive at estimates of average building requirements for each of the EU/BT combinations treated in the commercial model. The adaptation of ADL's Northeast region building loads to unit electricity demands (electrical use coefficients) by service territory requires the adjustment of weather sensitive loads to the prevailing climatic conditions.

4.3.2 Future Intensities

The computation of forecast year intensities is described in Table 4.4. Intensities are, by definition, the product of the saturation (fraction of floorspace with end-use) and the electrical use coefficients (average annual KWH/FT^2 of floorspace with end-use). This is expressed mathematically by Equation 4.13. Note that the intensities are specified by 4 end-uses and 10 building types. In practice, however, many of the inputs are trivial. (E.g., saturations are defined as 1 for i = 3 and 4).

The time dependence of the electric use coefficient ("EUC") is obtained by incrementing the 1975 values by changes in end-use demands due to conservation practices initiated in the post-1975 era. In Reference 6, three levels of efficiency improvements are considered: 1) improvements which provide quick payback and require minimal engineering expertise (e.g., insulation, reduced lighting requirements, and other "housekeeping"), (2) level 1

improvements plus off-the-shelf technologies that require building and equipment modification (e.g., night setback, HVA/C system controls), and 3) levels 1 & 2, plus capital intensive modifications requiring considerable engineering support (e.g., building automated systems, waste heat reclamation). These three groupings are labelled by "m" in Table 4.4.

The energy savings that the technology and modifications associated with each conservation level would achieve are provided in Reference 6 for each U.S. region. These savings are to be applied against the base line loads discussed above. The matrix of percentage efficiency improvements is given in Table 4.5 by level, building type and end-use. They are also broken down by new buildings and 1975 stock ("retrofit").

The overall savings are functions both of the energy requirement reductions related to the conservation level and the penetration of these levels. Here, level "penetration" is defined as the fraction of floorspace in the given year and BT/EU combination at the given level. The average savings are then given by the sum over levels of the product of level penetration ("$PEN_{t,i,k,m}$") and percent improvement ("$PIMP_{t,i,k,m}$") as given in Equation 4.12.

The time dependence of the electrical use coefficients can then be written as the initial value multiplied by a decreased demand factor (Equation 4.11). The penetration of the conservation level technology groupings is dependent on a number of factors: initial costs, consumer preference, capital availability, pay-back time and electricity costs. Using linear programming techniques, optimal energy technologies by building type (new or retrofit market) and end-use have been computed (Reference 6). The mix of penetrations which result are functions of inputted economic assumptions. Consequently, the forecast scenarios can incorporate sensitivity to a range of assumptions on, e.g., future fuel costs. The electrical intensities require, in addition to the electrical use coefficients, "saturation" estimates. (Equation 4.13).

An additional factor must be taken into account for the electric space heat end-use: the possible use of heat pumps. Penetration analysis suggests that electric space heat with heat pump is cost-effective over conventional electric resistance heating for all new construction to 1985. The model allows for a market response delay by phasing in the fraction of new electrically space heated buildings which have heat pumps to unity in 1985. Additionally, the model incorporates the cautious assumption that solar heating and air conditioning will have an insignificant impact on overall load during the forecast period. In the case of water heating, where electricity consumption is relatively insignificant, solar energy would substitute primarily for fossil fuels.

TABLE 4.4
ELECTRIC ENERGY INTENSITIES

Indices

t	Year (1975 = 1)
i	Commercial end-use (i = 1 to 4)
k	Building type (k = 1 to 5)
n	Existing or new buildings (n = 1 to 2)
m	Conservation levels

Variables

INTEN	Electrical intensity (average annual KWH/FT^2)
EUC	Electrical use coefficient (= INTEN with all saturations = 1)
SAT	Saturation (fraction floorspace with end-use)
PEN	Market fraction ("penetration")
PIMP	Percent (÷100) energy savings (i,k,n) at given conservation
PENSUM	Fractional energy decrease
HPFRAC	Fraction new electrically heated buildings
COP	Heat pump coefficient of performance

Equations

From definitions:

$$EUC_{t,i,k,n} = (1 - PENSUM_{t,i,k,n}) \times EUC_{1,i,k,n} \quad (4.11)$$

where

$$PENSUM_{t,i,k,n} = \sum_m PIMP_{t,k,n,m} \times PEN_{t,i,k,n,m} \quad (4.12)$$

and

$$INTEN_{t,i,k,n} = SAT_{t,i,k,n} \times EUC_{t,i,k,n} \quad (4.13)$$

except for new electric space heating building where heat pumps are phased-in:

$$INTEN_{t,1,k,2} = (HPFRAC_t/COP + (1-HPFRAC_t)) \times SAT_{t,1,k,2} \times EUC_{t,1,k,2} \quad (4.14)$$

where HPFRAC is given the following linear parameterization:

$$HPFRAC_t = \begin{cases} \left(\frac{t-1}{10}\right) \times HPFRAC_{11} & \text{for } t \leq 11 \\ HPFRAC_{11} & t > 11 \end{cases} \quad (4.15)$$

TABLE 4.5
FRACTION OF LOAD SAVED

Building Type	End-Use	Conservation Level					
		Retrofit Market			New Market		
		1	2	3	1	2	3
Office	Heating	.11	.15	.23	.25	.35	.40
	Cooling	.13	.17	.34	.20	.35	.47
	L & P	.25	.50	.50	.15	.25	.25
	Aux	.17	.28	.38	.10	.16	.20
Retail	Heating	.08	.23	.25	.30	.42	.50
	Cooling	.12	.20	.20	.25	.37	.46
	L & P	.13	.25	.25	.15	.24	.30
	Aux	.18	.36	.45	.10	.16	.20
Hospital	Heating	.07	.15	.16	.20	.32	.40
	Cooling	.07	.24	.28	.15	.25	.33
	L & P	.08	.12	.17	.10	.15	.15
	Aux	.19	.25	.30	.10	.15	.15
Schools	Heating	.14	.21	.29	.30	.42	.50
	Cooling	.16	.26	.56	.25	.35	.41
	L & P	.12	.30	.42	.15	.20	.20
	Aux	.26	.33	.53	.20	.25	.30
Miscellaneous	Heating	.09	.15	.26	.30	.42	.50
	Cooling	.05	.12	.24	.25	.35	.40
	L & P	.09	.15	.24	.15	.15	.20
	Aux	.14	.23	.32	.15	.20	.20

4.4 Energy Forecast

The computation of commercial sector energies is a straightforward exercise once the forecasts for floorspace and electrical energy intensity have been obtained. The expressions for average annual energy consumption by end-use and building types are given in Table 4.6.

Calibration to base year sales is performed on total sales:

$$\text{Commercial Energy Sales, year } t = \sum_{i,k,n} \text{ENCEU}_{t,i,k,n} \qquad (4.16)$$

The model is first run from 1975 (t=1) to the base year (t = 1+base year - 1975). The total floorspace is then adjusted to normalize total sales in a given service territory to base year experience. An overall square foot adjustment factor scales each term in the energy sum (Equation 4.17). The necessity for such an adjustment is traced to the use of national average square foot per employee data. One finds, as anticipated, that such data closely approximates state averages except in service areas dominated by land-scarce urban centers.

TABLE 4.6
COMMERCIAL ENERGY FORECAST

Indices

t	Year (1975 = 1)
i	Commercial end-use (i = 1 to 4)
k	Building type (k = 1 to 5)
n	Existing or new buildings (n = 1 to 2)

Variables

ENCEU	Annual energy consumption
INTEN	Corresponding electrical energy intensity (See Table 4.4)
OSQFT	Remaining 1975 building stock floorspace (See Table 4.2)
NSQFT	New floorspace (See Table 4.2)

Equations

Retrofit market:

$$\text{ENCEU}_{t,i,k,1} = \text{INTEN}_{t,i,k,1} \times \text{OSQFT}_{t,k} \qquad (4.17)$$

New Construction:

$$\text{ENCEU}_{t,i,k,2} = \sum_{t'=2}^{t} \text{INTEN}_{t',i,k,2} \times \text{NSQFT}_{t',k} \qquad (4.18)$$

5. INDUSTRIAL SECTOR

As with the residential and commercial sectors, industrial energy consumption is broken down into products of energy using activities and energy intensities of those activities. The measure of activity in the case of industrial energy consumption is physical output (in units/year) for each major manufacturing subsector. The subsectors are chosen at the two-digit Standard Industrial Classification (SIC) level. Less detail would lose sensitivity to differing growth and electricity use trends among industries; more detail would require inputs beyond the capability of the current data base. The SIC's included in the forecast are given in Table 5.1.

The electric energy intensity for the industrial sector is correspondingly defined as average electricity consumption per unit of production. The growth in production is related to the level of economic growth and business activity in the state, while the electric intensity is a function of several major factors: process technology, pollution control requirements, conservation level, and fuel mix. In past decades, electrical energy growth has been driven by increases in production level, energy intensiveness in manufacturing processes, and increased fuel fraction for electricity, on the one hand, and a virtual absence of energy conservation, on the other. The job of forecasting is to adequately characterize historic experience and to incorporate a realistic range of growth in the demand-driving factors.

5.1 Model Structure

The model elements and their relationship are schematized in Figure 5.1. Growth in base year electric energy consumption by SIC are related to growths in production and electric energy intensity. The resultant electric energy demand must then be divided into the amount purchased and the amount self-generated since it is the purchased energy which is ultimately identified with utility sales. Changes in the fraction of electric energy consumption supplied by self-generated electricity must also be allowed for.

The forecast energy thus depends on the specifications of base year experience, the forecast of production growth, the trend in electric energy intensity, and the changes in fraction self-generated. These will be discussed, respectively, in Sections 5.2 to 5.5, and brought together in the energy forecast model described in Section 5.6.

TABLE 5.1
STANDARD INDUSTRIAL CLASSIFICATIONS

ESRG Index	SIC	Description
1	20	Food and Kindred Products
2	22	Textiles
3	23	Apparel and Other Textile Products
4	24	Lumber and Wood Products
5	25	Furniture and Fixtures
6	26	Paper and Allied Products
7	27	Printing and Publishing
8	28	Chemicals and Allied Products
9	29	Petroleum and Coal Products
10	33	Primary Metal
11	34	Fabricated Metal Products
12	35	Machinery (except electrical)
13	36	Electric Equipment
14	37	Transportation Equipment
15	30	Rubber and Plastics
16	31	Leather
17	32	Stone, Clay and Glass
18	38	Instruments, Related Products
19	39	Miscellaneous

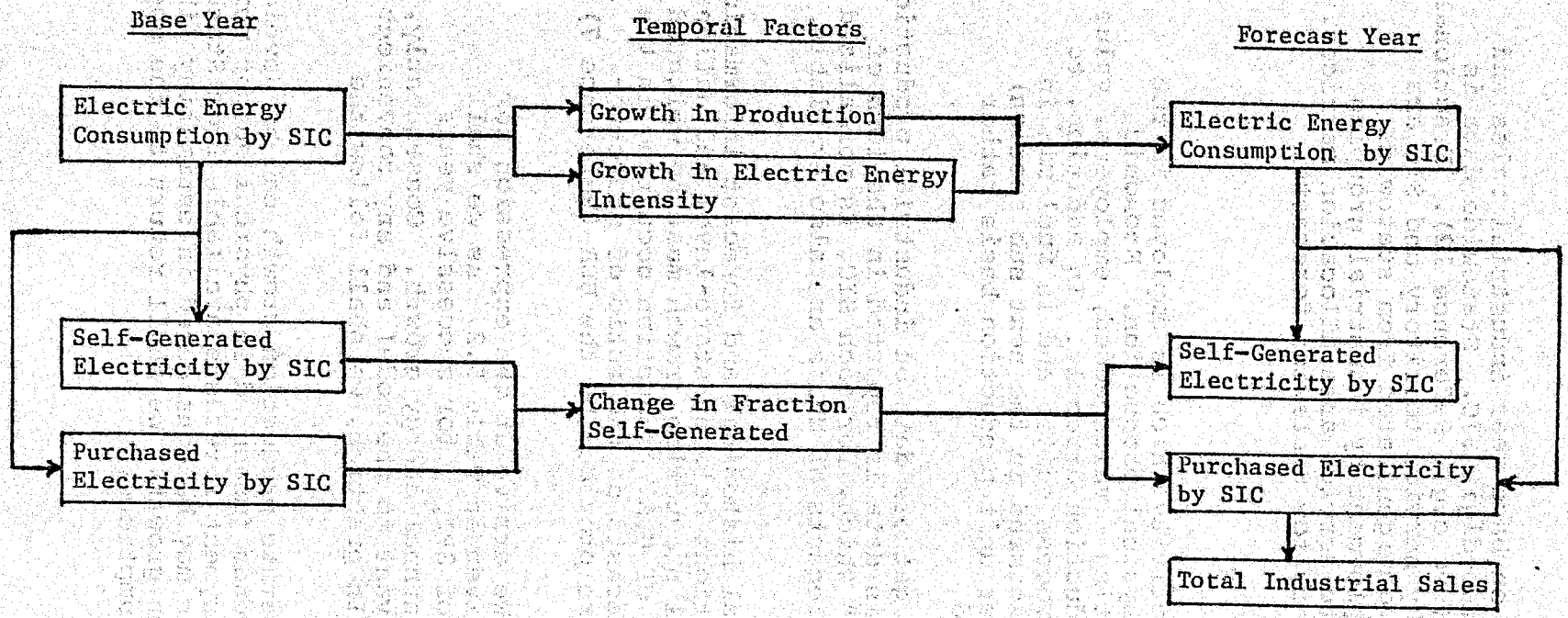


FIGURE 5.1
INDUSTRIAL SECTOR MODEL SCHEMATIC

5.2 Base Year Experience

The model requires inputs on base year industrial sales and self-generated electricity by two-digit SIC. Statewide data is available from public sources (see e.g., Reference 12). Fractional breakdowns of base year sales by service territory and SIC are generally available and may also be generated from statewide data on the basis of county employment by industrial grouping (Reference 9), and on county to service area allocation matrices. This is, of course, not necessary for Statewide forecasts.

5.3 Production Growth

The measure of industrial activity which is employed in the model is the level of actual physical production. Economic measures often used in forecasting - value added, employees, value of shipment - do not track production directly. In addition, to accurately capture trends in process shifts and in fuel mix in industry, energy intensity (discussed in the next sub section) should be expressed on a KWH per unit production basis rather than, say KWH per $ value added.

The Federal Reserve Board gathers data on industrial production nationally (Reference 13). This data is reported in the form of the "national production index" which, for each SIC, is normalized to 100 for 1967. Composite forecasts of NPI's are also available (Reference 14).

To make use of the national historical and forecast information, account must be taken of deviations between state-level and national trends. Specifically, national production growth must be weighted by any changes in the fraction of U.S. production occurring in the state. The best available forecasts on the ratio of state-to-national production activity are provided by the BEA (Reference 7) on the basis of earnings.

Combining these factors, we arrive at the expression for state production index (SPI) given in Table 5.2. As we shall see in Section 5.6, the ratio of $SPI_{t,j}$ for successive years alone is utilized in defining annual energy growth. Consequently, the absolute values are irrelevant to the model and any convenient normalization is acceptable. In practice, we shall follow the FRB's normalization procedure.

Alternative estimates of state production growth can be developed from combining productivity trends (measured in physical output per manhour) with state-level employment forecasts available from State planning offices. Both methods may be considered in estimating likely ranges of industrial production growth. We shall return to the specifics when discussing input data assumptions.

TABLE 5.2
STATE PRODUCTION INDEX FORECAST

Indices

t	Year (base year = 1)
j	Industrial grouping by 2 digit SIC (j = 1 to 19)

Variables

NPI	National production index
SPI	State production index
SNER	State to national earnings ratio

Equation

$$SPI_{t,j} = SNER_{t,j} \times NPI_{t,j} \qquad (5.1)$$

5.4 Electrical Energy Intensity

Electrical energy intensity - average consumption per unit of physical output - has changed over time for three major reasons:* adoption of capital intensive production technologies, changes in the mix of fuels used for thermal and process energy, and increased use of energy management practices. The historic time series intensities may differ radically by SIC classification and by geography since the impact of these factors will be a function of particular manufacturing conditions, fuel prices and availability, employment constraints, technology vintage, and state policy climate. We shall discuss later the methods for estimating ranges of future electric intensity for industries in the State.

5.5 Fraction Self-Generated

Up to this point, industrial electricity consumption has been forecasted on the basis of the total demand for electricity on the customer's side of the meter:

$$\text{Total KWH Demand} = \text{Production} \times \text{Intensity}$$

where intensity is expressed in terms of unit production requirements. Only part of this demand must be met by the utility, however, since many industries produce some of their electricity requirements in-house.

Therefore, an additional factor--the fraction of total electrical energy consumption which is self-generated--is necessary in computing forecast industrial sales. This fraction may change over present values as a result of national energy policy, developing state interest in addressing regulatory and other barriers to such investment, and renewed interest among industrial planners in combined energy systems as a result of the increasing costs of electricity. Therefore, the historic decrease in the fraction self-generated is likely to reverse. The degree will depend on scenario assumptions based on existing studies of cogeneration potential and on historic levels experienced in the State.

5.6 Energy Forecast

The basic elements required for the industrial sector have now been described; they are brought together in the energy forecast model summarized in Table 5.3. The iteration (Equation 5.5) is first initialized for the base year. The fractional breakdown of industrial sales (Equation 5.2) is used to define base year sales by SIC. Total energy is derived from purchased energy

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* Short term fluctuations related to, e.g., business cycle or large plant relocations, are not germane to the long-range forecast which depends only on secular trends.

using base year values for the fraction self-generated (Equation 5.3). The growth index of Equation 5.4 (=1 + average annual rate of growth in year t) is based on the growths in state production index (Section 5.3) and electric energy intensity (Section 5.4). Finally, forecasted total energy consumption is decreased by the self-generated component to arrive at the forecast for industrial sales (Equation 5.6).

TABLE 5.3
INDUSTRIAL ENERGY FORECAST

Indices

t	Year (base year = 1)
j	Industrial grouping by 2-digit SIC (j = 1 to 19)

Variables

TESIC	Total electric energy consumption
PENSIC	Purchased electric energy consumption
ISALES	Base year total industrial sector sales
SEI	Electric intensity
SPI	State production index
MIX	Fraction base year industrial sales breakdown
IND	Growth index
SGEN	Fraction self-generated

Equations

Initialize (t=1):

$$PENSIC_{1,j} = MIX_j \times ISALES \quad (5.2)$$

$$TESIC_{1,j} = PENSIC_{1,j}/(1 - SGEN_{1,j}) \quad (5.3)$$

For t>1, define growth index:

$$IND_{t,j} = (SEI_{t,j} \times SPI_{t,j}) / (SEI_{t-1,j} \times SPI_{t-1,j}) \quad (5.4)$$

Then,

$$TESIC_{t,j} = IND_{t,j} \times TESIC_{t-1,j} \quad (5.5)$$

$$PENSIC_{t,j} = TESIC_{t,j} \times (1-SGEN_{t,j}) \quad (5.6)$$

6. OTHER ENERGY REQUIREMENTS

The residential, commercial, and industrial sectors account for the bulk of energy consumption. The residual categories are street and highway lighting, railroads, company use, losses, and sales for resale. Of these, the last item represents KWH sales to other electric utilities. Since we are interested in only demand for electricity on the utility system (not on itself), this category can be ignored.

The category "losses" refers to electric energy lost in the transmission and distribution lines in the course of serving system customers. Utility "company use" is the energy consumed by the electric utilities themselves in business operations. These two categories - losses and company use - are accounted for in the model by a fraction of total sales ($FRLS_t$ in Table 6.1). That is

$$FRLS_t = \left(\frac{\text{losses and company use}}{\text{total sales}} \right)_t$$

Total sales includes, in addition to the three main sectors discussed in earlier sections, sales for railroad and street and highway lighting. Total energy from the "other" sector is then derived from Equation 6.1. Yearly energy sales from the three main sectors are inputed from the respective sectoral models, base year data for "other" sales, losses and company use are readily available from utility records. Deviations from base year values are provided by Company forecasts or can be independently estimated.

TABLE 6.1
OTHER ENERGY

Indices

t	Year (base year = 1)

Variables

$FRLS_t$	Losses and company use as a fraction of total sales
SUM_t	Sum of energy sales to residential, commercial and industrial sectors
$OSALES_t$	Energy sold for street and highway lighting and railroads
$OTHEN_t$	Energy sendouts in "other" category

Equation

$$OTHEN_t = OSALES_t + FRLS_t \times (SUM_t + OSALES_t) \qquad (6.1)$$

7. PEAK POWER

In the preceding sections, we have concentrated on the electrical energy forecasting model. Here, we shall turn instead to the method for translating these results into peak power demand forecasts ("demand" henceforth). Power, being the rate at which energy is expended, will be expressed in units of 1000 KWH/Hour or simply MW.

In developing peak power forecasts, a compromise between a disaggregated end-use approach and gross load factor approach has been adopted. The former requires excessive data requirements on the composition of demand at peak. The latter loses the ability to track changes in the relationship between energy and peak due to shifts in the relative contribution of load components as a result of differing end-use growth rates or changes in use patterns. The system peak (summer and winter) is analyzed in terms of two components - "weather sensitive demand" and "base demand". In addition, certain impacts of load shifting are explicitly treated. In other words, changes in system load factor due to a changing mix of base to seasonal load and due to shifts of some energy-using operations off-peak are included.

The computational specifics are summarized in Table 7.1. First, the total energy is calculated by summation over the separate end-use forecasts developed in the sectoral models (Equations 7.1 to 7.4). The problem next is to group weather sensitive energies on the one hand, and base energy, on the other hand. By weather sensitive energy we mean extra electrical energy consumed as a result of seasonal climatic variation. For example, electric space heating energy is completely winter weather sensitive while energy consumed for comfort cooling is completely summer weather sensitive. Such strictly weather sensitive end-uses are grouped together in Equation 7.5 while the weather sensitive fractions WSFR are given in Table 7.2. Additionally, the seasonal fluctuation in the other residential usages, defined in Equation 7.6, gives the variation of seasonal usage from average levels.

Next, weather sensitive commercial end-uses are identified in Equation 7.7. The notational convention is correctly incorporated by identifying summer (p=1) and winter (p=2) correctly with the cooling and electric space-heating end-uses, respectively. Breakdowns on weather sensitive to non-weather sensitive energy requirements in the industrial and "other" categories are not available. However, these sectors generally show minimal seasonal variation since, for example, monthly industrial process requirements are correlated to market fluctuations which, in a long term model, can be treated as temporally random. Consequently, industrial and "other" energy will be included in our "base" energy category. It is worth stressing that the division into weather sensitive and non-weather sensitive components is only necessary anyway when the relative weight of component contributions to peak change. If the shape of the annual load curve is not expected to change, a single load factor would suffice in mapping annual energy to seasonal peak.

The overall weather sensitive energy by season is formed as the summation of its sectoral components. For summer, we have the simple sum of Equation 7.10. For winter, two additional complications arise: (1) the model allows for the possibility of thermal storage in the commercial sector and (2) heat pump efficiencies (which are functions of temperature) must be reduced in calculating the winter peak. We shall discuss these in turn.

Rate differentials by time-of-day, if large enough, can make capital investment in thermal storage systems economically attractive. We have allowed for this possibility in the most promising case of commercial space heating. That fraction of usage which is shifted to off winter peak should not be included in the winter weather sensitive energy used to compute winter peak. This is taken into account explicitly in the second term of Equation 7.11 where the "fraction off-peak commercial weather sensitive" (FOPCWS) is phased in linearly from zero for the assumed start-up of time-of-use rates to a value assumed for the year 2000 (Equation 7.12). The values selected depend on scenario assumptions on the likelihood and nature of future time-of-use rates.

The other complication in deriving the winter weather sensitive energy is the decrease in heat pump coefficient of performance at colder temperatures. If average seasonal energies were used to drive the winter weather sensitive peak, underestimates of peak demand would result since more KWH of electric input per KWH of heating output are required on colder days. The third term in Equation 7.11 corrects for this effect. Forecast annual electrical energy consumption for heat pumps, are computed in the residential and commercial energy programs (called TREHP and TCOHP, respectively). The coefficient of performance correction factors (COPCR and COPCC for residential and commercial sectors, respectively) are defined as the ratio of average to coldest day COP. The method and assumptions for estimating the corrections are discussed later.

Next, the base energy is defined by subtracting the strictly weather sensitive parts from total energy (Equation 7.8). Also subtracted is an estimate of residential "base" energy consumption that would be shifted to off-peak should TOU rates be adopted for the residential customer class. The off-peak shifted energy is paramaterized in Equation 7.9 where estimates of the start-up year and fraction of time-flexible end-use consumption shifted are required. Time-flexible end-use consumption is defined here (after Reference 15) as the energy used for clothes dryer, clothes washer, dish washer and water heater. These are the end-uses that could most conveniently be shifted in response to off-peak reduced rates and for which the customer would experience little or no life-style alteration. Additional load shifting is conceivable - e.g., timers on freezer and refrigerator automatic defrost devices and thermal storage - but considered less probable.

Armed with the base and weather sensitive energy component, the summer and winter peaks are computed in Equation 7.15. The "coincident load factors are defined here, for a given component of demand, as the ratio of the contribution to the utility system peak and the energy. Since energies will

be expressed in 10^6 KWH (GWH) and demand will be expressed in MW, the "coincident load factors" are in units of $(10^3 \text{ hours})^{-1}$. They are derived in Equations 7.13 and 7.14 from base year experience. The base year energies are derived within the model as discussed above, while base year summer and winter peaks are those experienced in the base year (weather normalized if available). The division into "base" and "weather sensitive" peak is derived from analysis of the variation in monthly peaks as a function of temperature as will be explicated in the data discussion.

TABLE 7.1
PEAK POWER MODEL

Indices

t	Year (base year = 1)
p	Season (1 = summer, 2 = winter)
i,k,j,n	End-use indices as defined in Sections 3-5

Variables

BY	Base year
TOTEN	Total energy requirements
BD	Base demand in base year
AFBEU	Average seasonal fluctuations of residential "base" end-uses
BE	Base energy
WSE	Weather sensitive energy
RESSA	Residential sales
COMMSA	Commercial sales
INDSA	Industrial sales
OTHEN	"Other" energy requirements
ENREU	Energy consumption residential end-uses
ENCEU	Energy consumption commercial end-uses
PENSIC	Purchased energy industrial by SIC
CLFB	Coincident load factor--base
CLFWS	Coincident load factor--weather sensitive
RTOUY	TOU rate start-up year--residential sector
CTOUY	TOU rate start-up year--commercial sector
FOPRB	Fraction time-elastic energy consumption shifted off-peak
FOPRBT	Fraction time-elastic energy consumption shifted off-peak by 2000
OPBER	Base energy shifted to off-peak in residential sector
FOPCWS	Fraction commercial weather sensitive demand off-peak
FOPCWT	Fraction commercial weather sensitive demand off-peak by year 2000
WSFR	Weather sensitive fraction residential end-uses
COPCR	Coefficient of performance correction factor - residential
COPCC	Coefficient of performance correction factor - commercial
TRHP	Total energy consumed by residential heat pumps
TCOHP	Total energy consumed by commercial heat pumps
PEAK	Peak

(continued)

TABLE 7.1 (Continued)

Variables (Continued)

CNWH	Fraction of residential waterheating load controlled in year t

Equations

Sectoral energies:

$$RESSA_t = \sum_{i=1}^{14} ENREU_{t,i} \quad (7.1)$$

$$COMMSA_t = \sum_{k=1}^{5} \sum_{i=1}^{4} \sum_{n=1}^{2} ENCEU_{t,k,n,i} \quad (7.2)$$

$$INDSA_t = \sum_{j=1}^{19} PENSIC_{t,j} \quad (7.3)$$

Total energy:

$$TOTEN_t = RESSA_t + COMMSA_t + INDSA_t + OTHEN_t \quad (7.4)$$

Define intermediate sums:

$$RWSSUM_{t,p} = \sum_{i=10}^{13} WSFR_{i,p} \times ENREU_{t,i} \quad (7.5)$$

$$AFBEU_{t,p} = \sum_{i=1}^{9} WSFR_{i,p} \times ENREU_{t,i} \quad (7.6)$$

$$CWSSUM_{t,p} = \sum_{k,n} ENCEU_{t,k,n,3-p} \text{ (3-p is end-use label)} \quad (7.7)$$

then

$$BE_t = TOTEN_t - \sum_{p=1}^{2} (RWSSUM_{t,p} + CWSUM_{t,p}) - OPBER_t \quad (7.8)$$

where

$$OPBER_t = \begin{cases} CNWH_t \times ENREU_{t,8} \\ FOPRB_t \left[\sum_{i=6,7,9} ENREU_{t,i} + (1-CNWH_t) \times ENREU_{t,8} \right] + CNWH_t \times ENREU_{t,8} \end{cases}$$

$$\text{for } \begin{cases} t \leq RTOUY \\ t > RTOUY \end{cases}$$

and

$$FOPRB_t = (t-RTOUY)/(2001-BY-RTOUY) \times FOPRBT \quad (7.9)$$

TABLE 7.1 (Continued)

Weather sensitive energy:

$$WSE_{t,1} = RWSSUM_{t,1} + CWSSUM_{t,1} \quad (7.10)$$

$$WSE_{t,2} = RWSSUM_{t,2} + (1-FOPCWS_t) \times CWSSUM_{t,2} + TREHP_t \times (COPCR-1) + TCOHP_t \times (COPCC-1) \quad (7.11)$$

where

$$FOPCWS_t = \begin{cases} 0 & \text{for } t \leq CTOUY \\ ((T-CTOUY) \,/\, (2001 - BY - CTOUY)) \times FOPCWF & \text{for } t > CTOUY \end{cases} \quad (7.12)$$

Define:

$$CLFB = BD \,/\, BE_1 \quad (7.13)$$

$$CLFWS_p = (PEAK_p - CLFB \times (BE+AFBE_{1,p}))/WSE_{1,p} \quad (7.14)$$

then

$$PEAK_{t,p} = CLFB \times (BE_t + AFBE_{t,p}) + CLFWS_p \times WSE_{t,p} \quad (7.15)$$

TABLE 7.2
SEASONAL VARIATION OF RESIDENTIAL ENERGY USE

End-Use	Summer	Winter
Refrigerator	.05	-.04
Freezer	.03	-.04
Range	-.05	.03
Lighting	-.08	.05
TV	-.02	.02
Clothes Dryer	-.04	.01
Clothes Washer	-.04	.01
Dishwasher	-.04	.02
Water Heater	-.05	.05
AC-Room	1.0	0
AC-Central	1.0	0
ESH	0	1.0
Ht. Aux.	0	1.0
Misc.	0	0

Based on Reference 52.

8. DISCUSSION OF INPUT DATA AND ASSUMPTIONS

The model, as described in Sections 3 through 7, simulates electricity demand at the point of consumption. It is a tool for mapping a set of input data (defining historic experience, equipment ownership growth, technology shifts, fuel switching, etc.) onto a set of output results (system and end-use energy requirement forecasts, peak levels, etc.). This section describes the data utilized and assumptions made in generating the high case and low case forecasts. It is worth reemphasizing that the uncertainty bands in input parameters are intended to represent the plausible range of business-as-usual futures. Other cases, such as a conservation scenario forecast based on, say, the impacts of a State commitment to demand-reducing policies and alternative technology implementation, are considered in Volume II of this report.

The computer program that ESRG has developed to implement the model allows for flexibility in the choice of both inputs and outputs. The data explication below is intended to correspond closely to the model descriptions given earlier. With cross-referencing to the discussion of the mathematical structure of the appropriate submodel, this should allow the reader to fully understand the basis for the forecasts reported in Section 1. The base year, which serves as the departure point for forecasting, is 1977 throughout the study since this was the most recent year of experienced sales breakdowns available from PECO.

8.1 Residential Sector

Here we shall concentrate on the data inputs used to drive the residential forecast model described in Section 3: demographics, saturations, and factors affecting unit usage levels.

8.1.1 Demographics

Base year and projected Statewide population data was available from four sources: Refs. 7, 18, 21, and 22. Both high and low cases use the Pennsylvania Office of State Planning and Development (OSPD) state population data, a middle-range forecast relative to others available (see Table 8.1). Note that the independent population projection

produced by the federal government sources show smaller growth rates than does that of the OSPD for the state as a whole. It is thus deemed a reasonably optimistic basis for both statewide population forecasts and for the five county region served, in the main, by PECO. State and service area growth rates, it will be recalled, are used for substate commercial floorspace growth allocation and to drive the hospital and health sector floorspace growth (Sec. 4.2.2 and Table 4.2). Additionally, as we shall see below, the population forecasts are utilized in developing residential customer growth estimates.

Base year residential customer estimates are from Company sources (Refs. 19, 20). We have consistently included residential customers on master metered rates in the residential category though the Company reports such sales as commercial. In generating customer growth rates, the OSPD five county growth rates need to be combined with trends in the population per household which has been decreasing gradually since 1950. For example, the U.S. average has decreased from 3.14 persons per household in 1970 to 2.86 in 1977. The corresponding values for Philadelphia are 3.21 and 2.91, respectively. Future trends are, of course, somewhat uncertain. For example, PECO has assumed values of persons per household phased to 2.71 by 1990 (Ref. 19, p. 44). For that year, we have assumed values of 2.55 in the high case based on Census projections (quoted in Ref. 19) and the 2.75 for the low case based on Ref. 23. Had we used the PECO assumption, our base residential forecast would be decreased somewhat.

TABLE 8.1
COMPARISON OF FOUR FORECAST SOURCES ON POPULATION

Area	Source	Ref.	Ratio 1985/1975	Ratio 2000/1975	Gr. Rate to 85	Gr. Rate to 2000	Publ. Date
Penn.	Census Series II-A	22	1.019	1.051	.19%	.20%	March, 1979
	Census Series II-B		1.014	1.039	.14%	.15%	
5 Counties/Penn.	O.S.P.D. / State Gov. Office	18	1.020	1.043	.20%	.17%	June, 1978
			1.031	1.067	.31%	+.26%	
Penn.	BEA	7	1.014	1.04	.14%	+.156%	1977
5 Counties	PECO	19	-	1.086	-	+.33%	Dec., 1978

The other required demographic input is the breakdown of total households into single family and multifamily units which, it may be remembered, is used to track differential use patterns in a number of the end-use submodels. It is commonly assumed that the relative demand for multifamily units should increase over time due to assumed decreases in family size and the increasing fraction of total population that is elderly and/or single. In the 1970-1977 period, approximately 50% of the new construction were multifamily units. We have assumed a continuation of that breakdown in the high case and an increase to 55% in the low case. The base year breakdown reflects the inclusion of the single point metered apartments (131,400 for 1977 from Ref. 19, p. 175-6). Table 8.2 summarizes the high and low case residential customer projections.

TABLE 8.2
RESIDENTIAL CUSTOMER PROJECTIONS (10^6 CUSTOMERS)

	Base	1980		1985		1990		1995	
	Year	Low	High	Low	High	Low	High	Low	High
Single Family	.961	.975	.985	.998	1.027	1.020	1.069	1.025	1.075
Multifamily	.331	.342	.355	.361	.397	.379	.440	.384	.445

8.1.2 Appliance Saturations

Appliance saturation assumptions are summarized in Table 8.3. The symbols in parentheses give the nomenclature used in Equation 3.5 for the saturation logistics curve. The end-uses not included in the table have predetermined saturation values: lighting and miscellaneous are each fixed at one, while heating auxiliary saturation is defined as one minus the electric space heat saturation.

Appliance saturation data, both in the base year and in earlier years, was given in the PECO Forecast document (Ref. 19). Estimations of terminal saturations also were referenced against PECO saturation estimates. For the appliances, the growth indices ("A") are computed by fitting the logistic curve (Sec. 3.2) to historical saturation data. Guidance in estimating the terminal saturation levels was derived from econometric relationships between appliance saturation and price/income variables. Specifically, saturation growths to

the year 2000 were calculated using the econometric relationships given in Refs. 32 and 33, driven by the following annual growth rates:

	Income	Electricity Price	Oil Price	Natural Gas Price
High Case	1.5%	1%	4%	4%
Low Case	.5%	2.5%	2%	2.5%

In all cases, the terminal saturations employed exceed these estimates.

TABLE 8.3
APPLIANCE SATURATION ASSUMPTIONS

Appliance	Base Year Sat("SBY")	High Case		Low Case	
		Terminal Sat("STERM")	Growth Parameter ("A")	Sat("STERM")	Growth Parameter ("A")
Refrig(SF)	1.20	1.20	0	1.20	0
(MF)	1.04	1.04	0	1.04	0
Freezer(SF)	.28	.50	.169	.28	0
(MF)	.09	.15	.157	.09	0
Range	.38	.50	.107	.38	0
TV(SF)	2.00	2.20	.118	2.00	0
TV(MF)	1.20	1.20	0	1.20	0
Cl. Dryer	.35	.60	.086	.45	.134
Cl. Washer	.80	.85	.124	.80	0
Dishwasher	.35	.80	.069	.60	.090
Water Heat	.13	-	-	-	-
AC/room	.918	1.20	.014	1.00	.036
AC/cen.(SF)	.152	.40	.140	.25	.184
(MF)	.152	.40	.140	.25	.184
ESH(SF)	.023	-	-	-	-
(MF)	.098	-	-	-	-

Increases in the number of electric space heat and water heating customers were formulated in terms of penetration rates in Secs. 3.3.7 and 3.3.9, respectively. The penetration rates are modeled to increase linearly from initial year to 1990 values using the data below.

	High Case		Low Case	
	1978	1990	1978	1990
Single family	.50	.65	.30	.30
Multifamily	.70	.65	.60	.30

Historic penetration rates have been dependent on a complex mix of factors: construction practices, gas curtailment policy, economic promotion, etc. From 1970 to 1973, penetration rates in the PECO service area fluctuated, ranging from .13 to .34, then increased rapidly to over .50 in the gas curtailment years of 1974 and 1975. Given the recent rebound of the gas market, bans on new master metered units, and the continuing economic inferiority of electric heating, our assumption of continued high electric space heat penetration may be a source of forecast overestimation.

8.1.3 Unit Electricity Usage

The demographic and saturation computations generate the number of units by end-use. There remains the description of input data to drive the electricity usage per unit submodels (the "C" in Equation 3.1). Average unit usage for the base year is given in Table 8.4 along with the efficiency improvements assumed in the forecast runs. The latter require some clarifying comments:

- The efficiency improvements are at FEA target levels (Reference 34). These targets may well be exceeded in the forecast period; the Secretary of Energy is mandated, under the National Energy Conservation Policy Act, (Title IV, §422) to "prescribe standards which achieve the maximum improvement in energy efficiency which the Secretary determines is technologically feasible and economically justified" (Reference 35). On this criterion, improvements of 52% versus the FEA-targeted 28% are possible for refrigerators (Reference 36), 33% versus 15% for electric water heaters (Reference 37), and so on.

- The achievement date in the FEA program is 1980. The forecasts assume 1981 and 1985 for the low and high cases, respectively.

- Improvements in the energy requirements of hot water heaters have also been included at FEA-targeted levels (3.7% for clothes washers, 17% for dishwashers, with 1981 and 1985 phase-in dates for the low and high cases, respectively). Though such increased thermal efficiencies do not affect electrical consumption, they will impact indirectly on electric hot water requirements (see Section 3.3.7).

TABLE 8.4

APPLIANCE USE DATA

Appliance	Base Year Average Annual Unit Usage†	Forecast Unit Efficiency Improvement††
	Kwh	Percent
Refrigerators*	1704	28
Freezers*	1372	22
Ranges	700	3
Televisions (B&W)	280	23
Televisions (Color)		13
Clothes Dryers	993	4
Clothes Washers	103	0
Dish Washers	363	20
Water Heaters	5160	15
Room A/C	293	22
Central A/C	2187	17
Space Heaters	11560	0
Heating Auxiliaries	419	0
Lighting	700	(see text)

* Weighted over frost-free and standard units
† Source: References 17, 19, 31, 38, 39 and Text.
†† Source: Reference 34 and text. Efficiency Improvement defined as percent energy reduction in this study.

- Energy reductions for televisions are not assumed to be as large as the government targets; the forecasts assume 29% and 13% for black-and-white and color models, respectively, while the corresponding FEA levels are 52% and 28%. The improvements are due to a phase-out of tube-type models in favor of solid state models. Current usage levels are approximately (Reference 38):

	Black-and-white	Color
Tube	220 kwh/unit	528
Solid state	100	320

We have assumed the 1977 units at five-eighths of the 1972 to 1980 improvement which works out to 367 kwh/unit and 141 kwh/unit for the base year vintage of color and black-and-white types, respectively. The efficiency improvements are then computed to allow for ultimate switch-over to 100% solid state.

- The base year averages in Table 8.4 are averages over all housing types. For certain end-uses, consumption levels for single family and multifamily homes should be adjusted to capture the effects of variations in the size of the living space and the number of inhabitants. The averages were disaggregated over housing types based on the following typical SF to MF unit use relationships: 4 to 3 for refrigerators, freezers and water heaters, and 2 to 1 for central air conditioning and space heat.

8.1.4 Thermal Integrity Impacts

The building envelope characteristics of single family and multifamily dwelling units determine the final demand for three temperature sensitive end-uses: electric space heating, air-conditioning, and electrically driven auxiliaries associated with non-electric (e.g. oil and gas) heating. This final demand is to be distinguished from the electricity demand which of course would embody other efficiency factors associated with the conversion devices themselves (e.g. A/C COP, heat pump COP, etc.) and which are treated separately and additively by the model.

Prototypical savings levels for single and multifamily units (broken down by new and retrofit markets) are defined in Volume II, Sec. 3.2. The Base Scenario embodies thermal integrity improvements associated with "business-as-usual" trends. No retrofit of existing electrically heated homes is assumed. On the other hand, there is substantial potential for improvement due to retrofit of existing non-electrically heated homes to higher levels of thermal integrity. The Base Scenario assumes that a cumulative penetration of 25 percent of the retrofit market at the prototypical levels will occur over twenty years. Given the rapidly rising costs of home heating oil this is a modest assumption. The high case assumes 40 percent achieved by 1998 and the low case assumes 10 percent is achieved by 1998. The penetration of the retrofit market is assumed to grow linearly starting at zero in the base year.

The full discussion of the estimated existing thermal integrity levels and improvements appears in Volume II of this report, in which the Base Scenario and Conservation Scenario are compared. The improvements entail increased levels of insulation, weatherstripping, and storm windows and doors, the details of which are presented in Volume II along with associated reductions in heating and cooling loads for prototypical dwelling units to which the measures are applied. At this point we can summarize the Base Scenario average thermal integrity improvements which are expressed relative to the average existing energy loads.

Heating Auxiliaries

Electrically driven auxiliaries (fans, pumps, motors, blowers) associated with home heating systems are assumed to use electrical energy in rough proportion to the total heating demand. Thus improvements resulting in a 20 percent reduction in final demand met by an oil heating system would also result in a 20 percent reduction in electrical energy consumed by heating auxiliaries. The results of the Base Scenario estimates presented in Volume II are reproduced here,

HEATING AUXILIARIES
(TIMP)

	High		Low	
	Single Family	Multi Family	Single Family	Multi Family
Retrofit	.02	.02	.08	.08
New	.20	.20	.20	.20

where TIMP is the fraction reduction in final demand relative to existing usage. TIMP for new units is the improvement in all new units relative to the average existing units. TIMP for retrofit units is the average improvement in 1998 relative to the average existing units, assuming 10 percent and 40 percent cumulative penetration in the High and Low cases respectively. These are phased in linearly from zero over the twenty years. Thus, the Base Scenario entails average unit savings of 120 KWH and 60 KWH for all new single family and multifamily units relative to average existing usage. The Base Scenario assumes that no more than these levels are achieved, even in the low case, for new units. Given the rapidly rising costs of home heating this can be considered to be a conservative assumption.

Air-Conditioning

The Base Scenario assumes that savings calculated for the prototypical units described in Volume II of this report will apply on a fractional basis to all service-area specific air-conditioning loads. The levels of thermal integrity are applied with the same penetration assumptions as described for heating auxiliaries. The table below summarizes the results presented in Volume II.

HEATING AUXILIARIES
(TIMP)

	High		Low	
	Single Family	Multi Family	Single Family	Multi Family
Retrofit	0	0	.05	.05
New	.10	.15	.10	.15

Electric Space Heating

A detailed description of the average existing building shell characteristics and usage are described in Volume II of this report. Average annual requirements for electric space heating are in the neighborhood of 16000 KWH for single family units and 8300 KWH for multifamily units. The estimated 5 percent lower usage for new units would results in savings of about 800 KWH and 415 respectively for single family and multifamily units. The 5 percent figure is used in the high case while 10 percent improvements in new homes versus the base year mix of electrically heated homes is assumed in the low case.

8.1.5 Additional Data Requirements

The basic model structure utilizes base year and forecast counts of residential customers, saturations of the various end-uses and usage per unit to derive sectoral energy demand. However, there are a number of additional factors peculiar to each appliance type which influence usage and thus overall demand. The following provides a brief discussion of each of these factors, by end-use.

Refrigerators and Freezers

The refrigerator/freezer submodel (Sec. 3.3.1) requires input data on average annual usage for new units in the base year and for old units (defined as units which come on line one average appliance lifetime prior to the base year). This was necessary to account for the phenomenon of increasing unit usage over time which implies that retired units will, in the first part of the forecast period, require less energy than their replacement. Also, efficiency improvements need to be incorporated from new unit--not average--stock levels to avoid underestimating energy demand growth.

For refrigerators, we need an estimate of unit usage for the 1962 vintage. According to Ref. 36, the average size for 1962 was .38M^3 which, at 40×10^6 joules/dayM^3 for average frost-free refrigerator usage for that year, implies 1540 KWH/year for frost-free units. Frost-free sales in 1962 were 27% of the total. Removing the frost-free feature decreases energy consumption by about 29% (Ref. 40, p. 15). Combining we have for the 1962 vintage units:

$$\text{Refrigerator UNOLD} = 1540 \times .27 + 1540 \times .73 \times (1-.29) = 1215 \text{ KWH/unit/year}$$

Similarly, for the 1961 freezer vintage, based on data in Ref. 19, average size was about 14ft^3, usage was at .33 KWH/ft^3/day and .20 KWH/ft^3/day for frost-free and non-frost-free units, respectively, and about 30% of freezer sales were frost-free. Combining, we have:

$$\text{Freezer UNOLD} = 1220 \text{ KWH/unit/year}$$

Average unit usage for new units is based on shipment data. Mean capacities and annual energy requirements across size and models are (Reference 41):

	Mean Capacity (ft^3)	Energy Use (KWH/year)
Refrigerators	16.67	1510
Freezers	16.48	1300

Electric Range

The electric range submodel (Section 3.3.2) requires input date to simulate the effects of microwave oven penetration. There

are two issues: what fraction have microwaves and what is the effect of those that do on energy use? The latter is straightforward; field studies (Reference 42) indicate that electric ranges with microwave ovens require 84% of the electric energy which would otherwise be consumed. The energy demand factor ("EDF") in Table 3.3 is thus set at 0.84 in the forecasts. For PECO service territory, the Company analysis of microwave penetration in Reference 19 was in agreement with other utilities' projections and their data was incorporated into the forecast model.

Lighting

There are a number of reasons to suspect that lighting energy demands decrease: smaller family size, trend in housing mix toward smaller units, conservation induced by increasing prices, more efficient flourescent bulbs and new lighting technology. Furthermore, the new energy legislation allows the Secretary of Energy to develop efficiency standards for end-uses consuming more than 150 kwh per year per household, a criterion which includes lighting.

In the high case, we have made the cautious assumption that none of these demand decrementing factors significantly impacts lighting levels. In the low case, we have included the possibility of market penetration of screw-in fluorescent bulbs. These bulbs are 70% more efficient than incandescent bulbs. Cost-benefit analysis indicates that 22% of the residential market is currently capturable by the new bulb (Reference 46). In the low case, it is thus assumed that penetration levels reach 25% by the end of the forecast period. That is, in the low case, "MF" in Table 3.4 is phased linearly from zero in the base year to .25 in 1997 while "RELEFF" is phased linearly from 0 to .30 so that the overall effect phases quadratically to a 7.5% reduction after twenty years.

Televisions

The television submodel (Section 3.3.4) requires two additional items of data. The first is a use factor for redundant sets ("DUF" in Table 3.5). This refers to the ratio of energy consumption of second and third sets to the primary set. Estimates in the literature vary widely. The forecasts incorporate a typical range (Reference 44) of 80% in the high case and 25% in the low case. The second item is the mix between black-and-white and color of future television sales. The market fraction of black-and-white television sales historically was (Reference 45):

1967	1968	1969	1970	1971	1972	1973	1974	1975	1976
.51	.49	.47	.48	.44	.49	.43	.43	.43	.403

Based upon PECO data, Reference 19, the model runs use .55 for the base year fraction of black-and-white sets. Regression against time on the above data leads to a value of .20 in 1997. Consequently, the forecast spans this value by assuming the fraction black-and-white goes to 40% in the low case and phases to zero by 1997 in the high case.

Water Heater

In addition to the inputs already discussed, the electric water heater submodel (section 3.3.7) requires some additional data inputs. The first characterizes the change in home hot water requirements for end uses other than dishwashers and clothes washers. (These are discussed above.) This factor ("HWREOT" in Table 3.9) could reflect, for example, the effects of slow flow shower devices, which could save, according to manufacturers' estimates, about 75% of the thermal energy in hot water. Assuming a similar potential in other faucets, reductions in "other" hot water demand would be .75 times the ultimate market fraction. The latter is taken as zero in the high case and 8% in the low case after 1981.

The other inputs concern the range of likely impact of solar hot water devices. To gain an heuristic understanding of the possibilities, consider the following penetration analysis. First define payback (in years) by:

$$PB_t = C \times (1-TI) \times (1-D)^t / E \times F \times P \times (1+I)^t$$

where

PB = payback
C = first cost
TI = tax incentive
D = cost deflation
E = kilowatthour demand
F = fraction served by solar
P = electric price
I = electric price increase
t = year

Substituting a realistic range of values:

	C	TI	D	E	F	P	I
high	$2500	.2	.01	4000	.5	.05	.01
low	$1500	.3	.02	4000	.5	.05	.02

we have

	PB-1977	PB-1997
High	19 years	12.8
Low	10	4.5

Based on 30% penetration at payback of seven years (Reference 47) and zero penetration at twenty year payback, the above assumptions lead to:

	Penetration	
	1977	1997
high	0	.17
low	.18	.53

on average penetrations over the forecast period of about 8% and 35% for the two cases. To be cautious, the forecasts have been based on zero penetration of solar hot water in the high case and penetration phased linearly from zero in the base year to 20% in 1997 in the low case.

Electric Space Heat

There are three elements in the submodel (Section 3.3.9) that need to be specified relating to solar heating, heat pump penetration, and heat pump coefficients of performance. These will be discussed in turn.

- In estimating the penetration of solar assist technology, we first calculate a range of possible paybacks. The methodology is analogous to the computation of solar hot water paybacks described earlier. Here, we substitute first costs ranging from $6,000 to $8,000, real cost deflation at 3% in the low case after Reference 50 . These lead to penetration estimates defined here as the fraction of the additional electric space heat units that come on-line in 1997 with the solar assist feature at approximately 25% in the low demand case and 5% in the high demand case. In the forecasts, we have used more pessimistic assumptions to allow for possible institutional impediments and errors in the range of input parameters. These are:

High Case	Zero solar space heating in the forecast period
Low Case	Zero solar space heating to 1985. Penetrations increase linearly from zero to 25% and 5% in 1997 for single family and multifamily units, respectively.

- Heat pumps have been capturing an increasing fraction of the electric space heat market. The fundamental reason is that heat pump-assisted electric space heat appears to have superior economics to resistance heating. Some rough estimates of relative costs are contained in Table 8.5.

TABLE 8.5

RELATIVE ECONOMICS OF ALTERNATIVE HEATING AND COOLING SYSTEMS

	First Cost*	Capital+	Heating Fuel++	Total
Electric Resistance	$1300	$140	$550	$690
Natural Gas	2200	240	210	450
Electric Heat Pump	2950	320	275	595
Electric Resistance with A/C	3050	330	550	880
Gas with A/C	3950	430	210	640

* Northeast estimates for single family units in 1979 dollars (References 8, 24, 43)

\+ Assumed financed at 9 percent over twenty years

++ Fuel costs based on 5¢/KWH electricity, 11,000 KWH per household, gas boiler efficiency at 0.7, heat pump COP = 2, and comparable insulation levels in new homes

The figures indicate that gas heating is the most cost-effective option considering heating costs alone, though heat pump costs are also lower than resistance electric costs. However, if one compares heat pump carrying costs to resistance and gas with air-conditioning (since this is the equivalent commodity, remembering that heat pumps are year-round devices), it appears that heat pumps are competitive with gas heating and superior to resistance heating. Consequently, it is assumed that the rapid increase in saturation of electric heating is associated with increasing fractions of new electrically heated homes which use heat pumps. Table 8.6 below provides the assumptions of fractions of new homes with heat pumps, for the base year and for terminal saturations. These estimates tend to be based upon PECO-provided data and discussion, as well as the considerations outlined above. It is assumed that, in each case, growth in heat pump penetration will peak by 1990.

TABLE 8.6

HEAT PUMP FRACTION OF ESH PENETRATION IN PECO SERVICE TERRITORY

	Initial Fraction	Terminal Fraction	
		Low	High
Single family	.788	.788	1.00
Multifamily	.063	.50	1.00

The fraction of existing ESH customers with heat pumps is set, using Company provided information, at .55 and 0 for single and multifamily units, respectively.

- Heat pump coefficient of performance (COP) is defined as the ratio of kwh heating output to kwh electric input (for operating the compressor and fans). Data on unitary air-to-air heat pumps is taken from a recent evaluation performed at Argonne National Laboratory (Reference 51) for typical models. COP varies both with size and outdoor temperature. The model requires average and low temperature values in order to estimate average COP over the heating season in forecasting energy, and the lower COP operating at the lower temperatures of the winter peak. We have assumed capacities of approximately three tons and fifteen tons for the residential and commercial sectors, respectively.

  Performance data is summarized in terms of a "nominal" COP given at Air Conditioning and Refrigeration Institute's test standards* and an adjustment factor for outdoor temperature. The adjustment factor is parameterized as follows:

$$Y=A+B\cdot T+C\cdot T^2$$

  where

  A,B, and C are coefficients
  T is outdoor temperature in ^{o}F
  Y is perfentage of nominal COP at temperature T.

Table 8.7 summarizes the data.

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*47^{o}F. outdoor dry-bulb, 43^{o}F. outdoor wet-bulb and 70^{o}F. indoor dry-bulb temperature.

TABLE 8.7

HEAT PUMP PERFORMANCE DATA

	Nominal COP	Temperature Range (^{o}F)	A	B	C
Residential	2.4	$-10 \leq T \leq 20$	61.6	1.26	-0.0[illegible]
		$+20 \leq T \leq 70$	44.66	1.855	-0.0[illegible]
Commercial	2.7	$-10 \leq T \leq 20$	56.75	0.875	0.0[illegible]
		$+20 \leq T \leq 70$	65.32	0.531	0.0[illegible]

For the forecast region, an average and low temperature must be defined in order to estimate average COP and COP at peak. The method devised for computing regional temperature characteristics is summarized in Table 8.8.

TABLE 8.8
COP TEMPERATURE VARIATION CALCULATION

Indices

m	Month (m=1 to 12)
l	Locality
s	Sector (1≡residential; 2≡commercial)

Variables

A_s, B_s, C_s	Coefficients (see Table 8.5)
$STNDRD_s$	Nominal COP (see Table 8.5)
$TEMPL_{m,l}$	Mean monthly temperature, month "m", locality "l"
$TEMP_m$	Mean monthly temperature, month "m" in forecast area
$LOTEML_l$	Low temperature in locality "l"
LOTEMP	Low temperature in forecast area
POP_l	Population in locality "l"
DAY_m	Number of days in month "m"
HDD_m	Heating degree days in month "m"
$PCCOPM_{s,m}$	Percent of nominal COP in sector "s", month "m"
$PCCOPA_s$	Percent of nominal COP - average
$PCCOPL_s$	Percent of nominal COP - low
$COPA_s$	Average COP in sector "s"
$COPL_s$	Low COP in sector "s"

Equations

$$TEMP_m = \left(\sum_l TEMPL_{m,l} \times POP_l\right) / \left(\sum_l POP_l\right) \quad (8.1)$$

$$HDD_m = \begin{cases} (65 - TEMP_m) \times DAY_m & \text{for } TEMP_m \leq 65 \\ 0 & \text{for } TEMP_m > 65 \end{cases} \quad (8.2)$$

$$PCCOPM_{s,m} = A_s + B_s \cdot TEMP_m + C_s \cdot TEMP_m^2 \quad (8.3)$$

$$PCCOPA_s = \left(\sum_m HDD_m \times PCCOPM_{s,m}\right) / \sum_m HDD_{s,m} \quad (8.4)$$

$$LOTEMP = \left(\sum_l LOTEML_l \times POP_l\right) / \sum_l POP_l \quad (8.4)$$

$$PCCOPL_s = A_s + B_s \cdot LOTEMP + C_s \cdot LOTEMP^2 \quad (8.5)$$

$$COPA_s = PCCOPA_s \times STNDRD_s / 100 \quad (8.6)$$

$$COPL_s = PCCOPL_s \times STNDRD_s / 100 \quad (8.7)$$

For the PECO service area, five localities were used to compute the mean monthly temperature. This temperature was used in Equation 8.3 (which is a rewrite of the equation above in model code) to define percentage of nominal COP on a monthly, sectoral and service area basis. Mean monthly temperature data is taken from Reference 52. The coefficients are from Table 8.7. These monthly values are in turn weighted by monthly heating degree days (a measure of monthly usage) to arrive at the annual percentage of nominal COP (Equation 8.4). The heating degree days are computed by subtracting the average monthly temperatures (when they are less than 65°F) from 65°F and multiplying by the number of days in the month (Equation 8.2). The low temperature is construed as the average temperature on the day of the winter peak. Finally, average and low COP's are computed in Equations 8.6 and 8.7.

The results are as follows:

Heat Pump COP's

	Average	Low
Residential	2.248	1.763
Commercial	2.507	1.886

As with other appliances, efficiency improvements are anticipated for heat pumps. The forecasts assume improvements of 4% and 15% by 1987 for the high and low cases, respectively.

Miscellaneous Usage

There are a number of structural factors contributing to the moderation of the historic growth in miscellaneous appliance usage:

- decreasing population per household
- approach to market saturation
- increased efficiencies
- price-induced conservation
- substitutional effects (e.g., small kitchen appliances precluding use of others)

Consequently, the use per customer has been essentially constant--or slightly decreasing over the past five years in many utility service territories. The present forecast is nonetheless conservative, assuming for the high case a 100% increase in miscellaneous use per customer during the forecast period while assuming no increase in the low case.

8.1. Appliance Lifetimes

Actual appliance lifetimes have been used rather than the commonly-employed United States Department of Agriculture figures for average year of appliance possession by the first owner.

TABLE 8.9

APPLIANCE LIFETIMES IN YEARS

Appliance	Lifetime
Refrigerator	20
Freezer	24.9
Range	16.9
Lighting	NA
Television	14.7
Clothes Dryer	15.3
Clothes Washer	12.3
Dish Washer	13.5
Water Heater	10
Room A/C	11
Central A/C	11
Space Heat	NA
Heating Auxiliary	NA
Miscellaneous	NA

NA = not applicable
Source: Reference 53

8.2 Commercial Sector

The discussion below of commercial forecast input assumptions parallels the model description in Section 4.

8.2.1 1975 Floorspace

Initial estimates of the 1975 PECO service territory commercial floorspace is needed as input to the floorspace submodel which is summarized in Table 4.2. The computational methodology is explained in Section 4.2.1. The results are given below:

E S R G

TABLE 8.10

COMMERCIAL FLOORSPACE

Commercial Category	1975 Floorspace (10^6 ft^2)
1. F.I.R.E.	20.686
2. Federal Government	11.413
3. State, Local Government	31.043
4. Professional Services	9.028
5. Wholesale & Retail	151.880
6. Trucking, Warehousing	51.982
7. Other Transportation	15.454
8. Communications	3.745
9. Lodging, Personal Services	13.082
10. Business & Repair Services	29.866
11. Amusement, Recreation	30.868
12. Railroad	2.201
13. Health Services	58.009
14. Schools, Education	95.363

The total of 524.6 million square feet is compatible with the Company estimate for 1978 of 543 million square feet (Ref. 26).

8.2.2 Floorspace Growth Indices

As indicated in Section 4.2.2, employment growth is used as the proxy for floorspace growth for the first twelve commercial categories. The growth factors used in the forecast are summarized below in Table 8.11. The low case is based on OSPD's Pennsylvania forecasts of employees by commercial category (Reference 18). Additionally, we have

$$\text{employees} = (\text{employees/earnings}) \times \text{earnings}$$

Earnings projections for Pennsylvania were derived from BEA (Reference 7). Estimates of employees-to-earnings were developed by regressing on historic data on employees and earnings for the 1963-1976 period. It was found that for each of the commercial categories, using a 2% annual rate of increase (for consistency with residential high case economic assumptions) of employee earnings consistently gives higher forecasts than the historic trends. Consequently, it was judged that this rate of increase leads to a satisfactory upper bound on employment growth.

TABLE 8.11

EMPLOYMENT GROWTH INDICES

Commercial Category	Emp. 1985÷Emp. 1975		Emp. 2000÷Emp. 1975	
	High Case	Low Case	High Case	Low Case
1. F.I.R.E.	1.371	1.162	1.609	1.434
2. Fed. Government	1.092	1.008	1.085	.993
3. State&Local Gov.	1 518	1.154	1.986	1.350
4. Prof. Services	1.510	1.126	1.995	1.354
5. Retail	1.205	1.061	1.214	1.126
6. Truck & Ware.	1.403	1.154	1.561	1.376
7. Other Trans.	1.083	.895	.895	.725
8. Communications	1.463	1.080	1.951	1.242
9. Lodging&Pers.Ser.	.947	1.051	.736	.986
10. Bus.&Repair Ser.	1.652	1.282	2.067	1.785
11. Amuse.&Recrea.	1.063	1.097	1.022	1.227
12. Railroad	.828	.817	.572	.580

Hospital floorspace growth is equated with population growth forecasts discussed in the demographic subsection. School floorspace growth is equated with growth in school age population from Reference 18.

8.2.3 1975 Electric Intensities

Electric intensity estimates are required to initialize the commercial sector energy growth iteration as described in Section 4.3.1 and Table 4.4. PECO experienced 1975 commercial energy (Reference 19) and 1975 floorspace data were used to develop an overall energy intensity (KWH/Ft^2/YEAR). Then intensities appropriate to building type and end-use were developed by prorating Northeast electric use coefficients from Reference 8 (as quoted in Reference 6), with weather sensitive usage scaled, as appropriate, by heating and cooling degree days. Weighted values for the latter are 5018 and 1028, respectively, for PECO service territory counties from Reference 52. The resulting coefficients are shown in Table 8.12 for both the existing 1975 stock and prototypical new floorspace.

TABLE 8.12

COMMERCIAL ELECTRIC USE COEFFICIENTS (KWH/YEAR/FT^2)

Building Type	Existing				New			
	Htg.	Cooling	Lt&Power	Aux.	Htg.	Cooling	Lt&Power	Aux.
Office	5.6	5.6	4.8	3.6	8.0	3.9	4.8	3.0
Retail	2.6	6.3	12.4	4.4	4.0	4.3	12.4	4.0
Hospital	6.1	7.2	12.0	6.4	9.9	3.3	12.0	6.0
Schools	5.1	9.2	5.2	3.0	7.3	3.3	5.2	2.4
Other	2.9	6.3	6.8	4.4	4.4	2.4	6.8	4.0

Very little source data exists on commercial saturations. Electric space heat saturations appear to be similar to residential space heat saturation levels (Refs.19, 26, 31) and the base year values were assumed to be comparable in the forecast. Additionally, Reference 6 provides regional estimates of commercial heating and cooling saturations which are used here as a cross check.

8.2.4 Future Intensities

The methodology for incorporating future adjustments to electric intensities is described in Section 4.3.2. Penetration of the conservation levels has been computed in Reference 6 for the northeast based on cost optimization analysis of commercial investments in equipment and building shell modification; fuel cost annual average escalations of 1.3%, 2.1% and 3.8% for electricity, oil and natural gas, respectively, to 2000 and National Energy Act incentives. The penetration levels derived from this analysis are displayed below in Table 8.13 for the years 1985 and 2000. Consult Table 4.4 for definitions. Note that separate penetration matrices are developed for the electric space heat end-use. These are fractions of floorspace at these conservation levels; the remainder, when the sum is less than one, have no conservation above base year levels.

TABLE 8.13

CONSERVATION LEVEL PENETRATION FRACTIONS

		Electric Space Heat						Other End-Uses					
		Existing			New			Existing			New		
Year	Building Type	Level 1	2	3	1	2	3	1	2	3	1	2	3
1985	Office	1	--	--	--	1	--	1	---	---	--	1	---
	Retail	--	--	--	--	.92	.08	--	.99	--	.40	.60	--
	Hospitals	--	--	--	.90	.10	--	--	--	--	.41	.59	--
	Schools	--	--	--	1	--	--	.99	--	--	1	--	--
	Other	--	--	--	1	---	---	--	--	--	1	--	--
2000	Office	--	1	--	--	1	--	--	--	1	--	.89	.11
	Retail	--	1	--	--	--	1	--	1	--	--	--	1
	Hospitals	--	1	--	--	1	--	--	1	--	--	1	--
	Schools	1	--	--	.57	.43	--	.22	--	.78	.44	.56	--
	Other	--	--	--	1	--	--	.78	--	--	.90	.10	--

The relationship between the levels and load saved is given in Table 4.5. The fractional penetrations contained in Table 8.13 were used directly in the low case forecast since they depend on the assumption of investment according to economic optimization. For the high case, it was assumed that such an optimization does not occur and half the fractional penetrations of Table 8.13 were employed.

Growth in electric space heat saturation is based on a range of market penetrations for both the new building and retrofit markets. Specifically, electric space heat is assumed to capture 30% of the space heat markets in the low case and 50% for the high case. These same penetrations are used for the existing stock where the size of the ESH retrofit market is based on a thirty year lifetime for existing equipment. The saturation assumptions are summarized in Table 8.14.

TABLE 8.14

COMMERCIAL SECTOR ELECTRIC SPACE HEAT SATURATIONS

Case	Building Vintage	Year	
		Base	2000
High	Existing	4%	30%
	New	50%	50%
Low	Existing	4%	20%
	New	30%	30%

The use of heat pumps is expected to increase over the forecast period (see analogous discussion for residential sector). The Company, for example, assumes that 70% of new small commercial and industrial space heat customers will install heat pumps by 1988. The high and low forecasts incorporate such increases for the new commercial space heating customers. Specifically, heat pump usage as a fraction of new heating usage is phased linearly from zero in 1975 to 50% and 100% by 1985 for the high and low cases, respectively. Heat pump COP assumptions and analyses for the commercial sector will be found in Sec. 8.1.5.

Air Conditioning saturation of commercial floorspace for 1975 was taken at .66 based on the data for small commercial and industrial customers (Ref. 19, P. 237). This figure was cross-checked by matching calculated summer weather-sensitive commercial sector consumption to experienced seasonal sales. In the low case, it has been assumed that existing unit saturations will stay constant while saturation in new commercial structures will increase by from .66 to .80 due to HP penetrations. In the high case, both new and existing units are assumed to experience an increase, with 80% of existing units having cooling by the year 2000 and 100% of new commercial units having A/C by that year.

The use of heat pumps is expected to increase over the forecast period. The high and low cases assume, respectively, values phased linearly up to 50 percent and 100% heat pump of ESH usage by 1985 for new commercial floorspace. Heat pump COP assumptions and analyses for the commercial sector will be found in 8.1. (See, especially, Table 8.8).

8.3 Industrial Sector

The industrial sector model is described in Section 5. Data requirements are of three kinds: base year experience, production growth, and electric intensity. These are discussed below sequentially.

8.3.1 Base Year Experience

Total base year industrial sales was 8085.1 Gwh (10^6 KWH) with the fractional breakdown by two-digit SIC given below (Refs. 19 and 26).

TABLE 8.15

INDUSTRIAL SALES MIX

SIC	Fraction of Sales
20	.081
22	.015
23	.007
24	.002
25	.001
26	.069
27	.024
28	.127
29	.148
30	.054
31	.001
32	.022
33	.213
34	.040
35	.045
36	.053
37	.041
38	.013
Misc.	.044

8.3.2 Production Growth

The model requires growth estimates of "State Production Indices" as indicated in Table 5.3, Equation 5.4. The mechanism for weighting National Production Indices to the State level is described in Table 5.2. That methodology, with National Production Index forecasts from Reference 14 and earnings projections from Reference 7, is used to establish production growths. These growth assumptions are summarized in Table 8.16 which gives production levels relative to the base year (base year = 1) for two selected years.

TABLE 8.16

STATE INDUSTRIAL GROWTH BY STANDARD INDUSTRIAL CLASSIFICATION

SIC	SPI 1985 / SPI 1977	SPI 2000 / SPI 1977
20	.96	1.58
22	1.01	1.02
23	1.13	1.27
24	1.14	1.25
25	1.28	1.60
26	1.32	1.60
27	1.26	1.64
28	1.39	1.99
29	1.12	1.05
30	1.59	2.36
31	1.03	.95
32	1.13	1.22
33	1.36	1.62
34	1.24	1.52
35	1.31	1.67
36	1.40	1.83
37	1.32	1.66
38	1.50	1.94
39 (+ mining)	1.57	1.95

8.3.3 Electric Energy Intensity

Industrial electric intensity is defined as the average consumption of electricity per unit of physical output by two-digit manufacturing SIC. Changes in electrical intensity are incorporated in the energy forecast. (See Table 5.3, Equation 5.4.)

We begin by investigating the historic trend in the electrical intensities for the State of Pennsylvania. Linear regression is used to develop time trends for the 1963-1976 period. The computation is summarized in Table 8.17. The historic production index is derived from national production index data (Reference 13) and state-to-national earnings ratios (Reference 7) as discussed in Section 5.3 (Equation 8.8). The intensities are then formed as the ratio of total electrical energy consumption (purchased and self-generated) from Reference 12, and state production indices for each historic year and SIC (Equation 8.9).

The time axis is then shifted so that the resultant intercept is automatically based on the base year = 1 (Equation 8.10). This assures consistency with the convention adopted in the model, thus allowing for direct input of the regression analysis results into the main program. The number of historic years is allowed to vary (Equation 8.11). Finally, after defining some intermediate summations, the slopes and intercepts are computed.

TABLE 8.17
ELECTRICAL INTENSITY REGRESSION ANALYSIS

Indices

BY	Base year
j	Industrial grouping by two-digit SIC (j=1 to 19)
r	labels historic year (r=1 to N)

Variables

$YR1_r$	Historic year (calendar)
YR_r	Historic year (scale shifted to BY=1)
START	First historic year used in regression
END	Last historic year used in regression
N	Number of historic years in regression
$SPIH_{r,j}$	State Production Index for historic year "r", SIC "j"
$NPIH_{r,j}$	National Production Index for historic year "r", SIC "j"
$SNER_{r,j}$	State-to-national earnings ratio for year "r", SIC "j", in %
$SEI_{r,j}$	Electric intensity in year "r", SIC "j"
BI_j	Intercept, SIC "j"
$SLOPEI_j$	Slope, SIC "j"
$SPROSH_{r,j}$	State process energy in year "r", SIC "j"

Equations

$$SPIH_{r,j} = NPIH_{r,j} \times SNER_{r,j} / 100 \quad (8.8)$$

$$SEI_{r,j} = SPROSH_{r,j} / SPIH_{r,j} \quad (8.9)$$

$$YR_r = YR1_r - BY + 1 \quad (8.10)$$

$$N = END - START + 1 \quad (8.11)$$

$$SLOPEI_j = \left(N \times \sum_{r=1}^{N} YR_r \cdot SEIH_{r,j} - \left[\sum_{r=1}^{N} YR_r\right] \times \sum_{r=1}^{N} SEI_{r,j}\right) / \left(N \times \sum_{r=1}^{N} YR_r^2 - \left[\sum_{r=1}^{N} YR_r\right]^2\right) \quad (8.12)$$

$$BI_j = \left(\sum_{r=1}^{N} SEI_{r,j} - SLOPEI_j \times \sum_{r=1}^{N} YR_r\right) / N \quad (8.13)$$

$$SEI_j = BI_j + SLOPEI_j \times (t-1) \quad (8.14)$$

In addition to the state-specific trends in electric energy intensity, we have also investigated the trend on a national basis. These two trends formed the basis for estimating the time behavior of electric energy intensity. Specifically, the forecasts reflect the choice which maximizes or minimizes growth for the high and low forecasts, respectively. The specific choice, given in the terminology of Table 8.17, is given below in Table 8.18.

TABLE 8.18

STATE ENERGY INTENSITY INDEX

SIC	High Case	Low Case
20	1.2	0.9
22	1.3	0.9
23	1.4	0.9
24	1.9	0.9
25	1.2	0.9
26	1.0	0.9
27	1.3	0.9
28	0.7	0.8
29	1.0	0.9
30	0.8	0.9
31	1.6	0.9
32	1.0	1.0
33	1.2	1.0
34	1.2	0.9
35	1.0	0.9
36	1.0	0.8
37	1.1	1.1
38	1.7	0.9
39	0.6	0.9

8.3.4 Fraction Self-Generated

Recent studies have indicated that a sharp increase in industrial cogeneration is likely with or without government interaction. The primary reason is the escalating costs of electricity. To estimate the range of likely effects, we assume, in the high case, that base year levels (References 19, 26) do not change. For the low case, we assume historic state levels (Reference 12) re-achieved by 1985, or the lowest level 1985 potential for the Northeast given in Ref. 27 for SICs 26, 28, and 29 (steam turbines, no government action) achieved by the year 2000 or the potential cogeneration levels found by the Pennsylvania Electric Association and

provided in Reference 26, whichever is higher. The input data assumptions for fraction self-generated (SGEN in Table 5.3) are shown in Table 8.19.

TABLE 8.19

FRACTION SELF-GENERATED BY TWO-DIGIT SIC

SIC	BASE YEAR	1985 HIGH CASE	1985 LOW CASE
20	.071	.071	.099
22	0	0	.021
23	0	0	.004
24	.343	.343	.343
25	0	0	.019
26	.201	.201	.466
28	.047	.047	.223
29	.303	.303	.54
30	0	0	.063
31	0	0	.171
32	0	0	.101
33	.131	.131	.266
34	0	0	.002
35	0	0	.005
36	0	0	.081
37	.154	.154	.154
38	0	0	.007
39	0	0	.004

8.4 Other Energy Requirements

Sales to customers other than those in the three major service sectors are discussed in Section 6. Base year energy sales to the "other" category for PECO are 1182 Gigawatthours (References 19, 26). This represents about 4% of total company sales. PECO forecasts of other energy sales (Reference 19) are accepted in the ESRG model. The other required input datum is line losses and the own-use of electric utility company. This enters the program as a fraction of total sales. (See Table 6.1 and discussion.) This is derived as 6% from output and sales data contained in Reference 28.

8.5 Peak Power

The peak power computations are summarized in Section 7. Careful scrutiny of Table 7.1 will reveal that this part of the model is driven by outputs from the other submodels with the exception of two kinds of data: (1) characterization of base year peak and (2) forecasts of load management impact. These will be discussed in turn.

There are three items of load data required for the state: winter peak, summer peak and "base peak". In the base year 1977, the winter peak of 4519 MW was given by PECO (Reference 26) and the corrected summer peak of 5580 MW was drawn from Reference 19.

The base peak is defined in Section 7 as the non-weather sensitive portion of the peak. PECO gives this figure as 3763 MW for 1977 (Reference 19). This figure closely cross-checked the ESRG analysis of the relationship between monthly peaks (Reference 26) and mean temperature on the peak day (Reference 30) as follows:

$$Peak_m = Base\ Peak + A \times (65 - T_m)$$

where

m = month (exclusive of summer months, June-September)
Peak = peak load
T_m = mean temperature
Base Peak, A = regression coefficients

The base peak, consistent with its definition, is defined by the absence of heating degree days on the monthly peak day. A fit was obtained resulting in a base peak value of 3757 megawatts.

The final data requirements concern the possible impact of load management in the forecast period. In particular, the possibility of some load shifting is included as indicated in Table 7.1. Section 7 provides a discussion of the underlying load management mechanisms modelled to shift peak demand. In the residential sector, time-of-use rates are expected to influence the patterns of time-flexible appliances. In the commercial sector, thermal storage is anticipated to influence time-of-use. Residential storage, commercial use shift, and industrial load management have not been assumed to have any impact during the forecast period, possibly a conservative input in terms of peak shaving. Forecast assumptions are summarized in Table 8.20 below.

TABLE 8.20

LOAD MANAGEMENT

Case	Year Impact Begins	Impact Year 1990				
		Ind.	Res. Use Shift*	Res. Thermal Storage	Comm. Use Shift**	Comm. Thermal Storage
High	2000+	0	0%	0	0	2%
Low	1983	0	25%	0	10%	5%

* FOPRB in Table 7.1
** FOPCWS in Table 7.1

Finally, in driving peak demand and establishing base and weather-sensitive load factors, controlled water heaters must be removed as indicated in Sec. 7. The fraction of electric water heaters which are controlled in the base year is given in Ref. 19 as .60. This is assumed to decrease to .47 by 1990 consistent with Company assumptions of no additons in the number of controlled heaters. Unit usage of controlled heaters is taken at 2/3 the unit usage from uncontrolled heaters based on Company load analysis. Should the number of controlled water heaters not remain constant, peak forecasts would, of course, be adjusted downward.

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JOHN K. STUTZ

Research Scientist
Secretary of the Corporation
Energy Systems Research Group

DOCUMENT FOLDER

Education

Ph.D.: Mathematics, Princeton University, 1969.
B.S.: Mathematics, State University of New York at Stony Brook, 1965.

Experience

1977 - Present: Energy Systems Research Group, Inc. Responsibility for mathematical modelling for a range of energy studies, especially electrical demand forecasting and input-output analysis of the labor impacts of energy alternatives; research on cost of electric service and rate design issues; analysis of energy price impacts on consumers.

1976 - 1977: Associate Professor, Mathematics Department, Fordham University. Co-director of the joint B.S. program in economics and mathematics.

1971 - 1976: Assistant Professor to Associate Professor, State University of New York at Albany, Mathematics Department, then Allen Center.

1969 - 1971: Instructor, Mathematics Department, Massachusetts Institute of Technology.

ESRG Research

Forthcoming: Testimony, Pennsylvania Public Utility Commission (Duquesne Light Co.). Long-range forecast of electric energy and demand.

Forthcoming: Testimony, Pennsylvania P.U.C. (Pennsylvania Power Co. and CAPCO). Long-range demand forecast.

Forthcoming: Testimony, Docket R-79060865, Pennsylvania P.U.C. (Philadelphia Electric Co.) Long-range demand forecast (base case and conservation policy case).

Forthcoming: Long Range Forecast of Ohio Electric Demand, ESRG Study No. 79-24. Principal Investigator.

Forthcoming: Testimony, Case 20055, Massachusetts Department of Public Utilities (New Bedford Gas and Edison Light Co.). Electricity conservation strategies and alternative generation options; critique of and adjustments to long-range electric demand forecast.

Forthcoming: Testimony, Case 1232, Rhode Island Public Utility Commission (Blackstone Valley Electric Co.). Critique of cost of service study and analysis of alternative rate designs.

October 1979: Testimony, Case U-6217, Michigan Public Service Commission (Detroit Edison Co.). Forecast critique.

September 1979: Energy and Jobs: Analyzing the Economic Impacts of State Policies to Promote Energy Conservation, ESRG Study No. 79-01. Development of input-output model and application to a region in Massachusetts. Principal Investigator.

September 1979: Testimony, The New York State Energy Master Planning and Long Range Electric and Gas System Proceeding. Long-range electric demand and the employment implications of energy conservation.

July 1979: Base Case Forecast and Employment Impacts of the Conservation Policy Case Alternative, volumes I and III of ESRG Study No. 79-12, Electricity Requirements in New York State. Principal Investigator for Volume III.

June 1979: Long-Range Forecast of Electric Energy and Demand in the Service Territory of the Duquesne Light Company, ESRG Study No. 79-17. Principal Investigator.

May 1979: Testimony, Case 19494, Massachusetts DPU (Boston Edison Co.). Growth in electric demand.

May 1979: Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model, ESRG Study No. 79-06, A Report to the New England Conference of Public Utility Commissioners. Co-author.

May 1979: Testimony, Case U-6006, Michigan P.S.C. (Detroit Edison Co.). Forecast critique.

March 1979: Testimony, Cases 27461 and 27462, New York Public Service Commission (Central Hudson Gas and Electric Co.). Critique of revenue and demand forecasts.

February 1979: Analyzing the Impacts of Energy Prices on New England Residents, ESRG Study No. 79-01. Principal Investigator.

December 1978: Energy Demand Study: Power Authority of the State of New York, ESRG Study No. 78-15. Principal Investigator.

December 1978: Economic Impact of an Electricity Rate Increase in New York City, ESRG Study No. 78-14. Principal Investigator.

December 1978: Gas Production from Nuclear Power Plant Waste Heat: An Economic Analysis, ESRG Study No. 78-12. Co-author.

October 1978: Testimony, Docket 780701, Connecticut Public Utilities Control Authority (United Illuminating Co.). Forecast critique and long-range demand forecast.

October 1978: The Employment Creation Potential of Energy Conservation and Solar Technologies: The Implications of the Long Island Jobs Study for New England, 1978-1993. Principal investigator.

September 1978: Long Range Forecast of Electric Energy and Demand in New York State, ESRG Study No. 78-07. Co-author.

September 1978: Testimony, Case 27319, N.Y. Public Service Commission (Power Pool Long Range Plan). Forecast critique and demand forecast.

May 1978: A Methodology for Estimating Total Economic and Employment Impacts of Energy Related Construction, ESRG Study No. 78-03. Principal Investigator.

March 1978: Testimony, Docket 438, Pennsylvania Public Utility Commission (Philadelphia Electric Co.). Forecast critique and demand forecast.

September 1977: Testimony, Dockets 770319 and 770320, Connecticut Public Utilities Control Authority (Northeast Utility System). Forecast critique, conservaation options; comparative costs of generation alternatives.

April 1977: Assessing Demand, Alternative Generating Strategies, and Utility Economics in the Service Territory of Orange and Rockland Utilities, ESRG Study No. 77-01. Co-author.

April 1977: Testimony, Cases 27094 and 27095, N.Y. Public Service Commission (Orange and Rockland Utilities).

Other Publications

April 1979: Production of Synthetic Gas from Nuclear Energy Sources, Los Alamos Scientific Laboratory Report LA-7592-MS. Co-author.

February 1979: "Energy Policy and Employment," People Energy Primer, Syracuse Peace Council.

1976: "Equisingularity and Local Analytic Geometry," Proceedings of the American Mathematical Society, Summer Institute on Several Complex Variables.

April 1976: "Residual Equisingularity," with Joseph Becker. Proceedings of the American Mathematical Society, vol. 56.

1974: "Primitive Elements for Modules over O(Y)," Duke Mathematics Journal, vol. 4.

1973: "The C^1 Embedding Dimension of Certain Analytic Sets," with J. Becker. Duke Mathematics Journal, vol. 40.

1973: "Resolving Singularities via Local Quadratic Transformations," with J. Becker. Proceedings of the Conference on Singularities, Rice University Studies, vol. 59.

1973: "Wings in Analytic Sets," Indiana University Mathematics Journal, vol. 22.

1972: "Equisingularity and Equisaturation in Codimension I," American Journal of Mathematics, vol. 94.

1972: "Analytic Sets as Branched Coverings," Transactions of the American Mathematical Society, vol. 166.

1970: "The Representation Problem for Differential Operators on Analytic Sets," Math. Ann., vol. 189.

Selected Papers and Professional Activities

1979 - present: Consultant to National Consumer Law Center. Electric utility load research methodology.

1978 - 1979 Consultant to Council on Economic Priorities. Energy and employment.

1979: "Assessing Local Employment Impacts of Conservation and Solar-Related Activities," Conference sponsored by the International Solar Energy Society, Georgia Office of Energy Resources, and Solar Energy Research Institute.

October 1978: Panelist on electric utility rate structures and load forecasting, national meeting of the Critical Mass Energy Project.

August 1978: Participant, Boston workshop on electricity supply and demand planning sponsored by the National Governors' Association, National Association of Regulatory Utility Commissioners, and Department of Energy.

Fall 1977: "The Role of Public Agencies in Utility Load Forecasting Proceedings," Lawyers' Guild meeting, Hartford.

November 1977: "Utility Electrical Demand Projections," Northeastern Political Science Association meeting, Mt. Pocono, Pennsylvania.

Summer 1975: Invited speaker, American Mathematical Society's Summer Institute on Analytic Functions of Several Complex Variables.

1973: Invited Participant, Rice University Conference on Singularities of Analytic Sets.

1972 - Present: Referee, Proceedings of the American Mathematical Society and Duke Mathematics Journal.

1969 - 1975: Reviewer for Mathematical Reviews and Zentralblat für Mathematik.

Awards and Honors

State University of New York Faculty Fellowship, Summer 1972 and Summer 1973.

National Science Foundation Cooperative Fellowship, 1965 - 1967.

Professional Societies

American Mathematics Society.

Exhibit ___ (JS-2)
Schedule A

DIFFERENCES IN RESIDENTIAL PER CUSTOMER CONSUMPTION
(KWH/YEAR IN 1987)

		PECO	ESRG	Difference
1.	Refrigerators	2068	1861	207
	Freezers	452	389	63
	Subtotal	2520	2250	270
2.	Electric Space	909	689	220
	Heating Auxiliaries	363	387	-24
	Subtotal	1272	1076	196
3.	Miscellaneous	1016	433	583
4.	Other Major Appliances*	3295	3263	32
	Total	8103	7022	1081

*Includes Ranges, Lighting, TV, Clothes Washers, Dishwashers, Clothes Dryers, Water Heaters, and Room and Central A/C.

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COMPARISON OF ENERGY USE IN COOKING APPLIANCES

Food item	Appliance	kWh	Min.	Temp°F	Comments
4 baked potatoes	Large oven	2.3	60	400	No preheat
	Microwave oven	0.3	16		
	Toaster oven	0.5	75	425	
Chicken (cut up)	Large oven	2.0	65	350	
	Microwave oven	0.55	25		
	Fry pan	0.5	60	300-350	Two chickens were used
	Crock pot	0.7	6.5hr.	lo & hi	in crockpot experiment
Meat loaf	Large oven	2.0	60	350	
	Microwave oven	0.22	10		
	Toaster oven	0.35	60	350	
Brownies(9X13"pan) 23 X 33cm	Large oven	1.6	30	350	Microwave quality not as good as conv. oven
	Microwave oven	0.22	10		
Corn bread	Large oven	1.5	20	350	
	Microwave oven	0.15	7		Not browned well in MW
Frozen peas(petite)	Stove top	0.16	6	hi	Brought water to boil & turned off burner. Peas continued to cook.
	Microwave	0.11	5		
Beef stew	Large oven	2.7	5 hrs.	275	
	Crock pot	1.15	12hrs.	lo	Beef is browned first in fry pan method.
	Electric fry pan	0.7	4 hrs.	300	
Toast (2 slices French bread)	Pop up toaster	0.035			
	Toaster oven	0.060			
Toast (2 slices regular bread)	Pop up toaster	0.025			It takes over 17 pieces of toast in broiler to toast more efficiently than 2 slice toaster.
	Large oven broiler	0.2			
Water (2 cups cold start)	Stove(lid off)	0.176	7	hi	
	Stove(lid on)	0.151	6	hi	
	Microwave	0.121	5.5		

ENERGY USED IN COOKING A COMPLETE MEAL THREE DIFFERENT WAYS

Meal	Cooked together in a large oven	Cooked separately in microwave oven	Cooked in separate oven, stove top & toaster oven
5 pound ham(canned)	2.5 kWh	0.55 kWh	2.5 kWh (lg.oven)
8 oz. frozen petite peas		0.11 kWh	0.16kWh (stove top)
4 medium yams		0.35 kWh	0.5 kWh (toaster ov.)
9 X 9" (23 X 23cm) pine-apple upside down cake		0.22 kWh	2.0 kWh (lg.oven earlier)
	2.5 kWh	1.23 kWh	5.16 kWh

Source: N. Smith. "Energy Management and Appliance Efficiency in Residences" in Proceedings of the International Conference on Energy Use Management, October, 1977.

COMPUTATION OF COMMERCIAL FLOOR SPACE GROWTH USING WHARTON ASSOCIATES PHILADELPHIA SMSA EMPLOYMENT GROWTHS

CATEGORY	1975 SQ. FT. ($\times 10^6$)	RATIO	1985 SQ. FT ($\times 10^6$)
1. Finance, Insurance, Real Estate (FIRE)	20.686	1.179	24.39
2. Federal Government	11.413	1.101	12.57
3. State and Local Government	31.043	1.101	34.18
4. Professional Service	9.028	1.451	13.10
5. Retail and Wholesale	151.880	1.225 (1)	186.05
6. Trucking and Warehouse	51.982	.907	47.15
7. Other Transportation	15.455	.907	14.02
8. Communication	3.745	.907	3.40
9. Lodging and Personal Service	13.082	1.451	18.98
10. Business and Repair Service	29.866	1.451	43.34
11. Amusement & Recreation Service	30.868	1.451	44.79
12. Railroad	2.201	.907	2.00
13. Schools	58.009	1.020 (2)	59.17
14. Hospitals	95.363	.814 (3)	77.63
	524.62		580.77

(1) Average of wholesale and retail

(2) based upon utility population growth

(3) based upon school age population growth

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PHILADELPHIA ELECTRIC COMPANY SYSTEM FORECAST

VOLUME LL:

THE STATE CONSERVATION POLICY CASE

Paul D. Raskin
John K. Stutz

November, 1979

ENERGY SYSTEMS RESEARCH GROUP, INC.
Boston, Massachusetts 02109

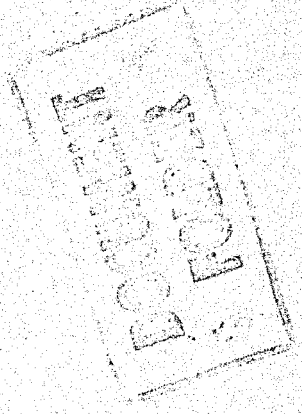
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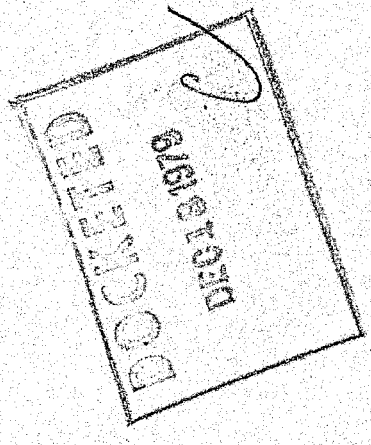
PHILADELPHIA ELECTRIC COMPANY SYSTEM FORECAST

VOLUME II:

THE STATE CONSERVATION POLICY CASE



Paul D. Raskin
John K. Stutz



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E S R G

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1. INTRODUCTION AND RESULTS

1.1 Background

Volume I presented a long range Base Case forecast of electric energy and peak demand for the service area of the Philadelphia Electric Company (PECO). The Base Case, by definition, models growth in electricity consumption under the assumption of no major change in the current energy policy framework in the state of Pennsylvania. The Conservation Policy Case developed in this volume is based on a different assumption. The Conservation Case assumes the development of a state-level policy commitment to energy conservation during the 1980's entailing an integrated set of conservation-motivated energy management policies, regulations, and activities.

The Conservation Policy Case is a scenario that attempts to address the consequences for PECO energy and demand growth should Pennsylvania opt to actively induce substantially higher levels of conservation practice. Growth is, in part, shaped by government's policy stance. Continuation of conventional governmental policy, generally assumed in demand forecasting, has very different electric system planning implications than does conservation policy activism.

The Base and Conservation scenarios are not offered as "hard" predictions of precise future levels of energy consumption. Rather, they are quantitative estimates intended to highlight the differential outcome of two choices for Pennsylvania's electric energy future differing only by the degree of State conservation policy.

Clear analytic definition of the two scenarios--Base and Conservation Policy--allows insight into their comparative advantages. Such key issues as differences in power plant construction requirements, relative economic impacts, environmental repercussions, and employment tradeoffs may then be discussed. Thus, the relative effects provide useful information for the evaluation of the two energy development alternatives independent of the reliability of the absolute forecast levels taken separately.

This volume is devoted to specifying and motivating a plausible conservation policy package for Pennsylvania,

quantifying the effects of the various policy elements included in the analysis, reporting the forecast results based on the selected policy scenario and contrasting these results to Base Case electric growth. The Conservation Policy Case forecast is an attempt to provide a realistic and quantifiable interventionist policy strategy, showing how a deliberate leap toward energy management could render invalid both the Base Case forecast of Vol. I and PECO's own in-house forecast (Reference 21).

There are two caveats to the Conservation Policy analysis as presented here which should be stressed. First, the focus is on the demand side of electric energy consumption. Though the results have important implications both for other fuel sources and for electric generation planning, we shall not address these issues here. Second, while the policy array adopted for the purpose of investigation is intended to be realistic and defensible, there is no claim that it is either exhaustive or precise in every detail. Indeed, there are a number of additional conservation policy options worthy of consideration by planners should the conservation route be embarked upon. Further, provision of the regulatory specifics, is appropriately the task of the energy policy bodies of the State. The policy package that has been adopted should thus be viewed as heuristic. It points to a realizable alternative, constrained only by the twin criteria of technical feasibility and social cost optimality--not current institutional resistance.

1.2 Selected Results

Results of the Conservation Policy Case are presented in aggregate and disaggregate form, respectively, in Tables 1.1 and 1.2. For contrast, Conservation and Base Case results are shown together in Table 1.3. It should be stressed that the conservation measures focus on cost-effective energy conservation. Load management programs--load limiting devices, time-of-use rates, interruptible rates, and the like--have not been included beyond the Base Case levels in this analysis. Consequently, Conservation Case peak load decrements reflect only the flow through of the overall increases in end-use efficiency assumed in the Base/Conservation transition.

TABLE 1.1
CONSERVATION CASE
PECO SECTORAL ENERGY AND PEAK DEMAND FORECAST

CONSERVATION SCENARIO							
PECO	ENERGY IN GWH					PEAK POWER LOAD IN MW	
	RESIDENT.	SUMMER.	INDUSTR.	OTHER	TOTAL	SUMMER	WINTER
1977	8438.	8852.	8085.	2775.	28150.	5580.	4519.
1978	8850.	8910.	8300.	2820.	28880.	5650.	4550.
1979	8630.	8950.	8500.	2870.	29160.	5740.	4760.
1980	8980.	9000.	8700.	2910.	29600.	5800.	4850.
1981	9110.	9040.	8800.	2960.	30010.	5880.	4850.
1982	9080.	9070.	9080.	2980.	30230.	5880.	5020.
1983	8980.	9080.	8950.	3000.	30010.	5840.	4980.
1984	8850.	9100.	8780.	3000.	29740.	5780.	4940.
1985	8810.	8860.	8560.	2980.	29240.	5660.	4880.
1986	8770.	8580.	8330.	2980.	28660.	5520.	4800.
1987	8730.	8300.	8070.	2950.	28070.	5380.	4720.
1988	8680.	8030.	8050.	3050.	27820.	5300.	4690.
1989	8680.	7780.	8020.	3130.	27560.	5210.	4660.
1990	8520.	7840.	7980.	3220.	27570.	5220.	4680.
1991	8510.	7820.	7950.	3330.	27710.	5220.	4680.
1992	8430.	8000.	7800.	3430.	27790.	5220.	4680.
1993	8340.	8080.	7860.	3520.	27810.	5220.	4680.
1994	8250.	8160.	7810.	3630.	27850.	5210.	4680.
1995	8150.	8240.	7750.	3730.	27850.	5210.	4680.
1996	8070.	8320.	7700.	3830.	27920.	5200.	4670.
1997	7980.	8400.	7630.	3930.	27940.	5200.	4670.
1998	7900.	8480.	7570.	4030.	27980.	5190.	4670.
1999	7830.	8560.	7500.	4130.	28020.	5190.	4660.
2000	7770.	8640.	7430.	4230.	28060.	5190.	4660.

TABLE 1.2
CONSERVATION CASE
PECO DISAGGREGATED ENERGY FORECAST (GWH)

CONSERVATION SCENARIO

PECO

	1977	1982	1987	1992	1997
1: REFRIGERATORS	2555.	2303.	2438.	2205.	1910.
2: FREEZERS	446.	507.	514.	498.	468.
3: RANGES	342.	374.	396.	409.	412.
4: LIGHTING	646.	599.	468.	484.	487.
5: TELEVISIONS	513.	516.	528.	547.	557.
6: CLOTHES DRYERS	448.	535.	607.	660.	690.
7: CLOTHES WASHERS	108.	113.	118.	123.	125.
8: DISH WASHERS	164.	194.	217.	238.	254.
9: WATER HEATERS	888.	822.	854.	807.	786.
10: ROOM A/C	348.	326.	235.	173.	128.
11: CENTRAL A/C	430.	555.	515.	454.	372.
12: SPACE HEATERS	520.	734.	777.	909.	818.
13: HEATINGAUXILIARY	544.	544.	452.	365.	262.
14: MISCELLANEOUS	508.	559.	614.	664.	700.

CONSERVATION SCENARIO

PECO

	1977	1982	1987	1992	1997
1: OFFICES					
1: HEATING	38.	75.	77.	78.	81.
2: COOLING	272.	285.	257.	241.	253.
3: LT & POWER	351.	359.	312.	293.	315.
4: AUXILIARIES	284.	272.	248.	234.	248.
2: RETAIL					
1: HEATING	32.	61.	59.	58.	57.
2: COOLING	628.	611.	582.	588.	601.
3: LT & POWER	1858.	1793.	1714.	1684.	1710.
4: AUXILIARIES	648.	583.	507.	485.	477.
3: HOSPITALS					
1: HEATING	24.	44.	42.	41.	43.
2: COOLING	276.	277.	234.	207.	210.
3: LT & POWER	689.	705.	645.	610.	618.
4: AUXILIARIES	372.	374.	315.	280.	285.
4: SCHOOLS					
1: HEATING	27.	41.	33.	31.	34.
2: COOLING	274.	236.	153.	114.	119.
3: LT & POWER	466.	401.	282.	256.	274.
4: AUXILIARIES	264.	213.	144.	120.	128.
5: OTHER					
1: HEATING	38.	76.	75.	75.	78.
2: COOLING	622.	646.	579.	536.	551.
3: LT & POWER	1041.	1288.	1378.	1481.	1693.
4: AUXILIARIES	670.	723.	648.	589.	627.

CONSERVATION SCENARIO

PECO

	1977	1982	1987	1992	1997
20: FOOD	658.	649.	609.	723.	834.
22: TEXTILES	120.	125.	117.	121.	125.
23: APPAREL	60.	68.	69.	75.	82.
24: LUMBER	15.	19.	16.	15.	13.
25: FURNITURE	11.	13.	13.	14.	15.
26: PAPER PRODUCTS	555.	582.	436.	356.	263.
27: PRINTING & PUBL.	195.	237.	250.	283.	319.
28: CHEMICALS	1024.	1080.	818.	825.	886.
29: PETROLEUM & COAL	1186.	1142.	646.	309.	-29.
33: PRIMARY METALS	1728.	2105.	1952.	1980.	1989.
34: FABRICAT. METALS	324.	380.	367.	422.	456.
35: MACHINERY	361.	423.	423.	451.	478.
36: ELECTRIC EQUIP.	428.	505.	484.	516.	533.
37: TRANSPORTATION	328.	409.	401.	423.	440.
30: RUBBER & PLASTIC	435.	551.	561.	595.	620.
31: LEATHER	4.	4.	4.	4.	5.
32: STONE,CLAY,GLASS	176.	185.	168.	171.	172.
38: INSTRUMENTS	102.	148.	175.	210.	247.
39: MISC. MANUFACT.	358.	438.	421.	398.	370.

TABLE 1.3
COMPARATIVE BASE/CONSERVATION CASE PECO FORECAST

YEAR	Energy (GWH)								Peakload (MW)			
	Residential		Commercial		Industrial		Other		Summer		Winter	
	Base	Cons	Base	Cons	Base	Cons	Base	Cons	Base	Cons	Base	Cons
1980	9030	8990	9000	9000	8700	8700	2920	2910	5820	5800	4870	4860
1985	9730	8810	9190	8860	9620	8580	3130	2990	6120	5660	5350	4880
1990	10270	8620	9420	7840	10210	7980	3560	3230	6400	5220	5770	4680
1995	10240	8160	9660	8240	10770	7750	4120	3730	6590	5210	6000	4680
2000	10210	7770	9900	8640	11310	7430	4690	4230	6760	5190	6210	4660

2. CONSERVATION POLICY OVERVIEW

2.1 The Scenario

The "scenario" can be a very useful device in energy analysis. If chosen judiciously, it presents a possible energy future for our consideration and deliberation. Usually, the scenario that is selected for forecasting purposes posits a future scene which does not differ radically from the present. In particular, smooth extrapolation of current behaviors and practices is often assumed. Such a "Base Case" scenario underlies the analysis of Volume I of this report and PECO's long range forecast (Reference 21). Quantitative disagreements between these two forecasts are traceable to the methodology of simulation rather than to major differences in technical, economic, or institutional assumptions.

The Conservation Policy scenario, on the other hand, is an attempt to present a possible alternative scene differing from that of the Base Case by one significant change in the script. Here, it is assumed that the State is mandated to develop and implement an integrated set of conservation policies. This mandate is assumed to be unprecedented within the State and pace-setting at the national level. The constraints are only these: compared to the alternative scenario of increased electricity production and power plant construction, the conservation policy measures should require no increase in out-of-pocket social costs, no environmental degradation, no overall employment deterioration, and no detrimental "externalities" (health and safety effects, capital availability impacts, etc.).*

It is not the purpose of this analysis to assign a probability to the realization of a Conservation Policy Scenario. The function of the scenario lies elsewhere: to present alternative pictures of the future for assessing the relative desirability of sets of actions. Should the Conservation Policy Scenario be viewed as the more socially attractive option, its role is to help focus attention toward its implementation. Energy forecasts are outputs of computer models, the accuracy of which is limited by the likelihood of the scenario upon which they are based and the accuracy by which they mathematically simulate the scenario features. Real world scenario choice involves, on the other hand, to some degree the output of policy decisions which emerge through the political process. The role of scenario analysis is to provide the political process with information on the feasibility and relative impacts of alternative policy directions and thereby to aid in effective social planning.

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*These constraints are put negatively in order to cast the policy net widely. Most of the conservation measures have quite positive impacts relative to the base scenario.

2.2 The Social Cost Criterion

The method proposed here for assessment of the economic attractiveness of conservation measures is relative social cost. Direct expenditures by society for energy conservation steps are compared with expenditures for the additional electric energy displaced by those steps to see which course is economically more attractive. Our use of a social cost criterion should not be taken to imply that the analytic scope of conventional economic theory, which we employ for our cost comparisons, is in itself sufficient to determine the relative merits of alternative social choices. First, cost/benefit tradeoffs for the social whole may impact differentially on consumer and investor subgroups or on geographic subregions. Second, social concerns which may validly influence policy directions--health and safety risks, environmental "externalities," aesthetics, equity considerations--can be treated with little or no precision through mathematical economics. Ultimately, the choice between alternative energy scenarios is not an output of narrow cost/benefit competitions, but distills through a complex political process to which economic analysis is but one of several important inputs. Nevertheless, the economic tradeoffs of different energy development strategies remain a significant dimension for policy consideration. The quantitative evaluation of relative economics may provide, if not a precise roadmap for optimizing social costs, information and guidance in the selection of competing models for energy development.

Full social cost/benefit analysis would include cost tradeoffs not directly reflected in price signals, such as environmental and health impacts, long-term repercussions on depletable resource usage and employment impacts. No non-controversial methodology exists for quantification of such factors. Therefore, we shall restrict the notion of social cost here to total direct expenditures by society for the alternative energy strategies. However, the conservation measures generally have more benign "external" impacts than the energy growth alternative, so that the narrow direct social cost/benefit assessments should be seen as merely suggestive of lower bounds on conservation measure cost attractiveness.

In assessing the relative social costs of the two scenarios under consideration (Base and Conservation Policy), the direct economic tradeoffs are conceptually straightforward. The cost associated with saving energy relative to Base Case levels is charged to the Conservation Policy Case, while the cost of producing the equivalent amount of energy is charged to the Base Case. In the parlance of cost/benefit analysis, one evaluates the net benefits of the Conservation Policy Case by computing the difference between the streams of costs and

savings, brought back to common dollars (present value) by a social discount rate. Specifically, we have the expression:

$$PVIC = \sum_i \sum_t \frac{\left(I_t^i - C_t^i\right)}{(1+d)^t}$$

where:

PVIC = present value of incremental benefits minus costs of achieving conservation scenario;

I_t = incremental costs of "saved" energy;

C_t = incremental costs of implementing conservation resources;

i = conservation measure;

t = year;

d = social discount rate reflecting time value of money.

This gives the relative savings of the conservation scenario over the non-conservation scenario. The word "incremental" signifies the extra costs and savings in making the transition to the conservation case. Costs incurred in both cases "wash," cancelling out in taking the differences in the stream of costs.

What we are typically doing in performing this kind of analysis is comparing the cost of delivering an extra kilowatt-hour of electricity with the cost of saving a kilowatt-hour of electricity. To see this, let

P_t = price per KWH of electricity

ΔKWH = KWHs saved annually by a given conservation measure.

Then, assuming an investment C_0 is made in year "0" in a conservation measure, we have

$$PVIC = \sum_{t=0}^{T_L} \frac{P_t \times \Delta KWH}{(1+d)^t} - C_0$$

where the limits on the first sum run over the lifetime of the measure T_L. Finally, we may simplify these relationships by assuming that escalation in the marginal electricity rate is roughly at the level of the discount rate, d. Proceeding, we arrive at:

$$PVIC/(\Delta KWH \times T_L) = P_0 - C_0/(\Delta KWH \times T_L)$$

where it is seen that the relevant measure of the benefits of investing C_0 dollars in conservation equipment (or policy initiatives) lasting T_L years and saving ΔKWH kilowatt-hours of electricity annually is the difference between the cost per KWH of adding an additional KWH, P_0, versus the costs per KWH of saving a KWH.

An illustration may be useful. Suppose we are looking at the costs and benefits of adopting appliance efficiency standards beyond those promulgated by the Federal Government for the year 1982. Typically, the incremental costs of producing a refrigerator 25 percent more efficient will be about $50. Assuming further a lifetime of 20 years and base case annual refrigerator consumption of electricity at 1500 KWH/unit, we have for the cost of saving electricity:

$$C_0/(T_L \times \Delta KWH) \approx 0.6¢/KWH$$

or less than a penny per KWH. On the other hand, the cost of delivering the extra energy depends on the specifics of the utility generation mix. If capacity is below reliability levels, the cost of construction of new generation and transmission facilities as well as added fuel costs must be charged to the incremental demand. If overcapacity exists in the system, the extra fuel costs of otherwise idle capacity constitute the incremental cost. Assuming the latter, a realistic assumption for PECO, in the years of our example, and ignoring additional customer and demand charges for the moment, the incremental cost for generating a KWH of electricity from, say, an oil-fired unit with a heat rate of 13,000/KWH and fuel costs of $3.00 per million BTU would be:

$$P_0 \approx 4¢/KWH$$

For this example, the cost of saving the KWH, 0.6¢, is far less than the cost of delivering it, 4¢.

The measures incorporated in the conservation scenario are all cost beneficial in the above sense, often decreasing social costs dramatically as in the above example. To reiterate, however, these economic estimates are but one dimension in weighing the alternatives. In addition to reducing costs, the conservation policy scenario tends to have other important benefits: fuel savings, pollution reduction, and employment increases.

2.3 Policy Framework

The measures constituting the state conservation policy package will be described qualitatively in this section. Quantification of conservation measure impacts is the subject

matter of Sections 3 through 5 of this report.

The selections are not intended to exhaust the universe of technologically available and social cost reducing state energy policy interventions. Rather, the policy package is intended to represent a suggestive, implementable, and realizable approach for managing energy demand growth over the next two decades. In formulating the scenario, policy options have been discarded which involve technologies of problematic economies in the forecast timeframe (e.g., industrial solar applications and photovoltaics), which are not clearly social cost beneficial (e.g., various load management approaches and extreme equipment and building shell efficiency standards), or are of minor overall importance (railroad and subway conservation potential, street lighting improvements, etc.). Exclusion of items from the conservation policy package is not intended to imply, necessarily, a negative assessment of their potential. Rather, the policies selected for this initial investigation of conservation policy potential in Pennsylvania have been limited to those which are currently most demonstrably promising.

Furthermore, it should be understood that the policy choices under consideration are modelled to occur at the state level. Federal policy initiatives are to be considered as the background for both the Base Case (Vol. I) and Conservation Policy Case forecast scenarios. Indeed, the only difference between the two scenarios is in the insertion, in the latter, of state-level policy measures. In other words, the question we are asking is: what would be the direct impact on electric energy requirements of state development and implementation of the Conservation Policy measures? Once this question is answered, the desirability of such an increase in state policy efforts can be assessed in terms of its relative effects on energy demands, environmental quality, the state economy, employment, and so on.

The conservation policy actions included in this scenario are listed in Table 2.1. All listed actions go beyond Base Case conservation levels. Thus, where "building envelope standards" are listed, we refer to building shell standards more stringent than those embodied in existing state or federal laws and regulations. Existing regulations and programs are already included in the scenario definition for the Base Case. The "policy package" embodied in Table 2.1 would affect almost all uses of electricity in Pennsylvania.

To model the Conservation Policy Case, a "shadow" model was added to the end-use simulation and forecast model described in Volume I. When the Conservation Case is operative,

the Base Case computations are interrupted and the incremental effects of each of the conservation measures are computed. The disaggregated ESRG end-use model thus proves an ideal vehicle for assessing the effect of specific conservation policies. For each measure, the year of initiation and the quantitative impact on building characteristics, energy-use practices, and equipment characteristics must be specified. The following sections of this volume describe and quantify the effects of scenario conservation policy elements in the residential, commercial, and industrial sectors respectively.

TABLE 2.1
CONSERVATION POLICY AREAS

Sector	Measure
Residential	Appliance Efficiency Regulation Mandated Lighting Efficiency Improvement Building Envelope Standards Plumbing Fixture Efficiency Electric Space Heat Restrictions Passive Solar Energy Requirements in New Construction
Commercial	Building Envelope Standards Passive Solar Energy Requirements in New Construction HVA/C System Equipment Efficiency Regulations HVA/C Operations Requirements Internal Load Requirements (lighting levels and ventilation rates) Electric Space Heat Regulation
Industrial	Cogeneration Regulation and Incentives (utility ownership mandate, back-up rate review, etc.) Industrial Conservation Program (services, audits, outreach) Building Standards

3. CONSERVATION POLICY ELEMENTS: RESIDENTIAL SECTOR

3.1 Equipment Efficiency

An important component of the residential part of the conservation scenario is a set of measures to improve the efficiency of operation of home appliances. In most cases, a set of appliance efficiency standards are specified and the savings that would result from the legislation of such standards is quantified. In other cases, specific standards are not proposed, but policy options for achieving technically feasible efficiency improvement targets are indicated and the level of energy savings computed.

For each appliance efficiency improvement incorporated, conservative criteria of technical feasibility have been used. The improvement must meet one or more of these criteria:

- The improvement is already embodied in appliances on the market.
- The improvement has been demonstrated in tests for the U.S. Department of Energy.
- The improvement is under active commercial development for near-term marketing.

Consequently, additional savings beyond those quantified in the conservation scenario may well be attainable through additional residential sector appliance efficiency improvement. Furthermore, adoption of policies to implement improvements now technically and economically feasible should encourage additional technical progress in residential appliances.

The concept of mandatory minimum efficiencies for appliances sold in a given jurisdiction has a precedent in both federal and state legislation. The first federal program was a voluntary one. This was the "energy conservation program for appliances," or "targets program," developed by the old Federal Energy Administration (FEA) pursuant to the Energy Policy and Conservation Act of 1976 (Ref. 1). The FEA analysis of "energy efficiency improvement targets" and associated energy savings is utilized in the base case residential forecast (Vol. I).

The FEA "targets program" demonstrated the technical and economic feasibility of improvements in appliance energy efficiency. This program is now essentially defunct, having been superceded by the National Energy Conservation Policy Act of 1978 (NECPA). Under NECPA the DOE will develop manda-

tory standards for a number of appliances (Ref. 2). NECPA permits states to retain appliance efficiency standards if they have them or to implement them subject to DOE approval if they do not. At this time, only California has a comprehensive state program of energy efficiency standards for appliances (Ref. 3).

The standards we propose here are technically more stringent than California's, which were developed a few years ago. However, they all satisfy the social cost-benefit criterion discussed in Section 2, i.e., the additional costs per KWH of electrical energy saved must be lower than the cost per KWH that would otherwise be provided by the utility. Most of the California standards are implemented in two steps, an intermediate and a final standard. We propose this format for Pennsylvania, with implementation of intermediate standards in 1982 and final standards in 1984. Policies are proposed for the following appliances:

- Refrigerators and refrigerator-freezers
- Freezers
- Electric ranges
- Electric water heaters
- Room air-conditioners
- Central air-conditioners
- Heat Pumps
- Lighting
- Plumbing fixtures

This section discusses each appliance in turn. Applicable policies or policy options are discussed. The energy savings realizable through policy implementation are quantified. Technical justification is presented. The average costs per unit for adoption of technical changes to attain the indicated efficiency levels are estimated. The cost tradeoffs of "purchasing" energy savings through more efficient appliances are analyzed. All dollar figures are constant (1979) unless otherwise indicated.

Refrigerator-Freezers

We propose a minimum efficiency standard for new refrigerator-freezers of all types. The standard is designed for auto-

matic-defrost refrigerators, but would also apply to the minority of refrigerators sold that do not fall into that category. The standard, energy savings, and costs are as follows:

TABLE 3.1
REFRIGERATOR STANDARD

	Year of Initiation	
	1982	1984
Standard (KWH/year)	400+(36×volume)*	400+(24×volume)
Energy Savings Increment (%)	12	19
Unit Cost Increment ($)	20	24

* In ft^3

For a 16 cubic foot refrigerator-freezer, the 1982 standard translates to a maximum energy consumption of 976 KWH per year or (assuming constant, 365 day operation) 2.7 KWH per day. The energy savings of 12 percent for the 1982 standards are calculated with respect to the FEA targets. The 19 percent savings is then relative to the reduced energy consumption level attained through the 1982 standards. Percentage savings is defined in the same way for the other standards discussed below. The conservation forecast computer runs use the minimum standards developed in this Section as average standards. Should some new appliances exceed the minimal levels, the conservation impacts would be correspondingly more stringent. In this report, we have, in the interest of forecast caution, assumed this not to be the case.

The 1980 FEA target efficiency is already attained by specific appliances on the market, such as the Amana ESFR-16 ft^3 refrigerator-freezer, which consumes 3 KWH/day (Ref. 4). DOE's Division of Buildings and Community Systems has a program to develop and commercialize new energy-saving technologies (Ref. 5). The program, in conjunction with Amana and Arthur D. Little, has developed a prototype 16 ft^3 refrigerator-freezer that consumes 2 KWH/day or less and is cost-effective (Ref. 6). The prototype thus consumes somewhat less than our 1984 standard requires (2.15 KWH/day for a 16 ft^3 model).

The costs of the energy savings that can be achieved through refrigerator improvement are low. FEA gave an average of $44 per unit as the average additional cost of units embodying the change from the 1972 (FEA base year) to 1980 efficiency improvements (entailing a shift in the energy factor from 3.8 to 5.28 cubic feet per KWH per day). Hoskins and Hirst, in developing a model for energy and cost analysis of a refrig-

erator (Ref. 7), estimated $92 per unit to take a 16 ft^3 unit from 4.6 KWH/day (somewhat "worse" than the FEA 1972 base) to 2.2 KWH/day. Examination of Hoskins and Hirst's detailed component costing suggests taking the difference of $44 as the cost of the FEA 1980-ESRG 1984 improvement, broken down as indicated in Table 3.1.

Refrigeration is the single most energy-consuming household electricity application (Volume I). Implementation of this standard will thus be an important conservation step. For refrigerators, standards presume the retention of the popular and energy-expensive automatic defrosting feature. Energy savings from the 1980 FEA target to 1984 ESRG are 29 percent. For a 16 ft^3 unit with a lifetime of 20 years, the cost per KWH (according to the social cost-benefit estimating procedure of Sec. 2) achieved through the purchase of equipment embodying the 1982 standard is about seven mills, or considerably less than the 1979 residential cost of electricity of about 6¢/KWH (Ref. 9). The cost per KWH of achieving the 1984 standard (relative to 1982) is about six mills for a 16 ft^3 unit. The economic attractiveness of the improvements may vary with unit size, but their overall economic advantage is clear.

Freezers

Efficiency standards are proposed for freezers of all types. The standard is designed for chest freezers. The minority of freezers sold that do not fall into that category would in effect need to be improved more than chest freezers. The standard, energy savings, and cost are as follows:

TABLE 3.2
FREEZER STANDARD

	Year of Initiation	
	1982	1984
Standard (KWH/year)	425+(36×volume)*	425+(24×volume)
Energy Savings Increment (%)	3	19
Unit Cost Increment ($)	5	35

* In ft^3

From a technical standpoint, the FEA 1980 per-unit energy consumption implied by the 1972-1980 EEI (energy efficiency improvement) is already attained by certain models on the market. ESRG's 1982 standard is attained by certain

models, such as Franklin's Signature models FFT-8948 and 8949, manually defrosted 20.8 ft^3 chest freezers (Ref. 10).

Freezers have not been studied in as much detail as refrigerator-freezers, although many of the technical and economic factors for freezers are treated in the relevant portions of refrigerator studies. FEA estimated $38 per unit for a smaller EEI than for refrigerators.

Overall energy savings from 1980 FEA to 1984 ESRG are 21 percent for freezers compared to 29 percent for refrigerators. Estimated dollar costs for further improvements are based on FEA figures and technical similarities between freezers and refrigerators. The cost per saved KWH in achieving the 1982 standards for a 15 ft^3 unit with a 24.9 year lifetime was less than eight mills, or under 15 percent of the average price of electricity (at 6¢/KWH). The incremental unit cost of achieving the 1984 standards is also under eight mills per KWH. If the cost of achieving the 1984 standard for a 15 ft^3 unit were ten times its estimated $40, the standards would still have positive social cost tradeoffs.

Electric Ranges

The FEA adopted only 40 percent of the potential per-unit energy savings found cost-effective by Science Applications, Inc. (SAI). SAI developed an analytical model and tested several units (Ref. 11). Of six feasible and cost-effective measures identified by SAI, FEA adopted but two. Electric range standards are proposed which will, in effect, compel incorporation of the other four measures.

The standard could be an overall performance standard, as with the previous two appliances, or it could consist of component requirements. "Range" is a mix of standard, self-cleaning oven, and microwave oven categories. Estimated energy savings from achieving some of the FEA-omitted steps by 1982 and the balance by 1984 are as follows:

TABLE 3.3
ELECTRIC RANGE STANDARD

	Year of Initiation	
	1982	1984
Energy Savings Increment (%)	2	2
Unit Cost Increment ($)	negligible	negligible

In its studies for the FEA, SAI found that feasible changes for ranges without self-cleaning ovens would result in negligible increases and that the improvements in ranges with self-cleaning ovens would reduce cost units. Thus the overall cost is "negligible" and may even be negative. Improving the efficiency of ranges in the feasible ways produces only economic benefits.

Electric Water Heaters

The electricity consumed by electric water heaters is a function both of the efficiency of the system and of the amount of hot water it must heat. In the conservation scenario two changes influence electricity consumption:

- Increased efficiency of conventional hot water heaters
- Decreased hot water usage.

The first of these changes is described here. Mandatory standards are proposed for electric hot water heaters. Such standards could be formulated in terms of standby loss, as they are in California and New York. However, for purposes of this analysis, the standards indicate specific steps, as follows:

TABLE 3.4
ELECTRIC WATER HEATER STANDARD

	Year of Initiation	
	1982	1984
Standard	Reduce factory setting on thermostat to 130°F	Insulate jacket with 4 inches of foam and distribution pipe with 1 inch of fiberglass
Energy Savings Increment (%)	5	2
Unit Cost Increment ($)	0	33

New York and California have legislated on hot water efficiency standards entailing a maximum electric heater jacket loss of 4 watt-hours per square foot of tank surface area per hour. California's staff analysis estimates an energy savings of 16 percent under the standard (Ref. 16), which is virtually the same as the FEA's 15 percent.

The FEA target for water heaters, however, does not include a reduced thermostat setting. In their energy and cost analysis of hot water heaters, Hoskins and Hirst found that a 10 degree reduction in temperature yielded a 5 percent energy savings (Ref. 12). Since the FEA test temperature for hot water heaters is 145°F while Hoskins and Hirst's is 140° it is reasonable to simply apply the whole energy savings estimate here. There is no cost for this measure.

FEA did include increased insulation in its efficiency improvement target. For the 1984 level, a change in jacket insulation from 4 inches of fiberglass to 4 inches of polyurethane foam and an increase in pipe insulation to one inch of fiberglass are included. From the social cost point of view, the price of saving a KWH through these measures is about 4¢, or substantially less than the cost of delivering the energy in the absence of the measure.

The heat pump water heater is an example of a promising development beyond changes used in the conservation scenario. It has been developed with DOE support. Due to high first cost and the need for an interior winter heat source it has not been introduced here as part of the conservation scenario, but could be considered at some point in the future.

Room Air-Conditioners

Mandatory minimum efficiency standards are proposed for both room and central air-conditioners. The former follow:

TABLE 3.5
ROOM AIR-CONDITIONER STANDARDS

	Year of Initiation	
	1982	1984
Standard (E.E.R.)	10	12
Energy Savings Increment (%)	21	17
Unit Cost Increment ($)	62	60

The standards are expressed in terms of the overall energy efficiency ratio (E.E.R.), which is defined as the unit's cooling capacity (BTU/hour) divided by its power requirements (watts). The standards are for 115 volt room air-conditioners, the kind typical of State residences. Units with an EER of 11.6 are on the market now (Ref. 22). The current state-of-the-art limit has been estimated at an EER of 13.5 (Ref.23). Production-weighted FEA per-unit costs associated with target

EEI were $54, or $31 per unit EER. This embodied a change from the 1972 average EER of 6.2 to the 1980 FEA target EER of 7.94. Inspection of advertisements for units currently available at retail suggests as little as $20 per incremental EER with wide EER variations for units with the same cooling capacity. The use of $30 per unit EER appears to be a conservative choice.

Based on an air-conditioner using an average 300 KWH/year, a reasonable estimate for Pennsylvania (Ref. 21), implementation of the 1982 standard would incrementally reduce electricity consumption by about 60 KWH. With an appliance lifetime of 11 years, the social cost would be about 9 cents per saved kilowatt-hour. Implementation of the 1984 standard would further reduce unit consumption by about 35 KWH per year at a social cost of roughly 15 cents per saved KWH. The incremental cost for delivering the extra KWH which the air-conditioner standards would save is actually considerably higher than the average cost due to their summer demand characteristics. Peak power consumption incurs higher costs due to additional capacity requirements and the need to run low efficiency "peakers" to meet load. The proper comparison would require an analysis of the incremental future costs of adding demand at PECO's summer peak. This is beyond the scope of the current investigation. However, as an indication, Con Ed in its recent rate request before the New York State Public Service Commission, suggests 21.4¢/KWH for summer peak charges. It appears, provisionally, that the air-conditioner standard adequately meets the social cost criterion.

Central Air-Conditioners

The standards proposed are as follows:

TABLE 3.6
CENTRAL AIR-CONDITIONING STANDARD

	Year of Initiation	
	1982	1984
Standard (EER)	8.7	9.5
Energy Savings (%)	8	8
Unit Cost Increment ($)	70	130

An EER of 8.0 was targeted by the FEA for 1980 and is incorporated in the California standards effective November, 1979. Unitary air-conditioner efficiencies currently range up to an EER of 11 (Ref. 23). The FEA calculation of the production-weighted improvement cost for moving from an EER of 6.5 (1975 base) to 8.0 was $84, or $56 per EER (1979 dollars). Discussions with manufacturers suggest that the incremental cost of going from the FEA target to an EER of 9.0 is about $100 per unit EER. Further increases are likely to be more costly. SAI found that "the evidence seems to indicate that it is more difficult and more expensive to increase the EER of high capacity products" (Ref. 32). Thus, while a modest incremental cost per EER appears to hold for room air-conditioners up to our proposed 1984 standard, increases in central air-conditioner EERs much above 9 would be increasingly costly. Our final standard is therefore only a bit above the intermediate standard. Based on SAI estimates we use $130 as the cost of the second stage improvement.

The cost of saving electricity through the 1984 standards, assuming a nominal usage of 2000 KWH/year, is about 6¢/KWH. Again, from the social cost point of view, since the proper comparison is with incremental peak load costs, the standard is attractive.

Heat Pump

In the past, competitive pressures in heat pump marketing have led to decreases in initial costs, but at the expense of lower efficiencies. The current energy price-induced interest in conservation has led to a reversal of this trend with manufacturers now introducing units at significantly higher efficiencies (Ref. 24).

Over the past several years, high efficiency heat pumps with improved compressor efficiencies, larger heat exchanges, lower balance point, and new defrost control, have become available which increase COPs by 15 to 25 percent over conventional systems (Ref. 25). Rated COPs are available at over 3.0 (Ref. 26), compared to the nominal value of 2.4 used in the non-conservation case of Volume I. Table 3.7 gives

the standard suggested for minimal heat pump COP levels:

TABLE 3.7
ELECTRIC HEAT PUMP STANDARD

	Year of Initiation
	1982
Efficiency Improvement (%)	25
Unit Cost Increment ($)	400

Source: Ref. 25

The unit cost increment is the cost beyond a conventional heat pump with a COP of 2.4 at the standard testing conditions. The measure results in an incremental electric space heat energy savings of approximately 1200 KWH per unit. Assuming a ten year lifetime, the social cost is estimated at about 3¢ per saved KWH. This adequately satisfies the criterion of being cost-competitive with the no policy alternative of producing the extra electricity where average costs are about 6¢ per KWH (though the rate RH heating customers currently face 3¢/KWH during the winter months).

Lighting

Lighting is treated somewhat differently from the other appliances in the Conservation Scenario. Due to the rapid turnover in electric lamps, especially in the incandescent market, energy efficiency improvements can rapidly begin to substantially reduce electricity demanded for lighting.

More energy-efficient lamps, especially incandescents or those intended to replace incandescents, tend to cost from three to ten times as much as conventional bulbs. They are, and/or are expected to be, cost-effective over their lifetimes with respect to replaced bulbs. Thus an efficiency standard for electric lamps--in the form of minimum lumens per watt at different size levels--are likely to be cost-justifiable. However, mandatory efficient bulb purchase may be burdensome on low-income groups unless connected with measures to subsidize first cost. We shall assume rather that other measures are developed to promote efficiency in lighting. A vigorous promotion of low-energy electric lamps, by state programs and/or through mandated utility information dissemination, will produce rapid penetration of new low-energy lamps.

Energy savings are targeted to be at levels consistent with the more efficient bulb being developed by the Duro-

Test Corporation under contract with the Massachusetts Institute of Technology (Ref. 13). This bulb is being developed now for marketing within a year (Ref. 14). It will replace a conventional 100 watt bulb and consume approximately 50 percent of the energy (i.e., it will be rated at 40 to 60 watts). The net incremental cost of the bulb (over the three shorter-lifetime conventional bulbs it would replace) is anticipated to be $2.00. The cost of saving the electrical energy comes out to less than 2¢ per KWH over bulb lifetime. The Conservation Scenario assumes a vigorous promotion campaign beginning in 1982 and building toward a target of a fifty percent reduction with respect to base year levels due to efficient bulb penetration. It should be stressed that the target is reasonable since a promotion policy would also tend to stimulate interest in higher-priced but longer-lifed and even more highly energy conserving lamps, such as the General Electric "Electronic Halarc" or "Circlite" lamps (Ref. 15).

Plumbing Fixtures

Plumbing fixture standards for new fixtures are assumed implemented in the Conservation Scenario. They apply to faucets and showerheads. The standards implemented are those now in effect in California.

According to the California Energy Commission (Ref. 16), substantial hot water demand reductions will be achieved. Forty-four percent of hot water for showers will be saved and twenty-nine percent of faucet hot water. Daily use will be reduced from 26.8 to 17.1 gallons per day, or thirty-six percent overall.

Cost increments are minimal, at about $2.50 more per fixture. CEC estimated the present worth of life energy savings (in 1976 dollars with electricity costs well under Pennsylvania 1976 price levels) at $120 for showerheads and $42 for faucets with electric water heaters. They were also found to be cost beneficial for gas hot water heaters. From the perspective of social cost tradeoffs, the energy is saved at well under 1¢/KWH, far less than the cost of producing the equivalent amount of energy.

The model uses resultant hot water savings to reduce electricity for heating hot water. Approximately ten percent of plumbing fixtures are replaced each year. Standards are assumed to be effective in 1981 with new fixtures phased in over the subsequent ten years.

Other Appliances

Due to insufficient analysis being available to date, Conservation Policy level standards for the remaining appliances

(clothes washer, clothes dryer, dishwasher, TV) are not included in this study. Socially cost-effective options may exist, but it is premature to identify them. The status of these additional appliance operational efficiency potentials should be reviewed periodically, especially as the DOE appliance efficiency program unfolds.

3.2 Building Envelope Quality

The thermal integrity characteristics of existing residential buildings and the potential for improvements of these characteristics provide the basis for state policies which would result in reductions in annual electric energy requirements and, most especially, peak demands relative to what would otherwise be experienced over the time horizon of the long range forecast. Of course, as with the other conservation measures, improvements deriving from new state conservation policies must be distinguished from those associated with existing codes and trends. Building shell characteristics affect the electrical energy requirements for three major temperature sensitive end-uses: electric space heating, air-conditioning, and electrically driven auxiliaries associated with non-electric (e.g. oil, gas) home heating. In order to estimate the policy impacts on the electrical energy usage for these three end-uses, average heating and cooling loads of prototypical existing and new structures (both single family and multifamily) are estimated with and without the policy related improvements in building shell characteristics. Furthermore, the average cost per KWH (or BTU) saved by implementing the new policy standards for building shell improvements is estimated and compared with the cost of satisfying the same demand in the absence of the improvements through the supply of electricity (or fuel). The social cost criterion for establishing the acceptability of the policies, namely, that the average cost of saving a KWH (or BTU) be lower than the average cost of otherwise supplying it, was found to be satisfied in all cases.

The principal ways in which new state energy conservation policy can effect improvements in the average thermal integrity, and therefore energy loads, of residential dwelling units over the long term can be divided twofold. The existing standards can be strengthened or replaced with new standards. These standards would apply to all new residential dwelling units, and the difference in KWH electricity savings between the existing and new standards can be attributed, for each end-use to the conservation policy scenario. In the conservation policy scenario the new codes are assumed to be in effect in 1982 and beyond. Thus until 1982 the conservation scenario and the Base ("business as usual") Scenario will be

identical with respect to the thermal integrity characteristic of new residential buildings. Both will embody the same average improvements in the heating and cooling energy loads for single family and multifamily dwellings relative to the existing average loads. After 1982 the conservation policy related energy savings will be greater.

In order that the state conservation policy affect improvements in the average thermal integrity of the existing stock through retrofit, this policy must establish targets which, through expanded efforts of state agencies, can be expected to be achieved by some target year, through, e.g., codes governing the resale process. In the conservation policy scenario it is assumed that through these efforts, by 1998 on the average one half of existing units achieve savings associated with the thermal integrity improvements possible through the retrofit of the prototypical existing units. This contrasts with the Base Scenario in which both the average improvements and the implementation of these improvements are lower than in the Conservation Scenario. In the Base Scenario it is assumed that by 1998 twenty-five percent of the full savings possible if all existing units retrofit to ASHRAE-90 equivalent levels will be achieved as a result of a continuation of existing efforts and trends. The efforts associated with the conservation policy for residential dwelling unit retrofit are assumed to begin in 1982. Thus, until 1982 both the Base and Conservation Scenarios will entail the same level of building shell related reductions in average unit heating and cooling usage. These levels are assumed to be linearly phased in to the full target levels in 1998. After 1982 the linear phase-in for the Conservation Scenario diverges from the Base Scenario in order to reach the higher 1998 target level of improvement.

In order to establish the levels of energy use reductions associated with the Base and Conservation Scenarios among existing and new units, for each end-use, it is necessary to describe the characteristics entailed by the scenarios. Residential single family and multifamily dwellings vary widely with respect to size, shape, amount of glazing, levels of wall, ceiling and floor insulation, amount of storm windows and doors, and the amount of weatherstripping. We shall represent single family and multifamily units by prototypes in order to estimate percentage savings associated with building shell improvements. These percentage savings for the prototypical units are used as proxies for the impacts on all units. The base year average heating and cooling requirements specific to each utility provide the absolute

values to which these percentage improvements in average energy usage are expressed in terms relative to the average usage of the base year stock. The building shell characteristics of the existing residential housing stock were not available for the PECO service area. Consequently, other Northeast data was used for making estimates (References 44-46). These are given below in Tables 3.8 and 3.9 for units with and without electric space heating.

For electric space heating, only new units are assumed to improve relative to the average existing stock; that is no retrofit improvements are assumed. Heating load in new homes relative to existing average unit usage are expressed as an average thermal integrity factor (TIF) below (see Table 3.10, Vol. I for mathematical definitions).

Thermal Integrity Factor for Electrically Heated Homes

	SF	MF
Base Scenario	.95	.95
Conservation Scenario	.65	.50

Thus the electric heating load savings in the Conservation Scenario over and above the Base Scenario due to thermal integrity improvements embodied in proposed new conservation codes are about 30 percent and 45 percent, respectively, in single family and multifamily homes, where these are percentages of the average base year usages (including all vintages of ESH homes currently existing). The assumed characteristics of new units in the Conservation and Base Case used in the analysis of ESH improvements are given in Table 3.10.

For non-electric heat units, the end-uses affected are air-conditioning and heating auxiliaries. Table 3.11 gives the characteristics of prototypical building representing base case and target retrofit improvements embodied in the State Conservation Scenario. The heating auxiliary improvements (fractional reductions in consumption) embodied in the Base and Conservation Scenarios are:

Heating Auxiliaries Thermal Integrity Improvements

	Single Family		Multifamily	
	Base	Conservation	Base	Conservation
Retrofit	.05	.20	.05	.25
New	.20	.50	.20	.60

TABLE 3.8
ESTIMATED AVERAGE
BUILDING SHELL CHARACTERISTICS
FOR PROTOTYPICAL EXISTING
RESIDENTIAL DWELLING UNITS
(ELECTRIC HEAT)

	Single Family	Multifamily
Wall Insulation	R12.5	R9
Ceiling Insulation	R18	R15
Storm Windows	100%	80%
Storm Doors	100%	80%
Infiltration (Weatherstripping)	80% Doors 50% Windows	80% Doors 50% Windows
No. of Stories	1.9	1 per unit(2 Story Structure)
Roof-Ceiling Area (insulatable)	~900ft^2 ~1900ft^2	~600ft^2/unit ~470ft^2/unit
Net Wall Area	~760ft^2	~500ft^2/unit
Floor Area	188ft^2	100ft^2
Windows	138 linear feet	127 linear feet
Doors	2 20 linear ft/ea.	1/unit 40% 1/10 units 60%
Estimated Annual End-Use Demand: Heating	~46 MMBTU/unit	~26 MMBTU/unit

TABLE 3.9
ESTIMATED AVERAGE
BUILDING SHELL CHARACTERISTICS
FOR PROTOTYPICAL EXISTING
RESIDENTIAL DWELLING UNITS
(NON-ELECTRIC HEAT)

	Single Family	Multifamily
Wall Insulation	R8.5	R5
Ceiling Insulation	R12.5	R9
Storm Windows	90%	75%
Storm Doors	85%	30%
Infiltration (Weatherstripping)	70% Doors 10% Windows	70% Doors 10% Windows
No. of Stories	1.9	1 per unit(2 Story Structure)
Roof-Ceiling Area	~900ft^2	~600ft^2/unit
(insulatable)	~1900ft^2	~470ft^2/unit
Net Wall Area	~760ft^2	~500ft^2/unit
Floor Area	188ft^2	100ft^2
Windows	138ft^2	127 linear feet
Doors	2 20 linear ft/ea.	1/unit 40% 1/10 units 60%
Estimated Annual End-Use Demand:		
Heating	~60 MMBTU/unit	~35 MMBTU/unit
Cooling	~17 MMBTU/unit	~11 MMBTU/unit

TABLE 3.10
ESTIMATED AVERAGE
BUILDING SHELL CHARACTERISTICS
FOR PROTOTYPICAL RESIDENTIAL
DWELLING UNITS AFTER IMPROVEMENTS
(ELECTRIC HEAT)

	Single Family		Multi Family	
	Base Case (New Units)	New Conservation Code (New Units)	Base Case (New Units)	New Conservation Code (New Units)
Wall Insulation	R12.5	R20	R12.5	R20
Ceiling Insulation	R20	R38	R12.5	R38
Storm Windows	100%+	100%	80%	100%
Storm Doors	100%	100%	100%	100%
Infiltration (Weatherstripping)*	80% Doors 50% Windows	100% Doors 100% Windows	80% Doors 50% Windows	100% Doors 100% Windows
Percent Savings in Heating Relative to Existing Units	5	35	5	50

* Although the existing code indicates a lower level of insulation protection we assume that the estimated higher levels in existing units will be maintained.

\+ The state code requirement of u = .69 implies an estimated 80% storm windows. Since we estimate 100% storm windows amongst existing SF units it is assumed that all new units will have 100% storm windows.

TABLE 3.11
ESTIMATED AVERAGE
BUILDING SHELL CHARACTERISTICS
FOR PROTOTYPICAL RESIDENTIAL
DWELLING UNITS AFTER IMPROVEMENTS
(NON-ELECTRIC HEAT)

	Single Family			Multifamily		
	Base Case (New Units)	New Conservation Code* (New Units)	Conservation Retrofit	Base Case (New Units)	New Conservation Code (New Units)	Conservation Retrofit
Wall Insulation	R12.5	R20	R14	R12.5	R20	R14
Ceiling Insulation	R20	R38	R38	R12.5	R38	R38
Storm Windows	90%+	100%	100%	80%+	100%	100%
Infiltration (Weatherstripping)	100%	100%	100%	100%	100%	100%
	70%Doors	100% Doors	100%Doors	70%Doors	100%Doors	100%Doors
	10%Windows	100% Windows	100%Windows	100%Windows	100%Windows	100%Windows
Percent Savings in Energy Use Relative to Existing Units						
Heating	20	50	40	20	60	50
Cooling	10	45	20	15	50	40

+ It is assumed that where existing units have levels above those implied by the state code (here about 80% storm windows). These levels are maintained amongst new units.

* New construction is also assumed to entail passive solar design which entails shading of exposed glazing.

These correspond to the "thermal integrity improvements" of Table 3.11, Volume I. As indicated there, they refer to improvements relative to average usage in existing dwellings. The values for the retrofit households refer to average improvements achieved by the year 1998, phased in linearly from zero in 1978 in the Base Case. In the Conservation Case the phased-in Base Case improvements occur until 1982 (the housing policy year), after which there is a linear phase-in of improvements reaching the conservation target level in 1998. In the new housing market, the improvements (TIN in Table 3.11, Vol. I) are constants, jumping to the conservation values in the appropriate year when the Conservation Case is in effect. The values can be obtained from the above Table 3.11, where it is assumed for the Base Scenario that 25 percent of the full 20 percent potential improvement embodied in the existing state code is achieved in the retrofit market over the next twenty years. For the Conservation Scenario a targeted cumulative 50 percent of the full potential improvements (40 percent SF and 50 percent MF) for the prototypical retrofit is achieved over the next twenty years.

The estimates for impacts on cooling loads are given below, where again they are expressed as thermal integrity improvements (TIE and TIN in Table 3.9, Vol. I). Here, too, the retrofit numbers represent 25 percent and 50 percent cumulative 20 year market penetration targets in the Base and Conservation cases, respectively.

Cooling Thermal Integrity Improvements

	Single Family		Multifamily	
	Base	Conservation	Base	Conservation
Retrofit	.04	.10	.04	.20
New	.10	.45	.15	.50

The social cost justification of the Conservation Scenario is established by estimating the additional costs per KWH saved entailed by the implementation of the Conservation Scenario measures beyond those already embodied in the Base Scenario. Thus, the additional insulation, storm windows and doors, weatherstripping, etc., costs per energy saved are estimated and compared with the existing costs for purchased energy. In estimating the costs, we use the dimensions, thermal integrity improvements, and energy savings of the prototype buildings, already described. Credit for the full savings associated with the prototype cooling load reductions is not assigned to the Conservation Scenario benefits. Rather, A/C saturations of 30 to 40 percent, well

below the average statewide saturations, are assumed. Estimates of retrofit costs were obtained from examination of References 46 and 47. These include $32 and $100 for storm doors, respectively, $.015 per ft^2 per unit R for roof-ceiling insulation (including labor), $8 each and 20¢ per linear foot for window and door weatherstripping. The cost of wall insulation is estimated to be $.088 per ft^2 per unit R (including labor).

These numbers are conservative in a number of respects. Since the full wall insulation costs are expressed per unit R-value, the additional costs of the Conservation Scenario are overestimated since it includes the large front-end costs some of which would already be entailed in the Base level of wall insulation. The calculation assumes per unit costs for new units at the retrofit levels, embodying a clear overestimate. Average annual costs are estimated by assuming a 20 year life for building improvements (7 years for weatherstripping).

The results are strongly supportive of the Conservation Policy Scenario on economic grounds. If one examines the conservation retrofit target for single family homes it is found that the cost per million BTU charged to saving fuel relative to the Base level of retrofit is about $2.33, whereas at 90¢ per gallon of home heating oil the cost would be about $6.40 per MMBTU for purchasing the fuel in the absence of the Conservation measure. This comparison does not take into account the savings in electricity which would occur in heating auxiliary and air-conditioning end-uses. Expressed differently, the combined cost per KWH of purchased energy is about .66¢, whereas at 90¢ per gallon the cost of fuel oil can be expressed as about 2.2¢ per KWH. Electricity costs are, of course, substantially higher than this. Thus, the cost of saving energy through the retrofit of single family houses to the Conservation Policy levels is less than one-third of what it would otherwise cost to purchase that energy in the form of fuel oil and electricity. The results for multifamily homes are similar 0.61¢ per KWH purchased energy is saved in going from the Base Scenario retrofit levels to the Conservation Policy target levels.

The additional cost per KWH saved in new electrically space heated homes in going from the Base Scenario levels of thermal integrity to the Conservation Scenario levels is about 2¢ per KWH for single family and 1.3¢ per KWH for multifamily units. This is lower than the average cost for existing electricity at the margin. Again, these cost estimates are conservative in that the same unit costs for thermal integrity improvements as used for retrofit were used for new construction. One would expect unit costs for building shell improvements in new construction to be lower.

Finally, for non-electrically heated new homes, the cost of conservation is estimated to be about .8¢ and .7¢ per saved KWH respectively for single family and multi-family dwelling units. These are considerably lower than the roughly 2.2¢ per KWH estimated for purchased home heating oil. Again, these estimates are conservatively high since they involve unit costs for retrofit rather than for new construction.

3.3 Electric Space Heat Regulations

Of all the electrically consuming end-uses in the residential sector, electric space heat (ESH) promises to grow most rapidly in the forecast period. In the PECO service area, ESH currently accounts for about 6 percent of residential consumption but is likely to represent fully 35 percent of the overall growth in residential electric energy consumption*. In view of this, the conservation and cost implications of allowing this unrestrained growth deserves special policy scrutiny.

ESH is a generic category representing various technologies for space heating with electricity. For purposes of analysis, we may divide the ESH category into subdivisions (see Vol. I, Sec. 3.3.9): direct resistance heating, electrically driven heat pump, and supplementary electric heat for solar heat systems. The ESH policy regulation refers only to the first of these alternatives. Specifically, the recommended regulation is to ban additional direct resistance heating.

There are two major alternatives for the customer who otherwise would have selected electric resistance heating: heat pump or conventional fossil-fuel heating systems.** Indeed, the conservation model is designed to allocate the new resistance ESH customers proportionately to these alternatives starting in 1982. The two year delay serves a dual purpose: (1) it allows for completion of new housing units already structurally committed to resistance heating and (2) it allows for deliberative development of the appropriate regulatory and enforcement mechanisms.

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* ESH will, of course, represent a larger fraction of residential class winter peak demand growth due to its seasonal demand characteristics.

** Throughout this study, active solar heating is assumed to have insignificant market penetration.

The justification for the resistance heat ban, as with all conservation policies, rests with the likelihood of substantially decreasing state energy consumption costs. Let us consider these in turn.

The energy consumption tradeoffs in substituting a heat pump or fossil fuel system for direct electric resistance heat are quite favorable. For the case of the heat pump substitution, energy consumption is more than halved. This is traced to the "pumping" property of heat pumps in which delivered in-door heat is composed of both thermal energy transferred from outdoor air (or water) and the electricity delivered to run the pump. The ratio of heat delivered to electrical energy consumed is called the coefficient of performance (COP), a measure of the efficiency. In Pennsylvania, the seasonally averaged COP has a value somewhat greater than two (Vol. I, Sec. 8), implying an electrical energy saving of over 50 percent.

The energy savings in substituting fossil fuel for resistance heating are comparable. This is illustrated schematically in Table 3.12. Primary energy requirements for delivering a unit of end-use heating energy more than double if a resistance rather than fossil fuel system is employed. This is due to the large conversion losses inherent in the thermodynamics of electricity production. The conversion losses in the table are based on a 33 percent plant efficiency (electrical energy out to primary energy in) and another 6-10 percent electric energy loss in delivering the electricity through the transmission and distribution grid.* On the other hand, for the fossil fuel system (oil or natural gas), boiler efficiencies are on the order of 60 to 70 percent (the latter is assumed in Table 3.12) and could be up to 80 percent in newer units with improved maintenance practices.

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* The assumption of 33 percent efficiency (heat rate of 10,200 BTU per KWH) may substantially underestimate primary fuel consumption for resistance heating. The incremental production of electricity to supply the extra resistance heating in the State, especially near winter peak demand conditions, may involve the dispatching of plants of considerably lower efficiencies.

TABLE 3.12
RESISTANCE/FOSSIL FUEL PRIMARY ENERGY COMPARISON
(Arbitrary Units)

	Primary Energy	Conversion Loss	Delivered Heating Energy
Resistance Heating	3.3	2.3	1
Fossil Fuel Heating	1.5	0.5	1

In other words, compared to both the heat pump and fossil fuel alternatives, the resistance heating represents a substantial energy penalty for the state. The decision to install a direct resistance heating system is a decision to increase necessary energy consumption for the end-use by a factor greater than two. The policy of banning resistance heating satisfies the criterion of substantial energy savings. Let us briefly look at the social cost criterion.

In utilizing the social cost/benefit estimation approximation of Section 2, we use the following data characteristics of costs and savings in new single family homes.

	Incremental Capital Cost	Equipment Lifetime	Incremental Energy Savings
Heat Pump	$1650	10 years-HP 30 years-duct work	5000 KWH
FF System	$650	15 years-boiler 30 years-duct work	5000 KWH

For the heat pump, we compute the price of saving electricity (the ratio of the cost increment to the total KWH saving) at about 2¢/KWH. This should be compared to the cost of supplying the extra electricity. The social cost criterion appears adequately satisfied.

We now turn to the case of the fossil fuel alternative to direct electric resistance heating. Natural gas is assumed to be the competitive fuel in the analysis. Here the cost/benefit calculation is a bit more complicated since, in addition to substituting an additional capital investment to save electricity, one is also substituting fossil fuel consumption for electricity consumption for the remaining

energy requirement. Assuming reasonably cautious natural gas prices (e.g., $4.00/BTU fired in boilers at 0.7 efficiency), the fuel costs alone are less than 2¢/KWH or considerably less than the electric energy it substitutes for. To be conservative, we shall ignore such fuel substitution savings and turn to the capital cost penalties of the resistance heating/fossil fuel transition. Here, the cost of saving a KWH is computed to be less than 1¢/KWH, far better than the resistance ESH alternative. In passing, it should also be noted that on social cost grounds, the fossil fuel alternative is apparently also superior to the heat pump alternative.

It has been shown that banning resistance heating in favor of heat pump or fossil fuel heating satisfies the twin criteria of lowering both the energy consumed and the revenue required for energy services in the State, and does so in a dramatic fashion. It may appear, on the other hand, that for the case of substituting fossil fuels for electricity that another energy planning goal--minimizing scarce fuel consumption--may be violated. There is, however, no a priori reason to believe that this would be the case. We have already shown that substantially more primary fuel must be fired at generating stations to produce electric resistance heating than would be required in directly using the fuel in conventional decentralized boilers. Given that primary energy demand would be reduced through substituting fossil fuel heating for resistance ESH, the remaining question is what fuel types would be saved. Though detailed generation plant dispatch simulation runs with and without additional resistance ESH would be required to precisely confirm it, the probability is that the primary fuel saved would be oil. The reason is that economic dispatch of the utility generating system mandates minimizing overall operating costs. Plant-types with the lowest operating costs (nuclear, coal) are generally run to the limit consistent with planned and forced outage characteristics. Demand not met by these are then supplied by higher cost oil-generated electricity. For the forseeable future, a reduction in demand due to direct resistance heating flows through as saved oil at the point of electricity generation.* In other words, substituting even oil-fired home boilers (natural gas appears to be the probable alternative to ESH) for electric resistance heating in new units promises to cut oil consumption for heating by roughly one-half.

The ESH regulation thus appears justified on several grounds--energy conservation, social cost reduction, and scarce fuel management.

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* For example, in January 1978, 42% of PECO's electricity production was derived from oil-fired generating units (Ref. 20).

3.4 Solar Energy

Residential solar applications may be subdivided into two categories--passive and active. Passive solar strategies are based on architectural techniques for advantageously coupling building interfaces and the insolation environment. These considerations include building orientation, materials choices, fenestration, and shading design. Active solar, on the other hand, generally includes the solar collector, working fluid for heat transport, heat storage device, and supporting pumps and fans.

The satisfaction of minimal passive solar specifications is built into the Conservation Policy Scenario. The state regulatory apparatus would develop minimal passive solar compliance standards for new construction. The start-up target year is assumed to be 1982, the same year as for the conservation level insulation standards described in Section 3.2, in the forecast runs.

Estimates of likely construction cost additions and energy savings in incorporating passive solar measures in building design appear in the literature (e.g., Refs. 17,18). Cost typically varies from $450 to $1000 for the achievement of from 12 to 50 percent heating energy savings per household. In this analysis, a conservation policy target of 25 percent reduction in heating requirements (at $640 additional expenditure) is assumed. This measure could easily meet the social cost/benefit criterion. The cost per KWH of saving electricity (or the equivalent in fossil fuel) is less than 1¢ given the assumptions above and a cautious 25 year lifetime for the structural measures involved. The cost of delivering the energy in the absence of such a measure is (and will be), of course, considerably higher. Note that passive solar design measures also have energy saving implications for summer air-conditioning loads. This additional credit has not been incorporated in this study.

The role for state policy in increasing the market penetration of active solar systems is less clear. There are a number of areas for initiatives: tax inducements, encouragement of solar-related business, low-cost financing schemes, development of marginally costed rates for back-up electricity (see Ref. 19), etc. However, it appears that the primary initiatives in the development of a viable solar industry will come from federal measures designed to create sufficient demand to support manufacturing economies of scale and an adequate institutional infrastructure. Consequently, the potential for substantial policy leverage at the state level is not obvious. Furthermore, at current

costs for solar systems the capital investment does not lead to compelling social benefits. Assuming that 30 to 50 percent of annual hot water and/or heating loads would be met by a typical system with costs in the neighborhood of $2000 and $7000, respectively, the solar investment costs from 8¢-12¢ per saved KWH. These borderline economies imply that policy priority must be given to developing a market demand sufficient to lower real first costs. This continues to be the direction of federal policy in this area. No new state policy initiatives to increase the penetration of active solar energy systems in Pennsylvania are assumed in the Conservation Policy Case.

4. CONSERVATION POLICY ELEMENTS: COMMERCIAL SECTOR

Three areas of state policy action are included in the Conservation Scenario: equipment efficiency and operational improvements, building property standards, and electric space heat regulation. As with the residential sector, policies to induce the purchase of solar equipment are not included; it is assumed that the federal government will take the main initiative to encourage active solar.

The commercial sector consists of a considerably more heterogeneous set of consumers than does the residential sector. It is thus necessary to treat the commercial sector on a more aggregated basis. We shall follow the procedures of the Base Case forecasting model, where the analysis focuses on five building types (office, retail, school, hospital and miscellaneous) and two vintages (1975 stock and new construction).

4.1 Equipment Efficiency and Building Standards

For each of the building types, we wish to identify a package of cost-effective, technologically available conservation measures to indicate the possible impacts of commercial sector conservation policies. These may affect the physical properties of buildings, internal loads/comfort conditions, and HVAC* components and operations. Three levels of conservation have been identified in Volume I, Section 4.3 (see especially Table 4.5) based on the work in References 26-28. The first level is based on readily available "quick fix" items. The second level adds a set of established, basic techniques. The third level includes some capital-intensive modifications requiring considerable engineering support. The measures affect the physical building properties (e.g., sealing, caulking, insulation), HVAC systems and controls (forty separate items), internal loads/comfort conditions (lighting intensity levels, ventilation characteristics), and operation and maintenance practices.

In the Conservation Policy Case, it is assumed that mandated commercial building standards will be designed at the equivalent of Level 3 discussed in Volume I. The per cent reductions in electricity requirements and associated costs are presented in Table 4.1. These energy saving and initial costs estimates are with respect to 1975 consumption levels (see Vol. I, Sec. 8, Table 8.21). New building is designed to be above and beyond current energy conservation

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* Heating, Ventilating, and Air-Conditioning

standards such as ASHRAE Standard 90-75.

The nonconservation scenario (the Base Case) already includes considerable post-1975 conservation in the commercial sector with the penetration levels varying with building-type and end-use. This is related to market responsiveness to price-induced quick payback conservation practices already at play under business-as-usual assumptions.* Again, the Conservation Policy savings and costs are relative to 1975 practices, not Base Case assumptions which already include some post-1975 Conservation penetration.

The improvement levels summarized in Table 4.1 appear to be reasonable targets for policy analysts. Other investigations of considerable potential, based on conventional technologies, give analogous results. For example, using an analogous end-use/engineering approach, recent studies suggest achievable conservation levels of over 40 percent relative to 1975 usage (Refs. 29,30).

Based on the cost data in Table 4.1 and a nominal equipment lifetime of 10 years, the costs of achieving conservation technology level appears quite acceptable, generally less than 1¢ per saved KWH. However, it should be emphasized that data limitations require that the commercial sector analysis be dealt with on a generic basis currently. The quantification of savings and costs are meant to be suggestive of the cost-effective potential for state-induced policy intervention. Recent work dwelling on the engineering details of the transition to more efficiency in commercial consumption should contribute to a more precise specification of the possibilities (see, e.g., Ref. 31).

In the Conservation Case forecasts, it is assumed that the commercial sector standards do not begin impacting until 1985. In the retrofit market, the conservation policy level is phased in over a five year period from 1985. In addition to the complexities of detailed development of the building envelope and equipment efficiency regulations, state energy agencies could play a useful role in the dissemination of design and operational modification information to building industry professionals. It is assumed that the long lead time to standard initiation could be used to generate sufficient institutional readiness for their implementation.

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* The commercial sector modelling approach and data assumptions are discussed in Sections 4 and 8 of Volume I.

TABLE 4.1
COMMERCIAL SECTOR CONSERVATION POLICY
COSTS AND SAVINGS

Building Type	Initial Cost ($/ft^2)	Fraction of Energy Saved			
		Heating	Cooling	Light& Power	Auxiliary
Office					
· 1975 Stock	.58	.23	.34	.50	.38
· New	.47	.40	.47	.25	.20
Retail					
· 1975 Stock	.52	.25	.20	.25	.45
· New	.42	.50	.46	.30	.20
Hospital					
· 1975 Stock	1.30	.16	.28	.17	.30
· New	1.04	.40	.33	.15	.15
School					
· 1975 Stock	1.10	.29	.56	.42	.53
· New	.88	.50	.41	.20	.30
Other					
· 1975 Stock	1.30	.26	.24	.24	.32
· New	1.04	.50	.40	.20	.20

Source: Refs. 26-28.

4.2 Electric Space Heat Regulation

The commercial sector electric space heat regulation is the same as that defined for the residential sector in Section 3.3. Specifically, based on the positive implications for energy conservation and social costs, the regulation bans additional direct electric resistance heating. The regulation is assumed to come into effect in the Conservation Case forecast in 1982. Additionally, as was the case for the residential sector, heat pump efficiency improvement standards are folded in for the Conservation Scenario. As discussed earlier, twenty-five percent COP improvements in new units over Base Case equivalents beginning in 1982 is technologically and cost justified.

5. CONSERVATION POLICY ELEMENTS: INDUSTRIAL SECTOR

Three broad industrial conservation policy areas are encompassed by the Conservation Scenario framework addressing building standards, an energy extension service, and cogeneration inducement. The first two, discussed in the next subsection, relate to the electric energy demand requirements in the industrial sector. The extension service, for example, is a state conservation program that would promote socially cost-effective methods of improving electric energy productivity, such as process efficiency improvements through improved operational practices and equipment efficiencies, decreased lighting and HVAC requirements.

The third element, cogeneration policy, on the other hand, relates primarily to the supply side of the electricity supply/demand equation. Here, the Conservation Policy Scenario envisions an increase in the amount of electricity produced in industrial settings simultaneous with the production of process thermal energy (steam, hot water, direct heat). This increase is related to state initiatives in fostering the development of an appropriate institutional and regulatory framework for increasing the amount of cogenerated electricity to socially optimal levels.

5.1 Conservation Program

There are two major components of electricity in industrial installations: energy for buildings (lighting and HVAC) and energy for process (machinery, pumps, materials control, and so on). The former typically amounts to 20-30 percent of electrical consumption, though this breakdown may vary with industry. The State Conservation Policy Scenario for industry breaks down into these two subdivisions. Electrical energy for buildings (especially the office sections of industrial structures) would be subject to the building shell, comfort equipment efficiency, and operational improvements associated with commercial sector building and equipment efficiency standards (see Sec. 4.1). Process energy requirements are assumed to be affected, not by regulation, but through an active statewide information and technical assistance outreach program.

In the Conservation Policy forecasts, it is assumed that an industrial conservation program beyond Base Case levels commences in 1982 and is targeted to achieve ten

percent statewide relative energy savings after five years. Thus, the program effort is designed to achieve a substantial level of improvement by 1987 in overall industrial electric energy intensiveness* relative to that in the Base Case. Like other economic variables, industrial output is the same in both scenarios.

The ten percent statewide industrial electrical energy efficiency improvement appears to be a comfortably realistic target for the substantially increased governmental effort characterizing the Conservation Scenario. First of all, the effects of more stringent standards on the building consumption component, using the office category of the commercial sector as a guide, will yield this level. Second, investigation elsewhere has found electricity conservation potential acceptable to industry of up to 20 percent (Ref. 35).

Furthermore, the proposed information and technical assistance program could have substantial effects in industry cost-effective conservation. Such a program could be conducted by a full-fledged energy extension service. This ideally would build on the current Pennsylvania Technical Assistance Program (Penn Tap) which gives advice to enterprises and refers them to qualified energy auditors and consultants, as one of ten state energy extension services (EES) funded by the U.S. Department of Energy. Assuming that an enhanced EES could reach most of Pennsylvania's industrial firms, we estimate program costs at roughly $17.5 million per year.

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* Intensiveness is consumption per unit output. See Volume I, Secs. 5.4 and 8.3.

Our cost estimate for contacts with clients is $350 per client contact, based on doubling a DOE finding in its evaluation of the pilot 10-state EES program (Ref. 33). The evaluation surveyed 2,375 clients (and 2,500 non-clients in a "companion survey"), who were interviewed during the year in which they received assistance. It was found that the average cost to the small business client served was $158 in current dollars. A four-year program reaching 50,000 industrial firms per year at $350 per contact would cost $70 million. With the savings payoff measured in thousands of GWHs (million kilowatt-hours), the state social cost investment is quite attractive (less than 2¢ per saved KWH).

The conservation practices and investments induced would result from voluntary action, based on their being cost-effective from the industry point of view. The DOE's EES evaluation suggests that an EES would produce significant additional conservation investment. The EES client group in the survey invested 55 percent more in conservation efforts than did the comparison sample. (While this was not broken down by client type, the small business clientele had the highest "take action" differential, with 18 percent more clients taking action than non-clients.) The scope and variety of attractive potential conservation in industry are great. Industries have cut electricity use 10, 20, and 30 percent and major conservation technologies--more efficient electric motors, to name one--are actively being developed and marketed.

The assumed ten percent potential electric energy savings appears at this time a reasonable goal around which to develop an industrial conservation program as described above. Basic policy criteria--social cost and benefits, energy conservation, and so on--seem adequately satisfied. The currently missing ingredient--sufficient resources and institutional commitment to mount such a campaign--is precisely the premise of the Conservation Policy Case.

5.2 Cogeneration Policy

Industrial cogeneration, defined here as the simultaneous in-plant production of electricity and process thermal energy, is widely recognized as a promising energy conservation technique (Refs. 36-41). The essence of the cogeneration concept is the integration of two otherwise separate steam systems: utility produced high temperature steam to drive electric generating equipment, and industrial lower temperature steam for manufacturing process. In the absence of cogeneration, the utility's unutilized "waste" steam (amounting to roughly two-thirds of the primary energy input) is discharged to the environment, while additional fuel is

consumed separately in industrial steam producing boilers (or for direct-heat).

Cogeneration systems combine these complementary systems. In an industrial setting, electricity is generated on-site with the resulting low temperature steam captured for process requirements. Energy conservation results from the efficiency of utilizing the steam output of the electric production system as an input to manufacturing process. Illustrative comparative energetics are shown below in Table 5.1 for a generic case (Ref. 41, p. 3).

TABLE 5.1

Cogeneration Versus Separate Generation Of Electricity and Steam For A Large Industrial Plant

Separate Generation Mode

	Energy Resources			Useful Energy	Energy Efficiency (%
	50 Btu →	Central Station	—electricity→	19 Btu	37
	100 Btu →	Plant Boilers	—steam→	84 Btu	84
Total	150 Btu			103 Btu	69

Cogeneration Mode

	125 Btu →	Cogenerating Industrial Power Plant	—electricity→	19 Btu	82
			—steam→	84 Btu	
Total	125 Btu			103 Btu	82

Source: Ref. 41.

Pennsylvania industry currently generates approximately 7 percent of its electrical requirements (nationally, the figure is about 10 percent). By comparison, West Germany currently produces 13 percent of its total electrical energy requirements through cogeneration (Ref. 48). The potential for cost-effective cogeneration appears to be very great. One recent study (limited to only very large

industrial steam users) found the national potential at two to six times current levels depending on whether or not electricity not consumed at the plant was exported to the utility distribution grid (Ref. 36). Another study, which considered greater size variation but only three industrial sectors (chemicals, petroleum refining, and paper and pulp), found even greater economic potential: up to 68 percent of 1974 total electricity consumption depending on the technology used (Ref. 37). Potential in New Jersey has been estimated at comparable levels (Ref. 39).

The technical potential is vast; these studies suggest the economic potential is also great.* The central issue for conservation policy is the state government's role in overcoming the barriers to the social cost-effective development of this major indigenous energy resource.

The institutional impediments to the full take-off of cogeneration in the state are multiple. ESRG, in a recent report to the State Energy Office of New York State (Ref. 41), set out to identify the institutional and regulatory barriers to cogeneration investment by state industry. A number of large manufacturers were interviewed on their perceptions and intentions with regard to cogeneration as were all relevant state agencies. It was found that while some firms are actively reviewing their positions on cogeneration in the light of increasing electricity costs, there remain substantial barriers. The main institutional barriers include:

- Requirements for much higher return on cogeneration than other investments.
- Fear of regulatory scrutiny.

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* A sample economic estimate may be instructive. The incremental costs above steam equipment alone of installing a coal-fired boiler/cogeneration system to produce, say, 200,000 lbs/hr of steam is about $600/KW (Ref. 37). Assuming operation and maintenance at 3 mills/KWH, an 80 percent capacity factor (fraction of time on-line) and a 20 percent annual fixed charge rate, the non-fuel costs are about 1.5¢/KWH. Only the incremental fuel (above the fuel that would have been consumed to produce the process steam alone) is properly charged to the electricity production. The incremental heat rate is about 5000 BTU/KWH, so that the fuel charges at $2.00/$10^6$BTU are approximately 1¢/KWH. The total production costs, 2.5¢/KWH, would be quite competitive in Pennsylvania.

- Unfavorable rate structures for back-up electricity (which discourage sporadic use of electricity).
- Concern about environmental regulation.

The state's role, should it adopt conservation policy orientation, lies in the development of an integrated framework for removing regulatory confusion, reviewing and establishing adequate utility/industry interface policy (particularly concerning back-up charges), and creating adequate institutional mechanisms for initiating projects, raising capital, and implementing projects.

State government has a great deal of leverage here. It can aggressively work to develop a coherent regulatory framework for cogeneration addressing electric rates, fuels policy, and the application of environmental standards. It can develop a technical services capability to promote cogeneration by providing information and advice to would-be cogenerators.

Yet a more direct initiative could come from using the state regulated public utility system to own, construct, and maintain in-plant cogeneration systems. This approach has been discussed widely in the literature and is universally felt to dramatically increase the likely level of cogeneration potential in the future (Refs. 18, 37-39, 43). Utility ownership heretofore has not received policy emphasis in the State. Indeed, many investor-owned utilities are ambivalent at best on cogeneration development, apparently fearing an erosion of their economic base. But a utility ownership program addresses many of the current obstacles to cogeneration expansion. Specifically:

- The required rate of return is lowered (perhaps 12 percent vs. 20 to 40 percent for industrial ownership).
- Utility expertise and skills are already in-house.
- Regulation is already part of the utility business.
- Optimal plant sizes could be built because industrial electric supply and demand balancing would be less important.

Appropriate regulatory mechanisms for assuring that utilities exhaust cogeneration potential in their service area should be the subject of careful deliberation by state agencies. It has been suggested, for example, that utility rate increase requests be coupled to a review of utility per-

formance in exploring the development of cogeneration (Ref. 40).

There are thus major areas for state policy action in removing impediments to optimal levels of cogeneration development in the State. The Conservation Policy Case levels for increased cogeneration has been targeted at a doubling of cogenerated electricity from Base Case levels. Much of this could be satisfied through the use of the utilities to develop this resource. The economic potential for inplant generation increases substantially in the utility ownership mode. This increase has been estimated, for 1985, as 75 percent in Reference 37 (p. I-9) and over 100 percent in Reference 38 (p. 3.1 ff.). Furthermore, as state policy addresses such issues as reasonable stand-by rates, environmental regulation impacts, and utility/industry interface problems while promoting cogeneration through its technical service arm, a larger fraction of the economic potential will be realized. The precise quantitative potential depends on more detailed analysis of the specific industry characteristics in Pennsylvania and on the degree of government resource and institutional commitment to enhancing the cogeneration resource. The Conservation Policy Case begins to implement incremental cogeneration over Base Case levels attributable to state policy initiatives in 1982 and gradually increases incremental cogeneration until, in 2000, it is double the Base Case level. All indications are that such a target is attainable.

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