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
$0.303 \times$	.686
$(\text{Coal Capacity})^{0.588} \times$	4.09
1.26 if Scrubber ×	4.84
.90 if common-sited unit ×	3.43
1.26 if West ×	5.45
.77 if South Central ×	4.22
.74 if Southern ×	5.56
.85 if Southeast (but not Southern Company) ×	3.19
1.16 if Northeast ×	1.93
1.19 if American Electric Power ×	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
$6.46 \times$	2.69
$(\text{Nuclear Capacity})^{0.575} \times$	13.40
$(\text{MW})^{-0.208} \times$	2.63
$(\text{AE})^{-0.102} \times$	6.08
1.27 if Northeast ×	6.39
1.20 if Tower ×	5.24
.91 if Common-Sited ×	2.36
1.35 if "Dangling"	4.75

R^2 = .921 F - Value = 63.5
Adjusted R^2 = .907

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

<u>MW</u> is the capacity of the unit in megawatts

<u>AE</u> 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

"<u>Dangling</u>" 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 accordinc 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:

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

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 Exhibit **DS-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[1] 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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EXHIBIT A

THE ESRG ELECTRICAL SYSTEMS GENERATION EXPANSION MODEL

E S R G

990a

EXHIBIT A

THE ESRG ELECTRICAL SYSTEMS GENERATION EXPANSION MODEL

INTRODUCTION

This exhibit summarizes the aims and methodology of the ESRG Electrical Systems Generation Expansion Model (ESGEM). After stating its major objectives, the exhibit describes the algorithmic procedures utilized by the model in carrying out these objectives.

MODEL OBJECTIVES

ESGEM was conceived as a tool for the analysis of capacity planning as presently implemented by electrical supply systems. It was designed in particular to be adaptable to the requirements of an individual utility and to be easy and inexpensive to run.

In constructing the model, the authors had in mind a number of issues which frequently arise concerning the merits of a given generation expansion plan: the following twelve issues addressed by the model convey the range of problems which informed its design:

1. The Costs of Over- Versus the Costs of Under-Forecasting

Even the best load forecast incorporates a substantial error band. Utility planners should, therefore, be required to determine the economic consequences of error, both on the low as well as on the high side. These sources of error include (1) systematic forecast error, plus, (2) stochastic fluctuations in demand, e.g., those caused by weather. This issue can be addressed directly through the use of ESGEM, which calculates the expected social cost of operation of a utility system at various levels of reliability, and which accounts directly for the costs of curtailment (including blackouts) relative to the costs of excess capacity.

2. The Magnitude of Potential Energy Deficiencies

ESGEM calculates the expected level of energy deficiency in a utility system. It disaggregates this deficiency into various subcategories defined in terms of measures that are undertaken to rectify the deficiency, short of providing new generating units.

3. The Probability of Demand Shortfalls and Overcapacity

Given a defined capacity mix, the model calculates the probability of any given level of capacity shortfall or excess. Included here is the classic loss-of-load probability parameter as a special case.

4. The Impact of Load Management and Demand Curtailment Options

The need for generating capacity (including reserve) can be obviated either through load management (i.e., the alteration of load patterns subject to an overall energy constraint) or through innovative demand curtailment. i.e., the short-term reduction of demand in such fashion as to mitigate economic impacts. ESGEM is specifically designed to analyze potential costs associated with both types of options.

5. The Calculation of an Optimal Reserve Margin

ESGEM calculates the expected present value of social costs (for energy served and unserved) associated with alternative reserve margins and then chooses that level of reserve which minimizes social cost.

6. The Specification of an Optimal Capacity Mix

ESGEM chooses an optimal mix of plants yearly so as to minimize the expected cost of generation to the consumer, subject to various technical constraints on plant operation (as, for example, energy limitations on hydro facilities or limits on the continuous operation of peakers).

7. Random Loads and Outages

ESGEM is constructed so as to account both for random variations in the load as well as for random forced outages in specific generation units.

8. Load Curve Analysis

ESGEM assimilates as input an hourly load curve for an electrical supply system defined over an entire year. The impact of any changes in this load curve can be directly assessed. For instance, the model can be employed for the analysis of impacts on a utility system induced by non-central station generation within its service area (e.g., co-generation, low-lead hydro, and wind power).

9. Generation Planning - Reliability Feedback

Systems which employ a smaller number of sizeable plants may risk the possibility of consequential outages and resulting excess demand. By contrast, systems comprised of a large number of small plants may penalize rate payers by foregoing potential economies of scale. These tradeoffs and their potential rate impacts can be directly explored through ESGEM.

10(a). Optimal Retirement

ESGEM identifies plants that warrant retirement on economic grounds: it indicates appropriate dates of retirement.

10(b). Change in Plant Operations

ESGEM identifies desirable changes of existing plant operation, e.g., from Baseload to Cycling operation, since it outputs the exact number of hours per year that it is optional for each plant to run.

11. Interconnect and Energy Imports

The need for capacity can also be mitigated through an increase in transmission interconnections and the formation of centrally dispatched power pools. ESGEM incorporates these options explicitly and can analyze economy and emergency power purchases separately. It calculates the required energy and the changes in total system costs which would occur through such arrangements. It also calculates the effect of alternative interconnection arrangements on system reliability (LOLP, blackout probability, etc.) and on the optimal reserve margin.

12. Long-Term Capacity Assignments

The possibility of assigning capacity for intervals of one or more years within the framework of a vigorous market for energy exports (and imports), may impact the social costs of generation. ESGEM is designed to account costs both in the presence and in the absence of assignment. It is thus able to analyze potential benefits that would accrue from greater economic coordination among separate utility systems.

SUMMARY OF MODEL OPERATION

Major subcomponents of the ESRG model are shown in Figure 1.

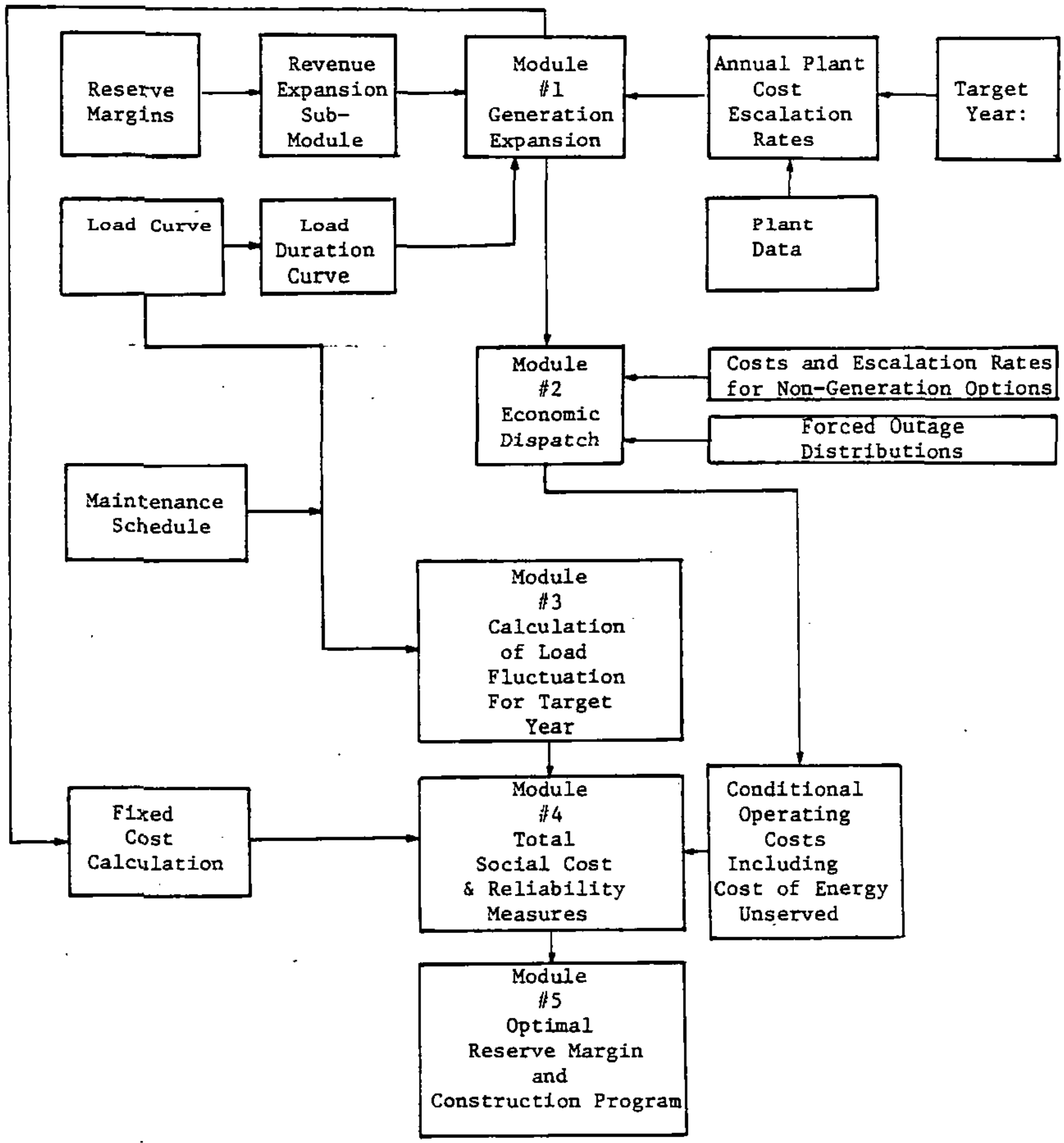
For a given electrical supply system a list of plants (including their capacities, forced outage rates, maximum capacity factors, planned maintenance periods, capital costs, and fixed and variable costs) is introduced as data. These include (1) facilities already on line, (2) specific plants under construction, and (3) a series of "generic" options representing a set of feasible technologies of differing fuel types and sizes.

Given this set of plants and their associated cost and technical characteristics, the generation expansion module calculates for each year of a specified time interval and for specified levels of generating reserves, an "optimal" mix of both new and old plants. The model is "forward looking" in the sense that plants already partially or fully constructed can be accounted at their incremental cost. Costs expended in the past will figure into the optimization process only at the option of the user. This option may be useful, however, in the case when the utility can recover some of the cost of their plants through firm sales.

Once the time stream of plant construction, plant retirements, and plant assignments is determined by the generation expansion module, the module moves to the dispatching module. Here a sequence of simulations is performed with the number of simulations specified by the user. For a given chronological curve the model simulates dispatch of supply options so as to minimize operating costs (economic dispatch). The model first employs generation options and economy imports. Once these are exhausted the model assesses the possibility of imported emergency power, and finally it dispatches the "soft" curtailment options, i.e., options which

Figure 1

SCHEMATIC OF THE ESGEM MODEL



DUE SEPT. 2, 1977 1978 & 1979	DUE SEPT. 2, 1980	DUE AUG. 13, 1981	DUE SEPT. 2, 1981	DUE SEPT. 2, 1982, 1983, 1984, 1985, 1986, 1987 & 1988 - PRINCIPAL IS PAYABLE $26,875.00 ANNUALLY EXCEPT FINAL PAYMENT DUE SEPT. 2, 1988 IS $30,000. INTEREST AMOUNT IS FOR PAYMENT DATE INDICATED.		DUI SEP: 19
$ -	$ -	$ -	$ -	$ -		$
-	-	-	-	-		
-	-	81,000.00	-	-		
-	-	976.44	-	-		
27,500.00	-	-	-	-		
				($26,875.00 TO $30,000.00 ANNUALLY)		
-	26,875.00	-	26,875.00			
-	17,150.00	-	15,268.75	13,387.50	Sept. 2, 1982	
-	-	-	-	11,506.25	Sept. 2, 1983	
-	-	-	-	9,625.00	Sept. 2, 1984	
-	-	-	-	7,743.75	Sept. 2, 1985	
-	-	-	-	5,862.50	Sept. 2, 1986	
-	-	-	-	3,981.25	Sept. 2, 1987	
-	-	-	-	2,100.00	Sept. 2, 1988	
-	-	-	-	-		
-	-	-	-	-		
34,125.00	34,125.00	-	34,125.00	34,125.00		34,12
-	-	-	-	-		
10,000.00	10,000.00	-	10,000.00	-		
-	-	-	-	-		
-	-	-	-	-		
-	-	-	-	-		
-	-	-	-	-		
-	-	-	-	-		
-	-	-	-	-		
-	-	-	-	-		

involve the mandatory, controlled, or voluntary curtailment of load (including voltage reductions), but whose social costs are small relative to blackouts. The costs of unmet energy in the form of limited or full-system blackouts are calculated only where there is still additional demand on the system after the soft curtailment options have been invoked.

As plants are loaded by the dispatch module, their outage characteristics are simulated. Forced outages are assumed to follow a Bernoulli (on-off) distribution with parameters specified as data, based on experienced forced outage rates. Planned maintenance is allowed for by derating plants over an "allowed planned maintenance season" which is also user specified.

As plants are loaded or used for generating power, the model aggregates operating costs incorporating fuel costs, variable operations and maintenance costs, and variable environmental costs. Total production costs are statistical averages over a larger number of stochastic or Monte Carlo simulations of demand and plant outage fluctuations in order to eliminate the possibility of anomalous outcomes. The total social costs of operation are calculated by adding the costs of imports and energy not served (curtailment options).

Such a series of simulations are undertaken for each load at a given year for a specified reserve margin. The simulations yield a function for the social cost of operation under those conditions. The expected social cost is calculated by weighting the cost at a given load by the probability of the given load determined by the typical annual load curve and the stochastic fluctuations or randomness to be expected in this load curve. This yields an expected total social cost of operating for a given year at a given reserve margin.

The program then adds to this expected cost of operation, the incremental fixed costs associated with the calculated generation mix. This includes fixed operation and maintenance costs, annulized capital costs, and fixed carrying charges such as depreciation and taxes. This yields a time stream of total incremental social costs at a given reserve margin. These costs are then discounted to a single year's constant dollars.

A more detailed description of each module follows:

MODULE #1: Generation Expansion

The operation of this module is shown in Figures 2 and 3. Given an hourly load curve $LC(\tau)$ for a utility, we calculate the load duration curve defined as

$$(1) \quad LDC^{-1}(MW_o) = \frac{1}{LDC} \int_0^{8760} LC(\tau)\,d\tau \times \text{Logical}^{+} \left\{ LC(\tau) - MW_o \right\}$$

$$\text{where logical}^{+} = \begin{cases} 1 \text{ if } LC(\tau) \geq MW_o, \\ 0 \text{ if } LC(\tau) < MW_o. \end{cases}$$

For MW_1 and MW_2 shown in Figure 2, $LDC^{-1}(MW_1)$ and $LDC^{-1}(MW_2)$ are both equal to the integrated length of the broken lines shown. $LDC^{-1}(MW_o)$ is the number of hours in a year where the load is greater than or equal to MW_o.

For a calculated load duration curve (see Figure 3) we decompose the area under the curve, i.e., the energy requirements of the system, into a set of differential energy elements which represent the energy corresponding to a given level of load MW and required by the system for LDC(MW*) hours.

FIGURE 2

DERIVATION OF A LOAD DURATION CURVE
FROM A TIME - DEPENDENT LOAD CURVE

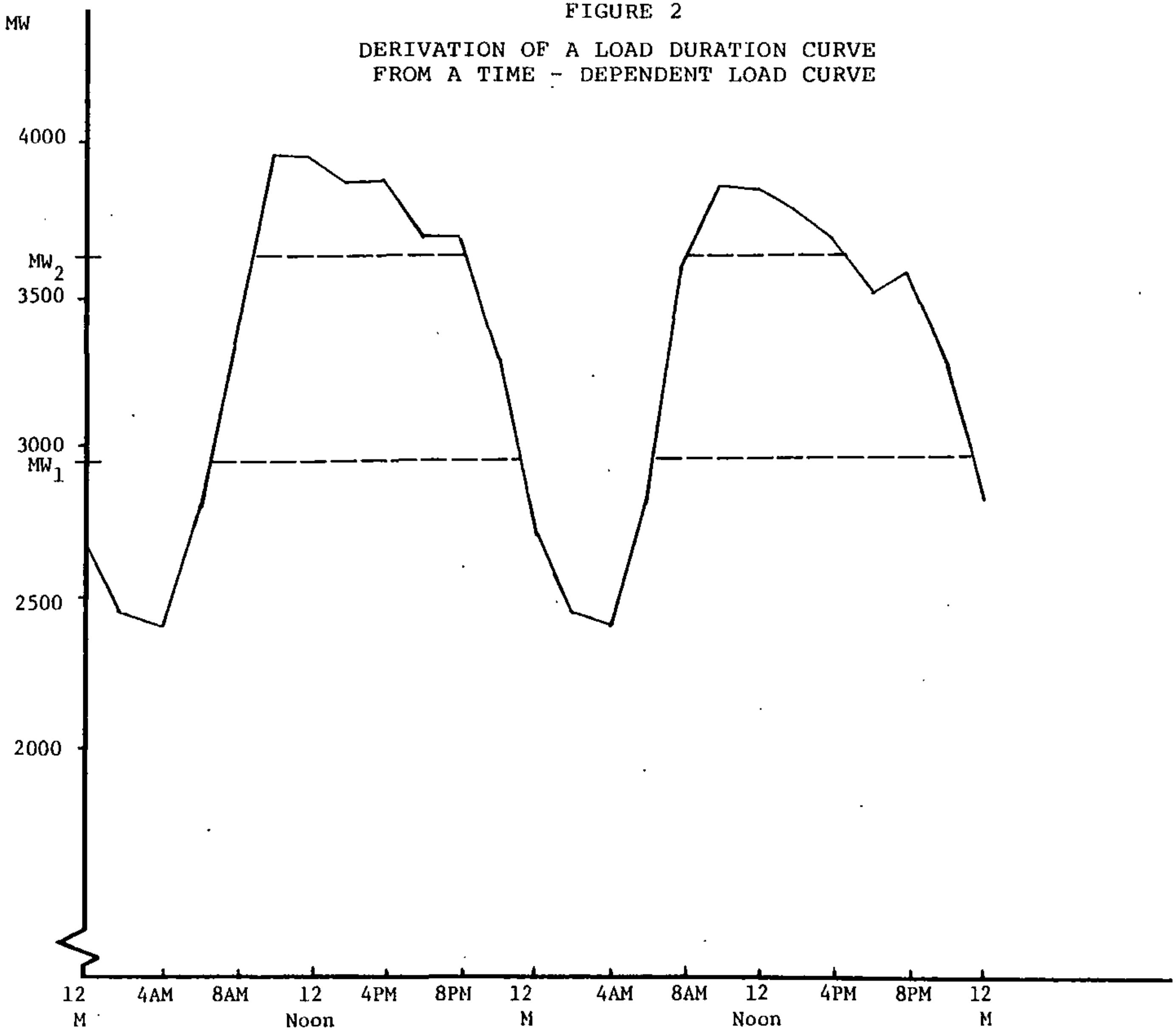


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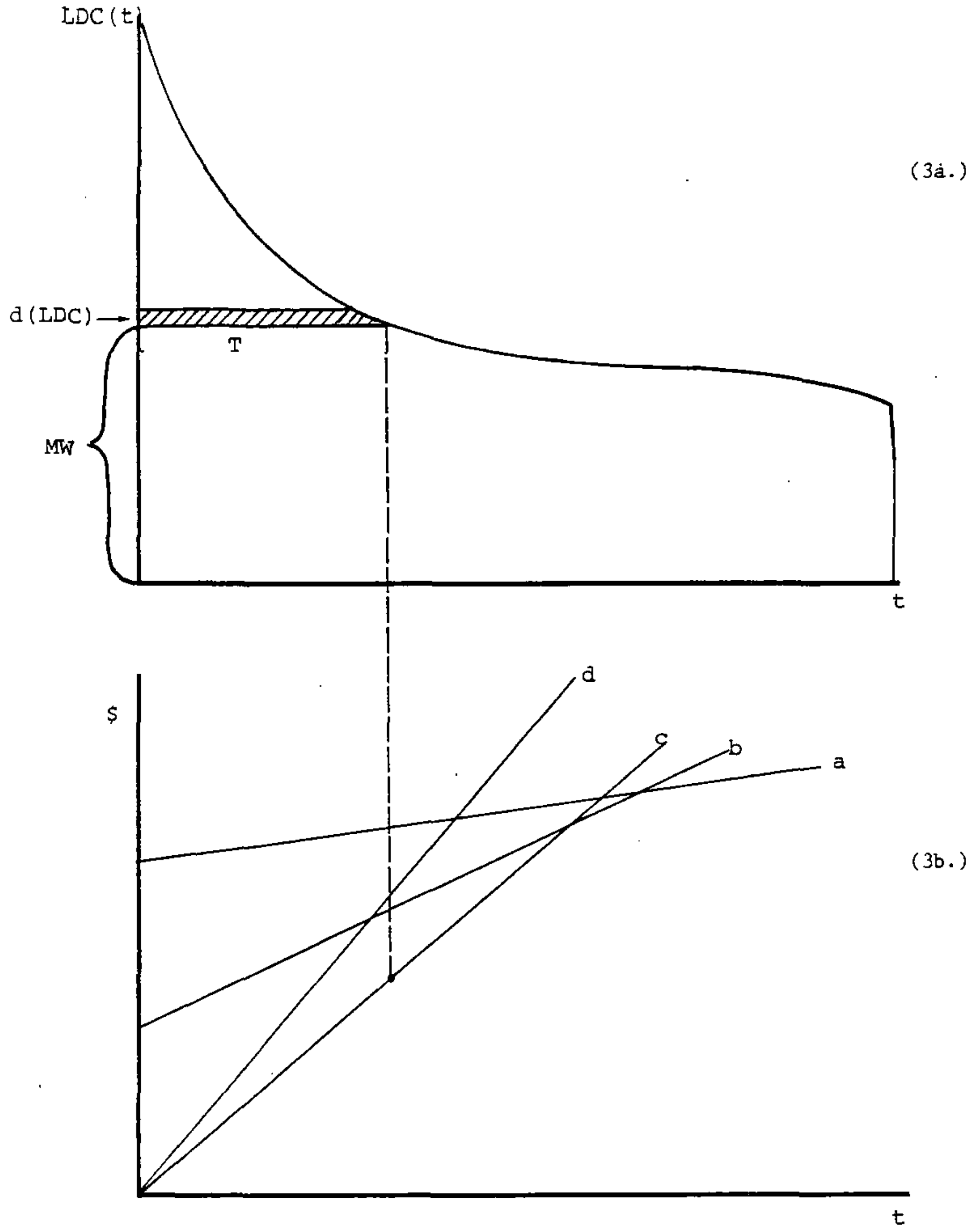
FIGURE 3
Selection of Optimal Generating
Units from Load Duration Curve in ESGEM



Below the load duration curve in Figure 3 are cost curves for a selection of facilities, both old and new. These are calculated as the cost (in dollars) of a unit of generating technology i operating for t hours among alternatives a, b, c and d. For example, c is the cheapest way of providing energy at MW megawatts for t hours as required by the system.

The module searches all such differential bands of energy, starting with base load energy, finds the minimum cost means of serving that energy, and then assigns a unit megawatt of this optimal technology to the mix. The individual costs of each differential band are then summed to produce the total cost of supply.

Calculating the Reserve Margin

Were we to follow this procedure over the entire load duration curve, we would indeed determine a least cost mix of plants whose total capacity is exactly equal to the peak load. In fact, it is prudent for utility planners to account for the possibility of supply requirements in excess of peak loads due to such contingencies as forced outages, uncertainty in load, forecast error, etc. The excess of supply relative to peak is termed reserve.

ESGEN calculates the reserve in the following manner (illustrated schematically in Figure 4). For every differential energy element at a given load, Module I first calculates the least cost facility capable of meeting the load. It then tests to see whether the plant can run t hours in light of its maximum annual capacity factor entered as data. Where this indeed limits operation to less than t, the capital cost is multiplied by t/(MAX t), and yields the cost per derated kilowatt.

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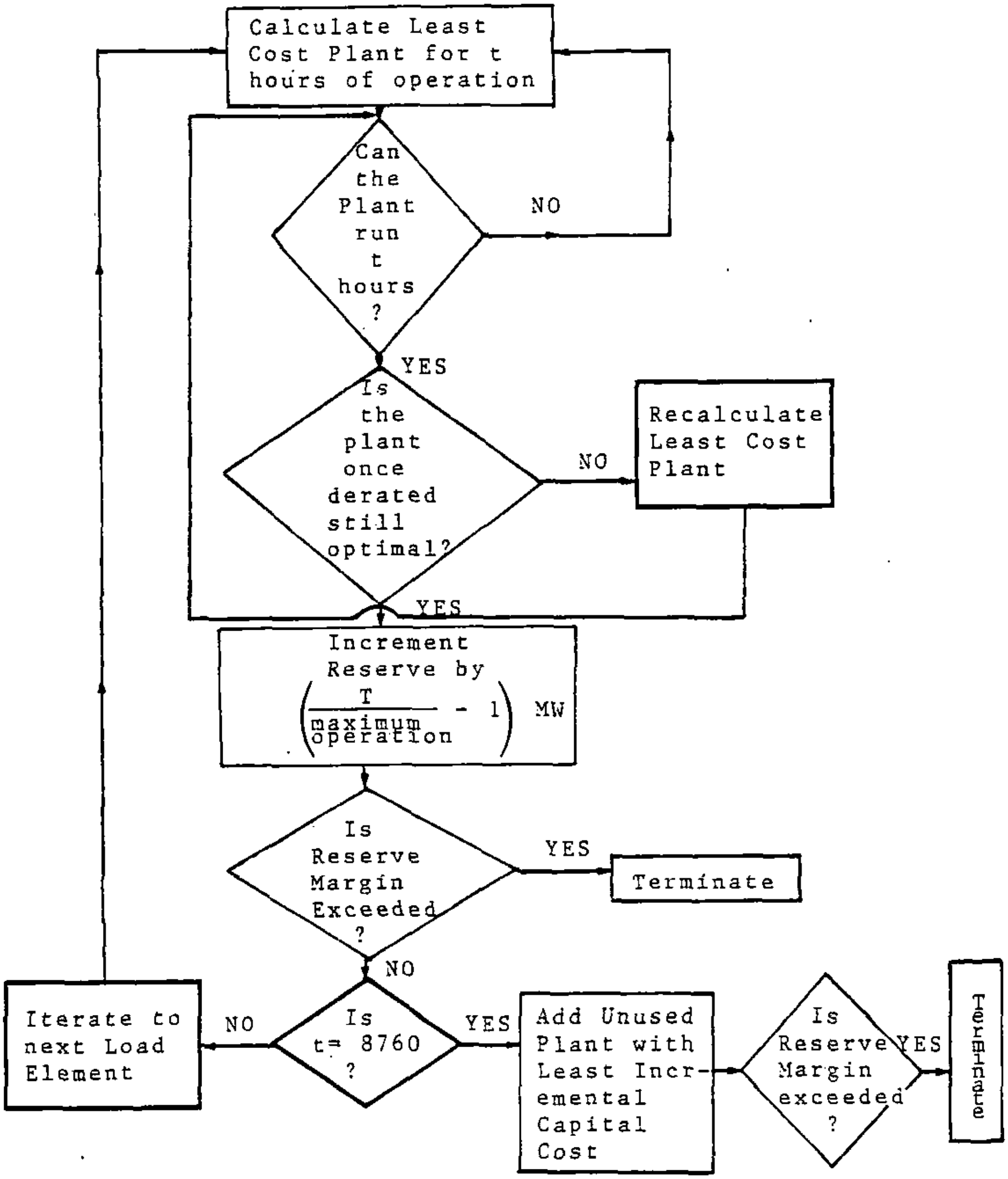
FIGURE 4
Schematic Flow Chart of Optimal
Generation Module (Module I)



If this expanded cost is still optional, the module introduces (t/MAX t)-1 of this facility's capacity as reserve.

Reserve is accumulated until the specified reserve margin is exceeded. Where the reserve is never exceeded throughout the costing iteration procedure, the program introduces a sequence of unused plants as reserve. These will include either old plants which had not heretofore entered the optimal mix or new generics in order of increasing costs. This sequence terminates once the reserve margin is exceeded.

Capacity Assignments

Module #1 is capable at the users' option of assuming a market for excess capacity from any given facility. In this case, the program would mandate a given (optional) number of megawatts from a particular facility. This amount would be wholly independent of the size of the facility. Implicitly we are assuming here that the utility can mandate construction of the plant and then assign the excess over its own needs to some other electrical supply system at cost.

Where the assignment of arbitrarily small portions of a power plant to another utility is assumed to be unrealistic, as it usually is, the program is able at the users' option to round off the capacity included within a single utility's mix to any given block size or fraction of the overall capacity of the plant. This allows for the scenarios of no assignments or assignment in discrete blocks.

Energy Limited Generation Options

Module I can accommodate the possibility of such options as run-of-the-river hydro, pumped storage, or economic energy imports, where the limitation on overall use is constrained on the basis of energy as well as power capacity.

The Use of Incremental Costs

It should be noted that the default option on Module I is that capital costs include only the incremental rather than the full costs of capital. If a plant has been in operation for twenty years, the fixed costs already long committed do not play a role in the economic comparison with other plants. Current carrying charges and fixed O and M are relevant, however, and are included as fixed charges in the cost comparison.

This default option can be waived for plants where cancellation implies a full or nearly full recovery of costs of its construction to date, either through tax writeoffs or assignments of capacity.

MODULE #2: Economic Dispatch

Given the generation mix selected, the operation of this module proceeds first by defining a given load level and then by ranking generation options (plus economy imports) in order of increasing operating cost including fuel cost, variable cost of operations and maintenance, and variable costs due to reduced efficiency as a consequence of environmentally mandated retrofits.

The program successively loads plants in order of increasing operating costs. It tests whether the plant is in fact on-line by generating a random number between 0 and 1 and ascertaining whether this number is less than the plant forced outage rate. If the test is positive, the plant is assumed off line and the program proceeds to the next plant until all plants have been dispatched.

Non-Generation Options

The above procedure is iterated until such time as the hourly load is exhausted. Where the totality of generation options including economy imports is insufficient to meet load, the following sequence of non-generation options is invoked, in the order listed.

I. Emergency imports
II. Controlled access hot water heating
III. Controlled access space heating
IV. Controlled access air conditioning
V. Interruptable contracts
VI. Voluntary appeals
VII. 5% voltage reductions
VIII. 8% voltage reductions
IX. Limited and rotating blackouts
X. Full system blackouts

In the course of the dispatch procedure, the operating costs are accumulated. The costs of non-generation supply is accounted for at very conservative or high values on the basis of the most recent studies.

Together these costs define the expected operating cost for a given load and a single simulation. These expected costs are then averaged over a large number of simulations as specified by the user, in order that average simulated plant availability match the historical data.

Planned Maintenance

For each load a pair of expected costs are specified. During one portion of the year, we assume that planned maintenance is possible: during the peak demand parts of the year, planned maintenance is precluded. The costs are calculated for the planned maintenance period by derating the capacity of all plants. The derating factor is equated to the length of the maintenance (or refueling) period divided by the length of the season over which maintenance is allowed. For the no maintenance period no derating is imposed.

Defining the Expected Cost Function

Figure 5 shows the range of loads over which expected costs are calculated by Module II. Both peak and minimum annual loads are subject to some random variation. Given assumed probability functions for these parameters, we extend the range upward from the peak and downward from the minimum a given number of standard deviations (t) as defined by the user. This generates a function of the following form:

$$\text{Expected operating Cost} = f\left\{\text{Load, Maintenance/No Maintenance}\right\}$$
$$\left(\text{minimum } b \cdot \tau\right) \leq \text{Load} \leq \left(\text{Peak} \quad \text{Peak} + b_o t\right)$$

MODULE III: Calculation of Load Probabilities

Given an expected annual load curve, $LC(\tau)$, Module III assumes for each hour of the year a normal probability distribution, with expected value $LC(\tau)$ and a standard deviation equal to $A_o \times LC(\tau)$ with A_o defined by the user. In other words, the dispersion corresponding to any load value is directly proportional to the magnitude of the load.

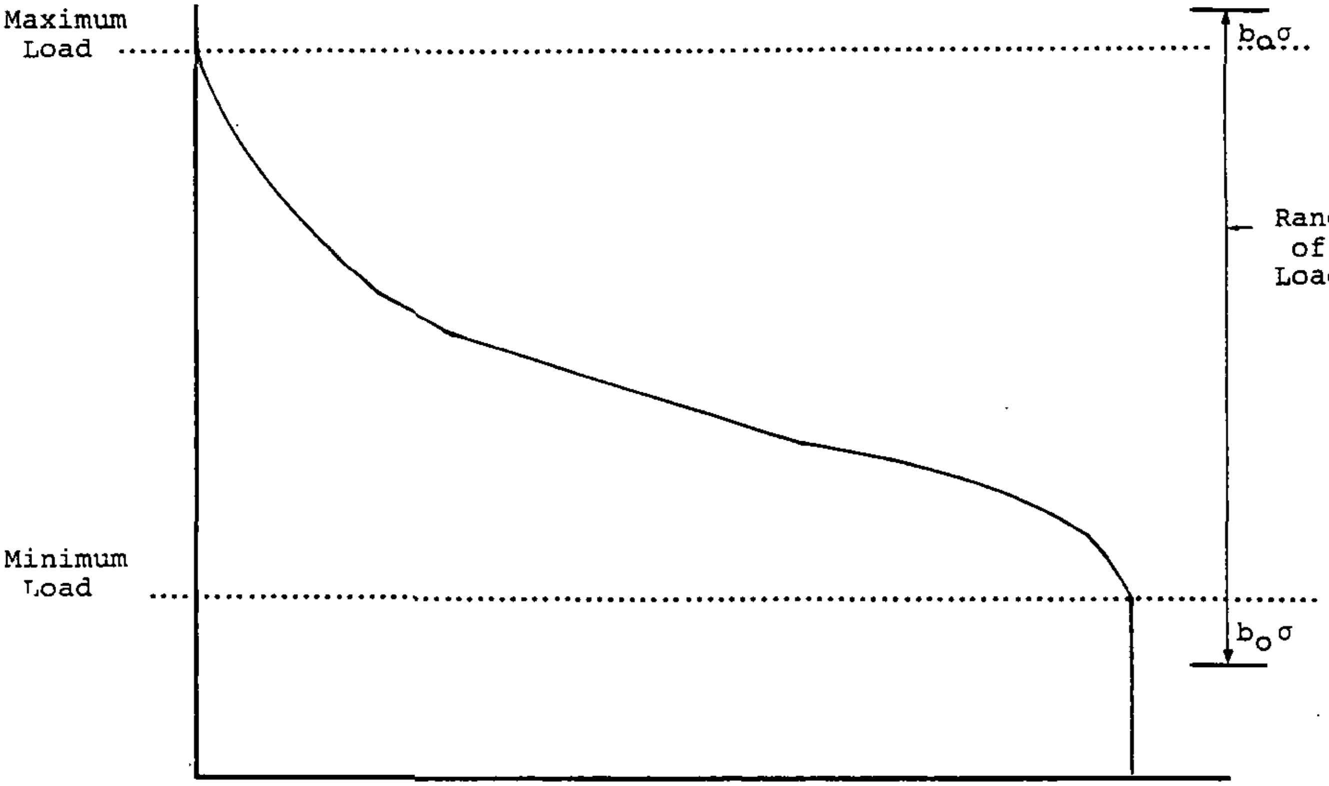
Given this probabilistic formulation, the program calculates the joint probability function

P(Load, Maint/No Maint),

which describes the probability of a given load assuming either that it occurs during the no maintenance or the maintenance season. The user

FIGURE 5

RANGE OF LOADS EMPLOYED FOR CALCULATION OF
EXPECTED SOCIAL COST



inputs those hours of the year where maintenance is possible. Using the desired probability functions, the module sums the probability of a given load over all hours of the year where maintenance is possible and then over all hours of the year where maintenance is disallowed.

MODULE IV: The Calculation of Expected Social Cost

This module computes expected social cost at a given reserve margin by weighting the conditional values found in Module II with the probability values calculated in Module III. This yields the expected operating cost at a given reserve margin. To this are added the fixed costs associated with the optimal generation mix output from Module I.

In mathematical terms:

$$\begin{aligned}\text{TOTAL SOCIAL COST} &= \text{Total Fixed Cost (Reserve Margin, Year)}\\ &+ \sum_{\text{Loads}} \text{Probability (Load, Maint)} \times \text{Expected Operating Cost (Load, Maint)}\\ &+ \sum_{\text{Loads}} \text{Probability (Load, No Maint)} \times \text{Expected Operating Cost (Load, No Maint)}\end{aligned}$$

MODULE V: The Optimal Reserve Margin

This final module consists of two steps:

A. The expected social cost for each year at a given reserve margin is discounted by the nominal social rate of discount. The overall present value of the cost stream is then calculated over a user defined time interval.

B. The program searches among discounted streams for all allowable reserve margins and specifies that margin where toal expected social cost is minimized.

Output Format

Apart from total expected levelized social cost and the optimal reserve margin, the model generates a large quantity of additional information. Exhibit C displays sample output from the program. The actual reserve margin is always greater than the target when the assignment option is limited and plants have to be incorporated in well-defined increments.

Under the heading option are listed supply options entering the optimal mix at a level greater than zero. For each of these options expected total hours of operation and expected energy generated is printed out. Hours are disaggregated into hours within the allowed maintenance period and hours where no maintenance is allowed to occur. Also listed for each option are rated capacities and capacity factors. Finally, the expected costs associated with each option are disaggregated into four categories: energy, variable operations and maintenance, carrying charges, and capital costs. For facilities currently on line, capital costs are accounted at their incremental values only. For facilities under construction, capital costs are accounted at either full or incremental cost depending on the particular scenario. Facilities planned but as yet not constructed are, of course, always accounted at full cost.

EXHIBIT B

SAMPLE PLANT DATA FILE

1. PECO

NAMELIST PEI

		PTYPE	FTYPE	CAP	FOUTR	FUEL	VAROP	FIXCAP	FIXCC	MAINT	CAPFAC
1	BARB5	3	6	17.	0.042	0.026	0.0142	0.	0.72	1680	0.30
2	BARB6	3	6	19.	0.232	0.026	0.0142	0.	0.72	672	0.30
3	BARB7	3	6	17.	0.075	0.026	0.0142	0.	0.72	672	0.30
4	CHEST7	3	4	13.	0.089	0.058	0.0142	0.	0.72	1344	0.30
5	CHEST8	3	4	13.	0.089	0.058	0.0142	0.	0.72	168	0.30
6	CHEST9	3	4	13.	0.089	0.058	0.0142	0.	0.72	336	0.30
7	CROMB1	1	2	137.	0.140	0.015	0.0034	0.	11.72	1344	0.71
8	CROMB2	1	3	183.	0.151	0.046	0.0034	0.	14.61	336	0.81
9	CROY11	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
10	CROY12	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
11	CROY21	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
12	CROY22	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
13	CROY31	2	4	48.	0.323	0.048	0.0047	0.	0.27	0	0.30
14	CROY32	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
15	CROY41	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
16	CROY42	2	4	48.	0.323	0.048	0.0047	0.	0.27	0	0.30
17	DELA7	2	3	126.	0.040	0.038	0.0027	0.	8.14	336	0.85
18	DELA8	2	3	124.	0.040	0.038	0.0027	0.	8.14	336	0.85
19	DELA9	3	4	15.	0.042	0.065	0.0142	0.	0.72	840	0.30
20	DELA10	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
21	DELA11	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
22	DELA12	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
23	EDDY1	1	2	301.	0.180	0.014	0.0030	0.	10.17	1680	0.63
24	EDDY2	1	2	311.	0.200	0.015	0.0030	0.	10.17	1344	0.65
25	EDDY3	2	3	380.	0.250	0.045	0.0030	0.	11.95	336	0.71
26	EDDY4	2	3	380.	0.250	0.045	0.0030	0.	11.95	1680	0.56
27	EDDY10	3	4	13.	0.089	0.058	0.0142	0.	0.72	672	0.30
28	EDDY20	3	4	13.	0.089	0.058	0.0142	0.	0.72	672	0.30
29	EDDY30	3	4	15.	0.042	0.058	0.0142	0.	0.72	1680	0.30
30	EDDY40	3	4	15.	0.042	0.058	0.0142	0.	0.72	1680	0.30
31	FALLS1	3	4	15.	0.042	0.058	0.0142	0.	0.72	1008	0.30
32	FALLS2	3	4	15.	0.042	0.058	0.0142	0.	0.72	840	0.30
33	FALLS3	3	4	15.	0.042	0.058	0.0142	0.	0.72	168	0.30
34	MOSER1	3	4	15.	0.042	0.059	0.0142	0.	0.72	168	0.30
35	MOSER2	3	4	15.	0.042	0.059	0.0142	0.	0.72	168	0.30
36	MOSER3	3	4	15.	0.042	0.059	0.0142	0.	0.72	840	0.30
37	MUDDY1	4	7	110.	0.092	0.0	0.0	0.	2.74	336	0.19
38	MUDDY2	4	7	110.	0.092	0.0	0.0	0.	2.74	336	0.19
39	MUDDY3	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
40	MUDDY4	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
41	MUDDY5	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
42	MUDDY6	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
43	MUDDY7	4	7	110.	0.092	0.0	0.0	0.	2.74	672	0.19
44	MUDDY8	4	7	110.	0.092	0.0	0.0	0.	2.74	672	0.19
45	PEACH2	1	1	447.	0.200	0.004	0.0009	0.	17.42	840	0.70
46	PEACH3	1	1	439.	0.200	0.004	0.0009	0.	17.42	840	0.70
47	DIESEL	3	4	19.	0.850	0.048	0.0009	0.	0.72	336	0.30
48	PLMT9	3	4	29.	0.415	0.064	0.0142	0.	0.72	336	0.20
49	PLMT15	3	4	29.	0.415	0.064	0.0142	0.	0.72	336	0.30
50	RICH9	2	3	166.	0.150	0.039	0.0049	0.	23.39	168	0.81
51	RICH21	3	4	33.	0.111	0.055	0.0142	0.	0.72	672	0.30
52	RICH22	3	4	33.	0.111	0.055	0.0142	0.	0.72	672	0.30
53	RICH31	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
54	RICH32	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
55	RICH41	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
56	RICH42	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
57	RICH43	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30

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58	RICH44	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
59	RICH51	3	4	33.	0.111	0.058	0.0142	0.	0.72	672	0.30
60	RICH52	3	4	33.	0.111	[illegible]	0.0142	0.	0.72	672	0.30
61	RICH61	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
62	RICH62	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
63	RICH71	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
64	RICH72	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
65	RICH81	3	4	51.	0.269	0.050	0.0142	0.	0.72	1008	0.30
66	RICH91	3	4	51.	0.269	0.050	0.0142	0.	0.72	2016	0.30
67	RICH92	3	4	51.	0.269	0.050	0.0142	0.	0.72	2016	0.30
68	SCHY1	2	3	159.	0.150	0.035	0.0030	0.	17.32	1008	0.73
69	SCHY3	1	3	49.	0.120	0.016	0.0030	0.	17.32	84	0.87
70	SCHY5	3	3	32.	0.120	0.060	0.0030	0.	17.32	84	0.67
71	SCHY10	3	4	13.	0.089	0.060	0.0142	0.	0.72	168	0.30
72	SCHY11	3	4	15.	0.042	0.060	0.0142	0.	0.72	1680	0.30
73	SOUTH1	3	3	178.	0.150	0.050	0.0019	0.	9.12	336	0.81
74	SOUTH2	3	3	178.	0.150	0.050	0.0019	0.	9.12	336	0.81
75	SOUTH3	3	4	13.	0.089	0.063	0.0142	0.	0.72	840	0.30
76	SOUTH4	3	4	13.	0.089	0.063	0.0142	0.	0.72	840	0.30
77	SOUTH5	3	4	13.	0.089	0.063	0.0142	0.	0.72	168	0.30
78	SOUTH6	3	4	13.	0.089	0.063	0.0142	0.	0.72	168	0.30
79	CONEM1	1	2	176.	0.379	0.014	0.0019	0.	9.56	168	0.60
80	CONEM2	1	2	176.	0.351	0.014	0.0019	0.	9.56	168	0.63
81	CONEMD	3	4	2.	0.060	0.048	0.0142	0.	0.72	168	0.30
82	KEYST1	1	2	179.	0.275	0.014	0.0023	0.	8.93	672	0.65
83	KEYST2	1	2	179.	0.265	0.014	0.0023	0.	8.93	168	0.71
84	KEYSTD	3	4	2.	0.092	0.048	0.0142	0.	0.72	0	0.30
85	SALEM1	1	1	468.	0.200	0.004	0.0010	0.	18.67	840	0.70
86	SALEM3	3	4	16.	0.043	0.056	0.0142	0.	0.72	840	0.30
87	CONO1	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
88	CONO2	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
89	CONO3	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
90	CONO4	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
91	CONO5	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
92	CONO6	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
93	CONO7	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
94	CONO8	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
95	CONO9	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
96	CONO10	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
97	CONO11	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
98	SALEM2	1	1	474.	0.160	0.004	0.0010	1182.	56.26	1148	0.70
99	LIMERIK1	1	1	1055.	0.160	0.004	0.0010	1508.	66.75	1148	0.70
100	LIMERIK2	1	1	1055.	0.160	0.004	0.0010	1508.	66.75	1148	0.70
101	GNUC	1	1	10000.	0.160	0.004	0.0010	2913.	110.30	840	0.70
102	GCOAL3	1	2	10000.	0.160	0.014	0.0034	1050.	45.32	336	0.80
103	GCOAL6	1	2	10000.	0.210	0.014	0.0034	1000.	47.00	336	0.75
104	GCOAL10	1	2	10000.	0.260	0.014	0.0034	1150.	50.36	336	0.70
105	COMBINED	2	2	10000.	0.110	0.012	0.0039	1410.	59.33	840	0.80
106	OILCYCLE	2	3	10000.	0.110	0.040	0.0030	520.	29.42	336	0.85
107	PKGCT	3	4	10000.	0.050	0.048	0.0142	225.	8.71	168	0.30
108	ECONOMY	6	5	913.	0.100	0.046	0.0	0.	0.0	0	0.50
109	EMRGENCY	6	5	500.	0.500	0.096	0.0	0.	0.0	0	1.10
110	INTERUPT	6	5	0.	0.0	0.0	0.0	0.	0.0	0	1.10
111	LMHW	6	5	64.	0.0	0.200	0.0	0.	0.0	0	0.25
112	LMSH	6	5	0.	0.0	0.200	0.0	50.	0.0	0	1.10
113	LMAC	6	5	0.	0.0	0.200	0.0	50.	0.0	0	1.10
114	VOLAP	6	5	170.	0.0	0.200	0.0	0.	0.0	0	0.10
115	BRNOUT5	6	5	150.	0.0	0.100	0.0	0.	0.0	0	0.10
116	BRNOUT8	6	5	100.	0.0	0.150	0.0	0.	0.0	0	0.10
117	PARTIAL	99	5	10000.	0.0	5.000	0.0	0.	0.0	0	1.00

EXHIBIT B

SAMPLE PLANT DATA FILES

2. ESRG LOW

Exhibit ___ (DS-B)
Sheet 3 of 6

NAMELIST ESLI

		PTYPE	FTYPE	CAP	FOUTR	FUEL	VAROP	FIXCAP	FIXCC	MAINT	CAPFAC
1	BARB5	3	6	17.	0.042	0.026	0.0142	0.	0.72	1680	0.30
2	BARB6	3	6	19.	0.232	0.026	0.0142	0.	0.72	672	0.30
3	BARB7	3	6	17.	0.075	0.026	0.0142	0.	0.72	672	0.30
4	CHEST7	3	4	13.	0.089	0.058	0.0142	0.	0.72	1344	0.30
5	CHEST8	3	4	13.	0.089	0.058	0.0142	0.	0.72	168	0.30
6	CHEST9	3	4	13.	0.089	0.058	0.0142	0.	0.72	336	0.30
7	CROMB1	1	2	137.	0.140	0.015	0.0034	0.	11.72	1344	0.71
8	CROMB2	1	3	183.	0.151	0.046	0.0034	0.	14.61	336	0.81
9	CROY11	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
10	CROY12	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
11	CROY21	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
12	CROY22	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
13	CROY31	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
14	CROY32	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
15	CROY41	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
16	CROY42	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
17	DELA7	2	3	126.	0.040	0.038	0.0027	0.	8.14	336	0.85
18	DELA8	2	3	124.	0.040	0.038	0.0027	0.	8.14	336	0.85
19	DELA9	3	4	15.	0.042	0.065	0.0142	0.	0.72	840	0.30
20	DELA10	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
21	DELA11	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
22	DELA12	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
23	EDDY1	1	2	301.	0.180	0.014	0.0030	0.	10.17	1680	0.63
24	EDDY2	1	2	311.	0.200	0.015	0.0030	0.	10.17	1344	0.65
25	EDDY3	2	3	380.	0.250	0.045	0.0030	0.	11.95	336	0.71
26	EDDY4	2	3	380.	0.250	0.045	0.0030	0.	11.95	1680	0.56
27	EDDY10	3	4	13.	0.089	0.058	0.0142	0.	0.72	672	0.30
28	EDDY20	3	4	13.	0.089	0.058	0.0142	0.	0.72	672	0.30
29	EDDY30	3	4	15.	0.042	0.058	0.0142	0.	0.72	1680	0.30
30	EDDY40	3	4	15.	0.042	0.058	0.0142	0.	0.72	1680	0.30
31	FALLS1	3	4	15.	0.042	0.058	0.0142	0.	0.72	1008	0.30
32	FALLS2	3	4	15.	0.042	0.058	0.0142	0.	0.72	840	0.30
33	FALLS3	3	4	15.	0.042	0.058	0.0142	0.	0.72	168	0.30
34	MOSER1	3	4	15.	0.042	0.059	0.0142	0.	0.72	168	0.30
35	MOSER2	3	4	15.	0.042	0.059	0.0142	0.	0.72	168	0.30
36	MOSER3	3	4	15.	0.042	0.059	0.0142	0.	0.72	840	0.30
37	MUDDY1	4	7	110.	0.092	0.0	0.0	0.	2.74	336	0.19
38	MUDDY2	4	7	110.	0.092	0.0	0.0	0.	2.74	336	0.19
39	MUDDY3	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
40	MUDDY4	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
41	MUDDY5	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
42	MUDDY6	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.19
43	MUDDY7	4	7	110.	0.092	0.0	0.0	0.	2.74	672	0.19
44	MUDDY8	4	7	110.	0.092	0.0	0.0	0.	2.74	672	0.19
45	PEACH2	1	1	447.	0.200	0.004	0.0009	0.	17.42	840	0.70
46	PEACH3	1	1	439.	0.200	0.004	0.0009	0.	17.42	840	0.70
47	DIESEL	3	4	19.	0.850	0.048	0.0009	0.	0.72	336	0.30
48	PLMT9	3	4	29.	0.415	0.064	0.0142	0.	0.72	336	0.30
49	PLMT15	3	4	29.	0.415	0.064	0.0142	0.	0.72	336	0.30
50	RICH9	2	3	166.	0.150	0.039	0.0049	0.	23.39	168	0.83
51	RICH21	3	4	33.	0.111	0.055	0.0142	0.	0.72	672	0.30
52	RICH22	3	4	33.	0.111	0.055	0.0142	0.	0.72	672	0.30
53	RICH31	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
54	RICH32	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
55	RICH41	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
56	RICH42	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30

57	RICH43	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
58	RICH44	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
59	RICH51	3	4	33.	0.111	0.058	0.0142	0.	0.72	672	0.30
60	RICH52	3	4	33.	0.111	0.058	0.0142	0.	0.72	672	0.30
61	RICH61	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
62	RICH62	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
63	RICH71	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
64	RICH72	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
65	RICH81	3	4	51.	0.269	0.050	0.0142	0.	0.72	1008	0.30
66	RICH91	3	4	51.	0.269	0.050	0.0142	0.	0.72	2016	0.30
67	RICH92	3	4	51.	0.269	0.050	0.0142	0.	0.72	2016	0.30
68	SCHY1	2	3	159.	0.150	0.035	0.0030	0.	17.32	1008	0.73
69	SCHY3	1	3	49.	0.120	0.016	0.0030	0.	17.32	84	0.87
70	SCHY9	3	3	32.	0.120	0.060	0.0030	0.	17.32	84	0.87
71	SCHY10	3	4	13.	0.089	0.060	0.0142	0.	0.72	168	0.30
72	SCHY11	3	4	15.	0.042	0.060	0.0142	0.	0.72	1680	0.30
73	SOUTH1	3	3	178.	0.150	0.050	0.0019	0.	9.12	336	0.81
74	SOUTH2	3	3	178.	0.150	0.050	0.0019	0.	9.12	336	0.81
75	SOUTH3	3	4	13.	0.089	0.063	0.0142	0.	0.72	840	0.30
76	SOUTH4	3	4	13.	0.089	0.063	0.0142	0.	0.72	840	0.30
77	SOUTH5	3	4	13.	0.089	0.063	0.0142	0.	0.72	168	0.30
78	SOUTH6	3	4	13.	0.089	0.063	0.0142	0.	0.72	168	0.30
79	CONEM1	1	2	176.	0.379	0.014	0.0019	0.	9.56	168	0.60
80	CONEM2	1	2	176.	0.351	0.014	0.0019	0.	9.56	168	0.63
81	CONEMD	3	4	2.	0.060	0.048	0.0142	0.	0.72	168	0.30
82	KEYST1	1	2	179.	0.275	0.014	0.0023	0.	8.93	672	0.65
83	KEYST2	1	2	179.	0.265	0.014	0.0023	0.	8.93	168	0.71
84	KEYSTD	3	4	2.	0.092	0.048	0.0142	0.	0.72	0	0.30
85	SALEM1	1	1	468.	0.200	0.004	0.0010	0.	18.67	840	0.70
86	SALEM3	3	4	16.	0.043	0.056	0.0142	0.	0.72	840	0.30
87	CON01	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
88	CON02	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
89	CON03	5	7	35.	0.090	0.0	0.0	0.	4.00	0	0.40
90	CON04	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
91	CON05	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
92	CON06	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
93	CON07	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
94	CON08	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
95	CON09	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
96	CON010	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
97	CON011	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
98	SALEM2	1	1	474.	0.260	0.004	0.0010	1182.	56.26	1148	0.60
99	LIMERIK1	1	1	1055.	0.260	0.004	0.0010	1764.	74.68	1148	0.60
100	LIMERIK2	1	1	1055.	0.260	0.004	0.0010	1764.	74.66	1146	0.60
101	GNUC	1	1	10000.	0.260	0.004	0.0010	2913.	110.30	840	0.60
102	GCOAL3	1	2	10000.	0.160	0.014	0.0034	1058.	47.27	336	0.60
103	GCOAL6	1	2	10000.	0.210	0.014	0.0034	1103.	48.78	336	0.75
104	GCOAL10	1	2	10000.	0.260	0.014	0.0034	1197.	51.94	336	0.70
105	COMBINED	2	2	10000.	0.140	0.012	0.0039	1460.	61.01	940	0.80
106	OILCYCLE	2	3	10000.	0.110	0.040	0.0030	520.	29.42	336	0.85
107	PKGCT	3	4	10000.	0.050	0.048	0.0142	225.	8.71	168	0.30
108	ECONOMY	6	5	913.	0.100	0.046	0.0	0.	0.0	0	0.50
109	EMRGENCY	6	5	500.	0.500	0.096	0.0	0.	0.0	0	1.10
110	INTERUPT	6	5	0.	0.0	0.0	0.0	0.	0.0	0	1.10
111	LMHW	6	5	64.	0.0	0.200	0.0	0.	0.0	0	0.25
112	LMSH	6	5	0.	0.0	0.200	0.0	50.	0.0	0	1.10
113	LMAC	6	5	0.	0.0	0.200	0.0	50.	0.0	0	1.10
114	VOLAP	6	5	170.	0.0	0.200	0.0	0.	0.0	0	0.10
115	BRNOUT5	6	5	150.	0.0	0.100	0.0	0.	0.0	0	0.10
116	BRNOUT8	6	5	100.	0.0	0.150	0.0	0.	0.0	0	0.10
117	PARTIAL	99	5	10000.	0.0	5.000	0.0	0.	0.0	0	1.00

EXHIBIT B

SAMPLE PLANT DATA FILES

3. ESRG HIGH

NAMELIST ESHI

		PTYPE	FTYPE	CAP	FOUTR	FUEL	VAROP	FIXCAP	FIXCC	MAINT	CAPFAC
1	BARB5	3	6	17.	0.042	0.026	0.0142	0.	0.72	1680	0.30
2	BARB6	3	6	19.	0.232	0.026	0.0142	0.	0.72	672	0.30
3	BARB7	3	6	17.	0.075	0.026	0.0142	0.	0.72	672	0.30
4	CHEST7	3	4	13.	0.089	0.058	0.0142	0.	0.72	1344	0.30
5	CHEST8	3	4	13.	0.089	0.058	0.0142	0.	0.72	168	0.30
6	CHEST9	3	4	13.	0.089	0.058	0.0142	0.	0.72	336	0.30
7	CROMB1	1	2	137.	0.140	0.015	0.0034	0.	11.72	1344	0.71
8	CROMB2	1	3	183.	0.151	0.046	0.0034	0.	14.61	336	0.81
9	CROY11	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
10	CROY12	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
11	CROY21	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
12	CROY22	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
13	CROY31	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
14	CROY32	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
15	CROY41	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
16	CROY42	2	4	49.	0.323	0.048	0.0047	0.	0.27	0	0.30
17	DELA7	2	3	126.	0.040	0.038	0.0027	0.	8.14	336	0.85
18	DELA8	2	3	124.	0.040	0.038	0.0027	0.	8.14	336	0.85
19	DELA9	3	4	15.	0.042	0.065	0.0142	0.	0.72	840	0.30
20	DELA10	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
21	DELA11	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
22	DELA12	3	4	13.	0.089	0.065	0.0142	0.	0.72	672	0.30
23	EDDY1	1	2	301.	0.180	0.014	0.0030	0.	10.17	1680	0.63
24	EDDY2	1	2	311.	0.200	0.015	0.0030	0.	10.17	1344	0.65
25	EDDY3	2	3	360.	0.250	0.045	0.0030	0.	11.95	336	0.71
26	EDDY4	2	3	380.	0.250	0.045	0.0030	0.	11.95	1680	0.5E
27	EDDY10	3	4	13.	0.089	0.058	0.0142	0.	0.72	672	0.30
28	EDDY20	3	4	13.	0.089	0.058	0.0142	0.	0.72	672	0.30
29	EDDY30	3	4	15.	0.042	0.058	0.0142	0.	0.72	1680	0.30
30	EDDY40	3	4	15.	0.042	0.058	0.0142	0.	0.72	1680	0.30
31	FALLS1	3	4	15.	0.042	0.058	0.0142	0.	0.72	1008	0.30
32	FALLS2	3	4	15.	0.042	0.058	0.0142	0.	0.72	840	0.3
33	FALLS3	3	4	15.	0.042	0.058	0.0142	0.	0.72	168	0.3
34	MOSER1	3	4	15.	0.042	0.059	0.0142	0.	0.72	168	0.3
35	MOSER2	3	4	15.	0.042	0.059	0.0142	0.	0.72	168	0.3
36	MOSER3	3	4	15.	0.042	0.059	0.0142	0.	0.72	840	0.3
37	MUDDY1	4	7	110.	0.092	0.0	0.0	0.	2.74	336	0.1
38	MUDDY2	4	7	110.	0.092	0.0	0.0	0.	2.74	336	0.1
39	MUDDY3	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.1
40	MUDDY4	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.1
41	MUDDY5	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.1
42	MUDDY6	4	7	110.	0.092	0.0	0.0	0.	2.74	0	0.1
43	MUDDY7	4	7	110.	0.092	0.0	0.0	0.	2.74	672	0.1
44	MUDDY8	4	7	110.	0.092	0.0	0.0	0.	2.74	672	0.1
45	PEACH2	1	1	447.	0.200	0.004	0.0009	0.	17.42	840	0.7
46	PEACH3	1	1	439.	0.200	0.004	0.0009	0.	17.42	840	0.7
47	DIESEL	3	4	19.	0.850	0.048	0.0009	0.	0.72	336	0.[illegible]
48	PLMT9	3	4	29.	0.415	0.064	0.0142	0.	0.72	336	0.[illegible]
49	PLMT15	3	4	29.	0.415	0.064	0.0142	0.	0.72	336	0.[illegible]
50	RICH9	2	3	166.	0.150	0.039	0.0049	0.	23.39	168	0.[illegible]
51	RICH21	3	4	33.	0.111	0.055	0.0142	0.	0.72	672	0.[illegible]
52	RICH22	3	4	33.	0.111	0.055	0.0142	0.	0.72	672	0.[illegible]
53	RICH31	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.[illegible]
54	RICH32	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.[illegible]
55	RICH41	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.
56	RICH42	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.
57	RICH43	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.

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58	RICH44	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
59	RICH51	3	4	33.	0.111	0.058	0.0142	0.	0.72	672	0.30
60	RICH52	3	4	33.	0.111	0.058	0.0142	0.	0.72	672	0.30
61	RICH61	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
62	RICH62	3	4	33.	0.111	0.058	0.0142	0.	0.72	336	0.30
63	RICH71	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
64	RICH72	3	4	21.	0.216	0.055	0.0142	0.	0.72	1008	0.30
65	RICH81	3	4	51.	0.269	0.050	0.0142	0.	0.72	1008	0.30
66	RICH91	3	4	51.	0.269	0.050	0.0142	0.	0.72	2016	0.30
67	RICH92	3	4	51.	0.269	0.050	0.0142	0.	0.72	2016	0.30
68	SCHY1	2	3	159.	0.150	0.035	0.0030	0.	17.32	1008	0.73
69	SCHY3	1	3	49.	0.120	0.016	0.0030	0.	17.32	84	0.87
70	SCHY9	3	3	32.	0.120	0.060	0.0030	0.	17.32	84	0.87
71	SCHY10	3	4	13.	0.089	0.060	0.0142	0.	0.72	168	0.30
72	SCHY11	3	4	15.	0.042	0.060	0.0142	0.	0.72	1680	0.30
73	SOUTH1	3	3	178.	0.150	0.050	0.0019	0.	9.12	336	0.81
74	SOUTH2	3	3	178.	0.150	0.050	0.0019	0.	9.12	336	0.81
75	SOUTH3	3	4	13.	0.089	0.063	0.0142	0.	0.72	840	0.30
76	SOUTH4	3	4	13.	0.089	0.063	0.0142	0.	0.72	840	0.30
77	SOUTH5	3	4	13.	0.085	0.063	0.0142	0.	0.72	168	0.30
78	SOUTH6	3	4	13.	0.089	0.063	0.0142	0.	0.72	168	0.30
79	CONEM1	1	2	176.	0.375	0.014	0.0019	0.	9.56	168	0.60
80	CONEM2	1	2	176.	0.351	0.014	0.0019	0.	9.56	168	0.63
81	CONEMD	3	4	2.	0.060	0.048	0.0142	0.	0.72	168	0.30
82	KEYST1	1	2	179.	0.275	0.014	0.0023	0.	8.93	672	0.65
83	KEYST2	1	2	179.	0.265	0.014	0.0023	0.	8.93	168	0.71
84	KEYSTD	3	4	2.	0.092	0.048	0.0142	0.	0.72	0	0.30
85	SALEM1	1	1	468.	0.200	0.004	0.0010	0.	18.67	840	0.70
86	SALEM3	3	4	16.	0.043	0.056	0.0142	0.	0.72	840	0.30
87	CONO1	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
88	CONO2	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
89	CONO3	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
90	CONO4	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
91	CONO5	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
92	CONO6	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
93	CONO7	5	7	36.	0.090	0.0	0.0	0.	4.00	0	0.40
94	CONO8	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
95	CONO9	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
96	CONO10	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
97	CONO11	5	7	65.	0.090	0.0	0.0	0.	4.00	0	0.40
98	SALEM2	1	1	474.	0.260	0.004	0.0010	1182.	73.26	1148	0.60
99	LIMERIK1	1	1	1055.	0.260	0.004	0.0010	1907.	79.12	1148	0.60
100	LIMERIK2	1	1	1055.	0.260	0.004	0.0010	1907.	79.12	1148	0.60
101	GNUC	1	1	10000.	0.260	0.004	0.0010	3158.	117.90	840	0.60
102	GCOAL3	1	2	10000.	0.160	0.014	0.0034	1111.	49.05	336	0.80
103	GCOAL6	1	2	10000.	0.210	0.014	0.0034	1164.	50.83	336	0.75
104	GCOAL10	1	2	10000.	0.260	0.014	0.0034	1257.	53.96	336	0.70
105	COMBINED	2	2	10000.	0.140	0.012	0.0039	1510.	62.69	840	0.80
106	OILCYCLE	2	3	10000.	0.110	0.040	0.0030	520.	29.42	336	0.85
107	PKGCT	3	4	10000.	0.050	0.048	0.0142	225.	8.71	168	0.30
108	ECONOMY	6	5	913.	0.100	0.046	0.0	0.	0.0	0	0.50
109	EMRGENCY	6	5	500.	0.500	0.096	0.0	0.	0.0	0	1.10
110	INTERUPT	6	5	0.	0.0	0.0	0.0	0.	0.0	0	1.10
111	LMHW	6	5	64.	0.0	0.200	0.0	0.	0.0	0	0.25
112	LMSH	6	5	0.	0.0	0.200	0.0	50.	0.0	0	1.10
113	LMAC	6	5	0.	0.0	0.200	0.0	50.	0.0	0	1.10
114	VOLAP	6	5	170.	0.0	0.200	0.0	0.	0.0	0	0.10
115	BRNOUT5	6	5	150.	0.0	0.100	0.0	0.	0.0	0	0.10
116	BRNOUT8	6	5	100.	0.0	0.150	0.0	0.	0.0	0	0.10
117	PARTIAL	99	5	10000.	0.0	5.000	0.0	0.	0.0	0	1.00

EXHIBIT C

SAMPLE ESGEM RUN

BASED UPON:

PECO CONSTRUCTION PROGRAM

PECO DEMAND FORECAST

FULL PECO PLANT CAPITAL COSTS

Exhibit ___ (DS-C)
Sheet 1 of 24

1020a

LOAD CURVE: [illegible] PLANT DATA: [illegible] LOAD GROWTH: [illegible] RESERVE MARGINS: INPUT D.H.A.

OPTION	KILOWATTS CAPACITY	HOURS OF USE MAINT	NONMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1981 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
[illegible]	[illegible]	1180.9	[illegible]	[illegible]	0.320	1.59	3.78	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1.74	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.311	1.50	2.74	0.01	[illegible]	[illegible]	43.3
[illegible]	13.	3.0	[illegible]	4.5	0.000	0.00	0.00	0.01	0.0	0.02	[illegible]
[illegible]	13.	[illegible]	[illegible]	5.1	0.001	0.00	0.00	0.01	0.0	0.02	[illegible]
[illegible]	[illegible]	5.3	[illegible]	8.0	[illegible]	0.01	0.00	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.375	[illegible]	3.10	1.00	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	7.42	[illegible]	[illegible]	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.02	0.01	[illegible]	0.29	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.010	0.24	0.02	0.01	0.0	0.27	[illegible]
[illegible]	49.	[illegible]	[illegible]	207.4	[illegible]	0.56	0.05	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	135.2	179.2	[illegible]	[illegible]	0.05	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	32.1	[illegible]	[illegible]	0.009	0.23	0.02	0.01	0.0	[illegible]	[illegible]
[illegible]	49.	33.2	[illegible]	87.5	0.009	0.21	0.02	0.01	0.0	0.25	[illegible]
[illegible]	49.	43.0	62.2	105.1	0.011	[illegible]	0.03	0.01	0.0	0.33	4.9
[illegible]	126.	3064.5	4812.4	7876.9	0.861	43.70	2.00	1.15	0.0	47.73	950.3
[illegible]	121.	3104.5	4777.7	7882.2	0.859	42.88	2.03	1.13	0.0	46.85	930.7
[illegible]	[illegible]	2.1	[illegible]	2.4	0.000	[illegible]	[illegible]	0.01	0.0	[illegible]	[illegible]
[illegible]	13.	[illegible]	[illegible]	[illegible]	0.000	[illegible]	0.00	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	3.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	3.0	0.000	0.00	0.00	[illegible]	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	38.34	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.001	[illegible]	0.00	0.01	0.0	0.03	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	7.1	0.001	0.01	0.00	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	5.8	[illegible]	[illegible]	0.001	0.01	0.00	0.01	0.0	[illegible]	[illegible]
[illegible]	15.	6.6	[illegible]	[illegible]	0.001	0.01	0.00	0.01	0.0	0.02	[illegible]
[illegible]	15.	6.4	2.8	9.2	0.001	0.01	0.00	0.01	0.0	0.02	[illegible]
[illegible]	15.	[illegible]	[illegible]	4.4	0.001	[illegible]	0.00	0.01	0.0	0.02	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.00	0.00	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.04	[illegible]	0.01	0.0	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	1934.7	0.310	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	1727.7	0.220	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	1922.9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	1235.1	1946.7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	129.	653.1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.34	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	726.7	[illegible]	2500.9	[illegible]	[illegible]	0.0	[illegible]	0.0	0.74	[illegible]
[illegible]	[illegible]	2501.1	4180.9	[illegible]	[illegible]	12.57	2.72	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	2550.5	[illegible]	6716.2	0.690	[illegible]	2.80	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	19.	75.1	204.6	277.7	0.028	0.27	0.00	0.02	0.0	0.29	[illegible]
[illegible]	29.	1.6	[illegible]	2.2	0.000	0.00	0.00	[illegible]	0.0	0.03	[illegible]
[illegible]	29.	[illegible]	[illegible]	[illegible]	0.001	[illegible]	0.00	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	156.	2931.1	4247.6	7178.7	0.784	53.89	6.28	4.35	0.0	[illegible]	[illegible]
[illegible]	33.	16.0	21.0	37.0	0.004	0.07	0.02	0.03	0.0	0.12	[illegible]
[illegible]	33.	18.6	22.8	41.4	0.004	0.09	0.02	0.03	0.0	0.13	1.5
[illegible]	33.	3.8	2.4	6.2	0.001	0.01	0.00	0.03	0.0	0.04	0.2
[illegible]	33.	4.1	1.8	5.9	0.001	0.01	0.00	0.03	0.0	0.04	0.2
[illegible]	21.	14.8	21.7	36.5	0.004	0.04	0.01	0.02	0.0	0.07	0.7
[illegible]	21.	13.9	20.7	34.6	0.003	0.03	0.01	0.02	0.0	0.06	0.5
[illegible]	21.	10.3	14.1	24.4	0.002	0.03	0.01	0.02	0.0	0.05	0.4
[illegible]	21.	7.0	4.1	11.1	0.001	0.01	0.00	0.02	0.0	0.03	0.2
[illegible]	33.	3.7	1.6	5.3	0.001	0.01	0.00	0.03	0.0	0.04	0.2
[illegible]	33.	3.9	1.5	5.4	0.001	0.01	0.00	0.03	0.0	0.04	0.2
[illegible]	33.	6.3	2.8	9.1	0.001	0.02	0.00	0.03	0.0	0.05	0.3
[illegible]	33.	3.7	1.4	5.1	0.001	0.01	0.00	0.03	0.0	0.04	0.2
[illegible]	21.	8.1	3.1	11.2	0.001	0.01	0.00	0.02	0.0	0.03	[illegible]
[illegible]	21.	6.3	3.2	9.6	0.001	0.01	0.00	0.02	0.0	0.03	[illegible]
[illegible]	51.	13.5	14.9	28.3	0.003	0.08	0.02	0.04	0.0	[illegible]	[illegible]
[illegible]	51.	20.5	21.8	42.3	0.003	0.08	0.02	0.04	0.0	0.14	[illegible]
[illegible]	51.	[illegible]	[illegible]	[illegible]	0.002	[illegible]	0.01	0.04	0.0	0.11	0.7
[illegible]	159.	2674.7	4414.5	[illegible]	0.711	41.71	3.34	3.09	0.0	48.34	789.7
[illegible]	49.	3097.7	4654.8	7752.5	0.876	7.25	1.27	0.95	0.0	9.50	376.2
[illegible]	32.	30.4	34.3	64.7	0.007	0.15	0.01	0.62	0.0	0.78	2.0
[illegible]	13.	3.1	1.1	4.2	0.000	0.00	0.00	0.01	0.0	0.02	0.1
[illegible]	15.	3.3	1.1	4.4	0.000	0.00	0.00	0.01	0.0	0.02	0.1
[illegible]	175.	264.4	573.4	837.8	0.073	6.87	0.24	1.02	0.0	8.76	114.0
[illegible]	175.	142.3	324.6	[illegible]	0.041	3.82	0.13	1.82	0.0	5.78	[illegible]
[illegible]	13.	[illegible]	0.8	2.6	0.000	0.00	0.00	0.01	0.0	0.01	[illegible]
[illegible]	13.	3.0	1.1	4.1	0.000	0.00	0.00	0.01	0.0	0.02	[illegible]
[illegible]	13.	[illegible]	0.9	4.0	0.000	0.00	0.00	0.01	0.0	0.02	0.1
[illegible]	13.	2.9	[illegible]	[illegible]	[illegible]	0.00	0.00	0.01	0.0	0.02	[illegible]
[illegible]	176.	2126.6	3174.6	5301.2	[illegible]	14.02	1.75	1.09	0.0	18.37	915.0
[illegible]	176.	2240.1	3466.3	5706.4	[illegible]	15.63	[illegible]	1.09	0.0	19.63	784.7
CONEMD	2.	27.7	32.0	59.7	0.007	0.01	0.00	0.00	0.0	0.01	0.1
KEYST1	179.	2350.7	3879.0	6229.7	[illegible]	16.24	[illegible]	1.79	0.0	20.67	1022.9
KEYST2	179.	2544.1	3859.3	6403.3	[illegible]	17.79	[illegible]	1.79	0.0	22.48	1120.8
KEYSTD	2.	29.0	41.2	70.2	[illegible]	[illegible]	0.00	0.00	0.0	0.01	[illegible]

POOR ORIGINAL

86 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0[illegible]1	[illegible]	0.00	[illegible]	0.0	0.0[illegible]	[illegible]
87 CON01	[illegible]	[illegible]	[illegible]	[illegible]	0.421	0.0	0.0	0.1[illegible]	0.0	0.16	[illegible]
88 CON02	[illegible]	[illegible]	[illegible]	[illegible]	0.421	0.0	0.0	0.1[illegible]	0.0	0.16	[illegible]
89 CON03	[illegible]	[illegible]	[illegible]	[illegible]	0.42[illegible]	0.0	0.0	0.16	0.0	0.16	131.[illegible]
90 CON04	[illegible]	1461.1	[illegible]	[illegible]	0.407	0.0	0.0	0.16	0.0	0.16	178.4
91 CON05	[illegible]	1459.0	[illegible]	[illegible]	0.41[illegible]	0.0	0.0	0.16	0.0	0.16	130.2
92 CON06	56.	1448.3	[illegible]	[illegible]	0.405	0.0	0.0	0.16	0.0	0.16	1[illegible]7.9
93 CON07	56.	1449.1	[illegible]	[illegible]	0.[illegible]	0.0	0.0	0.16	0.0	0.16	130.[illegible]
94 CON08	65.	1505.6	[illegible]	[illegible]	0.415	0.0	0.0	0.29	0.0	0.29	2[illegible]4.3
95 CON09	65.	[illegible]	[illegible]	[illegible]	0.411	0.0	0.0	0.29	0.0	0.29	234.[illegible]
96 CON010	65.	1498.6	2134.0	36[illegible]3.6	0.421	0.0	0.0	0.29	0.0	0.29	239.4
97 CON011	65.	1483.1	2167.2	3650.2	0.417	0.0	0.0	0.29	0.0	0.29	237.3
98 SALEM2	209.	2515.4	4505.4	7021.7	0.689	5.89	1.41	13.18	27.47	47.96	1257.9
108 ECONOMY	913.	2847.8	3751.8	6602.6	0.513	228.42	0.0	0.0	0.0	228.42	4103.9
109 EMRGENCY	500.	0.6	0.1	0.7	0.000	0.02	0.0	0.0	0.0	0.02	0.1
111 LANW	51.	1.4	0.0	1.4	0.000	0.02	0.0	0.0	0.0	0.02	0.1
114 VOLAF	120.	0.8	0.0	0.9	0.000	0.01	0.0	0.0	0.0	0.01	0.0
115 BRNOUT5	150.	0.1	0.0	0.1	0.000	0.00	0.0	0.0	0.0	0.00	0.0
116 BRNOUT8	100.	0.1	0.0	0.1	0.000	0.00	0.0	0.0	0.0	0.00	0.0
117 PARTIAL	******	0.0	0.0	0.0	0.0	0.02	0.0	0.0	0.0	0.02	0.0
118 TOTAL	******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0009 = 0.0 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0002 = 0.5 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 862.0 MILLION (1981) = $ 739.7 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 32002. GWH
INCREMENTAL ELECTRICITY COST [illegible] 1981 CENTS PER KWH = 2.3 1979 CENTS PER KWH
LOAD FACTOR 59.32

TOTAL COSTS IN 1981 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	458.	393.
VARIABLE O&M	58.	50.
CARRYING CHARGES	91.	78.
INCREMENTAL CAPITAL	27.	24.

IMPORT OPTIONS:	COST IN 1981 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	228.42	195.83	4103.9
EMRGENCY	[illegible]	0.01	0.1

TOTAL [illegible] COST [illegible] MILLION (DISCOUNTED TO 1979)
[illegible] MILLION (DISCOUNTED TO 1979)

POOR ORIGINAL

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[illegible] PECO [illegible] PECO [illegible] PECO LOAD GROWTH: PECO RESERVE MARGINS: INPUT D.N.A. 60

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OPTION	CAPACITY	COSTS OF USE [illegible]	[illegible]	[illegible]	ANNUAL CAP FAC	COSTS (MILLIONS OF 1987 DOLLARS) [illegible]	[illegible]	CARBON	CAPITAL	TOTAL	GWH GENERATED
1 BARB5	[illegible]	[illegible]	2323.1	[illegible]	[illegible]	[illegible]	[illegible]	0.02	0.0	3.60	44.0
2 BARB6	[illegible]	800.3	1840.8	[illegible]	0.272	[illegible]	0.97	0.02	0.0	3.71	45.2
3 BARB7	17.	964.6	1919.7	2884.3	0.300	2.68	0.95	0.02	0.0	3.66	44.6
8 CROMB2	133.	90.3	167.1	257.7	0.024	[illegible]	0.20	4.03	0.0	7.78	38.1
9 CROY11	49.	19.4	52.3	71.7	0.007	[illegible]	0.02	0.02	0.0	0.31	2.8
10 CROY12	49.	22.8	59.5	82.3	0.009	[illegible]	0.03	0.02	0.0	0.42	3.8
11 CROY21	49.	14.7	31.2	45.8	0.005	0.21	0.02	0.02	0.0	0.25	2.2
12 CROY22	49.	18.5	34.2	52.8	0.005	0.22	0.02	0.02	0.0	0.26	2.3
13 CROY31	49.	12.8	19.5	32.3	0.004	0.15	0.01	0.02	0.0	0.18	1.5
14 CROY32	49.	30.6	58.0	88.6	0.010	0.40	0.03	0.02	0.0	0.45	4.1
15 CROY41	49.	14.9	47.8	62.7	0.006	0.26	0.02	0.02	0.0	0.30	2.6
16 CROY42	49.	27.3	45.3	72.5	0.008	0.36	0.02	0.02	0.0	0.37	3.3
17 DELA7	126.	1206.1	2668.1	3874.2	0.396	33.73	1.78	1.54	0.0	37.05	432.5
18 DELA8	124.	1363.9	3117.0	4480.9	0.461	38.63	2.04	1.52	0.0	42.18	501.0
23 EDDY1	301.	2152.5	3509.3	5661.8	0.488	27.55	5.81	4.61	0.0	37.97	1285.9
24 EDDY2	311.	1830.7	3357.9	5188.6	0.450	28.12	5.53	4.76	0.0	38.41	1225.3
25 EDDY3	380.	143.7	300.1	443.9	0.037	11.31	0.56	6.84	0.0	18.71	123.9
26 EDDY4	380.	205.9	443.9	649.7	0.043	12.98	0.64	6.84	0.0	20.46	142.2
35 MOSER2	15.	7.9	8.2	16.2	0.002	0.02	0.00	0.02	0.0	0.05	0.2
36 MOSER3	15.	8.0	8.2	16.2	0.002	0.02	0.00	0.02	0.0	0.05	0.2
37 MUDDY1	110.	757.1	1277.2	2034.2	0.223	0.0	0.0	0.45	0.0	0.45	214.7
38 MUDDY2	110.	769.6	1080.2	1849.8	0.203	0.0	0.0	0.45	0.0	0.45	195.8
39 MUDDY3	110.	723.1	1047.9	1770.9	0.202	0.0	0.0	0.45	0.0	0.45	194.8
40 MUDDY4	110.	769.2	1068.7	1837.8	0.210	0.0	0.0	0.45	0.0	0.45	202.2
41 MUDDY5	110.	731.4	1049.9	1781.4	0.203	0.0	0.0	0.45	0.0	0.45	195.9
42 MUDDY6	110.	725.5	1074.0	1799.5	0.205	0.0	0.0	0.45	0.0	0.45	197.9
43 MUDDY7	110.	747.3	1304.5	2051.7	0.215	0.0	0.0	0.45	0.0	0.45	207.2
44 MUDDY8	110.	772.0	1341.2	2113.1	0.222	0.0	0.0	0.45	0.0	0.45	213.5
45 PEACH2	447.	2500.4	4094.9	6595.3	0.678	19.94	3.60	11.72	0.0	35.26	2653.7
46 PEACH3	439.	2495.6	4253.9	6749.5	0.692	20.01	3.61	11.51	0.0	35.13	2662.7
47 DIESEL	19.	18.4	33.9	52.3	0.006	0.09	0.00	0.02	0.0	0.11	1.0
48 PLNT9	29.	2.0	0.5	2.5	0.000	0.01	0.00	0.03	0.0	0.04	0.1
49 PLNT15	29.	2.8	1.4	4.2	0.000	0.02	0.00	0.03	0.0	0.05	0.1
51 RICH21	33.	14.2	14.1	28.3	0.003	0.08	0.02	0.04	0.0	0.14	0.8
52 RICH22	33.	8.5	10.9	19.4	0.002	0.07	0.01	0.04	0.0	0.11	0.6
53 RICH31	33.	7.8	10.3	18.1	0.002	0.07	0.01	0.04	0.0	0.11	0.6
54 RICH32	33.	8.3	9.3	17.7	0.002	0.07	0.01	0.04	0.0	0.11	0.6
55 RICH41	21.	11.4	9.5	20.9	0.002	0.04	0.01	0.02	0.0	0.08	0.4
56 RICH42	21.	10.8	10.6	21.5	0.002	0.04	0.01	0.02	0.0	0.07	0.4
57 RICH43	21.	4.0	4.2	8.2	0.001	0.02	0.00	0.02	0.0	0.04	0.2
58 RICH44	21.	7.4	9.5	16.8	0.002	0.03	0.01	0.02	0.0	0.06	0.3
59 RICH51	33.	8.5	9.5	18.0	0.002	0.06	0.01	0.04	0.0	0.11	0.5
60 RICH52	33.	7.3	10.2	17.5	0.002	0.06	0.01	0.04	0.0	0.11	0.5
61 RICH61	33.	8.0	9.1	17.1	0.002	0.06	0.01	0.04	0.0	0.11	0.5
62 RICH62	33.	8.1	9.2	17.3	0.002	0.06	0.01	0.04	0.0	0.11	0.6
63 RICH71	21.	7.5	9.2	16.7	0.002	0.03	0.01	0.02	0.0	0.06	0.3
64 RICH72	21.	9.9	10.2	20.2	0.002	0.04	0.01	0.02	0.0	0.07	0.4
65 RICH81	51.	19.0	30.7	49.8	0.005	0.21	0.04	0.06	0.0	0.31	2.1
66 RICH91	51.	12.7	23.5	38.3	0.003	0.15	0.03	0.06	0.0	0.24	1.5
67 RICH92	51.	17.4	29.8	47.2	0.004	0.16	0.04	0.06	0.0	0.27	1.8
68 SCHY1	157.	1369.1	2964.5	4333.5	0.407	40.25	2.56	4.15	0.0	46.94	566.6
69 SCH53	49.	1191.1	3624.3	4815.3	0.496	6.21	0.96	1.28	0.0	9.15	213.0
70 SCHY9	52.	11.8	26.4	[illegible]	0.004	0.14	0.01	0.83	0.0	0.98	1.1
71 SCHY10	13.	[illegible]	[illegible]	[illegible]	0.001	0.02	0.00	0.01	0.0	0.03	0.1
72 SCHY11	15.	[illegible]	[illegible]	[illegible]	0.001	0.03	0.00	0.02	0.0	0.05	0.1

POOR ORIGINAL

Exhibit ___ (DS-C)
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[illegible]	[illegible]	[illegible]	198.4	[illegible]	[illegible]015	[illegible]	[illegible]	2.44	0.0	4.47	19.2
[illegible]	12.	[illegible]	1.5	[illegible]	0.000	[illegible]	0.00	0.01	0.0	0.02	0.1
[illegible] SOUTH[illegible]	1[illegible]	[illegible]	2.4	[illegible]	0.001	0.02	[illegible]	0.01	0.0	0.03	0.1
[illegible] SOUTH5	1[illegible]	[illegible]	7.3	10.3	0.001	0.02	[illegible]	0.01	0.0	0.03	0.1
[illegible] SOUTH6	15.	[illegible]	7.[illegible]	1[illegible]	0.001	0.02	[illegible]	0.01	0.0	0.03	0.1
79 CONEM1	1[illegible]	[illegible]30.0	3042.1	[illegible]73.1	[illegible]	18.[illegible]	2.47	2.05	0.0	23.37	865.3
80 CONEM2	1[illegible]	[illegible]	3185.8	[illegible]	[illegible]	19.1[illegible]	2.57	2.53	0.0	24.23	898.3
81 CONEM3	[illegible]	25.1	31.4	[illegible]	[illegible]	[illegible]	[illegible]	0.00	0.0	0.02	0.1
82 KEYST1	172.	2134.7	3540.9	[illegible]	[illegible]	18.65	[illegible]	2.40	0.0	24.09	876.8
83 KEYST2	172.	2202.3	3427.0	[illegible]	[illegible]	20.1[illegible]	3.28	[illegible]10	0.0	25.84	947.5
84 KEYST3	2[illegible]	21.1	31.1	52.2	0.006	0.01	0.00	0.00	0.0	0.02	0.1
85 SALEM1	468.	2555.2	4231.0	6786.2	0.683	21.04	4.22	13.16	0.0	38.41	2799.4
86 SALEM3	16.	8.5	10.6	19.2	0.002	0.03	0.01	0.02	0.0	0.06	0.3
87 CONO1	36.	1492.5	2132.5	3625.0	0.414	0.0	0.0	0.22	0.0	0.22	130.5
88 CONO2	36.	1473.1	2190.8	3663.9	0.418	0.0	0.0	0.22	0.0	0.22	131.9
89 CONO3	36.	1388.0	2104.8	3592.8	0.410	0.0	0.0	0.22	0.0	0.22	129.3
90 CONO4	36.	1510.1	2095.6	3605.7	0.412	0.0	0.0	0.22	0.0	0.22	129.8
91 CONO5	36.	1431.3	2206.3	3637.6	0.415	0.0	0.0	0.22	0.0	0.22	131.0
92 CONO6	36.	1420.6	2204.0	3624.6	0.414	0.0	0.0	0.22	0.0	0.22	130.5
93 CONO7	36.	1485.1	2114.2	3599.4	0.411	0.0	0.0	0.22	0.0	0.22	129.6
94 CONO8	65.	1419.0	2154.0	3573.0	0.408	0.0	0.0	0.39	0.0	0.39	232.2
95 CONO9	65.	1507.2	2150.3	3657.5	0.418	0.0	0.0	0.39	0.0	0.39	237.7
96 CONO10	65.	1467.9	2193.2	3661.1	0.418	0.0	0.0	0.39	0.0	0.39	238.0
97 CONO11	65.	1510.7	2230.9	3741.6	0.427	0.0	0.0	0.39	0.0	0.39	243.2
98 SALEM2	474.	2552.5	4433.6	6986.2	0.686	21.59	4.29	40.15	54.15	119.98	2846.8
99 LIMERIK1	1055.	2521.0	4283.7	6804.7	0.669	46.48	9.31	106.03	331.56	493.39	6185.4
100 LIMERIK2	1055.	2558.8	4296.4	6855.1	0.675	46.86	9.39	106.03	331.56	493.84	6235.8
108 ECONOMY	913.	1028.7	2438.2	3466.9	0.203	151.82	0.0	0.0	0.0	151.82	1626.8
109 EMRGENCY	500.	1.2	1.1	2.3	0.000	0.16	0.0	0.0	0.0	0.16	0.8
111 LOAD	64.	2.9	6.4	9.3	0.001	0.24	0.0	0.0	0.0	0.24	0.6
114 VOLAP	170.	1.8	6.4	8.2	0.001	0.56	0.0	0.0	0.0	0.56	1.4
115 BRNOUT5	150.	1.7	6.3	8.0	0.000	0.09	0.0	0.0	0.0	0.09	0.4
116 BRNOUT8	100.	0.8	0.2	1.0	0.000	0.02	0.0	0.0	0.0	0.02	0.1
117 PARTIAL	*******	0.0	0.2	0.2	0.0	0.58	0.0	0.0	0.0	0.58	0.1
118 TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0000 =   0.1 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0   =   0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0011 =   3.9 DAYS IN TEN YEARS

TOTAL SYSTEM COST = 1740.3 MILLION (1987) = [illegible] 940.3 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 37852. GWH
INCREMENTAL ELECTRICITY COST [illegible] 4.6 1987 CENTS PER KWH = 2.5 1979 CENTS PER KWH
LOAD FACTOR [illegible]

[illegible]

[illegible]

POOR ORIGINAL

Exhibit [illegible] (DS-C)
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1992 PECO LOAD CURVE: PECO PLANT DATA: PECO LOAD GROWTH: PECO RESERVE MARGINS: INPUT [illegible]

OPTION	DESIGNATED CAPACITY	HOURS OF USE [illegible]	[illegible]	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1992 DOLLARS) ENERGY	VAROGM	CARCHG	CAPITAL	TOTAL	GWH GENERATED
1 BARB5	17.	1609.9	2342.8	3952.7	0.304	4.54	1.23	0.02	0.0	5.80	45.2
2 BARB6	19.	975.7	1822.3	2818.0	0.293	4.87	1.33	0.03	0.0	6.25	48.7
3 BARB7	17.	1066.7	1855.6	2922.3	0.304	4.54	1.23	0.02	0.0	5.80	45.2
8 CROM82	183.	123.2	220.5	343.5	0.032	6.92	0.33	5.14	0.0	12.40	50.5
9 CROY11	49.	42.3	77.1	119.4	0.012	0.77	0.05	0.03	0.0	0.84	5.3
10 CROY12	49.	82.4	122.1	204.5	0.023	1.38	0.09	0.03	0.0	1.50	9.7
11 CROY21	49.	66.3	119.6	185.0	0.021	1.27	0.08	0.03	0.0	1.37	8.8
12 CROY22	49.	50.3	80.9	131.3	0.014	0.89	0.06	0.03	0.0	0.97	6.2
13 CROY31	49.	50.1	86.5	136.5	0.013	0.81	0.05	0.03	0.0	0.88	5.6
14 CROY32	49.	56.6	93.1	149.8	0.016	0.98	0.06	0.03	0.0	1.07	6.9
15 CROY41	49.	49.6	74.3	123.9	0.013	0.79	0.05	0.03	0.0	0.87	5.5
16 CROY42	49.	74.5	106.4	180.9	0.019	1.19	0.07	0.03	0.0	1.29	8.3
17 DELA7	126.	1634.3	3189.0	4823.3	0.497	62.16	2.85	1.97	0.0	66.98	548.8
18 DELA8	124.	1459.3	2792.2	4251.6	0.434	53.36	2.44	1.94	0.0	57.74	471.1
23 EDDY1	301.	2345.8	4016.0	6361.8	0.565	40.70	8.58	5.88	0.0	55.17	1488.5
24 EDDY2	311.	1870.2	3339.8	5210.0	0.467	37.24	7.33	6.08	0.0	50.64	1271.4
25 EDDY3	380.	198.9	384.1	583.0	0.046	20.47	0.88	8.73	0.0	30.08	152.6
26 EDDY4	380.	299.9	607.0	906.8	0.064	28.46	1.22	8.73	0.0	38.41	212.2
35 MOSER2	15.	6.5	6.3	12.9	0.001	0.03	0.00	0.02	0.0	0.06	0.2
36 MOSER3	15.	6.4	4.5	11.0	0.001	0.03	0.00	0.02	0.0	0.05	0.2
37 MUDDY1	110.	719.6	1075.5	1795.1	0.197	0.0	0.0	0.58	0.0	0.58	189.8
38 MUDDY2	110.	706.3	1249.9	1956.2	0.214	0.0	0.0	0.58	0.0	0.58	206.3
39 MUDDY3	110.	723.0	1079.7	1802.7	0.206	0.0	0.0	0.58	0.0	0.58	198.3
40 MUDDY4	110.	742.2	1085.5	1827.6	0.209	0.0	0.0	0.58	0.0	0.58	201.0
41 MUDDY5	110.	730.7	1117.0	1847.6	0.211	0.0	0.0	0.58	0.0	0.58	203.2
42 MUDDY6	110.	745.5	1098.4	1843.8	0.210	0.0	0.0	0.58	0.0	0.58	202.8
43 MUDDY7	110.	725.2	1347.2	2072.4	0.217	0.0	0.0	0.58	0.0	0.58	208.9
44 MUDDY8	110.	712.6	1361.5	2074.1	0.217	0.0	0.0	0.58	0.0	0.58	208.9
45 PEACH2	447.	2531.3	4361.5	6892.8	0.707	30.84	4.79	14.96	0.0	50.59	2767.5
46 PEACH3	439.	2551.5	4239.4	6791.0	0.697	29.88	4.64	14.70	0.0	49.22	2681.9
47 DIESEL	19.	28.9	33.8	62.8	0.007	0.16	0.00	0.03	0.0	0.19	1.1
48 PLAT9	29.	3.9	2.2	6.1	0.001	0.03	0.00	0.04	0.0	0.08	0.2
49 PLAT15	29.	3.6	3.3	6.7	0.001	0.04	0.01	0.04	0.0	0.08	0.2
51 RICH21	33.	15.1	23.9	39.0	0.004	0.19	0.03	0.05	0.0	0.26	1.1
52 RICH22	33.	14.6	22.1	36.6	0.004	0.17	0.03	0.05	0.0	0.25	1.1
53 RICH31	33.	9.0	10.9	17.8	0.002	0.11	0.02	0.05	0.0	0.17	0.6
54 RICH32	33.	8.6	11.4	20.0	0.002	0.11	0.02	0.05	0.0	0.17	0.6
55 RICH41	21.	8.5	18.4	26.9	0.002	0.07	0.01	0.03	0.0	0.11	0.4
56 RICH42	21.	9.4	9.6	19.0	0.002	0.06	0.01	0.03	0.0	0.10	0.4
57 RICH43	21.	[illegible]	26.6	[illegible]	0.003	0.08	0.01	[illegible]	0.0	0.13	0.5
58 RICH[illegible]	[illegible]	12.0	22.[illegible]	[illegible]	0.003	0.10	0.02	[illegible]	0.0	0.15	0.6
59 RICH51	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.09	0.01	[illegible]	0.0	0.14	0.5
60 RICH52	33.	7.4	9.5	[illegible]	0.002	[illegible]	0.01	[illegible]	0.0	0.15	0.5
61 RICH61	[illegible]	[illegible]	[illegible]	[illegible]	0.001	[illegible]	0.01	0.05	0.0	0.13	0.4
62 RICH62	[illegible]	4.9	[illegible]	[illegible]	0.001	[illegible]	0.01	[illegible]	0.0	0.11	0.3
[illegible]	[illegible]	11.[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	0.12	0.5
[illegible]	[illegible]	11.[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	0.14	0.6
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	0.39	1.8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	[illegible]	1.1
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.04	[illegible]	0.0	[illegible]	1.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	[illegible]	623.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	15.99	231.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	[illegible]	1.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.0	[illegible]	0.1
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.1

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[illegible] SOUTH[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.011	[illegible]	0.06	3.12	0.0	[illegible]	16.7
[illegible] SOUTH3	[illegible]	4.6	4.0	8.6	0.001	[illegible]	0.00	0.02	0.0	0.04	0.1
76 SOUTH4	16.	5.5	4.1	9.6	0.001	0.02	0.00	0.02	0.0	0.04	0.1
77 SOUTH5	16.	[illegible]	4.4	9.3	0.001	0.02	0.00	0.02	0.0	0.04	0.1
78 SOUTH6	16.	4.7	4.1	8.8	0.001	0.02	0.00	0.02	0.0	0.04	0.1
79 CONEM1	17[illegible].	2126.8	3177.1	5303.9	0.591	24.76	3.43	3.23	0.0	31.32	911.9
80 CONEM2	1[illegible].	2241.0	3357.2	5598.2	0.623	26.10	3.51	3.23	0.0	32.84	961.2
81 CONEMD	[illegible]	25.0	26.1	51.1	0.006	0.02	0.00	0.00	0.0	0.02	0.1
82 KEYST1	179.	2354.9	3588.8	5943.7	0.619	26.29	4.28	3.06	0.0	33.63	968.0
83 KEYST2	179.	2500.8	3666.0	6166.8	0.679	28.85	4.69	3.06	0.0	36.59	1061.8
84 KEYSTD	2.	24.6	21.6	46.2	0.005	0.02	0.00	0.00	0.0	0.02	0.1
85 SALEM1	468.	2535.3	4228.0	6763.3	0.694	31.69	5.46	16.79	0.0	53.94	2843.8
86 SALEM3	16.	9.4	10.9	20.3	0.002	0.05	0.01	0.02	0.0	0.08	0.3
87 CONO1	36.	1498.1	2195.7	3693.8	0.422	0.0	0.0	0.28	0.0	0.28	133.0
88 CONO2	36.	1470.4	2157.7	3628.1	0.414	0.0	0.0	0.28	0.0	0.28	130.6
89 CONO3	36.	1454.7	2199.9	3654.6	0.417	0.0	0.0	0.28	0.0	0.28	131.6
90 CONO4	36.	1416.8	2178.6	3594.8	0.410	0.0	0.0	0.28	0.0	0.28	129.4
91 CONO5	36.	1437.1	2195.5	3632.7	0.415	0.0	0.0	0.28	0.0	0.28	130.8
92 CONO6	36.	1420.3	2182.6	3602.9	0.411	0.0	0.0	0.28	0.0	0.28	129.7
93 CONO7	36.	1416.4	2133.5	3549.9	0.405	0.0	0.0	0.28	0.0	0.28	127.8
94 CONO8	65.	1479.2	2139.1	3618.3	0.413	0.0	0.0	0.50	0.0	0.50	235.2
95 CONO9	65.	1485.1	2174.0	3659.2	0.418	0.0	0.0	0.50	0.0	0.50	237.8
96 CONO10	65.	1436.8	2140.4	3577.2	0.408	0.0	0.0	0.50	0.0	0.50	232.5
97 CONO11	65.	1440.3	2103.6	3543.9	0.405	0.0	0.0	0.50	0.0	0.50	230.4
98 SALEM2	474.	2503.5	4424.6	6928.1	0.680	31.46	5.42	51.25	45.50	133.62	2822.9
99 LIMERIK1	1055.	2542.0	4396.8	6938.8	0.682	70.21	12.11	135.33	308.71	526.36	6300.8
100 LIMERIK2	1055.	2545.7	4388.0	6933.7	0.681	70.17	12.10	135.33	308.71	526.31	6297.4
103 GCOAL6	600.	2945.4	4524.7	7470.1	0.612	87.37	21.02	54.19	174.72	337.31	3217.7
108 ECONOMY	913.	1266.6	2465.1	3731.8	0.238	261.07	0.0	0.0	0.0	261.07	1903.9
109 EMRGENCY	500.	2.3	2.0	4.3	0.000	0.29	0.0	0.0	0.0	0.29	1.0
111 LMHW	64.	2.7	2.7	5.3	0.001	0.20	0.0	0.0	0.0	0.20	0.3
114 VOLAP	170.	2.2	2.4	4.6	0.000	0.30	0.0	0.0	0.0	0.30	0.5
115 BRNOUT5	150.	1.7	0.6	2.3	0.000	0.09	0.0	0.0	0.0	0.09	0.3
116 BRNOUT8	100.	1.3	0.4	1.7	0.000	0.06	0.0	0.0	0.0	0.06	0.1
117 PARTIAL	*******	0.0	0.4	0.4	0.0	1.99	0.0	0.0	0.0	1.99	0.1
118 TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0001 = 0.2 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0006 = 2.2 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 2405.8 MILLION (1992) = $ 914.0 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 42643. GWH
INCREMENTAL ELECTRICITY COST 5.8 1992 CENTS PER KWH = 2.1 1979 CENTS PER KWH
LOAD FACTOR 59.3%

TOTAL COSTS IN 1992 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	812.	299.
VARIABLE O&M	115.	42.
CARRYING CHARGES	498.	183.
INCREMENTAL CAPITAL	838.	308.

IMPORT OPTIONS:	COST IN 1992 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	[illegible]	95.99	1903.9
EMRGENCY	[illegible]	0.10	1.0

TOTAL CURTAILMENT COST $ 2.64 MILLION ([illegible]) = $ 0.97 MILLION (DISCOUNTED TO 1979)
BLACKOUT COST $ [illegible] MILLION (1992) = $ [illegible] MILLION (DISCOUNTED TO 1979)

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EXHIBIT C

SAMPLE ESGEM RUN

BASED UPON:

ESRG CONSTRUCTION PROGRAM

ESRG DEMAND FORECAST

ESRG LOW COST AND FULL PLANT CAPITAL COSTS

E S R G

LOAD CURVE: PECO   PLANT DATA: ESL1   LOAD GROWTH: ESRG   RESERVE MARGINS: INPUT 6.0%; ACTUAL 6.5%

MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1981 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
17.	1115.6	2317.1	3432.7	0.306	1.54	0.76	0.01	0.0	2.31	45.6
19.	1107.8	1810.6	2918.4	0.306	1.71	0.84	0.02	0.0	2.57	50.9
17.	1113.9	1817.2	2931.1	0.308	1.54	0.76	0.01	0.0	2.32	45.9
137.	2604.1	4390.5	6994.6	0.666	13.78	3.17	1.87	0.0	18.82	799.4
	73.1	121.1	194.2	0.019	0.48	0.05	0.02	0.0	0.54	8.3
48.	55.1	149.6	204.7	0.020	0.50	0.05	0.02	0.0	0.56	8.6
48.	30.4	118.9	149.3	0.017	0.42	0.04	0.02	0.0	0.47	7.2
48.	34.9	69.9	104.8	0.012	0.29	0.03	0.02	0.0	0.34	5.1
128.	3014.3	4581.3	7595.7	0.815	41.38	2.83	1.20	0.0	45.41	899.9
124.	3049.7	4674.0	7723.7	0.836	41.73	2.86	1.19	0.0	45.77	907.6
301.	2245.5	4322.7	6568.2	0.591	24.92	5.45	3.57	0.0	33.94	1558.4
311.	2387.7	4105.2	6492.9	0.618	28.82	5.89	3.69	0.0	38.40	1683.4
320.	209.0	424.3	633.3	0.038	6.96	0.45	5.30	0.0	12.70	127.8
350.	366.1	683.7	1049.8	0.067	12.15	0.78	5.30	0.0	18.22	223.1
110.	783.0	1088.4	1871.4	0.206	0.0	0.0	0.35	0.0	0.35	198.1
110.	779.9	1055.0	1873.9	0.206	0.0	0.0	0.35	0.0	0.35	198.4
110.	764.6	1099.1	1863.7	0.215	0.0	0.0	0.35	0.0	0.35	207.2
110.	739.2	1014.5	1753.7	0.201	0.0	0.0	0.35	0.0	0.35	194.0
110.	783.8	1056.3	1840.2	0.210	0.0	0.0	0.35	0.0	0.35	202.4
110.	778.2	1061.5	1839.7	0.210	0.0	0.0	0.35	0.0	0.35	202.4
110.	783.7	1401.0	2184.7	0.229	0.0	0.0	0.35	0.0	0.35	220.5
110.	781.0	1378.1	2159.1	0.226	0.0	0.0	0.35	0.0	0.35	218.0
447.	2539.4	4307.0	6846.4	0.702	12.88	2.89	9.08	0.0	24.85	2750.7
432.	2499.4	4264.1	6763.4	0.694	12.49	2.80	8.92	0.0	24.21	2668.1
10.	5.5	20.6	30.1	0.003	0.03	0.00	0.02	0.0	0.05	0.5
168.	2401.9	3836.6	6238.5	0.660	45.30	5.49	4.53	0.0	55.32	960.0
159.	2341.4	4350.2	6691.6	0.689	40.67	3.36	3.21	0.0	47.24	960.3
49.	2980.6	4412.0	7392.6	0.833	6.92	1.25	0.99	0.0	9.16	357.6
176.	2126.6	3260.5	5387.1	0.603	14.76	2.06	1.96	0.0	18.78	929.7
176.	2245.3	3405.5	5650.8	0.633	15.48	2.16	1.96	0.0	19.61	975.3
179.	2324.6	3933.7	6258.3	0.657	16.30	2.75	1.86	0.0	20.91	1026.9
179.	2548.6	3858.9	6407.5	0.717	17.81	3.01	1.86	0.0	22.67	1121.6
468.	2570.0	4221.2	6791.2	0.698	13.40	3.34	10.19	0.0	26.92	2860.5
38.	1427.1	2166.2	3593.3	0.410	0.0	0.0	0.17	0.0	0.17	129.4
38.	1462.7	2133.1	3595.9	0.410	0.0	0.0	0.17	0.0	0.17	129.5
38.	1484.2	2199.9	3684.1	0.421	0.0	0.0	0.17	0.0	0.17	132.6
38.	1451.4	2112.0	3563.4	0.407	0.0	0.0	0.17	0.0	0.17	128.3
38.	1438.2	2130.5	3568.7	0.407	0.0	0.0	0.17	0.0	0.17	128.5
38.	1455.1	2101.2	3556.3	0.406	0.0	0.0	0.17	0.0	0.17	128.0
38.	1450.4	2166.6	3617.0	0.413	0.0	0.0	0.17	0.0	0.17	130.2
65.	1523.6	2238.0	3761.6	0.429	0.0	0.0	0.30	0.0	0.30	244.5
65.	1442.3	2263.5	3705.8	0.423	0.0	0.0	0.30	0.0	0.30	240.9
65.	1447.6	2164.0	3631.6	0.415	0.0	0.0	0.30	0.0	0.30	236.1
65.	1445.1	2131.5	3576.6	0.408	0.0	0.0	0.30	0.0	0.30	232.5
474.	2133.4	3765.9	5899.3	0.579	11.26	2.80	31.10	0.0	45.16	2403.8
913.	2459.6	4011.7	6471.4	0.386	171.90	0.0	0.0	0.0	171.90	3088.3
500.	20.6	78.5	99.1	0.004	1.90	0.0	0.0	0.0	1.90	16.3
64.	35.8	71.3	107.1	0.011	1.45	0.0	0.0	0.0	1.45	6.0
170.	23.8	55.5	79.3	0.006	2.11	0.0	0.0	0.0	2.11	8.7
150.	13.4	12.2	25.5	0.003	0.42	0.0	0.0	0.0	0.42	3.5
100.	9.8	10.5	20.3	0.001	0.18	0.0	0.0	0.0	0.18	1.0
*******	5.7	1.7	7.5	0.0	13.87	0.0	0.0	0.0	13.87	2.3
*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

LTS

PROBABILITIES:
.OUTS 0.0009 = 3.1 DAYS IN TEN YEARS
LTS 0.0 = 0.0 DAYS IN TEN YEARS
ENT OPTIONS 0.0122 = 44.6 DAYS IN TEN YEARS

COST $ 734.3 MILLION (1981) = $ 601.4 MILLION (DISCOUNTED TO 1979)
CITY GENERATED 30858. GWH
ELECTRICITY COST 2.4 1981 CENTS PER KWH = 1.9 1979 CENTS PER KWH
78.3%

IN 1981 $MILLION		DISCOUNTED TO 1979 $MILLION
	384.	314.
	56.	46.
RGES	103.	84.
CAPITAL	0.	0.

ES:	COST IN 1981 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
	171.90	140.78	3088.3
	1.90	1.55	16.3

LMENT COST $ 18.03 MILLION (1981) = $ 14.77 MILLION (DISCOUNTED TO 1979)
T $ 13.87 MILLION (1981) = $ 11.36 MILLION (DISCOUNTED TO 1979)

POOR ORIGINAL

LOAD CURVE: PECO PLANT DATA: ESL1 LOAD GROWTH: ESRG RESERVE MARGINS: INPUT 14.0%; ACTUAL 14.0%

	MEGAWATTS CAPACITY	HOURS OF USE MAINT	NONMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1981 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
	17.	1157.1	2413.3	3570.4	0.318	1.60	0.78	0.01	0.0	2.39	47.4
	19.	1158.6	1885.9	3044.5	0.319	1.79	0.88	0.02	0.0	2.68	53.1
	17.	1084.2	1980.9	3065.1	0.320	1.61	0.79	0.01	0.0	2.41	47.7
	137.	2636.7	4512.1	7148.7	0.679	14.05	3.23	1.87	0.0	19.15	815.0
	49.	42.6	50.8	93.4	0.010	0.25	0.02	0.02	0.0	0.29	4.3
	49.	48.2	55.7	103.8	0.011	0.27	0.03	0.02	0.0	0.31	4.7
	49.	36.3	35.4	71.7	0.007	0.18	0.02	0.02	0.0	0.22	3.2
	49.	21.8	51.8	73.6	0.006	0.16	0.01	0.02	0.0	0.19	2.7
	49.	56.3	64.4	120.7	0.013	0.32	0.03	0.02	0.0	0.36	5.5
	49.	54.9	73.5	128.4	0.013	0.33	0.03	0.02	0.0	0.38	5.7
	49.	31.2	48.5	79.7	0.009	0.22	0.02	0.02	0.0	0.26	3.9
	49.	36.8	43.0	79.7	0.009	0.22	0.02	0.02	0.0	0.26	3.8
	126.	2966.3	4455.1	7421.5	0.791	40.13	2.75	1.20	0.0	44.08	872.9
	124.	3078.7	4695.5	7774.2	0.835	41.72	2.86	1.18	0.0	45.75	907.3
	301.	2300.6	4396.8	6697.4	0.603	25.43	5.56	3.57	0.0	34.56	1590.2
	311.	2392.8	4051.2	6444.0	0.614	28.63	5.85	3.69	0.0	38.17	1672.2
	380.	185.3	422.4	607.7	0.037	6.64	0.43	5.30	0.0	12.37	122.0
	380.	411.4	774.7	1186.1	0.076	13.80	0.89	5.30	0.0	19.99	253.5
	110.	748.4	1097.2	1845.6	0.203	0.0	0.0	0.35	0.0	0.35	195.3
	110.	795.2	1383.3	2178.5	0.239	0.0	0.0	0.35	0.0	0.35	229.8
	110.	774.1	1092.1	1866.2	0.213	0.0	0.0	0.35	0.0	0.35	205.3
	110.	786.1	1094.2	1880.3	0.215	0.0	0.0	0.35	0.0	0.35	206.8
	110.	771.8	1068.0	1839.7	0.210	0.0	0.0	0.35	0.0	0.35	202.4
	110.	769.6	1049.9	1819.5	0.208	0.0	0.0	0.35	0.0	0.35	200.1
	110.	746.1	1379.4	2125.5	0.222	0.0	0.0	0.35	0.0	0.35	214.3
	110.	759.5	1332.1	2091.6	0.219	0.0	0.0	0.35	0.0	0.35	211.2
	447.	2511.1	4165.7	6676.8	0.686	12.57	2.82	9.08	0.0	24.47	2685.0
	439.	2479.8	4258.7	6738.5	0.691	12.44	2.79	8.92	0.0	24.15	2657.5
	19.	25.9	33.0	56.9	0.006	0.06	0.00	0.02	0.0	0.08	1.1
	166.	2373.2	3794.2	6167.4	0.648	44.49	5.39	4.53	0.0	54.41	942.9
	51.	28.7	30.0	58.7	0.006	0.15	0.04	0.04	0.0	0.24	2.5
	159.	2660.0	4300.1	6960.1	0.691	40.78	3.37	3.21	0.0	47.37	963.0
	49.	3004.6	4419.5	7424.2	0.836	6.94	1.28	0.99	0.0	9.19	358.7
	178.	97.6	161.4	259.0	0.022	2.07	0.08	1.89	0.0	4.04	34.2
	176.	2146.8	3289.0	5435.7	0.608	14.89	2.08	1.96	0.0	18.93	938.1
	176.	2250.1	3401.5	5651.6	0.633	15.49	2.16	1.96	0.0	19.61	975.4
	2.	33.3	22.7	56.0	0.006	0.01	0.00	0.00	0.0	0.01	0.1
	179.	2368.0	3688.9	6057.0	0.637	15.82	2.67	1.86	0.0	20.35	996.4
	179.	2552.6	3861.1	6413.5	0.718	17.82	3.01	1.86	0.0	22.69	1122.7
	2.	33.2	31.4	64.6	0.007	0.01	0.00	0.00	0.0	0.01	0.1
	468.	2521.1	4233.0	6754.2	0.693	13.31	3.32	10.19	0.0	26.82	2842.3
	16.	19.4	18.8	38.2	0.004	0.04	0.01	0.01	0.0	0.06	0.6
	36.	1496.3	2220.2	3716.5	0.424	0.0	0.0	0.17	0.0	0.17	133.8
	36.	1433.7	2101.2	3534.9	0.404	0.0	0.0	0.17	0.0	0.17	127.3
	36.	1431.8	2213.3	3645.2	0.416	0.0	0.0	0.17	0.0	0.17	131.2
	36.	1452.3	2112.5	3564.8	0.407	0.0	0.0	0.17	0.0	0.17	128.3
	36.	1441.6	2242.4	3684.0	0.421	0.0	0.0	0.17	0.0	0.17	132.6
	36.	1420.7	2203.3	3623.9	0.414	0.0	0.0	0.17	0.0	0.17	130.5
	36.	1438.9	2179.3	3618.3	0.413	0.0	0.0	0.17	0.0	0.17	130.3
	65.	1440.6	2123.7	3564.3	0.407	0.0	0.0	0.30	0.0	0.30	231.7
	65.	1530.4	2223.8	3754.2	0.429	0.0	0.0	0.30	0.0	0.30	244.0
	65.	1449.6	2146.3	3595.9	0.410	0.0	0.0	0.30	0.0	0.30	233.7
	65.	1472.1	2187.6	3659.7	0.418	0.0	0.0	0.30	0.0	0.20	237.9
	474.	2223.0	3808.8	6031.8	0.593	11.53	2.87	31.10	0.0	45.51	2462.2
Y	913.	2302.1	3878.0	6180.1	0.385	171.28	0.0	0.0	0.0	171.28	3077.3
CY	500.	14.4	9.9	24.4	0.001	0.66	0.0	0.0	0.0	0.66	5.7
	64.	13.5	12.7	26.2	0.003	0.34	0.0	0.0	0.0	0.34	1.4
	170.	11.0	3.6	14.6	0.001	0.44	0.0	0.0	0.0	0.44	1.8
S	150.	6.5	2.3	8.8	0.001	0.12	0.0	0.0	0.0	0.12	1.0
3	100.	3.6	1.1	4.8	0.001	0.08	0.0	0.0	0.0	0.08	0.5
L	*******	3.2	1.0	4.2	0.0	6.78	0.0	0.0	0.0	6.78	1.1
	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

ESULTS

AD PROBABILITIES:
ACKOUTS 0.0005 = 1.8 DAYS IN TEN YEARS
KOUTS 0.0 = 0.0 DAYS IN TEN YEARS
LMENT OPTIONS 0.0030 = 10.9 DAYS IN TEN YEARS

EM COST $ 726.7 MILLION (1981) = $ 595.1 MILLION (DISCOUNTED TO 1979)
TRICITY GENERATED 30858. GWH
L ELECTRICITY COST 2.4 1981 CENTS PER KWH = 1.9 1979 CENTS PER KWH
R 59.3%

TS IN 1981 $MILLION		DISCOUNTED TO 1979 $MILLION
	386.	316.
O&M	56.	46.
CHARGES	105.	86.
L CAPITAL	0.	0.

TIONS:	*COST IN 1981 $MILLION*	*DISCOUNTED TO 1979 $MILLION*	*ENERGY IN GWH*
	171.28	140.28	3077.3
	0.66	0.54	5.7

TAILMENT COST $ 7.77 MILLION (1981) = $ 6.37 MILLION (DISCOUNTED TO 1979)
COST $ 6.78 MILLION (1981) = $ 5.56 MILLION (DISCOUNTED TO 1979)

1981 PECO LOAD CURVE: PECO PLANT DATA: ESL1 LOAD GROWTH: ESRG RESERVE MARGINS: INPUT 22.0%; ACTUAL 22.1%

		MEGAWATTS	HOURS OF USE			ANNUAL	COSTS (MILLIONS OF 1981 DOLLARS)					
	OPTION	CAPACITY	MAINT	NOMAINT	TOTAL	CAPFAC	ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
1	BARB5	17.	1113.0	2406.5	3519.5	0.313	1.57	0.77	0.01	0.0	2.36	46.6
2	BARB6	19.	1104.8	1895.3	3000.1	0.315	1.76	0.87	0.02	0.0	2.65	52.4
3	BARB7	17.	1123.2	1891.7	3014.9	0.316	1.58	0.78	0.01	0.0	2.38	47.0
4	CHEST7	13.	3.0	2.6	5.6	0.001	0.00	0.00	0.01	0.0	0.02	0.1
5	CHEST8	13.	4.0	2.7	6.6	0.001	0.01	0.00	0.01	0.0	0.02	0.1
6	CHEST9	13.	3.5	2.7	6.2	0.001	0.01	0.00	0.01	0.0	0.02	0.1
7	CROMB1	137.	2537.3	4362.9	6900.2	0.657	13.60	3.13	1.87	0.0	18.60	788.0
9	CROY11	49.	33.7	59.2	92.9	0.010	0.26	0.02	0.02	0.0	0.30	4.5
10	CROY12	49.	47.6	108.0	155.6	0.015	0.38	0.04	0.02	0.0	0.43	6.5
11	CROY21	49.	21.9	50.6	72.5	0.007	0.19	0.02	0.02	0.0	0.22	3.2
12	CROY22	49.	15.6	31.6	47.2	0.005	0.12	0.01	0.02	0.0	0.15	2.1
13	CROY31	49.	47.4	143.7	191.1	0.019	0.47	0.04	0.02	0.0	0.53	8.1
14	CROY32	49.	51.7	128.1	179.7	0.019	0.47	0.04	0.02	0.0	0.53	8.0
15	CROY41	49.	13.1	47.8	60.9	0.005	0.14	0.01	0.02	0.0	0.16	2.4
16	CROY42	49.	31.4	54.2	85.7	0.008	0.19	0.02	0.02	0.0	0.22	3.3
17	DELA7	126.	2939.1	4473.7	7412.8	0.795	40.33	2.76	1.20	0.0	44.29	877.1
18	DELA8	124.	3096.0	4717.0	7813.0	0.843	42.08	2.88	1.18	0.0	46.14	915.2
23	EDDY1	301.	2287.0	4340.0	6637.0	0.598	25.21	5.52	3.57	0.0	34.29	1576.4
24	EDDY2	311.	2367.2	4348.1	6715.3	0.635	29.60	6.05	3.69	0.0	39.34	1728.9
25	EDDY3	380.	212.7	438.7	651.3	0.042	7.66	0.49	5.30	0.0	13.45	140.6
26	EDDY4	380.	447.5	815.2	1262.7	0.080	14.54	0.93	5.30	0.0	20.77	267.0
27	EDDY10	13.	3.2	2.4	5.7	0.001	0.00	0.00	0.01	0.0	0.02	0.1
28	EDDY20	13.	3.8	3.2	6.9	0.001	0.01	0.00	0.01	0.0	0.02	0.1
29	EDDY30	15.	3.8	3.2	6.9	0.001	0.01	0.00	0.01	0.0	0.02	0.1
30	EDDY40	15.	3.4	3.1	6.6	0.001	0.01	0.00	0.01	0.0	0.02	0.1
31	FALLS1	15.	1.8	2.6	4.4	0.000	0.00	0.00	0.01	0.0	0.02	0.1
32	FALLS2	15.	2.2	2.7	4.9	0.001	0.00	0.00	0.01	0.0	0.02	0.1
33	FALLS3	15.	3.9	3.2	7.1	0.001	0.01	0.00	0.01	0.0	0.02	0.1
37	MUDDY1	110.	797.5	1119.1	1916.6	0.211	0.0	0.0	0.35	0.0	0.35	202.9
38	MUDDY2	110.	767.1	1359.8	2126.9	0.233	0.0	0.0	0.35	0.0	0.35	224.3
39	MUDDY3	110.	772.4	1082.9	1855.3	0.212	0.0	0.0	0.35	0.0	0.35	204.1
40	MUDDY4	110.	745.8	1068.9	1814.7	0.207	0.0	0.0	0.35	0.0	0.35	189.8
41	MUDDY5	110.	743.6	1037.7	1781.3	0.203	0.0	0.0	0.35	0.0	0.35	185.8
42	MUDDY6	110.	754.8	1058.2	1813.0	0.207	0.0	0.0	0.35	0.0	0.35	189.4
43	MUDDY7	110.	755.3	1401.7	2157.0	0.226	0.0	0.0	0.35	0.0	0.35	217.4
44	MUDDY8	110.	761.5	1425.2	2186.7	0.229	0.0	0.0	0.35	0.0	0.35	220.4
45	PEACH2	447.	2542.8	4100.5	6643.3	0.683	12.53	2.81	9.08	0.0	24.42	2674.7
46	PEACH3	439.	2543.8	4004.9	6548.7	0.674	12.14	2.72	8.92	0.0	23.78	2582.1
47	DIESEL	19.	25.7	51.7	77.4	0.008	0.08	0.00	0.02	0.0	0.10	1.4
50	RICH9	166.	2430.3	3795.6	6225.9	0.663	45.52	5.51	4.53	0.0	55.56	864.6
51	RICH21	33.	8.4	5.2	13.6	0.001	0.03	0.01	0.03	0.0	0.06	0.4
52	RICH22	33.	9.2	4.4	13.6	0.001	0.03	0.01	0.03	0.0	0.06	0.4
53	RICH31	33.	3.7	2.8	6.5	0.001	0.01	0.00	0.03	0.0	0.04	0.2
55	RICH41	21.	8.3	19.7	28.0	0.002	0.02	0.01	0.02	0.0	0.04	0.3
56	RICH42	21.	5.1	4.1	9.2	0.001	0.01	0.00	0.02	0.0	0.03	0.2
57	RICH43	21.	3.2	2.8	6.0	0.001	0.01	0.00	0.02	0.0	0.03	0.1
58	RICH44	21.	4.0	3.1	7.1	0.001	0.01	0.00	0.02	0.0	0.03	0.1
63	RICH71	21.	6.0	3.4	9.4	0.001	0.01	0.00	0.02	0.0	0.03	0.2
64	RICH72	21.	6.3	3.9	10.2	0.001	0.01	0.00	0.02	0.0	0.03	0.2

POOR ORIGINAL

Exhibit ___ (DS-C)
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66 RICHB1	51.	15.2	30.2	45.3	0.003	0.08	.02	0.04	0.0	0.16	1.5
67 RICHB2	51.	18.1	23.1	41.2	0.004	0.10	0.03	0.04	0.0	0.16	1.6
68 SCHY1	159.	2695.4	4282.6	6978.0	0.693	40.88	3.38	3.21	0.0	47.47	865.3
69 SCHY3	49.	3027.5	4418.6	7446.0	0.840	6.98	1.26	0.99	0.0	9.24	360.7
73 SOUTH1	178.	102.3	237.8	340.1	0.028	2.60	0.10	1.89	0.0	4.59	43.0
78 SOUTHG	13.	1.7	2.6	4.3	0.000	0.00	0.00	0.01	0.0	0.02	0.1
79 CONEM1	176.	2114.2	2993.5	5107.8	0.572	14.00	1.95	1.96	0.0	17.92	882.0
80 CONEM2	176.	2246.7	3417.2	5663.9	0.634	15.52	2.17	1.96	0.0	19.65	977.5
81 CONEMD	2.	22.9	32.1	55.0	0.006	0.01	0.00	0.00	0.0	0.01	0.1
82 KEYST1	179.	2361.6	3845.9	6207.5	0.652	16.19	2.74	1.86	0.0	20.78	1018.7
83 KEYST2	179.	2571.4	3882.3	6453.7	0.722	17.93	3.03	1.86	0.0	22.82	1128.7
84 KEYSTD	2.	23.0	24.6	47.6	0.005	0.01	0.00	0.00	0.0	0.01	0.1
85 SALEM1	468.	2520.4	4289.2	6809.7	0.699	13.41	3.34	10.19	0.0	26.94	2864.0
86 SALEM3	16.	4.3	3.2	7.5	0.001	0.01	0.00	0.01	0.0	0.02	0.1
87 CON01	36.	1433.8	2134.0	3567.8	0.407	0.0	0.0	0.17	0.0	0.17	128.4
88 CON02	36.	1511.6	2178.1	3689.6	0.421	0.0	0.0	0.17	0.0	0.17	132.8
89 CON03	36.	1530.1	2128.4	3659.6	0.418	0.0	0.0	0.17	0.0	0.17	131.7
90 CON04	36.	1436.0	2221.2	3657.3	0.417	0.0	0.0	0.17	0.0	0.17	131.7
91 CON05	36.	1432.1	2093.1	3525.1	0.402	0.0	0.0	0.17	0.0	0.17	126.9
92 CON06	36.	1449.3	2101.5	3550.8	0.405	0.0	0.0	0.17	0.0	0.17	127.8
93 CON07	36.	1418.5	2105.0	3523.6	0.402	0.0	0.0	0.17	0.0	0.17	126.8
94 CON08	65.	1443.7	2129.5	3573.2	0.408	0.0	0.0	0.30	0.0	0.30	232.3
95 CON09	65.	1418.9	2224.6	3643.5	0.416	0.0	0.0	0.30	0.0	0.30	236.8
96 CON010	65.	1431.7	2116.0	3547.7	0.405	0.0	0.0	0.30	0.0	0.30	230.6
97 CON011	65.	1423.3	2157.1	3580.4	0.409	0.0	0.0	0.30	0.0	0.30	232.7
98 SALEM2	474.	2207.4	3803.3	6010.7	0.591	11.49	2.86	31.10	0.0	45.45	2452.8
108 ECONOMY	913.	2459.3	4089.2	6548.5	0.400	177.99	0.0	0.0	0.0	177.99	3187.9
109 EMRGENCY	500.	0.9	1.0	1.9	0.000	0.05	0.0	0.0	0.0	0.05	0.5
111 LMHW	64.	1.6	1.3	2.9	0.000	0.04	0.0	0.0	0.0	0.04	0.2
114 VOLAP	170.	0.9	0.6	1.5	0.000	0.04	0.0	0.0	0.0	0.04	0.2
115 BRNOUT5	150.	0.8	0.1	0.8	0.000	0.01	0.0	0.0	0.0	0.01	0.1
116 BRNOUT8	100.	0.8	0.0	0.8	0.000	0.01	0.0	0.0	0.0	0.01	0.1
117 PARTIAL	*******	0.5	0.0	0.5	0.0	0.78	0.0	0.0	0.0	0.78	0.1
118 TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS.

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0001 = 0.2 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0003 = 1.2 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 730.7 MILLION (1981) = $ 598.5 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 30858. GWH
INCREMENTAL ELECTRICITY COST 2.4 1981 CENTS PER KWH = 1.9 1979 CENTS PER KWH
LOAD FACTOR 59.3%

TOTAL COSTS IN 1981 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	390.	319.
VARIABLE O&M	56.	46.
CARRYING CHARGES	106.	86.
INCREMENTAL CAPITAL	0.	0.

IMPORT OPTIONS:	COST IN 1981 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	177.99	145.77	3197.9
EMRGENCY	0.05	0.04	0.5

TOTAL CURTAILMENT COST $ 0.88 MILLION (1981) = $ 0.73 MILLION (DISCOUNTED TO 1979)
BLACKOUT COST $ 0.79 MILLION (1981) = $ 0.64 MILLION (DISCOUNTED TO 1979)

1981 PECO LOAD CURVE: PECO PLANT DATA: ESL1 LOAD GROWTH: ESRG RESERVE MARGINS: INPUT 30.0%; ACTUAL 31.6%

	OPTION	MEGAWATTS CAPACITY	HOURS OF USE MAINT	NONMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1981 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
1	BARB5	17.	1080.8	2451.4	3532.2	0.313	1.57	0.77	0.01	0.0	2.35	46.6
2	BARB6	19.	1083.4	1875.4	2958.8	0.308	1.73	0.85	0.02	0.0	2.59	51.3
3	BARB7	17.	1110.8	1950.5	3061.3	0.319	1.60	0.79	0.01	0.0	2.40	47.6
4	CHEST7	13.	2.5	1.7	4.2	0.000	0.00	0.00	0.01	0.0	0.01	0.0
5	CHEST8	13.	2.8	9.8	12.5	0.001	0.01	0.00	0.01	0.0	0.02	0.2
6	CHEST9	13.	3.3	10.1	13.4	0.001	0.01	0.00	0.01	0.0	0.03	0.2
7	CROM81	137.	2613.5	4333.0	6946.5	0.662	13.69	3.15	1.87	0.0	18.72	794.4
8	CROY11	49.	25.0	55.6	80.6	0.009	0.22	0.02	0.02	0.0	0.25	3.7
10	CROY12	49.	25.0	48.0	73.0	0.008	0.20	0.02	0.02	0.0	0.23	3.4
11	CROY21	49.	13.7	31.0	44.7	0.004	0.11	0.01	0.02	0.0	0.13	1.9
12	CROY22	49.	20.2	35.8	56.0	0.006	0.15	0.01	0.02	0.0	0.18	2.6
13	CROY31	49.	33.2	57.8	91.1	0.010	0.26	0.02	0.02	0.0	0.30	4.4
14	CROY32	49.	36.6	86.8	123.4	0.011	0.29	0.03	0.02	0.0	0.33	4.9
15	CROY41	49.	21.9	23.6	45.5	0.005	0.12	0.01	0.02	0.0	0.15	2.1
16	CROY42	49.	23.6	47.0	70.6	0.008	0.20	0.02	0.02	0.0	0.23	3.4
17	DELA7	126.	2964.6	4437.5	7402.1	0.791	40.12	2.75	1.20	0.0	44.06	872.6
18	DELA8	124.	3103.3	4674.7	7777.9	0.837	41.80	2.86	1.18	0.0	45.84	908.1
19	DELA9	15.	0.8	0.8	1.6	0.000	0.00	0.00	0.01	0.0	0.01	0.0
20	DELA10	13.	0.7	0.6	1.4	0.000	0.00	0.00	0.01	0.0	0.01	0.0
21	DELA11	13.	0.7	0.6	1.4	0.000	0.00	0.00	0.01	0.0	0.01	0.0
22	DELA12	13.	0.7	0.6	1.4	0.000	0.00	0.00	0.01	0.0	0.01	0.0
23	EDDY1	301.	2279.9	4274.4	6554.3	0.591	24.91	5.45	3.57	0.0	33.83	1557.7
24	EDDY2	311.	2378.0	4087.6	6465.6	0.613	28.61	5.85	3.69	0.0	38.14	1670.7
25	EDDY3	380.	228.0	499.7	727.7	0.053	9.64	0.62	5.30	0.0	15.56	177.1
26	EDDY4	380.	362.2	711.8	1074.0	0.072	13.10	0.84	5.30	0.0	18.24	240.7
27	EDDY10	13.	2.5	9.9	12.5	0.001	0.01	0.00	0.01	0.0	0.02	0.1
28	EDDY20	13.	2.5	1.3	3.8	0.000	0.00	0.00	0.01	0.0	0.01	0.0
29	EDDY30	15.	2.5	9.8	12.4	0.001	0.01	0.00	0.01	0.0	0.02	0.1
30	EDDY40	15.	2.0	9.8	11.8	0.000	0.00	0.00	0.01	0.0	0.02	0.1
31	FALLS1	15.	1.0	1.2	2.2	0.000	0.00	0.00	0.01	0.0	0.02	0.0
32	FALLS2	15.	1.0	1.3	2.3	0.000	0.00	0.00	0.01	0.0	0.02	0.0
33	FALLS3	15.	2.6	9.9	12.5	0.001	0.01	0.00	0.01	0.0	0.03	0.2
34	MOSER1	15.	0.9	1.2	2.1	0.000	0.00	0.00	0.01	0.0	0.02	0.0
35	MOSER2	15.	0.8	1.2	2.0	0.000	0.00	0.00	0.01	0.0	0.01	0.0
36	MOSER3	15.	0.9	1.1	2.1	0.000	0.00	0.00	0.01	0.0	0.02	0.0
37	MUDDY1	110.	753.7	1374.9	2128.6	0.233	0.0	0.0	0.35	0.0	0.35	224.4
38	MUDDY2	110.	747.7	1072.9	1820.6	0.200	0.0	0.0	0.35	0.0	0.35	192.7
39	MUDDY3	110.	775.0	1074.0	1849.1	0.211	0.0	0.0	0.35	0.0	0.35	203.4
40	MUDDY4	110.	727.8	1045.0	1772.8	0.202	0.0	0.0	0.35	0.0	0.35	185.0
41	MUDDY5	110.	785.9	1022.6	1808.6	0.206	0.0	0.0	0.35	0.0	0.35	198.9
42	MUDDY6	110.	757.1	1067.4	1824.6	0.208	0.0	0.0	0.35	0.0	0.35	200.7
43	MUDDY7	110.	758.4	1423.6	2181.9	0.228	0.0	0.0	0.35	0.0	0.35	219.9
44	MUDDY8	110.	758.4	1370.2	2128.6	0.223	0.0	0.0	0.35	0.0	0.35	214.8
45	PEACH2	447.	2555.5	4227.2	6782.7	0.697	12.77	2.86	9.08	0.0	24.72	2727.9
46	PEACH3	439.	2513.9	4103.2	6617.1	0.680	12.25	2.75	8.92	0.0	23.91	2615.2
47	DIESEL	19.	18.6	49.9	68.5	0.007	0.07	0.00	0.02	0.0	0.09	1.2
48	PLMT8	29.	0.2	0.6	0.8	0.000	0.00	0.00	0.02	0.0	0.03	0.0
49	PLMT15	29.	0.1	0.8	0.9	0.000	-0.00	0.00	0.02	0.0	0.03	0.0
50	RICH9	166.	2320.8	3625.4	5946.1	0.635	43.60	5.28	4.53	0.0	53.40	823.8
51	RICH21	33.	14.8	17.9	32.7	0.003	0.07	0.02	0.03	0.0	0.11	1.0
52	RICH22	33.	9.1	17.3	26.4	0.002	0.05	0.01	0.03	0.0	0.09	0.7
53	RICH31	33.	1.3	1.0	2.2	0.000	0.01	0.00	0.03	0.0	0.03	0.1
54	RICH32	33.	1.1	1.2	2.3	0.000	0.01	0.00	0.03	0.0	0.03	0.1
55	RICH41	21.	5.6	2.0	7.6	0.001	0.01	0.00	0.02	0.0	0.03	0.1
56	RICH42	21.	5.6	9.0	14.6	0.001	0.02	0.00	0.02	0.0	0.04	0.2
57	RICH43	21.	11.0	17.6	28.7	0.003	0.04	0.01	0.02	0.0	0.06	0.5
58	RICH44	21.	4.5	9.7	14.2	0.001	0.02	0.00	0.02	0.0	0.04	0.3
59	RICH51	33.	1.1	1.3	2.3	0.000	0.00	0.00	0.03	0.0	0.03	0.1
60	RICH52	33.	2.0	1.7	3.7	0.000	0.01	0.00	0.03	0.0	0.04	-0.1
61	RICH61	33.	1.0	0.9	1.8	0.000	0.00	0.00	0.03	0.0	0.03	0.1
62	RICH62	33.	0.6	1.3	1.9	0.000	0.00	0.00	0.03	0.0	0.03	0.1
63	RICH71	[illegible]	[illegible]	[illegible]	14.6	0.001	[illegible]	[illegible]	0.02	0.0	0.04	0.3

Exhibit ___ (DS-C)
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66	RICH91	51.	13.0	18.9	31.9	0.002	0.06	.02	0.04	0.0	0.12	1.1
67	RICH92	51.	15.2	15.7	30.9	0.003	0.08	0.02	0.04	0.0	0.14	1.2
68	SCHY1	159.	2644.4	4234.4	6878.8	0.603	40.28	3.33	3.21	0.0	46.82	851.0
69	SCHY3	49.	3041.1	4482.8	7523.9	0.849	7.05	1.28	0.99	0.0	9.32	364.4
71	SCHY10	13.	0.8	0.3	1.1	0.000	0.00	0.00	0.01	0.0	0.01	0.0
72	SCHY11	15.	0.8	0.9	1.7	0.000	0.00	0.00	0.01	0.0	0.01	0.0
73	SOUTH1	178.	100.4	270.2	370.6	0.030	2.84	0.10	1.89	0.0	4.84	47.0
74	SOUTH2	178.	57.8	109.4	167.2	0.014	1.37	0.05	1.89	0.0	3.31	22.6
75	SOUTH3	13.	0.8	0.8	1.6	0.000	0.00	0.00	0.01	0.0	0.01	0.0
76	SOUTH4	13.	0.6	0.9	1.5	0.000	0.00	0.00	0.01	0.0	0.01	0.0
77	SOUTH5	13.	0.8	0.9	1.7	0.000	0.00	0.00	0.01	0.0	0.01	0.0
78	SOUTH6	13.	0.8	0.9	1.7	0.000	0.00	0.00	0.01	0.0	0.01	0.0
79	CONEM1	176.	2102.6	3153.0	5255.6	0.588	14.40	2.01	1.96	0.0	18.37	907.1
80	CONEM2	176.	2243.8	3406.1	5649.9	0.632	15.48	2.16	1.96	0.0	19.60	875.1
81	CONEMD	2.	22.5	32.3	54.8	0.006	0.01	0.00	0.00	0.0	0.01	0.1
82	KEYST1	179.	2302.0	3651.1	5953.1	0.626	15.54	2.63	1.86	0.0	20.02	878.8
83	KEYST2	179.	2532.4	3815.2	6347.5	0.711	17.64	2.98	1.86	0.0	22.48	1111.1
84	KEYSTD	2.	23.7	32.4	56.1	0.006	0.01	0.00	0.00	0.0	0.01	0.1
85	SALEM1	468.	2539.4	4198.0	6737.4	0.692	13.28	3.31	10.19	0.0	26.79	2837.1
86	SALEM3	16.	4.9	10.1	15.0	0.001	0.01	0.00	0.01	0.0	0.03	0.2
87	CON01	36.	1534.8	2129.3	3664.0	0.418	0.0	0.0	0.17	0.0	0.17	131.8
88	CON02	36.	1439.6	2128.8	3568.4	0.407	0.0	0.0	0.17	0.0	0.17	128.5
89	CON03	36.	1456.5	2244.8	3701.4	0.423	0.0	0.0	0.17	0.0	0.17	133.2
90	CON04	36.	1497.8	2215.9	3713.7	0.424	0.0	0.0	0.17	0.0	0.17	133.7
91	CON05	36.	1515.5	2169.9	3685.4	0.421	0.0	0.0	0.17	0.0	0.17	132.7
92	CON06	36.	1436.5	2166.9	3603.4	0.411	0.0	0.0	0.17	0.0	0.17	129.7
93	CON07	36.	1444.0	2098.3	3542.3	0.404	0.0	0.0	0.17	0.0	0.17	127.5
94	CON08	65.	1435.1	2119.9	3555.1	0.406	0.0	0.0	0.30	0.0	0.30	231.1
95	CON09	65.	1456.6	2144.8	3601.4	0.411	0.0	0.0	0.30	0.0	0.30	234.1
96	CON010	65.	1422.3	2123.6	3546.0	0.405	0.0	0.0	0.30	0.0	0.30	230.5
97	CON011	65.	1442.0	2144.5	3586.6	0.408	0.0	0.0	0.30	0.0	0.30	233.1
98	SALEM2	474.	2239.3	4034.1	6273.4	0.815	11.86	2.98	31.10	0.0	46.04	2553.3
100	ECONOMY	913.	2512.7	3985.8	6498.5	0.402	178.81	0.0	0.0	0.0	178.91	3214.3
109	EMRGENCY	500.	0.5	0.1	0.6	0.000	0.01	0.0	0.0	0.0	0.01	0.0
111	LMHW	64.	0.2	0.0	0.2	0.000	0.00	0.0	0.0	0.0	0.00	0.0
114	VOLAP	170.	0.2	0.0	0.2	0.000	0.01	0.0	0.0	0.0	0.01	0.0
115	BRNOUT5	150.	0.2	0.0	0.2	0.000	0.00	0.0	0.0	0.0	0.00	0.0
116	BRNOUT8	100.	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.00	0.0
117	PARTIAL	*******	0.0	0.0	0.0	0.0	0.00	0.0	0.0	0.0	0.00	0.0
118	TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0000 = 0.0 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0000 = 0.1 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 730.1 MILLION (1981) = $ 597.8 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 30858. GWH
INCREMENTAL ELECTRICITY COST 2.4 1981 CENTS PER KWH = 1.9 1979 CENTS PER KWH
LOAD FACTOR 59.3%

TOTAL COSTS IN 1981 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	387.	317.
VARIABLE O&M	56.	46.
CARRYING CHARGES	108.	88.
INCREMENTAL CAPITAL	0.	0.

IMPORT OPTIONS:	COST IN 1981 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	178.91	146.52	3214.3
EMRGENCY	0.01	0.00	0.0

TOTAL CURTAILMENT COST $ 0.01 MILLION (1981) = $ 0.01 MILLION (DISCOUNTED TO 1979)
BLACKOUT COST $ 0.00 MILLION (1981) = $ 0.00 MILLION (DISCOUNTED TO 1979)

LOAD CURVE: PECO   PLANT DATA: ESLI   LOAD GROWTH: ESRG   RESERVE MARGINS: INPUT 6.0%; ACTUAL 6.0%

MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1987 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
17.	202.7	296.2	498.9	0.046	0.48	0.17	0.02	0.0	0.68	6.8
15.	152.4	232.4	384.7	0.039	0.46	0.16	0.02	0.0	0.65	6.4
17.	202.5	310.6	513.1	0.053	0.56	0.20	0.02	0.0	0.79	7.9
127.	2566.4	4077.8	6644.2	0.629	17.43	4.62	2.89	0.0	24.94	754.7
43.	79.9	148.1	227.0	0.022	0.94	0.08	0.02	0.0	1.04	9.6
45.	100.3	180.4	280.7	0.031	1.30	0.11	0.02	0.0	1.44	13.4
45.	46.7	66.8	113.5	0.011	0.47	0.04	0.02	0.0	0.53	4.8
45.	118.2	192.9	311.1	0.033	1.40	0.12	0.02	0.0	1.54	14.3
45.	125.4	193.3	318.7	0.034	1.42	0.12	0.02	0.0	1.56	14.5
45.	120.0	166.7	286.7	0.032	1.36	0.12	0.02	0.0	1.50	13.9
45.	98.1	159.2	257.4	0.028	1.16	0.10	0.02	0.0	1.29	11.9
45.	64.9	113.3	178.1	0.017	0.70	0.06	0.02	0.0	0.79	7.2
128.	2664.8	4299.9	6964.7	0.739	62.86	3.96	1.85	0.0	68.67	815.4
124.	2296.5	3973.5	6270.0	0.657	54.98	3.47	1.82	0.0	60.26	713.1
301.	2290.0	4136.2	6426.3	0.582	32.86	8.28	5.51	0.0	46.66	1533.8
311.	2443.0	4122.7	6565.7	0.611	38.19	8.99	5.69	0.0	52.87	1664.1
360.	276.7	364.0	640.7	0.047	14.32	0.85	8.17	0.0	23.35	156.9
110.	789.9	1275.6	2066.4	0.227	0.0	0.0	0.54	0.0	0.54	218.3
110.	804.9	1314.9	2119.8	0.232	0.0	0.0	0.54	0.0	0.54	223.9
[illegible]	795.0	1033.7	1828.7	0.209	0.0	0.0	0.54	0.0	0.54	201.2
[illegible]	779.6	1025.6	1806.5	0.206	0.0	0.0	0.54	0.0	0.54	198.7
110.	773.1	1047.1	1820.2	0.208	0.0	0.0	0.54	0.0	0.54	200.2
110.	816.2	1297.5	2113.7	0.241	0.0	0.0	0.54	0.0	0.54	232.5
110.	777.2	1325.2	2102.4	0.221	0.0	0.0	0.54	0.0	0.54	212.5
110.	793.1	1298.4	2091.5	0.220	0.0	0.0	0.54	0.0	0.54	211.7
447.	[illegible]	4222.9	6734.5	0.691	20.34	4.38	14.02	0.0	38.74	2706.7
432.	2518.1	3975.6	6493.7	0.668	19.31	4.16	13.77	0.0	37.24	2570.0
12.	29.0	66.7	95.7	0.010	0.16	0.00	0.02	0.0	0.18	1.6
166.	1878.9	3222.0	5100.8	0.528	60.76	6.77	6.99	0.0	74.53	768.0
155.	2555.1	4049.0	6604.1	0.644	63.71	4.85	4.96	0.0	73.51	897.2
45.	2677.6	4063.2	6740.9	0.756	10.54	1.75	1.53	0.0	13.82	324.7
175.	2141.3	3263.3	5404.6	0.605	19.84	3.19	3.03	0.0	26.06	932.7
175.	2233.6	3403.4	5637.0	0.631	20.70	3.33	3.03	0.0	27.05	972.8
175.	2220.6	3956.5	6177.1	0.648	21.57	4.20	2.87	0.0	28.64	1014.0
175.	2734.9	3669.3	6404.2	0.717	23.85	4.64	2.87	0.0	31.36	1120.9
465.	2550.0	4160.4	6710.4	0.690	21.24	5.09	15.73	0.0	42.06	2827.3
12.	71.5	109.3	180.8	0.018	0.29	0.07	0.02	0.0	0.38	2.6
33.	1473.3	2113.9	3587.5	0.410	0.0	0.0	0.26	0.0	0.26	129.2
33.	1465.0	2114.9	3579.9	0.409	0.0	0.0	0.26	0.0	0.26	128.9
35.	1507.9	2194.4	3702.3	0.423	0.0	0.0	0.26	0.0	0.26	133.3
35.	1521.9	2189.3	3711.1	0.424	0.0	0.0	0.26	0.0	0.26	133.6
33.	1420.8	2219.0	3639.8	0.416	0.0	0.0	0.26	0.0	0.26	131.0
33.	1514.9	2172.0	3686.9	0.421	0.0	0.0	0.26	0.0	0.26	132.7
36.	1521.5	2223.0	3745.0	0.428	0.0	0.0	0.26	0.0	0.26	134.8
65.	1505.2	2167.2	3672.4	0.419	0.0	0.0	0.47	0.0	0.47	238.7
65.	1495.8	2170.8	3666.6	0.419	0.0	0.0	0.47	0.0	0.47	238.3
65.	1491.3	2171.5	3662.8	0.418	0.0	0.0	0.47	0.0	0.47	238.1
65.	1422.7	2172.3	3595.0	0.410	0.0	0.0	0.47	0.0	0.47	233.7
474.	2242.1	3863.7	6105.7	0.600	18.72	4.48	48.00	0.0	71.21	2491.5
600.	3302.4	5133.7	8436.1	0.798	89.20	25.66	51.05	136.03	301.94	4192.4
512.	1770.4	3195.4	4965.8	0.275	205.50	0.0	0.0	0.0	205.50	2202.0
500.	24.7	66.8	93.4	0.005	3.97	0.0	0.0	0.0	3.97	20.4
64.	51.4	42.1	93.5	0.009	2.09	0.0	0.0	0.0	2.09	5.1
170.	44.6	30.9	75.4	0.007	4.43	0.0	0.0	0.0	4.43	10.9
150.	25.5	20.9	47.4	0.005	1.24	0.0	0.0	0.0	1.24	6.1
100.	16.9	11.0	27.9	0.003	0.77	0.0	0.0	0.0	0.77	2.5
*******	12.5	9.7	22.3	0.0	44.75	0.0	0.0	0.0	44.75	4.4
*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SULTS

-I PROBABILITIES:
-CKOUTS 0.0025 = 9.3 DAYS IN TEN YEARS
OUTS 0.0 = 0.0 DAYS IN TEN YEARS
.MENT OPTIONS 0.0107 = 38.0 DAYS IN TEN YEARS

.Y COST $ 1326.0 MILLION (1987) = $ 596.6 MILLION (DISCOUNTED TO 1979)
RICITY GENERATED 33114. GWH
- ELECTRICITY COST 4.0 1987 CENTS PER KWH = 1.8 1979 CENTS PER KWH
: 59.3%

S IN 1987 $MILLION		DISCOUNTED TO 1979 $MILLION
	621.	279.
&M	104.	47.
-ARGES	202.	91.
- CAPITAL	136.	61.

IONS:	COST IN 1987 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
	205.50	92.45	2202.0
	3.97	1.78	20.4

'AILMENT COST $ 53.27 MILLION (1987) = $ 23.97 MILLION (DISCOUNTED TO 1979)
.OST $ 44.75 MILLION (1987) = $ 20.13 MILLION (DISCOUNTED TO 1979)

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LOAD CURVE: PECO   PLANT DATA: ESL1   LOAD GROWTH: ESRG   RESERVE MARGINS: INPUT 14.0%: ACTUAL 14.2%

MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1987 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
17.	100.2	152.5	252.7	0.022	0.24	0.08	0.02	0.0	0.34	3.3
19.	81.9	133.0	214.9	0.022	0.27	0.10	0.02	0.0	0.39	3.7
17.	98.2	135.0	233.1	0.024	0.26	0.09	0.02	0.0	0.37	3.6
137.	2599.7	4042.3	6642.0	0.629	17.44	4.62	2.89	0.0	24.95	755.1
49.	41.0	39.7	80.7	0.009	0.37	0.03	0.02	0.0	0.42	3.8
49.	46.5	56.0	102.4	0.011	0.45	0.04	0.02	0.0	0.52	4.7
49.	25.9	15.6	41.5	0.005	0.19	0.02	0.02	0.0	0.23	2.0
49.	45.7	69.9	115.6	0.012	0.50	0.04	0.02	0.0	0.56	5.1
49.	49.6	88.7	138.3	0.015	0.62	0.05	0.02	0.0	0.70	6.4
49.	43.9	92.6	136.5	0.015	0.61	0.05	0.02	0.0	0.69	6.3
49.	40.0	53.4	93.4	0.010	0.41	0.04	0.02	0.0	0.47	4.2
49.	32.2	61.4	93.6	0.009	0.40	0.03	0.02	0.0	0.45	4.1
125.	2771.8	4257.2	7029.0	0.746	63.51	4.00	1.85	0.0	69.36	823.8
124.	2528.5	4081.2	6609.7	0.696	58.26	3.37	1.82	0.0	62.75	755.9
301.	2306.3	4248.3	6554.6	0.592	33.46	8.43	5.51	0.0	47.40	1561.4
311.	2353.4	4052.7	6406.1	0.599	37.39	8.80	5.69	0.0	51.88	1629.3
380.	260.7	450.0	710.7	0.051	15.40	0.91	8.17	0.0	24.48	168.7
380.	126.6	173.2	299.9	0.018	5.56	0.33	8.17	0.0	14.07	60.9
110.	800.0	1306.5	2106.5	0.231	0.0	0.0	0.54	0.0	0.54	222.5
110.	791.8	1352.4	2144.2	0.235	0.0	0.0	0.54	0.0	0.54	226.3
110.	788.2	1267.9	2056.1	0.235	0.0	0.0	0.54	0.0	0.54	226.2
110.	748.4	996.2	1744.6	0.199	0.0	0.0	0.54	0.0	0.54	191.9
110.	792.2	1273.0	2065.1	0.236	0.0	0.0	0.54	0.0	0.54	227.2
110.	775.5	1062.1	1837.6	0.210	0.0	0.0	0.54	0.0	0.54	202.1
110.	792.6	1328.9	2121.5	0.223	0.0	0.0	0.54	0.0	0.54	214.6
110.	787.0	1215.1	2102.1	0.221	0.0	0.0	0.54	0.0	0.54	212.6
447.	2544.6	4184.7	6729.3	0.691	20.34	4.39	14.02	0.0	38.74	2707.1
439.	2501.3	4101.2	6602.5	0.678	19.60	4.23	13.77	0.0	37.60	2608.9
19.	12.5	15.0	27.5	0.003	0.05	0.00	0.02	0.0	0.07	0.5
166.	1967.5	3333.5	5321.1	0.553	63.64	7.09	6.99	0.0	77.72	804.3
51.	42.9	41.0	83.8	0.008	0.37	0.09	0.07	0.0	0.53	3.6
51.	20.5	21.4	41.9	0.004	0.17	0.04	0.07	0.0	0.28	1.7
51.	19.9	18.7	38.6	0.004	0.16	0.04	0.07	0.0	0.27	1.6
159.	2666.1	3993.5	6659.6	0.656	64.84	4.93	4.96	0.0	74.73	913.2
49.	2876.6	4258.0	7134.5	0.803	11.19	1.86	1.53	0.0	14.58	344.8
176.	2144.6	3210.7	5355.2	0.600	19.67	3.16	3.03	0.0	25.86	924.3
176.	2233.9	3341.0	5574.9	0.624	20.47	3.29	3.03	0.0	26.79	962.3
2.	39.5	35.6	75.1	0.008	0.02	0.00	0.00	0.0	0.02	0.2
179.	2305.4	3691.4	5996.8	0.630	20.97	4.08	2.87	0.0	27.92	985.6
179.	2540.4	3784.9	6325.3	0.708	23.56	4.58	2.87	0.0	31.01	1107.3
2.	45.8	42.7	88.5	0.010	0.02	0.01	0.00	0.0	0.03	0.2
462.	2549.8	4140.1	6690.0	0.686	21.18	5.07	15.73	0.0	41.99	2819.2
36.	1423.6	2240.1	3663.7	0.418	0.0	0.0	0.26	0.0	0.26	131.9
36.	1419.6	2177.9	3597.5	0.411	0.0	0.0	0.26	0.0	0.26	129.5
36.	1418.8	2183.9	3602.7	0.411	0.0	0.0	0.25	0.0	0.26	129.7
36.	1429.7	2209.8	3639.4	0.415	0.0	0.0	0.26	0.0	0.26	131.0
36.	1467.9	2156.8	3624.7	0.414	0.0	0.0	0.26	0.0	0.26	130.5
36.	1472.8	2121.9	3594.7	0.410	0.0	0.0	0.26	0.0	0.26	129.4
36.	1429.8	2216.6	3646.4	0.416	0.0	0.0	0.25	0.0	0.26	131.3
65.	1508.8	2145.3	3654.1	0.417	0.0	0.0	0.47	0.0	0.47	237.5
65.	1483.7	2127.3	3610.9	0.412	0.0	0.0	0.47	0.0	0.47	234.7
65.	1454.6	2204.6	3659.2	0.418	0.0	0.0	0.47	0.0	0.47	237.9
65.	1523.1	2170.1	3693.2	0.422	0.0	0.0	0.47	0.0	0.47	240.1
474.	2132.8	3790.2	5923.1	0.581	18.13	4.34	48.00	0.0	70.47	2412.6
600.	3329.5	5055.6	8385.1	0.787	88.00	25.31	51.05	136.03	300.39	4136.1
913.	1911.4	3356.0	5267.4	0.284	211.86	0.0	0.0	0.0	211.86	2270.1
500.	21.9	30.8	52.6	0.003	2.44	0.0	0.0	0.0	2.44	12.5
64.	18.1	6.2	24.3	0.003	0.57	0.0	0.0	0.0	0.57	1.4
170.	16.0	5.4	21.4	0.002	1.24	0.0	0.0	0.0	1.24	3.0
150.	11.5	3.4	15.0	0.001	0.37	0.0	0.0	0.0	0.37	1.8
100.	7.2	2.3	9.5	0.001	0.27	0.0	0.0	0.0	0.27	0.9
*******	6.4	2.2	8.6	0.0	13.55	0.0	0.0	0.0	13.55	1.3
*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

JLTS

; PROBABILITIES:
TAOUTS 0.0010 = 3.6 DAYS IN TEN YEARS
UTS 0.0 = 0.0 DAYS IN TEN YEARS
ENT OPTIONS 0.0028 = 10.1 DAYS IN TEN YEARS

COST $ 1308.4 MILLION (1987) = $ 588.6 MILLION (DISCOUNTED TO 1979)
ICITY GENERATED 33114. GWH
~~ELECTRICITY COST 4.0 1987~~-CENTS PER-KWH = - 1.8-1979 CENTS PER-KWH - -
59.3%

	IN 1987 $MILLION	DISCOUNTED TO 1979 $MILLION
	628.	282.
	104.	47.
RGES	210.	95.
CAPITAL	136.	61.

INS:	COST IN 1987 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
	211.86	95.31	2270.1
	2.44	1.10	12.5

LMENT COST $ 16.00 MILLION (1987) = $ 7.20 MILLION (DISCOUNTED TO 1979)
IT $ 13.55 MILLION (1987) = $ 6.10 MILLION (DISCOUNTED TO 1979)

OPTION	MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1987 DOLLARS) ENERGY	VAROAM	CARCHG	CAPITAL	TOTAL	GWH GENERATED
1 BARB5	17.	63.9	112.8	176.7	0.016	0.17	0.06	0.02	0.0	0.25	2.3
2 BARB6	19.	57.6	103.2	160.9	0.016	0.19	0.07	0.02	0.0	0.28	2.7
3 BARB7	17.	62.9	112.3	175.2	0.018	0.19	0.07	0.02	0.0	0.28	2.7
4 CHEST7	13.	5.3	2.3	7.6	0.001	0.01	0.00	0.02	0.0	0.03	0.1
5 CHEST8	13.	3.4	2.3	5.6	0.001	0.01	0.00	0.02	0.0	0.03	0.1
6 CHEST9	13.	6.7	2.5	9.2	0.001	0.01	0.00	0.02	0.0	0.03	0.1
7 CROMB1	137.	2620.4	4324.3	6944.7	0.654	18.12	4.80	2.89	0.0	25.81	784.3
8 CROY11	49.	21.7	11.5	33.2	0.004	0.15	0.01	0.02	0.0	0.18	1.5
10 CROY12	48.	30.2	33.2	63.4	0.006	0.25	0.02	0.02	0.0	0.30	2.6
11 CROY21	49.	19.7	16.3	36.0	0.004	0.15	0.01	0.02	0.0	0.18	1.6
12 CROY22	49.	33.9	40.8	74.7	0.008	0.34	0.03	0.02	0.0	0.38	3.5
13 CROY31	48.	35.4	67.8	103.3	0.011	0.46	0.04	0.02	0.0	0.52	4.7
14 CROY32	48.	49.0	71.2	120.2	0.012	0.52	0.05	0.02	0.0	0.58	5.4
15 CROY41	48.	29.8	67.4	97.2	0.008	0.35	0.03	0.02	0.0	0.41	3.8
16 CROY42	48.	17.9	16.9	34.8	0.004	0.16	0.01	0.02	0.0	0.20	1.7
17 DELA7	126.	2702.0	4271.3	6973.3	0.733	62.36	3.83	1.85	0.0	68.13	808.8
18 DELA8	124.	2385.7	3800.1	6185.8	0.658	54.90	3.46	1.82	0.0	60.18	712.1
23 EDDY1	301.	2312.9	4261.5	6574.4	0.584	33.56	8.46	5.51	0.0	47.53	1566.3
24 EDDY2	311.	2359.7	3964.6	6324.3	0.593	37.05	8.72	5.68	0.0	51.46	1614.4
25 EDDY3	380.	239.6	448.3	687.9	0.042	12.75	0.75	8.17	0.0	21.68	138.7
26 EDDY4	380.	133.7	172.8	306.5	0.018	5.62	0.33	8.17	0.0	14.13	61.5
27 EDDY10	13.	10.1	3.8	13.8	0.002	0.02	0.00	0.02	0.0	0.04	0.2
28 EDDY20	13.	12.0	4.0	16.0	0.002	0.02	0.01	0.02	0.0	0.05	0.2
29 EDDY30	15.	12.3	3.8	16.1	0.002	0.03	0.01	0.02	0.0	0.05	0.2
30 EDDY40	15.	11.7	4.2	16.0	0.002	0.03	0.01	0.02	0.0	0.05	0.2
31 FALLS1	15.	12.3	3.8	16.2	0.002	0.03	0.01	0.02	0.0	0.05	0.2
32 FALLS2	15.	11.2	3.8	15.0	0.002	0.03	0.01	0.02	0.0	0.05	0.2
33 FALLS3	15.	11.8	3.7	15.5	0.002	0.03	0.01	0.02	0.0	0.05	0.2
37 MUDDY1	110.	789.4	1281.4	2070.7	0.227	0.0	0.0	0.54	0.0	0.54	218.7
38 MUDDY2	110.	792.5	1315.7	2108.2	0.231	0.0	0.0	0.54	0.0	0.54	222.8
39 MUDDY3	110.	744.9	1005.1	1749.9	0.200	0.0	0.0	0.54	0.0	0.54	192.5
40 MUDDY4	110.	757.8	1248.5	2006.3	0.229	0.0	0.0	0.54	0.0	0.54	220.7
41 MUDDY5	110.	782.2	1041.9	1824.1	0.208	0.0	0.0	0.54	0.0	0.54	200.8
42 MUDDY6	110.	821.9	1050.8	1872.7	0.214	0.0	0.0	0.54	0.0	0.54	206.0
43 MUDDY7	110.	797.4	1354.0	2151.5	0.226	0.0	0.0	0.54	0.0	0.54	217.5
44 MUDDY8	110.	810.2	1334.8	2145.0	0.225	0.0	0.0	0.54	0.0	0.54	217.1
45 PEACH2	447.	2547.4	4142.6	6690.0	0.688	20.23	4.36	14.02	0.0	38.61	2692.6
46 PEACH3	439.	2481.5	4198.6	6680.1	0.685	19.81	4.27	13.77	0.0	37.84	2636.1
47 DIESEL	19.	7.5	7.8	15.3	0.002	0.03	0.00	0.02	0.0	0.05	0.3
50 RICH9	166.	1888.8	3047.5	4936.3	0.517	59.54	6.64	6.89	0.0	73.17	752.5
51 RICH21	33.	18.2	8.7	26.9	0.003	0.08	0.02	0.04	0.0	0.16	0.8
52 RICH22	33.	13.2	6.5	19.6	0.002	0.07	0.02	0.04	0.0	0.13	0.6
53 RICH31	33.	10.8	3.5	14.4	0.002	0.05	0.01	0.04	0.0	0.11	0.5
54 RICH32	33.	8.2	2.9	11.2	0.001	0.04	0.01	0.04	0.0	0.09	0.4
55 RICH41	21.	10.6	4.3	15.0	0.002	0.03	0.01	0.03	0.0	0.07	0.3
56 RICH42	21.	11.9	4.8	16.7	0.002	0.04	0.01	0.03	0.0	0.07	0.3
57 RICH43	21.	11.6	4.8	16.5	0.002	0.04	0.01	0.03	0.0	0.07	0.3
58 RICH44	21.	12.1	4.9	16.9	0.002	0.04	0.01	0.03	0.0	0.07	0.3
59 RICH51	33.	9.4	2.7	12.1	0.001	0.03	0.01	0.04	0.0	0.08	0.3
60 RICH52	33.	5.9	2.6	8.5	0.001	0.03	0.01	0.04	0.0	0.08	0.2
61 RICHG1	33.	3.4	2.2	5.7	0.001	0.02	0.00	0.04	0.0	0.07	0.2
62 RICHG2	33.	12.2	4.0	16.2	0.002	0.06	0.01	0.04	0.0	0.12	0.5
63 RICH71	21.	10.8	5.1	15.9	0.002	0.03	0.01	0.03	0.0	0.07	0.3
64 RICH72	21.	14.5	[illegible]	[illegible]	0.002	0.04	0.01	0.03	0.0	0.08	0.4

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66 RICH91	51.	11.2	9.3	20.5	0.002	0.	0.02	0.07	0.0	0.17	0.8
67 RICH92	51.	17.2	6.2	23.4	0.002	0..	0.02	0.07	0.0	0.18	0.9
68 SCHY1	159.	2497.8	3749.3	6247.1	0.609	60.23	4.58	4.96	0.0	69.77	848.3
69 SCHY3	49.	2801.2	4201.2	7002.4	0.786	10.95	1.82	1.53	0.0	14.30	337.5
79 CONEM1	176.	2166.7	3251.9	5418.6	0.607	19.90	3.20	3.03	0.0	26.13	935.3
80 CONEM2	176.	2249.3	3405.2	5654.5	0.633	20.76	3.34	3.03	0.0	27.13	975.9
81 CONEMD	2.	22.3	13.3	35.6	0.004	0.01	0.00	0.00	0.0	0.01	0.1
82 KEYST1	179.	2345.6	3767.5	6113.1	0.642	21.37	4.16	2.87	0.0	28.40	1004.6
83 KEYST2	179.	2534.4	3863.6	6398.0	0.716	23.83	4.64	2.87	0.0	31.33	1119.9
84 KEYSTD	2.	23.4	12.6	36.0	0.004	0.01	0.00	0.00	0.0	0.01	0.1
85 SALEM1	468.	2529.7	4090.1	6619.8	0.681	20.97	5.02	15.73	0.0	41.72	2790.2
86 SALEM3	16.	11.1	4.4	15.5	0.002	0.03	0.01	0.02	0.0	0.05	0.2
87 CON01	36.	1510.8	2144.3	3655.2	0.417	0.0	0.0	0.26	0.0	0.26	131.6
88 CON02	36.	1485.3	2248.4	3733.7	0.426	0.0	0.0	0.26	0.0	0.26	134.4
89 CON03	36.	1511.8	2188.7	3700.5	0.422	0.0	0.0	0.26	0.0	0.26	133.2
90 CON04	36.	1448.8	2214.1	3662.9	0.418	0.0	0.0	0.26	0.0	0.26	131.9
91 CON05	36.	1499.3	2184.5	3683.8	0.421	0.0	0.0	0.26	0.0	0.26	132.6
92 CON06	36.	1520.5	2200.1	3720.6	0.425	0.0	0.0	0.26	0.0	0.26	133.8
93 CON07	36.	1502.0	2182.9	3684.9	0.421	0.0	0.0	0.26	0.0	0.28	132.7
94 CON08	65.	1508.8	2204.5	3713.4	0.424	0.0	0.0	0.47	0.0	0.47	241.4
95 CON09	65.	1428.2	2234.2	3662.4	0.418	0.0	0.0	0.47	0.0	0.47	238.1
96 CON010	65.	1524.0	2214.7	3738.7	0.427	0.0	0.0	0.47	0.0	0.47	243.0
97 CON011	65.	1489.7	2162.1	3651.8	0.417	0.0	0.0	0.47	0.0	0.47	237.4
98 SALEM2	474.	2143.1	3828.6	5971.7	0.586	18.27	4.38	48.00	0.0	70.65	2431.7
102 GCOAL3	600.	3299.6	5130.0	8429.6	0.796	88.87	25.59	51.05	136.03	301.64	4181.7
108 ECONOMY	913.	1988.6	3297.8	5286.4	0.295	220.11	0.0	0.0	0.0	220.11	2358.6
109 EMRGENCY	500.	3.5	1.8	5.4	0.000	0.20	0.0	0.0	0.0	0.20	1.0
111 LMHW	64.	1.2	0.5	1.7	0.000	0.03	0.0	0.0	0.0	0.03	0.1
114 VOLAP	170.	0.3	0.3	0.6	0.000	0.02	0.0	0.0	0.0	0.02	0.1
115 BRNOUT5	150.	0.1	0.1	0.2	0.000	0.00	0.0	0.0	0.0	0.00	0.0
116 BRNOUT8	100.	0.1	0.1	0.2	0.000	0.00	0.0	0.0	0.0	0.00	0.0
117 PARTIAL	*******	0.0	0.0	0.1	0.0	0.05	0.0	0.0	0.0	0.05	0.0
118 TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0000 = 0.0 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0002 = 0.7 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 1284.0 MILLION (1987) = $ 577.7 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 33114. GWH
INCREMENTAL ELECTRICITY COST 3.9 1987 CENTS PER KWH = 1.7 1979 CENTS PER KWH
LOAD FACTOR 59.3%

TOTAL COSTS IN 1987 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	613.	276.
VARIABLE O&M	103.	46.
CARRYING CHARGES	211.	95.
INCREMENTAL CAPITAL	136.	61.

IMPORT OPTIONS:	COST IN 1987 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	220.11	99.02	2358.6
EMRGENCY	0.20	0.09	1.0

TOTAL CURTAILMENT COST $ [illegible] MILLION (1987) = $ 0.05 MILLION (DISCOUNTED TO 1979)
BLACKOUT COST $ 0.05 MILLION (1987) = $ [illegible] MILLION (DISCOUNTED TO 1979)

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Exhibit (DS-C)
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1987 PECO LOAD CURVE: PECO PLANT DATA: ESL1 LOAD GROWTH: ESRG RESERVE MARGINS: INPUT 30.0%; ACTUAL 32.1%

OPTION	MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1987 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
1 BARB5	17.	101.5	146.0	247.5	0.022	0.24	0.09	0.02	0.0	0.35	3.3
2 BARB6	19.	66.8	109.5	176.3	0.018	0.21	0.08	0.02	0.0	0.31	3.0
3 BARB7	17.	103.6	157.5	261.1	0.026	0.28	0.10	0.02	0.0	0.40	3.8
4 CHEST7	13.	2.5	0.8	3.3	0.000	0.00	0.00	0.02	0.0	0.02	0.0
5 CHEST8	13.	2.5	0.9	3.4	0.000	0.01	0.00	0.02	0.0	0.02	0.0
6 CHEST9	13.	2.6	0.9	3.5	0.000	0.01	0.00	0.02	0.0	0.02	0.0
7 CROMB1	137.	2599.8	4166.2	6766.1	0.638	17.67	4.68	2.89	0.0	25.25	765.1
8 CROY11	49.	14.3	14.8	29.2	0.003	0.13	0.01	0.02	0.0	0.17	1.4
10 CROY12	49.	17.2	14.5	31.8	0.003	0.14	0.01	0.02	0.0	0.17	1.4
11 CROY21	49.	7.4	6.6	14.0	0.002	0.06	0.01	0.02	0.0	0.08	0.7
12 CROY22	48.	14.3	18.9	33.2	0.004	0.15	0.01	0.02	0.0	0.19	1.6
13 CROY31	48.	18.0	22.5	40.6	0.004	0.19	0.02	0.02	0.0	0.23	1.8
14 CROY32	49.	21.6	42.6	64.2	0.006	0.26	0.02	0.02	0.0	0.30	2.7
15 CROY41	49.	10.2	19.0	29.2	0.003	0.12	0.01	0.02	0.0	0.15	1.2
16 CROY42	48.	11.2	13.5	24.7	0.002	0.08	0.01	0.02	0.0	0.11	0.8
17 DELA7	126.	2628.5	4135.6	6764.1	0.718	61.12	3.85	1.85	0.0	66.82	782.8
18 DELA8	124.	2367.5	3889.3	6256.8	0.649	54.37	3.43	1.82	0.0	59.61	705.2
19 DELA9	15.	2.3	0.8	3.1	0.000	0.01	0.00	0.02	0.0	0.03	0.0
20 DELA10	13.	0.5	0.5	1.0	0.000	0.00	0.00	0.02	0.0	0.02	0.0
21 DELA11	13.	2.3	0.8	3.0	0.000	0.01	0.00	0.02	0.0	0.02	0.0
22 DELA12	13.	2.3	0.3	2.5	0.000	0.00	0.00	0.02	0.0	0.02	0.0
23 EDDY1	301.	2283.1	4293.6	6576.7	0.583	33.51	8.45	5.51	0.0	47.46	1563.8
24 EDDY2	311.	2390.8	4185.9	6576.7	0.612	38.27	9.01	5.69	0.0	52.97	1667.7
25 EDDY3	380.	296.1	435.1	731.2	0.050	15.19	0.90	8.17	0.0	24.26	166.4
26 EDDY4	380.	147.8	262.9	410.8	0.026	7.80	0.46	8.17	0.0	16.44	85.5
27 EDDY10	13.	4.5	2.3	6.7	0.001	0.01	0.00	0.02	0.0	0.03	0.1
28 EDDY20	13.	6.2	3.2	9.3	0.001	0.01	0.00	0.02	0.0	0.03	0.1
29 EDDY30	15.	6.4	4.6	10.9	0.001	0.02	0.00	0.02	0.0	0.04	0.1
30 EDDY40	15.	6.7	4.7	11.4	0.001	0.02	0.00	0.02	0.0	0.04	0.1
31 FALLS1	15.	5.6	2.5	8.1	0.001	0.01	0.00	0.02	0.0	0.04	0.1
32 FALLS2	15.	5.7	2.5	8.2	0.001	0.01	0.00	0.02	0.0	0.04	0.1
33 FALLS3	15.	3.5	1.3	4.7	0.000	0.01	0.00	0.02	0.0	0.03	0.1
34 MOSER1	15.	0.7	0.6	1.3	0.000	0.00	0.00	0.02	0.0	0.02	0.0
35 MOSER2	15.	2.4	0.9	3.3	0.000	0.01	0.00	0.02	0.0	0.03	0.0
36 MOSER3	15.	2.5	0.9	3.4	0.000	0.01	0.00	0.02	0.0	0.03	0.0
37 MUDDY1	110.	791.3	1300.3	2091.7	0.229	0.0	0.0	0.54	0.0	0.54	220.8
38 MUDDY2	110.	782.3	1275.3	2057.7	0.226	0.0	0.0	0.54	0.0	0.54	217.3
39 MUDDY3	110.	752.6	1021.8	1774.4	0.203	0.0	0.0	0.54	0.0	0.54	195.2
40 MUDDY4	110.	674.8	1021.3	1696.1	0.194	0.0	0.0	0.54	0.0	0.54	186.6
41 MUDDY5	110.	791.4	1041.2	1832.7	0.209	0.0	0.0	0.54	0.0	0.54	201.6
42 MUDDY6	110.	782.7	1058.0	1840.7	0.210	0.0	0.0	0.54	0.0	0.54	202.5
43 MUDDY7	110.	680.8	1279.1	1959.9	0.205	0.0	0.0	0.54	0.0	0.54	197.5
44 MUDDY8	110.	778.4	1371.4	2149.8	0.225	0.0	0.0	0.54	0.0	0.54	217.1
45 PEACH2	447.	2499.5	4165.5	6665.0	0.684	20.14	4.34	14.02	0.0	38.48	2679.8
46 PEACH3	439.	2535.5	4139.3	6674.7	0.686	19.82	4.27	13.77	0.0	37.86	2637.8
47 DIESEL	19.	12.9	12.0	24.9	0.003	0.04	0.00	0.02	0.0	0.07	0.5
48 PLMT9	29.	0.2	0.5	0.7	0.000	0.00	0.00	0.04	0.0	0.04	0.0
49 PLMT15	29.	2.3	0.8	3.1	0.000	0.01	0.00	0.04	0.0	0.05	0.1
50 RICH9	166.	1882.8	3082.2	4965.1	0.514	59.09	6.59	6.99	0.0	72.67	746.9
51 RICH21	23.	8.3	6.0	14.3	0.001	0.05	0.01	0.04	0.0	0.10	0.4
52 RICH22	33.	6.4	5.6	12.0	0.001	0.04	0.01	0.04	0.0	0.08	0.4
53 RICH31	33.	5.0	1.8	6.8	0.001	0.02	0.01	0.04	0.0	0.07	0.2
54 RICH32	33.	4.9	1.2	6.2	0.001	0.02	0.00	0.04	0.0	0.07	0.2
55 RICH41	21.	5.9	4.5	10.3	0.001	0.02	0.01	0.03	0.0	0.05	0.2
56 RICH42	21.	6.6	[illegible]	[illegible]	0.001	0.02	0.01	0.03	0.0	0.06	0.2
57 RICH43	[illegible]	6.5	[illegible]	[illegible]	0.001	0.02	0.01	0.03	0.0	0.06	0.2
58 RICH44	21.	4.1	[illegible]	8.4	0.001	0.02	0.00	0.03	0.0	0.05	0.2
59 RICH51	32.	2.6	[illegible]	[illegible]	0.000	0.01	0.00	0.04	0.0	0.06	0.1
60 RICH52	33.	2.5	[illegible]	[illegible]	0.000	[illegible]	0.00	0.04	0.0	0.06	0.1
[illegible]	33.	0.7	[illegible]	[illegible]	0.000	0.00	0.00	0.04	0.0	0.05	0.0
[illegible]	[illegible]	3.7	[illegible]	[illegible]	0.001	0.02	0.01	0.04	0.0	0.07	0.2
[illegible]	[illegible]	[illegible]	[illegible]	9.7	0.001	[illegible]	0.00	0.03	0.0	0.05	0.2
					[illegible]		[illegible]	[illegible]	[illegible]	0.06	0.2

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6?	CH91	51.	7.7	3.8	11.5	0.001	0.0?	0.01	0.07	0.0	0.1?	[illegible]
67	CH92	51.	6.8	11.6	18.4	0.001	0.05	0.01	0.07	0.0	0.13	0.5
68	SCHY1	159.	2578.4	3964.8	6543.2	0.633	62.59	4.76	4.96	0.0	72.31	881.5
69	SCHY3	49.	2629.1	4080.8	6709.9	0.753	10.49	1.74	1.53	0.0	13.76	323.1
71	SCHY10	13.	2.4	0.8	3.2	0.000	0.01	0.00	0.02	0.0	0.02	0.0
72	SCHY11	15.	2.4	0.9	3.3	0.000	0.01	0.00	0.02	0.0	0.03	0.0
73	SOUTH1	178.	47.3	60.4	107.7	0.011	1.74	0.06	2.92	0.0	4.72	17.1
74	SOUTH2	178.	86.3	131.5	217.9	0.017	2.65	0.09	2.92	0.0	5.66	26.1
75	SOUTH3	13.	2.3	0.8	3.1	0.000	0.00	0.00	0.02	0.0	0.02	0.0
76	SOUTH4	13.	2.4	0.9	3.3	0.000	0.01	0.00	0.02	0.0	0.02	0.0
77	SOUTH5	13.	2.3	0.8	3.1	0.000	0.01	0.00	0.02	0.0	0.02	0.0
78	SOUTH6	13.	2.4	0.9	3.3	0.000	0.01	0.00	0.02	0.0	0.02	0.0
79	CONEM1	176.	2146.9	3299.1	5446.0	0.610	19.99	3.21	3.03	0.0	26.24	939.8
80	CONEM2	176.	2235.8	3346.0	5581.8	0.625	20.50	3.30	3.03	0.0	26.82	963.5
81	CONEMD	2.	9.6	14.4	24.0	0.003	0.01	0.00	0.00	0.0	0.01	0.1
82	KEYST1	179.	2369.0	3886.3	6255.2	0.657	21.86	4.25	2.87	0.0	28.98	1027.3
83	KEYST2	179.	2561.7	3895.1	6456.8	0.723	24.04	4.68	2.87	0.0	31.59	1130.2
84	KEYSTD	2.	7.4	14.2	21.6	0.002	0.00	0.00	0.00	0.0	0.01	0.0
85	SALEM1	468.	2534.4	4237.3	6771.7	0.695	21.42	5.13	15.73	0.0	42.28	2850.2
86	SALEM3	16.	6.4	4.8	11.2	0.001	0.02	0.00	0.02	0.0	0.04	0.2
87	CON01	36.	1505.9	2160.5	3666.4	0.418	0.0	0.0	0.26	0.0	0.26	132.0
88	CON02	36.	1429.4	2092.6	3522.0	0.402	0.0	0.0	0.26	0.0	0.26	126.8
89	CON03	36.	1501.0	2187.4	3688.4	0.421	0.0	0.0	0.26	0.0	0.26	132.8
90	CON04	36.	1416.5	2221.7	3638.1	0.415	0.0	0.0	0.26	0.0	0.26	131.0
91	CON05	36.	1473.6	2247.3	3720.8	0.425	0.0	0.0	0.26	0.0	0.26	133.9
92	CON06	36.	1525.6	2216.2	3741.8	0.427	0.0	0.0	0.26	0.0	0.26	134.7
93	CON07	36.	1520.4	2217.5	3737.9	0.427	0.0	0.0	0.26	0.0	0.26	134.6
94	CON08	65.	1428.6	2214.3	3642.9	0.416	0.0	0.0	0.47	0.0	0.47	236.8
95	CON09	65.	1448.7	2248.9	3697.6	0.422	0.0	0.0	0.47	0.0	0.47	240.3
96	CON010	65.	1437.7	2206.2	3643.9	0.416	0.0	0.0	0.47	0.0	0.47	236.9
97	CON011	65.	1451.2	2229.7	3680.8	0.420	0.0	0.0	0.47	0.0	0.47	239.3
98	SALEM2	474.	2159.0	3806.1	5965.1	0.585	18.27	4.38	48.00	0.0	70.64	2430.9
102	GCOAL3	600.	3339.1	5093.0	8432.1	0.788	88.14	25.36	51.05	136.03	300.58	4142.9
108	ECONOMY	913.	1830.2	3159.5	4989.7	0.277	207.00	0.0	0.0	0.0	207.00	2218.1
109	EMRGENCY	500.	0.2	0.5	0.7	0.000	0.03	0.0	0.0	0.0	0.03	0.1
111	LMHW	64.	2.1	0.3	2.4	0.000	0.06	0.0	0.0	0.0	0.06	0.2
114	VOLAP	170.	2.1	0.3	2.4	0.000	0.16	0.0	0.0	0.0	0.16	0.4
115	BRNOUT5	150.	2.1	0.2	2.3	0.000	0.03	0.0	0.0	0.0	0.03	0.1
116	BRNOUT8	100.	0.3	0.2	0.5	0.000	0.02	0.0	0.0	0.0	0.02	0.1
117	PARTIAL	*******	0.2	0.2	0.4	0.0	1.34	0.0	0.0	0.0	1.34	0.1
118	TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0000 = 0.2 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0003 = 1.0 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 1286.7 MILLION (1987) = $ 578.9 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 33114. GWH
INCREMENTAL ELECTRICITY COST 3.9 1987 CENTS PER KWH = 1.7 1979 CENTS PER KWH
LOAD FACTOR 59.3%

TOTAL COSTS IN 1987 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	621.	200.
VARIABLE O&M	103.	47.
CARRYING CHARGES	217.	98.
INCREMENTAL CAPITAL	136.	61.

IMPORT OPTIONS:	COST IN 1987 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	207.00	93.13	2218.1
EMRGENCY	0.03	0.01	0.1

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Exhibit ___ (DS-C)
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POOR ORIGINAL

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LOAD CURVE: PECO PLANT DATA: ESL1 LOAD GROWTH: ESRG RESERVE MARGINS: INPUT 6.0%; ACTUAL 6.1%

MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1992 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
17.	61.9	109.7	170.6	0.015	0.30	0.08	0.03	0.0	0.42	2.3
18.	55.8	101.7	157.5	0.016	0.36	0.10	0.04	0.0	0.49	2.7
17.	54.0	101.7	155.7	0.016	0.32	0.09	0.03	0.0	0.44	2.4
127.	2530.5	4262.2	6792.7	0.646	22.86	6.81	4.15	0.0	33.82	775.3
48.	71.2	95.5	166.7	0.018	1.11	0.09	0.03	0.0	1.24	7.8
48.	64.8	105.8	171.8	0.018	1.08	0.09	0.03	0.0	1.20	7.5
48.	123.8	157.5	281.3	0.030	1.84	0.16	0.03	0.0	2.03	12.8
48.	64.1	100.4	164.5	0.018	1.11	0.09	0.03	0.0	1.23	7.7
[illegible]	85.6	123.4	209.0	0.023	1.41	0.12	0.03	0.0	1.56	9.9
[illegible]	88.1	96.6	184.7	0.020	1.24	0.11	0.03	0.0	1.38	8.7
41.	115.0	152.8	267.8	0.029	1.77	0.15	0.03	0.0	1.95	12.4
41.	109.3	136.3	245.6	0.026	1.60	0.14	0.03	0.0	1.77	11.2
122.	2933.5	4406.5	7340.0	0.784	98.07	6.04	2.65	0.0	106.76	865.8
124.	3046.1	4552.3	7598.4	0.816	100.43	6.19	2.61	0.0	109.23	886.6
[illegible]	2274.8	4241.0	6515.9	0.588	42.40	12.02	7.91	0.0	62.34	1550.6
[illegible]	2364.7	4126.0	6490.7	0.616	49.12	13.00	8.17	0.0	70.30	1677.4
384.	65.7	555.6	621.3	0.055	24.74	1.43	11.73	0.0	37.91	184.5
384.	492.3	919.1	1411.4	0.093	41.52	2.40	11.73	0.0	55.65	309.5
[illegible]	744.8	1107.3	1852.2	0.203	0.0	0.0	0.78	0.0	0.78	195.9
[illegible]	714.0	1123.1	1837.1	0.201	0.0	0.0	0.78	0.0	0.78	194.1
[illegible]	722.3	1065.8	1787.4	0.204	0.0	0.0	0.78	0.0	0.78	196.6
[illegible]	729.3	1095.1	1824.6	0.208	0.0	0.0	0.78	0.0	0.78	200.7
[illegible]	731.4	1042.6	1774.0	0.203	0.0	0.0	0.78	0.0	0.78	195.1
[illegible]	718.5	1102.5	1820.9	0.208	0.0	0.0	0.78	0.0	0.78	200.3
[illegible]	723.8	1154.2	1878.0	0.197	0.0	0.0	0.78	0.0	0.78	190.2
[illegible]	757.0	1376.2	2134.2	0.223	0.0	0.0	0.78	0.0	0.78	215.3
449.	2477.3	4105.6	6582.9	0.676	29.50	6.16	20.12	0.0	55.78	2647.4
455.	2530.5	4124.1	6654.6	0.684	29.31	6.12	19.76	0.0	55.19	2630.2
[illegible]	41.4	64.1	105.5	0.012	0.28	0.00	0.04	0.0	0.32	1.9
159.	2392.8	3607.9	6000.7	0.639	108.06	11.77	10.03	0.0	129.86	929.5
159.	2673.6	4159.1	6832.7	0.678	98.56	7.32	7.12	0.0	113.00	944.7
49.	2950.0	4342.4	7292.4	0.822	16.82	2.73	2.19	0.0	21.75	352.8
179.	2120.5	3135.5	5256.0	0.590	24.68	4.46	4.35	0.0	33.49	909.0
179.	2235.0	3305.0	5540.0	0.620	25.97	4.70	4.35	0.0	35.01	956.3
179.	2353.4	3763.0	6116.4	0.643	27.30	5.98	4.12	0.0	37.39	1005.3
179.	2354.5	3501.5	6355.9	0.712	30.21	6.61	4.12	0.0	40.95	1112.7
488.	2532.1	4210.9	6749.9	0.693	31.67	7.34	22.58	0.0	61.59	2842.0
33.	1440.8	2145.3	3586.0	0.409	0.0	0.0	0.37	0.0	0.37	129.1
33.	1430.5	2174.7	3605.2	0.412	0.0	0.0	0.37	0.0	0.37	129.8
33.	1421.3	2211.3	3632.6	0.415	0.0	0.0	0.37	0.0	0.37	130.8
33.	1452.8	2212.8	3665.6	0.418	0.0	0.0	0.37	0.0	0.37	132.0
33.	1418.2	2163.4	3581.6	0.409	0.0	0.0	0.37	0.0	0.37	128.9
33.	1434.5	2240.0	3674.5	0.419	0.0	0.0	0.37	0.0	0.37	132.3
33.	1503.2	2146.5	3649.7	0.417	0.0	0.0	0.37	0.0	0.37	131.4
65.	1459.3	2130.5	[illegible]	0.409	0.0	0.0	0.67	0.0	0.67	233.1
65.	1508.4	2143.8	3652.1	0.417	0.0	0.0	0.67	0.0	0.67	237.4
65.	1506.1	2158.7	3664.8	0.418	0.0	0.0	0.67	0.0	0.67	238.2
65.	1475.9	2136.1	3612.0	0.412	0.0	0.0	0.67	0.0	0.67	234.8
474.	2187.4	3816.8	6004.2	0.590	27.28	6.33	68.91	0.0	102.52	2448.3
500.	3322.3	5141.6	8463.9	0.796	113.57	36.75	73.29	136.03	359.64	4182.5
913.	2455.9	3875.8	6332.7	0.417	457.63	0.0	0.0	0.0	457.63	3337.4
500.	31.9	65.0	96.9	0.004	5.40	0.0	0.0	0.0	5.40	18.9
34.	28.3	39.4	67.7	0.006	2.03	0.0	0.0	0.0	2.03	3.4
170.	18.3	21.3	39.6	0.003	2.82	0.0	0.0	0.0	2.82	4.7
150.	14.0	6.4	20.4	0.002	0.66	0.0	0.0	0.0	0.66	2.2
100.	7.6	4.2	11.9	0.001	0.44	0.0	0.0	0.0	0.44	1.0
*******	6.7	1.9	8.6	0.0	47.95	0.0	0.0	0.0	47.95	3.2
*******	0.1	0.0	0.1	0.0	10.99	0.0	0.0	0.0	10.99	0.7

PROBABILITIES:
CUTS 0.0010 = 3.6 DAYS IN TEN YEARS
E 0.0000 = 0.0 DAYS IN TEN YEARS
T OPTIONS 0.0077 = 28.2 DAYS IN TEN YEARS

COST $ 2075.7 MILLION (1992) = $ 566.8 MILLION (DISCOUNTED TO 1979)
CITY GENERATED 34878. GWH
LECTRICITY COST 6.0 1992 CENTS PER KWH = 1.6 1979 CENTS PER KWH
9.3%

1992 $MILLION		DISCOUNTED TO 1979 $MILLION
	955.	261.
	155.	42.
ES	302.	82.
PITAL	135.	37.

	COST IN 1992 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
	457.63	124.97	3337.4
	5.40	1.48	18.9

ENT COST $ 64.88 MILLION (1992) = $ 17.72 MILLION (DISCOUNTED TO 1979)
$ 58.93 MILLION (1992) = $ 16.09 MILLION (DISCOUNTED TO 1979)

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LOAD CURVE: PECO PLANT DATA: ESL: LOAD GROWTH: ESRG RESERVE MARGINS: INPUT 14.0%: ACTUAL 15.3%

	MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1992 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
	17.	42.2	46.8	88.9	0.008	0.17	0.05	0.03	0.0	0.24	1.3
	19.	36.3	38.1	74.4	0.008	0.17	0.05	0.04	0.0	0.25	1.3
	17.	35.7	34.6	70.3	0.007	0.15	0.04	0.03	0.0	0.22	1.1
	137.	2595.3	4244.0	6839.3	0.651	23.01	6.86	4.15	0.0	34.02	780.7
	49.	44.4	48.0	92.4	0.010	0.63	0.05	0.03	0.0	0.72	4.4
	49.	51.2	79.4	130.6	0.012	0.74	0.06	0.03	0.0	0.83	5.2
	49.	70.6	97.7	168.4	0.019	1.16	0.10	0.03	0.0	1.30	8.1
	49.	37.2	34.2	71.5	0.007	0.46	0.04	0.03	0.0	0.53	3.2
	49.	44.6	62.4	107.0	0.012	0.73	0.06	0.03	0.0	0.83	5.1
	49.	66.4	90.6	157.0	0.016	1.01	0.09	0.03	0.0	1.12	7.1
	49.	69.0	81.0	150.0	0.016	1.01	0.09	0.03	0.0	1.13	7.1
	49.	61.0	105.8	166.9	0.018	1.12	0.10	0.03	0.0	1.26	7.9
	126.	2823.4	4232.5	7055.9	0.751	93.95	5.79	2.65	0.0	102.39	829.4
	124.	3016.8	4532.6	7549.4	0.812	99.91	6.15	2.61	0.0	108.66	882.1
	301.	2299.7	4184.1	6483.9	0.587	42.29	11.99	7.91	0.0	62.19	1546.5
	311.	2424.3	4078.8	6503.1	0.613	48.94	12.95	8.17	0.0	70.06	1671.0
	380.	242.8	457.7	700.5	0.050	22.32	1.29	11.73	0.0	35.35	166.4
	380.	452.7	842.2	1294.9	0.084	37.65	2.18	11.73	0.0	51.56	280.7
	110.	706.6	1103.3	1809.9	0.199	0.0	0.0	0.78	0.0	0.78	191.3
	110.	730.6	1136.6	1867.3	0.205	0.0	0.0	0.78	0.0	0.78	197.4
	110.	727.9	1104.2	1832.1	0.209	0.0	0.0	0.78	0.0	0.78	201.5
	110.	723.8	1082.8	1806.6	0.206	0.0	0.0	0.78	0.0	0.78	198.7
	110.	730.4	1087.9	1818.3	0.208	0.0	0.0	0.78	0.0	0.78	200.0
	110.	751.6	1099.3	1850.9	0.211	0.0	0.0	0.78	0.0	0.78	203.6
	110.	690.5	1399.6	2090.1	0.218	0.0	0.0	0.78	0.0	0.78	210.1
	110.	654.7	1355.4	2050.1	0.214	0.0	0.0	0.78	0.0	0.78	206.3
	447.	2548.1	4210.9	6759.0	0.694	30.29	6.32	20.12	0.0	56.74	2718.5
	439.	2537.3	4224.7	6762.0	0.694	29.75	6.21	19.76	0.0	55.73	2670.2
	19.	30.6	51.0	81.5	0.009	0.21	0.00	0.04	0.0	0.25	1.5
	166.	2315.5	3616.3	5931.8	0.630	106.55	11.61	10.03	0.0	128.19	916.5
	33.	18.5	36.7	55.2	0.006	0.27	0.06	0.06	0.0	0.39	1.7
	33.	17.2	43.5	60.7	0.006	0.27	0.06	0.06	0.0	0.39	1.7
	21.	17.1	36.9	53.9	0.005	0.16	0.03	0.04	0.0	0.23	1.0
	21.	20.6	41.3	61.9	0.006	0.18	0.04	0.04	0.0	0.27	1.1
	51.	28.3	31.9	60.2	0.006	0.38	0.09	0.09	0.0	0.57	2.5
	51.	20.7	36.5	57.2	0.005	0.32	0.08	0.09	0.0	0.50	2.2
	51.	34.6	37.4	72.0	0.006	0.41	0.10	0.09	0.0	0.60	2.7
	159.	2652.3	4298.1	6950.3	0.686	99.76	7.41	7.12	0.0	114.28	956.1
	49.	2881.9	4309.3	7191.2	0.811	16.61	2.70	2.19	0.0	21.51	348.3
	178.	164.4	243.0	407.4	0.038	8.78	0.29	4.20	0.0	13.26	58.9
	176.	118.6	180.4	299.0	0.025	5.75	0.19	4.20	0.0	10.13	38.6
	176.	2130.1	3243.4	5373.5	0.602	25.18	4.55	4.35	0.0	34.08	927.4
	176.	2261.5	3451.3	5712.8	0.639	26.77	4.84	4.35	0.0	35.96	985.6
	2.	38.4	45.9	84.3	0.009	0.03	0.01	0.00	0.0	0.04	0.2
	179.	2321.9	3809.9	6131.7	0.644	27.34	5.95	4.12	0.0	37.45	1007.0
	179.	2558.4	3885.2	6443.7	0.721	30.63	6.70	4.12	0.0	41.45	1127.6
	2.	38.1	46.1	84.2	0.010	0.03	0.01	0.00	0.0	0.04	0.2
	468.	2537.5	4161.8	6699.3	0.688	31.45	7.29	22.58	0.0	61.32	2822.0
	36.	1491.6	2148.1	3639.7	0.415	0.0	0.0	0.37	0.0	0.37	131.0
	36.	1443.5	2219.6	3663.1	0.418	0.0	0.0	0.37	0.0	0.37	131.8
	36.	1455.8	2194.2	3650.0	0.417	0.0	0.0	0.37	0.0	0.37	131.4
	36.	1425.3	2188.9	3614.2	0.413	0.0	0.0	0.37	0.0	0.37	130.1
	36.	1447.2	2237.0	3684.2	0.421	0.0	0.0	0.37	0.0	0.37	132.6
	36.	1455.3	2210.0	3665.4	0.419	0.0	0.0	0.37	0.0	0.37	132.0
	36.	1436.3	2225.1	3661.3	0.418	0.0	0.0	0.37	0.0	0.37	131.6
	65.	1441.4	2230.7	3672.1	0.419	0.0	0.0	0.67	0.0	0.67	238.7
	65.	1442.6	2241.0	3683.6	0.421	0.0	0.0	0.67	0.0	0.67	239.4
	65.	1430.9	2213.2	3644.1	0.416	0.0	0.0	0.67	0.0	0.67	236.9
	65.	1434.8	2179.7	3614.6	0.413	0.0	0.0	0.67	0.0	0.67	234.9
	474.	2187.1	3894.7	6081.8	0.597	27.60	6.40	68.91	0.0	102.92	2477.0
	600.	3305.5	5096.3	8401.8	0.806	115.03	37.22	73.29	136.03	361.58	4236.4
Y	913.	2380.5	3774.9	6155.4	0.379	415.18	0.0	0.0	0.0	415.18	3027.8
DY	500.	5.5	15.0	20.5	0.001	0.82	0.0	0.0	0.0	0.82	2.9
	64.	12.8	17.4	30.2	0.003	1.14	0.0	0.0	0.0	1.14	1.9
	170.	12.8	16.9	29.6	0.002	1.44	0.0	0.0	0.0	1.44	2.4
E	150.	1.6	9.4	10.9	0.000	0.17	0.0	0.0	0.0	0.17	0.6
3	100.	0.6	1.1	1.7	0.000	0.07	0.0	0.0	0.0	0.07	0.2
_	*******	0.4	0.9	1.4	0.0	7.28	0.0	0.0	0.0	7.28	0.5
	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SULTS

AD PROBABILITIES:
ACKOUTS 0.0002 = 0.6 DAYS IN TEN YEARS
OUTS 0.0 = 0.0 DAYS IN TEN YEARS
MENT OPTIONS 0.0034 = 12.6 DAYS IN TEN YEARS

EM COST $ 1988.2 MILLION (1992) = $ 542.9 MILLION (DISCOUNTED TO 1979)
TRICITY GENERATED 34878. GWH
_ ELECTRICITY COST 5.7 1992 CENTS PER KWH = 1.6 1979 CENTS PER KWH
F 59.3%

E IN 1992 $MILLION		DISCOUNTED TO 1979 $MILLION
	959.	262.
&M	156.	43.
HARGES	311.	85.
_ CAPITAL	136.	37.

IONS:	COST IN 1992 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
	415.18	113.38	3027.8
	0.82	0.22	2.9

1992 PECO   LOAD CURVE: PECO   PLANT DATA: ESL   LOAD GROWTH: ESRG   RESERVE MARGINS: INPUT 22.0%; ACTUAL 23.3%

OPTION	MEGAWATTS CAPACITY	HOURS OF USE MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1992 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
1 BARB5	17.	33.1	47.8	80.9	0.007	0.14	0.04	0.03	0.0	0.20	1.0
2 BARB6	19.	21.7	11.2	32.9	0.003	0.08	0.02	0.04	0.0	0.13	0.8
3 BARB7	17.	30.4	37.4	67.8	0.007	0.14	0.04	0.03	0.0	0.21	1.0
4 CHEST7	13.	6.7	2.5	9.2	0.001	0.02	0.00	0.02	0.0	0.05	0.1
5 CHEST8	13.	7.0	2.1	9.1	0.001	0.02	0.00	0.02	0.0	0.05	0.1
6 CHEST9	13.	9.5	2.5	12.0	0.001	0.03	0.01	0.02	0.0	0.06	0.2
7 CROMB1	137.	2556.2	4330.2	6886.5	0.654	23.14	6.90	4.15	0.0	34.19	784.8
9 CROY11	49.	37.0	73.5	110.4	0.012	0.73	0.06	0.03	0.0	0.83	5.1
10 CROY12	49.	34.0	41.3	75.3	0.007	0.43	0.04	0.03	0.0	0.50	3.0
11 CROY21	49.	45.9	69.0	114.9	0.013	0.77	0.07	0.03	0.0	0.87	5.4
12 CROY22	48.	28.2	26.8	55.1	0.006	0.38	0.03	0.03	0.0	0.44	2.6
13 CROY31	48.	49.4	96.7	146.1	0.014	0.88	0.07	0.03	0.0	0.98	6.1
14 CROY32	48.	38.8	62.3	101.1	0.011	0.68	0.06	0.03	0.0	0.77	4.8
15 CROY41	49.	37.1	71.3	108.4	0.012	0.75	0.06	0.03	0.0	0.85	5.2
16 CROY42	49.	49.0	75.0	124.0	0.013	0.82	0.07	0.03	0.0	0.92	5.7
17 DELA7	126.	2847.7	4244.2	7091.8	0.764	95.47	5.88	2.65	0.0	104.00	842.8
18 DELA8	124.	3020.7	4504.3	7525.0	0.805	99.00	6.10	2.61	0.0	107.71	874.0
23 EDDY1	301.	2253.3	4186.9	6440.2	0.581	41.92	11.88	7.81	0.0	61.72	1533.1
24 EDDY2	311.	2318.8	4182.6	6501.4	0.613	48.85	12.96	8.17	0.0	70.08	1671.4
25 EDDY3	380.	262.3	500.6	762.9	0.052	23.23	1.34	11.73	0.0	36.31	173.2
26 EDDY4	380.	477.4	838.8	1316.3	0.080	40.02	2.31	11.73	0.0	54.07	268.4
27 EDDY10	13.	8.7	2.8	11.3	0.001	0.02	0.01	0.02	0.0	0.05	0.1
28 EDDY20	13.	8.8	2.7	11.5	0.001	0.02	0.01	0.02	0.0	0.05	0.1
29 EDDY30	15.	8.7	3.0	12.7	0.001	0.03	0.01	0.03	0.0	0.06	0.2
30 EDDY40	15.	8.1	3.2	12.2	0.001	0.03	0.01	0.03	0.0	0.06	0.2
31 FALLS1	15.	8.0	3.4	12.4	0.001	0.03	0.01	0.03	0.0	0.06	0.2
32 FALLS2	15.	10.3	3.7	14.0	0.002	0.03	0.01	0.03	0.0	0.07	0.2
33 FALLS3	15.	10.5	4.0	14.5	0.002	0.04	0.01	0.03	0.0	0.07	0.2
34 MOSER1	15.	2.6	1.3	3.9	0.000	0.01	0.00	0.03	0.0	0.04	0.1
35 MOSER2	15.	2.6	1.4	4.0	0.000	0.01	0.00	0.03	0.0	0.04	0.1
36 MOSER3	15.	4.9	1.4	6.3	0.001	0.01	0.00	0.03	0.0	0.04	0.1
37 MUDDY1	110.	688.9	1124.6	1813.5	0.198	0.0	0.0	0.78	0.0	0.78	191.5
38 MUDDY2	110.	728.7	1108.6	1838.3	0.202	0.0	0.0	0.78	0.0	0.78	194.4
39 MUDDY3	110.	735.6	1135.7	1871.3	0.214	0.0	0.0	0.78	0.0	0.78	205.8
40 MUDDY4	110.	732.5	1091.8	1824.3	0.208	0.0	0.0	0.78	0.0	0.78	200.7
41 MUDDY5	110.	714.3	1095.0	1809.3	0.207	0.0	0.0	0.78	0.0	0.78	199.0
42 MUDDY6	110.	737.1	1125.7	1862.8	0.213	0.0	0.0	0.78	0.0	0.78	204.8
43 MUDDY7	110.	718.8	1405.3	2124.1	0.222	0.0	0.0	0.78	0.0	0.78	213.8
44 MUDDY8	110.	708.3	1368.7	2077.0	0.217	0.0	0.0	0.78	0.0	0.78	209.1
45 PEACH2	447.	2483.1	4258.2	6741.3	0.691	30.17	6.30	20.12	0.0	56.58	2707.2
46 PEACH3	439.	2483.1	4085.1	6568.3	0.675	28.92	6.04	19.76	0.0	54.71	2595.0
47 DIESEL	19.	16.3	86.0	102.3	0.010	0.24	0.00	0.04	0.0	0.28	1.7
50 RICH8	166.	2411.6	3619.5	6031.1	0.646	108 21	11.90	10.03	0.0	131.14	938.4
51 RICH21	33.	12.7	6.8	19.6	0.002	0.10	0.02	0.06	0.0	0.18	0.6
52 RICH22	33.	12.7	7.3	20.0	0.002	0.10	0.02	0.06	0.0	0.18	0.6
53 RICH31	33.	5.8	1.8	7.6	0.001	0.04	0.01	0.06	0.0	0.11	0.2
54 RICH32	33.	5.4	1.9	7.3	0.001	0.04	0.01	0.06	0.0	0.11	0.2
55 RICH41	21.	13.3	6.6	19.9	0.002	0.06	0.01	0.04	0.0	0.11	0.4
56 RICH42	21.	15.4	5.3	20.7	0.002	0.06	0.01	0.04	0.0	0.12	0.4
57 RICH43	21.	14.9	6.6	21.7	0.002	0.07	0.02	0.04	0.0	0.12	0.4
58 RICH44	21.	14.2	[illegible]	[illegible]	0.002	0.06	0.01	0.04	0.0	0.11	0.4
59 RICH51	33.	8.8	2.2	10.0	0.001	0.05	0.01	0.06	0.0	0.13	0.3
60 RICH52	33.	5.9	2.3	[illegible]	0.001	0.05	0.01	0.06	0.0	0.12	0.3
61 RICH61	33.	6.8	2.0	[illegible]	0.001	0.05	0.01	0.06	0.0	0.12	0.3
62 RICH62	33.	2.6	[illegible]	[illegible]	0.000	0.02	0.00	0.06	0.0	0.08	0.1
63 RICH71	21.	[illegible]	[illegible]	[illegible]	0.001	[illegible]	0.01	0.04	0.0	0.08	0.3
64 RICH72	21.	7.7	[illegible]	[illegible]	0.001	0.03	0.01	0.04	0.0	0.08	0.2

POOR ORIGINAL

Exhibit ___ (DS-C)
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66 RICH01	51.	21.0	23.1	44.2	0.003	[illegible]	0.05	0.09	0.0	0.36	1.4
67 RICH02	51.	16.6	25.6	42.3	0.003	0.02	0.05	0.09	0.0	0.37	1.5
68 SCHY1	158.	2676.5	4078.0	6754.5	0.670	97.40	7.24	7.12	0.0	111.75	933.5
69 SCHY3	49.	2954.3	4271.7	7226.0	0.812	16.63	2.70	2.19	0.0	21.52	348.6
71 SCHY10	13.	1.7	1.1	2.8	0.000	0.01	0.00	0.02	0.0	0.03	0.0
72 SCHY11	15.	2.5	1.2	3.7	0.000	0.01	0.00	0.03	0.0	0.04	0.0
73 SOUTH1	178.	148.7	273.0	421.7	0.038	8.85	0.29	4.20	0.0	13.33	58.4
74 SOUTH2	178.	91.5	164.5	256.0	0.023	5.33	0.18	4.20	0.0	9.70	35.8
75 SOUTH3	13.	2.4	1.2	3.6	0.000	0.01	0.00	0.02	0.0	0.03	0.0
76 SOUTH4	13.	1.5	1.1	2.6	0.000	0.01	0.00	0.02	0.0	0.03	0.0
79 CONEM1	176.	2148.5	3248.8	5397.3	0.604	25.29	4.57	4.35	0.0	34.22	931.5
80 CONEM2	176.	2240.1	3318.2	5558.4	0.622	26.05	4.71	4.35	0.0	35.11	959.5
81 CONEMD	2.	23.7	36.6	60.3	0.007	0.02	0.00	0.00	0.0	0.03	0.1
82 KEYST1	179.	2350.4	3752.8	6103.3	0.642	27.24	5.96	4.12	0.0	37.32	1003.2
83 KEYST2	179.	2567.7	3872.1	6439.8	0.721	30.61	6.70	4.12	0.0	41.43	1127.3
84 KEYSTD	2.	25.6	37.0	62.6	0.007	0.02	0.01	0.00	0.0	0.03	0.1
85 SALEM1	468.	2545.8	4136.1	6681.9	0.687	31.38	7.28	22.58	0.0	61.23	2815.8
86 SALEM3	16.	10.5	5.0	15.5	0.002	0.04	0.01	0.03	0.0	0.08	0.2
87 COND1	36.	1500.5	2148.7	3649.2	0.417	0.0	0.0	0.37	0.0	0.37	131.4
88 COND2	36.	1495.5	2165.2	3660.8	0.418	0.0	0.0	0.37	0.0	0.37	131.8
89 COND3	36.	1456.8	2103.1	3560.0	0.406	0.0	0.0	0.37	0.0	0.37	128.2
90 COND4	36.	1469.9	2222.0	3691.9	0.421	0.0	0.0	0.37	0.0	0.37	132.9
91 COND5	36.	1476.1	2232.1	3708.2	0.423	0.0	0.0	0.37	0.0	0.37	133.5
92 COND6	36.	1426.2	2141.4	3567.6	0.407	0.0	0.0	0.37	0.0	0.37	128.4
93 COND7	36.	1434.0	2127.1	3561.0	0.407	0.0	0.0	0.37	0.0	0.37	128.2
94 COND8	65.	1464.1	2149.0	3613.1	0.412	0.0	0.0	0.67	0.0	0.67	234.8
95 COND9	65.	1486.8	2226.0	3712.8	0.424	0.0	0.0	0.67	0.0	0.67	241.3
96 COND10	65.	1488.0	2101.5	3589.5	0.410	0.0	0.0	0.67	0.0	0.67	233.3
97 COND11	65.	1434.0	2191.5	3625.5	0.414	0.0	0.0	0.67	0.0	0.67	235.7
98 SALEM2	474.	2183.1	3926.8	6109.9	0.599	27.71	6.43	68.91	0.0	103.05	2486.8
102 GCOAL3	600.	3321.6	5090.3	8412.0	0.791	112.82	36.51	73.28	136.03	358.65	4155.1
108 ECONOMY	913.	2482.3	3821.5	6303.8	0.404	443.58	0.0	0.0	0.0	443.58	3234.9
109 EMRGENCY	500.	0.5	1.0	1.5	0.000	0.12	0.0	0.0	0.0	0.12	0.4
111 LMHW	64.	1.1	0.2	1.3	0.000	0.05	0.0	0.0	0.0	0.05	0.1
114 VOLAP	170.	1.1	0.2	1.3	0.000	0.11	0.0	0.0	0.0	0.11	0.2
115 BRNOUT5	150.	0.7	0.1	0.8	0.000	0.04	0.0	0.0	0.0	0.04	0.1
116 BRNOUT8	100.	0.7	0.1	0.8	0.000	0.04	0.0	0.0	0.0	0.04	0.1
117 PARTIAL	*******	0.7	0.1	0.8	0.0	1.86	0.0	0.0	0.0	1.86	0.1
118 TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0001 = 0.3 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0002 = 0.6 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 2006.1 MILLION (1992) = $. 547.8 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 34878. GWH
INCREMENTAL ELECTRICITY COST 5.8 1992 CENTS PER KWH = 1.6 1979 CENTS PER KWH
LOAD FACTOR 59.3%

TOTAL COSTS IN 1992 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	957.	261.
VARIABLE O&M	155.	42.
CARRYING CHARGES	312.	85.
INCREMENTAL CAPITAL	136.	37.

IMPORT OPTIONS:	COST IN 1992 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	443.58	121.13	3234.9
EMERGENCY	0.12	0.03	0.4

TOTAL [illegible] MILLION (1992) = $ [illegible] MILLION (DISCOUNTED TO 1979)
[illegible] MILLION (1992) = $ [illegible] MILLION (DISCOUNTED TO 1979)

Exhibit ___ (DS-C)
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1992 PECO   LOAD CURVE: PECO   PLANT DATA: ESL1   LOAD GROWTH: ESRG   RESERVE MARGINS: INPUT 30.0%; ACTUAL 30.2%

	OPTION	MEGAWATTS CAPACITY	HOURS OF USL MAINT	NOMAINT	TOTAL	ANNUAL CAPFAC	COSTS (MILLIONS OF 1992 DOLLARS) ENERGY	VARO&M	CARCHG	CAPITAL	TOTAL	GWH GENERATED
1	BARB5	17.	24.2	34.0	58.1	0.005	0.11	0.03	0.03	0.0	0.17	0.8
2	BARB6	19.	22.1	29.3	51.4	0.005	0.12	0.03	0.04	0.0	0.19	0.9
3	BARB7	17.	18.3	23.7	42.0	0.004	0.09	0.02	0.03	0.0	0.14	0.6
4	CHEST7	13.	2.2	2.0	4.2	0.000	0.01	0.00	0.02	0.0	0.03	0.0
5	CHEST8	13.	3.4	2.1	5.5	0.001	0.01	0.00	0.02	0.0	0.04	0.1
6	CHEST9	13.	2.2	1.8	4.0	0.000	0.01	0.00	0.02	0.0	0.03	0.1
7	CROMB1	137.	2584.1	4375.8	6959.9	0.657	23.26	6.93	4.15	0.0	34.34	788.8
8	CROMB2	183.	187.8	328.1	515.9	0.045	9.93	0.64	6.91	0.0	17.48	72.4
9	CROY11	49.	31.1	46.3	77.4	0.008	0.48	0.04	0.03	0.0	0.55	3.3
10	CROY12	49.	21.5	22.5	43.9	0.004	0.26	0.02	0.03	0.0	0.32	1.9
11	CROY21	49.	52.6	81.6	134.2	0.014	0.84	0.07	0.03	0.0	0.85	5.9
12	CROY22	49.	19.1	22.8	41.9	0.004	0.27	0.02	0.03	0.0	0.33	1.9
13	CROY31	49.	32.1	44.0	76.1	0.008	0.52	0.04	0.03	0.0	0.60	3.6
14	CROY32	49.	38.7	55.0	93.7	0.010	0.63	0.05	0.03	0.0	0.72	4.4
15	CROY41	49.	46.6	45.2	91.8	0.010	0.61	0.05	0.03	0.0	0.68	4.2
16	CROY42	49.	42.8	63.4	106.2	0.010	0.62	0.05	0.03	0.0	0.71	4.3
17	DELA7	126.	2864.4	4326.0	7190.4	0.769	96.19	5.82	2.65	0.0	104.77	848.2
18	DELA8	124.	3065.1	4574.7	7639.9	0.818	100.81	6.21	2.61	0.0	109.62	889.9
19	DELA9	15.	0.1	0.4	0.5	0.000	0.00	0.00	0.03	0.0	0.03	0.0
20	DELA10	13.	0.1	0.4	0.6	0.000	0.00	0.00	0.02	0.0	0.03	0.0
21	DELA11	13.	0.1	0.4	0.5	0.000	0.00	0.00	0.02	0.0	0.03	0.0
22	DELA12	13.	0.1	0.3	0.4	0.000	0.00	0.00	0.02	0.0	0.03	0.0
23	EDDY1	301.	2290.8	4246.5	6537.3	0.580	42.57	12.07	7.91	0.0	62.54	1556.5
24	EDDY2	311.	2328.8	4157.5	6486.4	0.613	48.93	12.85	8.17	0.0	70.06	1670.7
25	EDDY3	380.	265.0	466.7	731.7	0.052	23.04	1.33	11.73	0.0	36.10	171.7
26	EDDY4	380.	466.7	778.1	1244.8	0.084	37.58	2.17	11.73	0.0	51.48	280.1
27	EDDY10	13.	3.4	2.3	5.7	0.001	0.01	0.00	0.02	0.0	0.04	0.1
28	EDDY20	13.	3.6	2.3	5.9	0.001	0.01	0.00	0.02	0.0	0.04	0.1
29	EDDY30	15.	3.8	2.4	6.1	0.001	0.01	0.00	0.03	0.0	0.04	0.1
30	EDDY40	15.	3.8	2.5	6.3	0.001	0.01	0.00	0.03	0.0	0.04	0.1
31	FALLS1	15.	4.4	2.6	7.0	0.001	0.02	0.00	0.03	0.0	0.05	0.1
32	FALLS2	15.	4.2	2.3	6.6	0.001	0.02	0.00	0.03	0.0	0.05	0.1
33	FALLS3	15.	4.5	2.9	7.4	0.001	0.02	0.00	0.03	0.0	0.05	0.1
34	MOSER1	15.	0.2	0.6	0.8	0.000	0.00	0.00	0.03	0.0	0.03	0.0
35	MOSER2	15.	0.3	0.6	0.9	0.000	0.00	0.00	0.03	0.0	0.03	0.0
36	MOSER3	15.	1.4	0.7	2.1	0.000	0.00	0.00	0.03	0.0	0.03	0.0
37	MUDDY1	110.	705.4	1082.3	1787.7	0.196	0.0	0.0	0.78	0.0	0.78	189.0
38	MUDDY2	110.	707.2	1084.7	1791.9	0.197	0.0	0.0	0.78	0.0	0.78	188.4
39	MUDDY3	110.	742.7	1089.0	1831.7	0.209	0.0	0.0	0.78	0.0	0.78	201.5
40	MUDDY4	110.	737.8	1074.8	1812.6	0.207	0.0	0.0	0.78	0.0	0.78	199.4
41	MUDDY5	110.	723.8	1092.2	1816.0	0.207	0.0	0.0	0.78	0.0	0.78	199.8
42	MUDDY6	110.	713.9	1114.2	1828.1	0.208	0.0	0.0	0.78	0.0	0.78	201.1
43	MUDDY7	110.	709.3	1382.4	2091.7	0.218	0.0	0.0	0.78	0.0	0.78	210.5
44	MUDDY8	110.	712.2	1382.2	2094.4	0.218	0.0	0.0	0.78	0.0	0.78	210.8
45	PEACH2	447.	2502.0	4110.1	6612.1	0.679	29.64	6.19	20.12	0.0	55.95	2660.1
46	PEACH3	439.	2507.2	4175.8	6683.1	0.686	29.41	6.14	19.76	0.0	55.31	2639.0
47	DIESEL	19.	34.9	55.1	90.0	0.010	0.23	0.00	0.04	0.0	0.27	1.6
48	PLMT9	29.	0.1	0.5	0.6	0.000	0.00	0.00	0.05	0.0	0.06	0.0
49	PLMT15	29.	0.1	0.1	0.2	0.000	0.00	0.00	0.05	0.0	0.06	0.0
50	RICH9	166.	2348.1	3495.7	5843.9	0.615	104.02	11.33	10.03	0.0	125.39	894.8
51	RICH21	33.	4.8	2.6	7.4	0.001	0.04	0.01	0.06	0.0	0.11	0.2
52	RICH22	33.	4.4	[illegible]	7.5	0.001	0.04	0.01	0.06	0.0	0.11	0.2
53	RICH31	33.	1.6	1.5	3.1	0.000	0.01	0.00	0.06	0.0	0.08	0.1
54	RICH32	33.	1.6	0.7	2.3	0.000	0.01	0.00	0.06	0.0	0.08	0.1
55	RICH41	21.	[illegible]	[illegible]	7.1	0.001	0.02	0.00	0.04	0.0	0.07	0.1
56	RICH42	21.	4.5	[illegible]	[illegible]	0.001	0.03	[illegible]	0.04	0.0	0.07	0.2
57	RICH43	21.	[illegible]	[illegible]	[illegible]	0.001	0.03	[illegible]	0.04	0.0	0.07	0.2
58	RICH44	21.	[illegible]	[illegible]	[illegible]	0.001	0.02	0.01	0.04	0.0	0.07	0.1
59	RICH51	[illegible]	[illegible]	[illegible]	[illegible]	0.000	0.01	0.00	0.06	0.0	0.08	0.1
60	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.000	0.01	0.00	0.06	0.0	0.07	0.0
61	[illegible]	[illegible]	[illegible]	1.6	[illegible]	0.000	0.02	0.00	0.06	0.0	0.08	0.1
62	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.000	0.01	0.00	0.06	0.0	0.07	0.1

POOR ORIGINAL

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66 RICHB1	51.	3.3	3.5	6.8	0.001	0.04	0.01	0.09	0.0	0.14	0.3
67 RICHB2	51.	8.3	5.6	13.9	0.001	0.07	0.02	0.09	0.0	0.18	0.5
68 SCHY1	159.	2693.8	4127.3	6821.1	0.674	97.99	7.28	7.12	0.0	112.39	939.3
69 SCHY3	49.	2917.9	4354.5	7272.5	0.818	16.74	2.72	2.19	0.0	21.65	350.9
71 SCHY10	13.	0.1	0.6	0.8	0.000	0.00	0.00	0.02	0.0	0.03	0.0
72 SCHY11	15.	0.2	0.6	0.7	0.000	0.00	0.00	0.03	0.0	0.03	0.0
73 SOUTH1	178.	127.8	196.5	324.3	0.029	6.76	0.22	4.20	0.0	11.18	45.4
74 SOUTH2	170.	88.4	103.3	191.8	0.018	4.27	0.14	4.20	0.0	8.60	28.6
75 SOUTH3	13.	0.1	0.5	0.6	0.000	0.00	0.00	0.02	0.0	0.03	0.0
76 SOUTH4	13.	0.1	0.6	0.7	0.000	0.00	0.00	0.02	0.0	0.03	0.0
77 SOUTH5	13.	0.1	0.6	0.7	0.000	0.00	0.00	0.02	0.0	0.03	0.0
78 SOUTH6	13.	0.1	0.3	0.5	0.000	0.00	0.00	0.02	0.0	0.03	0.0
79 CONEM1	176.	2132.2	3255.6	5387.7	0.603	25.25	4.57	4.35	0.0	34.16	929.8
80 CONEM2	176.	2299.8	3473.2	5773.0	0.646	27.05	4.89	4.35	0.0	36.30	996.4
81 CONEMD	2.	21.7	31.4	53.1	0.006	0.02	0.00	0.00	0.0	0.03	0.1
82 KEYST1	179.	2311.8	3718.9	6030.7	0.634	26.91	5.89	4.12	0.0	36.82	891.1
83 KEYST2	179.	2546.2	3810.4	6356.6	0.712	30.22	6.61	4.12	0.0	40.95	1112.8
84 KEYSTD	2.	21.3	31.7	53.0	0.006	0.02	0.00	0.00	0.0	0.03	0.1
85 SALEM1	468.	2529.8	4212.2	6742.0	0.692	31.63	7.33	22.58	0.0	61.54	2838.2
86 SALEM3	16.	3.4	3.0	6.3	0.001	0.02	0.00	0.03	0.0	0.05	0.1
87 CONO1	36.	1423.5	2193.6	3617.1	0.413	0.0	0.0	0.37	0.0	0.37	130.2
88 CONO2	36.	1498.5	2145.4	3643.9	0.416	0.0	0.0	0.37	0.0	0.37	131.2
89 CONO3	36.	1441.8	2231.4	3673.2	0.419	0.0	0.0	0.37	0.0	0.37	132.2
90 CONO4	36.	1510.6	2163.3	3673.9	0.419	0.0	0.0	0.37	0.0	0.37	132.3
91 CONO5	36.	1438.9	2168.3	3607.2	0.412	0.0	0.0	0.37	0.0	0.37	129.8
92 CONO6	36.	1427.6	2176.9	3604.5	0.411	0.0	0.0	0.37	0.0	0.37	129.8
93 CONO7	36.	1418.8	2155.3	3574.1	0.408	0.0	0.0	0.37	0.0	0.37	128.7
94 CONO8	65.	1432.1	2093.1	3525.2	0.402	0.0	0.0	0.67	0.0	0.67	229.1
95 CONO9	65.	1455.0	2213.1	3668.1	0.419	0.0	0.0	0.67	0.0	0.67	238.4
96 CONO10	65.	1509.3	2137.6	3646.9	0.416	0.0	0.0	0.67	0.0	0.67	237.0
97 CONO11	65.	1515.1	2166.4	3681.5	0.420	0.0	0.0	0.67	0.0	0.67	239.3
98 SALEM2	474.	2202.3	3946.6	6148.9	0.603	27.90	6.47	68.91	0.0	103.28	2503.3
102 GCOAL3	600.	3323.1	5128.0	8451.1	0.798	113.95	36.87	73.28	136.03	360.14	4196.5
107 PKGCT	140.	21.8	31.7	53.5	0.004	0.70	0.18	3.15	10.44	14.47	4.9
108 ECONOMY	913.	2386.2	3773.0	6159.2	0.395	432.98	0.0	0.0	0.0	432.98	3157.6
109 EMRGENCY	500.	0.1	0.2	0.3	0.000	0.02	0.0	0.0	0.0	0.02	0.1
111 LMHW	64.	0.0	0.1	0.1	0.000	0.00	0.0	0.0	0.0	0.00	0.0
114 VOLAP	170.	0.0	0.1	0.1	0.000	0.01	0.0	0.0	0.0	0.01	0.0
115 BRNOUT5	150.	0.0	0.1	0.1	0.000	0.00	0.0	0.0	0.0	0.00	0.0
116 BRNOUT8	100.	0.0	0.0	0.0	0.000	0.00	0.0	0.0	0.0	0.00	0.0
117 PARTIAL	*******	0.0	0.0	0.0	0.0	0.04	0.0	0.0	0.0	0.04	0.0
118 TOTAL	*******	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SUMMARY RESULTS

LOSS-OF-LOAD PROBABILITIES:
PARTIAL BLACKOUTS 0.0000 = 0.0 DAYS IN TEN YEARS
TOTAL BLACKOUTS 0.0 = 0.0 DAYS IN TEN YEARS
ALL CURTAILMENT OPTIONS 0.0000 = 0.1 DAYS IN TEN YEARS

TOTAL SYSTEM COST $ 2017.4 MILLION (1992) = $ 550.9 MILLION (DISCOUNTED TO 1979)
TOTAL ELECTRICITY GENERATED 34878. GWH
INCREMENTAL ELECTRICITY COST 5.8 1992 CENTS PER KWH = 1.6 1979 CENTS PER KWH
LOAD FACTOR 59.3%

TOTAL COSTS IN 1992 $MILLION		DISCOUNTED TO 1979 $MILLION
FUEL	960.	262.
VARIABLE O&M	156.	43.
CARRYING CHARGES	322.	88.
INCREMENTAL CAPITAL	146.	40.

IMPORT OPTIONS:	COST IN 1992 $MILLION	DISCOUNTED TO 1979 $MILLION	ENERGY IN GWH
ECONOMY	432.98	118.24	3157.6
EMRGENCY	0.02	0.00	0.1

TOTAL CURTAILMENT COST $ 0.06 MILLION (1992) = $ 0.02 MILLION (DISCOUNTED TO 1979)
BLACKOUT COST $ 0.04 MILLION (1992) = $ 0.01 MILLION (DISCOUNTED TO 1979)

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EXHIBIT D

ESCALATION RATES
(Annual Percentages)

E S R G

ESCALATION RATES

(Annual Percentages)

	1980	1981	1982	1983	1984	1985 and beyond
PECO						
INFLATION	6.5	5.5	5.0	---→		
FUELS:						
Nuclear	8.2	---→				
Coal	8.0	---→				
Oil	10.0	10.0	10.0	10.0	10.0	8.0 ---→
NG	12.3	11.3	10.8	---→		
NON GEN	10.0	10.0	10.0	10.0	10.0	8.0 ---→
OPERATION & MAINTENANCE	6.5	5.5	5.0	---→		
DISCOUNT	8.0	---→				
ESRG LOW						
INFLATION	8.5	7.5	---→			
FUELS:						
Nuclear	8.2	---→				
Coal	8.0	---→				
Oil	10.0	10.0	10.0	10.0	10.0	8.0 ---→
NG	14.3	13.3	---→			
NON GEN	10.0	10.0	10.0	10.0	10.0	8.0 ---→
OPERATION & MAINTENANCE	8.5	7.5	---→			
DISCOUNT	10.5	---→				
ESRG HIGH						
INFLATION	10.0	9.0	---→			
FUELS:						
Nuclear	12.0	---→				
Coal	12.0	---→				
Oil	14.0	14.0	14.0	14.0	14.0	12.0 ---→
NG	15.8	14.8	---→			
NON GEN	14.0	14.0	14.0	14.0	14.0	12.0 ---→
OPERATIONS & MAINTENANCE	10.0	9.0	---→			
DISCOUNT	12.0	---→				

EXHIBIT E

CAPITAL COSTS

Exhibit ___ (DS-E)
Sheet 1 of 7

TABLE E-1

CAPITAL COSTS

300 Mw NEW COAL UNIT

		Yearly Direct Constr. Exp. (1979 Constr. $/Kw)	ESRG Yearly Dir. Constr. Exp. (Current $/Kw)		AFDC RATE (PERCENT)		ESRG Yearly AFDC Expend. (Current $/Kw)		INFLATION RATE (PERCENT)		TOTAL YEARLY EXPEND. (1979 $/Kw)	
			Low	High	Low	High	Low	High	Low	High	Low	H
1980	Initial	18.18	20.21	20.48	10.5	12.5	2.12	2.36	8.5	10.0	20.6	2
	Prior		22.33	22.84			2.12	2.74				
1981	Current	15.15	18.55	19.05	9.5	12.0	.88	1.14	7.5	9.0	18.5	1
	Total		40.88	41.89			3.00	3.88				
	Prior		43.88	45.77			4.17	5.49				
1982	Current	36.36	49.03	51.06	9.5	12.0	2.33	3.06	7.5	9.0	44.3	4
	Total		92.91	96.83			6.50	8.55				
	Prior		99.41	105.38			9.44	12.64				
1983	Current	153.78	228.44	241.10	9.5	12.0	10.85	14.47	7.5	9.0	184.5	18
	Total		327.85	346.48			20.29	27.11				
	Prior		348.14	373.59			33.07	44.83				
1984	Current	267.42	437.56	468.12	9.5	12.0	20.78	28.09	7.5	9.0	339.1	348
	Total		785.70	841.71			53.85	72.92				
	Prior		839.55	914.63			79.76	109.76				
1985	Current	217.42	391.86	424.94	9.5	12.0	18.61	25.50	7.5	9.0	314.7	331
	Total		1231.41	1339.57			98.37	135.26				
	Prior		1329.78	1474.83			126.33	176.98				
1986	Current	49.24	97.69	107.45			4.64	6.45	7.5	9.0	136.6	157
	Total		1427.47	1582.28			130.97	181.43				
		757.55	1558.44	1765.71							1058.3	1110

TABLE E-2

CAPITAL COSTS

600 MW NEW COAL UNIT

		Yearly Direct Constr. Exp. (1979 Constr. $/Kw)	ESRG Yearly Dir. Constr. Exp. (Current $/Kw)		AFDC RATES (PERCENT)		ESRG Yearly AFDC Expend. (Current $/Kw)		INFLATION RATE (PERCENT)		TOTAL YEARLY EXPEND (1979 $/Kw)	
			Low	High	Low	High	Low	High	Low	High	Low	Hi
1980	Initial	15.48	17.20	17.44	10.4	12.5	1.63	2.09	8.5	10.0	17.4	1
	Prior		18.83	19.53			1.79	2.34				
1981	Current	7.74	9.48	9.73	9.0	12.0	.45	.58	7.5	9.0	8.3	1
	Total		28.31	29.26			2.24	2.92				
	Prior		30.55	32.18			2.90	3.86				
1982	Current	10.83	11.82	15.34	9.0	12.0	.56	.92	7.5	9.0	12.2	1
	Total		42.37	47.52			3.46	4.78				
	Prior		45.83	52.30			4.35	6.28				
1983	Current	37.14	55.17	58.23	9.0	12.0	2.62	3.49	7.5	9.0	46.1	4
	Total		101.00	110.53			6.97	9.77				
	Prior		107.97	120.30			10.26	14.44				
1984	Current	157.09	257.04	274.99	9.0	12.0	12.21	16.50	7.5	9.0	192.9	19
	Total		365.01	395.29			22.47	30.94				
	Prior		387.48	426.23			36.81	51.15				
1985	Current	273.17	492.34	533.90	9.0	12.0	23.39	32.03	7.5	9.0	354.7	36
	Total		879.82	960.13			60.20	83.18				
	Prior		940.02	1043.31			89.30	125.20				
1986	Current	222.09	440.91	484.63	9.0	12.0	20.94	29.08	7.5	9.0	329.2	34
	Total		1380.93	1527.94			110.24	154.28				
	Prior		1491.17	1682.22			141.66	201.87				
1987	Current	50.30	109.99	122.55	9.0	12.0	5.22	7.35	7.5	9.0	142.7	16
	Total		1601.16	1804.77			146.88	209.22				
		773.84	1748.04	2013.99							1103.4	116

E S R G

Fxhibit ___ (DS-E)
Sheet 3 of 7

TABLE E-3

CAPITAL COSTS

1000 MW NEW COAL UNIT

		Yearly Direct Const. Exp. (1979 Constr. $/Kw)	ESRG Yearly Dir. Constr. Exp. (Current $/Kw) Low	ESRG Yearly Dir. Constr. Exp. (Current $/Kw) High	AFDC RATES (PERCENT) Low	AFDC RATES (PERCENT) High	ESRG Yearly AFDC Expend. (Current $/Kw) Low	ESRG Yearly AFDC Expend. (Current $/Kw) High	INFLATION RATE (PERCENT) Low	INFLATION RATE (PERCENT) High	TOTAL YEARLY EXPEND. (1979 $/Kw) Low	TOTAL YEARLY EXPEND. (1979 $/Kw) High
1980	Initial	16.29	18.11	18.35	10.5	12.5	1.72	2.20	8.5	10.0	18.3	18.
	Prior		19.83	20.55			1.88	2.47				
1981	Current	4.89	5.99	6.15	9.0	12.0	.28	.37	7.5	9.0	7.0	7.
	Total		25.82	26.70			2.16	2.84				
	Prior		27.98	29.54			2.66	3.54				
1982	Current	4.89	6.59	6.77	9.0	12.0	.31	.41	7.5	9.0	7.6	8.
	Total		34.57	36.31			2.97	3.95				
	Prior		37.54	40.26			3.57	4.83				
1983	Current	9.77	14.51	15.32	9.0	12.0	.69	.92	7.5	9.0	13.9	14.
	Total		52.05	55.58			4.26	5.75				
	Prior		56.31	61.30			5.35	7.36				
1984	Current	39.10	63.98	68.45	9.0	12.0	3.04	4.11	7.5	9.0	50.0	51.
	Total		120.29	129.75			8.39	11.47				
	Prior		128.68	141.22			12.22	16.95				
1985	Current	165.36	298.03	323.19	9.0	12.0	14.16	19.39	7.5	9.0	208.3	212.
	Total		426.71	464.41			26.38	36.34				
	Prior		453.09	500.75			43.04	60.09				
1986	Current	287.54	570.84	627.45	9.0	12.0	27.11	37.65	7.5	9.0	38[illegible].8	393.
	Total		1023.93	1128.20			70.15	97.74				
	Prior		1094.01	1225.92			103.94	147.11				
1987	Current	233.78	511.22	569.57	9.0	12.0	24.28	34.17	7.5	9.0	355.2	373.
	Total		1605.23	1795.49			128.22	181.28				
	Prior		1733.45	1976.77			164.68	237.21				
1988	Current	52.95	127.54	144.04	9.0	12.0	6.06	8.64	7.5	9.0	154.1	177.
	Total		1860.99	2120.81			170.74	245.85				
		814.57	2031.73	2366.67							1197.2	1257.

E S R G

TABLE E-4
CAPITAL COSTS

LIMERICK 1 and 2

		Yearly Direct Constr. Exp. (1979 Constr. $/KW)	ESRG Yearly Dir. Constr. Exp. (Current $/Kw)	AFDC RATE (PERCENT)	ESRG Yearly AFDC Expend. (Current $/Kw)	INFLATION RATE (PERCENT)	TOTAL YR EXPEND. (1979 $/Kw)
			Low High	Low High	Low High	Low High	Low Hig
1970	Initial	7.01	2.95	4.9%	.15	5.4%	6.7
	Prior		3.10		.20		
1971	Current	33.07	$\boxed{15.14}$	6.3%	.48	5.1%	29.9
	Total		18.24		$\boxed{.68}$		
	Prior		18.92		1.42		
1972	Current	41.08	$\boxed{20.37}$	7.5%	.76	4.1%	39.6
	Total		39.29		$\boxed{2.18}$		
	Prior		40.05		2.56		
1973	Current	63.13	$\boxed{33.15}$	6.4%	1.06	5.8%	61.1
	Total		73.20		$\boxed{3.62}$		
	Prior		76.82		5.15		
1974	Current	75.15	$\boxed{43.69}$	6.7%	1.46	9.7%	76.1
	Total		120.51		$\boxed{6.61}$		
	Prior		127.12		9.02		
1975	Current	77.15	$\boxed{51.18}$	7.1%	1.82	9.6%	85.6
	Total		178.30		$\boxed{10.84}$		
	Prior		189.14		13.62		
1976	Current	99.20	$\boxed{70.40}$	7.2%	2.53	5.3%	113.5
	Total		259.54		$\boxed{16.15}$		
	Prior		275.69		20.40		
1977	Current	100.20	$\boxed{76.91}$	7.4%	2.85	5.5%	124.5
	Total		352.60		$\boxed{23.25}$		
	Prior		375.85		27.06		
1978	Current	80.16	$\boxed{69.31}$	7.2%	2.50	10.0%	111.7
	Total		445.16		$\boxed{29.56}$		
	Prior		474.72		53.17		
979	Current	55.11	$\boxed{55.11}$	11.2%	3.09	13.0%	111.4
	Total		529.83		$\boxed{56.26}$		

Exhibit ___ (DS-E)
Sheet 5 of 7

TABLE E-4 c+d

CAPITAL COSTS

LIMERICK 1 and 2
(Continued)

		Yearly Direct Constr. Exp. (1979 Constr. $/Kw)	ESRG Yearly Dir. Constr. Exp. (Current $/Kw)		AFDC RATE (PERCENT)		ESRG Yearly AFDC Expend. (Current $/Kw)		INFLATION RATE (PERCENT)		TOTAL YRL. EXPEND. (1979 $/Kw)	
			Low	High	Low	High	Low	High	Low	High	Low	High
	Prior		586.09				61.54	73.26				
1980	Current	60.12	65.64		10.5%	12.5%	3.45	4.10	8.5%		120.4	130.
	Total		651.73				64.99	77.36				
	Prior		716.72	729.09			68.09	87.49				
1981	Current	64.13	75.68	75.68	9.5%	12.0%	3.59	4.54	7.5%	9.0%	126.3	139.
	Total		792.40	804.77			71.68	92.03				
	Prior		864.08	896.80			82.09	107.61				
	Current	65.13	82.75	82.75	9.5%	12.0%	3.93	4.97	7.5%	9.0%	134.6	149.
	Total		946.83	979.55			86.02	112.58				
	Prior		1032.85	1092.13			98.12	131.06				
1983	Current	61.12	83.64	83.64	9.5%	12.0%	3.97	5.02	7.5%	9.0%	139.1	154.
	Total		1116.49	1175.77			102.09	136.08				
	Prior		1218.58	1311.85			115.77	157.42				
1984	Current	53.11	78.24	78.24	9.5%	12.0%	3.72	4.69	7.5%	9.0%	136.5	154.
	Total		1296.82	1390.09			119.49	162.11				
	Prior		1416.31	1552.20			134.55	186.26				
1985	Current	42.08	66.71	66.71	9.5%	12.0%	3.17	4.00	7.5%	9.0%	131.2	151.
	Total		1483.02	1618.91			137.72	190.26				
	Prior		1620.74	1809.17			153.97	217.10				
1986	Current	19.04	32.51	32.51	9.5%	12.0%	1.54	1.95	7.5%	9.0%	112.3	136.
	Total		1653.25	1841.68			155.51	219.05				
	Prior		1808.76	2060.73			171.83	247.29				
1987	Current	7.01	12.88	12.88	9.5%	12.0%	.61	.77	7.5%	9.0%	103.0	129.
	Total		1821.64	2073.61			172.44	248.06				
			1994.08	2321.67							$1764.	$1907.

E S R G

TABLE E-5

CAPITAL COSTS

GENERIC 1200 Mw NUCLEAR UNIT

		Yearly Direct Constr. Exp. (1979 Constr. $/Kw)	ESRG Yearly Dir. Constr.Exp. (Current $/Kw) Low	ESRG Yearly Dir. Constr.Exp. (Current $/Kw) High	AFDC RATE (PERCENT) Low	AFDC RATE (PERCENT) High	ESRG Yearly AFDC Expend. (Current $/Kw) Low	ESRG Yearly AFDC Expend. (Current $/Kw) High	INFLATION RATE (PERCENT) Low	INFLATION RATE (PERCENT) High	TOTAL YEAR: EXPEND. (1979 $/Kw) Low	TOTAL YEAR: EXPEND. (1979 $/Kw) High
1979	Initial	111.3	111.3	111.3	9.5	12.0	10.57	13.36	13.0		121.9	124.7
	Prior		121.87	124.65			11.58	14.96				
1980	Current	20.2	22.50	22.80	9.5	12.0	1.07	1.37	8.5	10.0	32.4	37.6
	Initial		144.37	147.39			12.65	16.33				
	Prior		157.02	163.76			14.92	19.65				
1981	Current	16.9	20.69	21.26	9.5	12.0	.98	1.28	7.5	9.0	31.4	35.2
	Initial		177.71	185.02			15.90	20.93				
	Prior		193.61	205.95			18.39	24.71				
1982	Current	43.8	59.06	61.51	9.5	12.0	2.81	3.69	7.5	9.0	64.1	71.7
	Initial		252.67	267.46			21.20	28.40				
	Prior		273.87	295.86			26.02	35.50				
1983	Current	106.2	157.75	166.51	9.5	12.0	7.49	9.99	7.5	9.0	141.9	148.9
	Initial		431 62	462.37			33.51	45.49				
	Prior		465.13	507.86			44.19	60.94				
1984	Current		234.47	250.85	9.5	12.0	11.14	15.05	7.5	9.0	200.0	210.5
	Initial		699.60	758.71			55.33	75.99				
	Prior		754.93	834.70			71.72	100.16				
1985	Current		392.00	425.09	9.5	12.0	18.62	25.51	7.5	9.0	309.7	325.4
	Initial		1146.93	1259.87			90.34	125.67				
	Prior		1237.27	1385.54			117.54	166.26				
1986	Current		589.03	647.44	9.5	12.0	27.98	38.85	7.5	9.0	438.7	462.1
	Initial		1826.30	2032.98			145.52	205.11				
	Prior		1971.82	2238.10			187.32	268.57				
1987	Current		741.09	825.68	9.5	12.0	35.20	49.54	7.5	9.0	535.3	568.8
	Initial		2712.91	3063.78			222.52	318.11				
	Prior		2935.43	3381.89			278.87	405.83				
1988	Current		580.74	655.84	9.5	12.0	27.54	39.35	7.5	9.0	458.5	502.2
	Initial		3516.17	4037.73			306.41	445.18				

1054a

TABLE E-5

CAPITAL COSTS

GENERIC 1200 Mw NUCLEAR UNIT

		Yearly Direct Constr. Exp. (1979 Constr. $/Kw)	ESRG Yearly Dir. Constr.Exp. (Current $/Kw)		AFDC RATE (PERCENT)		ESRG Yearly AFDC Expend. (Current $/Kw)		INFLATION RATE (PERCENT)		TOTAL YEAR EXPEND. (1979 $/Kw)	
			Low	High	Low	High	Low	High	Low	High	Low	High
	Prior		3822.58	4482.91			363.15	537.95				
1989	Current	118.0	313.08	358.38	9.5	12.0	14.87	21.50	7.5	9.0	332.2	382.1
	Initial		4135.66	4841.29			378.02	559.45				
	Prior		4513.68	5400.74			428.80	648.09				
1990	Current	28.7	83.88	97.32	9.5	12.0	3.98	5.84	7.5	9.0	231.0	288.5
	Initial		4597.56	5490.06			432.78	653.93				
			5030.34	6151.99							2895.9*	3158.0

* Due to a minor calculation error $2913/Kw was used in the ESGEN Program.

Q. Please state your name and business address.

A. My name is Don M. Shakow. My business address is Energy Systems Research Group, Inc., 120 Milk Street, Boston, Massachusetts.

Q. Have you reviewed the prepared testimony of Mr. Emil Kasum concerning your earlier testimony of November 13, 1979?

A. Yes, I have.

Q. Please summarize your findings.

A. The major contentions in Mr. Kasum's rebuttal testimony are either incorrect in substance or else irrelevant to the major conclusions noted in my testimony.

1. The major purpose of the ESGEM model is not to conduct detailed planning for a utility system, but rather to identify implicit planning biases in the utility planning process. Thus, the relative sophistication of the PECO model versus the ESRG model is not at issue. What is at issue is whether the ESGEM model is able to elicit consequential biases in the PECO generation expansion plan.

2. The major relevant assertion of Mr. Kasum that ESGEM is biased against base load generation is incorrect.

3. The alleged inaccuracies in data employed in the application of ESGEM are minor. Rather, the data exhibited by Mr. Kasum indicate a set of highly unrealistic assumptions regarding economic data. This has only served to reinforce any previously stated concerns over biases in the PECO generation planning process.

4. Mr. Kasum's statements indicate an incomplete understanding of the assumptions and algorithms employed in ESGEM. Much of his

criticisms are, therefore, inappropriate or inaccurate.

5. In particular, Mr. Kasum's comparison of the PECO mix to the ESRG mix constitutes a logically inappropirate comparison of a mix which is suboptimal relative to the PECO cost assumptions and a mix which is allegedly optimal by PECO standards. His quantitative results are therefore of no consequence.

Q. Have you been able to undertake a comparison of ESGEM and the PECO generation planning and production costing models?

A. No; I have not. During the course of these proceedings, we submitted several interrogatories requesting sample output from PECO generation planning and reliability studies for the years 1978-1992 (e.g., Q.GLF.1 and Q.GLF.2). The Company was not responsive to our request and provided only a tabulation of results for the year 1981.

Computer output from the PECO Production Cost Program was provided only in response to a telephone request made by myself to Mr. Craig Burgraff of the Consumer Advocate's Office on December 18, 1979. This output was with reference to the runs made in respect to the ESRG "optimal mix" and did not permit sufficient time for an analytic comparison of the two programs.

Q. Mr. Kasum states that the omission of startup costs by ESGEM biases the results against baseload. Would you please comment?

A. Quite the contrary. The decision to ignore startup costs results in a mix which is biased in favor of baseload. The assumption is, therefore, conservative.

Specifically, were we to follow the daily load cycle by employing baseload technologies for cycling purposes, we would either incur startup costs characteristic of baseload plants which are relatively high as compared to comparable costs for cyclers (to the extent that such plant could be started up at all!) or else we would spin baseload plants at off peak hours. In either case the costs would be unfavorable as compared to the increased use of intermediate plants. The program would no doubt specify to an even greater degree the use of non-baseload plants.

Q. Mr. Kasum states that the ESRG model does not account for the benefits of pumped storage via the PECO Muddy Run facility. Is Mr. Kasum correct in his presumption?

A. No, he is not. Pumped storage load was assumed in the sample annual load curve employed in the model.* This serves to flatten out the load and to highlight the advantages of baseload. Pumped storage is employed in the dispatching portion of the model in a manner so as to replicate the experienced rates of energy supply. Thus, while the energy losses involved in the actual pumping process are not explicit in the model, the salient aspects of this technology as they pertain to the analysis of generation mix are preserved and account for the advantages of pumped storage in magnifying the economic benefits of baseload.

Q. Mr. Kasum states that the absence of a multi-year optimization algorithm in ESGEM, i.e., the practice of optimizing for "individual years" suggests a bias against baseload. Is this observation accurate?

* We have just been informed that pumped storage load was not included in response to our request for PECO hourly load data. We had assumed that our request for hourly load data implied all sources of load including pumped storage. In my estimation, however, this omission does not affect the major results of my testimony.

A. No, it is not. Under realistic assumptions, the model is unambiguous in its rejection of new baseload options for each of the years 1981, 1987, and 1992, with the exception of the intermediate sized coal plants as noted in my earlier testimony. Optimization over combinations of years will not specify plants that have been excluded for a range of individual years spanning the overall planning horizon.

Q. Are the 25 samples taken in the ESGEM model insufficient as claimed by Mr. Kasum?

A. We have performed a detailed analysis of the stochastic "flutter" implied by samples of varying sizes and have concluded that a sample size of 25 yields results in which anomalous outcomes are kept to a reasonable minimum. For example, the increase in voltage reductions from .2 to 2.3 hours per year as noted by Mr. Kasum imposes additional costs of $50,000, or roughly 40 parts in one million of the total social costs in question. It will, therefore, have no censequential impact on results of the model.

Q. Is Mr. Kasum accurate in his claim that ESGEM imports economy power predominently during peak hours?

A. No, he is not. ESGEM "loads" economy power so as to replicate experienced rates of energy supply via this means. It does so in a way which is consistant with the requirements of economic dispatch As a consequence, there is a substantial use of economy power during off-peak hours.

Q. Mr. Kasum claims that the LOLP concept as employed by PECO is equivalent to the industrial standard. Is this claim correct?

Q. No, it is not. Professor R. L. Sullivan of the University of Florida, the author of a recently published and widely used textbook entitled Power System Planning, makes the following assertion:

> "Although there are several interpretations of LOLP, the most common is simply that it represents the *percent of time*, over some finite interval, that a loss-of-load can occur due to unit forced outages" [1] (italics are mine).

This citation is included in a section entitled "State of the Art" and implies that there has been some recent evolution in this category. The ESRG model employs a definition of LOLP as suggested by this more up-to-date conception.

Q. Is Mr. Kasum correct in assuming that voltage reductions are necessarily taken to maintain spinning reserve and that blackouts would be necessary at a much earlier stage in the supply-demand adjustment process within the ESGEM model?

A. No, he is not. The objective of employing spinning reserve is to create a buffer in the event of unanticipated variations in the load. As a buffer its very purpose is to absorb fluctuations by getting drawn down periodically. In recognition of this fact, a recent E.P.R.I. study of reliability employs a model in which

> "as capacity outages further deplete reserves the operator can waive the remaining operating reserves. This step causes the operating reserves in the system to go to zero." [2]

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[1] E.P.R.I. "Workshop Proceedings: Power System Reliability Research Needs and Priorities" WS 77-60, October, 1978, p. 6-43.

[2] E.P.R.I. "Generating System Reliability Analysis for Future Cost-Benefit Studies", EA-958, p. 5-9.

The omission of an explicit mention of spinning reserve in the ESGEM model does not preclude its presence implicitly. We are fully cognizant of the fact that a portion of the overall reserve would be allocated to spinning reserve.

Q. How would the above observations effect the results shown in Table EK-1?

A. The "additional blackout costs" displayed in Table EK-1 would be reduced substantially in light of a periodic running down in spinning reserves. The original conclusions in my testimony as they pertain to the optimal reserve margin would still obtain.

Q. Mr. Kasum states that my assumption that peak load can be reduced by up to 170 Mw prejudices the reliability analysis because "the public response to voluntary load curtailment diminishes as the number of appeals per year increases." Please comment.

A. The 170 Mw maximum reduction via public appeals represents less than 3% of the current PECO peak load. By contrast, Mr. C. W. Frederickson, a witness on behalf of the CAPCO Pool has stated that during a winter storm in 1977, "a public appeal resulted in a reduction in peak load of approximately 7%."[1] Assuming a target reserve margin of 14% and ESRG load and (low) cost assumptions, public appeals are employed for approximately 20 hours per year, which suggests that the 7% figure is reasonable and that the assumption employed in the ESRG model in regard to public appeals is biased on the low side.

Q. Mr. Kasum states that the use of social cost rather than an explicit reliability standard is inconsistent with current utility practice. Please comment.

[1] I-79070317, Set 1, question 21.

A. Mr. M. Bhavarasu in a recent article in the EPRI Journal[(1)] states with reference to the one day in ten years and other reliability indices:

> "This is an intuitive approach, which is used when no other is available."

This observation is especially pertinent to the ESRG analysis. A major purpose of our model is to identify the impact of utility planning biases on social costs, which will be borne by ratepayers. In light of this objective, a crude reliability index without reference to these social costs would be irrelevant to our purposes.

Q. Mr. Kasum states that the interpolated ESRG social costs at alternative reserve margins justify an optimal level of between 22 and 30 percent. Is this assertion justified?

A. The assertion is not justified. Below is a table showing 1979 social costs at various reserve levels under ESRG assumptions.

	Reserve Margin (%)		
Year	14	22	30
81	585.1	598.5	587.9
87	588.6	577.7	578.9
92	542.9	547.8	550.8

Both the column sums as well as the sum of the two, 2-element partial sums* yield results which are lowest for the 14% column. No reasonable interpolation procedure would, therefore, show the 14% margin as the inferior of the three.

Q. Mr. Kasum asserts that the ESRG nuclear cost estimates do not take account of economies of scale in nuclear generating technology. Please comment.

(1) "Reliability Measures for System Planning", EPRI Journal December 1978, p. 11.

* 1981 + 1987 and 1987 + 1992

A. The ESRG methodology enables a determination of the effect of the variable, size, on plant performance. As such it folds in a number of considerations pertinant to plant size including both economies of scale and frequency of forced outages due to the large number of components and the greater complexity associated with larger facilities. The literature indicates that overall, an inverse relationship between plant performance and rated capacity obtains[1]. I have validated this result using a non-linear regression technique in combination with multivariate analysis of variance.[2] These results suggest that the positive effect of scale economies is being outweighed in practice by a disproportionate number of costly forced outages.

Q. Mr. Kasum in table EK-3 cites a sample of projected nuclear plant capital costs that range from $1 320./Kw to $ 1937 /Kw for a plant with a 1990 in service date. Do these estimates represent the expert consensus of opinion on this issue?

A. By no means. William E. Mooz of the RAND Corporation estimates the projected costs of LWR's on which construction begins in 1980 of the order of $2000 /Kw. Since such a plant is likely to be completed before 1990 and must be inflated from 1976 to 1979, it is clear that the range suggested by Mr. Kasum is out of line with the results of this study. Similarly PASNY has estimated the cost of their Green County facility at $3.1 billion or $2580/Kw. This latter plant is scheduled to come on line in 1988. When these latter estimates are compared to the coal cost estimates cited by Mr. Kasum in table EK-3, ratios of the ordr of 2.5 are indicated.

Q. Mr. Kasum states that as a consequence of modifications in the AFUDC calculations, the current dollar cost of the Limerick plant should be reduced to $3251 million. Is this consistent with your calculations?

A. No it is not. From exhibit DMS-E in my earlier testimony I calculate the current dollar cost of Limerick at $7023 million including $4586 million, direct cost and $2437 million, AFUDC. Even granting the 956 million which Mr. Kasum proposes to substract from this figure leaves a net figure of $6067 million. This is still almost double the PECO estimate and would not materially affect my conclusions.

1. See, for example, J. Fowler, R. Goble, and C. Hohenemser, 'Power Plant Performance,' Environment , April, 1978.

2. See D. Shakow and R. Goble, ' Some Underlying Costs of Nuclear Power, The Quantification of Uncertainty,' Worcester MA, Dec. 1979.

Q. What would be the consequences of using the Gross National Product Deflator in place of the Consumer Price Index in the cost assumptions as suggested by Mr. Kasum?

A. In my opinion, the effect would be to generate outcomes even less favorable to baseload and nuclear expansion. Specifically, our escalation estimates, both for plant construction and operating expense would not change. The use of a composite index such as the CPI and the GNPD pertains only to an overall inflationary process rather than to escalation in some given product or service. However, once the current dollar cost figure was computed it would be deflated by a factor which is smaller than the factor used in my present calculations. Real costs would, therefore, rise.

Q. Is the cost comparison shown in table EK-8 of Mr. Kasum's testimony an indication that the PECO plan is less costly than the ESRG optimal plan?

A. No it is not. The ESRG optimum is based on underlying load and cost assumptions. Given the PECO assumptions, for example, the mix is likely to be very different from the mix under ESRG assumptions. The comparison shown in Mr. Kasum's testimony is, therefore, between the PECO mix and some suboptimal mix which ESRG does not necessarily endorse. As such,the displayed results are irrelevant to my conclusions.

Q. Does this complete your testimony?

A. Yes it does.

MR. BOCK: Your Honor, before we proceed with the next witness, based on redirect of the Consumer Advocate outlining the basis and the study and number to use, is Your Honor ready to rule on the motion to strike?

THE ADMINISTRATIVE LAW JUDGE: Not at this time.

MR. HALL: Your Honor, before we begin with the next witness, I wonder if I could make one request? There is due to be filed today a brief by Your Honor in support of the company certification. I was wondering if Your Honor would entertain a request to have that brief filed the first thing tomorrow morning?

THE ADMINISTRATIVE LAW JUDGE: Yes.

MR. HALL: Thank you, Your Honor.

MR. BURGRAFF: We would now offer Dr. Shakow at this point. He has not been sworn as yet.

DON M. SHAKOW, was called as a witness on behalf of the Consumer Advocate, being first duly sworn according to law, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BURGRAFF:

Q Could you state your name and business address for the record, please?

A Don M. Shakow, and my business address is

Energy System Research Group, Inc., 120 Milk Street, Boston.

MR. BURGRAFF: Dr. Shakow has prepared a narrative testimony and exhibits DS-A through DS-E, which we will provide three copies to the Reporter at a future point in time.

BY MR. BURGRAFF:

Q Do you have those materials in front of you, Doctor?

A Yes, I do.

Q Were they prepared by you under your direct supervision or control?

A Yes, they were.

Q And if I asked you the same questions today as contained therein, would your answers be the same?

A Yes.

Q Do you have any corrections you would like to make at this time?

A No, I don't.

Q And is the information accepted therein true and correct to the best of your information, knowledge and belief?

A Yes.

MR. BURGRAFF: We would ask that Dr. Shakow's Statement B be identified as Consumer Advocate's Statement No. 4 along with the attendant exhibits, DS-A through DS-E.

THE ADMINISTRATIVE LAW JUDGE: Without objection, they will be so identified.

(Multi-page document which is the testimony of Don M. Shakow, with accompanying exhibits DS-A through DS-E was marked Consumer Advocate's Statement No. 4 for identification.)

MR. BURGRAFF: Now Dr. Shakow is available for cross-examination.

THE ADMINISTRATIVE LAW JUDGE: Mr. Hall?

MR. HALL: Good afternoon, Dr. Shakow. How are you?

DR. SHAKOW: I am fine, thank you.

MR. HALL: Before we begin, Dr. Shakow -- Your Honor, I would move at this time to strike Dr. Shakow's entire testimony, the theory of that testimony and recommendations that are made in it, that the company should terminate construction of its Limerick generating unit.

As Your Honor is aware, the company filed objections to interrogatories previously with regard to the Limerick matter and has taken the position that Limerick, its timing and whether it should be built or not, are not issues directly affecting the rates in this case and should not be decided in this case and the company adheres to that position and based on that, I move to strike Dr. Shakow's testimony in its entirety.

In addition, the company would especially move to strike that portion of Dr. Shakow's testimony which recommends that this Commission adopt for Philadelphia Electric Company a new reserve reliability criteria which is different than that which has been historically employed by this Commission for utilities subject to this jurisdiction.

The company believes such an issue is one of Statewide applicability and should be raised in a Statewide proceeding and in addition, believes that that particular issue again does not directly effect rates in this proceeding and it is indeed an extremely complex, extremely difficult issue and one with extremely great effects upon the health and safety of members of the Commonwealth, and for that reason believes it should not be considered in a proceeding such as this where there are extreme time constraints on all parties.

MR. BURGRAFF: Your Honor, if I might respond, Dr. Shakow, we would note that the objections raised by the company to any matter having to do with Limerick as to its relevancy to this proceeding has been raised before. I believe the Commission has given direction in that regard.

I might note that Dr. Shakow's testimony in essence is a unified whole and as a technical matter, it is not that easy to split it up. As a legal matter, I already think we have the direction set forth as to how Limerick will be treated in this case.

As far as reliability is concerned, I think it relevant. The company has offered their own viewpoint as to appropriate reliability level for their system. I don't think the objection is really going to its relevance. It seems to go whether this proceeding is the proper form. We agree it is a difficult issue, but we agree it is the proper form.

I am not sure what a generic proceeding would do given the differences within various utilities in Pennsylvania. I don't see any other form more appropriate than a rate case dealing with this company in particular.

MR. SEGAL: If Your Honor please, if I may, Your Honor, the company's motion is inappropriate for two separate and related reasons.

First of all, it is a matter of law. The company has already raised the issue of the relevancy of Limerick. Your Honor has already ruled that Limerick is relevant to these proceedings. That question was then certified to the Commission. The Commission has ruled adverse to the company and that is now the law of the case.

Second of all, the issue of Limerick is directly relevant to the setting of rates in this proceeding for two reasons. One, it is very much involved with the area of excess capacity which is then the topic of testimony concerning possible adjustments to rate base as a result of any possible excess capacity and, second of all, the company's own witness, Mr. Paquette, has testified that a major reason for requesting rate relief is the need to attract capital for the company's construction company which as Mr. Paquette, himself, has stated primarily involves the construction of Limerick facilities.

I think for those two separate reasons, one very clearly that the issue of Limerick is relevant to rates in this case, and for that reason, the motion should be denied and a separate reason it is the law of the case as established by the Commission that the motion cannot be granted.

THE ADMINISTRATIVE LAW JUDGE: Thank you. I will deny the motion. I cannot find that the material is relevant or irrelevant or unduly repetitious.

MR. HALL: Your Honor, we will take an exception to your ruling, but we will not seek a certification of the Commission at this time.

THE ADMINISTRATIVE LAW JUDGE: I am sure the Commission will be very happy to hear that.

CROSS-EXAMINATION

BY MR. HALL:

Q Dr. Shakow, turning first to your educational background, do I understand correctly that you have a Bachelor of Science degree in Humanities and Sciences?

A A Bachelor of Science in Humanities and Sciences.

Q What is a Bachelor's Degree of Humanities and Sciences?

A It is a program offered by the Massachusetts Institute of Technology in which you specialize in both scientific fields and in humanities, particular fields, and my scientific specialty was figures and mathematics and my humanistic specialty was economics and history.

Q And your Doctor's Degree is in Economics, is that correct?

A That is correct.

Q And I take it you do not have any degrees in the field of engineering?

A I do not have any degrees, no, although I should note that one of my outside fields for my economics degree was when you take two outside fields and this is the primary basis for your oral examinations, and one of my fields was in the Industrial Engineering Department and the exams administered by this Department.

Q During the period that you were seeking your Doctorate Degree, were you employed in any capacity?

A I was employed for a time by the University of California at Davis as a Lecturer in Economics.

I was employed by the University of California at Berkley as an Instructor of Economics.

I was employed by Western Washington State College as a Lecturer in Economics.

I was also employed by Weyhauser Corporation as a Research Analyst.

Q When did you receive your Bachelor's Degree?

A 1962.

Q When did you receive your Doctorate Degree?

A 1972.

Q Were you full-time employed after leaving college initially? Did you have any full-time position between 1962 and 1972?

A I spent two years in Israel. If you want me to go into my activities there, I would be happy to.

Q No, that is all right.

Now since I take it we have covered all of your employment up to 1972 at this point, is that correct?

A No, not quite. As I indicated on my vitae, from 1970 through 1975, I was essentially self-employed.

Q You indicated you had a vitae? Do you know where that is?

A It wasn't clear to me whether you had received copies of that or not. We can provide you with it if necessary.

Q Now, in 1970 to 1975.

A I was self-employed in business.

Q But what did you do in business?

A I was in the food business on the West Coast.

Q What did you do in the food business?

A I was a wholesaler of various kinds of food stuffs, produce, grains and other food stuffs.

Q Now following 1975, what did you do?

A In 1975, I was employed by Mathematical Science Northwest, and a consulting firm based in Washington as an Economitrician. I was so employed until 1976.

In 1976, I assumed the position of Assistant Professor of Economics at Clark University in Wooster, Massachusetts and am so employed at present.

Q How long have you been associated with ESRG?

A I have been associated with ESRG for approximately seven months.

Q I have used that several times. Can you provide us with the words that go with the initials?

A Energy System Research Group.

Q Have you ever previously testified, Doctor, in opposition to the construction of a nuclear plant?

A No, I have not. I am not so testifying today so far as I know.

Q Doctor, would I be correct that you have had no professional experience in either design or operating capacities as an engineer?

A That is certainly correct.

Q Would I be correct that you have never been employed by a utility and charged with the operation of its system?

A That is very true.

Q And would I be correct that you have never been employed as a financial analyst or adviser to investors?

A That is likewise correct.

Q And would I be further correct that you have never been employed as a utility rate expert accounting witness?

A That is also true.

Q Have you ever been professionally employed, Doctor, to render opinions with regard to the income tax code? The Federal income tax code?

A Absolutely not.

Q Have you ever been professionally engaged to advise on the lifespan of nuclear fossil power plants for the purpose of utility depreciation?

A No, I have not.

Q Did you, as a part of your study, which is the basis of your testimony in this proceedings, Doctor, make a study of the generating plant reserve margins of other Pennsylvania or PJM utilities other than PECO?

A Not as part of the preparation of the study, although I should indicate that I am currently engaged in such a study.

Q But prior to making this testimony, you were not?

A Not prior to the testimony.

Q And I take it similarly, you did not make a study of the anticipated future load or generating plant construction programs of such companies?

A That is not correct. I have done an analysis of load forecasting procedures by the Duquesne Light Company and have advised the Energy Systems Research Group with regard to my analysis.

Q And this is in regard to Duquesne Light Company?

A That is right.

Q And it is with regard to the load forecasting methodology employed by them?

A That is correct.

Q And is this on behalf of the Pennsylvania Office of Consumer Advocate?

A No, it was not.

Q Have you made a study, Doctor, of the available generating plant sites in the Philadelphia Electric Company service territory?

A No, I have not.

Q Are you aware of the various legal restrictions placed upon the operations of generating plants within that area?

A No, I am not.

Q And I take it that would include environmental restrictions, Doctor?

A Specifically for Philadelphia?

Q Philadelphia.

A The answer is no. I should note that we did submit interrogatories regarding the cost of various environmental regulations as they pertain to the construction cost of generation facilities, and we did not receive information in that regard.

Q But you, yourself, have never undertaken a study of the environmental laws of the Commonwealth of Pennsylvania or the Federal regulations as they would be applicable to the service territory of Philadelphia Electric?

A Specifically in regard to the Philadelphia Electric Company?

Q Yes.

A No.

Q Doctor, have you analyzed the contract by which Philadelphia Electric Company will sell capacity and ~~engineering~~ electricity from its Salem-2 facility to ~~Public Service~~ General Public Utilities

Electric and Gas?

A I have looked at that. I should note that I specifically excluded an analysis of that contract in my testimony.

Q What do you mean, Doctor?

A The testimony pertains to an analysis of this sale based on certain explicitly stated assumptions which we can go into during the course of this cross-examination, so I would say in my analysis that I might have made independently of this contract is not germane to my testimony.

The statements in my testimony, as they pertain to the sale of Salem-2, are developed under certain explicit assumptions as I stated in my testimony.

Q Now, Doctor, the analysis in your testimony has been made on a current basis and by that I mean you have not attempted to reconstruct conditions which existed at the time Philadelphia Electric Company decided to build the Limerick Station?

A That is very true.

Q You have rather stood today and looked only to the future to exercise your judgment?

A That is correct. I assume that that plant was undertaken in the late 1960's and early 1970's and I have not put myself in a position of Assistant Planner during that period of time.

Q Now the basis of your testimony is obtained from results which you ha~~d~~ve taken from an econometric model, ESRG ESGEM Computer Model, is that not correct?

A That is not correct. That is not the econometric computer we employed.

An econometric computer is a model developed from historical data and employs statistical estimates based on that historical data.

But this model, I think, is totally different from the econometric model. There is no resemblance whatsoever.

I employed econometric models to a very large degree for load forecasting and this does not bear any relationship to those models.

Q Thank you, Doctor.

A You are welcome.

Q I misused that term twice today. Would you agree with me, Doctor, that the function of the model that you have employed is to obtain an accurate mathematical representation of the Philadelphia Electric Company's power production system both as it exists today and under alternative future generating plant expansion proposals?

A Could you repeat that question? It doesn't sound quite right and I want to make sure I am answering concisely.

(Whereupon, the previously referred to question was reread by the Reporter as follows:

Q I misused that term twice today. Would you agree with me, Doctor, that the function of the model that you have employed is to obtain an accurate mathematical representation of the Philadelphia Electric Company's power production system both as it exists today and under alternative future generating plant expansion proposals?)

(Testimony continued on next page.)

THE WITNESS: I would say I would not characterize the purpose of my model in that way. The purpose is not to represent the production system, but rather to indicate what would be an optimal generation expansion plan and reserve margin from the social cost perspective. So I think if we are going to indicate the purpose of the model, we should phrase it somewhat differently.

BY MR. HALL:

Q I take it boiling down your words into a few key ones, the purpose of the model is to measure social cost, is that correct?

A. I think that is fair.

Q What are social costs as you define them, Doctor?

A. Social costs, as I define them are the costs that the consumer would have to pay in light of one, a given generation expansion plan; two, a given production system, assuming economic dispatch of plants, which not only represent the way the Philadelphia Electric Company effects dispatches. I haven't made an independent study of this. And social cost explicitly takes into account what is called consumer time preference. That is it weights as a dollar at one point of time differently from a dollar at another point of time. It takes into account the preference the consumers might exhibit of a dollar at a period closer to the present.

Q If I can try and summarize what you have stated, Doctor, I deduce three elements in your answer. One, it takes into account a generation plant expansion; two, it takes into account economic dispatch and three, the time value of money. Is that a fair statement?

A. That is correct. I don't know if that's exhaustive, but those elements are certainly present.

Q Now, could we agree that the model that you have constructed represents the Philadelphia Electric Company's system through what could fairly be termed mathematical symbolism?

A. Well, represents, I think, is the word that just to be literal here, I take some exception to in that I have not, as I said, undertaken an independent analysis of the dispatching procedure employed by Philadelphia Electric Company. In the event that the economic dispatch simulated by my model departs from practices by the company, I would not want to suggest that this is in fact, a representation.

Q What is the principal basis of your economic dispatch system?

A. Principal basis is that plants are dispatched in order of increasing operating costs.

Q Do you include in your costing analysis to determine what is economic and what is not, start-up costs?

A. Start-up costs - -

Q I guess my real question is what do you c onsider in determining where a unit would list under your concept of economic dispatch?

A. I see. That's fair. Fuel costs, operations and maintenance costs. We also have a category in there for an environmentally related cost. But as I noted earlier, the company was not responsive to our interrogatories in that regard. So we could not include numbers associated with that category.

Q And that category would be what? Capital costs?

A. No. Not capital costs. We are talking about operating costs, so it would include, for example, higher heat rates as a consequence of the installation of various pollution control devices, for example. Costs that are associated with company conformance with various anticipated environmental regulations.

Q But I take it you don't assume any start-up costs in your economic dispatch model?

A. That's correct.

Q Doctor, could you agree with me that there are three possible sources of error in a model such as the one which you have used? I don't mean by the question to suggest that they are there.

A I understand.

Q Only that they are possible.

A Absolutely.

Q First off, such a model could be potentially inaccurate in its representation of a specific facility, which it seems to represent. Is that a possible source of inaccuracy?

A Only where representation is an issue. As I noted before, my model is a normative rather than positive model, to use a term that's current in economics. By this I mean I am trying to determine what would be best from consumer's point of view, and to the extent that the company practices ~~the~~ depart from what is best from the consumer's point of view in the course of its operating its system, this would be reflected in its merchandise.

I want to steer away from the question of representation. It diverts us somewhat from the purpose of my model.

Q Perhaps it is an unfortunate wording. Leaving aside operating parameters that can be controlled by the managers or by the modeler, I take it the purpose of the model is to accurately depict those parameters which cannot be removed by choice. Such as a capacity of units, such as costs which are known and which cannot be varied by a choice of management and so forth?

A. I would agree with that.

Q. Is that not correct?

A. Yes.

Q. And I take it a second possible inaccuracy in the results achieved through the application of a model such as this would include the nature of the assumptions and the various data input? Data could be wrong. Is that not correct?

A. Oh, most certainly.

Q. And I take it finally there could be simple mathematical or computer programming errors which would cause certain errors in the results?

A. That's very true.

Q. Now, Doctor, your choice of optimal generating plant expansion programs and reserve margins has been made on the basis of a comparison of total social costs over a 1980 to 1992 planning horizon, is that not correct?

A. That is correct.

Q. Doctor, referring you to table 1, you there show in the fifth column over, under the real cost of 1979 column a column which I take it reflects the social costs which you have calculated for the indicated years and the total for the period, is that not correct?

A. That's correct.

Q And what is included, for example, in the social cost figure 739.7, which is the first figure there stated?

A 739.7? The social cost for any year would include the similar factors to wit: Well, maybe I should describe the procedure. I think that would make things clearer since the answer in reference to 739.7 would apply to any figure shown in the course of this testimony. We initially calculated an optimal generation expansion mix. We then employ that mix and simulate the production of electricity employing this mix.

This yields a series of operating costs. The operating costs are then added to the fixed costs associated with the mix. Now, I should indicate from the outset that the fixed costs do not include all fixed costs of facilities currently on line. It includes only a portion of those fixed costs.

Q Is that it?

A I think for now. If you want to probe deeper --

Q Let's begin with operating costs. Now, operating costs, obviously, include fuel costs?

A Yes, they do.

Q And it obviously includes all of the general costs which arise from operating a station such as the men there to operate it?

A That's correct.

Q And the other day to day costs that you have?

A That's true.

Q I take it it would also include maintenance costs?

A It does include it.

Q Any other element? Are taxes included?

A I don't think we included them in the variable component.

Q I take it if we were to go back to your Exhibit C, Doctor - -

A Yes.

Q - - we might be able to relate these to specific items that you have used in your program. Looking at page 7 of 24, one sees in the middle var. O & M, variable operating and maintenance?

A That's correct.

Q I take it the items I have read would be included in that column?

A Correct.

Q Next to that is energy and I take it that's the actual cost of the fuel used in the generation?

A That's correct.

Q And next to that on the other side is ~~card~~ Cash, which I take it is carrying charge?

A That is correct. That's not included in the operating cost.

Q What is included in carrying charge?

A For plants one through eighty-seven, we include only fixed operations and maintenance expenses.

Q What is a fixed operation and maintenance expense?

A Fixed operating and maintenance expense would be, I shouldn't say operating. I should say fixed maintenance expenses. There would be a cost associated with the maintenance of the plant without accounting for operations.

For example, a plant requires a watch person to make sure that no trespassers enter the premises, so that, for example, would be included in this charge.

Q Okay. Now, this does not include, I take it, any capital carrying charges? In other words, this does not --

A That is correct. It does not.

Q No return and no taxes?

A That is correct. Not for those plants. For plants one through eighty-seven.

Q You keep saying one through eighty-seven. I can't find those on mine. Are they both on page 7?

A Note on sheet 1 of 24 in Exhibit DSC, under the heading option, to the left of the page, there are some plant options noted and next to each of the plant operations is a number. I'm referring to plants numbered one through eighty-seven.

Q And what is the capacity, megawatt capacity of the one that ends eighty-seven?

A. I cannot hear you, sir. Would you repeat that, please?

Q What is the megawatt capacity of the plant that is number eighty-seven on your list?

A. Sixty-five.

Q That's right above 474?

A. That is correct.

Q Now, for all of those plants, there's no carrying charges?

A. That is correct.

Q That would include depreciation, I take it?

A. There are no charges incorporated in that column other than what I have defined as fixed maintenance.

Q Now, looking at the 474 number, which I take it is Salem 2, is that not right?

A. That is correct.

Q Now, does that unit have associated with it any costs other than those that we have discussed?

A. In the operations - - oh, yes. On the carrying charge, yes. It includes depreciation. It includes taxes.

Q Return?

A As well as fixed maintenance.

Q Fixed maintenance?

A Yes. It includes fixed maintenance as well as do the others.

Q It includes all of the other components?

A Yes.

Q Does it include a return on the investment?

A That's factored in in a slightly different manner.

Q How is it factored in?

A It is factored in through the category capital. Let me take a moment, please.

(Pause)

A (Continuing) I guess here we are dealing with the incremental cost option. So there would not be a carrying of - - there would not be a capital charge. I was including only charges that would be in addition to those presently incurred by consumers. So since Salem 2 expenses have been virtually completed and have been incurred, there's no way of eliminating those charges to consumers. And since we are dealing here with incremental costs only, the entry under capital would be zero. However, in the event we do include plants such as the Limerick facility or any of the generic options where incremental costs would be expended in the future, in that case, we do include capital charge. So for example, let me direct your attention to say sheet 13 of 24, under option 102, generic call three, you will note that there is a capital charge associated with that option.

Q How can you tell, Doctor, whether this is an incremental or a full cost computer run?

A Well, the question was in regard to all options we employed incremental cost as a general principle. In addition, with regard to the Limerick facility, specifically, we distinguish between what we term the full cost and the incremental cost option. This was necessitated by the fact that the Limerick facilities are partially complete so they're really in a unique situation as far as PECO's generating mix is concerned.

PECO's general expenses which find that either plants that are already on line or in case of Salem 2, just about on line, or on the other extreme, generic facilities which have not been commenced, insofar as their construction is concerned. The only exception to this is the Limerick facility which is partially built and so therefore, we distinguish between the full and incremental cost, specifically with regard to the Limerick units.

Q Now, Doctor, you seem to be making various gradations here between generating plants?

A That's correct.

Q The first gradation, I take it, are plants that are presently installed, and presently on line. For them, we only include in the analysis operating costs and fixed operating and maintenance costs, is that not correct?

A That's correct.

Q Then we have another group of plants who are kind of a category away from that which I think includes only Salem 2 at this point?

A That's correct.

Q And for Salem 2, we include operating costs, fixed operating and maintenance costs and depreciation?

A That's correct.

Q But no return on investment?

A That's correct.

Q And no taxes?

A No. Taxes are included in here.

Q Taxes are included?

A Yes. I mentioned that before.

Q Then finally, we have Limerick and generic plants where we include all of the things included for Salem and something in addition, is that not correct?

A That's correct.

Q What is the addition?

A The addition is the return on investment.

Q Why do we distinguish between return on investment for Salem 2 and Limerick?

A Because we were - - our question was to what degree will consumers incur extra costs as a consequence of the imposition of new facilities? In the case of Salem 2, the plant has already been capitalized and presumably is entering the rate base and there was no question as to what the incremental costs were with respect to Salem 2. With respect to Limerick, this is precisely what is at issue and the model was developed in such a way so as to address a number of pertinent questions that applied to this proceeding.

For example, let's talk about the older plants just one minute. You might ask why did we exclude all costs other than fixed maintenance from the calculation of the old plants? Well, the answer is the following: In order to compute the effects of all these other factors, we would have had to request data regarding capitalization of all these other plants and this would have lengthened the analysis substantially. Since, in our opinion, the inclusion of these costs would only have biased our results in favor of lower reserve margins as I will point out later, I'm sure, in this cross examination. We felt that it was not germane to the issue at hand.

Likewise, in the case of Salem 2, the issue of capital, total capital cost for Salem 2 was not at issue because the incremental cost of including the Salem 2 or excluding it was not germane to the question of what would be and what would not be included.

In the case of Limerick facilities, on the other hand, these questions are germane and therefore, we have undertaken a number of analyses of the Limerick facilities, including assumptions which impute the full capital cost of these facilities, specifically including costs that have already been expended by the company and alternatively, costs that apply just to the portion of the construction budget that has not already been undertaken.

For the generic plants, we invariably include the full cost.

Q Referring you again to table 1, Doctor, you there show various columns across the page. Now, the first column is entitled Demand. I take it that depicts the company's load forecast projections and where it says ESRG, it projects Dr. Stutz' load forecast projections?

A. That is correct.

Q I take it the choice between those two for purposes of whether to build Limerick or not to build Limerick is not particularly significant, is that correct?

A. It is not at all significant.

Q I take it we can see that on table 6 where it can be seen that two cases of the eight which are put together there, which differ only because of the load growth selection, doesn't make any difference to the results?

A. That's very true.

Q. And I guess that would be case two and eight would be the two - -

A. That's correct.

Q. Now, you show a second column on table 1 which is titled forecast assumption cost. Now, does that refer to the cost which you assign to future generating plants, and by that, I mean capital cost of construction. And in addition, various operating parameters and inflation rates?

A. That's correct.

Q. Are those basically the three major cost assumptions?

A. I should mention, too, that the differences in terms of capacity factors assumptions as well, and that is also subsumed under the term cost even though that is strictly speaking, incorrect.

Q. So let me just repeat that if I can, to get the concepts in mind of the first is a difference in capital cost assumptions between you and the company?

A. Correct.

Q. The second is a difference between capacity factors between you and the company for say a coal plant or nuclear plant?

A. Yes.

Q And the third is a difference in inflation rates or discount rates?

A. Inflation rates, discount rates, escalation rates.

Q Now, the plant construction plan column, I take it, reflects a difference between what you have determined to be an optimum construction plant and that which is presently being pursued by the company?

A. That's correct.

Q Now, in the year column, you show three years, 1981, '87 and '92.

A. That's correct.

Q As well as a total column?

A. That's correct.

Q Now, the total column, as I understand it, represents total social costs as we have previously defined them from 1980 to 1992, is that not correct?

A. I believe it is '81 through '92.

Q Okay. Now, the three years that are shown are the years in which you have actually computed through your computer analysis as social costs?

A. That's correct.

three

Q Now, between those ~~two~~ years, you have not made actual computations, is that not correct?

A. That's correct.

Q You have, in deriving the total that you indicate extrapolated?

A. Interpolated.

Q Interpolated?

A. That's correct.

Q Between the years 1981, '87, 1987 and '92, is that correct?

A. Yes. That's correct.

Q Would you agree with me that that injects a potential error in that where there is a significant change in the generating plant mix in between the years indicated, say years '81 to '87, say there was a change in 1985, that change could have significant social cost consequences as you measure them, but the interpolation technique would not fully reflect the change?

A. I would submit that this is the source of minor error. In my judgment, major error would not result from this interpolation procedure.

Q Suppose the change occurred in 1988? Would the error be more major than one/that occurred in 1986?

A. I can't make a judgment on that.

Q Would it assist your judgment if there were more years following the change? To the next measurement point?

A. I don't wish to comment on that. I would have to run the program in order to assess the nature of the error, completely. I should add that this is only a potential source of error. In my judgment, it is not consequential in terms of the statements that I make in my testimony.

Q. But I take it to be sure, one would have to run the program?

A. That is true.

(Transcript continues on next page)

Q Now, you have used different reserve levels in your re liability analysis, is that correct?

A That is correct.

Q Now do I fairly summarize your proposal with respect to reserve reliability , Doctor, as being the company should not employ a standard such as it does now which is a fixed reliability standard of one day in ten years but should employ an economic analysis?

A Most certainly. That summarizes my feelings.

Q And the economic analysis is an analysis which compares the cost of curtailment and by cost of curtailment we mean the cost of shutting a person off who wants electric ity who can't have it because we don't have enough generating plant versus the cost of building a generating plant to supply it to him, is that correct?

A I think that is an inaccurate representation of what I describe as the cost of curtailment. I would describe it in a slightly different way. It is not the way you said is incorrect. The tentative remarks don't reflect the spirit of this undertaking. In the event that the total generation capacity of the company in addition to what it can reasonably import would not be sufficient to meet the load, then there is certain consequences that ensue.

We disaggregated these consequences and have attempted to assess a cost with these various consequences.

Consequences included in this procedure include such things as interruption to customers under a series of interruptible rates involving a reduction and then they rank to actual curtailment at the extreme end of this analysis, so describing this as a situation of shutting off power, I think is really missing some of the spirit that underlines this mind.

Q But your proposal, Doctor, does it not include as a measurement of the cost of actually shutting off power to various persons?

A It includes that as one among several components, yes.

Q And you include that in your economic tradeoff?

A That is correct.

Q Now, Doctor, I take it real 1979 costs means the dollars shown under that column have been trended back ~~in~~ with an appropriate discount rate?

A They have been discounted, correct.

Q Now, Doctor, I note that in the first note at the bottom of the page it says: "Defined as total production and curtailment costs plus capital costs of new plant net ~~over~~ of return and income tax." Now that refers to your total social cost.

Now is that net ~~over~~ of return ~~in~~ and income tax as to all plants, the old ones as well as Limerick?

A It is assuming net of return for the old plants and income tax for the old plants. In the case of Limerick, I suppose this was run under -- yes, I guess that is, strictly speaking, not quite true for Limerick.

Insofar as we used incremental costs, we include that the return relative to that incremental cost, if we use the full cost, it is relative to that full cost with the exception of Limerick, I suppose that is true.

Q Or with the exception of your generic coal unit in other cases?

A Yes.

Q Now I take it you include a return, what do you do with regard to income tax?

A With regard to income tax, I think that was intended to reflect the situation for the older plants, so that we exclude Limeric and generic because the representation there in that is not quite accurate.

Q So for Limerick, you would include both return and income tax?

A That is right.

Q How do you determine the return ~~on~~ and income tax on Limerick, Doctor?

A Let me refer to my testimony, if I may. I don't keep all of these numbers in my mind.

Q Sure.

A The return was equal to what we defined in our scenario for the discount rate. That is the return that we employed. The income tax, I can't find precise reference in my testimony to income tax. The number that sticks in my mind is three per cent, but I can't verify that from a perusal of my testimony. If necessary, I will provide that later on. I think it is on the order of three per cent.

Q Now it is your testimony then that the return on Limerick and other generic and future type plants equals the discount rate that is employed?

A That is what we employed for purposes of this model. You always have a problem in running a model as complex as this in the choice of everyone of your parameters, so to some extent, I have to take responsibility for that number and I accept that, but I don't think it would be correct to state that I have undertaken an exhaustive analysis of future returns on particularly allowed returns on investment as determined by the regulatory bodies in 1985 through 1990, so this represents a number that we felt is reasonable citing it equal to the social rate of return, but one shouldn't take it too serious.

Q I promise, Doctor, I won't try to make you a rate of return witness.

Now, Doctor, you indicated taxes were taken in a three per cent rate.

A As I said, I don't recall precisely. I would have to check that with my staff and review my testimony once again. I thought I could extract it through a perusal of my testimony.

Q Well, the specific number does not interest me. Was it a flat rate?

A It was for the purpose of this model.

Q Flat rate?

A Yes.

Q How have you reflected the investment tax credit?

A We have not.

Q How about accellerated depreciation?

A We have not.

Q Would not the investment tax credit and accellerated depreciation offset to some degree the rate of return requirement for future plants?

A Yes, I would agree. However, I don't think it is very consequential in terms of the outcome of this program. I would say maybe talking about a difference between an annual fixed charge rate of say 16 to 18 per cent. I don't know exactly how it would come down, but in my assessment, it would not be consequential. It is a problem I recognize in the analysis, but I decided not to undertake an exhaustive analysis in this area.

I think the number we are using for a fixed charge is applied to the cost of the facility or within ball park figures given the uncertainties involved in future estimates.

Q Would you agree with me, Doctor, when you take an investment tax credit, you get an immediate tax deduction?

A Yes.

Q And assuming the time value of money, you have that deduction for a substantial period before it is flowed back?

A That is true.

Q Would that not increase the significance of that as an item in your planning horizon?

A It would indeed. It is a question of how consequentially they pertain to the output of the model. In my judgment, although it operates in the direction you indicate, sir, it is not of major consequence in determining the principal results that emerge from the calculations employed in the model.

Q But you have not run the model with that included?

A No, as I indicated, I have not.

Q Now, Doctor, you show four separate cases in Table 1. Can we agree, Doctor, that for comparative purposes, the only cases we can compare are the two PECO demand cases, one against the other and the two ESRG, one against the other? In other words, you are comparing apples to oranges?

A Well, it depends how the apples and oranges relate to one another. For example, if I show an ESRG case emerges with lower costs than the PECO case, then if we note the fact that the ESRG cost assumptions are relatively pessimistic as compared to PECO cost assumptions, generally speaking, although I can't speak to all the particulars, then we can, in fact, make that comparison, but if anything, the ESRG cost assumption will buy us the total cost upward so employing PECO assumptions to be sure would lower the cost estimate, so I think in certain cases one can make those comparisons.

Q Well, Doctor, I am talking about comparisons where you are comparing social ~~cases~~ costs at the company's load forecast versus ESRG's load forecast. In that instance, aren't you comparing costs that have included in there different levels of energy consumption and, therefore, different levels of energy-related costs?

A I don't quite understand your point. What we are saying here is that given a series of assumptions, let's assume that these are the assumptions that materialize, these are the assumptions in regard to future possibility, let's assume they materialized and let's assume that we compare, given these assumptions, that a particular construction plant that certainly can be compared for purposes of assessing optimal versus the imposed generation plan of PECO. That would certainly disaggregate the effect of the PECO construction plan as compared to the effect of running what we turn an optimal construction plan, so in that respect, you are correct.

However, we might want to make a different comparison. We might want to compare what the social costs will be of PECO construction plant as attempted in the first line under that table with what the cost would be in the event that ESRG assumptions are realized, number one, and number two, that we optimize in the way suggested by the ESRG model so that kind of comparison, I think, is quite reasonable although it is in variance with the comparisons that you are suggesting.

Q At Page 5 of your prepared testimony, Doctor, you testified that the model was run, by that you mean the ESGEM model was run only for target reserves of six, 14, 22 and 30 per cent, is that correct?

A That is correct.

Q And I take it what you have in fact done is you have run the model for each year, 1981, 1987, and 1992 of each of those reserve models?

A That is correct.

Q And you then have compared different social costs, and let's remove from consideration at this point the different generating plant options and say you were looking at reserve margins to decide what is the best of those. You chose comparative social costs for this reserve ~~of~~ margins, is that correct?

A That is correct.

Q And you based your comparison on, how many figures in front of you, 12 figures, correct?

A That is correct.

Q And you pick an optimum reserve margin based on the lowest social cost for 1981, for 1987?

A No, that is not correct.

Q Why is it wrong?

A The problem with the way you describe this is, in fact, we run the model at a given reserve margin for the three years taken as a whole and then we calculate together the present value calculation, the net present value for those three years and then we make the comparisons between the various reserve of margins on the basis of the total discount for social costs for each reserve margin.

Q Are you telling me, Doctor, that you make a choice as to the proper reserve margin based on the total three-year analysis?

A That is correct.

Q How did you arrive at your 14 and 22 per cent in this procedure, then, Doctor?

A I compared the social costs in the manner that I have described for a reserve margin of 6, 13, 22 and

30 for a number of scenarios that I considered realistic. In general, these involved the ESRG load forecast as well as the ESRG cost assumptions. I attempted to focus primarily on what I have termed in this testimony the ESRG low cost assumption. Note that I believe this is more realistic than the high cost assumption. In fact, if presented. I would submit that the high cost assumptions are more realistic of the two, but I wanted to employ assumptions that were conservative as possible.

For runs employing these assumptions, the social cost was minimized at either 14 or 22 per cent.

Q All right. Let me see if I understand. Let me take a step back, Doctor. What we are doing is we are making computations for three years worth of data.

A That is correct.

Q 1981, 1987 and 1992?

A Correct.

Q We are trying to determine from that analysis two principal things. What the appropriate reserve margin should be and what the future generating plant should be?

A That is correct.

Q And we run those analysis in conjunction or do we run them separately?

A We run them in conjunction. The reserve margin implies a particular generating mix.

Q Doctor, on Table 1, what reserve ~~of~~ margin is associated with your total figure for the ESRG? The low ESRG, the fourth case indicated, that is the 6906.3 ~~7960.6~~3 figure.

A I would have to refer back to my computer runs to establish that.

Q Would you do that?

A Yes. I will make a note of that.

Q You mean you can't do that now?

A Well, it might take me as long as five minutes to go through all this material now. If you would like me to do that, I would like to accommodate you, but it would delay this somewhat.

Q Would you agree with me today that the 6906 is an interpolation for the 12-year period based on the three years based on the numbers shown? In other words, within that 69063 there is the 542.9 ~~5,240~~ and the 577 .7 ~~per cent~~.

A Oh, definitely.

Q And this is the ESRG preferred case, I take it? Is that correct?

A I wouldn't characterize it as a preferred. I would characterize it as a conservative type - preferred.

As I indicated, the ESRG high are the ones I consi'ered to be more realistic to the ESRG low.

Q Now, Doctor, you have testified in choosing the appropriate reserve ~~of~~ margin out of the four calculations that were made, you used a three-year analysis whereby you combined the individual indicated social costs and the preferred generating plant expansion program to determine which was the lowest social cost, is that right?

A That is correct.

Q On a three-year basis?

A Yes.

Q Did you choose the generating expansion program before you chose the reliability criteria?

A The reserve margin specified initially and the social cost as well as the generation mix is calculated so as to be consistent with the reserve margin, but it is the reserve margin that is specified.

Q What do you mean specified?

A We start with the six per cent reserve margin. We specify that. Then we calculate the generation mix given the six per cent. Then generation mix associated with the six per cent, we then simulate production for the system and assess production cost. That is the cost reported as associated with the six per cent.. We do that for all the years in question and discount.

We then proceed to 14 per cent and go through the same procedures and then again the 22 per cent and again the 30 per cent.

After this entire calculation is completed, we compare the discounted value for the various reserve margins and select what we determine as an optimal reserve margin based on criteria of minimizing social costs.

Q Have you previously selected a capacity expansion program which is optimal to be used when you are making your analysis of what the reserve margin should be?

A No, the reserve margin determines the capacity. One is contingent on the other. I could amplify precisely how this is done in the model if you desire, sir.

Q Doctor, if the three numbers that go into making the 69,063, are those all stated at the same reserve margin?

A Yes. I am confident that the report in this table is with respect to the optimal reserve margin, whatever that might be, for the scenario in question. Obviously for the PECO case, this is not a real consideration.

In the PECO case the generation mix is taken as given, but for the plant construction plans noted in Table 1 as ESRG construction plan, we chose the 1979 costs associated with what we term the optimum reserve plan.

Q And that could be anywhere from 14 to 22 per cent?

A It could be zero to 22 per cent.

(Testimony continued on next page.)

Q How can we have an optimal reserve margin, Doctor, which varies, if we made a three year analysis to pick out the one that was best? I thought in responding to an earlier question of mine - -

A. No, you are misunderstanding, sir. For a given scenario, we are talking about really two scenarios among the four indicated in table 1. Those are the third and fourth scenarios where we indicate under plant construction plan, ESRG. Now, all I'm saying is for three, we chose a given reserve margin which we applied throughout and for four, we chose a given reserve margin that we applied throughout. It is reasonable that these might differ, given the fact of the input assumptions of it.

So what we are saying is that given the input assumptions specified in table 1, for example, under the third scenario, assuming the PECO demand forecast on one hand and the PECO cost assumptions on the other, particular reserve margin will be optimal. Say 22 percent, which is, to the best of my recollection, precisely what we had in mind here.

If we employ ESRG forecast demand, and ESRG costs. Then in fact, the ESRG optimal reserve margin we apply. For any given scenario, we apply a consistent reserve margin throughout.

Q 22 percent?

A. 22 percent, 14 percent, whatever.

Q Now, Doctor, the calculations have been made at discreet reserve level, 6 percent, 14 percent, 22 percent and 30 percent. Now, am I correct that based upon your calculations, you only know what the social costs are at those four discreet levels?

A. I should indicate these are target levels. There may be some small deviations from those target levels which emerge in the course of optimal generation. These are of the order of two to three or two to five percent, so the actual reserve margins that emerge from the program may be of the order of say, 22.3 percent or 22.1 percent. These refer - - the reserve margins that we have been referring to heretofore in this cross examination are target reserve margins.

Q My point, Doctor, is you have - - let us say that you have calculated the social costs for each of the four levels and the best social cost indicated to you is 22 percent. That is the lowest social cost?

A. Yes.

Q That isn't the one you would select?

A. That's the target reserve margin that they would select.

Q Isn't it in fact true that all that calculation would tell you about social cost relative to reserve margin is that the lowest social cost relative to reserve margin would fall somewhere between 14 percent and 30 percent and that you would not know whether 22 percent was, itself, the lowest level?

A. That is true. Except for the fact that socially all the reserve margins that we calculated were assumptions that we considered a plausible range between 14 and 22 percent. So as a consequence, after completing the analysis for a very large number of scenarios, I felt that even had we run the analysis, say, at reserve margin intervals of 1 percent, which we could have done, in principle, that the optimal reserve margins would, in fact, apply it some value between 14 and 22 percent.

Q Doctor, referring to Exhibit C, now, this is a sample ~~gem~~ ESGEM run, is it not?

A. That is correct.

Q And the one I am looking at is at pages 15 and 16 of 24 and it is identified as ESRG construction program, ESRG demand forecast?

A. Where does it say construction program?

Q It says that on the cover sheet before page 7 of 24. And ESRG low cost and full plant capital?

A. Where does it say ESRG construction program? I want to identify the page. Oh, under Exhibit C. Okay. I see. Fine. Thank you.

Q Yes?

A. You are referring to sheet 15 and I couldn't find it on my sheet.

Q Now, on sheet 15, this is for the year 1987 as we can see up in the left hand corner?

A That's correct.

Q And it is for 22 percent targeted reserve level?

A That's correct.

Q And the total system cost which is the total social cost is 577.7, is that not correct?

A That is correct.

Q Now, this computer run that you have provided here as Exhibit C is in fact, the computer run that goes along with the 1987 figure on table 1 under ESRG, ESRG low, ESRG plant construction plan. Is that not correct?

A That's correct.

Q And that's 22 percent?

A Yes.

Q Referring you to sheet 8, we there have the reserve margin of 14 percent for the year 1981, and we have a total social cost of 595.1. Now, that sheet is, in fact, is it not, the sheet which is comparable to or in fact the development costs of the 1981 figure shown on table 1 under ESRG, ESRG low, ESRG, is that not correct?

A Yes. It is.

Q So in fact in your cases you increase or decrease reserve reliability margins, is that not correct?

A. No. These are just sample runs. They are not taken to indicate our choice of the optimal reserve margins. They are just meant to display the output from our computer runs. They don't imply anything about these reserve margins that we selected as optimum. In fact, they don't show the discounting procedure at all. As you will note.

Q This does not show the discounts?

A. It doesn't not show the discounting procedure over time. It shows the discounting procedure year by year, but it does not, in any sense, imply a comparison of the reserve margins. It is merely a display of output from our computer program based on ESRG load growth assumptions and ESRG low plant data assumptions.

At 14 percent reserve margins noting sheet 8 of 424, for example.

Q This is merely a display of what your computer produced?

A. Precisely true. As I said, I do not have at hand in a readily available form a comparison of the discounted social cost. So I can't tell you for that reserve margin which is the preferred reserve margin. I indicated that the optimal reserves range for what we consider to be plausible assumptions 14 to 22 percent. That's the only statement I'm making about optimal reserve margins to this point in the cross examination.

Q Okay. Now, you have indicated that this does not show discounted costs?

A It does not show the sum of discounted costs over the three years and a comparison of those discounted costs with discounted costs associated with other alternative reserve margins. It merely shows the discounted cost for a given year at a specified reserve margin.

Q Doctor, referring you, again, to Exhibit C, sheets 16 and 18 - -

A Yes. You are referring to number 15, 16 and 18, aren't you?

Q Well, just 16 and 18 are the only two sheets we have to compare for purposes of this question.

Doctor, you there show a sheet on sheet 15 we see that this analysis for 15 and 16 is a 22 percent reserve margin. For the analysis on pages sheet 17 and 18, we see that that's a 30 percent reserve margin as shown at the top of page 17?

A That's correct.

Q 17?

A That's correct.

Q Now, looking at the loss of load probabilities, Doctor, I note that despite the fact that we have increased the reserve margin and therefore, one would presumably think ~~the~~ system reliability, we have a greater number of brownouts at line 115, which are voltage reductions. By comparison of 2.3 for the 30 percent reserve margin versus 0.2 and we have a greater number of blackouts at the 30 percent margin versus the 22 percent by 0.2 versus 0. Can you explain to me, Doctor, whe~~re~~y increasing the reserve margin results in a greater amount of load curtailment?

A. Surely. This is a simulation program which means that we generate random numbers and on the basis of those random numbers, attempt to calculate what production costs would look like given certain eventualities. Now, any simulation program on occasion, may spew out random numbers that are in the extreme of the range and presumably that's what happened in this 30 percent run, we are not talking about major discrepancies here. We are talking about fairly minor discrepancies.

What I assume occurred was in the 30 percent run at the time of system peak, for example, we had an outage in, say, a major baseload plant. This is a random event. We do attempt to allow for this by averaging over 25 simulations, and we find that in general, averaging over 25 simulations will produce results that are to our satisfaction, accurate results.

However, there are certain minor anomalies which can occur with respect to a simulation program of this type.

MR. HALL: Your Honor, I wonder if this would be a good point for a brief recess? I would note that I probably have at least two more hours for Dr. Shakow. I would propose to finish if others wish to stay. It is up to Your Honor.

THE WITNESS: I have an 8:00 o'clock plane and anything consistent with that constraint would be fine with me. Two hours is no problem.

THE ADMINISTRATIVE LAW JUDGE: Let's take a brief recess.

(A brief recess was taken.)

THE ADMINISTRATIVE LAW JUDGE: Are you ready?

BY MR. HALL:

Q Doctor, could you define for me what the investment tax credit is?

A Investment tax credit is a percentage of new investment that the Government allows the corporation to subtract from its taxes.

Q Now, Doctor, the conclusions of your study, or I guess the best pictorial representations of what those conclusions are would be on tables 6 and 10, is that not correct?

A I have to look at 6 and 10.

Q That's page 20 and 57?

A We can address those tables. I won't characterize that as in any sense summarizing the overall testimony. But it there. It is fair game.

Q I would agree with you, Doctor. I merely found it most useful in my efforts to understand the process.

A I appreciate that.

Q Now, looking at table 6, it there shows eight cases, is that not correct?

A That's correct.

Q We have already gone over and discussed what's in the load growth column and the plant column and the capital cost column. Not the capital cost column. Is that correct?

A Would you repeat that?

Q We have discussed what is meant by PECO and what is meant by ESRG and what is meant by PECO and ESRG low in the plant cost column, is that not correct?

A That's correct. We have done that.

Q I note that under case two and case eight, Limerick is selected?

A That's correct.

Q I take it the purpose of each of these cases is to include various different assumptions and see what is the optimal new capacity under those assumptions, is that not correct?

A That is precisely correct.

Q Now, under the PECO plants costs and the incremental capital costing method, Limerick is selected, is that not correct?

A. That is correct.

Q And it makes no difference whether you have got the PECO or the ESRG load growth?

A. That's true.

Q What is the incremental capital cost method, Doctor?

A. Incremental capital cost means that the account only shows costs of the Limerick facility which have not already been committed. As I understand it, the company has already committed roughly 900 million dollars, and that is not accounted as part of the capital cost under this assumption.

Q It is your understanding that's $900 million in the study?

A. I won't swear by those figures. That's a number that comes to mind. I just want to mention that for purposes of identification here, I don't want to in any sense commit myself to it.

Q You say we don't consider the sunk capital costs, and by that I mean what you refer to as the $900 million?

A. That's right.

Q Does that mean that in our generating plant computer program runs, when we are costing Limerick, we only include capital carrying charge costs, i.e. return, depreciation and taxes, as to that amount which is yet to be expended to complete the plant?

A I believe so, but I would have to refer back to my data sheets in order to confirm that.

Q Could you do that, please?

A I would say for fixed maintenance, that would be computed relative to the plant as a whole. No, I don't believe that's true. As a matter of fact, I think that the income tax, et cetera, would be computed on the entire capital cost of the plant. Yes. That's what we did. That is proper.

Q So in other words, it is your testimony that what you do when you incrementally cost something is you include all of the variable operating and maintenance costs as we define it in our earlier discussions?

A Yes.

Q The energy costs as we defined it?

A Maybe I can rationalize that. If that would be appropriate, I would be happy to do so at this point.

Q Let me run through the list and I will let you go on.

A Fine.

Q We include all of the taxes relative to the entire capital cost of the plant?

A. That's right.

Q But we only include the return applicable to the incremental part of the investment yet to be expended?

A. Yes.

Q We only include the depreciation applicable to the incremental part yet to be expended?

A. Yes.

Q Why do we split the return and the taxes in that fashion?

A. I think - -

Q . What I had in mind was the following reasoning. Let's assume that the plants were canceled. Then the question is what would be capitalized and included in the rate base and would remain as a kind of a sunk cost from the consumers - -

A Don't forget, everything we are doing here is from the standpoint of optimizing social costs which I have defined as costs from the perspective of the consumer. Now, under the assumption that there's no way of my knowing this, under the assumption that cancellation would still lead to a capitalization of this plant so that the ratepayers would have to assume at least the return on that figure, it seems reasonable to run a scenario in which we excluded that from the incremental cost which distinguishes between the case where we keep the plant in and where we cancel. If we cancel, obviously, I shouldn't say obviously, but my guess is that the company could make the argument that it should not pay property taxes, for example, on plant that's basically excluded from the generating capacity of the company. Now, maybe that wouldn't be the case. And a future litigation, some other results might arise, but at least it seems reasonable to make that as one of our 25 assumptions.

We make runs in addition to the eight described here and it seemed as if that was at least a reasonable thing to assume and to pursue.

Q And that is to assign total tax cost but only partial return costs?

A Yes. Exactly. You follow my reasoning, I see.

Q No.

A You don't?

Q No.

A Should I go through it again?

Q If you can shorten it, yes, please.

A Okay. We are asking the question what would be the impact of a cancellation as compared to the maintenance of the facility, and the completion of the facility. Now, there's been certain amounts of moneys expended on the plant. If the plant were canceled, it wouldn't be of use to anybody. But nonetheless, it is possible it could be capitalized and included in the rate base.

There's no way of knowing exactly how the Commission would proceed on this matter. But that's at least a possibility. If that's the case, the only costs that would remain for the consumer would be the return on that portion. I'm assuming that for tax purposes, one could get a write-off on the plant. That's why one makes the distinction between taxes on one hand and return on the other.

Q Now, Doctor, turning on table 2, page 6, you show a 600 MW coal plant as entered into case two or your case two assumption. Where do you get that plant?

A Where did I get that plant?

Q Yes.

A That is one of our generic options. As you may recall from the description of the program we employed a fairly sizable set of generic options which we allowed in principle to enter the generation mix. This included a large number of plants. It included, for example, three distinct types of coal plants ranging from coal plants with the capacity of 300 megawatts to coal plants with a capacity of 900 megawatts. It included, in addition, a nuclear plant which we termed a generic nuclear plant.

It included various combustion turbines, combined cycle facilities and so forth. What this table is indicating is that of all those generic facilities, the one that enters the capacity mix is the 600 megawatt coal plant under the assumptions indicated.

Q In all of the other cases, Doctor, that are indicated here, do you not include 300 MW coal plants? In other words, where you've got 2400 coal there, that is 300 MW coal plants?

A Yes.

Q Isn't the 1500 PM 300 MW plants? Five of them?

A Yes. I think it is indicated. This table doesn't really disaggregate the cases where we would have say, a 600 megawatt coal, or 2300 coal plants. That's not quite right. What's indicated is the total capacity of the generic option. I can't tell you from looking at this table exactly the technology that's involved in the particular scenarios.

Let me - - however, referring, let's refer again, for example, to Exhibit DSC, say sheet 14. Note under option 102 that the optimal generation mix under the assumptions of ESRG load growth and ESRG low plant data assumptions, the generic technology that enters the mix is generic coal of 300 megawatts and two of those enter the mix. And this is indicated under 102 by the term G coal three, which suggests a coal technology where the unit size is 300 megawatts, then under the megawatts capacity, 600 is indicated, which suggests that we have two of those facilities entering the mix.

Q And your social cost minimization criteria indicated to you that for PECO plant costs and incremental capital costs, it was best to construct the two Limerick plants and in addition, 600 MW/coal plants?

A. That's correct.

Q For a 30 percent reserve margin?

A. That's correct.

Q Do you know how much the 600 MW coal plants add to the cost analysis?

A. I cannot tell you offhand. If I'm not mistaken, I have - - I'm not sure if it was in response to interrogatory or some of the other documentation I read, I did come cross some indication that PECO planning for that period did incorporate at least one coal facility. So this is - - I should indicate that I think it is noteworthy that my model, given PECO's assumptions, generates an outcome that is fairly consistent with the PECO planning mix, as it is presently conceived. That would pertain to the reserve margins as well as to the generation mix.

Q Now, Doctor, I believe you indicated at one point in your testimony that indeed, if you do accept that incremental costing is the way to go and that PECO plant cost levels are the appropriate levels that indeed the Limerick units should be construeted and that is the best social cost alternative?

A. That's correct.

Q Now - -

A I hasten to add, of course, that I disagree pretty violently with those assumptions, so in fact, I'm not making the recommendation of this sort.

Q Now, Doctor, in determining whether to choose incremental or full costs as the appropriate costing methodology, you indicate two factors which must be considered, I believe.

A Yes.

Q The first and each of them go really to the same point which is the possibility of the company recovering its sunk investment in the Limerick units?

A That's true.

Q Despite their cancellation?

A That is correct, precisely. I should say cancellation is not the only alternative. One possibility is the company selling its shares in the plant. In which case the plant would be built, but the company would not assume any of the cost burden.

Q Now, have you made any study, Doctor, of the potential for selling the Limerick units when they go into service in the mid 1980's?

A I'm sure that is something the company is as anxious to find out about as I am. No, I have not.

Q You have not?

A No.

Q Now, Doctor, you spoke about tax credits, the potentiality of tax credits in the event that the plant is terminated and the company is unable to sell it, is that not correct?

A Yes. I should have mentioned, I did not, but I should also have mentioned the whole question I alluded to before as to whether the cost of an incomplete facility would be incorporated in rate base. I think that is very pertinent here as well.

(Transcript continues on next page)

Q And what is that option you just referred to?

A I said that this is the question as to whether the cost expended on an incompleted facility would be incorporated in the rate base.

As I indicated before, if they would be incorporated in the rate base, there is some justification for using the incremental cost.

Q And that is because the company would then recover its investment in that plant?

A That is correct, and from the consumer standpoint, the only difficulty would pertain to the incremental. They would have to pay for the sunk cost.

Q So it is your testimony that if, in fact, the Commission had adopted the policy of permitting the company or was inclined to adopt the policy permitting the company to recover for the sunk costs, in the Limerick Plant in the event the Commission were to order termination of the plant construction and assuming it had the authority to do so, if it decided to permit the company to recover those costs, the rate you should use is incremental?

A I didn't quite say that. What I said was that this would be a germane consideration. There are many other things to be considered. The tax situation has to be considered and the market for this power in addition would have to be considered if the company could refer its fuel costs, by assuming the power or by sinking the power.

Then I would propose using the actual cost measure.

Q Well, putting those two considerations aside, do you have any others to offer us in response to my question?

A Not at the moment, but I am sure if I could consider the matter, I would have a good number. I think it a very complicated issue.

Q Now referring to the tax credits, what provisions of the income tax code go to what you are referring to, Doctor?

A I don't care to discuss that. All I said in my testimony was that this would be germane in some sense to the degree that the company was forced to assume some continual payment as a consequence of this incompleted facility. It would certainly affect the matter of incremental cost, but I have not undertaken an exhaustive analysis of what provisions of the tax code are really here. All I am saying is this general category tax code is one of the factors that has to be considered in making this judgment.

I have not presumed to analyze the specific provisions that are applicable here.

Q I take it you presume there are some provisions there without having made an analysis?

A Well, I think one can justify this on a realistic ground. For example, let's consider property tax. If property taxes were waived on this incompleted facility, that means that the incremental cost of calculation would go up by a certain amount.

The difference between a cancelled plant and a plant undertaken would be more substantial in the event the company would have its property tax waived on these facilities, so I think one can conceive realistically of size where this general category tax would be relevant without going into the particulars in terms of the tax code.

Q I take it you have made no study of whether the Philadelphia Electric Company would have sufficient taxable income in the future or the past to be able to use any such tax deductions as the code might grant it as a result of losses incurred from the ~~capsulation~~ cancelation?

A If I were to make all the studies you suggest, it would be a very ambitious project.

Q One last question on this point. You have not included in any of your cost analysis and particularly your full cost analysis any factor, have you, for the uncertainties which relate to whether or not the company, in fact, will be able to recover its sunk costs in Limerick if that plant is terminated?

A Well, that is why we have run into a large number of scenarios. The purpose of scenarios formulation is to account for various alternative possibilities and why do we account for various alternative possibilities when it would be easier to stick to one, and we don't know what possibility is going to materialize, so scenario development, I would say, is an explicit response to uncertainty.

Q Doctor, in Table 1, Case 4, have you included any factor to reflect the risk which the company will experience?

A What table was this?

Q Table 1, Case 4. Have you included any factor to reflect that risk which the company will experience that it will not recover the sunk costs in Limerick if the plant is terminated, and by factor, I mean cost factor?

A As I indicated, it depends on the specifications here. I believe Case 4 in Table 1 was run in the full cost assumption, so that would be consistent, for example, with the assessments of the fuel capacity of Limerick to some other company.

As an example, I could give you our scenario as well.. That would be consistent with that, but what is important here to note is this was run under full cost assumption, so Limerick was accounted at its full cost assumption.

Q What is important to me, Doctor, is the answer is no, is that not right?

A I forgot the original question.

Q The original question is you have included no cost in your case 4, which is, as I understand it, your preferred case to reflect the potentiality that the company will not recover its sunk costs in Limerick. You have simply assumed that it will do so?

A That it will recover its sunk costs?

Q Yes.

A In effect, that is correct. I would like to correct my answer to that question ever so slightly. I would say it is consistent with the assumption that the company recover its sunk costs. It is also consistent with the assumption that none of the expense of construction budget is included in the rate base which would be an adverse assumption from the company's standpoint, so there are a range of consumptions that are consistent with that, so I spoke to hastily in response to your question.

It is consistent with that assumption, but it does not assume it explicitly.

Q In fact, there is no addition to the costs shown to account for the risk that the company will not recover from Limerick?

A The critical thing --

Q You can answer that yes or no and explain as you choose.

A Let's go through this again. Why don't you start the question once again? My memory is very short at this hour. I hear the question when you asked it but there has been an intervening comment in the question and I lose my mind.

Q In Case 4, Doctor Shakow, there are no factors, no costs, no consideration given for the fact that if the company terminates Limerick, it may do so by losing the entire existing investment in that plant.

Answer that yes or no and go on with whatever you want to say.

A No, that is one of the possibilities. I think the answer is no. The answer is yes to your specific question that it is consistent.

Q I don't want consistency. I want does it consider it or does it not? Are the costs increased as a result of this uncertainty or not?

A As I understand your question, I think the answer is yes, although the possibility exists that I haven't understood your question.

Q Well, I thought I was pretty clear. Why don't you try and explain to me how these costs have been increased as a result of the company's loss because of the termination of the Limerick plant?

A What we are trying to do, we are trying to distinguish a case where the difference to the consumer of a cancellation equals the full cost of the plant. That is the critical thing here.

Now if the company, for example, is not able to incorporate the expended construction costs in the rate base, then that would be a case in which a cancellation from a consumer's standpoint would mean that there would be no responsibility undertaken by the ratepayers for the plant. This would compare to a case where Limerick was completed and which the full cost presumably would be incorporated in the rate base, so the difference between cancellation and no cancellation is the full cost of the plant.

This would be true also under the scenario. If the company were able to assign all the capacity of Limerick, then the consumers would likewise not assume any of the responsibility as compared to the case where Limerick was incorporated and the generation mix was generated power and the consumers in that case would assume total responsibility, so what I am suggesting then is here we have two scenarios. One very adverse from the standpoint of the company and the other relatively desirable from the standpoint of the company and the contingency from the standpoint of the company and yet in both cases, the difference between the plant actually being included in the rate base and included in the generation mix and the plant not being included in the generation mix includes the full construction budget.

Q I take it, Doctor, the social cost, as you have measured them, of 6906 would be the same regardless of whether the company sold Limerick or merely ate it?

A Yes, that is right.

Q Doctor, would you turn to Sheet 14 of 19 of Exhibit A. Doctor, do you have that page?

A 14, Exhibit A, sure.

Q Now referring you to the section where it speaks of the use of incremental costs, I would like to read you the following passage and state my interpretation of it and see if you agree. It says in that passage, "It should be noted that the default option on Model 1 is the capital costs include only the incremental rather than the full cost of capital. If a plant has been in operation for 20 years, the fixed costs already committed do not play a role in the economic comparison with other plant. Current carrying charge and fixed O&M are relevant, however, and are included of fixed charges in the cost comparison. This default option can be waived for plant where cancellation requires full recovery of cost of its construction to date, either through tax writeoffs or assignment of catastrophe."

Now the initial paragraph in that would indicate

1136a that incremental costs should be considered where investment will be lost?

A Let's go back a little bit. The critical consideration is what the difference is between the inclusion of a plant and the exclusion of a plant. That is what I am trying to get across to you. Perhaps the phraseology is a little confusing, but as plant presently on line, it is clear when we retire the plant, the critical thing will be the application of the costs that have to be assumed by the consumer.

When we consider a plant that is presently under construction such as Limerick, the critical consideration again is what will be the difference from the consumer's standpoint between the inclusion of the plant and its exclusion. I think that is the point I am trying to get across here and it is, I think, consistent of what I had been saying over the course of the last 15 minutes.

Q Doctor, would you agree that the Philadelphia Electric Company could sell a plant presently on line and producing power?

A It could in principle, yes. I see no reason why not.

Q Why shouldn't we use the full cost for that as well?

A Because I guess for the plant on line, the only realistic option seems to be retirement rather than sale.

Q Well, Doctor, I guess you are correct. A /In principle, we could, I imagine, elaborate the model to incorporate the possibility of an assignment, say of plant currently on line. If that is the case, then we should include the full capital cost. I think that is fairly true. I should note though that in my estimation, were we to do that, it would merely confirm our results to even greater degree because what would happen is the cost parity of just the higher reserve margin would be still greater than it is under our present assumption and so it is a consequence that would be a greater tendency to optimize reserve margins at lower levels, so one can perceive the omission of this possibility as a conservative approach.

I will go through that again.

Q No, I can follow that very easily, Doctor, but I take it that would also depend, Doctor, if you are removing a unit from service when you put in your incremental base load plant, you are then removing capital cost to offset the capital cost of that plant, are you not?

A Yes,to some degree. I think there is a certain degree of ~~ex~~dis tortion that I will admit as a consequence of this omission. However, as I indicated, I think it opts in a conservative direction. In fact, the reason for our omission possibility as I indicated before is largely a particular question, we would have had to obtain data regarding the capitalization of all these old plants and it was difficult enough to similate the information regarding the new plant without magnifying the data requirement of the program and the reason we did omit to this information was because, as I indicated, we felt it would only tend to confirm our result. We could make our case obviously without using this dimension.

Q Returning to your, I will call it modeling, for lack of a better word, how have you represented in your programing the company's pump storage operations?

A The only distinction we make between pump storage and run-of-the-river hydro -- let me correct that. There is no effective distinction made between pump storage and run-of-the-river hydro. Both are considered energy limited options and enter the generation mix subject to an energy constraint, so we didn't really consider the effect of pumping exclusively. That again is to some degree a deficiency in the model, but I feel it rather consequential.

(Testimony continued on the next page.)

Q You didn't consider the cost of energy to pump?

A. To pump, precisely.

Q Is that not correct?

A. That's not included presently in that.

Q Now, how have you modeled, Doctor, the company's participation in the Pennsylvania, New Jersey and Maryland interchange? Or interconnection?

A. I would say only the crudest way. We distinguished b etween economy emergency and force. One thing. We attempted to employ our energy construction payments based on the economy imports, experienced energy consumption, I suppose, over the recent past. We derived the data from responses to interrogatories, and since the economy imports are provided under the power pool, this pertains directly to the experience of Philadelphia Electric in the power pool.

We specified emergency power as an option. We entered the rates associated with the emergency power as at the rates - - well, not precisely but at roughly the emergency rates associated with the PJM power pool, in that we costed out that kind of power at 10 percent above the most expensive PECO plant.

I understand that in fact we should have taken the most expensive plant in the pool, but again, we are into the same kind of problem as before. We would have had to find out all the information for all of the various facilities in the pool. So that was not practicable.

We had some fairly, I would say, abstract or simplified assumptions on the interconnects which probably are really exact representations of the reality, but we think are adequate for the purposes of this testimony.

Q Now, with regard to maintenance outages, how have you reflected those in your model?

A That's a fairly important part of our model. We designate a period of the year that we considered to be the maintenance period. We derived this maintenance period as a representation, simplified representation of actual maintenance practices by the company. I think it was in response to this document here, supplement number 6 to tariff electric Pa. PUC No. 25, which has some data on maintenance, and while we didn't model the maintenance for every particular plant, that enabled us to give a rough idea of when maintenance was practiced by the company.

The maintenance period that we defined is composed of weeks 17 through 23 of the year plus weeks 36 through 50. And that's defined as our allowed maintenance period.

Q And when a unit goes down for maintenance, Doctor, does it do it by a deration?

A Yes.

Q By that I mean you don't assume the unit is off for eight weeks or ten weeks entirely?

A That's correct.

Q What you do is if it was Salem 1, instead of putting it in for this half a year period which you allow me, you back it down to a portion of its indicated capacity?

A The precise method in which we do that is somewhat complex, but essentially it is a deration method. We feel this is reasonable, again, in light of the purposes of this testimony in that what we are really looking for is the cost of extreme events, that is cases where the plant is simply not available and particularly where this coincides with extremes in the load so as to create a situation of supply demand imbalance. That's what's going to generate social costs at the low end of our reserve margins.

Now, if we derate rather than assuming that the plant is not there, then we are assimilating a fraction of the capacity in our mix. And so the likelihood of experience and, say, costs due to blackout or other curtailment is less likely to be significant.

So we account this as a conservative assumption, even though strictly speaking, we should have modeled it precisely.

Q I take it it is a conservative assumption because it reduces the cost of curtailment. It reduces the numbers of hours the curtailment will occur?

A. In effect, yes.

Q Now, you don't believe the company's figures for what Limerick 1 and 2 will cost, do you, Doctor?

A. No.

Q Would you agree with me that about a ballpark difference between your position and the company's position is a total cost of the company's part of 3.1 billion and on your part, either 4.2 or 4.9 billion?

A. I think so. My memory is really rather weak, so I can't account for all these figures, but that sounds general.

Q I wouldn't give you bad figures.

A. I just don't want to take responsibility for them.

Q Now, in calculating the cost of Limerick, as well as the cost of your generic coal and generic nuclear options, and indeed in developing certain of your plant capacity factors, you have relied, have you not, on an analysis which was prepared by a Mr. Charles Komanoff, is that not true?

A. That is true. I would say not with respect to capacity factors. I have done a good deal of research on my own in the area of capacity factor. I am not going to implicate Komanoff in the capacity factor calculation. Komanoff's analysis is confined to an estimation of the direct 1979 dollar construction cost.

Q Okay. And this appears at pages 44 and 45 of your testimony, doesn't it, Doctor?

A I'm taking a look. Yes, it does.

Q Now, this is a pretty detailed analysis that Mr. Komanoff has done, isn't it?

A In my opinion, it is, yes.

~~Q And in your opinion, it is?~~

Q Could I summarize what Mr. Komanoff has done this way, and would it be fair, Mr. Komanoff has taken a publication which was put out by the Energy Information Administration, which publication, itself, took data from utility FERC form ones and classified that data in particular fashions?

A Yes. I don't know if he - - he may have referred directly to the FERC form ones. I'm not sure if it was via this indirect route. I don't know if you have been supplied with the latest publication by Mr. Komanoff. Unless my - - let's see. Does my testimony state that in there? That he went through this route particularly?

Q Doctor, your testimony indicates as does your answer to our request for the data that these were private communications between you and Mr. Komanoff?

A Yes. But he indicated that it was in FERC form one, specifically.

Q Well, Mr. Komanoff, as I understand it, has taken cost data with respect to nuclear plants and coal plants completed during a period of 1972 to 1978, is that not correct?

A I believe that's correct, yes.

Q And this data comes either directly from FERC form 1 or I believe you have indicated in a response to an interrogatory through a publication from FERC form one?

A Let me just check. That's possible. What interrogatory response was that?

Q Response one.

A It is taken from utilities annual - - assembled in the annual publication. Okay?

Q Yes.

A I guess that's ambiguous as to where he got it from. It just indicates that it's been so assembled.

Q Now, having taken this data, it is indicated that Mr. Komanoff applied some Handy Whitman Indices to it. Would you know how he did that, Doctor?

A I assume that he, in order to get his dependent variable in the form of 1979 construction dollars and given the fact that the reporting on these forms presumably is in current dollars, that he discounted these current dollars estimates by the real escalation rates as derived from the

Handy Whitman Index. So just so we could get a '79 figure.

Q Now, you - -

A That's what I assume he did. I have not communicated directly with Mr. Komanoff on that matter. This is really a presumption on my part. That's what I would have done if I was doing the analysis.

Q This material that Mr. Komanoff has provided to you, is it published anywhere?

A I have it on hand. However, the text states not for public dissemination, so even though I have it in hand, and can refer to it in the course of this cross examination, I am not impowered at this time to let it go. It is not copywrited material as yet.

Q You cannot provide us with a copy of it?

A I am not saying that. I could not today provide you with a copy of it. I would have to consult first with Mr. Komanoff.

Q You responded in response to our interrogatories you could not.

A I could not at the time of the interrogatories because I had not consulted with Mr. Komanoff. I have still not communicated with Mr. Komanoff. If compelled to do so, then I will, in fact, consult Mr. Komanoff. I should also mention that I think that a precursor of this analysis which at least suggests the methodology is available in the form of testimony which Mr. Komanoff presented before the New Jersey Public Service Commission. I can get the exact date for you if you would require it. I don't think the results are necessarily consistent in every numeric detail, but I believe there are at least methodological consistencies. So that is of public record.

Q Are you familiar, Doctor, with the characterization of Mr. Komanoff which was made by the New Mexico Public Service Commission in the case No. 1216?

A. Sounds like it was unfavorable.

Q Let's see if you are familiar with it. The Commission stated and I quote, at pages 14 and 15 of its order, "Mr. Charles Komanoff, Energy Projects Director of the Council on Economic Priorities, appeared as an expert witness on behalf of Intervenors, Attorney General of New Mexico. Mr. Komanoff testified concerning the capacity factors of nuclear and coal fired generating units,

"Capital costs, fuel costs and operating and maintenance costs of coal and nuclear units. The record shows that Mr. Komanoff has little or no engineering training and experience. His only college degree is a BA in Applied Mathematics. Mr. Komanoff's analysis of coal and nuclear capacity factors depends almost exclusively upon the result of the statistical analysis of existing units. The credibility of Mr. Komanoff's testimony in other areas was considerably weak and by his demonstrated lack of engineering expertise or training, lack of familiarity with the specific details of the utility in question, demonstrated lack of familiarity with conditions in New Mexico pertaining to coal and coal costs and numerous unsupported assumptions and calculations.

"For example, Mr. Komanoff's claimed expertise in the area of nuclear fuel costs was largely based upon his attendance at a one week summer course at the Massachusetts Institute of Technology." Are you familiar with that statement?

A. That summer course? I'm a graduate of Massachusetts Institute of Technology. As I have indicated. But I have not come across that particular course.

MR. BURGRAFF: Could we please have a cite from the opinion and also the case number?

MR. HALL: Yes. The case is case number 1216. It is in the matter of the participation of Public Service Company of New Mexico as tenant in common and electric generating station. I would note that I have read from an original order that was issued in the proceeding. There was a subsequent order in which the language that I have read was struck on the request of the Attorney General, although with no indication of disagreement in the subsequent order.

It was merely done.

A. I am compelled to comment - - I would like to comment on this.

MR. BURGRAFF: Is this published anywhere in PUR, that type thing?

MR. HALL: I do not have a citation of that nature, no.

MR. BURGRAFF: So you are not sure if it is published or not? You don't have a citation?

MR.HALL: Not in the PUR, no.

MR. SEGAL: Could you provide copies of that to the parties?

MR. HALL: That would be no problem.

MR. SEGAL: May I inquire, that copy to which you are referring, is that a certified copy from the New Mexico Commission?

MR. HALL: I have a certified copy of the subsequent order. I do not, in my possession here, have a certified copy of the original order. I do know there is one. I don't have it with me.

MR. SEGAL: The order from which you quoted, I take it that is the one that is not the certified copy?

MR. HALL: That is the original order, that is correct.

MR. BURGRAFF: Will we be able to see both of them?

MR. HALL: Yes.

MS. BUSH: I believe that Dr. Shakow had a comment.

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 those 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. Komanoff 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. Shakow 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 those initial costs.

The motion would end at the bottom of Page 52 since the 8.65 per cent stated in that last line also comes from Mr. Komanoff.

MR. NOGEE: 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, 1978 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 1979.

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

MS. BUSH: I might add that Dr. Shakow 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. Shakow 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. Komanoff.

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

MR. HERSHEY: 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 4:55 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. Shakow, employing the Komanoff equation, you have calculated a direct per KW cost of $1,002 per KW 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 $1,002 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 dangling refers to a situation where one unit has been completed but the second unit has not.

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

Q Dr. Shakow, I didn't ask you for a discussion of the equation. 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.

MS. 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 any stretch of the imagination.

MS. 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. I could 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 what

I am doing at each step.

BY MR. HALL:

Q Doctor, 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.

78789 is multiplied by .57 and that yields a value of 45303. The size of the facility is 1055. That is in turn multiplied by minus .208. That yields a value of minus 219.44.

AE is taken as 38 and this in turn is multiplied by minus .102. That yields a value of minus 3.876.

Northeast is applicable here since we are talking about a plant located in the northeast. Thus we enter the value plus 1.27.

The designs of cooling towers, so the tower yield is 1.20.

There is a common sited 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 us.

A The NC is 78789, which I multiplied by the indicated coefficient and I get 45303.

MW is 1055 multiplied by minus .208 which yields 219.44.

AE was 38 times .102 minus yield minus 3.876.

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 45083.08.

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 MW and the EA by the minus .208, is that correct?

A That is correct.

Q Those are powers? They are not multiplication. The .0755 is also a power.

A I misread that.

Q Our problem is, Doctor, we have calculated what we think the correct figure is and it is $450, which is a little less than your $1,002. 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 powers.

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 geared the common estimates to the construction budget as provided by the company and proportioned that construction budget relative to the Komanoff 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 meaning.

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 tell me how you have used the 8.65 per cent rate for nuclear plant capital cost of excavation?

A What page is that?

Q Page 52, which I believe you have taken from Mr. Komanoff.

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. Komanoff?

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 2.65 that is two lines above. May I answer that please?

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

Are you familiar, Doctor, with the term immature 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 maturation appears to be consequential for units of relatively small size, that is between say four to 650 or 700 megawatts, for larger units, this alleged maturation has not been in evidence at least through the experience that we have noted so far.

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

Nonetheless, the work that I am referring to seems to indicate very good maturation for plants of this kind.

I believe I have some dates 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 PWR's. There is the 69 per cent figure. All the other figures show, I would say, a fairly insignificant maturation. 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.

A 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

1164a 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, gives some rough indication of increasing instability in this variable, but is no 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 Incex, Doctor? That is the question.

A Well, as in the case of all these somewhat speculative assumptions and my assessment, 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 tracked 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.

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

Q Doctor, 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, Doctor -- well, strike that. Doctor, there's shown in Exhibit D a discount rate, and the ESR low case that's shown to be 10.5 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, netted down to 1979 dollar units. As I indicated earlier in this cross examination.

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

A Not necessarily. It depends upon what the escalation assumptions are like. If the escalation is at a rate that when you factor everything in faster than the discount rate, then this will not turn out to be the case.

It is fairly complex, since we are talking about a number of disparate escalation rates, associations with fuel, operation and maintenance, capital, per factoring in AFDUC. 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 PECO case and the ESRG low case for fuels with the exception of natural gas, which I believe you will agree is not used by PECO 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 Now, the inflation rates, though, are only applied to certain operating and maintenance expenses, is that not correct?

A In the direct form. But to some degree, the fuel costs are calibrated 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 employed. Is that not correct?

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

Q It is line ten.

A Yes. I do indeed say that.

Q Referring to page 26, Doctor, table 8, if you know, what is the fuel source for Delaware 7, Delaware 8 and Schuylkill 1?

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

Q Delaware 8.

A Delaware 8 would be oil and Schuylkill 1 would also be oil.

Q And what capacity factors have you assigned to these oil-fired units under your optimal expansion mix for 1992?

A They are indeed 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 oil that we assumed in that scenario which is the ESL 1 scenario, the low scenario, so we are talking about an inflation rate of ten percent.

If we account that relative to the capital cost inflation, associated with the Limerick facilities, given a projected capital cost inflation rate of what did we use? It's 2.65 percent or something of that order. That would yieldaa 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 PECO'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 those 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. Doctor, referring you to Sheet 8 of Schedule C, now, this is the ESRG load growth and ESRG optimum case. And for the year 1981 with the reserve margin of 14 percent. Would you know, Doctor?

A Can you refer 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, Doctor, whether there is a Southwark Unit shown on that page and so there's no suspense about it, it is the 178 figure above 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 DSC?

Q Right.

A Okay. Yes.

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

A What sheet is this, please?

Q Ten.

A Ten. No, we have two Southwark Units.

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

A Yes. Two Southwark Units.

Q Now, turning to pages 14 and 16 -- and this is the 1987 year, with reserve margin of 14 percent, and the 1987 year reserve margin of 22 percent.

A Yes.

Q Do we have any Southwark 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 Southwark units in that analysis, Doctor?

A Yes. There are.

Q Are there two Southwark units?

A That's right.

Q Could you explain to me, Doctor, what has happened in that during 1981 we have one Southwark 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 admittedly, some refinement is in order in this dimension, 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 me 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 what 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 anomaly affects the testimony in a consequential way. I should also mention that a colleague of mine at ESRG 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 weeded out. Some kind of rationalization that goes out.

Q. Doctor, do your social costs 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, need, in response to some of the interrogatories, you actually pursued an analysis, I forget, with respect to which unit 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 restrictions.

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 PECO plant, and that cost penalty is stated to be 96.3 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 96.3?

Q Yes.

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

Q Would you agree with me, Doctor, that in 1981, there has been no change in plant mix between the PECO and ESRG?

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

Q In other words, in the ESRG 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 these four reserve margins and then shows 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 On page 22, Doctor, you address the assignment or not assignment of the Salem 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 DSB under 98, 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 Is that on page 2 of 6?

A That is on page DSB, Sheet -- it doesn't really matter which one. This happens to be ESRG high, but it really doesn't matter. It is true for all the scenarios. But for example, Sheet 6 of 6 under 98 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 GPU 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 Doctor, I am trying to determine the nature of your statement in that first paragraph that under the assumption that GPU 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 expedient from the PECO 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 parenthetical 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 come across some statements, particularly in the statement made by the company to FERC, I believe it is a July statement, in which if I understood 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.

So if that is the case, and if I understand 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 employ 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 allowing 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 when one compares the costs which are not desirable outcomes, to be sure, for what I term "soft curtailment options", it turns out that the costs incurred by the consumers 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 blackouts occur, the cost of these load balckouts, you allow the blackout, 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 standard based on economic analysis which assigns ~~class~~ costs to load blackouts and, if it is considered that the cost of a load blackout is less than the cost ~~of a load~~ reserve generating capacity, that it ~~blackout~~ ~~to~~ allow the blackout, 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 turns out on balance, the two sum 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 blackouts under that case will occur in 1.8 days ~~and~~ in 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~~ rc 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 these 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, what 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 these 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 8 of Exhibit C, you have not retained 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 know, 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. Telson 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 evaluation 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 Corwin Study of 1978. The Corwin 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 3.75 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 is if the Corwin study is to any degree accurate, ithas been supported by a large number of constituencies, then the estimates for the PECO area should be somewhat below the 3.75 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 essential desirable outcomes can be identified purely on the basis of a technical probablistic analysis. Preliminary investigation suggests that this assumption is invalid."

Are you suggesting, Doctor, that this Commission should alter the reserve rl liability standard for the Philadelphia Electric Company on the basis of ~~the~~ a 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 LLOP 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 LLOP 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. Shakow. 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 on 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 size nuclear facility. That would be Whoops 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 tantamount 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 these 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. NOGEE

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 these 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 effect 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 opt 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. NOGEE:

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. Those are the only alternatives.

Q You did not calculate, for example, the cost of possible regeneration 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 ESRG 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 assumptions 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)

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PHILADELPHIA ELECTRIC COMPANY
Rate Investigation Docket No. 865

Testimony of Thomas H. Weiss
on behalf of
Office of Consumer Advocate

November 1979

Q. Mr. Weiss, please state your address and occupation.

A. I live in Arnold, Maryland. I am a public utilty rate consultant with Hess & Lim, Inc. Our business address is 5809 Annapolis Road, Hyattsville, Maryland 20784.

Q. What is your educational background and experience in the public utility field?

A. In January, 1970, I graduated from North Carolina State University in Raleigh, North Carolina with the degree of Bachelor of Science in Electrical Engineering. I then joined General Telephone Company of the Southeast at its general offices in Durham, North Carolina, where I held the positions of Supervising Plant Extensions Engineer and Supervising Planning Engineer. In these positions, I was responsible for the development of tactical and strategic capital expansion plans and recommendations involving likely rate and revenue impacts resulting from those plans. While assigned to these positions, I attended the Duke University Graduate School of Business Administration and in May, 1973, I received the degree of Master of Science in Management.

In June, 1973, I was assigned as the Company's Alabama Division Engineering Manager, where I had responsibility for all telephone engineering functions for the Company's operations in the state of Alabama. In 1975 I was returned to the Company's general offices as Revenue and Earnings Manager, where I had responsibility for the development and filing of rate increase petitions before regulatory bodies in the states of Tennessee, South Carolina and Alabama. In 1976, I was named Service Manager-Budgets and Results, again at the Company's general offices, where I was responsible for the development of the Company's total operating expense budget and the monthly analysis of expenditures and productivity factors associated with it.

In July, 1978, I accepted my present position with Hess & Lim, Inc. Since coming with the firm, my duties have included the analysis of rate increase petitions before the Federal Energy Regulatory Commission and regulatory bodies in the states of New York, New Mexico, South Dakota, Pennsylvania, and Texas. These analyses have been related to cost of service, rate design, and engineering matters pertaining primarily to telephone, gas, electric and steam utilities.

I am a registered professional engineer in the states of Maryland and Alabama.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the North Carolina Society of Professional Engineers and the National Society of Professional Engineers.

Q. Have you testified previously in public utility rate proceedings?

A. Yes. I have testified in proceedings before the New York Public Service Commission with regard to telephone cost of service and rate design issues, as those issues affect central station alarm companies in that state. I have testified before the Federal Energy Regulatory Commission with regard to the ratemaking determinations of electric rate base, revenues, operation and maintenance expenses, and depreciation. I have testified before the Pennsylvania Public Utility Commission with regard to The Bell Telephone Company of Pennsylvania (R.I.D. 719) request for increased rates. This testimony dealt with the analysis of the Company's claims for increased operating expenses stemming from labor cost projections which the Company made.

Q. What is your responsibility in this proceeding?

A. On behalf of the Commonwealth, Office of Consumer Advocate, I am responsible for analyzing the Philadelphia Electric Company's claimed cost of service and for making recommendations with respect to the overall level of revenues requested. I will present testimony in two parts, the first of which will contain my analysis and recommendations regarding the Philadelphia Electric Company claims for original cost rate base. The second part of my testimony will deal with the Company's claims for adjusted levels of book operating revenues, expenses and the overall need for increased revenues by Philadelphia Electric Company.

Q. Have you reviewed the Company's testimony and exhibits that have been presented to the Commission thus far in the proceeding?

A. Yes, I have. In addition, I have requested and received from the Company and have reviewed various documents supporting its testimony and exhibits. I have also examined other data which I consider relevant to the Company's application for general rate relief.

Q. Have you relied on the testimony of any other witness in developing your recommendations as to the cost of service for the Philadelphia Electric Company?

A. Yes. I have adopted the recommendations of the Consumer Advocate witness, the Energy Systems Research Group, with regard to its forecasts of energy, peak load and PECO system reliability. I have adopted the capital structure and cost rates as recommended by Dr. Marcus, the rate of return witness for the Office of Consumer Advocate. In addition, my analysis relies on the testimony and exhibits of my associates, Robert G. Towers and Michael L. Arndt, as to their recommendations regarding tax normalization and the cash component of working capital, respectively.

Q. Would you please summarize your conclusions with regard to the Company's claims for its original cost rate base?

A. The Company has overstated its claim for original cost rate base in five areas:

(1) The Company's rate base reflects the full cost of owning and operating all of its existing generating plant, even though a substantial portion of its generating capacity is unnecessary to render adequate and reliable service.

(2) The Company's claim for an estimated average balance of nuclear fuel in the reactor of Salem Unit No. 1 for the twelve months ending March 31, 1980, is overstated because it fails to properly reflect the scheduled period of reload.

(3) The Company's claim for fossil fuel inventory based on 45-day supply at the mine mouth stations and a 60-day supply in the Philadelphia area stations is inflated due to the Company's unsupported claim for a "desired" base inventory level.

(4) The Company has failed to reflect the effects of the Commission's decision in R.I.D. 438 as it relates to the Theodore Barry & Associates audit report (May, 1977) of the Salem Unit No. 1.

(5) The Company has overstated its working capital claim. The analysis of the Company's working capital claim and recommended changes to it are addressed by Mr. Arndt.

Q. With regard to the issue of excess generating capacity, would you please state the Company's generating capacity reserve for 1978?

A. Based on a peak load of 5,318 megawatts at the time of system peak in 1978 and the total installed capacity connected to load of 7,926 megawatts at the time of system peak load, the Company had an installed reserve capacity of 49 percent of system peak demand. At the time of the peak, however, for various reasons, only 7,215 megawatts were available to supply the demand which results in a net reserve generation capability of 35.7 percent. It must be noted that the figures just quoted are actual statistics for the year ended December 31, 1978, and are in no way modified to reflect an adjustment for normal weather conditions.

Q. Does the Company's projected installed reserve capacity for 1979 differ from that experienced in 1978?

A. Yes, it does. For 1979, according to Company witness Boyer, the Company projects an installed reserve capacity of 36 percent of projected system peak demand.

Q. Is a reserve generating capacity in the 1978 range of 36 to 49 percent necessary to insure the provision of adequate and reliable electric service?

A. No. As a matter of fact, maintaining such a large reserve generating capacity can be a severely detrimental position for a company to be in from the standpoint of providing electrical service at the lowest possible cost. In the case of Philadelphia Electric Company, a substantial portion of its generating capacity is represented by oil-fired plants which have characteristically high heat rates which, in turn, mean relatively high fuel costs and a susceptibility to unstable fuel prices which have existed since 1973, the beginning of our first hard-hitting experience with the use of oil as an economic weapon in the world market.

Q. Is there a generally accepted standard for reserve margins employed throughout the electric utility industry?

A. No, there is no generally accepted industry-wide standard. But, in my experience, I am aware of recommended or contractually-agreed-to reserve margins in the range from approximately 15 percent to 25 percent of estimated peak demand for a given system. As an example, the Staff of the Federal Energy Regulatory Commission in a Staff Report entitled "Projected 1977 1978 Winter Electric Load-Supply Situation, Contiguous United States", dated December 1, 1977, has noted that electric utilities generally plan for an <u>installed reserve</u> margin of between 15 percent and 25 percent of peak demand. This range of reserve margins is comparable to the 49 percent installed reserve margin carried by Philadelphia Electric Company in 1978.

Q. What major factors govern the installed reserve margin level for a given system?

A. Reserve margins can be a function of a number of items, which include system economic dispatch criteria, the type and availability of the fuel used by the system, the degree of separation between the two major peaks which a system will experience during the measured period, the adequacy of the transmission and switching system to which the generation units are attached, etc. All of these factors will play into the decision of the proper reserve margin applicable to a given generation system. Needless to say, various individuals will assess the importance of each of the factors in widely differing ways. For example, the Company has determined that a reserve margin of as high as 25 percent would be required in the 12 months ended March 31, 1980. The Mid-Atlantic Area Council (MAAC), in which Philadelphia Electric Company and its Pennsylvania-Jersey-Maryland Interconnect Agreement associates are participants, suggests that a 22 percent margin should be sufficient to insure a loss of load probability not greater than one day in ten years. The Energy Systems Research Group, the Consumer Advocate's load forecasting and system reliability consultants in this case, suggest that, for the year 1981, in order to insure a loss of load probability of one day in ten years, Philadelphia

Electric Company will require an installed reserve capacity margin in the range of 14 to 22 percent. So, clearly, the number of reserve margins which may be suggested for a given system are partly a function of the number of opinions which are solicited regarding the matter. In no case, however, is the reserve margin ranging upwards of the Company's 1979 figure of 36 percent deemed justified, even by its own suggested criteria.

Q. What is the effect on the Company's claimed rate base of maintaining excess generating capacity?

A. The original cost rate base as stated is excessive because it includes in net electrical plant that portion of the investment associated with the unneeded generating capacity. Rate base is further overstated by the inclusion of fuel inventories and materials and supplies related to the unneeded generating capacity.

In addition, the operating expenses claimed by the Company are too high because they include various fixed charges associated with the redundant investment. These fixed costs include depreciation, property taxes, and maintenance. Production expenses may be marginally overstated because they tend to be related to actual use.

Q. Is it reasonable for ratemaking purposes to assess the Company's current ratepayers with all of these costs?

A. It would be reasonable to assess current ratepayers with these costs if the Company can demonstrate: (1) that its investment in the unneeded plant was a prudent decision when made, (2) that the excessive capacity currently existing is the result of changes in circumstances beyond the Company's control, and (3) that it is taking prompt action to eliminate the uneconomic condition. It must be emphasized that, in order to allow the Company to assess its current ratepayers with the burden of paying for excess capacity, all three of the aforementioned criteria must be met. Failure to meet any one or indeed all of these criteria would indicate that the Company had failed to act in the best interests of its customers and its stockholders.

Q. In your opinion, has the Company failed to meet any or all of the three criteria which you have just mentioned?

A. Yes, the Company's current excess capacity stems from decisions which were in the process of being made in the early to mid-sixties, when the Company was planning the Eddystone 3 and 4 generating units. During this time, oil-fired generation appeared to be a viable long-term base load generation alternative and these plants were so planned. By the late 1960's, expenditures were being made to effect the completion of the Philadelphia Electric Company interest in nuclear plants at Peach Bottom and Salem. The decisions to build these plants appeared to be prudent at that time. By the early to middle 1970's, when these plants were still in the construction stages, it was becoming very apparent that the costs required to effect completion of nuclear plants were being inflated by needed improvements in nuclear safety regulations. Also during this time it was becoming clear that fossil fuels and, in particular, fuel oil were becoming so expensive as to nearly preclude electric utilities from any further consideration of constructing oil-fired capacity. Electric energy rates began to rise generally to reflect these higher costs of generation and utilities began to see a slowdown in their previously predicted growth rates. In spite of these factors, Philadelphia Electric Company continued with its construction plans in an unmodified fashion and even planned the construction of the additional capacity at the Limerick Station, which was scheduled to go in service in the 1983/85 time frame but has now been delayed until 1985/87 because its capacity is deemed by the Company not to be needed until the later time frame. As a result of these actions, the Eddystone 3 and 4 units which were originally planned as base load units now have load factors more characteristic of intermediate to peaking-type facilities. Throughout this entire period between the mid-sixties to the mid-seventies, when economic change in the energy industry was so prevalent, the Company failed to recognize the ramifications of these higher fuel and construction costs and thereby failed to make appropriate arrangements for the orderly retirement of what clearly could be seen as uneconomical excess capacity. Only now is the Company making any effort to adjust its admittedly excess capacity by retiring the previously mothballed units at Richmond 12 and Barbadoes 3 and 4. These retirements come only after this Commission's findings in R.I.D. 438.

In summary then, while the Company's most recently constructed units were in the planning stages, all indications seemed to point to the need for the capacity which those units would provide. However, as these units were in the construction phase, operation and construction costs were escalating at unprecedented rates, thereby precipitating higher operation costs for existing oil-fired units (peakers) and higher electric rates were causing a trend toward more stable adjusted peak demands. It is during this period that the Company failed in its burden of attending to the interests of both its customer population and its stockholders by failing to adequately plan for the orderly retirement of its most expensive and unneeded generating capacity.

Q. Mr. Weiss, how can the investment associated with Philadelphia Electric Company's excess generating capacity be eliminated from rate base for ratemaking purposes in this case?

A. There are several ways of adjusting rate base to recognize the existence of excess capacity. One way is to exclude the investment in designated units based on an analysis of the current use of production plant, efficiencies of the various plants, and the Company's own retirement plans.

A second method would be to reduce the investment and related costs in all production plant by a factor representing the unneeded capacity as a percentage of total capacity. This, however, is a less desirable method in that it fails to adequately assess the operating efficiencies of individual units.

Still another method for adjusting rate base to remove excess capacity would be to designate older facilities as those which are representative of the unneeded capacity and remove the investment from the determination of the Company's revenue requirement. This method is inappropriate again because, although the plants may be the oldest in the Company's production plant inventory, there is no guarantee that they are, in fact, the least efficient and, hence, the method may confer upon the Company a significant advantage in that, since the plants are the earliest production vintages, they would tend to be the most highly depreciated and, hence, the adjustment would have minimum impact on the Company's stockholders.

Q. Are there any other techniques available for dealing with the problem of excess capacity?

A. Yes, there is one other method which I would view to be viable if it were determined that the present excess capacity may be needed at sometime in the future. This method involves the removal from rate base of the investment representing the excess capacity and the capitalization of a modified allowance for funds used during construction (AFUDC) on the removed plant until such time as the plant is deemed to be needed. In order that the financial risk of this temporary excess capacity be borne by the appropriate party, it would be necessary that the AFUDC rate used for this purpose include equity return at the zero cost level. In this regard, the AFUDC rate would represent only the embedded cost of debt at the time of the declaration of capacity excess and would, therefore, be lower than the rate which the Company would be applying to new construction. This approach also would require a cessation of annual depreciation expense.

Q. Why should the AFUDC rate applied to the investment in excess capacity be less than the rate currently applied to new construction?

A. By eliminating the equity component, the Company's investors are properly not being given the opportunity to accrue a return on the excess capacity. It would be fair to the investors since, after the plant was returned to service, they would be permitted to recover a full return on their legitimate investment and not be penalized by bearing the full burden of the debt costs associated with the excess capacity. This method has a severe drawback, however, in that, although present customers would avoid the costs associated with excess capacity, future customers would be required to pay those costs even though they had no responsibility for them. In addition, employment of this method of recognizing, for ratemaking purposes, an allowance for excess capacity would require clear evidence that the Company had no plans for the construction of additional capacity in the near future.

Q. What method are you recommending for dealing with the costs associated with excess generating capacity in this case?

A. My recommendation involves a determination of the level of excess capacity and the subsequent identification of the units representative of the excess on the basis of the elimination of the least economical units. In addition, I recommend that the Commission should follow its previously-established precedents of flowing through to the Company's customers the benefits of recurring tax savings associated with its construction program.

Q. How have you determined the level of Philadelphia Electric Company's excess capacity in this case?

A. I began with the 7,689 megawatt installed generating capacity which the Company shows will be installed at the time of its estimated peak in the summer of 1981. From this installed capacity, I subtract 6,914 megawatts which represents the capacity necessary to service the Company's 1981 peak demand (per Energy Systems Research Group Inc. (ESRG) base case forecast) with an installed generating reserve margin set at the midpoint of the 14 percent to 22 percent range as identified by the ESRG witnesses in their testimony as adequate to maintain a loss of load probability of one day in ten years. These calculations yield an excess capacity of some 775 megawatts during the 1981 summer peak. It should be noted that the installed capacity used in this calculation reflects the recent retirement of the Company Richmond No. 12 and Barbadoes 3 and 4 units.

In order to decide which units should be eliminated for ratemaking purposes to reflect the removal of excess capacity from rate base, I reviewed statistics describing the utilization of the Company's generating units in 1978 as obtained from its filings with the Federal Energy Regulatory Commission (Forms 1 and 12), the Company's retirement plans as outlined by Mr. Boyer in his testimony and exhibits and the Company response to data request IR-3, Q. 82. On the basis of my review, I would exclude the costs associated with the following units:

Chester 5 and 6	124 megawatts
Richmond No. 9	166 megawatts
Barbadoes Nos. 6 and 7	38 megawatts
Southwark Units 1-6	420 megawatts
Total	748 megawatts

These adjustments imply a reduction in generating capacity for ratemaking purposes to the level of 6,944 megawatts, based on the estimated peak load of 5,860 megawatts and the mid-point (18%) of the recommended installed reserve requirement as projected by ESRG for the summer of 1981.

Based on this load reduction scenario, I have determined that the depreciated original cost of these units totals $25,043,000. This amount is eliminated from rate base as the reduction associated with excess capacity.

Q. Turning to the issue of the Company's fossil fuel inventory levels, would you please state your concern over the Company's rate base claims in this area.

A. My concern stems from the fact that the Company is requesting a "desired" base inventory level which they have been unable to support based on any consideration of projected fuel usage (TR 1297-1299). In other words, the Company has failed to demonstrate that, beginning with its level of fuel inventory on hand at the beginning of the test year less the fuel usage projected for the test year, plus the volume of fuel purchased throughout the test year, yields a requirement for the base inventory levels as shown at DPS-2, p. C-24.

Q. Have you made a study of the Company's inventory requirements for coal and oil?

A. Yes, I have. Using the Company's actual reported data for 1978 as developed from its FERC Form 1, I developed a level of fuel inventory requirements by individual generating station and priced these inventories at the cost levels suggested by the Company at Exhibit DPS-2, p. C-24. The results of my analysis indicate that the Company has overstated the cost of maintaining an objective inventory level for coal by approximately $9 million. My analysis of the Company's oil inventory levels has indicated that there is no reason to adjust for a change in working capital requirements associated with this fuel type.

Q. Now, let us turn to the issue of the Company's claim for nuclear fuel balance in the Salem Unit No. 1 reactor. Would you please explain your concern about this matter.

A. The Company's claim for average nuclear fuel balance associated with the Salem No. 1 nuclear plant is overstated in that it fails to adequately weight the fuel balance on hand during the test year, even assuming the Company's own numbers. I have performed an adjustment to rectify this deficiency. This adjustment is outlined in my Exhibit___(THW-1), p. 2 which shows that the Company has overstated its average nuclear fuel balance by some $2,250,000.

Q. Are there any other adjustments which you have made to the Company's claimed original cost rate base in this case?

A. Yes, based on the Commission decision regarding Theodore Barry & Associates' audit of the Salem No. 1 construction practices and the resulting Commission decision in R.I.D. 438, I have eliminated from rate base in this case a total of $10,500,000 from the Company's claimed rate base.

In addition, I have adopted the cash working capital recommendations of my associate, Mr. Arndt, and, in doing so, reduced the Company's rate base by a total of some $13 million.

My Exhibit___(THW-1) summarizes my adjustments to the Company's rate base and shows my recommendation of $2,441 million as the rate base in this case as opposed to the Company's $2,501 million claim, a reduction of some $60 million.

It must be noted that the figures appearing on this exhibit have not been adjusted for any changes in our recommendations regarding deferred income taxes. Any adjustment to this category of rate base will, of necessity, depend on our further analysis of the Company's revenue requirements, including its claims for pro forma operating revenues and expenses as outlined in Exhibit DPS-2. This analysis is due to be complete and the testimony prepared for distribution to the interested parties at a later time.

Ex-THW-6

In the process of redirect examination of Mr. Weiss on December 11, 1979, Mr. Hall requested references to support Mr. Weiss' statement regarding the non-taxablity of revenues collected from customers for ultimate use as payment for spent nuclear fuel disposal and nuclear plant decommissioning. Mr. Weiss contended in his statement that such funds collected from customers and held by an escrow agent would not be subject to income tax. The suggested treatment is based on the concept of constructive receipt of income as defined in the Revenue Regulations. The following are the references requested by Mr.Hall:

1. Income tax regulations Section 1.451-2 (a), Constructive receipt of income-General rule. This section clearly indicates that the receipt of cash or other assets in advance of their being earned is taxable at the time of receipt if the recipient has complete unhampered use of the funds. Conversely, if the receipt of the funds is subject to substantial limitations such as those described in Pa.PUC Decision at R.I.D. 392, no tax would apply until the funds are made available for use by the Company. Under such circumstances, funds so collected would be included in gross income only when the Company withdrew them from escrow for use to meet the future storage and decommissioning expense. At that time, deductible expense will be booked in an amount equal to the escrow disbursement to income thereby resulting in no increase in taxable income. To quote from the Regulation:

   "(a) General Rule. Income although not actually reduced to a taxpayer's possession is constructively received by him in the taxable year during which it is credited to his account, set apart for him, or otherwise made available so that he may draw upon it at any time, or so that he could have drawn upon it during the taxable year if notice of intention to withdraw had been given. However, income is not constructively received if the taxpayer's control of its receipt is subject to substantial limitation or restrictions"(emphasis added).

2. Pa.PUC v. Pennsylvania Electric Company, R.I.D. 392 (June 28, 1978). At pages 24 and 25 of its Order in this case the Commission outlines very specific circumstances under which an annuity collected from ratepayers is invested in a heavily restricted escrow fund consisting of Commonwealth of Pennsylvania general obligation bonds. This finding sufficiently encumbers the receipts so as to render them excluded from income until needed to meet the offsetting expense and is consistent with Income Tax Regulations Section 1.451.

you, either?

A No, sir.

Q Mr. Weiss, was or is the opinion which you express as to the propriety and level of an adjustment on account of what you view as excess capacity influenced to a significant degree by what you have calculated as the indicated reserve margin of 49 per cent during 1978?

A Is my adjustment related to the 49 per cent that I show on Page 7?

Q I don't mean in a mathematical sense, but in a judgmental sense?

A No. It is, however, related to the net reserve generation capacity of 35.7, which I quoted earlier.

Q Mr. Weiss, if you know, is the standard for electric system reliability stated in terms of reserve margins or in terms of some other formulation?

A In its purest sense, it is stated in some other formulation.

Q And could you state for us what that other formulation is?

A I believe the probability or the average probability of an outage creating at least a partial blackout of one day in ten years in the case of PECO and the Mid-Atlantic Council.

Q Is that same reserve reliability or is that sam

FILE CONTINUED