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J.H. Eto, J. McMahon, and P. Chan

December 1984

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FINANCIAL IMPACTS ON UTILITIES OF LOAD SHAPE CHANGES PROJECT

STAGE III SUMMARY REPORT

The Virginia Electric and Power Company

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Lawrence Berkeley Laboratory
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December, 1984

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I INTRODUCTION

Efficiency standards for residential appliances can affect the earnings of electric utilities. The magnitude and direction of the effect depends on the retail rate and marginal cost structure of the individual utility. The goal of this LBL project is to develop tools and procedures to measure this effect for a range of different utilities. We use two end-use models in sequence to estimate the load shape changes induced by residential appliance standards, and a modified formulation of the accountant's statistic for earnings before interest and taxes (EBIT) to calculate the financial impact.

The end-use, engineering/economic orientation of the first model is essential for capturing the appliance-specific effects of differing levels of efficiency standards. The hourly time step of the second model yields diversified system load impacts. These features of the models play important roles in the calculation of financial impacts. The calculations rely on information typically available from individual utility departments, but which are rarely presented as an integrated whole.

This report summarizes specific features of and results from a case study of Virginia Electric and Power Company (VEPCO). LBL has also performed case studies of the Detroit Edison Company [1] and the Pacific Gas and Electric Company [2]. A third LBL report describes the methods and tools for calculating EBIT and major findings from all three case studies [3]. The discussion in this report assumes knowledge of the results and terminology contained in these reports.

The report is organized in four sections. First, we discuss the background for our study of VEPCO. Second, we list the procedures used to model load shape changes and intermediate results. Third, we describe the assumptions used to calculate financial impacts from the model outputs. Fourth, we summarize our results and general observations.

II THE VIRGINIA ELECTRIC AND POWER COMPANY

The Virginia Electric and Power Company represents an intermediate case in our study of the financial impacts of load shape changes on electric utilities. VEPCO's low cost base load generating mix of coal and nuclear power plants closely resembles that of the Detroit Edison Company. On the margin, oil and gas are used for generation. As with the Pacific Gas and Electric Company, VEPCO anticipates healthy load growth and a need for additional supplies of electricity. Residential sales are roughly fifty percent greater than Detroit Edison's and about twenty percent less than Pacific Gas & Electric's. Unlike both utilities, VEPCO's residential rates are not steeply inverted; instead, they are relatively flat. Finally, VEPCO's system peak demands can occur in either winter or summer.

Previous case studies showed operating margin effects are typically negative (roughly, marginal cost < average revenue); thus, the magnitude of capacity savings (always > 0) decides the net financial impact of a standard. Capacity savings are greatest for standards that target the main contributors to system peak demands. For VEPCO, significant capacity savings will result only from a standard addressing both summer and winter peaks.

For this case study, we examine the financial impacts of a standard mandating high efficiency central air-conditioners and heat pumps. In addition, modest increases are assumed for the efficiencies required of other residential appliances. Table 1 summarizes the efficiencies called for in the standard. As in previous case studies, the standards are assumed to take effect in 1987. The impacts are measured by predicting and comparing sales and load changes from a base case and this policy case. In addition, we assume a crude model of regulatory response.

Table 1. Policy Case Appliance Efficiencies

year	1984	1988	1992	1996	2000
space heating (AFUE)*					
electric	100	100	100	100	100
gas	77	86	87	88	89
oil	86	91	91	91	91
air conditioning					
room (EER)	7.4	9.0	9.0	9.1	9.1
central (SEER)	7.0	12	12	12	12
water heater (percent)					
electric	82	93	93	93	93
gas	62	82	82	82	82
refrigerators (ft^3/kWh/d)	7.1	11	11	11	11
freezers(ft^3/kWh/d)	13	22	22	22	22
ranges (percent)					
electric	44	45	45	46	46
gas	26	32	34	35	35

* annual fuel use efficiency

III MODELING LOAD SHAPE CHANGES

We used two models to forecast load shape changes. The first, the LBL Residential Energy Model, integrates engineering and economic data at an end-use level to predict consumption annually [4,5]. The second, the LBL Residential Hourly Demand and Peak Load Model, is an engineering model that spreads the annual predictions over the hours of the year to yield kW loads [6].

The end-use orientation of the LBL Residential Energy Model requires substantial amounts of data. Information must be assembled characterizing the current stock of energy-using appliances and trends in appliance purchases, demographic variables, and economic factors.

We gathered these data from a variety of sources. The primary source of demographic and appliance saturation data was the documentation to VEPCO's own forecasting model [7]. In addition, we used DOE-2 building energy simulations to estimate the annual energy demands of new and existing Virginia single family housing [8,9]. We took energy prices and escalation rates from Energy Information Agency publications [10,11]. The LBL data base of national averages provided assumptions for the remaining inputs [5]. These inputs include the annual energy consumption of non-weather sensitive appliances, appliance lifetimes, age distributions, cost relationships for efficiency improvements, and market share and usage elasticities.

We chose first year marginal appliance saturations to ensure that VEPCO's forecast of 1997 appliance saturations would be met [7]. This decision was made to calibrate the LBL base case to VEPCO forecasts, in the absence of more detailed data. A consequence of the decision is that it reduces the the influence of LBL default values from market share elasticities on forecasts for the VEPCO service territory. The result is that, while the composition of residential energy use by end-use may vary slightly, total sales will be quite close to VEPCO forecasts.

Our final check of the model inputs is a backcast of historic sales and load profiles. For annual sales of electricity, the LBL Residential Energy Model agrees well with VEPCO's recent history. Table 2 compares our results to sales reported by VEPCO [12]. Note that the LBL backcasts have not been weather-adjusted.

Table 2. VEPCO Sales vs. LBL Backcast

	1981	1982	1983
VEPCO	13.40	13.27	14.26
LBL	13.48	13.80	14.30
(VEPCO-LBL)/VEPCO x 100	-0.6 %	-4.0 %	-0.3 %

all sales in 1000 GWh

Calibrating the LBL Hourly and Peak Demand Model was more difficult. The model used temperature data from a Weather Year for Energy Calculation (WYEC) hourly weather tape for Washington D.C. to distribute forecasts of annual consumption for the weather sensitive end-uses [19]. The load data provided by VEPCO, of course, is the result of actual weather conditions integrated over the entire geographic region served by the utility.

The results were, nevertheless, quite good. Figures 1 and 2 plot winter and summer peak day load profiles from a VEPCO study of residential loads [13] against LBL model results. The

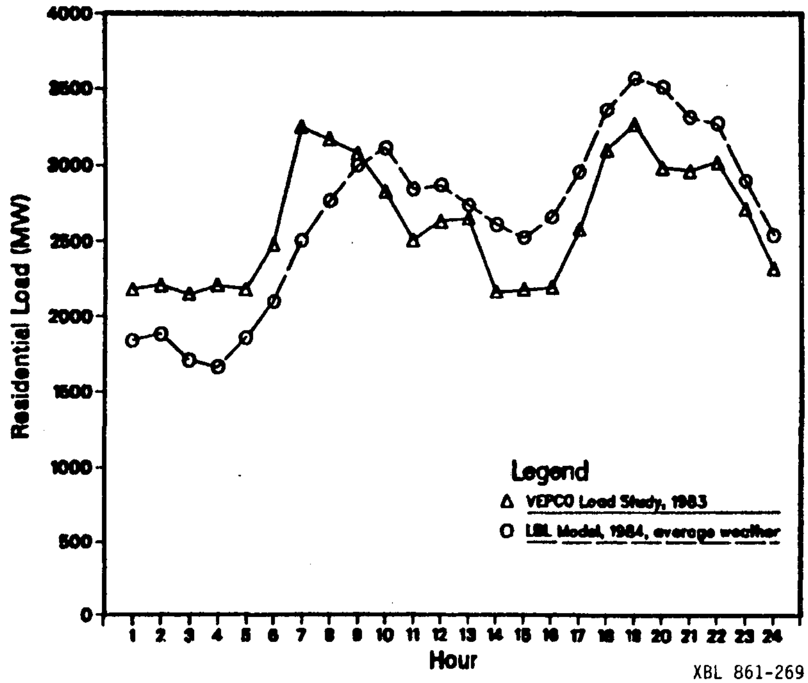

Figure 1. Comparison of VEPCO historic residential class peak winter day loads with LBL backcast residential class peak winter day loads. LBL backcasts have not been weather corrected.

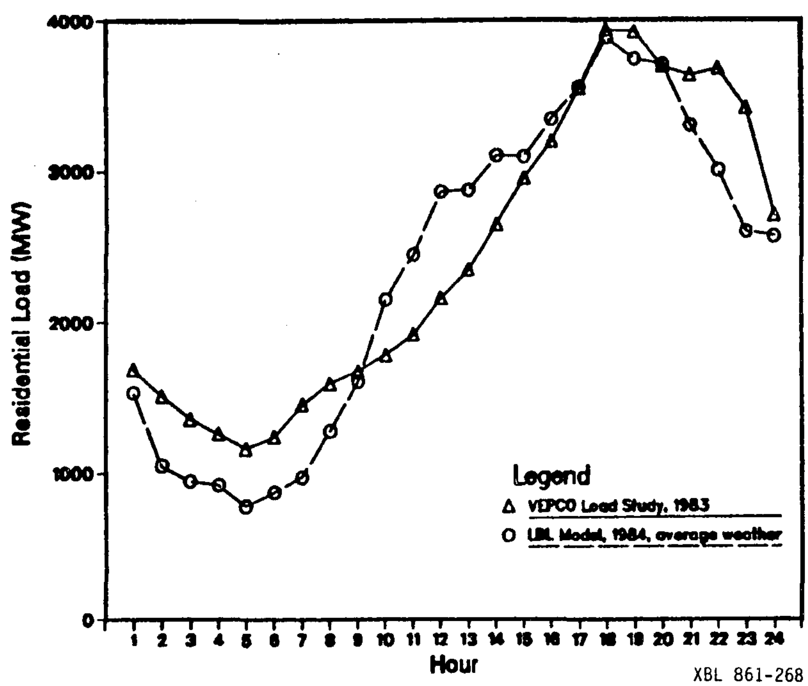

Figure 2. Comparison of VEPCO historic residential class peak summer day loads with LBL backcast residential class peak summer day loads. LBL backcasts have not been weather corrected.

LBL load shapes are qualitatively similar to VEPCO's; a more quantitative comparison cannot be made without comparable weather data.

LBL's base case forecasts show good agreement with VEPCO's predictions (due largely to the decision to incorporate VEPCO's appliance saturation forecasts). VEPCO anticipates residential sales to grow an average of 2.57 %/yr. from 1983 to 1997 [7]. LBL's base case predicts sales to grow 2.6 %/yr. over the same time period. For system peak demand growth, VEPCO expects 3.05 %/yr. in the winter and 2.64 %/yr. in the summer. LBL forecasts residential peak demand growth rates of 2.6 %/yr. and 2.1 %/yr. for these seasons, respectively. Note that LBL's peak demand forecasts cannot be compared directly to VEPCO's since LBL's are for only the residential class, not the entire VEPCO system. VEPCO forecasts do not distinguish individual class contributions to peak but, VEPCO load studies indicate the residential class is a major component of peak demands.

With this feature of VEPCO's loads in mind, LBL was not able to capture definitively the year that the VEPCO's forecasting model predicts system peak demand shifts from summer to winter. While the differences between winter and summer peaks are always very small, LBL predicts the cross-over for the ***residential class*** will take place in 1997. VEPCO predicts the cross-over for the ***system*** will take place in 1986.

LBL's policy case predicts dramatic peak load reductions with modest decreases in sales. Over the period of study, 1986 - 1994, winter peak demand growth declines from 2.8 %/yr. to 1.8 %/yr., and summer peak demand growth is virtually eliminated declining from 2.1 %/yr. to 0.2 %/yr. In 1994, these declines account for roughly 350 and 650 megawatts in winter and summer, respectively. Figures 3 and 4 compare winter and summer peak day load profiles for the base and policy case. Residential sales growth is reduced to a rate of 1.5 %/yr. from 2.6 %/yr.

These sales and load impacts are much higher than those estimated for a similar standard used in the Pacific Gas & Electric study [2]. In that study, a comparable standard reduced sales growth from 1.2 %/yr. to 1.1 %/yr. and peak demand growth from 1.6 %/yr. to 0.8 %/yr. This standard mandated high efficiency central air conditioners, but not high efficiency heat pumps. By including heat pumps in the VEPCO standard, we have targeted an additional end-use, which accounts for a much greater share of sales and load.

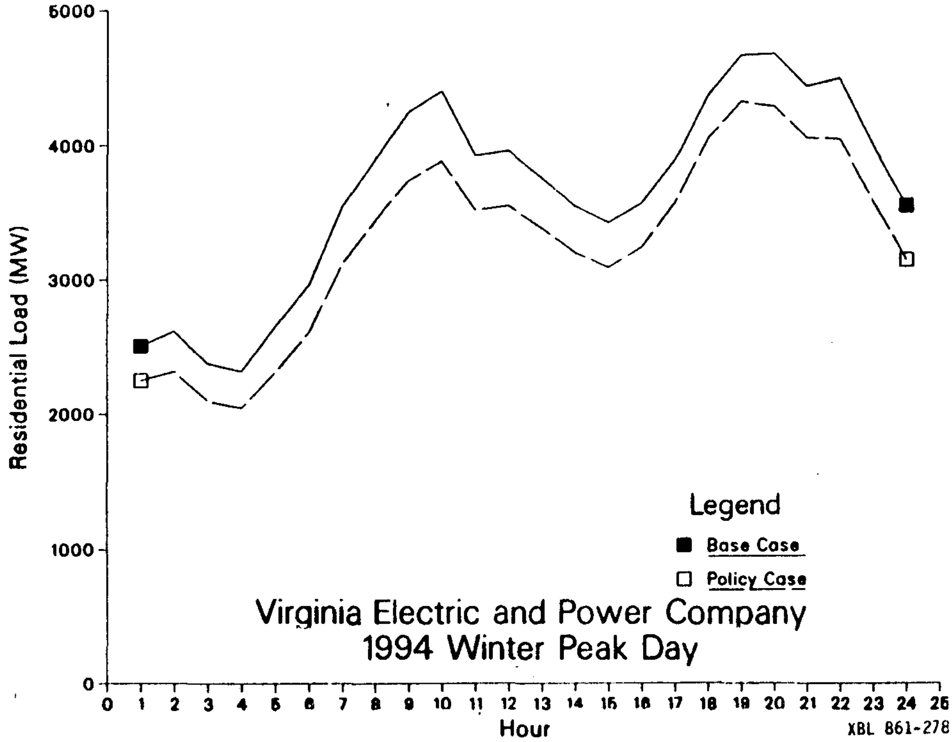

Figure 3. Comparison of base case residential class peak winter day loads with policy case residential class peak winter day loads.

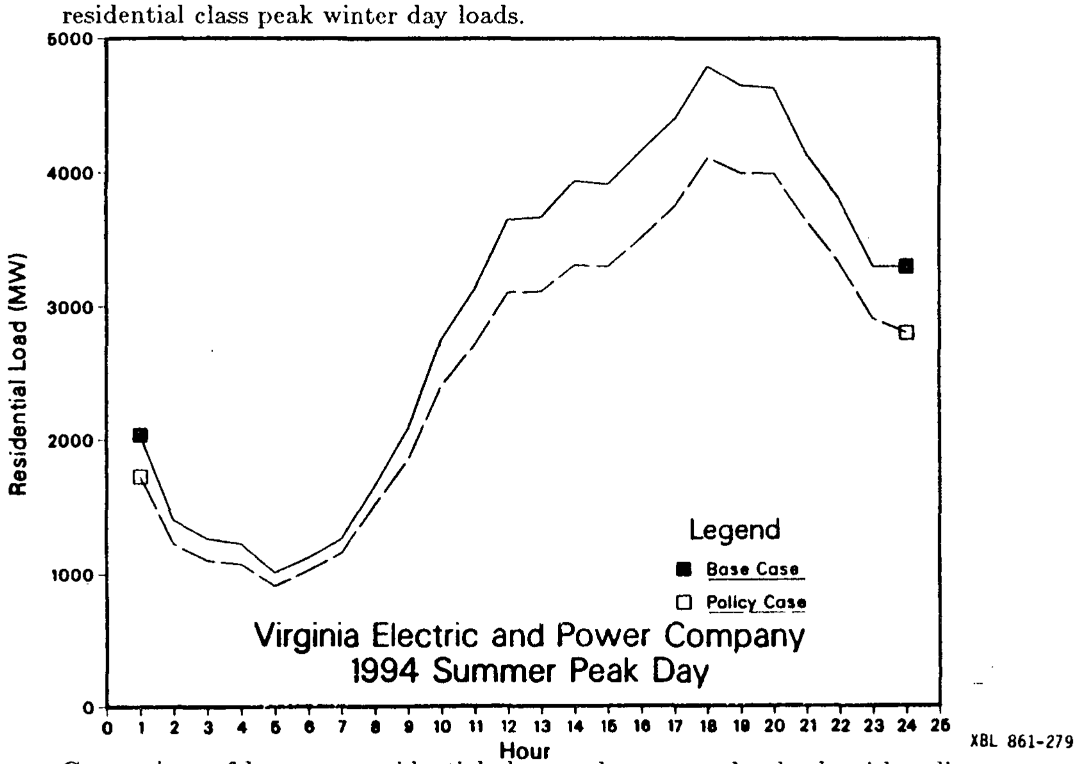

Figure 4. Comparison of base case residential class peak summer day loads with policy case residential class peak summer day loads.

IV CALCULATING FINANCIAL IMPACTS

Reduced sales of electricity have two primary financial impacts. First, operating margin changes result from lost sales and avoided production costs. Second, investment patterns are modified through reduced capacity needs.

To calculate revenue changes from lost sales, the block-rate structure of VEPCO's residential rates requires one to know the price at each tier and the number of kWh lost from each tier. Tier prices are estimated by escalating VEPCO's 1984 prices [14] at the real rates projected by the Energy Information Agency [11]. We make an estimate of changes in the distribution of the sales over consumption tiers with the Block-Adjustment Method. This technique accounts for differing levels of sales by adjusting the tier boundary of an existing cumulative sales frequency distribution (provided by VEPCO in the form of a bill frequency distribution [15]). Another LBL report contains a more detailed discussion of this technique [3]. Figure 5 compares VEPCO's bill and sales frequencies for the base period (winter).

Avoided production costs off-set the revenue impact of these sales losses. These costs are estimated by disaggregating annual sales into monthly on- and off-peak periods, factoring in transmission losses (the factor of 1.0906 comes from [16]), and referring to the results of a recent VEPCO production cost simulation [17]. This simulation yields results to 1992 (see Appendix 1); for 1994, we extrapolated each component at the average rate for 1984-92. We chose a 5 % annual inflation rate to express the results in 1984 dollars.

The second financial impact of an appliance standard results from capacity savings. We estimate these savings by considering the average kW reduction during the demand rating periods of the residential class [18] on three winter peak days. That is, we ignore our inability to model the system peak demand cross-over from summer to winter and treat winter peak demand reductions as reductions from system peaks. This decision lends conservatism to our results since the models predict even greater load reductions during the demand rating periods of the summer peak days.

VEPCO's estimate of the levelized annual marginal cost of capacity, adjusted for transmission losses and reserve margin, is 152.19 dollars/kW-yr in 1983 dollars [16]. For the calculation of the capacity value of the policy-induced shifts in demand, we reduced this quantity to isolate the component of revenue requirements represented by capital expenses (see 20 for a worked example of this relationship). We have approximated the relationship by a simple ratio of 1.7. The capacity value of these reductions is the present value of these demand reductions over the 15 year average lifetime of the appliances at the company's real cost of capital (8 %).

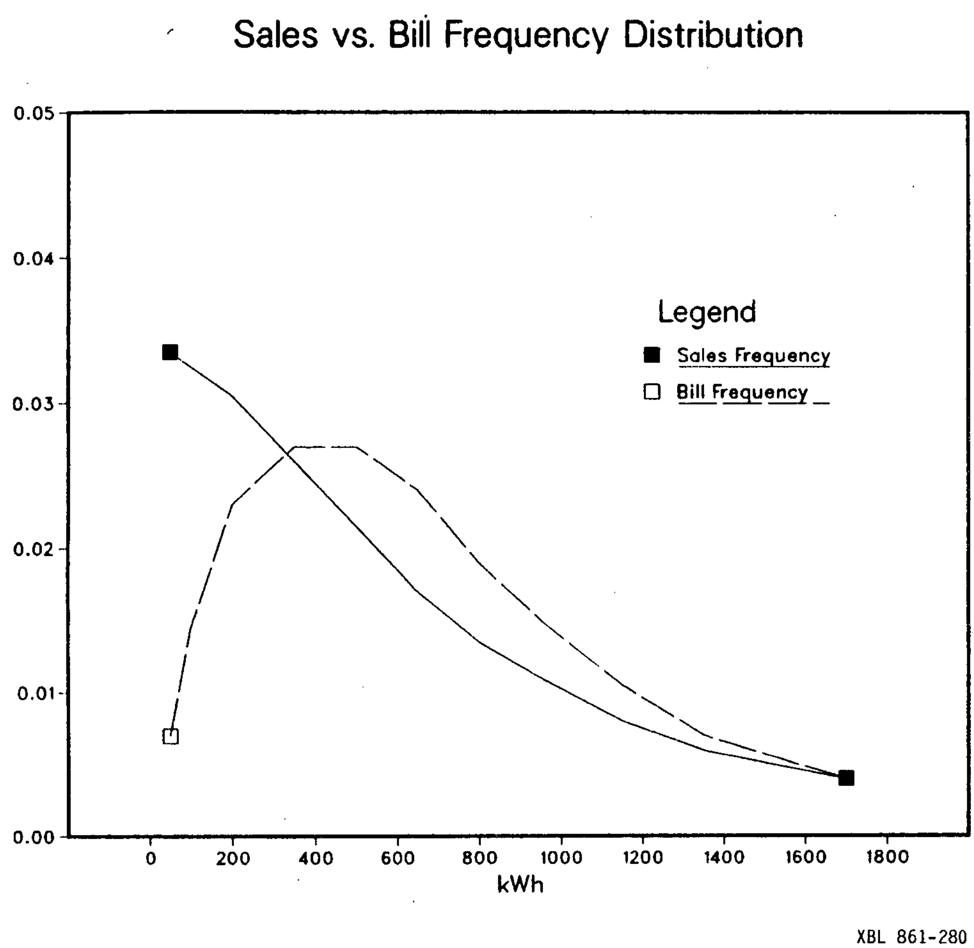

Figure 5. Bill vs. sales frequency distribution for VEPCO winter residential sales.

V FINANCIAL IMPACTS ON VEPCO

We assume a crude model of regulation for our calculation of operating margin changes. This model bounds the regulatory response to 4 and 8 years. In effect, this is to say an exogenous load shape changes take a minimum of 4 and a maximum of 8 years to be recognized and incorporated into a revised set of rates. We do not, for example, consider the reallocation of rate base, which would result from revised class allocation factors, which a new load survey would reveal.

Table 3 summarizes the components of the operating margin changes for selected years. This table indicates the operating margins changes are negative; revenues from lost sales exceed avoided production costs. This trend begins to reverse itself by 1994 due to substantial real price increases in production costs and reductions in the growth of average rate levels.

Table 3. VEPCO Operating Margin Results (1984dollars)

Year	Sales Loss (kWh)	Revenue Loss	(dollars/kWh)	Avoided Cost	(dollars/kWh)	Operating Margin
1988	384.7	-23.8	(.0618)	18.0	(.0430)	- 5.8
1990	747.7	-46.2	(.0618)	32.9	(.0404)	-13.3
1992	1128.2	-70.4	(.0624)	52.7	(.0437)	-17.7
1994	1542.9	-97.4	(.0631)	81.7	(.0485)	-15.7

all figures in millions

Table 4 summarizes the effects of the regulatory lag on these operating margin changes. In this table, we discount the losses at a 4 and 8 % real cost of capital.

Table 4. Present Value of Operating Margin Losses for VEPCO (Millions 1984 dollars)

	4%	8%
1987-1990	27.8	21.3
1987-1994	74.8	65.1

Table 5 summarizes results of the capacity savings calculations for selected years. In fact, capacity savings would continue to accrue after 1994 until the market "caught-up" to the efficiencies mandated by the standards. For these calculations, we assume an 8 % real cost of capital.

On this table, incremental capacity savings refer to the difference between the current year gross capacity savings and those of the previous year. Present value is calculated using an 8 % real cost of capital.

Taken together, these Tables point to the dominating effect of capacity savings on the financial impacts of the appliance standard. Figure 6 summarizes this result on an annual basis using

Table 5. VEPCO Capacity Savings

Year	Capacity Savings (MW)	Incremental Savings (MW)	Present Value (Million 1984 dollars)
1988	83.3	41.6	24.6
1990	167.7	42.2	21.4
1992	260.6	46.5	20.2
1994	351.4	45.4	16.9

8 % as the real cost of capital. In every year, positive benefits accrue, ranging from 1 to 19 millions of 1984, present-value dollars. Put another way, the present value of several years of capacity savings nearly outweighs the cumulative effect (at a 4 % real cost of capital) of 8 years of operating margin losses.

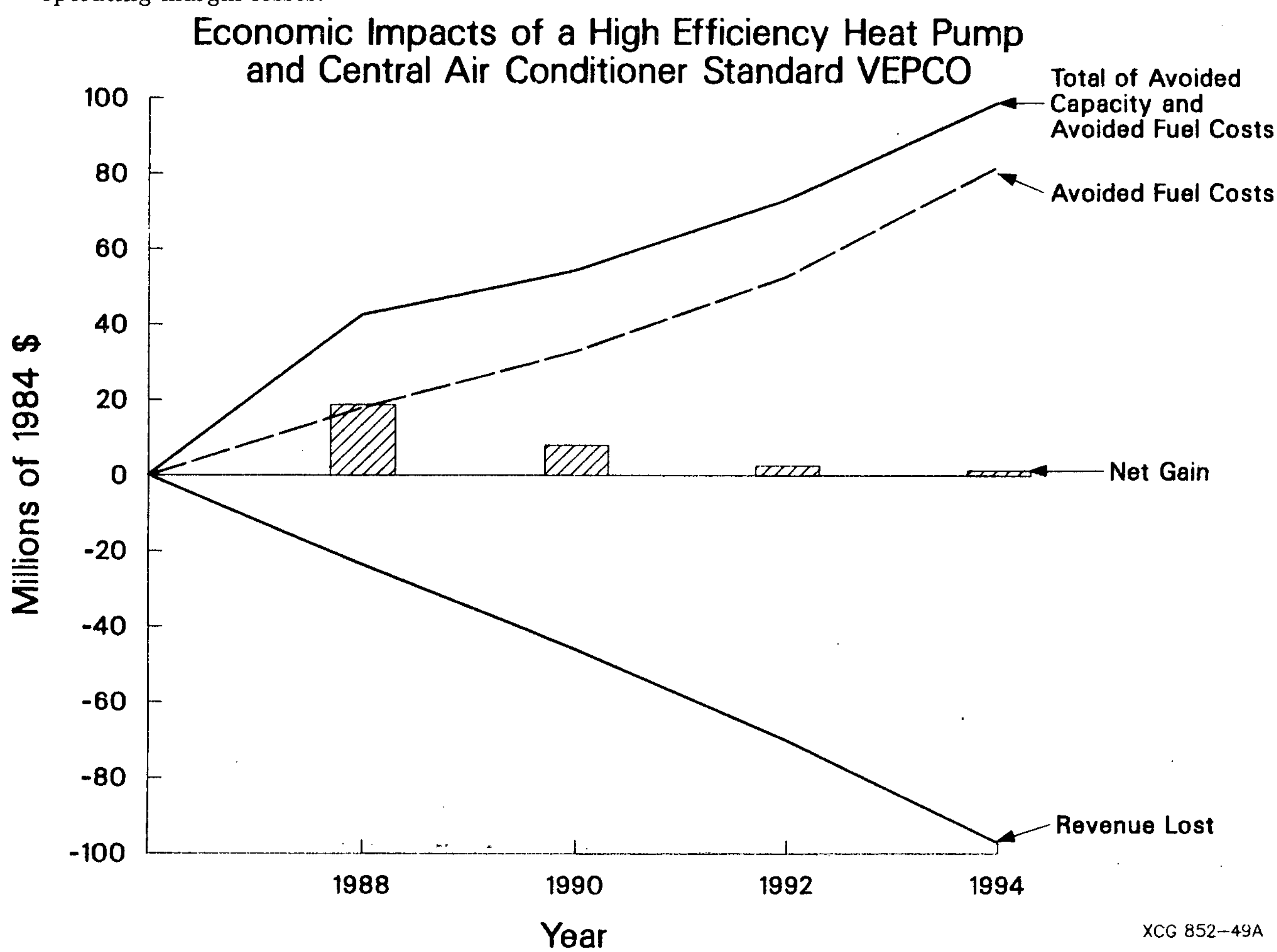

Figure 6. Financial impact of efficient residential appliances on the Virginia Electric and Power Company.

VI CONCLUSION

Our analysis indicates that an appliance standard targeting major components of system peak demands will have financial benefits for VEPCO. Under any scenario of regulatory lag, operating margin losses are small compared to the capacity value of this residential appliance efficiency standard.

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APPENDIX

VIRGINIA ELECTRIC AND POWER COMPANY
AVERAGE OF PEAK PERIOD ENERGY COSTS BY MONTH
FROM THE BASE AND NO COGENERATION CASES-CASE LAY65
FOR JANUARY, 1984 THROUGH DECEMBER, 1992
COSTS ARE ON AN CALANDER YEAR BASIS
(PEAK= 7 AM - 10 PM, MONDAY THRU FRIDAY)

YEAR=1984

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	43.70611	1	45.17177
2	37.49343	2	38.74478
3	30.17400	3	31.52674
4	24.54285	4	25.49471
5	23.20188	5	23.99717
6	34.58446	6	35.91882
7	35.62362	7	36.90098
8	40.19273	8	41.67259
9	41.50367	9	42.98483
10	43.40105	10	45.47727
11	29.87521	11	30.91226
12	33.92825	12	35.06189

YEAR=1985

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	56.81788	1	60.03395
2	51.88754	2	55.06911
3	51.89834	3	55.28212
4	59.61608	4	64.58365
5	35.30524	5	38.58506
6	30.34432	6	32.55254
7	38.79924	7	40.61451
8	40.42588	8	41.90545
9	37.05212	9	38.71567
10	33.26472	10	34.79213
11	35.02551	11	36.49293
12	44.13637	12	47.28765

YEAR=1986

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	68.70470	1	68.10436
2	62.12551	2	66.00701
3	42.83715	3	46.23154
4	45.38444	4	50.70379
5	29.40785	5	31.69217
6	34.77988	6	35.76017
7	40.33876	7	43.56212
8	48.33276	8	50.53628
9	37.32958	9	38.89693
10	43.31449	10	47.63078
11	36.40906	11	37.87226
12	38.41915	12	41.37959

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YEAR=1987

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	49.94284	1	53.79734
2	69.50455	2	64.88499
3	40.60928	3	46.64921
4	36.29856	4	40.17724
5	31.02168	5	34.54714
6	37.89288	6	39.68616
7	60.79235	7	93.14135
8	58.98206	8	94.13322
9	51.88282	9	56.09421
10	50.58553	10	57.47614
11	36.70605	11	38.55295
12	40.82357	12	46.16997

YEAR=1988

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	57.64328	1	61.00089
2	59.37323	2	81.65567
3	56.75473	3	60.11469
4	45.33562	4	56.67185
5	37.21645	5	38.29641
6	41.43359	6	44.12131
7	53.18926	7	58.20499
8	75.90066	8	76.79357
9	47.18172	9	54.19445
10	46.92738	10	55.22116
11	39.50976	11	42.09380
12	49.86893	12	56.01431

YEAR=1989

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	80.60418	1	96.30192
2	80.17759	2	92.27071
3	81.97872	3	79.96635
4	56.63143	4	70.99612
5	46.98568	5	56.36244
6	56.88701	6	62.70545
7	66.93923	7	75.76767
8	75.27754	8	80.42355
9	65.94193	9	80.51310
10	44.46136	10	48.66696
11	36.48067	11	38.87114
12	41.15274	12	43.98894

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COSTS ARE ON AN CALANDER YEAR BASIS
(PEAK= 7 AM - 10 PM, MONDAY THRU FRIDAY)

YEAR=1990

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	51.58564	1	58.42604
2	57.85629	2	64.47343
3	50.19303	3	57.93392
4	42.86086	4	46.42995
5	33.25345	5	36.20485
6	41.45875	6	44.57058
7	53.84158	7	62.54256
8	67.18797	8	113.30281
9	51.93508	9	59.32626
10	51.66060	10	58.70255
11	43.55022	11	46.92651
12	45.86500	12	50.96321

YEAR=1991

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	58.70954	1	66.60529
2	61.41720	2	70.20456
3	62.93022	3	90.56080
4	48.12761	4	53.52946
5	40.63091	5	45.41340
6	45.34379	6	48.78811
7	57.44620	7	64.13665
8	63.16845	8	74.08466
9	54.70367	9	63.87527
10	49.63765	10	55.00972
11	44.25634	11	47.62843
12	48.55381	12	54.22643

YEAR=1992

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	98.12770	1	109.22069
2	88.13872	2	84.25971
3	71.16058	3	87.26654
4	58.41570	4	63.49371
5	47.94591	5	54.72763
6	51.52230	6	55.56426
7	67.08384	7	72.73889
8	73.13221	8	93.98084
9	61.09717	9	72.44235
10	46.89358	10	52.40412
11	44.26157	11	46.44210
12	46.31805	12	51.10314

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YEAR	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	YEAR	NO COGENERATION CASE MARGINAL ENERGY COST	YEAR	AVERAGE
1984	34.85144	1984	36.15532	1984	35.50338
1985	42.88110	1985	45.49290	1985	44.18700
1986	43.95278	1986	46.53142	1986	45.24210
1987	47.08685	1987	55.44249	1987	51.26467
1988	50.86122	1988	57.03193	1988	53.94657
1989	61.12651	1989	68.90286	1989	65.01468
1990	49.27072	1990	58.31689	1990	53.79381
1991	52.91047	1991	61.17190	1991	57.04118
1992	62.84144	1992	70.30366	1992	66.57255

VIRGINIA ELECTRIC AND POWER COMPANY
AVERAGE OF OFF-PEAK ENERGY COSTS BY MONTH
FROM THE BASE AND NO COGENERATION CASES-CASE LAY65
FOR JANUARY, 1984 THROUGH DECEMBER, 1992
COSTS ARE ON AN CALANDER YEAR BASIS
(PEAK= 7 AM - 10 PM, MONDAY THRU FRIDAY)

YEAR=1984

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	22.93676	1	23.93703
2	24.13502	2	25.07544
3	17.48024	3	18.31141
4	16.52478	4	17.30135
5	15.19184	5	15.90294
6	19.84549	6	20.54732
7	20.10588	7	20.89355
8	22.30506	8	23.11423
9	21.67313	9	22.49252
10	26.91696	10	27.98883
11	21.54352	11	22.48165
12	22.10707	12	22.93965

YEAR=1985

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	27.66060	1	29.44071
2	30.44000	2	32.40146
3	30.20676	3	33.48525
4	37.46638	4	40.88546
5	20.27515	5	21.68873
6	19.34031	6	20.27572
7	26.30295	7	27.65178
8	25.80355	8	27.10698
9	27.31725	9	29.05301
10	23.40147	10	26.25522
11	30.32966	11	32.68676
12	35.95806	12	37.67617

YEAR=1986

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	47.93404	1	48.86265
2	47.87343	2	51.82926
3	35.76831	3	37.76325
4	38.78721	4	41.03173
5	22.71387	5	25.34675
6	26.04823	6	28.20811
7	34.39535	7	35.59316
8	35.74019	8	36.69881
9	30.67449	9	33.06568
10	38.64928	10	40.64315
11	35.56571	11	38.96351
12	37.02971	12	38.35151

VIRGINIA ELECTRIC AND POWER COMPANY
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YEAR=1987

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	38.79962	1	40.89400
2	51.99842	2	53.87031
3	37.38421	3	40.03467
4	28.16443	4	34.29037
5	26.18027	5	28.20371
6	28.86303	6	31.62833
7	44.96583	7	58.75175
8	43.75822	8	56.73827
9	39.21871	9	41.05862
10	43.86912	10	47.09506
11	33.35363	11	36.86297
12	39.37208	12	41.86654

YEAR=1988

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	43.31521	1	45.71480
2	50.10329	2	64.97192
3	45.28597	3	47.12138
4	40.59424	4	47.15915
5	29.65244	5	30.03573
6	31.99063	6	35.61667
7	42.17163	7	44.20677
8	52.57171	8	56.61638
9	38.59409	9	41.15010
10	41.44925	10	46.55614
11	36.08141	11	40.60143
12	45.28782	12	48.52754

YEAR=1989

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	60.81312	1	72.07492
2	68.06010	2	77.88262
3	55.55394	3	61.54361
4	46.70560	4	55.25195
5	42.98343	5	47.32158
6	43.76990	6	46.21322
7	49.34427	7	55.27418
8	51.13246	8	57.74593
9	48.37804	9	57.21132
10	36.70320	10	41.74328
11	32.24612	11	34.45773
12	35.86786	12	39.31428

VIRGINIA ELECTRIC AND POWER COMPANY
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YEAR=1990

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	42.06010	1	44.83355
2	49.70732	2	53.62866
3	44.12479	3	47.59813
4	36.58626	4	41.95117
5	27.79837	5	31.01273
6	32.65758	6	34.97855
7	43.99012	7	47.21423
8	48.26598	8	64.33942
9	42.53926	9	45.35527
10	43.89675	10	49.69418
11	39.69554	11	44.60522
12	41.46134	12	46.40773

YEAR=1991

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	45.97055	1	49.12758
2	53.91170	2	57.84303
3	50.74529	3	61.03691
4	42.51233	4	46.39264
5	34.36396	5	37.03112
6	35.43547	6	38.78111
7	45.96952	7	48.56645
8	46.83677	8	50.61897
9	44.90474	9	48.46548
10	41.97071	10	48.33788
11	39.55382	11	43.41270
12	43.99395	12	49.16307

YEAR=1992

MONTH	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	MONTH	NO COGENERATION CASE MARGINAL ENERGY COST
1	59.51250	1	71.05602
2	65.62495	2	70.34416
3	54.85281	3	65.82004
4	51.86976	4	53.10862
5	40.96547	5	47.86589
6	40.50191	6	44.79693
7	50.54626	7	52.93504
8	52.72608	8	62.21030
9	46.84383	9	50.60842
10	40.29562	10	44.92306
11	39.80565	11	43.29021
12	42.16121	12	45.34373

VIRGINIA ELECTRIC AND POWER COMPANY
AVERAGE OF OFF-PEAK PERIOD ENERGY COSTS BY YEAR
FROM THE BASE AND NO COGENERATION CASES-CASE LAY65

YEAR	BASE CASE(INCL. COGEN) MARGINAL ENERGY COST	YEAR	NO COGENERATION CASE MARGINAL ENERGY COST	YEAR	AVERAGE
1984	20.89715	1984	21.74883	1984	21.32299
1985	27.87518	1985	29.88394	1985	28.87956
1986	35.93582	1986	38.02980	1986	36.98281
1987	37.99396	1987	42.60788	1987	40.30092
1988	41.42481	1988	45.68983	1988	43.55732
1989	47.62984	1989	53.83622	1989	50.73303
1990	41.06528	1990	45.96824	1990	43.51676
1991	43.84740	1991	48.23141	1991	46.03941
1992	48.80884	1992	54.35853	1992	51.58369

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