Ex Attached to
Statements

PECO Statement No. 21A

R-850152
3-11-86
115 gt

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

REBUTTAL TESTIMONY OF

ALFRED WROBLEWSKI

RE: SINKING FUND DEPRECIATION

February 1986

REBUTTAL TESTIMONY OF ALFRED WROBLEWSKI

Q. Mr. Wroblewski, have you submitted Direct Testimony in this proceeding?

A. Yes, I have previously submitted Direct Testimony admitted into evidence in this proceeding as PECO Statement No. 21.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my testimony is to provide a portion of the Company's response to the proposals by Witnesses J. W. Wilson and R. J. Falkenberg that PECO employ sinking fund depreciation for Limerick 1.

Q. Would you please summarize Witness Wilson's position on the use of sinking fund depreciation for Limerick.

A. Yes. Witness Wilson makes the following points in favor of the use of sinking fund depreciation:

1. It equalizes total annual capital costs (depreciation plus return on investment) over the life of the plant. This contrasts with the decline of total capital costs from a higher initial level to near zero in the last year of the plant life under straight-line depreciation.
2. The use of sinking fund is analogous to the monthly payment schedules consumers face in the case of a home mortgage or automobile loan.
3. The sinking fund method of depreciation is generally recognized as appropriate for regulated utilities.
4. The first year revenue requirement for Limerick 1 decreases from \$842.3 million to \$708.8 million compared with the use of straight-line depreciation.

Q. Do you agree that sinking fund depreciation equalizes total annual capital costs over the life of the plant?

A. No, I do not agree with Witness Wilson on this point. Witness Wilson's analysis applies only to the original cost of a plant assuming that there will be no interim additions during the plant's life. Based on past experience, substantial interim additions of plant are required during the life of a thermal plant whether fossil or nuclear, and the Company has projected substantial capital additions for Limerick 1 over its life. Witness Wilson has not challenged this forecast of Limerick 1 capital additions. These later capital additions have a shorter remaining life and correspondingly higher straight-line depreciation accruals than the initial Limerick 1 investment. The sinking fund depreciation methodology therefore would not levelize revenue requirements over the life of a plant. On the contrary, its use would cause a rise in revenue requirements as a plant aged and is less capable of supporting them.

Q. Do you agree that consumer home mortgage or automobile financing is analogous to and a justification for sinking fund depreciation?

A. No. Witness Wilson fails to note that most long-term mortgages now require several points to be paid up front in addition to a down payment. Also, many mortgages today are refinanced, repaid upon sale, or have balloon payments, making them in effect short-term loans. Most auto loans are also short term and also generally require a down payment. The deferral of capital recovery on a short-term basis (3 to 5 years) is not comparable to the use of sinking fund depreciation for the long life plant (35 to 40 years) because of the compounding effect of the interest factor. For example, for a five-year loan at 10% interest, the ratio of last year to first year principal payment is 1.6. Using a 38-year period, this ratio increases to a startling 37.4. Witness

Wilson's proposal results in a first year depreciation expense of $5.74 million for Limerick 1 which rises to $424.27 million in the 37th year, an increase of 7291%! (See Exhibit JW-15, p. 1). Moreover, if a consumer defaults on a mortgage or car loan, the lender may repossess the collateral and has a down payment as additional security. Philadelphia Electric Company ordinarily does not require a deposit from residential consumers. In the case of commercial and industrial customers, the deposit is minimal (at most the cost of 2 months of service) in comparison to the Company's long term commitment to serve the customer. Based on the foregoing, I feel Witness Wilson's analogy between short term, front-end loaded consumer financing and long-term sinking fund depreciation is unwarranted and misleading.

Q. Do you agree with Witness Wilson's assertion that the sinking fund method of depreciation is generally recognized as appropriate for regulated utilities?

A. No. Witness Wilson cites four recently constructed thermal plants which he states are being depreciated using the sinking fund method. The plants cited are WPPSS2, Hatch, Vogtle and Centralia. This citation is seriously misleading. The utilities employing sinking fund depreciation for these plants are all publicly owned companies. All the investor-owned utilities who are involved in these projects employ straight-line depreciation as does PECO. In addition, the Vogtle plant has not yet been placed in service and is not currently accruing any depreciation.

Q. What depreciation methodology is generally recognized as appropriate for investor-owned utilities in your view?

A. Straight-line depreciation is currently the most generally recognized depreciation method for investor-owned utilities. The reason for this is that

Wilson's proposal results in a first year depreciation expense of $5.74 million for Limerick 1 which rises to $424.27 million in the 37th year, an increase of 7291%! (See Exhibit JW-15, p. 1). Moreover, if a consumer defaults on a mortgage or car loan, the lender may repossess the collateral and has a down payment as additional security. Philadelphia Electric Company ordinarily does not require a deposit from residential consumers. In the case of commercial and industrial customers, the deposit is minimal (at most the cost of 2 months of service) in comparison to the Company's long term commitment to serve the customer. Based on the foregoing, I feel Witness Wilson's analogy between short term, front-end loaded consumer financing and long-term sinking fund depreciation is unwarranted and misleading.

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Q. What depreciation methodology is generally recognized as appropriate for investor-owned utilities in your view?

A. Straight-line depreciation is currently the most generally recognized depreciation method for investor-owned utilities. The reason for this is that it is compatible with FERC's definition of depreciation. FERC defines depreciation as "the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance." (18 CFR, Ch.1, page 101, par. 12).

Q. Does the sinking fund method conform in principle to this definition of depreciation?

A. No, it does not. Sinking fund depreciation does not purport to track the loss in service value. As Witness Wilson explains, the primary purpose of sinking fund depreciation is to defer annual depreciation expense toward the end of plant life under the erroneous impression that this will levelize revenue requirements.

Q. Why is the straight-line method of depreciation claimed by the Company compatible with FERC's definition of depreciation in your opinion?

A. This methodology has been accepted by FERC for many years. Under straight-line depreciation, the depreciated cost of the plant decreases linearly over the life of the plant. This decline conforms with the linear aging of plant. For many years, age has been used in depreciation studies as the basic measure of loss in service value of plant. As of the early 1970's, more than 92% of the major privately-owned electric utilities reporting to the Federal Energy Regulatory Commission were using this method. (See "Public Utility Depreciation Practices" compiled and edited by the Depreciation Subcommittee of the NARUC, page 12 (1968)).

Q. Witness Wilson claims that the impact of sinking fund depreciation will reduce the first year revenue requirements from \$842.3 million to \$708.8 million or \$133.5 million. Do you agree with this conclusion?

A. I must disagree with this conclusion. Witness Wilson disregards the effects of the Company's phase-in plan which reduces the first year rate increase to one-third of the total revenue requirements. The pro rata effect of sinking fund on the Company's first year revenue requirement would be at most 1/3 x \$133.5 million or \$44.5 million using Witness Wilson's basic figures.

Q. Do you have any additional concern over the effects of Witness Wilson's proposed sinking fund depreciation for the Limerick plant?

A. Yes. The two most serious problems with sinking fund depreciation are that it significantly increases the total capital cost of Limerick to ratepayers and it defers the bulk of this recovery to the very late years of the plant's life. For example, based on Witness Wilson's figures (Ex. JW-14, p. 1), sinking fund depreciation will recover only \$104.2 million of the \$3771.0 million cost of Limerick 1 over the first ten years of life. This amounts to a recovery of only 2.76% of its cost over 25% of its life. Even more startling is the comparison of the revenue requirement during the last ten years of life. The sinking fund revenue requirements for that period are \$5.6 billion, or almost 300% higher than the \$1.9 billion under the straight line method. As a result of this deferred recovery, the total Limerick 1 life-time capital revenue requirement under sinking fund is \$22.0 billion or \$6.6 billion (more than 40%) higher than under straight-line depreciation. In other words, ratepayers will pay \$6.6 billion more for Limerick 1 in nominal dollars under the sinking fund method.

Q. What is your opinion of the sinking fund depreciation plan proposed by Witness Wilson for use with Limerick 1 unit?

A. The figures speak for themselves. The plan defers massive amounts of capital recovery to the end of life, increasing the total revenue requirement and the risk of capital recovery.

Q. Have you reviewed Witness Falkenberg's proposed sinking fund depreciation plan for Limerick?

A. Yes. Witness Falkenberg makes a number of arguments intended to support his sinking fund depreciation plan. His principal arguments are:

(1) The Commission allowed Pennsylvania Power and Light Company (PP&L) to use a modified sinking fund methodology.

(2) Depreciation expense is deferred into the future when it is needed.

(3) Without normalization annual carrying costs of a generating unit would be levelized.

(4) Levelized techniques are used in studying economics of nuclear plants and should be used for ratemaking purposes.

(5) Use of 6% sinking fund approximates the long-term inflation rate.

Q. Is the modified sinking fund method of depreciation allowed by the Commission in the PP&L case equivalent to Witness Falkenberg's proposed 6% sinking fund method?

A. No, it is significantly different. The PP&L method increases depreciation accruals annually from an initial base amount to the straight-line level in the 10th year. The annual increase is equal to the utility's overall rate of return, which would be 12.7% in the Limerick case. In contrast, Witness Falkenberg's method increases the annual accrual only 6% per year during this 10 year period, which produces a much greater deferral of depreciation than the PP&L method and would not reach straight-line levels in ten years. After the tenth year, the PP&L method switches to straight line depreciation over the remaining life. Witness Falkenberg's method continues sinking fund depreciation over the remaining life again producing greater depreciation deferrals than the PP&L method.

Q. Can you summarize the differences between the PP&L method and Witness Falkenberg's proposal?

A. Yes. Schedule 1 to my testimony compares the annual accrual and accrued depreciation under the two methods at various intervals during the life span of Limerick 1. It is apparent that Witness Falkenberg's 6% sinking fund method accruals and accrued depreciation are lower and result in substantially higher depreciation deferrals. In the 10th year, for example, Witness Falkenberg's depreciation is $42 million which is less than one-half the $86 million PP&L accrual. As a result of the continuation of sinking fund after the 10th year, Witness Falkenberg's accrued depreciation is $520 million short of the PP&L method accrued depreciation in the 30th year. These additional depreciation deferrals proposed by Witness Falkenberg will increase the total life time capital revenue requirements substantially.

Q. Are there any other differences between Witness Falkenberg's proposal and the PP&L case?

A. Yes. Witness Falkenberg proposes to use a revenue phase-in plan in addition to sinking fund depreciation. This would in effect further defer depreciation accruals in the first two years of Limerick's life. In the two PP&L cases, no revenue phase-in plan was applied in addition to the modified sinking fund plan.

Q. Mr. Wroblewski, have you calculated the depreciation accruals for PECO employing the PP&L modified sinking fund method?

A. Yes, these calculations are shown on Schedule 2 attached to my testimony. I should emphasize that the Company fully supports straight-line depreciation for all of its generating units including Limerick 1 and therefore does not favor adoption of either the Falkenberg or the PP&L sinking fund method.

Q. Do Witness Falkenberg's other arguments generally justify the use of sinking fund depreciation instead of the traditional straight line method?

A. No, they do not. As I previously noted on page 5, FERC defines depreciation as the loss in service value in its Uniform System of Accounts which has been adopted by the Commission. Straight line depreciation which uses age as a measure of the loss in service value has been accepted by FERC and most other regulatory bodies for many years and is virtually the universal standard used for accounting and ratemaking purposes by regulated electric utilities. The FERC definition of depreciation does not provide for any elements of Witness Falkenberg's sinking fund arguments: deferral of depreciation expense into the future when it is needed, levelizing the cost of a generating unit, levelized methods used in economic studies or relating depreciation to inflation. Finally, Witness Falkenberg does not claim that his sinking fund depreciation will track the loss in service value as well or better than the straight line method.

Q. Does this conclude your rebuttal testimony.

A. Yes, it does.

Comparison of Witness Falkenberg's

Proposed 6% Sinking Fund Depreciation

Plan with PP&L Modified Sinking Fund

(Million $)

	PP&L Method		Falkenberg Method	
Year	Annual Accrual	Accrued Depreciation	Annual Accrual	Accrued Depreciation
1	$29	$29	$25	$25
10	86	532	42	329
11	98	630	45	374
20	98	1513	76	918
30	98	2494	135	1974
37	98	3180	204	3179

The above figures are based on the $3,180 million cost of Limerick and 50% of common plant used by Witness Falkenberg.

Limerick #1 and 100% Common Facilities
Capital Recovery-Modified Sinking Fund (PP&L Method)
($1,000)

Year	Annual	Reserve	Net Plant	Return	Capital Recovery
1	$35,028	$35,028	$3,738,958	$479,296	$514,324
2	39,477	74,505	3,699,481	474,848	514,325
3	44,491	118,996	3,654,990	469,834	514,325
4	50,141	169,137	3,604,849	464,184	514,325
5	56,509	225,646	3,548,340	457,816	514,325
6	63,686	289,332	3,484,654	450,639	514,325
7	71,774	361,106	3,412,880	442,551	514,325
8	80,889	441,995	3,331,991	433,436	514,325
9	91,162	533,157	3,240,829	423,163	514,325
10	102,740	635,897	3,138,089	411,585	514,325
11	116,226	752,123	3,021,863	398,537	514,763
12	116,226	868,349	2,905,637	383,777	500,003
13	116,226	984,575	2,789,411	369,016	485,242
14	116,226	1,100,801	2,673,185	354,255	470,481
15	116,226	1,217,027	2,556,959	339,494	455,720
16	116,226	1,333,253	2,440,733	324,734	440,960
17	116,226	1,449,479	2,324,507	309,973	426,199
18	116,226	1,565,705	2,208,281	295,212	411,438
19	116,226	1,681,931	2,092,055	280,452	396,678
20	116,226	1,798,157	1,975,829	265,691	381,917
21	116,226	1,914,383	1,859,603	250,930	367,156
22	116,226	2,030,609	1,743,377	236,170	352,396
23	116,226	2,146,835	1,627,151	221,409	337,635
24	116,226	2,263,061	1,510,925	206,648	322,874
25	116,226	2,379,287	1,394,699	191,887	308,113
26	116,226	2,495,513	1,278,473	177,127	293,353
27	116,226	2,611,739	1,162,247	162,366	278,592
28	116,226	2,727,965	1,046,021	147,605	263,831
29	116,226	2,844,191	929,795	132,845	249,071
30	116,226	2,960,417	813,569	118,084	234,310
31	116,226	3,076,643	697,343	103,323	219,549
32	116,226	3,192,869	581,117	88,563	204,789
33	116,226	3,309,095	464,891	73,802	190,028
34	116,226	3,425,321	348,665	59,041	175,267
35	116,226	3,541,547	232,439	44,280	160,506
36	116,226	3,657,773	116,213	29,520	145,746
37	116,213	3,773,986	0	14,759	130,972
38					
39					
Total	$3,773,986				

@Annual accrual increases 12.7% annually to s/l level in 10th year. Total depreciable cost of Limerick #1 and 100% Common Facilities is $3,773,986 (ref C-5, TPH-2)

3,773,986

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MAR 12 1986

SECRETARY'S OFFICE
Public Utility Commission

PECO STATEMENT NO. 21B

R-850152
3-11-86

DOCKETED

MAR 17 1986

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PHILADELPHIA ELECTRIC COMPANY
DOCKET NO. R-850152

SUR-SURREBUTTAL TESTIMONY OF

ALFRED WROBLEWSKI

RE: SINKING FUND DEPRECIATION

MARCH 1986

SUR-SURREBUTTAL TESTIMONY OF ALFRED WROBLEWSKI

Q. Mr. Wroblewski, have you submitted testimony previously in this proceeding?

A. Yes. I submitted direct testimony which was admitted into evidence in this proceeding as Philadelphia Electric Company Statement No. 21 and rebuttal testimony which was admitted into evidence in this proceeding as Philadelphia Electric Company Statement 21A.

Q. What is the purpose of your sur-surrebuttal testimony?

A. The purpose of my testimony is to respond to the surrebuttal testimony on the issue of sinking fund depreciation.

Q. Mr. Wroblewski, do you have any comments concerning Mr. Chernick's negative economic depreciation as a justification of sinking fund depreciation?

A. Yes. "Public Utility Economics", by Paul S. Garfield and Wallace F. Lovejoy, (Prentice-Hall, Inc. 1965) defines economic depreciation as "the cost of depreciable assets consumed during a year, expressed in terms of the purchasing power of the original investment" (page 106). Based on this definition, it is difficult to imagine how economic depreciation could be negative in an inflationary period since it would require more inflated dollars to recover the purchasing power of the historic dollars. For example, the book noted above on page 107 cites a study made in 1960 by the National Conference of Electric and Gas Utility Accountants. That study based on 1959 data concluded that the electric and gas distribution industries would have to increase their annual depreciation charges by about one-third in order to restore the purchasing power loss in that year. The inflation in 1959 was only 2.4%. (implicit price deflator, 1959 over 1958 - Department of Commerce, Bureau of Economic Analysis).

On page 33, Mr. Chernick cites the FERC definition of depreciation correctly as "the loss in service value." He then switches to the economic depreciation concept in which he uses projected benefits to measure the value of Limerick 1. The problem with this switch is that FERC defines service value as the difference between original cost and net salvage value of electric plant. 18 CFR Ch. 1 (4-1-85 edition). Mr. Chernick's conclusion is thus based on a mixture of concepts which are inconsistent with the accepted FERC definitions of depreciation and the recognized definitions of economic depreciation described in the referenced literature.

In view of the foregoing, Mr. Chernick's negative economic depreciation in an inflationary period makes no sense and provides no justification for using sinking fund depreciation.

Q. Do you have any comments regarding Witness Wilson's surrebuttal testimony?

A. Yes. Dr. Wilson claims that sinking funding depreciation will more closely mirror the loss of service value than straight-line depreciation because the value of nuclear energy capacity will increase over time. The fact is that FERC defines depreciation as loss in service value and has accepted straight-line depreciation as its measure for many years as have most regulated electric utility companies (Statement 21A, page 5). Dr. Wilson's sinking fund plan defers massive amounts of capital recovery to the end of life (Statement 21A, page 6) and is not used by the investor owned utilities involved in the projects he cites in his testimony (Statement GEC-1B, page 39).

Q. Mr. Falkenberg identifies his surrebuttal Exhibit No. 1 as "Wroblewski Sinking Fund Depreciation". Is this an accurate characterization?

A. No. There seems to be some confusion concerning Philadelphia Electric Company's depreciation claim and the Pennsylvania Power & Light modified sinking fund method. Philadelphia Electric claims straight-line depreciation for Limerick No. 1 for reasons stated throughout my testimony. The straight-line depreciation claim is illustrated in Schedule 1 with total lifetime capital costs of $12.9 billion. The modified sinking fund method which PP&L proposed in R-822169 in Exhibit JOB 3, page 6, is illustrated in Schedule 2 for Limerick Unit 1 which shows total lifetime cost of $13.9 billion. The modified sinking fund method as proposed by the Commission Staff and adopted by the Commission in R-822169 is illustrated in Schedule 3 for Limerick No. 1. The total lifetime capital cost for this method is $13.3 billion. Mr. Falkenberg's proposed 6% sinking fund method is illustrated in Schedule 4 which shows a total lifetime capital cost of $15.8 billion.

Q. What modification did the Commission adopt for the PP&L sinking fund proposal?

A. The change adopted by the Commission increased the depreciation expense level over the years 10-17, thereby reducing the life time capital costs below the PP&L proposal cost. The Commission approved this sinking fund plan noting the lower total capital costs it produced for ratepayers.

Q. Mr. Wroblewski, do you think that sinking fund depreciation should become a generally accepted accounting practice in the electric utility industry?

A. No. It is obvious that, if it does, capital recovery in the industry will get out of hand. In only one jurisdiction involving two utilities Pennsylvania Power & Light and Philadelphia Electric Company over a span of less than five years, about a half-dozen different sinking fund methods have been proposed each producing very different results. None of these plans has considered the effects of interim plant additions and retirements, changes in inflation rates, return rates or life expectancy, to name a few important variables. If sinking fund becomes a generally accepted practice, it may very well destroy uniformity of accounting through a plethora of inscrutable plans which will eventually defy regulation, analysis and audit.

Q. Have you claimed, as Mr. Falkenberg charges, that capital additions to Limerick would be so substantial as to offset any decline in rate base due to depreciation?

A. No. I stated on page 3 of Statement 21A that the Company has projected substantial interim capital additions over the life of Limerick. This statement was made in rebuttal to Witness Wilson's assertion that sinking fund depreciation equalizes total capital costs over life. It is obviously true that any interim additions will cause a rising depreciation expense and net plant especially toward the end of life when the remaining life available for capital recovery is short. The straight-line method of depreciation in Schedule 1 with an annual accrual of $102 million is more suited to handle the additional capital costs of interim additions than Mr. Falkenberg's sinking fund method which has an accrual exceeding $200 million in the final years of life.

Q. Are there any indications that the sinking fund plan proposed by Mr. Falkenberg is generally inequitable and unfair?

A. Yes. The first year accrual under Mr. Falkenberg's 6% sinking fund plan is $25 million or 0.78%. The range of depreciation rates used by the PAIEUG members whom Mr. Falkenberg represents ranges from 5% to 14%. Although some of this difference may be due to differences in the life of assets, it appears that most of this group book tax depreciation rates. If Philadelphia Electric Company used tax rates, the rate on Limerick would exceed 10%. Considering that Philadelphia Electric Company must compete for capital, labor and services in the same area as this group, it would be very inequitable for this group to limit Philadelphia Electric Company to a depreciation rate of less than 1% for a substantial amount of its investment.

Q. Does this complete your sur-surrebuttal testimony?

A. Yes, it does.

LIM100SL
06-Mar-86

SCHEDULE 1

Limerick #1 and 100% Common Facilities
Straight Line Depreciation
($1,000)

Year	Annual	Reserve	Net Plant	Return	Capital Recovery
1	$102,000	$102,000	$3,671,986	$479,296	$581,296
2	102,000	204,000	3,569,986	466,342	568,342
3	102,000	306,000	3,467,986	453,388	555,388
4	102,000	408,000	3,365,986	440,434	542,434
5	102,000	510,000	3,263,986	427,480	529,480
6	102,000	612,000	3,161,986	414,526	516,526
7	102,000	714,000	3,059,986	401,572	503,572
8	102,000	816,000	2,957,986	388,618	490,618
9	102,000	918,000	2,855,986	375,664	477,664
10	102,000	1,020,000	2,753,986	362,710	464,710
11	102,000	1,122,000	2,651,986	349,756	451,756
12	102,000	1,224,000	2,549,986	336,802	438,802
13	102,000	1,326,000	2,447,986	323,848	425,848
14	102,000	1,428,000	2,345,986	310,894	412,894
15	102,000	1,530,000	2,243,986	297,940	399,940
16	102,000	1,632,000	2,141,986	284,986	386,986
17	102,000	1,734,000	2,039,986	272,032	374,032
18	102,000	1,836,000	1,937,986	259,078	361,078
19	102,000	1,938,000	1,835,986	246,124	348,124
20	102,000	2,040,000	1,733,986	233,170	335,170
21	102,000	2,142,000	1,631,986	220,216	322,216
22	102,000	2,244,000	1,529,986	207,262	309,262
23	102,000	2,346,000	1,427,986	194,308	296,308
24	102,000	2,448,000	1,325,986	181,354	283,354
25	102,000	2,550,000	1,223,986	168,400	270,400
26	102,000	2,652,000	1,121,986	155,446	257,446
27	102,000	2,754,000	1,019,986	142,492	244,492
28	102,000	2,856,000	917,986	129,538	231,538
29	102,000	2,958,000	815,986	116,584	218,584
30	102,000	3,060,000	713,986	103,630	205,630
31	102,000	3,162,000	611,986	90,676	192,676
32	102,000	3,264,000	509,986	77,722	179,722
33	102,000	3,366,000	407,986	64,768	166,768
34	102,000	3,468,000	305,986	51,814	153,814
35	102,000	3,570,000	203,986	38,860	140,860
36	102,000	3,672,000	101,986	25,906	127,906
37	101,986	3,773,986	0	12,952	114,938
38					
39					
Total	$3,773,986			$9,106,588	$12,880,574

Accrual = $3,773,986 / 37 years

CAPMS100
06-Mar-86

SCHEDULE 2

Limerick #1 and 100% Common Facilities
PP & L Capital Recovery-Modified Sinking Fund
($1,000)

Year	Annual	Reserve	Net Plant	Return	Capital Recovery
1	$34,801	$34,801	$3,739,185	$479,296	$514,097
2	39,221	74,022	3,699,964	474,876	514,097
3	44,202	118,224	3,655,762	469,895	514,097
4	49,816	168,040	3,605,946	464,282	514,098
5	56,143	224,183	3,549,803	457,955	514,098
6	63,273	287,456	3,486,530	450,825	514,098
7	71,309	358,765	3,415,221	442,789	514,098
8	80,365	439,130	3,334,856	433,733	514,098
9	90,571	529,701	3,244,285	423,527	514,098
10	102,074	631,775	3,142,211	412,024	514,098
11	116,378	748,153	3,025,833	399,061	515,439
12	116,378	864,531	2,909,455	384,281	500,659
13	116,378	980,909	2,793,077	369,501	485,879
14	116,378	1,097,287	2,676,699	354,721	471,099
15	116,378	1,213,665	2,560,321	339,941	456,319
16	116,378	1,330,043	2,443,943	325,161	441,539
17	116,378	1,446,421	2,327,565	310,381	426,759
18	116,378	1,562,799	2,211,187	295,601	411,979
19	116,378	1,679,177	2,094,809	280,821	397,199
20	116,378	1,795,555	1,978,431	266,041	382,419
21	116,378	1,911,933	1,862,053	251,261	367,639
22	116,378	2,028,311	1,745,675	236,481	352,859
23	116,378	2,144,689	1,629,297	221,701	338,079
24	116,378	2,261,067	1,512,919	206,921	323,299
25	116,378	2,377,445	1,396,541	192,141	308,519
26	116,378	2,493,823	1,280,163	177,361	293,739
27	116,378	2,610,201	1,163,785	162,581	278,959
28	116,378	2,726,579	1,047,407	147,801	264,179
29	116,378	2,842,957	931,029	133,021	249,399
30	116,378	2,959,335	814,651	118,241	234,619
31	116,378	3,075,713	698,273	103,461	219,839
32	116,378	3,192,091	581,895	88,681	205,059
33	116,378	3,308,469	465,517	73,901	190,279
34	116,378	3,424,847	349,139	59,121	175,499
35	116,378	3,541,225	232,761	44,341	160,719
36	116,378	3,657,603	116,383	29,561	145,939
37	116,383	3,773,986	0	14,781	131,164
38					
39					
Total	$3,773,986			$10,096,069	$13,870,055

@Annual accrual increases 12.7% annually to s/l level in 10th year. Total depreciable cost of Limerick #1 and 100% Common Facilities is $3,773,986.

PPLM0100
06-Mar-86

SCHEDULE 3

Limerick #1 and 100% Common Facilities
PP&L / PUC Modified Sinking Fund Depreciation
($1,000)

Year	Annual	Reserve	Net Plant	Return	Capital Recovery
1	$34,801	$34,801	$3,739,185	$479,296	$514,097
2	39,221	74,022	3,699,964	474,876	514,097
3	44,202	118,224	3,655,762	469,895	514,097
4	49,816	168,040	3,605,946	464,282	514,098
5	56,143	224,183	3,549,803	457,955	514,098
6	63,273	287,456	3,486,530	450,825	514,098
7	71,309	358,765	3,415,221	442,789	514,098
8	80,365	439,130	3,334,856	433,733	514,098
9	90,571	529,701	3,244,285	423,527	514,098
10	102,074	631,775	3,142,211	412,024	514,098
11	115,037	746,812	3,027,174	399,061	514,098
12	129,647	876,459	2,897,527	384,451	514,098
13	146,112	1,022,571	2,751,415	367,986	514,098
14	164,668	1,187,239	2,586,747	349,430	514,098
15	185,581	1,372,820	2,401,166	328,517	514,098
16	209,150	1,581,970	2,192,016	304,948	514,098
17	235,712	1,817,682	1,956,304	278,386	514,098
18	97,815	1,915,497	1,858,489	248,451	346,266
19	97,815	2,013,312	1,760,674	236,028	333,843
20	97,815	2,111,127	1,662,859	223,606	321,421
21	97,815	2,208,942	1,565,044	211,183	308,998
22	97,815	2,306,757	1,467,229	198,761	296,576
23	97,815	2,404,572	1,369,414	186,338	284,153
24	97,815	2,502,387	1,271,599	173,916	271,731
25	97,815	2,600,202	1,173,784	161,493	259,308
26	97,815	2,698,017	1,075,969	149,071	246,886
27	97,815	2,795,832	978,154	136,648	234,463
28	97,815	2,893,647	880,339	124,226	222,041
29	97,815	2,991,462	782,524	111,803	209,618
30	97,815	3,089,277	684,709	99,381	197,196
31	97,815	3,187,092	586,894	86,958	184,773
32	97,815	3,284,907	489,079	74,536	172,351
33	97,815	3,382,722	391,264	62,113	159,928
34	97,815	3,480,537	293,449	49,691	147,506
35	97,815	3,578,352	195,634	37,268	135,083
36	97,815	3,676,167	97,819	24,846	122,661
37	97,819	3,773,986	0	12,423	110,242
38					
39					
Total	$3,773,986			$9,530,721	$13,304,707

Based on $3,773,986 cost of Limerick #1 and 100% Common Plant used by Witness Falkenberg Annual Accrual increases at 12.7% annually through the 17th year. Straight line depreciation is used thereafter.

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SCHEDULE 4

Limerick #1 and 100% Common Facilities
Witness Falkenberg Sinking Fund
($1,000)

Year	Annual	Reserve	Net Plant	Return	Capital Recovery
1	$29,654	$29,654	$3,744,332	$479,296	$508,950
2	31,433	61,087	3,712,899	475,530	506,963
3	33,319	94,406	3,679,580	471,538	504,857
4	35,318	129,724	3,644,262	467,307	502,625
5	37,437	167,161	3,606,825	462,821	500,258
6	39,683	206,844	3,567,142	458,067	497,750
7	42,064	248,908	3,525,078	453,027	495,091
8	44,588	293,496	3,480,490	447,685	492,273
9	47,263	340,759	3,433,227	442,022	489,285
10	50,099	390,858	3,383,128	436,020	486,119
11	53,105	443,963	3,330,023	429,657	482,762
12	56,291	500,254	3,273,732	422,913	479,204
13	59,668	559,922	3,214,064	415,764	475,432
14	63,248	623,170	3,150,816	408,186	471,434
15	67,043	690,213	3,083,773	400,154	467,197
16	71,066	761,279	3,012,707	391,639	462,705
17	75,330	836,609	2,937,377	382,614	457,944
18	79,850	916,459	2,857,527	373,047	452,897
19	84,641	1,001,100	2,772,886	362,906	447,547
20	89,719	1,090,819	2,683,167	352,157	441,876
21	95,102	1,185,921	2,588,065	340,762	435,864
22	100,808	1,286,729	2,487,257	328,684	429,492
23	106,856	1,393,585	2,380,401	315,882	422,738
24	113,267	1,506,852	2,267,134	302,311	415,578
25	120,063	1,626,915	2,147,071	287,926	407,989
26	127,267	1,754,182	2,019,804	272,678	399,945
27	134,903	1,889,085	1,884,901	256,515	391,418
28	142,997	2,032,082	1,741,904	239,382	382,379
29	151,577	2,183,659	1,590,327	221,222	372,799
30	160,672	2,344,331	1,429,655	201,972	362,644
31	170,312	2,514,643	1,259,343	181,566	351,878
32	180,531	2,695,174	1,078,812	159,937	340,468
33	191,363	2,886,537	887,449	137,009	328,372
34	202,845	3,089,382	684,604	112,706	315,551
35	215,016	3,304,398	469,588	86,945	301,961
36	227,917	3,532,315	241,671	59,638	287,555
37	241,671	3,773,986	0	30,692	272,363
38					
39					
Total	$3,773,986			$12,068,177	$15,842,163

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06-Mar-86

SCHEDULE 4

Limerick #1 and 100% Common Facilities
Witness Falkenberg Sinking Fund
($1,000)

Year	Annual	Reserve	Net Plant	Return	Capital Recovery
1	$29,654	$29,654	$3,744,332	$479,296	$508,950
2	31,433	61,087	3,712,899	475,530	506,963
3	33,319	94,406	3,679,580	471,538	504,857
4	35,318	129,724	3,644,262	467,307	502,625
5	37,437	167,161	3,606,825	462,821	500,258
6	39,683	206,844	3,567,142	458,067	497,750
7	42,064	248,908	3,525,078	453,027	495,091
8	44,588	293,496	3,480,490	447,685	492,273
9	47,263	340,759	3,433,227	442,022	489,285
10	50,099	390,858	3,383,128	436,020	486,119
11	53,105	443,963	3,330,023	429,657	482,762
12	56,291	500,254	3,273,732	422,913	479,204
13	59,668	559,922	3,214,064	415,764	475,432
14	63,248	623,170	3,150,816	408,186	471,434
15	67,043	690,213	3,083,773	400,154	467,197
16	71,066	761,279	3,012,707	391,639	462,705
17	75,330	836,609	2,937,377	382,614	457,944
18	79,850	916,459	2,857,527	373,047	452,897
19	84,641	1,001,100	2,772,886	362,906	447,547
20	89,719	1,090,819	2,683,167	352,157	441,876
21	95,102	1,185,921	2,588,065	340,762	435,864
22	100,808	1,286,729	2,487,257	328,684	429,492
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36	227,917	3,532,315	241,671	59,638	287,555
37	241,671	3,773,986	0	30,692	272,363
38					
39					
Total	$3,773,986			$12,068,177	$15,842,163

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SECRETARY'S OFFICE
Public Utility Commission

PECO STATEMENT NO. 16A

R-850152
3-11-86
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PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PHILADELPHIA ELECTRIC COMPANY,

DOCKET NO. R-850152

REBUTTAL TESTIMONY OF

DAVID J. FARLING

COOPERS & LYBRAND

RE: ACCOUNTING ISSUES RELATED

TO PHASE-IN PROPOSAL

DOCKETED
MAR 17 1986

FEBRUARY 19, 1986

DOCUMENT
FOLDER

REBUTTAL TESTIMONY OF DAVID J. FARLING

Q. Mr. Farling have you previously presented direct testimony in this proceeding?

A. Yes. My direct testimony was previously admitted into evidence as PECO Statement 16.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is three-fold:

1. To provide an update of the deliberations of the Financial Accounting Standards Board ("FASB") concerning an amendment to Statement of Financial Accounting Standards No. 71 ("Statement 71"), " Accounting for the Effects of Certain Types of Regulation."

2. To determine whether the Company's phase-in plan and the alternative phase-in plans advanced by opposing parties comply with this proposed amendment and to explain the consequences of non-compliance.

3. To comment upon certain statements made in the direct testimony of Gregory A. Palast and John W. Wilson.

Q. Would you provide an update of the deliberations of the FASB concerning an amendment to Statement No. 71?

A. Yes. On December 19, 1985, the FASB issued an Exposure Draft of a proposed Statement of Financial Accounting Standards entitled "Regulated Enterprises - Accounting for Phase-In Plans, Abandonments, and Disallowances of Plant Costs ("proposed Statement") - an Amendment of Statement 71." A copy of this Exposure Draft is attached as Appendix A to my rebuttal testimony.

Q. What is an Exposure Draft?

A. An Exposure Draft is a formal proposal to amend the standards of financial accounting and reporting which sets forth the text of the proposed amendment, the proposed effective date and transition, and the basis for the proposed amendment. At the end of the exposure period, in this case April 30, 1986, the FASB reviews the comment letters to determine that all reasonable alternatives have been appropriately considered. In addition, a public hearing will be on June 4 - 6, 1986 in Stamford, Connecticut. Upon completion of the hearing and comment period, a vote is taken on the final Statement. A majority is required for adoption of the Statement.

Q. What are the proposed standards of financial accounting and reporting in the proposed Amendment to Statement 71?

A. The Exposure Draft would amend Statement 71 to reflect accounting for three events that recently have occurred in the electric utility industry: phase-in plans, plant abandonments, and disallowances of costs of newly completed plants.

Q. What is the proposed Standard of Financial Accounting and Reporting for phase-in plans?

A. Paragraph 3 of the proposed Statement defines a phase-in plan as "any plan that defers, for future recovery, either (a) a portion of the current operating costs of a newly completed plant, or (b) a portion of specified overall current operating costs of a regulated enterprise based on some measure related to a recently completed plant."

Paragraph 4 of the proposed Statement defines the criteria for deferral of operating costs. "All current operating costs that are deferred for future recovery by a regulator pursuant to a phase-in plan shall be capitalized as a separate asset (a deferred charge) if all of the following criteria are met....

A. The costs in question are deferred pursuant to a formal plan that has been agreed to by the regulator.

B. The plan specifies the timing of recovery of all costs that will be deferred under the plan.

C. All costs deferred under the plan are scheduled for recovery within 10 years of the date when deferrals begin."

Q. What happens if a phase-in plan does not meet these criteria?

A. If any of the aforementioned criteria are not met, none of the costs deferred for future realization under the phase-in plan can be capitalized for financial reporting purposes. With respect to existing phase-in plans, if the aforementioned criteria are not met, all costs previously deferred under the plan would have to be written off.

Q. What is the intended effective date of the proposed Statement?

A. The proposed Statement would be effective for fiscal years beginning after December 15, 1986.

Q. Please explain the rationale of the FASB in establishing the ten-year rule for phase-in plans.

A. The current operating costs of a utility are generally expected to be recovered in the rates charged for the current use of electricity. The deferral of such costs is to accommodate the users of electricity by mitigating an extreme rate increase which may otherwise arise from placing a significant plant into service. Paragraph 5(c) of Statement 71 requires that "it is reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers. This criteria requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs." The FASB has concluded that a phase-in plan that requires a period of longer than 10 years creates an unacceptable degree of uncertainty whether paragraph 5(c) of Statement 71 is met.

Q. Would the company's phase-in plan, as originally filed, meet the criteria required in the proposed Statement for deferral of costs for financial reporting purposes?

A. Yes. If the plan were accepted by the Commission, it would meet the criteria set forth in paragraph 4 of the proposed Statement. The Company's plan, as originally filed, includes a formal plan for recognition of unrecovered revenue, specifies the billing of such unrecovered revenue, and provides for full recovery within 10 years of the date deferrals began.

Q. Does the proposed Statement explain the accounting to reflect the Company's decision not to seek recovery of a return on the unrecovered revenue?

A. Yes. Paragraph 12 of the proposed Statement provides the following accounting guidance: "If part of the cost is disallowed indirectly (e.g., a disallowance of return on investment on a portion of the plant), an equivalent amount of cost shall be deducted from the reported cost of the plant and charged to expense (recognized as a loss)." The absence of a return is an indirect disallowance because the Company is entitled to a return on the deferred amount.

Q. How would this indirect disallowance be reflected in the financial statements of the Company?

A. The difference between the present value and the gross amount of the unrecovered revenue would be recognized as a loss at that time on the income statement, and the discounted amount of the unrecovered revenue would be recorded as a non-current asset.

Q. Have you reviewed the various phase-in plans presented by opposing parties to determine whether they would comply with the Exposure Draft of FASB 71?

A. Yes, I have reviewed the phase-in proposals presented by Witnesses Palast, Wilson, Falkenberg, King, and Chernick. As set forth below, each of these plans may violate the proposed amendment to FASB 71. Witness Palast's 17-year phase-in on its face violates the 10-year requirement of the proposed amendment to FASB 71. If the proposed amendment is adopted and Witness Palast's phase-in were accepted, the Company would be unable to reflect currently in its income statement any of the revenue unrecovered under the phase-in plan. Witness Chernick's proposal to phase-in Limerick 1 by only including it in rates to the extent of its benefits also would clearly violate the proposed amendment by deferring the recovery of current costs beyond ten years.

The sinking fund depreciation proposals of Wilson and Falkenberg and the levelized payment proposal of Witness King probably would not be considered generally accepted accounting principles. First, investor-owned electric utilities generally do not employ sinking fund depreciation in their accounting and financial reporting. Second, as explained in Mr. Wroblewski's rebuttal testimony, sinking fund depreciation defers a very large portion of a plant's capital recovery to the very end of a plant's life and thereby creates an additional risk of non-recovery of costs. Third, the proposed amendment defines current operating costs "to include interest, an allowance for equity funds..., and a normal allocation of depreciation and decommissioning costs." Since sinking fund depreciation is not a normal allocation of depreciation and since it creates an additional risk of non-recovery, there is substantial uncertainty whether sinking fund depreciation would be acceptable to the Securities and Exchange Commission ("SEC") and the accounting profession. To adopt the sinking fund method for a very large asset such as

Limerick 1 would, in my view, create a substantial risk that the Company's financial statements would not be presented in accordance with GAAP.

Q. Is the Commission required to establish rates in accordance with GAAP and FASB 71 in particular?

A. No, but it should clearly recognize the consequences of not doing so.

Q. What are these consequences?

A. The financial statements of the company must be prepared in accordance with GAAP for presentation to the stockholders of the Company. The SEC requires the accountants' report on these financial statements to state the accounting principles and practices reflected therein and to state whether the audit was made in accordance with Generally Accepted Auditing Standards. The Standards of Reporting which are included in the Generally Accepted Auditing Standards of the American Institute of Certified Public Accountants require the accountants' report to state whether the financial statements are prepared in accordance with GAAP. If a phase-in plan adopted by this Commission does not comply with GAAP and specifically FASB 71, no unrecovered revenue could be recognized in the Company's income statement. This would materially and adversely affect the Company's reported earnings and various financial indicators.

In addition, and of equal importance, the ten-year rule set forth in the proposed amendment reflects the conclusion of the FASB that phase-in plans longer than ten years create a significant risk of non-recovery of the unrecovered revenue or costs. If the Commission adopts a plan that does not comply with FASB 71, and the Company is not permitted to reflect the unrecovered revenue in its income statement, the financial community will obviously conclude that there is a substantial risk of non-recovery. This perception of increased risk will adversely affect the Company's ability to compete with other firms in the market place to attract capital at a reasonable cost.

Q. Mr. Palast has indicated that the non-inclusion of unrecovered revenue in the income statement, because of non-adherence to GAAP, is of no significance to investors because the situation can be described in the notes to the financial statements. Do you agree with Mr. Palast's position?

A. No. The disclosure of earnings information in the notes to financial statements is generally not a substitute for inclusion in the financial statements themselves. Notes should not correct the financial statements. Published earnings information in the industry is based upon the financial statements of utility companies, not upon information in their notes to financial statements. Comparison of the Company's earnings and financial statements to other companies in the industry would be extremely difficult and could be detrimental, if it was expected that users of financial statements would have to obtain the necessary earnings information from the footnotes to the financial statements.

Q. Do you agree with Mr. Palast's comment on page 37 that "changes to FASB 71 are speculative"?

A. No. I have previously explained in this testimony the issuance of an Exposure Draft concerning an amendment of Statement 71. Obviously, the final adoption of this amendment by the FASB must await the completion of due process; however, at present, in my opinion, a consensus would favor a maximum time period for recovery of deferred amounts under a phase-in plan.

Q. Do you agree with Mr. Palast's comment on page 37 indicating that "if Mr. Farling's predicted changes do occur, PECO's own phase-in plan fails to meet the standards to permit current recognition of deferred income"?

A. No. As explained above, if the proposed amendment is adopted, PECO's plan will comply, but it will be required to discount the unrecovered revenue to reflect its non-recovery of carrying charges on the unrecovered revenue.

Q. On page 38, Mr. Palast indicates, "to establish a 'test year,' for rate-setting purposes, utilities adjust their regulatory income statements and balance sheets to include such constructs as 'normalizations,' 'annualizations,' 'disallowances,' 'amortizations' and any number of adjustments to books which are not recognized at all for financial reporting purposes." Do you agree with his comment preceding this quotation indicating that, "it is extremely important that this Commission maintain the distinction between accounting methods used to set just and reasonable rates and the method by which the resulting income is reported"?

A. No. The purpose of the aforementioned adjustments is to make the "test year" representative of the future under normal conditions. The actual financial statements will reflect these adjustments to the extent they have occurred in the future. The purpose of "test year" and "actual" financial statements are different; however, the accounting methods under GAAP are the same. Recording an item of expense "above-the-line" or "below-the-line" is an expression of regulatory intent for inclusion or non-inclusion in rates. In any event, the expenditure is a transaction reflected in the financial statements. These circumstances are not analogous to a phase-in plan and do not represent different accounting for rate setting and for financial reporting purposes.

Q. On page 43, Mr. Palast indicates that, since the Company has not performed an economic study of its rate plan, as supposedly required by the Issues Paper, dated October 15, 1984, of the American Institute of Certified Public Accountants Public Utilities Subcommittee, the Company would be barred from currently reporting deferred revenue under the phase-in plan. Do you agree with this conclusion?

A. No. The Subcommittee indicated that economic studies, among other factors, should be considered in evaluating the probability of future recovery of deferred costs. The judgment of the persons involved and the circumstances would determine the appropriateness of such a study. Moreover, no such requirement appears in the proposed amendment.

Q. Do you agree with Mr. Palast's comment on page 77 that, "according to the proposed changes in FASB 71, the Company may not be permitted to report a return on the deferred revenue even if the return is granted by the Commission"?

A. No. The approval by the Commission of a return on unrecovered revenue, assuming the probability of collection from the customers, would permit recognition in the books of account.

Q. Do you have any comment relative to Dr. Wilson's comment on page 35 that "if regular rate proceedings are held, the Commission will have the opportunity to make corresponding rate changes as new circumstances may warrant"?

A. Yes. Statement 71 requires that future revenue will be provided to recover previously incurred costs so as to justify their deferral. Regular rate proceedings should not change such assurance or indirectly adjust the recovery of other costs in lieu thereof.

Q. Mr. Farling, are there any other aspects of the proposed amendment which are relevant to this proceeding?

A. Yes. Apart from the phase-in issue, it should be noted that if the proposed amendment is adopted, any disallowance of plant cost for imprudency must be charged to income in the year the disallowance occurs. This is a major change in present, generally accepted accounting principles and, if adopted, would greatly increase the financial impact of a prudency adjustment.

Q. Does this complete your testimony?

A. Yes, it does.

NO. 011 DECEMBER 19, 1985

Financial Accounting Series

EXPOSURE DRAFT

Proposed Statement of Financial Accounting Standards

Regulated Enterprises— Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs

an amendment of FASB Statement No. 71

This Exposure Draft of a proposed Statement of Financial Accounting Standards is issued by the Board for public comment. Written comments should be addressed to:

Director of Research and Technical Activities
File Reference No. 011

Comment Deadline: April 30, 1986

Financial Accounting Standards Board
of the Financial Accounting Foundation

Any individual or organization may obtain one copy of this Exposure Draft without charge until April 30, 1986 on written request only. For information on applicable prices for additional copies and copies requested after April 30, 1986 contact:

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Financial Accounting Standards Board
of the Financial Accounting Foundation
HIGH RIDGE PARK PO BOX 3821, STAMFORD, CONNECTICUT 06905-0821

REGULATED ENTERPRISES—ACCOUNTING FOR PHASE-IN PLANS, ABANDONMENTS, AND DISALLOWANCES OF PLANT COSTS

Notice of Public Hearing and Request for Written Comments

Hearing: June 4-6, 1986, 9:00 a.m.
Sheraton Hotel
First Stamford Place
Stamford, Connecticut

Deadline for Written Notice of Intent to Speak: April 1, 1986

Basis for hearing. The Financial Accounting Standards Board will hold a public hearing to obtain information from and views of interested individuals and organizations about the standards proposed in this Exposure Draft. The hearing will be conducted by Board and staff members.

Oral presentation requirements. An individual or organization wishing to speak at the public hearing should notify the FASB by April 1, 1986. The intended speaker should submit a position paper, an outline of a proposed presentation, or a comment letter addressing the standards proposed in this Exposure Draft by April 30, 1986. All submissions should be addressed to the director of research and technical activities at the address listed below. Speakers will be notified of the time scheduled for their presentations.

Format of the hearing. Speakers are allotted 30 minutes, of which 10 minutes are for their presentation and 20 minutes are for answering questions from the Board and staff. Speakers should not use their allotted time to read already submitted written comments as these comments already have been read and analyzed by the Board and staff. They also are included in the public record and will be available at the hearing for inspection.

Observers. Observers are welcome at the public hearing but may not participate in the discussions. Observers are urged to submit written comments.

Hotel reservations. Contact the Sheraton Hotel in Stamford, Conn. directly at (203) 967-2222 by May 14, 1986 for room reservations. Mention attendance at the hearing for special room rates.

Deadline for Submitting Written Comments: April 30, 1986

Written comments. Participation at the public hearing is not a prerequisite to submitting written comments on this project. Written comments are given the same consideration as public hearing testimony. Any individual or organization may send written comments to the director of research and technical activities at the address listed below by April 30, 1986.

* * *

Public files. A transcript of the public hearing and copies of all written submissions on the project will be available for inspection in the FASB's Public Reference Room. Copies are available for a duplication fee.

Orders. One copy of this Exposure Draft is available free of charge until April 30, 1986 by writing to the FASB Order Department at the address listed below. Prices for multiple orders and copies ordered after April 30, 1986 are available from the Order Department.

Additional information. For further details about the public hearing or about submitting written comments, please contact the FASB.

* * *

Financial Accounting Standards Board
File Reference 011
High Ridge Park
P.O. Box 3821
Stamford, CT 06905-0821
Telephone (203) 329-8401

Notice for Recipients of This Exposure Draft

This proposed Statement would be effective for fiscal years beginning after December 15, 1986. It would apply to events occurring after the effective date, and it would also apply to (a) all existing phase-in plans, (b) costs of abandoned plants for which rate orders have already been received, and (c) previously disallowed plant costs.

The Board asks respondents who believe that additional delay in the proposed effective date is warranted for their specific situations to describe their existing circumstances in detail and explain why a delay would be appropriate and what it would accomplish. Paragraphs 79 through 84 of the basis for conclusions describe the Board's deliberations concerning the effective date and transition in this proposed Statement, including a description of certain types of situations that might justify a delay in the effective date.

The Board also requests comments in response to this Exposure Draft regarding its conclusions about the application of its proposed Statement on accounting for income taxes to regulated enterprises. Those conclusions, which are related to the Board's current project on accounting for income taxes, are explained in paragraphs 85 through 87 of the basis for conclusions of this Exposure Draft.

Summary

This proposed Statement would amend FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation,* for three types of events that recently have occurred in the electric utility industry—phase-in plans, abandonments, and disallowances of costs of newly completed plants.

When a utility completes a new plant, conventional rate-making procedures establish rates to provide recovery of the current operating costs of the plant, including depreciation, interest, and a provision for earnings on shareholders' investment in that plant. In recent years, the cost of new plants has been much greater than in the past, so conventional rate-making procedures would have resulted in significantly increased rates for some utilities. Phase-in plans defer for recovery in future years part of the current operating costs related to a new plant that normally would be recovered through current rates. Phase-in plans were not specifically addressed in Statement 71. This proposed Statement would require that those deferred costs be capitalized provided that (a) the plan has been agreed to by the regulator, (b) the plan specifies when recovery will occur, and (c) all deferred amounts are to be recovered within 10 years of the plan inception. If any of those criteria is not met, this proposed Statement would prohibit capitalization of any deferred amounts.

This proposed Statement would amend Statement 71 to require the probable future revenue that is expected to result from the regulator's inclusion of the cost of an abandoned plant in allowable costs for rate-making purposes to be reported at its present value. If the carrying amount of the abandoned plant exceeds that present value, a loss would be recognized. Statement 71 requires that asset to be reported at the lesser of the cost of the abandoned plant or the probable gross revenue.

This proposed Statement would amend Statement 71 to require any disallowed costs of a newly completed plant to be recognized as a loss. Statement 71 requires asset impairments to be recognized but does not specify what constitutes impairment or how impairment should be recognized.

This proposed Statement would be effective for fiscal years beginning after December 15, 1986 and would apply to existing and future phase-in plans, recorded costs of previously abandoned assets and of assets for which abandonment becomes probable in the future, and previously disallowed plant costs and disallowances of plant costs that become probable in the future. Restatement of financial statements for prior fiscal years would be permitted but not required.

Proposed Statement of Financial Accounting Standards

Regulated Enterprises—Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs

an amendment of FASB Statement No. 71

December 19, 1985

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Proposed Statement of Financial Accounting Standards

Regulated Enterprises—Accounting for Phase-in Plans, Abandonments, and Disallowances of Plant Costs

an amendment of FASB Statement No. 71

December 19, 1985

INTRODUCTION

1. FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*, was issued in December 1982. Shortly after the Statement was issued, major events in the electric utility industry caused the Board to review the effects of the Statement on the accounting for those events. After considering the application of the Statement, the Board decided to amend Statement 71 to provide more specific guidance for some of those events and to change the accounting for others.

2. This Statement amends Statement 71 to specify accounting for phase-in plans, plant abandonments, and disallowances of costs of newly completed plants.

STANDARDS OF FINANCIAL ACCOUNTING AND REPORTING

Accounting for Phase-in Plans

3. For purposes of this Statement, a *phase-in plan* is any plan that defers, for future recovery, either (a) a portion of the current operating costs[1] of a newly completed plant or (b) a portion of specified overall current operating costs of a regulated enterprise based on some measure related to a recently completed plant.[2]

[1]The term *current operating costs*, as used in this Statement, includes interest, an allowance for equity funds (that is, amounts provided for earnings on shareholders' investment), and a normal allocation of depreciation and decommissioning costs.

[2]For example, a phase-in plan might defer a percentage of a utility's overall cost of capital based on the percentage of the enterprise's total capacity that results from the newly completed plant.

4. All current operating costs that are deferred for future recovery by a regulator pursuant to a phase-in plan shall be capitalized as a separate asset (a deferred charge) if all of the following criteria are met. If any of those criteria is not met, none of the costs that are deferred for future recovery under the plan shall be capitalized for financial reporting purposes.

a. The costs in question are deferred pursuant to a formal plan that has been agreed to by the regulator.
b. The plan specifies the timing of recovery of all costs that will be deferred under the plan.
c. All costs deferred under the plan are scheduled for recovery within 10 years of the date when deferrals begin.

Any indirect disallowance of costs of the newly completed plant contained in the phase-in plan shall be recognized in accordance with paragraph 12 of this Statement.

Allowance for Funds Used during Construction

5. Paragraph 15 of Statement 71 requires an allowance for funds used during construction, including a designated cost of equity funds, to be capitalized in specified circumstances as part of the acquisition cost of the related asset. That cost shall be capitalized under those circumstances only if its subsequent inclusion in allowable costs for rate-making purposes is probable.[3]

Other Capitalization of an Allowance for Equity Funds

6. An allowance for equity funds shall be capitalized, as a deferred charge, when it is deferred by the regulator in conjunction with the short-term deferral of a cost increase. In order for the allowance for equity funds to qualify for capitalization under this paragraph, the deferral and capitalization must be ordered by the regulator, and both the related cost and the associated allowance for equity funds must be expected to be recovered either through an automatic rate adjustment clause or in the rates provided in the next rate case.

7. An allowance for equity funds is not an "incurred cost that would otherwise be charged to expense" as that phrase is used in paragraph 9 of Statement 71. Accordingly, such an allowance shall not be capitalized pursuant to paragraph 9 of Statement 71.

[3]The term *probable* is used in this Statement consistent with its use in FASB Statement No. 5, *Accounting for Contingencies,* to mean that a transaction or event is likely to occur.

Accounting for Abandonments

8. When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process or plant-in-service, and the present value of the probable future revenues expected to be provided to recover the cost of that asset, if any, shall be reported as a separate asset (a deferred charge). Any excess of the carrying amount of the asset over that present value shall be recognized as a loss. The discount rate used to compute the present value shall be the overall rate of return allowed in the regulated enterprise's latest rate case in the jurisdiction in which recovery is expected to be received. In determining the present value, the enterprise shall consider such matters as (a) whether the regulator having jurisdiction has allowed recovery of and return on unrecovered investment in abandoned plants in the past, (b) the probable time period before such recovery is expected to begin, (c) the probable time period over which recovery will be provided, and (d) any probable disallowance of the cost of the abandoned asset. If the estimate of the probable recovery period is a range, the most likely period within that range shall be used to compute the present value. If no period within that range is more probable than any other, the present value shall be based on the minimum time period within that range. The recorded present value shall be adjusted from time to time as necessary if new information indicates that the amount to be recovered or the recovery period will be different from the estimates used to determine the present value. The amount of the adjustment shall be reported in the income statement as a loss or gain.

9. During the period between the date on which the present value of the probable future revenues expected to be provided is recognized and the date on which a rate order is received, the carrying amount shall be increased by accruing a carrying charge, using the rate that was used to compute the present value. Paragraph 26 and Schedule 2 of Appendix A illustrate that procedure.

10. When a rate order is received, the present value of the resulting future revenues shall be adjusted, if necessary, based on the recovery period specified in the rate order and the rate that was used for the calculation required by paragraph 8 above. The amount of the adjustment shall be reported in the income statement as a loss or gain.

11. Subsequent to the date of the rate order, the asset shall be amortized in a manner that will produce a constant return on the unamortized investment in the abandoned plant equal to the rate at which the probable revenues were discounted. Paragraph 28 and Schedule 3 of Appendix A illustrate that procedure.

Disallowances of Costs of Newly Completed Plants

12. When it becomes probable that part of the cost of a newly completed plant will be disallowed for rate-making purposes, the part of the cost that is expected to be disallowed shall be deducted from the reported cost of the plant and charged to expense (recognized as a loss). If part of the cost is disallowed indirectly (for example, by disallowance of return on investment on a portion of the plant), an equivalent amount of cost shall be deducted from the reported cost of the plant and charged to expense (recognized as a loss).

Amendments to Existing Pronouncements

13. This Statement amends Statement 71 as follows:

a. Paragraph 13 is superseded by the following:

> Appendix B and FASB Statement No. XX (this Statement) illustrate the application of the general standards of accounting for the effects of regulation.

b. Footnote 6 to paragraph 9 is superseded by the following:

> [6]The term *probable* is used in this Statement consistent with its use in FASB Statement No. 5, *Accounting for Contingencies.* Statement 5 defines probable as an area within a range of the likelihood that a future event or events will occur. That range goes from probable to remote, as follows:
>
> *Probable.* The future event or events are likely to occur.
> *Reasonably possible.* The chance of the future event or events occurring is more than remote but less than likely.
> *Remote.* The chance of the future event or events occurring is slight.

c. The following footnote is added after the term *capitalize* in the second sentence of paragraph 9:

> *Phase-in plans shall be accounted for in accordance with paragraphs 3 and 4 of Statement XX (this Statement). An allowance for equity funds shall be capitalized only in the circumstances described in paragraph 15 of Statement 71 and in paragraphs 3-7 of Statement XX (this Statement). Costs of abandoned plants shall be accounted for in accordance with paragraphs 8-11 of Statement XX (this Statement).

d. The following footnote is added to the end of paragraph 10:

> †Disallowances of costs of newly completed plants, whether direct or indirect, shall be accounted for in accordance with paragraph 12 of Statement XX (this Statement).

Effective Date and Transition

14. The provisions of this Statement shall be effective for fiscal years beginning after December 15, 1986 and interim periods within those fiscal years. Earlier application is permitted. Retroactive application of this Statement in fiscal years for which financial statements have previously been issued is permitted, in which case the financial statements of all prior periods presented shall be restated. In addition, the financial statements shall, in the year this Statement is first applied, disclose the nature of any restatement and its effect on income before extraordinary items, net income, and related per share amounts for each period presented and on retained earnings at the beginning of the earliest period presented.

15. If financial statements for prior fiscal years are not restated, the effects of applying this Statement to existing situations shall be reported as the cumulative effect of a change in accounting principle, as described in APB Opinion No. 20, *Accounting Changes,* and the effect of adopting this Statement on income before extraordinary items, net income, and the related per share amounts shall be disclosed.

16. Initial application of this Statement will require the following adjustments to previously recorded assets with corresponding adjustments to reported net income of prior years or to the cumulative effect of an accounting change in the year of the change:

a. Existing phase-in plans shall be evaluated under the criteria of this Statement. If those existing plans do not meet the criteria of this Statement for capitalization of deferred costs, all costs deferred under those plans that have previously been capitalized shall be written off.
b. Amounts that were recorded in prior years for recoverable costs of abandoned plants shall be adjusted to the present value of the probable future revenues that are expected to be provided to recover the cost of those abandoned plants. The

discount rate used to compute the present value shall be the overall rate of return allowed in the regulated enterprise's latest rate case preceding the date of the abandonment.

c. Disallowed plant costs of the kind covered in paragraph 12 shall be deducted from the reported cost of the related asset.

The provisions of this Statement need not be applied to immaterial items.

Appendix A

EXAMPLES OF APPLICATION OF THIS STATEMENT TO SPECIFIC SITUATIONS

17. This appendix provides guidance for application of this Statement to some specific situations. The guidance does not address all possible applications of this Statement. All the examples assume that the enterprise meets the criteria of paragraph 5 of Statement 71 for the application of Statement 71 by the enterprise. Cases like those illustrated in this appendix would probably involve income tax effects that could accrue to the utility in question. Some of those tax effects might be recognizable currently under APB Opinion No. 11, *Accounting for Income Taxes;* others might not be recognizable currently. The examples ignore those income tax effects because the amounts of those tax effects would be dependent on other taxable income.

18. Specific situations discussed in this appendix are:

	Paragraph Numbers
Accounting for a phase-in plan that includes an indirect disallowance	19–22
Accounting for abandonment	23–28
Accounting for a disallowance of plant cost	29–31
Accounting for a disallowance of plant cost resulting from a "cost cap"	32–34

Accounting for a Phase-in Plan That Includes an Indirect Disallowance

19. Utility A is an electric utility that operates solely in a single-state jurisdiction. On January 1, 19X1, Utility A's new electric generating plant becomes operational. The cost of that plant is $1 billion.

20. Utility A's regulator orders that the costs of the newly completed plant be phased in over a three-year period, as follows:

Year 1 A portion of the return on unrecovered investment is deferred by excluding 25 percent of the cost of the plant from the rate base.

Year 2 All of the remaining cost of the plant is to be included in the rate base with no recovery of previously deferred amounts.

Year 3 All of the remaining cost of the plant is to be included in the rate base, plus additional revenue is to be provided equal to the cost of capital excluded from rates in year 1.

The order does not provide for recovery of a return on Utility A's investment in the deferred amounts. Utility A's weighted-average cost of capital in its latest rate case was 11 percent.

21. The phase-in plan is partially a disallowance of plant costs because no return on investment is provided for the deferred amounts. That disallowance would be recognized when it became probable. The amount of equivalent cost disallowed would be determined as shown in Schedule 1. The recorded cost of the plant would be reduced by that amount, and a corresponding loss would be reported.

22. The disallowance will reduce revenues only in years 1 through 3, so the depreciation charge that would otherwise be recognized for that plant in years 1 through 3 would be reduced by the amount of the effective disallowance attributable to those years (the amount in column 4 on Schedule 1). Amounts deferred under the plan (the amount for months 1-12 in column 1 on Schedule 1) would be capitalized as a separate asset, and that asset would be amortized as recovery occurs (in months 25-36), using the amounts in column 1 on Schedule 1.

Accounting for Abandonment

23. Utility B operates solely in a single-state jurisdiction that, in the past, has permitted recovery of amounts prudently invested in abandoned plants over an extended period of time without a return on unrecovered investment during the recovery period. Utility B decides to abandon a plant that has been under construction for some time. Although the possibility of abandoning the plant has been under consideration, abandonment was not considered probable before the actual decision was made. The recorded cost of the plant is $523 million; and the company estimates that it will incur additional contract cancellation penalties of approximately $22.5 million, which will be paid in approximately 6 months. Utility B's weighted-average cost of capital allowed in its latest rate case was 11.25 percent.

24. In view of the accumulated cost of the abandoned plant, Utility B believes that it is probable that recovery of cost without return on investment during the recovery period will be granted over a period that will be not less than 5 years nor more than 10 years, but it has no basis for estimating the exact time period within that range

Schedule 1

Utility A
Determination of Effective Disallowance
Return on Investment Disallowed for Amounts Deferred under Phase-in Plan

Month	(1) Cost Deferral (Recovery)	(2) Cumulative Amount Deferred	(3) R.O.I. on Cumulative Deferral	(4) Effective Disallowance
	(amounts in thousands)			
1	$ 2,292	$ 2,292	$ 21	$ 0
2	2,291	4,583	42	21
3	2,292	6,875	63	41
4	2,292	9,167	84	61
5	2,291	11,458	105	80
6	2,292	13,750	126	99
7	2,292	16,042	147	118
8	2,291	18,333	168	137
9	2,292	20,625	189	155
10	2,292	22,917	210	173
11	2,291	25,208	231	190
12	2,292	27,500	252	207
13	0	27,500	252	224
14	0	27,500	252	222
15	0	27,500	252	220
16	0	27,500	252	218
17	0	27,500	252	216
18	0	27,500	252	214
19	0	27,500	252	212
20	0	27,500	252	210
21	0	27,500	252	208
22	0	27,500	252	206
23	0	27,500	252	204
24	0	27,500	252	202
25	(2,292)	25,208	231	201
26	(2,291)	22,917	210	182
27	(2,292)	20,625	189	164
28	(2,292)	18,333	168	146
29	(2,291)	16,042	147	129

Schedule 1
(continued)

Utility A
Determination of Effective Disallowance
Return on Investment Disallowed for Amounts Deferred under Phase-in Plan

Month	(1) Cost Deferral (Recovery)	(2) Cumulative Amount Deferred	(3) R.O.I. on Cumulative Deferral	(4) Effective Disallowance
	(amounts in thousands)			
30	(2,292)	13,750	126	112
31	(2,292)	11,458	105	95
32	(2,291)	9,167	84	78
33	(2,292)	6,875	63	62
34	(2,292)	4,583	42	46
35	(2,291)	2,292	21	31
36	(2,292)	0	0	15
Total loss to be recognized				$5,099

Computations:

Column (1) Cost of plant ($1 billion) × .25 × 11% ÷ 12
Column (2) Column (2) for prior month + Column (1) for current month
Column (3) Column (2) × 11% ÷ 12
Column (4) Present value (at beginning of month 1) at 11% of amount in Column (3) in prior month

that will be selected by the regulator. In view of the rate-making process in Utility B's jurisdiction, it will take approximately 18 months to obtain a rate order covering the abandoned plant.

25. When the abandonment becomes probable (in this case, at the date of the decision to abandon), Utility B would remove the plant from construction work-in-progress. It would record a new asset, a deferred charge representing the probable future revenues expected to result from the regulator's treatment of the cost of the abandoned plant, at the present value of the probable future revenues. In making that computation, the probable future revenues would be estimated at $9,091,667 per month for 5 years (based on an assumed straight-line recovery over the 5-year minimum period within the range), and those cash flows would be estimated to begin in 19 months. The computation of the amount to be recorded for the new asset and of the loss resulting from the abandonment would be:

Present value of $9,091,667 per month at 11.25% for 60 months, starting at the end of the 19th month (amount to be recorded as new asset)		$351,481,482
Cost of abandoned plant:		
Previously recorded cost	$523,000,000	
Cancellation charges to be accrued ($22,500,000 discounted at 11.25% for 6 months)	21,274,887	
Net cost		544,274,887
Loss to be recorded at time of abandonment		$192,793,405

26. Pending receipt of a rate order, Utility B would accrue carrying charges on the recorded asset at an 11.25 percent annual rate. Schedule 2 shows that computation. If it becomes probable that the period before rate action will be significantly longer or shorter than 18 months, the carrying amount of the new asset would be adjusted to reflect that new estimate.

Schedule 2

Utility B
Accrual of Carrying Charges on Asset Resulting from Abandoned Plant

Month	Recorded Amount Beginning of Month	Carrying Charges Accrued	Recorded Amount End of Month
1	$ 351,481,482	$ 3,295,106	$ 354,776,588
2	354,776,588	3,326,031	358,102,619
3	358,102,619	3,357,212	361,459,831
4	361,459,831	3,388,686	364,848,517
5	364,848,517	3,420,455	368,268,972
6	368,268,972	3,452,521	371,721,493
7	371,721,493	3,484,889	375,206,382
8	375,206,382	3,517,560	378,723,942
9	378,723,942	3,550,537	382,274,479
10	382,274,479	3,583,823	385,858,302
11	385,858,302	3,617,422	389,475,724
12	389,475,724	3,651,335	393,127,059
13	393,127,059	3,685,566	396,812,625
14	396,812,625	3,720,118	400,532,743
15	400,532,743	3,754,995	404,287,738
16	404,287,738	3,790,197	408,077,935
17	408,077,935	3,825,731	411,903,666
18	411,903,666	3,861,597	415,765,263

27. Assume that the rate order is received at the end of the 18th month and specifies a recovery period of 6 years. Utility B would reflect that change in estimate by recognizing an additional loss, as follows:

Present value of $7,576,389 per month at 11.25% for 72 months (adjusted carrying amount of asset)	$395,378,451
Less: Carrying amount of asset (per Schedule 2)	415,765,263
Loss to be recorded at time of rate order	$ 20,386,812

The discount rate would not be adjusted to the rate permitted in that new rate order. That new rate reflects current conditions rather than the conditions that prevailed at the time of the abandonment.

28. As recovery occurs, the recorded asset would be amortized so as to reflect earnings on the unamortized asset at the 11.25 percent rate initially used to determine the present value of the asset. Schedule 3 shows the details of that computation.

Accounting for a Disallowance of Plant Cost

29. Utility C operates in two state jurisdictions. After an extensive "prudence investigation," the regulator in one of those state jurisdictions disallows $865 million of the $3.6 billion total cost of Utility C's newly completed nuclear generating plant. That state jurisdiction represents approximately 50 percent of Utility C's operations, and approximately 50 percent of the output of the newly completed plant is expected to be used in that state. The regulator in Utility C's other state jurisdiction has not participated in the "prudence investigation," and there is no indication that a similar disallowance is likely in that jurisdiction.

30. After consultation with counsel, Utility C decides that it should appeal the regulator's disallowance. Counsel indicates that there are valid bases for an appeal, but there is no way to predict the outcome of an appeal. What accounting should result?

31. Utility C should recognize the effective disallowance as a loss. The effective disallowance is 50 percent of the amount disallowed, or $432.5 million, because only 50 percent of the plant's cost will be recoverable from customers in that state. The disallowance should be recognized when it occurs. The possibility of a court overturning a regulator's decision on a question of fact represents a gain contingency of the type that is not recognized until it occurs.

Schedule 3

Utility B
Computation of Amortization of Asset Resulting from Abandoned Plant

Month	(1) Unamortized Balance Beg. of Month	(2) Return at 11.25%	(3) Revenues	(4) Amortization of Cost (Col 3–Col 2)	(5) Unamortized Balance End of Month (Col 1–Col 4)
19	395,378,451	3,706,673	7,576,389	3,869,716	391,508,735
20	391,508,735	3,670,394	7,576,389	3,905,995	387,602,740
21	387,602,740	3,633,776	7,576,389	3,942,613	383,660,127
22	383,660,127	3,596,814	7,576,389	3,979,575	379,680,551
23	379,680,551	3,559,505	7,576,389	4,016,884	375,663,688
24	375,663,688	3,521,847	7,576,389	4,054,542	371,609,126
25	371,609,126	3,483,836	7,576,389	4,092,553	367,516,572
26	367,516,572	3,445,468	7,576,389	4,130,921	363,385,651
27	363,385,651	3,406,740	7,576,389	4,169,649	359,216,003
28	359,216,003	3,367,650	7,576,389	4,208,739	355,007,264
29	355,007,264	3,328,193	7,576,389	4,248,196	350,759,068
30	350,759,068	3,288,366	7,576,389	4,288,023	346,471,045
.	.	.	.	.	.
.	.	.	.	.	.
.	.	.	.	.	.
80	78,836,757	739,095	7,576,389	6,837,294	71,999,463
81	71,999,463	674,995	7,576,389	6,901,394	65,098,069
82	65,098,069	610,294	7,576,389	6,966,095	58,131,974
83	58,131,974	544,987	7,576,389	7,031,402	51,100,572
84	51,100,572	479,068	7,576,389	7,097,321	44,003,251
85	44,003,251	412,530	7,576,389	7,163,859	36,839,393
86	36,839,393	345,369	7,576,389	7,231,020	29,608,373
87	29,608,373	277,578	7,576,389	7,298,810	22,309,562
88	22,309,562	209,152	7,576,389	7,367,237	14,942,326
89	14,942,326	140,083	7,576,389	7,436,306	7,506,020
90	7,506,020	70,369	7,576,389	7,506,020	0

Note: All computations assume that revenues for a month are received at the end of the month. At the end of each month, the unamortized balance of the asset is equal to the present value of the remaining revenues of $7,576,389 per month at an 11.25 percent annual interest rate.

Accounting for a Disallowance of Plant Cost Resulting from a "Cost Cap"

32. Utility D, which operates solely in one state jurisdiction, is constructing a new electric generating plant. The cost of the plant, which was originally expected to be $1.25 billion, is now expected to be approximately $3.5 billion. Various parties have charged that certain cost increases were a result of imprudent management of the construction.

33. To avoid the cost and time delay that would be involved in a full-scale "prudence investigation" of the construction of the plant, Utility D and its regulator agree that the total cost of the plant that will be allowable in determining depreciation and that will be allowed in Utility D's rate base will be $3.4 billion. What accounting is required as a result of that agreement?

34. Based on the agreement, $100 million of probable cost has been disallowed. Accordingly, Utility D would write off $100 million of the cost of the plant as a loss resulting from a disallowance at the date of the agreement (or at the date that the agreement becomes probable, if that date preceded the date of the agreement). Subsequently, if additional increases in the cost of the plant become probable and those costs are not allowable under the agreed maximum cost, those increases would also be recognized as losses from disallowances when they become probable.

Appendix B

BACKGROUND INFORMATION

35. Statement 71 was issued in December 1982, effective for financial statements for fiscal years beginning after December 15, 1983. In early 1984, several different circumstances caused the Board to question whether the application of Statement 71 in practice was what the Board had intended.

36. Subsequent to issuing Statement 71, the Board became aware of several phase-in plans that involved capitalization of an allowance for equity funds on an operating plant. The Board considered issuing an Interpretation or permitting issuance of a Technical Bulletin to point out that capitalization of such an allowance was not permitted by Statement 71. However, after discussing the nature of phase-in plans and the reasons for their adoption with an affected company and its auditor, the Board decided to explore the use of phase-in plans in more depth before addressing the accounting for those plans.

37. During 1984, rate problems related to new nuclear electric generating plants of several utilities were widely discussed in the financial press. Comments credited to executives of those utilities indicated considerable question whether the utilities could bill rates based on the cost of those plants to their customers without losing a major part of their customer base. Some articles indicated that phase-in plans were likely for certain of those utilities, but they raised significant questions about the assurance of recovery of costs that would be deferred. Representatives of some regulatory commissions began to question the cost of certain of those new plants and to discuss possible major disallowances. Also, several plants in advanced stages of construction were abandoned. In a few states, courts ruled that utilities could not recover the costs of those abandoned plants from customers.

38. As a result of Board member concerns, the Board asked the staff to investigate whether guidance about the application of Statement 71 was needed in practice. The staff met several times with committees of Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners, and the Public Utilities Subcommittee of the American Institute of Certified Public Accountants (the AICPA Subcommittee). The Board also met with representatives of those groups and the Federal Energy Regulatory Commission.

39. In November 1984, the Board received an AICPA Issues Paper, "Application of Concepts in FASB Statement of Financial Accounting Standards No. 71 to Emerging Issues in the Public Utility Industry." That paper listed 17 specific issues related to current problems in the electric utility industry identified by the the AICPA Subcommittee. The Board also received a comment letter from EEI on the issues raised in the AICPA Issues Paper.

40. In April 1985, the Board's Task Force on Regulated Enterprises met and discussed a staff draft of a possible Exposure Draft that encompassed most of the conclusions included in this Statement.

41. Subsequent to the April task force meeting, the Board received 51 letters from 39 affected enterprises and other interested parties commenting on the positions proposed in the staff draft discussed at the task force meeting and on the Board's tentative conclusions reached at its public meetings subsequent to that task force meeting.

Appendix C

BASIS FOR CONCLUSIONS

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Appendix C

BASIS FOR CONCLUSIONS

Introduction

42. This appendix summarizes considerations that were deemed significant by members of the Board in reaching the conclusions in this Statement. It includes reasons for accepting certain views and rejecting others. Individual Board members gave greater weight to some factors than to others.

General Considerations

43. Various letters received as the Board was developing the conclusions in this proposed Statement objected to the Board's conclusions about accounting for abandonments and disallowances of costs of newly completed plants on the basis that those decisions departed from the historical cost model of accounting for enterprises generally. The Board provided its view of the current accounting model in paragraphs 66-70 of FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises.* Paragraph 66 acknowledges that the current model is not a pure "historical cost" model, as follows:

> Items currently reported in financial statements are measured by different attributes, depending on the nature of the item and the relevance and reliability of the attribute measured. The Board expects the use of different attributes to continue.

44. The Board also noted that the accounting specified by Statement 71 is itself a departure from the accounting framework applied by nonregulated enterprises generally. That Statement recognizes that rate actions of a regulator can have economic effects and requires certain items that would be charged to expense by nonregulated enterprises to be capitalized by regulated enterprises solely because the regulator's rate actions can provide reasonable assurance of future revenue. Both Statement 71 and this Statement extend the concept of cost capitalization to require, in certain circumstances, capitalization of an allowance for equity funds—an item that cannot be capitalized by a nonregulated enterprise.

45. The Board believes that a system that recognizes reasonable assurance of future revenues due to a regulator's actions as assets or as enhancements of assets must also recognize diminished prospects of future revenues due to a regulator's actions as

reductions of assets. General purpose financial statements that recognized asset enhancements but not asset decrements would lack representational faithfulness—a critical qualitative characteristic if financial statements are to be reliable.

46. The Board believes that the accounting required by this Statement for abandonments and disallowed plant costs is consistent with other accounting that is required by Statement 71 and by this Statement. For example, the cost of equity funds is included in the allowance for funds used during construction (AFUDC) that Statement 71 requires to be capitalized by certain regulated enterprises but is excluded from the interest capitalized by nonregulated enterprises. That item is included for regulated enterprises solely because the regulator's allowance of AFUDC for rate-making purposes enhances the regulated enterprise's prospects of future revenues. Similarly, the act of the regulator in disallowing part of the cost of a newly completed plant or providing recovery of the cost of an abandoned plant without return on investment diminishes the enterprise's prospects of future revenues.

47. Some letters received in connection with this project objected to the proposals contained in this Exposure Draft on the basis that some regulators might use the resulting reported amounts to reduce rates from the levels that would otherwise be permitted. The Board is aware of the relationship between the rates set by regulators and costs and capital structures used for general purpose financial reporting. A regulator's treatment of costs or capital structures may affect the amounts reported in general purpose financial statements in a variety of ways, as specified in Statement 71 and in this Exposure Draft. Similarly, regulators may look to generally accepted accounting principles for treatment of specific costs. In still other cases, regulators might base rates on costs or capital structures unrelated to those reported in general purpose financial statements.

48. The Board is also aware that, if an accounting standard has indirect financial consequences that some view as onerous, like changing the amounts of current revenue allowed by regulators, the failure to act also has consequences that would be equally onerous to others. The Board cannot control or limit the uses of general purpose financial statements, but more importantly, the Board cannot allow its decisions to be tailored to assist the special interests of some affected enterprises or any other special interests.

Accounting for Phase-in Plans

49. Accounting for phase-in plans involves two separate issues under Statement 71. The first issue is whether, in view of the perceived need for a phase-in plan resulting from the size of the rate increase that would otherwise be required, it is reasonable to

assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers in the future. Paragraph 5(c) of Statement 71 requires that such an assumption be reasonable as a condition for application of that Statement.

50. Recently, some phase-in plans have been discussed in public forums as ways of retaining major customers. Utility officials have indicated that major industrial customers would leave their utility's service area or develop alternative sources of supply if rates were increased sufficiently to recover the costs of a newly completed plant. In that environment, a phase-in plan might be an indication that the utility cannot bill and collect rates that will recover its costs, rather than merely be an accommodation in the billing of revenues for the convenience of the utility's customers.

51. The other issue raised by a phase-in plan is whether it is appropriate to capitalize an allowance for equity funds after a plant begins operating. Paragraph 15 of Statement 71 requires capitalization of an allowance for equity funds as part of the acquisition cost of an asset *during construction*. Statement 71 does not provide for capitalization of an allowance for equity funds under any other circumstances. Most of the phase-in plans that have been ordered by regulators require deferral of an allowance for equity funds. That allowable cost is usually selected for deferral because the amount is large and it does not necessarily represent a current cash outlay.

52. The AICPA Issues Paper noted that, under Statement 71, a cost that would otherwise be charged to expense could be capitalized pursuant to a phase-in plan if recovery through future rates was probable, but an allowance for equity funds could not be capitalized other than during construction of a physical asset. The Issues Paper recommended that the regulator's selection of a specific allowable cost for deferral should not be important to accountants because any allowable cost can be selected with equal economic effect.

53. The Board believes that an allowance for equity funds is different from other costs for which recovery is provided by regulators. It is not an incurred cost. Rather, an allowance for equity funds is a computed amount of earnings to which equity shareholders are deemed to be entitled if their capital is prudently employed in providing utility services to customers. In an accounting context, that allowance is regarded as an unidentified portion of net income rather than as a cost. Thus, some believe that a regulator's deferral of an allowance for equity funds is a denial of current income and a later regulator's inclusion of that allowance in allowable cost of a future year is additional income earned in that future year. They view the current recognition of that future income, by capitalizing an allowance for equity funds, as rec-

ognition of income that is not yet earned. This view, in part, led to the Board's decision, in Statement 71, not to provide for capitalization of an allowance for equity funds except as part of the acquisition cost during construction of an asset. Capitalization of an allowance for equity funds used during construction of an asset was permitted, in part, because the result was considered similar to the result of capitalizing interest under FASB Statement No. 34, *Capitalization of Interest Cost*, as would be done by nonregulated enterprises. Upon reconsideration, the Board concluded that certain rate actions of a regulator provide sufficient assurance of the existence of earnings to justify capitalization of an allowance for equity funds in the limited circumstances described in this proposed Statement.

54. The AICPA Issues Paper recommended that only the probability of future recovery should be considered important in accounting for a phase-in plan. The Issues Paper suggested a list of factors that should be considered in determining whether recovery of amounts deferred under a phase-in plan is probable, but it indicated that none of the listed factors should be considered necessary or conclusive.

55. The Board concluded that, in view of management's involvement with regulators and other interested parties in negotiating the terms of a phase-in plan and management's commitment to the plan, that same management might tend to conclude that recovery of all amounts deferred under the plan is probable, regardless of the terms of the plan and the surrounding circumstances. Accordingly, the Board concluded that it should set specific, limiting criteria to be used in making that determination.

56. In deciding what criteria to select, the Board examined the phase-in plans that have been proposed and implemented to date. Those plans have tended to fit one of three different patterns, as follows:

a. Some plans provide for decreasing amounts to be deferred year by year for several years followed by increasing amounts of those deferrals to be recovered over several more years, with full recovery of all deferred amounts scheduled to be accomplished within a relatively short period.
b. Other plans provide for decreasing deferrals for several years with recovery of the deferred amounts to be provided over the life of the related plant.
c. Still other plans defer some amount of current costs without specifying either the extent of future deferrals or when recovery will be accomplished. Some of those plans base the deferral on "excess capacity," with the assumption that deferrals will continue as long as the "excess capacity" continues and recovery will occur over the life of the related plant thereafter.

57. *Recovery of deferred costs over a relatively short period.* The Board concluded that the first type of phase-in plan (subparagraph 56(a)) might provide adequate assurance of future revenues that will recover costs and a return on investment while avoiding extreme rate increases associated with the new plant. Accordingly, the criteria of this Statement will generally require the capitalization of current operating costs that are deferred for rate-making purposes under that type of plan. Paragraph 5(c) of Statement 71 requires, as a criterion for application, that it be reasonable to assume that rates set at levels that will recover the enterprise's costs can be charged to and collected from customers during the recovery period. This Statement includes a requirement that all amounts deferred under a phase-in plan be recovered within 10 years because the Board believes that adoption of a phase-in plan that requires a longer period to recover those deferred amounts necessarily creates an unacceptable degree of uncertainty as to whether that criterion for application of Statement 71 is met.

58. *Recovery of deferred costs over the life of the related plant.* The second type of phase-in plan (subparagraph 56(b)) results in a pattern of decreasing rates during the period in which previously deferred amounts are being recovered. Unlike construction costs, current operating costs are typically incurred with the expectation that they will be recovered currently. The Board believes that a phase-in plan warrants recognition, for general purpose financial reporting, only if it is limited to its stated purpose—avoiding extreme rate increases that would inconvenience customers while providing adequate assurance of future revenues that will recover costs and a return on investment. The Board concluded that a phase-in plan that will decrease rates during the period in which previously deferred costs are being recovered and extend that recovery period over a period from 30 to 40 years does not furnish sufficient assurance of recovery to warrant recognition.

59. Phase-in plans that provide recovery of deferred amounts over the life of the related plant would capitalize deferred amounts as additional plant cost. The Board noted that such deferred costs are not additional plant costs. Reporting those deferred amounts as though they are plant costs impairs users' ability to make future comparisons of the recorded cost of the related plant with costs of similar plants owned by other utilities.

60. *Recovery period for deferred costs not specified by the plan.* The Board concluded that the last type of phase-in plan (subparagraph 56(c)) does not warrant the accounting treatment provided in paragraph 4 in general purpose financial statements because the provisions of such a plan undermine the fundamental assumption that it is reasonable to assume that rates based on the enterprise's costs can be billed

to and collected from customers. The Board believes that such a plan is not compatible with criterion 5(c) of Statement 71 because it provides no basis for concluding that recovery of deferred amounts is probable.

61. *No return on investment in deferred costs.* Some of the existing phase-in plans have deferred current operating costs for recovery in future periods and have not provided return on the investment in those deferred costs during the deferral period. The Board considered that type of phase-in plan and concluded that it is, in the environment that is subject to Statement 71, partially a deferral and partially a disallowance. The environment of individual cost-of-service regulation provides an enterprise an opportunity to earn a fair return on capital invested for the benefit of the enterprise's customers. In that environment, if costs are deferred solely to avoid the hardship to customers that would be caused by a significant increase in rates, the utility should be entitled to a return on the deferred amounts. If no return is provided, the regulator has indirectly disallowed part of the cost of the related plant and the accounting should reflect that disallowance.

Other Capitalization of an Allowance for Equity Funds

62. The Board also considered whether circumstances other than construction and phase-in plans might warrant capitalization of an allowance for equity funds. After considering a variety of circumstances, the Board concluded that capitalization is warranted in only one other type of situation.

63. In a rate case, regulators often identify specific changes in certain volatile costs for future recovery. For example, a regulator might conclude that the cost of fuel is sufficiently large and its price is sufficiently volatile that variations from the amount that is included in rates should be afforded recovery. In some cases, this is accomplished through an automatic adjustment clause that permits rates to be automatically adjusted to reflect variations in the cost of fuel used in prior periods. In other cases however, variations from the allowed cost of fuel are accumulated for action in the next rate case. Certain jurisdictions afford similar treatment to other costs. In those situations, the Board concluded that carrying costs on amounts invested in the accumulated deferred costs, including an allowance for equity funds, should be capitalized if recovery of those capitalized costs and a return on those deferred amounts over a relatively short period is probable.

Accounting for Abandonments

64. Historically, utilities usually have abandoned plants only in early stages of construction, rather than after major construction costs were incurred. Prior to Statement 71, regulated enterprises accounted for the costs of abandoned plants on a cost-recovery basis; that is, no loss was recorded so long as the regulator's allowance of revenues to recover those costs would recover the recorded costs. Statement 71 did not change that practice.

65. Recently, abandonments of plants under construction have become more common, and some utilities have abandoned plants during the later stages of construction. In many cases, the cost of abandoned plants is much greater than in the past; in a few cases, the utility's investment in those abandoned plants exceeds the total common shareholders' equity.

66. Regulators in many jurisdictions have provided recovery of the cost of abandoned plants without return on investment during the recovery period. That procedure has been described as a means of sharing the loss between customers and shareholders. A cost-recovery approach for accounting for abandonments was based on the view that the regulator was disallowing future earnings, rather than disallowing a portion of the cost of the abandoned plant. In reconsidering that issue in the context of today's environment, some Board members concluded that a cost-recovery approach, in effect, delays recognition of losses that are known to have been incurred. Although that approach might have little significance when applied to relatively immaterial items, the significance of the amounts involved in recent cases indicates that recognition of losses resulting from abandonments should not be delayed beyond the date when they are probable and reasonably estimable, or comparability of the financial statements will be impaired. Thus, the Board concluded that it should (a) emphasize the need for loss recognition as soon as a loss is probable and (b) require recognition of the disallowance of return on investment in abandoned assets when that disallowance becomes probable.

67. Other Board members believe that the probable future revenue that will result from inclusion of the cost of an abandoned plant in allowable costs for rate-making purposes is essentially a monetary asset. In their view, clearly the cost of an abandoned plant should be written off when abandonment is probable. The issue then is whether there is a basis for recognizing a different asset representing probable future revenues resulting from the regulator's action related to the abandonment. If it is probable that recovery of the cost of the abandoned plant will be provided for in future revenues, a new asset that is essentially a monetary asset should be recognized. That asset most closely resembles a long-term receivable that is usually recognized on

the basis of its present value. They believe that a similar measurement basis is appropriate for probable future revenue that will result from a regulator's treatment of the cost of an abandoned plant.

68. The Board concluded that accruing a carrying charge on, or recognizing accretion of, the present value of the probable future revenue related to an abandonment is appropriate for two reasons. First, the basis used to record those assets recognizes the regulator's disallowance of future return on investment as a loss in the period in which it becomes probable. The disallowance that has been recognized should not affect the reported results of operations in later years, and accrual of a carrying charge has the effect of reporting income similar to what it would have been if there had been no disallowance. Second, the nature of the resulting asset is similar to a long-term receivable, even though Board members believe that it lacks some of the characteristics of a receivable. Accordingly, they concluded that the subsequent reporting should be consistent with that afforded a long-term receivable, and accrual of a carrying charge is consistent with accounting for a long-term receivable reported at its present value.

69. The Board considered adopting a requirement that all assets solely representing probable future revenue resulting from a regulator's actions be recorded at the present value of the future cash flows and decided not to adopt such a requirement at this time. Some Board members noted that the requirement of Statement 71 to recognize those other assets on a cost-recovery basis, which was a continuation of prior practice, does not appear to have caused major problems in practice. Other Board members noted that the rate treatment anticipated during construction, prior to abandonment of that construction, was full recovery of both cost and return on investment, whereas the cost of repairing storm damage, which is sometimes afforded recovery over a period of time without return on investment, represents a cash outlay usually made with the anticipation of that rate treatment. Thus, if the Board were to conclude that recording that asset at the amount of the consideration paid is not appropriate, that conclusion would be based on considerations somewhat different from those that the Board applied to abandonments.

Disallowances of Costs of Newly Completed Plants

70. Paragraph 10 of Statement 71 addresses disallowances by a regulator. That paragraph indicates that when a disallowance occurs, "the carrying amount of any related asset shall be reduced to the extent that the asset has been impaired. Whether the asset has been impaired shall be judged the same as for enterprises in general."

71. Recently, several disallowances of major amounts of cost on newly completed plants have been well publicized. The AICPA Issues Paper concludes that "the measure of whether an asset has been impaired [when part of the cost of that asset is disallowed for rate-making purposes] is whether net cash inflows (revenues less applicable expenses) are sufficient to cover the cost of the asset. In measuring expenses, interest applicable to the unit should be included, but equity return would not be included."

72. The Board concluded that the view described in the AICPA Issues Paper, which appears to approximate existing practice, is a narrower interpretation of an "impairment," as referred to in paragraph 10 of Statement 71, than is appropriate for the events in question. The Board believes that an impairment evaluation includes the estimation of losses in value that become determinable as a result of an identifiable event. For example, nonregulated enterprises that decide to discontinue an operation usually judge whether the assets of the operation that will be discontinued are impaired. That impairment evaluation usually is made by comparing the carrying amount of the assets to the present value of the amounts that are expected to be realized from the sale of those assets. An enterprise that suffers damage in a fire judges the resulting impairment by comparing the damage to the probable insurance proceeds. If the damage exceeds the insurance proceeds, an impairment is recognized by recording a loss even if the damaged property can continue to operate profitably in its damaged condition. The Board concluded that a regulator's disallowance of part of the cost of a newly completed plant creates an impairment that warrants recognition.

73. Some Board members also believe that the stated reason for certain recent disallowances of plant costs—that the costs were not productive or were not necessary for the completion of the plant—indicates that those costs should not be included in the carrying amount of the related plant. Nonregulated enterprises do not continue to carry identified nonproductive costs as part of the cost of their fixed assets, and regulated enterprises also should not do so.

74. The Board believes that the credibility of financial reporting in general would be diminished by the failure to recognize a diminution in value and a corresponding loss that is generally agreed to have occurred. When a regulator disallows a significant part of the cost of a newly completed plant, financial statements that do not report that disallowance as a loss reflect adversely on the representational faithfulness of those financial statements and of financial statements generally. Thus, the Board decided to amend Statement 71 to require loss recognition for such a disallowance.

75. The Board considered making a more sweeping amendment of Statement 71, to require loss recognition for all cost disallowances by a regulator, whether related to a newly completed plant or otherwise. For example, regulators in some jurisdictions disallow costs of acquired companies in excess of the acquired company's book value and a variety of other types of costs. That approach was not taken because the Board concluded that the known problems in other areas do not warrant it.

Definition of Probable

76. The term *probable* was defined in Statement 71 differently from how it has been defined in other authoritative literature. The Board used a definition based on the definition used in FASB Concepts Statement No. 3, *Elements of Financial Statements of Business Enterprises,* because that definition was one of the criteria of an asset in Concepts Statement 3.

77. The AICPA Issues Paper questioned whether that definition was intended to be significantly different from the definition used in Statement 5 and indicated that the use of different definitions had caused some confusion in practice. The Board considered the concern expressed in the AICPA Issues Paper, and it decided to amend the definition in Statement 71 to a definition based on Statement 5.

78. The AICPA Issues Paper raised a number of other issues. After consideration, the Board decided that most of those issues were either judgment issues or involved unresolved legal questions; thus, the Board did not address those issues in this Statement.

Effective Date and Transition

79. The Board considered whether this Statement should be applied only to events occurring after the effective date or to all events of the types addressed. Applying this Statement only to events occurring after the effective date would diminish both comparability of the resulting financial statements among enterprises and consistency within an enterprise that had experienced such events both before and after the effective date. The types of events addressed by this Statement tend to have long-lasting effects on financial statements. For example, a decision whether to recognize a disallowance of plant cost as a loss affects reported depreciation and net income for the life of the related plant. Accordingly, the Board decided that this Statement should be applied to all phase-in plans, abandoned plants, and disallowed plant costs, regardless of whether those events occurred before or will occur after the effective date.

80. The Board also considered whether a longer time period between the date of issuance of this Statement and its effective date should be allowed, either for initial application of this Statement or for some or all existing phase-in plans, costs of abandoned plants for which rate orders have already been received, and disallowed plant costs.

81. Delayed application of accounting standards to existing situations is usually considered when either of two perceived problems is present. First, the change in accounting might change financial statement ratios that are the basis for restrictions under existing covenants. Those changes might restrict an affected enterprise's ability to pay dividends, issue new debt, and so forth. If required changes in the method of accounting for specific events or transactions result in accounting that is different from that contemplated when existing covenants were written, a delay period might be provided to allow affected enterprises sufficient time to obtain changes in those covenants.

82. Abandonments and disallowances have occurred in the past, and the past accounting for those events was well known. Accordingly, covenant restrictions that result from application of this Statement to abandonments and disallowances of plant costs might not have been intended by the parties to the covenant. Covenant restrictions that result from the accounting for phase-in plans required by this Statement are less likely to be unintended by the parties to the covenant. The need for such plans is unlikely to have been recognized when those covenants were adopted, and the parties are unlikely to have contemplated any specific accounting for those plans. Information available to the Board indicates that few enterprises that are likely to be affected by this proposed Statement would have existing covenant restrictions become effective as a result of the changes in accounting for abandonments and disallowances. In addition, it would appear generally that enterprises likely to be affected are not likely to be undertaking the actions that would be prohibited if the covenant restrictions were to become effective. That conclusion is based on disclosures of the nature of restrictive covenants in recent financial statements of companies that have been identified as having significant abandonments and disallowances.

83. The second reason for delayed application is that transactions might have been structured differently if the new rules had been known. Applied to a regulated environment, that argument usually would indicate that the rate order in question might have been different if the accounting required by this Statement had been required when the rate order was issued. That argument is unlikely to be valid for disallowances of return on investment in unrecovered cost of abandoned plants or disallowances of costs of newly completed plants. Those disallowances usually

reflect a regulator's intent to cause the cost of an abandoned plant to be shared by stockholders rather than to fall entirely on customers, and to charge a disallowed plant cost to shareholders rather than to customers; thus, the accounting required by this Statement merely reflects the regulator's intent. On the other hand, based on negotiations on recent phase-in plans, it appears that the accounting requirements might well influence the terms of the rate order that implements a phase-in plan. The Board is uncertain whether it is reasonable to believe that existing plans might be changed to comply with the requirements of this Statement; but, if that is likely, the Board would consider allowing sufficient time for that to be accomplished.

84. The Board concluded that, based on available information, it should not delay application of this Statement to existing situations. However, enterprises that believe that such a delay is warranted by their specific situation are invited to describe, in their comments on this proposed Statement, their existing circumstances and explain why they believe that a delay would be beneficial.

Accounting for Income Taxes

85. If specified criteria are met, paragraph 18 of Statement 71 precludes regulated enterprises from recognizing deferred taxes on timing differences when taxes are treated as allowable costs on an "as paid" basis. During the course of its deliberations on its current project on accounting for income taxes, the Board considered how a new FASB Statement on accounting for income taxes should be applied to an enterprise with regulated operations reported in accordance with Statement 71. The Board expects this Exposure Draft to be read by most of the parties that will be affected by that issue, so it decided to explain its decision on applicability of the proposed Statement on income taxes, and the effects of that decision, in this document.

86. One of the general standards of accounting for the effects of regulation, in paragraph 12 of Statement 71, is that "actions of a regulator can eliminate a liability only if the liability was imposed by actions of the regulator." In its income tax project, the Board has tentatively concluded that deferred income taxes are a liability or asset. The Board's tentative conclusion on the income tax project, when viewed in the context of the Board's conclusion in paragraph 12 of Statement 71, indicates that regulated enterprises should be required to recognize the tax liability or asset that results from application of the proposed income tax Statement. Accordingly, the Board tentatively concluded that the proposed Statement on income taxes would delete paragraph 18 of Statement 71—the paragraph that prohibits regulated enterprises from recording deferred income taxes in certain cases.

87. Paragraph 9 of Statement 71 requires a regulated enterprise that applies Statement 71 to capitalize an incurred cost that would otherwise be charged to expense if the following criteria are met:

a. It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. [Footnote reference omitted.]
b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. . . .

Accordingly, if the income taxes that result from recording deferred tax liabilities in accordance with the proposed Statement on income taxes meet those criteria, the regulated enterprise would record those income taxes as an asset when the deferred tax liability is recorded. The resulting asset and liability would not be offset for general purpose financial reporting; rather, each would be displayed separately for a user's evaluation.

Alternative Views

88. One Board member believes that generally accepted accounting principles apply to rate-regulated enterprises and that, as long as there is a direct relationship between incurred costs and rate making, paragraph 9 of Statement 71 is consistent with those principles. He does not believe that any case can be made under either generally accepted accounting principles or paragraph 9 of Statement 71 for the recognition of an allowance for equity funds (that is, earnings on shareholders' investment) when revenues necessary to produce those earnings are deferred under a phase-in plan. That proposed accounting results in income being recognized before it is earned. That Board member believes (a) the reference in paragraph 9 of Statement 71 to "incurred costs" rather than "allowable costs" is essential in order for the accounting for rate-regulated enterprises to be in accordance with generally accepted accounting principles; and (b) paragraph 9 in Statement 71, together with the clarification of the meaning of "probable" contained in this proposed Statement, should be adequate to deal with phase-in plans for rate-regulated enterprises meeting the criteria of paragraph 5 of Statement 71. If the latter proves not to be the case, then that Board member would accept criteria similar to those in paragraph 4 of this proposed Statement for determining whether incurred current operating costs qualify for deferral.

89. That Board member also believes the accounting in Statement 71 for the cost of abandoned plants and disallowed costs of operating plants are in accordance with the cost-recovery notion in generally accepted accounting principles, but acknowledges that a case can be made that the accounting proposed in this Statement for those two problems is also in accordance, or at least not in conflict, with generally accepted accounting principles. He believes, however, the case is not compelling, especially for (a) the accretion of the discount resulting from the fair valuing of the asset remaining after plant abandonments and (b) the write-off of disallowed costs of operating plants in all circumstances.

90. Another Board member does not support the accounting proposed in this Exposure Draft. Rather, he would reaffirm the existing provisions of Statement 71, including its conclusions that the "cost" of equity capital should not be capitalized after construction is completed and that only costs that would "otherwise be charged to expense" are candidates for capitalization as a result of rate actions. He does not see compelling reasons to consider major changes in Statement 71, which has been in effect for such a short time. He also sees no reason to modify the applicability of generally accepted accounting principles to regulated enterprises beyond those departures specifically called for by Statement 71.

91. That Board member disagrees with this proposed Statement primarily because it would extend required capitalization of the "cost" of equity capital both to operating plants, under phase-in plans, and to rate adjustment clauses and similar items. He is willing to accept the conclusion of Statement 71 that the equity component of an allowance for funds used during construction may be used as a surrogate for the additional interest that would be capitalized by enterprises in general. The concept of capitalizing carrying costs during construction, as an acquisition cost, is in accordance with generally accepted accounting principles. Extending capitalization beyond the construction period constitutes capitalization of a holding cost, which is not permitted for enterprises in general.

92. That Board member sees no reason to make an exception to this general prohibition against capitalizing holding costs in the case of regulated enterprises. In his view, such an exception would result in premature income recognition. Income related to imputed costs should be recognized when revenues are realized, not before.

93. That Board member also objects to the proposed requirement to value recoverable costs of abandoned plant at their present value. He would record the costs associated with abandoned plants at the lower of cost or gross recoverable amount. In his view, this cost-recovery approach, now specified by Statement 71, should not be

changed because it conforms with accounting for enterprises in general. Further, he believes that valuing recoverable costs on a present value basis results in inappropriate overstatements of income in subsequent periods.

94. Finally, that Board member objects to the proposed requirement to recognize disallowances of costs of newly completed operating plants as losses. In his view, a regulator's disallowance of part of the cost of a fixed asset is an event warranting disclosure but not accounting recognition. The asset should be carried at its acquisition cost provided this cost is not higher than the asset's gross recoverable amount. He believes that reflecting a disallowance as a loss, with a corresponding reduction of depreciable fixed assets, inappropriately overstates income of subsequent periods.

95. A third Board member disagrees with the conclusions of this proposed Statement on two counts. First, he believes that there is no justification for the recording of an asset for the allowance for equity funds after an asset has been acquired and is ready for its intended use. Second, he does not believe that impairment of a long-lived asset should be recorded based on the asset's discounted present value in the rate-regulated industries when similar impairments are generally recorded based on recoverable cost in other industries. In his opinion, both of those approaches result in making less profitable companies look the same as more profitable companies. By capitalizing deferrals under a phase-in plan, a company that is not receiving revenue to recover its current operating costs is made to appear as profitable as one that is. By recording revenues expected to result from abandonments at their discounted present value and by recording operating plants at the amount that will be allowed by the regulator, a company that is receiving revenues designed to provide recovery of less than full cost and return on investment is made to appear as profitable as a company that is receiving revenues equal to full cost and return on investment, once the loss required to achieve that answer is recognized. That Board member believes that making all companies appear to have the same return on investment should not be an objective of accounting.

PECO STATEMENT NO. 16B

R-850152
3-11-86
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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

SUR-SURREBUTTAL TESTIMONY

OF

DAVID J. FARLING

COOPERS & LYBRAND

RE: ACCOUNTING ISSUES RELATED TO PHASE-IN PROPOSAL

MARCH 1986

SUR-SURREBUTTAL TESTIMONY OF DAVID J. FARLING

Q. Mr. Farling, have you previously presented testimony in this proceeding?

A. Yes. I have previously submitted direct and rebuttal testimony in this proceeding.

Q. What is the purpose of your sur-surrebuttal testimony?

A. The purpose of my testimony is to respond to the surrebuttal testimonies of John W. Wilson, Randall J. Falkenberg and Gregory A. Palast.

Q. Mr. Wilson states in his surrebuttal testimony that there is nothing in the FASB 71 Exposure Draft which indicates that sinking fund depreciation is unacceptable. Is he correct?

A. No, he is not. As explained in my rebuttal testimony, the Exposure Draft assumes "normal allocation of depreciation costs." The adoption of sinking fund depreciation by the Company for Limerick 1 would clearly be inconsistent with the depreciation methods employed by virtually all other investor-owned utilities and non-regulated industries. In my judgment, the adoption of the sinking fund depreciation method in this case would be viewed as a phase-in plan and would be evaluated for acceptance under the FASB 71 Exposure Draft. The sinking fund depreciation method proposed by Witness Wilson would obviously violate the 10-year limitation in the Exposure Draft. Even if the 10-year period of recovery for a phase-in plan is extended or deleted in the final statement of the FASB, it will be much more difficult under the new definition of probable (i.e., the recovery of the deferred amount is likely to occur) to consider sinking fund depreciation to be an acceptable accounting method. For example, under a sinking fund methodology there is an ever increasing amount of depreciation over the life of a plant. This obviously increases the risk of non-recovery.

Q. Witness Falkenberg asserts that your conclusion that sinking fund depreciation is inconsistent with generally accepted accounting principles is in conflict with the opinion of the auditors for Pennsylvania Power & Light Company (PP&L). Is this an accurate comparison?

A. It is not. My rebuttal testimony was directed at the sinking fund proposal of Witness Falkenberg and did not address or even mention the PP&L modified sinking fund method. As Mr. Falkenberg should be aware, there are major differences between the pure sinking fund method initially proposed by Witness Falkenberg and the modified sinking fund method approved by the Commission for PP&L. Of principal significance, the pure sinking fund method proposed by Mr. Falkenberg in his direct testimony defers a much larger amount than the PP&L modified method and delays recovery of a substantial portion of this amount until the latter stage of the plant's life. By contrast, the deferrals under the PP&L method are much smaller, and they are recovered within the first half of the plant's life.

Q. Do you accept Mr. Falkenberg's conclusion that you employed a higher discount rate than Dr. Perl and Dr. Hieronymus?

A. No. My concerns over the sinking fund method of depreciation as a generally accepted accounting method were not based on any analysis of a proper discount rate. Depreciation is the allocation of utility plant cost over its estimated useful life in a systematic and rational manner. My conclusions as to the acceptability of sinking fund depreciation have nothing to do with a particular discount rate.

Q. Mr. Palast states that you used the opportunity in your rebuttal testimony to correct your previous guesses about the future of Statement 71, which you put forward in your original testimony. He further states that your "guesses about the actions of the FASB in your original testimony were dead wrong." Are these statements by Mr. Palast correct?

A. No. These statements by Mr. Palast are totally incorrect and without any factual basis. I must question whether he really understands or wants to understand the content of my testimony. The comments in my direct testimony on pages 12 and 14 concerning proposed changes to Statement 71 were entirely correct. Mr. Palast states that in my direct testimony I "urged this Commission to adopt, as a rule for regulation, FASB 71 changes proposed in an AICPA Issues Paper." This is a clear misrepresentation of my direct testimony. The stated purpose of my direct testimony was to determine whether PECO's phase-in plan complied with existing FASB 71 and to alert the Commission of possible future changes to FASB 71. I did not urge the Commission to adopt the AICPA Issues Paper as a rule for regulation, nor did I predict that the views expressed in the AICPA Issues Paper would be adopted.

Mr. Palast should note that, on pages 12 and 14 of my direct testimony, the source of my information concerning the likely changes to Statement 71 was commentary by the FASB and its staff, not by reference to the AICPA Issues Paper. The only two potential changes to FASB 71 discussed in my direct testimony were a time limit rule and a discounting requirement. Both of these changes were adopted in the exposure draft.

Q. Do you wish to comment on Mr. Palast's statement: "It would be unreasonable for this Commission to raise Philadelphia Electric Company rates under the Company's proposed plan on the basis of Mr. Farling's guess about what may or may not change in accounting rules for financial reporting purposes"?

A. Yes. As explained in my rebuttal testimony, it is most likely that generally accepted accounting principles will change for phase-in plans. It is also quite likely, based upon prevailing professional sentiment, that all costs deferred under phase-in plans will have to be recovered within a stipulated time period. The FASB has made it quite clear (Para. 57 of the proposed amendment to Statement 71) that a period longer than 10 years "creates an unacceptable degree of uncertainty as to whether the criterion for application of Statement 71 is met." The Commission's awareness and consideration of this proposed amendment are paramount for acceptable financial reporting by the Company for the reasons stated in my rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

PECO STATEMENT NO. 12A & Exh LAG-

R-850152
3-11-86
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PENNSYLVANIA PUBLIC UTILITY
COMMISSION V. PHILADELPHIA
ELECTRIC COMPANY

DOCKET NO. R-850152

REBUTTAL TESTIMONY

OF

LOUIS A. GUTH

REASONABLENESS OF PECO'S
ENERGY AND PEAK LOAD FORECASTS

FEBRUARY 19, 1986

REBUTTAL TESTIMONY OF LOUIS A. GUTH

Q. Please state your name and address for the record.

A. My name is Louis A. Guth. My business address is 123 Main Street, White Plains, New York.

Q. Mr. Guth, have you previously testified in this proceeding?

A. Yes. My direct testimony is marked PECO Statement No. 12.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is twofold. First, I will explain how the report that was introduced as OCA Exhibit 50 by the Office of Consumer Advocate, and a report referred to in OCA Exhibits 51 and 52, entered during cross examination of PECO witnesses, do not alter the analysis presented in my direct testimony. Second, I will respond to the testimony of Mr. Falkenberg regarding the reasonableness of PECO's sales and peak load forecasting methodology and forecast results.

Q. Mr. Guth, have you reviewed OCA Exhibit 50?

A. Yes. OCA Exhibit 50 is a report entitled "Electric Utility Forecast Accuracy Comparison, 1972-1983", prepared by the Bureau of Conservation, Economics, and Energy Planning (CEEP) of this Commission.

Q. Have you reviewed Mr. Hoch's rebuttal testimony concerning OCA Exhibit 50 (PECO Statement No. 13A)?

A. Yes. Mr. Hoch explains the reasons that PECO's early forecasts resulted in the error reflected in the Report. My analysis shows that over time, as compared with the other Pennsylvania utilities studied, PECO's forecasts were quite accurate.

Q. In your opinion, does the CEEP Report provide an appropriate basis for comparing the forecasting records of the seven Pennsylvania-based electric utilities?

A. Yes, to the extent that the Report compiles in one place the data of forecasts of peak load and energy demand for these companies made from 1972 through 1983. However, the report cautions in its preface that:

> In order to properly evaluate the variance between utility forecasts and experienced loads, it is important for the reader to understand that load forecasting is an imprecise science affected by many unpredictable factors.

I fully agree with this caution. However, I do not agree with the Report's claim that it "explains the accuracy of electric utilities capacity and energy forecasts from 1972 through 1983." It describes rather than explains. The description, moreover, may be subject to misinterpretation.

Q. Please explain.

A. The CEEP Report summarizes in two graphs the measured differences between (a) forecast and experienced peak demand, and (b) forecast and experienced energy demand. These graphs depict the "absolute average deviation from actual [peak or energy demand] for forecasts ranging from one year in advance out to 10 years in advance." These graphs ostensibly indicate that PECO's forecasts are consistently farthest from the mark. For example, PECO's average deviation for peak load is the highest in every case, except for forecasts one year in advance.

This result, however, is somewhat misleading. As computed, the forecasts filed in 1973 and in 1974 are the only ones for which a comparison with experience of a forecast of growth at least nine years in the future can be made, i.e., for the years 1982 and 1983 respectively. On the other hand, all twelve forecasts reviewed contain a forecast for one year in the future. Thus the early and most erroneous forecasts are used to calculate each average deviation; the latter, more accurate company forecasts get far less weight.

Q. Can you illustrate what you mean?

A. Yes. To illustrate this effect, I note that the graph on "Peak Load Forecast Accuracy" (page 5 of the CEEP Report) suggests that PECO has by far the highest average deviation in forecasts made six years in advance (nearly forty percent compared with just over thirty percent for the next highest company). Yet the measured deviations for each company's 1978 forecast of peak load for 1983 (i.e., six years in advance) are as follows:

Duquesne	39.19%
Penn Power	33.46
PP & L	31.24
PennElec	26.25
West Penn Power	24.41
PECO	14.14
Met Ed	12.83

Was PECO worst, or nearly the best? It is all a matter of perspective. I have made similar comparisons for peak load on Exhibit LAG-15.

Q. What conclusion do you reach based on these comparisons?

A. The conclusion I reach is the same as stated in my direct testimony. Based on these figures, as well as the data compiled by CEEP, it is evident to me that "by the latter 1970s, PECO had clearly adapted its forecasts to the new emerging trends consistent with the best information available at the time."

Q. Mr. Guth have you reviewed a report entitled "Philadelphia Electric Company System Forecast, Volume 1: The State Base Case Forecast," prepared by Messrs. Raskin, Stutz and McAnulty?

A. Yes.

Q. At the time you prepared your direct testimony in this proceeding were you aware of this report?

A. Yes. At page 10 of my direct testimony I noted that PECO forecasts prepared in the late 1970s and their underlying judgments "were consistent with the judgments of most other informed companies and agencies, given the information then available." I also noted that there were other forecasts then available which indicated much lower growth rates. In response to a subsequent interrogatory (see OCA Exhibit 51), I identified this report as one such forecast.

Q. Please explain how, if at all, you took into account this report and forecast in reaching your principal conclusion that "PECO forecasts were reasonable and prudent, given the information available to the company at the time the forecasts were adopted"?

A. We know with hindsight that the PECO forecasts of the period were too high. The lower forecasts, including the referenced report by Raskin, et al., proved to be much closer to actual experience. Given this knowledge, I considered whether the circumstances would warrant a conclusion that the PECO forecasts of the time were unreasonable. I concluded that the PECO forecasts were not unreasonable for at least three reasons.

First, the analysis underlying the PECO forecast was consistent with many other published analyses of energy and electricity demand growth. The PECO forecasts, moreover, were reviewed frequently in the course of rate cases and other proceedings. Whatever differences of opinion might have existed as to the outlook for load growth at the time, PECO's judgments were well within the bounds of reason.

Second, the lower forecasts such as the report by Raskin, et al., were all predicated in some fashion on estimates of economic growth and energy prices that have proven to be very wrong. These forecasts generally did not take into account the sharp increase in oil prices following the Iranian oil crisis of 1979, and they did not foresee the subsequent slump in U.S. economic activity. Had these elements been incorporated into these forecasts, they would have projected lower growth than was actually experienced, indeed substantially so.

Third, I did consider what would have been the likely PECO forecast as of early 1978 if PECO had perfect foresight with regard to economic growth and energy price factors. The analysis is set forth in my direct testimony, in PECO Statement No. 12, at pages 13-15. I concluded that "if, in the late 1970s, PECO forecasters had had perfect foresight of future energy and market conditions, they, and other forecasters using similar methodologies, would have produced projections that were reasonably consistent with subsequent actual sales and peak requirements."

In summary, although the report by Raskin, et al., and similar forecasts provide useful guidance in sorting through recent energy and load growth experience, they do not alter my conclusion that the PECO load forecasts were reasonable and prudent, given the information available at the time they were adopted.

Q. Have you reviewed OCA Exhibit 52?

A. Yes. OCA Exhibit 52 is an excerpt from the testimony of John K. Stutz, one of the authors of the Raskin, et al., report, and Richard A. Rosen.

Q. Does this excerpt alter your conclusion?

A. No. The analysis regarding the Raskin, et al., report applies equally to the excerpt contained in OCA Exhibit 52.

Q. Have you reviewed the prepared testimony of Randall J. Falkenberg in this proceeding on behalf of the Philadelphia Area Industrial Users Group (PAIEUG Statement No.1)?

A. Yes, I have.

Q. How does Mr. Falkenberg analyze PECO's forecasts of the late 1970's and early 1980's?

A. Mr. Falkenberg proposes to use simple linear trends of peak demand experience in a preceding ten year period as a test to distinguish "unavoidable" from "avoidable" forecast error in PECO ten year forecasts. Without commenting on the merits of Mr. Falkenberg's approach, I note that he finds that the PECO forecasts from 1978 forward consistently have negative "avoidable" forecast error. Now I do not know what a negative "avoidable" error is in substance; however, as Mr. Falkenberg calculates it, it means that PECO's forecasts were below the results projected by simple linear trends, i.e. putting ruler to paper.

Q. Do you have other concerns with Mr. Falkenberg's conclusions?

A. Yes, Mr. Falkenberg's standard of "avoidable" and unavoidable" error is absurd. He measures "unavoidable" error as the difference between his trend forecasts and actual experience. "Avoidable" error is then the extra margin of error in PECO's forecast. Again, Mr. Falkenberg gives no reason whatsoever why trend forecasts should have been used in any particular year. At best he seems to be saying: use the simple trend unless you have reasons to think load growth will deviate from that trend. But of course the PECO forecast is precisely a set of reasons and judgments on what will drive future load growth in its service area (See Attachment IR-OCA-6-24, 1984-1994 Forecast, November 1984).

The absurd nature of Mr. Falkenberg's test is underscored by the fact that he reports negative "avoidable" errors for PECO consistently from the 1978 forecast onward. For example, Exhibit 12-G, the 1978 forecast analysis, shows the 1983 historic load to have been 5879 MW. The trend analysis forecast for 1983 was 7032 MW, or an overestimate of 1153 MW. That is an "unavoidable" forecast error of 19.61% according to Mr. Falkenberg's approach. PECO's forecast for 1983 was 6710 MW, an overestimate of 831 MW. Thus, evidently from Mr. Falkenberg's perspective, PECO "avoided" 322 MW, or nearly 30 percent, of "unavoidable" error.

Finally, Mr. Falkenberg suggests that PECO's forecast errors -- at least prior to 1978 -- were, in part, avoidable and not all "bad luck." Does this mean that PECO forecasts from 1978 which generated negative "avoidable" error were the result of "good luck"? And I wonder what the results would have shown if PECO had had "good luck" in energy markets and in economic activity projections in its forecasts prior to 1978?

Q. In general, do you agree with Mr. Falkenberg's analysis of PECO forecasts from 1972 through 1985?

A. I am not so much troubled by his analysis as by his conclusions.

As to the analysis, Mr. Falkenberg seems to show in the various pages of Exhibit 12 to his direct testimony that PECO over forecast relative to linear trends from 1972 through 1977. Compare this with Exhibit LAG-14 in my direct testimony: I show the PECO forecasts above smoothed trend forecasts through 1976. So, at most we disagree about one year, 1977.

I concluded from my analysis that PECO may have been cautious initially in responding to changing trends. I also concluded that the struggle to adjust, and the time it took, were understandable -- without the benefit of Mr. Falkenberg's hindsight — because in the immediately preceding period the Company had been coping with rapid growth and concomitant concerns for meeting loads. Finally, I concluded that PECO had adjusted to the new environment it faced in load forecasting by the latter 1970's.

Q. What does Mr. Falkenberg conclude from this information?

A. Mr. Falkenberg seems to think that PECO assumed some greater risk by not immediately going to straight line trending — essentially fitting ruler to paper — in 1973. In my opinion, this is the worst sort of hindsight. (And it is also mildly amusing since this technique was precisely the one roundly criticized by critics of the industry in the early to mid 1970's)

Moreover, Mr. Falkenberg provides no basis for accepting linear trending of past ten year data other then that it worked in some instances. There is no explanation in Mr. Falkenberg's analysis of why load growth developed in the fashion that it did. Of course, Mr. Falkenberg is wrong even on this one reason: linear trending did not work prior to 1978; the forecasts derived simply were lower than PECO's and, therefore, less far from the actual in hindsight. From 1978 on, however, PECO would have been further off relying on trend analysis rather than its forecasting methodology.

Q. Can you summarize your response to Mr. Falkenberg's testimony?

A. In summary, and without commenting on the overall relevance of his testimony in any event, Mr. Falkenberg stopped short of undertaking any substantial analysis of how PECO's forecasts were established. He failed to address any of the hard questions about PECO's forecasts, stopping instead at what I describe in my own prepared direct testimony as a "first-cut" analysis. At most, Mr. Falkenberg simply confirms my own conclusions.

Q. Does that conclude your rebuttal testimony?

A. Yes.

DUQUESNE LIGHT COMPANY
PROJECTED PEAK LOAD BY FORECAST YEAR

	ACTUAL PEAK LOAD	1978	1979	1980	1981	1982	1983
1978	2379	2455					
1979	2296	2660	2385				
1980	2474	2745	2545	2395			
1981	2522	2845	2645	2485	2435		
1982	2031	2945	2700	2525	2600	2600	
1983	2184	3040	2755	2610	2675	2620	2260
DEVIATION FROM 1983 ACTUAL		39.19%	26.14%	19.51%	22.48%	19.96%	3.48%

Source: "Electric Utility Forecast Accuracy Comparison, 1972-1983", Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning, 1984.

METROPOLITAN EDISON COMPANY
PROJECTED PEAK LOAD BY FORECAST YEAR

	ACTUAL PEAK LOAD	1978	1979	1980	1981	1982	1983
1978	1571	1490					
1979	1503	1495	1520				
1980	1521	1500	1590	1590			
1981	1581	1555	1595	1600	1550		
1982	1404	1620	1665	1660	1590	1553	
1983	1489	1680	1735	1720	1640	1574	1550
DEVIATION FROM 1983 ACTUAL		12.83%	16.52%	15.51%	10.14%	5.71%	4.10%

Source: "Electric Utility Forecast Accuracy Comparison, 1972-1983", Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning, 1984.

PENNSYLVANIA ELECTRIC COMPANY
PROJECTED PEAK LOAD BY FORECAST YEAR

	ACTUAL PEAK LOAD	1978	1979	1980	1981	1982	1983
1978	2124	2145					
1979	2072	2225	2125				
1980	2177	2335	2200	2160			
1981	2204	2425	2325	2200	2100		
1982	1913	2530	2435	2390	2250	2321	
1983	2103	2655	2530	2460	2330	2337	2180
DEVIATION FROM 1983 ACTUAL		26.25%	20.30%	16.98%	10.79%	11.13%	3.66%

Source: "Electric Utility Forecast Accuracy Comparison, 1972-1983", Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning, 1984.

PENNSYLVANIA POWER AND LIGHT COMPANY
PROJECTED PEAK LOAD BY FORECAST YEAR

	ACTUAL PEAK LOAD	1978	1979	1980	1981	1982	1983
1978	4649	4850					
1979	4400	5080	4840				
1980	4835	5360	5080	4999			
1981	5096	5780	5250	5132	5007		
1982	4404	6090	5430	5267	5173	4960	
1983	4869	6390	5600	5433	5360	5020	4920
DEVIATION FROM 1983 ACTUAL		31.24%	15.01%	11.58%	10.08%	3.10%	1.05%

Source: "Electric Utility Forecast Accuracy Comparison, 1972-1983", Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning, 1984.

PENNSYLVANIA POWER COMPANY
PROJECTED PEAK LOAD BY FORECAST YEAR

	ACTUAL PEAK LOAD	1978	1979	1980	1981	1982	1983
1978	553						
1979	548	591					
1980	573	621	590				
1981	562	652	615	580	580		
1982	507	684	640	591	591	594	
1983	538	718	665	603	603	606	568
DEVIATION FROM 1983 ACTUAL		33.46%	23.61%	12.08%	12.08%	12.64%	5.58%

Source: "Electric Utility Forecast Accuracy Comparison, 1972-1983", Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning, 1984.

PHILADELPHIA ELECTRIC COMPANY
PROJECTED PEAK LOAD BY FORECAST YEAR

	ACTUAL PEAK LOAD	1978	1979	1980	1981	1982	1983
1978	5667	5700					
1979	5641	5850	5700				
1980	6095	6050	5850	5800			
1981	5731	6250	6000	5900	5900		
1982	5691	6480	6150	6000	6000	6000	
1983	5879	6710	6300	6100	6100	6100	5600
DEVIATION FROM 1983 ACTUAL		14.14%	7.16%	3.76%	3.76%	3.76%	-4.75%

Source: "Electric Utility Forecast Accuracy Comparison, 1972-1983", Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning, 1984.

WEST PENN POWER COMPANY
PROJECTED PEAK LOAD BY FORECAST YEAR

	ACTUAL PEAK LOAD	1978	1979	1980	1981	1982	1983
1978	2562	2600					
1979	2504	2700	2570				
1980	2607	2820	2740	2750			
1981	2692	2970	2830	2870	2630		
1982	2336	3090	2970	2960	2780	2706	
1983	2556	3180	2980	3000	2860	2748	2552
DEVIATION FROM 1983 ACTUAL		24.41%	16.59%	17.37%	11.89%	7.51%	-0.16%

Source: "Electric Utility Forecast Accuracy Comparison, 1972-1983", Pennsylvania Public Utility Commission, Bureau of Conservation, Economics & Energy Planning, 1984.

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PECO Statement 13A
R-850152
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PENNSYLVANIA PUBLIC UTILITY COMMISSION V.
PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

REBUTTAL TESTIMONY OF
WILLIAM C. HOCH, JR.

PECO ENERGY FORECASTS

DOCKETED
MAR 17 1986

February 19, 1986

REBUTTAL TESTIMONY OF WILLIAM C. HOCH, JR.

Q. Please state your name and business address for the record.

A. My name is William C. Hoch, Jr.. My business address is 2301 Market Street, Philadelphia, Penna.

Q. Mr. Hoch, have you previously testified in this proceeding?

A. Yes. My direct testimony is marked PECO Statement No. 13.

Q. What is the purpose of your rebuttal testimony?

A. I will respond from a forecaster's perspective to testimony by Mr. Falkenberg, PAIEUG Statement No. 1, regarding the propriety of a linear trend-extropolation type of forecast. I will also explain the results listed in OCA Exhibit 50, the CEEP/PUC report entitled "Electric Utility Forecast Accuracy Comparison, 1972-1983" and how they do not alter the conclusions reached in my direct testimony. Finally, I will clarify PECO's position on price elasticities, which was questioned in the direct testimony of Dr. Schinnar.

Q. You have testified that PECO uses a form of forecasting known as end-use and econometric analysis. Mr. Falkenberg has testified (PAIEUG Statement No. 1, P.R. 41-48) that a different form of forecasting, namely a simple "trendline analysis common in the utility industry in the 1970's" would have provided a more accurate forecast. Do you find this to be reasonable?

A. No. Mr. Falkenberg states that, "[H]istorically, the [trendline] approach had proven a successful forecasting tool." (PAIEUG Statement No. 1, p. 42 lines 14-15). In support, he merely mentions that one small utility, West Penn Power, used this method until 1980. West Penn discontinued this simplistic method in 1981 in favor of an econometric model prepared for them by Data Resources Inc. (DRI). This does not provide much support for Mr. Falkenberg's statement.

Mr. Falkenberg's trendline method works from time to time, depending on the set of years chosen and how one weighs recent years versus distant years. It works only if the future mirrors the past and growth occurs as a fixed increment rather than geometrically.

Q. Why did Mr. Falkenberg's trend line method appear to provide a closer forecast when he applied it to the 1960's and early 1970's period?

A. In our forecasts prepared in the early 70's we anticipated a fairly consistent growth rate, that is, a nearly constant percentage increase from year to year. This was true for most utilities. Recognizing this, it is obvious to a critic that when growth turns down, as it did sharply in the early '70's, a straight line regression can be plotted that will result in a lower end-point error than the upward curving line representing a constant percentage annual growth. Hindsight is perfectly clear in this regard.

Q. Do utilities now generally rely on trend line analysis?

A. No. We meet twice a year with the forecasting personnel of PJM member utilities and know that none rely on trend extrapolation. In addition, as I stated in my direct testimony, our supervisor of Market Research has been active since 1970 in the Electric Utility Market Research Council, a group of 30 utilities that compares various forecasts. Most significantly, a study entitled, "Selecting the Best Load Forecasting Techniques for Electric Utilities" issued by Battelle Laboratories, Columbus Division, in August 1985, presents an analysis of 49 large utility respondents. Of these respondents, none uses trend extrapolation. The study also presents a survey of 37 state regulatory Commissions. Of these Commissions, only one selected "Trend Extrapolation" as the "Best Technique". The preferred methods were: "End-Use" for residential; "Disaggregate Single

Equation Econometric" for commercial; and "Process Model" or "Disaggregate Single Equation Econometric" for industrial. This is similar to the approach PECO has developed and used since the mid-1970's. The survey of 37 Commissions resulted in 46 percent naming Trend Extrapolation as the "Worst Technique", well ahead of the second worst, "Customer Survey".

In addition, Mr. Falkenberg himself has pointed to an article entitled "Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective", by William R. Huss, which appeared in the December 26, 1985 issue of <u>Public Utilities Fortnightly</u> (PECO Exhibit 33). In his article, Mr. Huss compares trending, econometric and end-use methodologies, and concludes that historically:

> End-use models seem to be the big winner, outperforming econometric techniques for all horizons at a minimum of 90 per cent confidence level. End-use techniques also do better than trending approaches...

Q. Do you consider the linear trend extrapolation approach to be a reliable method of forecasting?

A. No. Please refer to Exhibit WCH-1 which shows PECO sales from 1920 to 1985. Exhibit WCH-1 is on log paper so that a straight line means a constant percentage growth rate. This Exhibit demonstrates that for many periods, such as from 1959 to 1973, load grew pretty much in this constant percentage growth rate fashion. Furthermore, even using a log scale it is clear that trends changed often enough to caution one against projecting linear growth. For example, compare the periods 1944 to 1946, 1947 to 1950, 1953 to 1954 and 1962 to 1963. Beginning in 1973, hindsight reveals that we entered into a completely new series of frequent disruptions in the growth of our economy.

Q. How have Mr. Falkenberg's trendline projections compared with PECO's forecasts in recent years?

A. They vary. As seen in Mr. Falkenberg's Exhibits 12-G through 12-M, his linear regression peak forecasts exceeded PECO's in each year from 1978 through 1983 and finally were about the same for the 1984 and 1985 forecasts. Had we relied on his forecast methodology for our 1982 forecast, for example, we would have projected the peak at 6618 MW in 1991, 348 MW higher than our realistic projection of 6270.

Q. During the early 1970s was there any evidence that led you to anticipate a non-linear growth rate?

A. Yes. As I stated in my direct testimony (PECO Statement No. 13,p. 13), the spans from 1962-67 and 1967 to 1973 had similar percentage growth rates. The average growth from 1962 to 1967 was 960 million kWh/year while from 1967 to 1973 it was 1,266 million kWh/year. Thus there was clearly not a linear pattern from 1962 to 1973. This is especially true when you realize that many forecasters give greater weight to recent data than to older data.

On top of this history of a steady percentage growth rate, we were experiencing a rapid growth in air conditioning load which seriously effected our summer peaks, and we were suffering from capacity shortages. This experience lead us to project that our sales and load would grow even faster than the historic trend.

Exhibit WCH-2 is a 10 year forecast prepared in 1970 by Predicasts, Inc. that projects a steady growth in air conditioner shipments from 1970 to 1980. Exhibit WCH-3 plots the actual units of residential air conditioning added in PECO's service territory to 1969 and forecasts the units to be added for the period 1970-1975. This exhibit was prepared in April 1970, forecasts a continued rapid growth in residential air conditioning units added. Exhibits WCH-2 and WCH-3 illustrate the type of rapid increase in air conditioning sales that led PECO to forecast that its sales and load would grow faster than even the historical percentage growth rate.

Exhibit WCH-4 presents the actual units of residential air conditioning added through 1973 and forecasts the units to be added for the period 1974-1979. This exhibit shows a sharp drop-off in units added in the early 1970's, and forecasts relatively little growth in units added for 1974-1979. Exhibit WCH-4 illustrates the adjustment downward in air conditioning sales that contributed to our forecasts for the early 1970's having missed the mark. This exhibit also illustrates the consequent leveling off of forecasted air conditioning sales growth (and thus electricity growth) that was reflected in PECO's energy forecasts by the mid-1970's.

Q. What do you conclude from Mr. Falkenberg's suggestion concerning trendline extrapolation?

A. Mr. Falkenberg states that he has not concluded that our forecasts were imprudent when developed (PAIEUG Statement No. 1, p. 41). Based on our observations regarding trends in percentage growth rates and the rapid growth in air conditioning load in late 1960's and early 1970's there was little reason at that time to place much confidence in projections derived from simple linear analysis.

Q. Mr. Falkenberg suggests that a forecaster should at least consider what the results of a trendline extrapolation would show in preparing a load forecast. Did you do so for the forecasts you developed for PECO from the mid-1970's up to today?

A. Of course. Any knowledgeable forecaster will review historic loads and their rate of growth as part of the information to be considered when developing a forecast. I understand Mr. Falkenberg to be suggesting little more than that a forecaster should have good reasons if he does not follow a simple trendline extrapolation. As discussed above, there were several compelling reasons why we chose not to follow a simplistic trendline extrapolation approach but instead chose to develop and perfect our end-use model. Indeed, as can be seen from Exhibit WCH-1, at least one reason that we were reluctant to embrace dramatic and immediate reductions in our load growth projections in the early 1970's was the historic trend from the previous twelve to fifteen years.

Q. OCA Exhibit No. 50 is a report issued by the Bureau of Conservation, Economics and Energy Planning (CEEP) of the Public Utility Commission, dated November 1984. Are you familiar with that Report?

A. Yes. We previously discussed it in the Limerick Unit No. 2 Investigation.

Q. Will you please explain why PECO had the greatest apparent error of the Pennsylvania utilities reviewed relative to 1983 actual energy sales versus the forecast made in 1972?

A. As noted in Exhibits WCH-2 and -3, our air conditioning load was growing exponentially while we had been suffering capacity shortages. This was expected to continue. However, after the severe recession following the Arab oil embargo in 1973, our growth as depicted in WCH-4 deteriorated rapidly due to losses in our core city. In brief, our summer load had been growing rapidly because we were in the most congested and warmest corner of the state. Then for the very reason that our territory did include this old, built-up area, our growth rate dropped to the lowest in the state (except for Duquesne Light Co.) as old plants were closed and a heavy, unexpected outmigration away from the problems of the City of Philadelphia, which accounted for half our load, ensued.

Q. Has this margin of error continued?

A. No. For example, the CEEP document reveals that from 1978 on, our percent of error in our energy forecasts was lower than that of West Penn Power, the company referred to by Mr. Falkenberg, in every year to 1983. In fact, PECO's error for 1983 from the 1978 energy forecast was lower than all other Pennsylvania utilities tabulated by CEEP except one.

A comprehensive review of the Report indicates that PECO's degree of error declined steadily after 1972 and by 1976 was about the same as for Pennsylvania Power and Light and Duquesne Light Co. More recent forecasts indicate the PECO errors have been smaller than most.

Q. Dr. Schinnar has suggested that PECO's calculation of price elasticity for the various classes of service are too low and therefore, if used in forecasting, would understate the adverse effect of the Limerick rate increase on sales. Is his concern well founded?

A. No. As the PECO forecast book indicates the PECO elasticity calculations to which Dr. Schinnar refers have never been used directly in the production of the forecast. Because of changing technology, economic conditions, international competition, the value of the dollar, etc., there is no way of knowing if historically derived elasticity coefficients would still apply over time. For this reason, the Company applies the <u>effect</u> of elasticity by reflecting in the forecast such factors as increasing conservation, improving technology, expected government policy and more energy efficient appliances and applications, which tend to decrease load. The forecast also reflects such factors as increasing mechanization and automation and the substitution of electricity for other fuels, which tend to increase load.

Q. Dr. Schinnar has used certain price elasticities in his STARLOC model. Do the level of these coefficients seem reasonable based on the experience of Philadelphia Electric?

A. No, they are much higher than we and other utilities have experienced. In the manufacturing sector, for example, electricity only accounts for 3% of value added compared to wages which account for 22% of value added. A 30% increase in electric rates would raise total production costs by only 1% while a 30% increase in wages would raise production costs by 7%. For this reason, manufacturers are continuing to substitute equipment for labor and the equipment usually uses electricity. In spite of rising electric rates since 1973, the use of electricity per manhour has been growing.

In the residential sector, Dr. Schinnar uses a long-run elasticity coefficient of -.73 which is much higher than the actual experience of Philadelphia Electric or the recent experience of other utilities in the United States which have indicated coefficients of about -.40.

Dr. Schinnar, in his STARLOC model, appears to have used price elasticity coefficients extracted from the literature generally and applied them specifically to the Philadelphia area without any confirmation that they represent reality in this area at this time. He has made no attempt to calculate price elasticities for this area.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

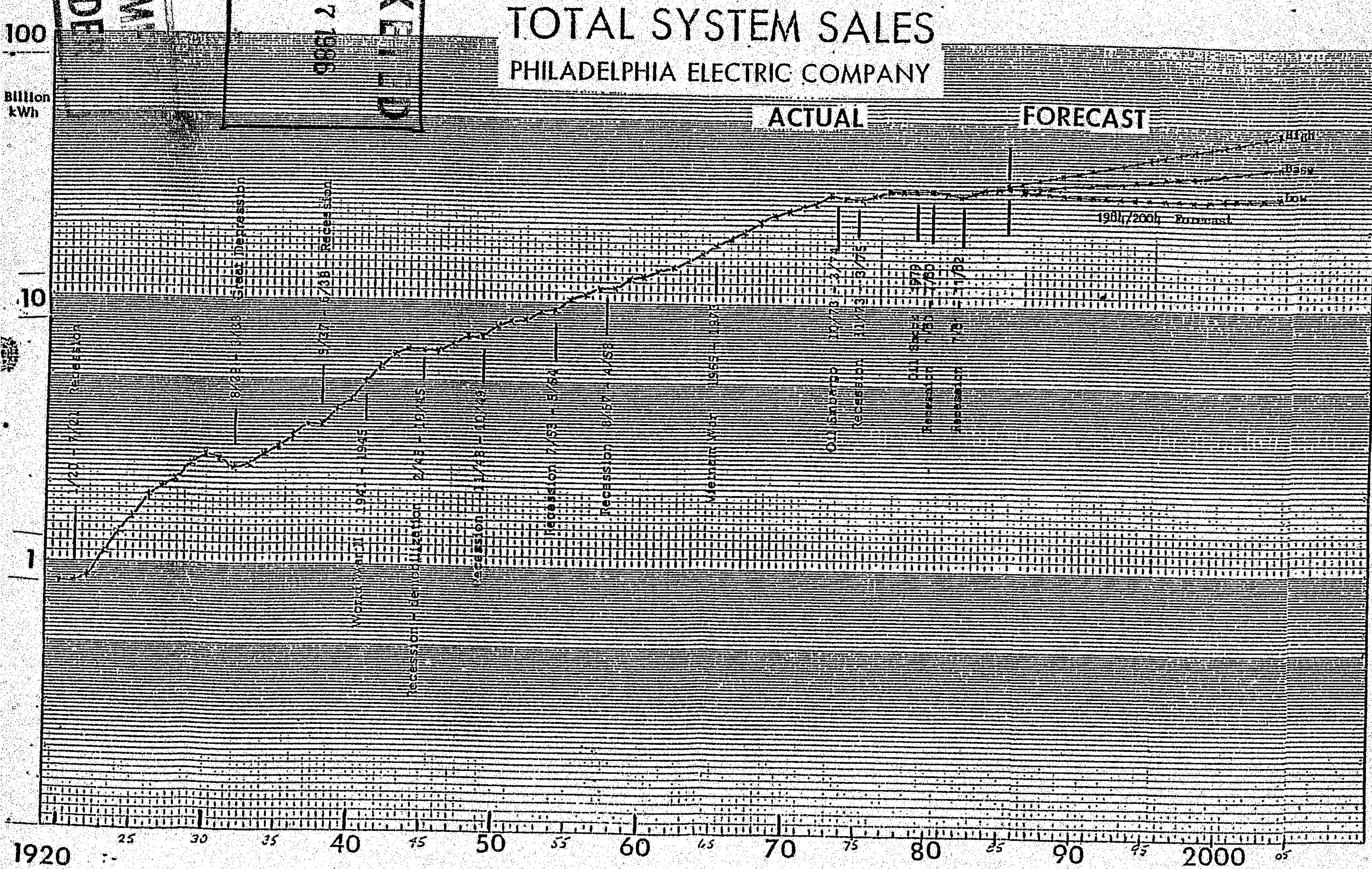


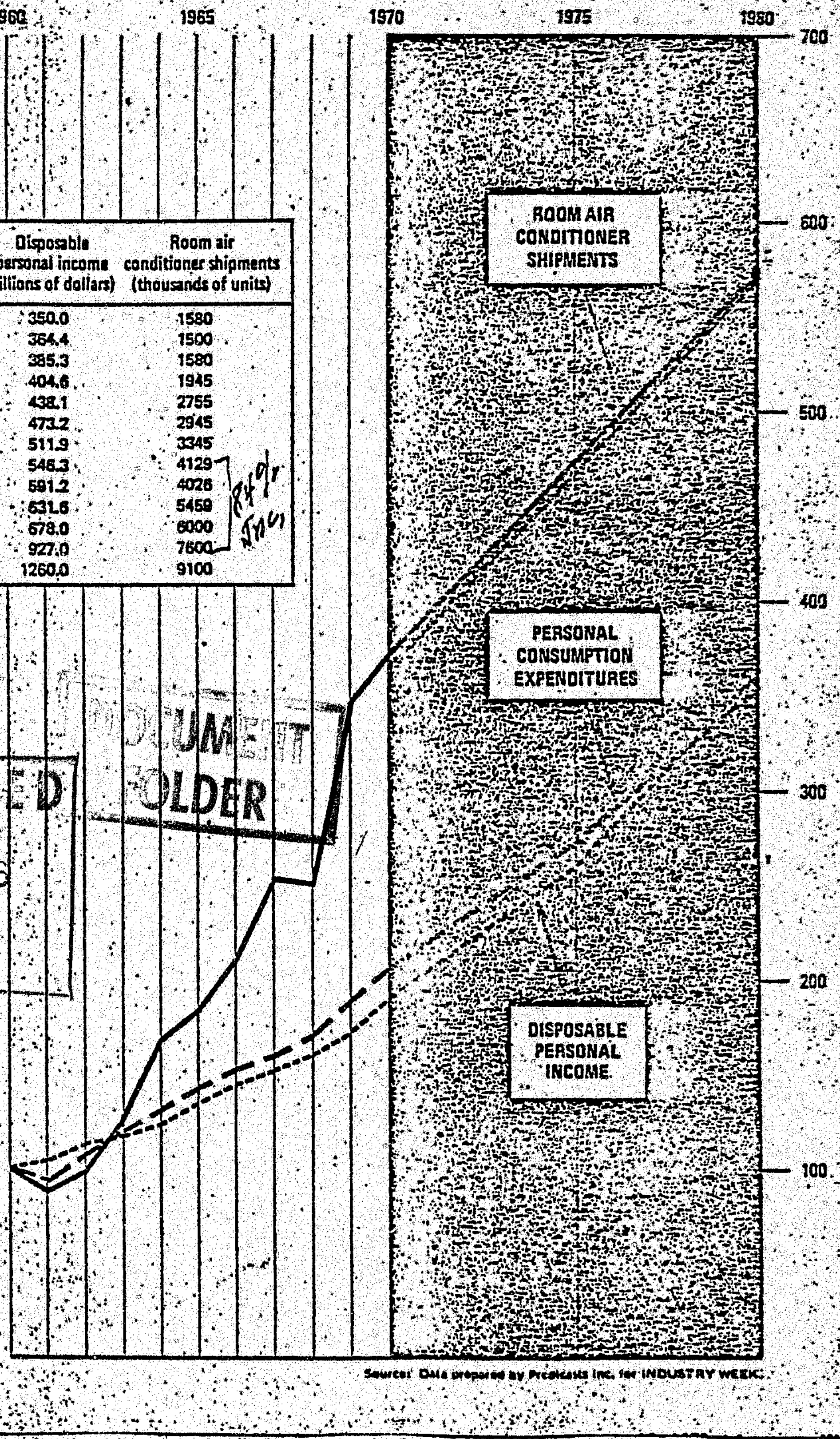
EXHIBIT WCH-1

Exhibit WCH - 2

TEN-YEAR FORECAST ROOM AIR CONDITIONERS

	Personable consumption expenditures durable goods (billions of dollars)	Disposable personal income (billions of dollars)	Room air conditioner shipments (thousands of units)
1960	45.3	350.0	1580
1961	44.2	364.4	1500
1962	49.5	385.3	1580
1963	53.9	404.6	1945
1964	59.2	438.1	2755
1965	66.3	473.2	2945
1966	70.8	511.9	3345
1967	73.1	546.3	4129
1968	84.0	591.2	4026
1969	90.0	631.6	5459
1970	92.0	678.0	6000
1975	124.0	927.0	7600
1980	160.0	1260.0	9100

84% incr

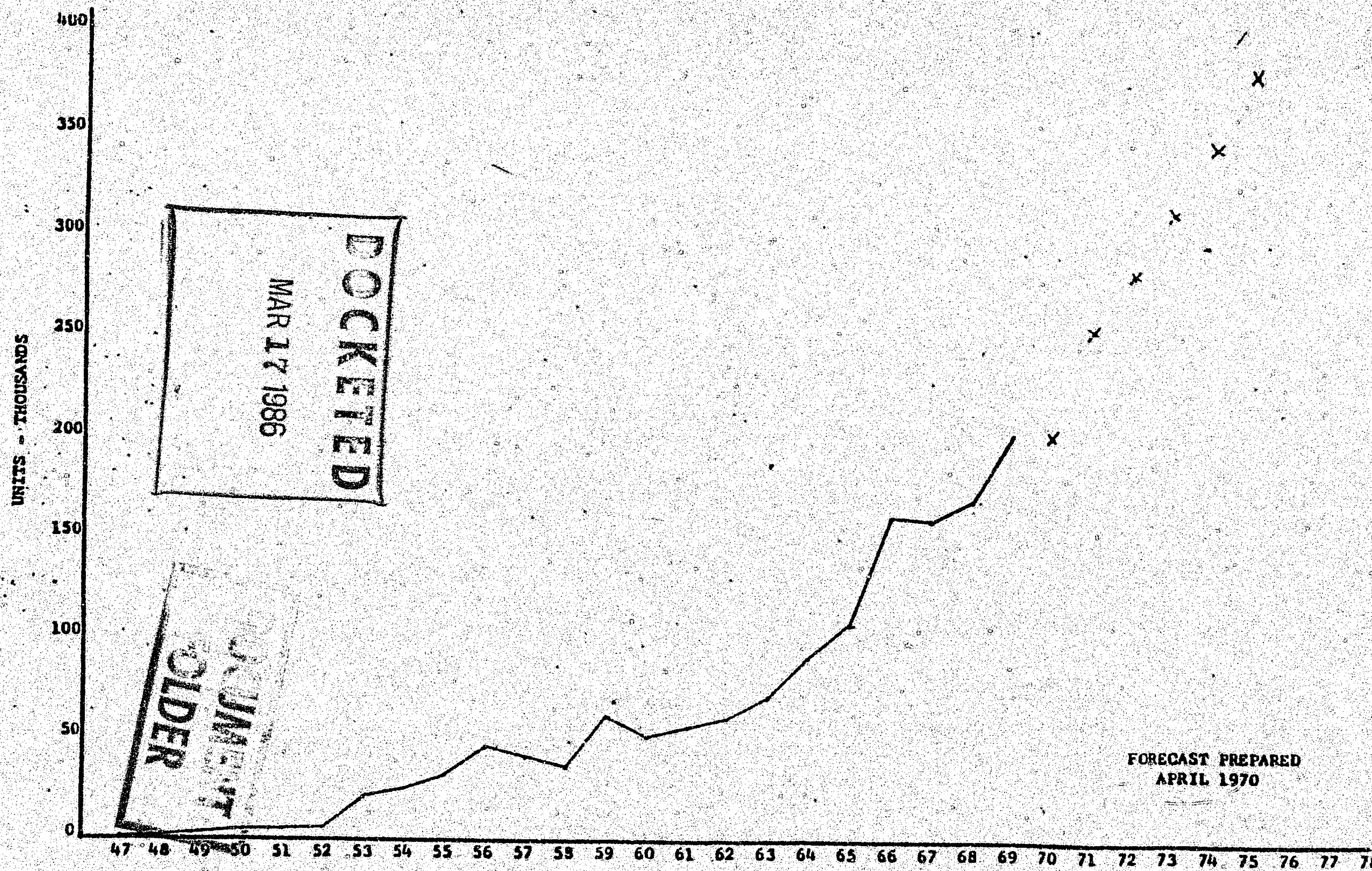


Percentage Growth 1960 = 100

Source: Data prepared by Predicasts Inc. for INDUSTRY WEEK.

EXHIBIT WCH-3

RESIDENTIAL AIR CONDITIONING ADDED
EQUIVALENT UNITS - ROOM COOLERS PLUS 3 X CENTRAL PLANTS
ACTUAL TO 1969 AND FORECAST TO 1975



RESIDENTIAL AIR CONDITIONING ADDED
EQUIVALENT UNITS - ROOM COOLERS PLUS 3 X CENTRAL PLANTS
ACTUAL TO 1973 AND FORECAST TO 1979

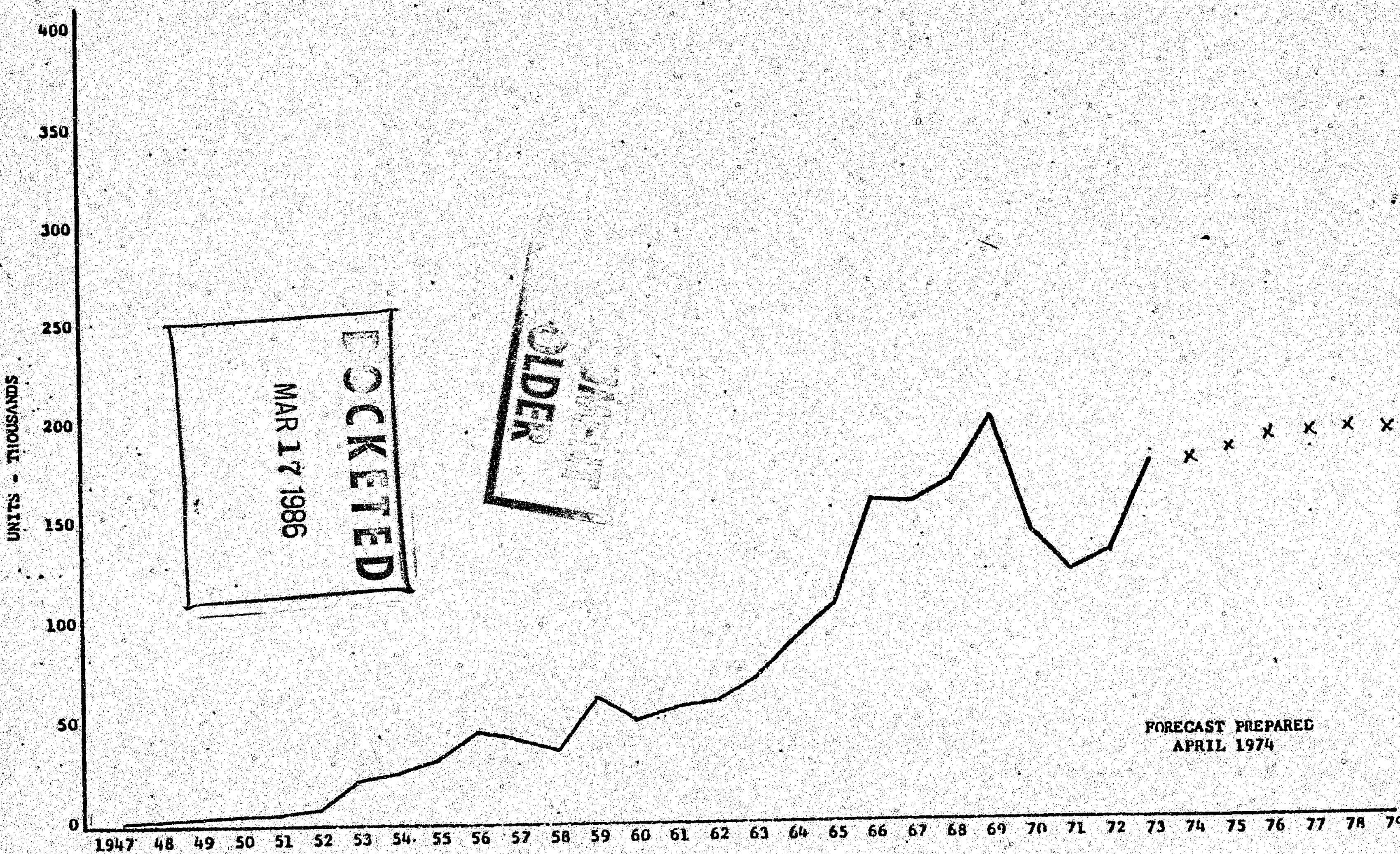


EXHIBIT WCH-4

RECEIVED

MAR 12 1986

SECRETARY'S OFFICE
Public Utility Commission

PECO STATEMENT NO. 13B

R-850152
3-11-86

WCH-
WCH-

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

DOCKETED
MAR 17 1986

SUR-SURREBUTTAL TESTIMONY

OF

WILLIAM C. HOCH, JR.

DOCUMENT
FOLDER

RESPONSE TO THE SURREBUTTAL
TESTIMONY OF RANDALL J. FALKENBERG

March 7, 1986

SUR-SURREBUTTAL TESTIMONY OF WILLIAM C. HOCH, JR.

Q. Please state your name and business address for the record.

A. My name is William C. Hoch, Jr. My business address is 2301 Market Street, Philadelphia, Pennsylvania.

Q. Mr. Hoch, have you previously testified in this proceeding?

A. Yes. My direct testimony is marked PECO Statement 13 and my rebuttal testimony is marked PECO Statement 13A.

Q. What is the purpose of your sur-surrebuttal testimony?

A. I will respond to several statements made in the surrebuttal testimony of Mr. Randall J. Falkenberg concerning his perception of the merits of straight-line trend projections. Mr. Falkenberg stated in his surrebuttal testimony that "[i]n effect I have shown that a very simple approach could have been used which would have produced results which were more reasonable vis-a-vis history." (Falkenberg surrebuttal testimony, p. 20.)

The simple approach expounded by Mr. Falkenberg is a straight-line trend extrapolation. Interestingly, he did not advocate this approach to suggest our recent forecasts might be much too low when his own projections from 1978 through 1983 produced higher forecasts than PECO's, as I pointed out on page 4 of my rebuttal testimony (PECO Statement 13A). It does no good to learn today that Mr. Falkenberg's method may have produced better results at certain alleged "critical times", when we can only identify those times in retrospect. Twenty-twenty hindsight demonstrates only that Mr. Falkenberg's straight-line trend approach is closer to the actual than PECO's approach during some periods and further from the actual than PECO's approach during other periods.

Q. Mr. Falkenberg submitted an exhibit with his surrebuttal testimony (Falkenberg Surrebuttal Exhibit 8) in support of his contention that "extrapolation or trending had proven to be a successful form of forecasting up to [1969]". Do you have any comments on his exhibit?

A. Yes. Mr. Falkenberg submitted only one page of <u>The 1970 National Power Survey</u> (page IV-4-35), which is dated 1969 (Falkenberg Surrebuttal Exhibit 8).

However, even a cursory review of his one page shows that it does not support his sweeping statement. To the contrary, Mr. Falkenberg's Surrebuttal Exhibit 8 states:

> Forecasting techniques are tools. No single method or group of techniques in itself assures success in forecasting. Knowledge and judgment of the forecaster in applying selected techniques in a given utility load situation are essential.
>
> . . . .
>
> The number and kinds of forecasting methods used vary considerably from utility to utility. Use of several methods is common. . . . Utilities with large cooling loads have an interest in developing estimates of historical cooling loads and load-weather relationships and use these in forecasting cooling loads. (Exhibit 8, p. 3 of 3).

Q. Is there other information contained in <u>The 1970 National Power Survey</u> which Mr. Falkenberg chose not to attach to his Exhibit 8, which is useful in determining the prevailing view of straight-line trend extrapolation in 1970?

A. Yes. I have attached several other pages from the same 1970 Survey as Exhibit WCH-5. These pages provide some useful information which Mr. Falkenberg apparently chose to ignore. For example, on pages IV-4-35 and 36, the Survey states that:

> Although extrapolation and correlation are fundamental to the art of load forecasting, they are not generally sufficient to assure the best results. Two additional ingredients that

> are often important to the development of a sound load forecast are the use of special information and the exercise of informed judgment.

It also should be noted that when "extrapolation" is referred to in the 1970 Survey, it does not simply mean straight line trends as Mr. Falkenberg suggests. Indeed, the 1970 Survey states:

> Specific methods [of extrapolation] include compound rates of growth, annual increments, fitting of mathematical growth curves... (Exhibit WCH-5, p. IV-4-35)

As I observed in my Statements 13 and 13A, PECO's growth rates were projected on a compound trend while Mr. Falkenberg supported a trend using "annual increments" or a straight line. With hindsight, Mr. Falkenberg's approach produced a forecast for the earlier period somewhat closer to actual than PECO's forecast, while, as demonstrated, this relationship was reversed in favor of PECO for later periods.

Q. Are there other statements in the 1970 Survey, not introduced by Mr. Falkenberg, which indicate that the prevailing view supported PECO's approach to load forecasting around 1970?

A. Yes. The following statements are pertinent to the state of forecasting in the period around 1970:

> The survey results reflect the dynamic nature of forecasting methodology in use during the period 1961-67. Forecasting methods have evolved to meet the particular needs and individual characteristics of the various utility systems. Several respondents adopted changes in methods during the seven-year period; others mentioned changes that are being considered.
>
> . . . .
>
> The wider daily and seasonal swings in loads experienced in the last few years and growth of new kinds of loads or changing patterns of growth have been among the

reasons for the search for new forecasting techniques. (Exhibit WCH-5, p. IV-4-36)

. . . .

The foregoing indicates that intermediate and long-term system load characteristics will continue to change. The daily and seasonal demand and energy requirements as well as annual peak load characteristics <u>probably will differ considerably from experiences of the past</u>. Consequently, the electric utility industry will need to evolve new techniques that predict accurately these changes. (Emphasis added) (Exhibit WCH-5, p. IV-4-51).

Moreover, page IV-4-15 of Exhibit WCH-5, contains a curve which clearly shows the compound (as opposed to linear) nature of growth of residential sales for the period 1940-1968.

Q. What do you conclude from a reading of this Survey?

A. I conclude that the 1970 Survey supports what PECO was doing with its forecasts and forecast methodologies in the 1970's.

Where the Survey talks about trending, it references compound growth rates at least as often as straight-line trends. In addition, the Survey supports the need for evolving forecast methodologies and not merely relying on older methods. The Survey also supports the belief, common at that time, that system load characteristics would continue to change requiring constant refinement of load forecasting metholodogies.

Q. Mr. Falkenberg agrees that end-use techniques have proven more successful than trending or econometric models for forecasting residential sales, and that "some Commissions" do not believe trending provides an adequate means of forecasting. However, he dismisses these facts by saying they are "recent developments" (Falkenberg surrebuttal testimony p. 21). Do you have any comments on his position?

A. Yes. In support of his position, Mr. Falkenberg misstates the material which I referenced in my rebuttal testimony. The material on which my conclusions were based was a report issued by Battelle Laboratories entitled "Selecting the Best Load Forecasting Techniques for Electric Utilities", reporting on a survey of 49 utilities and 37 commissions which revealed that trending forecasting was a low-rated method. The Battelle Report was not a report of just 1985 results. Rather it discussed changes in load forecasting approaches evolving throughout the 1970's up to the present. Nevertheless, Mr. Falkenberg persists in arguing that since the trending method had not been fully discredited in the early seventies, we should have used it then. This to me is akin to arguing that before Columbus, people who did not agree that the earth was flat, and plan accordingly, were following an unreasonable course. More importantly, however, we were aware of the kind of results a trending approach would produce, but rejected it for the numerous valid reasons discussed in my direct and rebuttal testimony. Indeed, even GEC witness John W. Wilson has criticised the use in the early 1970's of trend line forecasting, and has advocated the use of econometric methods. I have attached pertinent papers from Dr. Wilson's cross-examination by the Arkansas Public Service Commission at Docket No. 84-249-U as Exhibit WCH-6.

Q. Mr. Falkenberg, on page 22 of his surrebuttal testimony, suggests that PECO might have raised its forecast above the level it otherwise would have been out of a fear that it would experience capacity shortages. Is he correct?

A. No. Since his conclusion appears to be based on his reading of my rebuttal testimony, he misconstrued what I stated. My testimony was meant only to emphasize a useful fact concerning trends. PECO's forecasts in the sixties were generally too low, actually resulting in capacity shortages and many attempts to reduce peak use through frequent voluntary load curtailments by industry. Because the trend had changed to the upside, forecasts were adjusted upwards. My Exhibits WCH-2, 3 and 4 (PECO Statement 13A), show how air conditioning was being added at a compound rate, a situation not discernible a few years earlier through any linear trendline analysis. While one might have suspected that forecasts would rise more rapidly due to Commission pressures at that time to increase forecasts, it was the capacity shortages I referred to which confirmed that past forecasts had been too low. Thus an upward revision was indicated to accommodate, among other things, the air conditioning growth.

Q. Mr. Falkenberg questions PECO's air conditioning forecast, stating on page 22 of his surrebuttal testimony that air conditioning saturation advanced rapidly in the 1960's. However, "once people had an air conditioner and had their houses sufficiently chilled they didn't need to go out and buy an additional air conditioner". Had air conditioning actually reached a saturation level at that time as Mr. Falkenberg suggests?

A. No, not that anyone could predict at that time. Again, my Exhibits WCH-2, 3 and 4 show what was happening in the air conditioning market in that period. Air conditioning additions were being made at an accelerating rate until 1974. <u>Predicasts</u> projected that this would continue at least through 1980 (Exhibit WCH-2).

PECO made annual surveys of its market to support our forecasts. In our 1975 forecast, we reported that air conditioning saturation measured as a percent of all dwelling space fully cooled was at a level of 54%. Based on statements by customers without air conditioning indicating that the majority of them still wanted to acquire air conditioning, we assumed additions would continue at least to the early 1980's. While it is perfectly obvious as Mr. Falkenberg observes, that once a property is completely air conditioned no further cooling will be added, the statement is not helpful unless we analyze how many dwelling units are not yet cooled. Moreover, if a family buys one unit to cool a bedroom and decides that they like the effect, they may well purchase other units for other parts of the house.

Nevertheless, it is of interest to note that in our more recent forecasts we assume that saturation is being approached and that expected higher efficiencies will actually cause residential air conditioning usage to decline from an estimated 725 million kilowatt-hours in 1985 to 617 million kWh in 1994. This is a conservative estimate based on more units in use but offset by substantial improvements in operating efficiency.

Q. In summary, what are your conclusions?

A. I conclude that our forecasting methods have been shown to be much more acceptable in the industry over time than trending; that linear trending only works now and then in unpredictable time frames; that trending was a forecasting method that was accepted in the sixties but was being moved away from by utilities and commissions throughout the 1970's; that so-called "hindsight" has shown trending to be an unacceptable method of forecasting; and that our air conditioning forecasts were based on field data and were adjusted accordingly as newer data became available. Moreover, any inaccuracies in PECO's forecasts before 1977 or 1978 were due to "errors" which were unavoidable given the reasonable expectations and projections being made by the majority of forecasters at that time.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes, it does

OVERSIZE

DOCUMENTS

A REPORT TO THE FEDERAL POWER COMMISSION

THE METHODOLOGY

OF

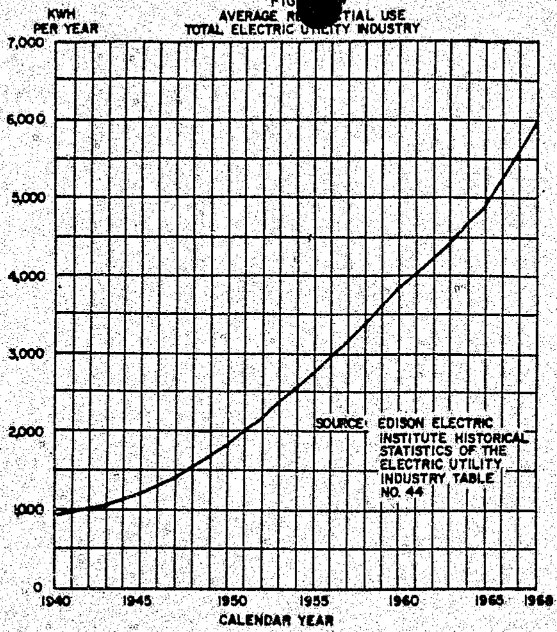
LOAD FORECASTING

PREPARED BY

THE TECHNICAL ADVISORY COMMITTEE
ON LOAD FORECASTING METHODOLOGY
FOR THE NATIONAL POWER SURVEY

1969

FIG
AVERAGE R TIAL USE
TOTAL ELECTRIC U ITY INDUSTRY



ONE MEASURE OF INCREASING AFFLUENCE IS THE INCREASED USE OF ELECTRICITY BY THE AVERAGE RESIDENTIAL CUSTOMER.

time as a natural by-product. The additional leisure has resulted in increasing the use of electrical devices for recreational purposes, such as television, radio and woodworking tools. Higher incomes have led to higher standards of home lighting and more lighting is being used for home decorative purposes.

Generally, there has been an increased demand for more home comforts and conveniences. Millions of room air conditioners have been installed in areas of the country subject to hot weather. Large numbers of medium and higher-priced homes are being constructed today with central air conditioning. Electric space heating has similarly begun to obtain acceptance, changing the shape of load patterns throughout the country. The trends indicate load patterns in the future will reflect a much greater sensitivity to weather and temperature variations than has been experienced in the past.

b. Commercial and Industrial

(1) *Commercial*

Commercial loads have very definite seasonal patterns although they are sometimes treated as a base load due to the historic importance of lighting. Specific applications producing seasonal variations in this class are again air conditioning and space heating. In areas of high saturation, the seasonal effect of air conditioning on load patterns has already been felt. In the remaining areas, small stores, filling stations and many schools will either rapidly adopt air conditioning or will become a small portion of the total commercial load.

Electric space heating is beginning to be accepted in commercial applications. The effect of "heat-with-light" applications on seasonal load patterns may be slight, since the load is dominated by high level lighting which can substitute in part or in whole as the heat source. Other electric heating applications, however, will have a substantial effect on seasonal load patterns.

(2) *Industrial*

Industrial loads are classified frequently as base loads subject primarily to economic variations. The very large industrial loads, particularly in the chemical and metal reduction categories, are usually in this group. These loads have little variation in seasonal load patterns and vary only slightly from hour to hour. It can be assumed that they lift an entire load curve uniformly.

Most other industrial loads may be usefully classified into groups having 1, 2 or 3-shift operations. The load pattern of each is distinctively related to the hours of operation. A certain amount of service-type load, which generally includes some air conditioning and, in some instances, space heating, is supplemental to the production portion of the load. Where investment in machinery and other facilities is quite high, the tendency is to have a multi-shift operation. When labor costs are a major component, the number of shifts tend to be more dependent upon economic conditions. Some industries such as mining and cement manufacturing or certain industrial practices such as retooling of facilities and vacation schedules have a seasonal impact on load patterns. In some industrial establishments a portion of the load may be interrupted by the supplier under special terms of an interruptible power supply contract.

Treatment of interruptible loads, load reductions due to strikes, plant shutdowns, etc. for forecasting purposes differs among systems. Some systems record load as experienced with no adjustments for any of the above. Others record the experienced load and adjust it to reflect what the load would have been if such occurrences had not taken place. Forecasts can similarly include or exclude the possibility of coincident strikes, vacations or reductions by voluntarily interrupted loads.

CHAPTER V—CURRENT FORECASTING METHODS

Forecasting techniques are tools. No single method or group of techniques in itself assures success in forecasting. Knowledge and judgment of the forecaster in applying selected techniques in a given utility load situation are essential. So is final judgment of the elements used in arriving at the ultimate load forecast.

The number and kinds of forecasting methods used vary considerably from utility to utility. Use of several methods is common. Differences in methods result in part from variations in economic and geographic conditions, system characteristics and mix of loads in the utility areas.[1] For example, population may change rapidly in one utility area and be stable in another. Utilities with large cooling loads have an interest in developing estimates of historical cooling loads and load weather relationships and use these in forecasting cooling loads. Utilities serving industrial loads which are highly responsive to the business cycle and which constitute a large proportion of total load usually put more emphasis upon analysis of industrial loads than do utilities serving a stable and small industrial load.

A. Basic Forecasting Methods

Forecasting methods can be grouped into two categories: extrapolation and correlation.

1. Extrapolation

Extrapolation is based upon the assumption that future growth will be a continuation of a discernible pattern of past growth. Specific methods include compound rates of growth, annual increments, fitting of mathematical growth curves and use of graphs of treated or untreated historical data.

Extrapolation often produces acceptable results because electric loads exhibit stable growth over rather long periods. Residential, outdoor lighting and service loads appear to be largely insulated from the business cycle. However, forecasters relying predominantly upon this method may fail to recognize underlying changes which eventually will affect future growth. For example, a succession of very hot summers might mask declining growth in non-air conditioning loads.

2. Correlation

Correlation relates electric power loads to selected associated factors. Correlation methods include scatter diagrams, simple correlation, multiple correlation and simple or complex models. While results from these techniques, especially the more sophisticated methods, cannot be accepted at face value but must be evaluated in terms of the theories underlying the techniques, including their limitations, they provide insight into the causes of past growth and its variation and quantify relationships between load and factors which affect load. This leads to a clearer understanding of the factors which cause growth and of their relative importance. Further, when forecasts deviate from actual loads, the correlation approach is helpful in identifying causes of deviation.

One problem associated with correlation methods is the need to obtain and select forecasts of these associated factors, i.e., independent variables, such as population, income, appliance saturation, etc. There is no assurance that this can be done with any greater accuracy than forecasting electric loads directly. Despite this difficulty, correlation is useful because it forces the forecaster to consider and analyze future load in a context of other factors rather than as a completely independent phenomenon.

It is important, however, that the analyst/forecaster avoid the mistake of drawing conclusions from spurious correlations which have a high degree of statistical significance but no logical relationship.

B. Special Information and Judgment

Although extrapolation and correlation are fundamental to the art of load forecasting, they

[1] Specific forecasting methods employed by four electric systems are detailed in Appendix A.

are not generally sufficient to assure the best results. Two additional ingredients that are often important to the development of a sound load forecast are the use of special information and the exercise of informed judgment.

1. Special Information

Special information is used to modify or reinforce the forecast. Examples include opinions of industrial plant managers as to probable future loads, planned utility promotion programs, the results of appliance surveys to determine present saturations and buying intentions, predictions of business activity and area and national electric power forecasts. Such information is not only an important indication of definite future planning for electric consumption by others, but also it is a stimulant to the forecaster in thinking about the possibility of new trends.

2. Informed Judgment

In forecasting, informed judgment is necessary in the selection of the factors to be analyzed and in the selection of the forecasting methods to be employed. It is also essential in determining the weight to be given to differing forecasts derived from use of several techniques. In uncertain situations when information is incomplete or when forces affecting load are not quantified, the informed judgment of the analyst is of particular importance. For example, he must decide whether forces favorable and unfavorable to growth of a new type of load are such that the new load is likely to become significant over the relevant planning period.

Finally, informed judgment plays a major if not decisive role in identifying likely future changes in trends, in selecting among competing forecasts of external forces such as economic activity and housing starts, in evaluating market penetration in such areas as air conditioning and heating and in identifying areas and degree of competition from alternate energy sources.

C. Survey of Industry Forecasting Methods

In order to determine the present state of the art of load forecasting in the industry, a survey was made of the current practices. Survey respondents were selected with the objective of including all types of systems, all areas of the country and all types of forecasting methodology rather than on a random basis. The survey-questionnaire was prepared and distributed through the FPC Regional Advisory Committees. Appendix E shows the format used. Thirty organizations responded. The techniques used by the respondents for short-term, intermediate-term and long-term load forecasting are discussed below.

The survey results reflect the dynamic nature of forecasting methodology in use during the period 1961–1967. Forecasting methods have evolved to meet the particular needs and individual characteristics of the various electric utility systems. Several respondents adopted changes in methods during the seven-year period; others mentioned changes that are being considered. This evolutionary process is found to be common in systems represented on the Committee as well as in the experience of those responding to the survey.

The wider daily and seasonal swings in loads experienced in the last few years and growth of new kinds of loads or changing patterns of growth of existing loads have been among the reasons for the search for new forecasting techniques. Another reason has been the increasing need for improved accuracy and more detailed forecasts to enable economic planning for greater use of energy interchange and larger generating units. Finally, improved forecasting methodology developed outside the industry along with the development and availability of greater computational capability also have been responsible for changes in load forecasting methodology.

1. Short-Term

Most utilities reported that hour-to-hour and day-to-day load forecasts are prepared by adding expected load changes to current or recent past loads. Nearly all reporting utilities indicated that expected weather conditions are considered in preparing forecasts 24 hours in advance. Half specifically report use of temperatures while only five refer to humidity or wind velocity. Nearly all indicated that historical hourly load patterns and day-of-week patterns are considered. Ten utilities report that changes in large industrial loads, strikes and other abnormal events are recognized in making the forecast.

Few of the reporting utilities use complex forecasting methods for short-term forecasting. However, a small number report developmental work to computerize hour-to-hour and day-to-day load forecasting, presumably to permit analysis of more new techniques often occur when some significant shift in the load mix or emergence of a new load is recognized. A frequent practice in these instances is to isolate the new load, analyze it and forecast it separately. An outstanding, recent example of this is the emergence of summer cooling loads. Many utilities have analyzed these loads, studied load-weather relationships and revised forecasting techniques to include forecasts of the cooling load.

The techniques described in this chapter and in Appendices A and B all focus on the better understanding of the past load patterns. The technique may be one that stresses demography, or one that focuses on economic conditions or one that centers the attention on weather condition. If such an isolated factor critically affects a specific system's load pattern, then such a technique will help in understanding the past growth pattern.

However, none of these techniques provides for certainty in forecasting. The accuracy of the forecast is still dependent on the input the forecaster uses. The isolation of the more important load variables may help concentrate efforts on those areas of most importance.

Adopting a new forecasting method normally requires a significant expenditure to gather data, to analyze the data and to evaluate results. A new forecasting method will be tried only if the expected benefits of improved accuracy in forecasting will offset the costs. While such costs have been reduced by greater processing capabilities of computers and wider availability of data, they are still substantial.

E. Future Research Possibilities

1. Short-Term

Many improvements in short-term forecasting techniques are expected to continue to appear in the next few years. Several utilities report development of empirical formulae for automating short-term forecasts of hourly loads based on previous loads, weather conditions incurred, weather forecasts and other such variables.

On-line computer programs may be developed which will enable utilities to analyze and compare forecasts and actual load patterns. These comparative analyses could lead to the development of accurate simulation formulae representative of system characteristics under every load situation. On-line computer programs also may be devised for the purpose of utilizing frequency distribution and probability formulae in examination of load forecasting accuracy.

One of the more important requirements lies in the area of improved weather forecasting. This may well come about from increased utilization of weather aircraft, orbiting earth satellites and sophisticated modern weather instruments. This could permit electric utilities to improve the accuracy of their forecasts of day-to-day demand and energy requirements.

2. Intermediate and Long-Term

More research and development work is being directed to improving forecasting techniques for the intermediate and the long-term forecasting periods. Better utilization of computers will enable utilities to develop equations for reflecting more completely the significant factors affecting load. Any improvement in long-term weather and economic projections can be translated into more accurate load forecasts.

As new markets for electric power appear, means for measuring the likely impact and forecasting it should be evolved. These markets may lie in the transportation field (electric automobiles, monorailways or other mass transportation media, not excluding electrified railways), in special industrial processes, in farm and home (robots), etc.

The foregoing indicates that intermediate and long-term system load characteristics will continue to change. The daily and seasonal demand and energy requirements as well as annual peak load growth characteristics probably will differ considerably from experiences of the past. Consequently, the electric utility industry will need to evolve new techniques that predict accurately these changes.

BEFORE THE

ARKANSAS PUBLIC SERVICE COMMISSION

In the Matter of: THE APPLICATION OF ARKANSAS POWER & LIGHT COMPANY FOR APPROVAL OF CHANGES IN RATES APPLICABLE TO RESIDENTIAL, GENERAL SERVICE, INDUSTRIAL AND OTHER RETAIL ELECTRIC SERVICE	Docket No. 84-249-U

Commission Hearing Room No. 1,
1000 Center Street,
Little Rock, Arkansas,
Monday, August 19, 1985.

PURSUANT TO ADJOURNMENT, the above entitled matter came on for further hearing at 8:30 a.m.

BEFORE:

DR. ROBERT E. JOHNSTON, Chairman;
PATRICIA S. QUALLS, Commissioner;
JAMES W. DANIEL, Commissioner.

VOLUME XIX

PHASE II

A/M REPORTERS, INC.
COURT REPORTERS

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(501) 661-1346

They started cutting back really to the extent that there were cutbacks in a period '73, '74, '75, and some lag behind that.

Q Did you not indicate in your testimony in the FERC Grand Gulf proceedings before Judge Head that you felt that most of the utilities were making erroneous high forecasts at that point in time?

A On '73, '74, '75, they were, and that's why they were cutting them back.

Q Would you agree with me, Dr. Wilson, that in the seventies, that the basic reason for the over-forecasting was because of erroneous assumptions as to what was going to occur, rather than the methodology that was being used to make load forecasts?

A I'd say that it was largely methodology rather than -- There's an element of both.

Certainly in the early seventies, prior to the oil embargo of November 1973, there was not the anticipation of the kind of price rises that we experienced in '74, '75, and subsequently.

But at that time, and extending into the latter part of the 1970s, most utilities in the United States made their forecasts by simply extrapolating historic trends.

It was little more than an exercise of putting annual observations down on a piece of paper and putting a ruler on it and extending the trend line. There was very little in the way of sophisticated forecasting that relief upon causal relationships, which is price elasticity and other determinants of power demands.

And it wasn't really until the mid to late 1970s that companies started adopting methodologies that were different than simple linear extrapolations.

Q Have you not observed in prior testimony that one of the precedent and basic causes of the over-forecasting was the assumptions that were being used, and even an econometric model given those assumptions would have resulted in excess forecasts, based on what actually occurred?

A Well, that would be the case. If there assumptions that price was not going to rise, and price rose, that would tend to produce excessive forecasts.

And certainly, in the early 1970s there was not the anticipation of the types of price increases that occurred in the period following 1973.

MR. DILLON: That's all I have. Thank you, doctor.

CHAIRMAN JOHNSTON: Back to the Attorney General.

MS. STALLCUP: No questions.

CHAIRMAN JOHNSTON: Opportunity for recross from the PSC Staff?

MR. WALDRUM: No questions, Your Honor.

CHAIRMAN JOHNSTON: That concludes, I believe, questions from the parties. From the Commission?

MS. QUALLS: No.

MR. DANIEL: I have none.

CHAIRMAN JOHNSTON: I have none -- No, well, let me ask one question, Dr. Wilson.

When did you first begin doing econometric modeling for forecasting?

THE WITNESS: With respect to the electric utility industry, I began my work on that in 1967, and I had, in fact, wrote my doctoral dissertation on demand forecasting for electric utilities. It was completed at Cornell University in 1969.

It was one of the first attempts to use statistical analysis and causal variables as a basis for evaluating demand growth and it was one of the first attempts to estimate price elasticity of demand. So it was almost twenty years ago.

CHAIRMAN JOHNSTON: Were you the first to ever do that?

THE WITNESS: No, there had been -- there had been some studies that had been done previously.

General Electric in the early 1960s had commissioned Franklin Fisher [phonetic] to do a study, because they were interested in how the price of elasticity would affect the sale of generating equipment.

And Fisher and Carl Cason [phonetic] published the results of the work that they did for GE in '61 or '62.

And there were some English economists by the name of Baxter and Reece who had done some studies with respect to the National Electric Board in Great Britain in the 1950s.

And there was a fellow by the name of John Felton at the University of Nebraska who had also done some work in the 1960s.

But the Fisher and Cason work was sort of the leading academic work on the subject. They're finding was that there was no relationship between the price of electricity and demand.

Their conclusion -- the conclusion of their analysis was essentially that the demand for power was independent of the price, and therefore, linear extrapolations were basically all right because there wasn't anything that was going to control it.

My thesis took on that conventional wisdom and I argued that the evidence was quite the contrary -- that even in the 1960s one could see from the historical relationships that had developed over time that changes in the price of electricity would affect demand.

And I would say in terms of reaching that conclusion, mine was probably the first serious work on that subject.

CHAIRMAN JOHNSTON: Which utilities adopted a similar forecasting method first? Do you know of any?

THE WITNESS: I couldn't tell you who adopted econometric procedures first.

There was largely a resistance on the part of the electric utility industry in the sixties and even early seventies to accept the proposition that their pricing policies would have an impact on demand.

And it was not a view that was generally shared at that time.

CHAIRMAN JOHNSTON: When was your first knowledge of electric utilities using econometric forecasts?

THE WITNESS: There were some that were starting to do it in 1972, '73.

It was an issue that was raised in conjunction with the 1970 National Power Survey, that was undertaken by the Federal Power Commission.

And I and some other people had advocated in the early 1970s, in conjunction with the development of the power survey, that forecasting move in that direction.

And Commonwealth Edison in Chicago and some other utilities, Pacific Gas and Electric in California, and certainly by '73, '74, Potomac Electric Power Company in the east, and some of the other eastern utilities were starting to develop econometric techniques.

But they certainly weren't placing full reliance upon them at that time. By the time '73 came around, there had been in addition to my work, quite a bit of additional research that had been done at Rand and at Oak Ridge and by university people around the country on the subject of price elasticity, demand for electricity, and better forecasting techniques.

And there was certainly within the professional area, and in the literature, there had been a great deal that had been done to verify and document that the methods that utilities had traditionally used were not reliable.

So when the Arab oil embargo hit in November of '73, and we moved forward into our first energy crisis in 1974, there were many utilities who made rapid efforts to improve their forecasting techniques, because they could see that what was happening was going to get them into trouble.

Potomac Electric Power, for example, had a -- had plans in '72 and '73 that were based upon forecasts assuming eight to ten percent compound growth into the future. They had developed maps that basically showed the Chesapeake Bay ringed by nuclear power plants by the year 2000 in order to fulfill the demand growth that they had been projecting using their linear techniques.

And they moved quickly in '73 and '74 to cancel their construction plans, abandon Douglas Point which was going to be their first major nuclear plant.

And as a result of those changes that were made rapidly in the early and mid 1970s, there hasn't been a new power plant sited in the State of Maryland, for example, for the last 12 years, anyway.

And if they had stuck with the kind of forecasting that they were doing in '72, '73, rather than making major modifications quickly in '74, '75, they would find themselves in a situation similar to the Middle South situation and a situation that pertains to other utilities.

But fortunately, they moved more quickly, changed their plans and they are financially very health at the present time.

CHAIRMAN JOHNSTON: I think that concludes my questions. Although, Dr. Wilson, let me excuse you from the stand, but if you would stay around just a moment, I want to pursue one other matter, which there is a faint, faint possibility I could call you back on it.

I don't think I would, but if you could stay for a couple of minutes.

THE WITNESS: I'll be glad to.

CHAIRMAN JOHNSTON: Now, as I understand it, that concludes the witnesses on Issue 1 of Phase II, i.e, we have concluded all the witnesses on the recovery of capacity costs, purchase of Grand Gulf capacity -- after only 97 days on this phase. It's not that long, it only seems that long, I think.

Mr. Dillon, before we do, there is one thing that has

PECO Statement No. 11-A

R-850152
3-11-86

Pennsylvania Public Utility Commission
v.
Philadelphia Electric Company

Docket No. R-850152

Rebuttal Testimony
of
Dr. Lewis J. Perl

RATE TREATMENT STANDARDS,
QUANTIFICATION OF DELAY DECISIONS,
DISCOUNT RATE, CAPITAL CONSTRUCTION COST RISKS,
ECONOMIC IMPACT OF RATE INCREASE

February 19, 1986

REBUTTAL TESTIMONY OF DR. LEWIS J. PERL

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony submitted by OCA witnesses Komanoff and O'Brien, PAIEUG witness Falkenberg, and UUC/UP witness Chernick, concerning various aspects of the Philadelphia Electric Company's investment in Limerick Unit No. 1. I will also respond to the cross-examination testimony of City witness Dr. Schinnar concerning the impact of the proposed rate increase on the Philadelphia MSA economy.

Q. Please summarize briefly your criticisms of each of these witnesses.

A. In my view, the only appropriate basis for disallowance of Limerick's investment is imprudence. Messrs. Komanoff, Falkenberg and Chernick have each presented life cycle calculations of the costs and benefits of Limerick from today's perspective, and Messrs. Chernick and Falkenberg use these results to suggest that some of the costs of the Limerick project should be absorbed by investors. Since these "after the fact" analyses cast no light on prudence, I believe that they are irrelevant to this rate recovery proceeding.

Mr. Falkenberg, after agreeing with Dr. Hieronymous that life cycle studies have no relevance with respect to prudence, argues that such "after-the-fact" cost-benefit tests are relevant in judging whether a plant is "used and useful." He seems to indicate that plants which are the result of prudent decisions but do not pass a cost-benefit test are not used and useful and are therefore subject to disallowance. I think that Mr. Falkenberg fundamentally misinterprets the used and useful test and that disallowance on the basis he suggests would not represent sound regulatory practice.

Mr. Falkenberg also argues for disallowance on the ground that PECO could have anticipated that there were "risks" of higher than expected costs for Limerick and slower than expected load growth. I think that all investment projects have such risks and, consequently, the existence of forseeable uncertainties is also an inappropriate basis for disallowance. Moreover, Mr. Falkenberg's estimates of the risk of higher than expected costs of Limerick were themselves implausible from a 1978 vantage point. Notwithstanding that his projection of the risk of high cost is implausible, this cost, even if foreseen, could not have justified cancelling the project.

My testimony will also address the assertions by both Mr. Chernick and Mr. Falkenberg that PECO's after-tax cost of money should not be used to evaluate investment decisions and that higher rates should be used instead.

Further, I will respond to Mr. Chernick's argument that my analysis of the prudence and quantification of PECO's delay decisions is incorrect in that I used too low a discount rate and that my analysis takes into account speculative events occurring at the end of Limerick's life.

I will also address Mr. O'Brien's argument that PECO delayed construction of the Limerick project by 27 months, causing an increase in project cost which should be disallowed. Mr. O'Brien presents no evidence to support the claim that any delay in Limerick's construction schedule was attributable to imprudence. Moreover, evidence on construction schedules for other nuclear units makes it highly implausible that Limerick could have been completed 27 months earlier in the absence of financial constraints. Even if I were to assume that Mr. O'Brien is correct concerning the extent and financial consequences of the delay, the appropriate disallowance would be only $2 million.

Finally, I will briefly address the testimony of Dr. Schinnar, who claims that the results of a model I used in the Lukens Steel case supports the work he has done in this case in measuring the impact of PECO's proposed rate increase on the Philadelphia MSA economy. His claim is simply untrue. My model was designed to measure the impact of an electric rate increase for the Pennsylvania Commonwealth and cannot be used without major modification to assess their effects for the Philadelphia area. Moreover, while the precise effect of these modifications is unclear, they would all tend to reduce markedly employment effects relative to what was observed for the Commonwealth.

<u>LIFE CYCLE ANALYSES</u>

Q. Why do you believe that present-day life cycle analyses are an inappropriate basis for disallowing rate recovery?

A. The central principle of cost-based regulation is that utility investors are entitled to receive a full and fair return on the costs of all prudently incurred investments. Prudence in this context means that the investments were sound, based upon the facts available when those decisions were made. Moreover, as virtually all parties to these proceedings acknowledge, since after-the-fact cost comparisons provide no guide to the prudence of underlying decisions, they cannot, in and of themselves, be used as a basis for disallowance.

This regulatory principle is based upon very sound economic principles. By insulating investors from certain market risks, regulated utilities are able to realize a much lower cost of money than competitive industries, the benefits of which are passed on to consumers. To impose risk-sharing where decision making was prudent, but outcomes are unfavorable, clearly creates uneven risks that would discourage investment in utilities. Investors, who would have no opportunity to earn an above-average return when prudent investments result in benefits to consumers, would be required to share the risks when things turn out badly. Under such asymmetric circumstances, investors would have no opportunity to earn a reasonable return on their investments. This approach is fatally short-sighted since it would adversely affect utility consumers by increasing the utility's future borrowing costs. In addition, it would lead utilities to avoid capital intensive options even when such options would result in substantial benefits to consumers.

Finally, the very range of results obtained by the various analysts in this proceeding highlights the inappropriateness of using life-cycle economics as a guide to disallowance. Dr. Hieronymous presented evidence that consumers stand to reap somewhere between $2-4 billion of net benefits from Limerick. Mr. Falkenberg, on the other hand, predicts a net $1.2 billion lifetime cost of Limerick, while Mr. Komanoff suggests a range of $2 to $3.2 billion net cost and Mr. Chernick suggests a range of $1.1 to $4.8 billion net cost. In part, these wide differences reflect differences in what is being analyzed. For example, some of the estimates are based on 50% of common plant and some on 100%, and some use the correct after-tax cost of money for the discount rate, while others use higher (and I believe inappropriate) rates. Notwithstanding these methodological problems, there is an enormous range in the possible costs of Limerick and its alternatives. Thus, the most I would conclude from such analyses is that consumers either will or will not benefit from Limerick. Because we will not know for sure, however, until some future date, such estimates cannot provide a proper basis for ratemaking treatment of Limerick.

Q. What significance do you attach to Mr. Falkenberg's argument that after-the-fact cost-benefit analyses provide a guide to the "usefulness" of the project and, hence, that any project which cannot affirmatively be shown to reduce consumer cost is not "useful" and should suffer disallowance?

A. This argument represents an indefensible interpretation of the "used and useful" standard. The conventional interpretation of this standard is simply that investments must actually be used in the production of electricity and must be useful in that regard. The used and useful standard was originally meant only to preclude return on investments which were not intended for use in, or had no relevance to, the production of electricity. The extension of this standard to make comparative evaluations of degrees of usefulness among alternatives, all of which might be used to generate power, distorts this standard far beyond its intended meaning.

Moreover, the application of the "used and useful" standard in this way represents far more than a mere supplement to the prudency standard as Mr. Falkenberg suggests. In fact, it stands in direct conflict with that standard. To allow after-the-fact cost-benefit analyses to determine whether a plant is used and useful clearly would render meaningless the guarantee of a fair return on prudent investments.

Q. What about Mr. Falkenberg's argument that investors should share in the downside risks of this project since these risks were foreseeable?

A. This argument makes no sense. Since the future is always uncertain, all investments have risks. As Mr. Falkenberg points out, it was possible, in 1978, that Limerick would cost more than its estimate, but it was also possible that it would cost less. Moreover, this was equally true of any alternative to the project. Not building Limerick, for example, would have raised the risk that PECO's consumers would become dangerously vulnerable to rising fossil fuel prices or to regulations that would drive up coal capital costs. Although any number of such uncertainties are always present, a company must nevertheless decide upon a course of action. And, the test of such decisions is whether, given the available data, its chosen course of action was reasonable. If the decision was reasonable, the investor should earn a fair return. Where an investment appears unfavorable at the time ratebase treatment is being considered, the consumer, who would reap any benefits if things go well, should in all fairness be expected to absorb the apparent costs.

Q. Would this not, as Mr. Falkenberg suggests, insulate investors from all risks and thereby entitle them to only risk free interest rates?

A. No. Even though it insulates them from some market risks, it does not insulate investors from imprudent management actions or from the effects of regulatory lag which are inherent in the regulatory process. The historic risk premiums earned by utility investors are designed to compensate them for just such risks. Since utility bonds and stocks carry interest rates which are higher than treasury bills, it is clear that utility investments are not viewed as risk free. On the other hand, since the overall cost of money to utilities is well below that of firms operating in a competitive market place, it is also clear that utility investors do not expect to be subjected to the full effect of market risks.

Q. What evidence would be necessary to show that PECO was imprudent to construct Limerick?

A. It would be necessary to establish either that specific actions or inactions by PECO's managers led to excessive costs or that, at any time during its construction, Limerick could have been replaced by a cheaper alternative. The parties opposing full ratebase treatment for Limerick have done neither. In fact, Mr. Komanoff, one of the earliest and most vociferous critics of nuclear power, testified in a 1979 hearing before the House Subcommittee on Energy and the Environment that nuclear plants which were 40 percent complete should be finished. According to Mr. Komanoff's source, the Nuclear Regulatory Commission's February 1979 "Construction Status Report, Nuclear Power Plants" (commonly referred to as the "Yellow Book"), Limerick Unit No. 1 at that time was 48 percent complete.

DISCOUNT RATES

Q. Please respond to both Mr. Chernick's and Mr. Falkenberg's suggestion that their use of higher discount rates is more appropriate than the rates used in your analysis.

A. The after-tax cost of money is the rate at which utilities can borrow or lend funds on behalf of their consumers. As such, it is the appropriate rate at which to evaluate investment decisions. Assuming that the goal is to minimize the expected cost of generation, any other rate, whether the pre-tax cost of money as Mr. Falkenberg argues or the consumers' private rate as

Mr. Chernick argues, will lead to less than optimal results.

Q. Please explain why the after-tax cost of money is the rate at which PECO can borrow and lend funds.

A. This can be illustrated by using a simple example which I have summarized in the attached Schedule 21. The utility in this example has a capital structure which is 50% equity and 50% debt. The interest on debt is 10%, the equity rate is 15% and the effective tax rate is 50%. Consequently, the weighted average cost of money (Mr. Falkenberg's discount rate concept) is 12.5% (50% x 15% + 50% x 10%). But the formula for the average after tax cost of money is:

$$ES \times ER + DS \times DR \times (1-TR)$$

where ES = equity share

ER = equity rate

DS = debt share

DR = debt rate

TR = tax rate

which in this case is: (.5 x. 15 + .5 x .5 x 10) or 10%. To evaluate the cost at which a utility can borrow on behalf of its consumers, we examine a hypothetical power plant with a capital cost of $100. The plant is assumed to have an operating life of two years and to be depreciable for tax purposes in one year. We have then considered two possible ways of collecting the revenue requirements from consumers. In the first case, we amortized the entire capital investment over the first year of plant life; in the second case, we amortized the capital investment over two years. When the plant is amortized over two years instead of one year, revenue requirements in the first year are reduced by $100, but revenue requirements in the second year are increased by $110. Thus, when accounting conventions are changed so as to save consumers $100 in year one, this $100 is paid back by consumers in year two at an interest rate which exactly equals the after-tax cost of money. It can be shown that this would also be true regardless of the assumptions made about the actual book life of the plant. Any adjustments to accounting conventions, which either defer revenues into the future or accelerate them into the present, occur at an interest rate which equals the after-tax cost of money. This result is true regardless of the AFUDC rate during the construction period for the plant. Thus, we can see that the after-tax cost of money and not the simple weighted average cost is the rate at which the company can borrow and lend funds on behalf of consumers.

Q. Why is the after-tax cost of money preferrable to using the consumer's own discount rate?

A. Perhaps the best way to illustrate why the after-tax cost of money to the utility is a more appropriate rate than the consumer's discount rate is with a graph. This graph is described in Schedule 22 attached to this rebuttal testimony. There, we describe consumers' preference pattern among various patterns of consumption in two periods. The vertical axis depicts consumption in period 2. Along the horizontal axis, we measure consumption in period 1. Every possible point in the figure represents a particular combination of consumption in both periods. The slanted lines drawn on the graph represent consumers' indifference curves. That is, the consumer is indifferent among all combinations of consumption which lie along a single line. The points on the highest indifference curve are the most attractive to consumers. The slopes of these indifference curves can be viewed as representing the consumers' internal discount rate. That is, they describe the rate at which the consumer would be willing to trade consumption today for consumption tomorrow.

Now, the choice of any investment option affects a consumers' consumption in both periods. Typically, investments decrease consumption in the first period and increase consumption in the second. If we know the effect of an investment on consumption in both periods, we can use this mapping of consumer preference to choose among options. This is equivalent to evaluating options at the consumers' discount rate.

Suppose, for example, the consumer is choosing between two generating options—one which yields the consumption pattern denoted by point A and the second yielding point B. Since B is on a higher indifference surface than A, at the consumers' discount rate, B is clearly preferred to A. In this particular context, B is preferred to A because the consumer has a relatively high discount rate and therefore places relatively little value on what happens in period 2. Since option B provides substantially more consumption in period 1, it is preferred. However, let's now change our example somewhat to allow this same consumer to borrow and lend funds at the <u>market</u> interest rate. This market interest rate is assumed to be the same regardless of whether the consumer is borrowing or lending. Given the existence of such a rate, each of the consumption bundles, A and B, can be used to trade for alternative bundles. Thus, by selecting the option A and then borrowing against it, the consumer can have more consumption in period 1 at the expense of having somewhat less consumption in period 2. On the other hand, by selecting option B and taking some of the income it generates in period 1 and lending it out, the consumer can reduce his consumption in period 1 and, by doing so, increase his consumption in period 2. As we can see from the graph, however, the existence of the opportunity to borrow and lend at a market interest rate changes the relative ranking of alternatives A and B. Whereas option B was previously preferred to option A when evaluated at the consumers' discount rate, given the opportunity to borrow and lend at a rate which is lower, option A is preferred over option B. By purchasing option A and then borrowing against future income, the consumer can reach an indifference curve which is higher than that which can be achieved by doing the same thing with option B. It is important to see that there is no asymmetry in the treatment. In this example, I am not assuming that a consumer can move funds around for option B but is stuck with option A. The consumer can choose either A or B and borrow and lend against either A or B.

It is also interesting to note that introducing the interest rate changes the decision rule used to evaluate options. When we were evaluating at the consumers' discount rate, the point that lay on the highest indifference surface was the best point. But as soon as we include the market interest rate, the rule for choosing the best point changes. Now, in order to choose the best point, we draw a line with the slope of the market interest rate through every point and the point that lies on the highest line will always prove to be the highest point of a welfare maximization. This is another way of saying that if there is an interest rate at which consumers can both borrow and lend, the option that has the highest present value at that market interest rate will always be the best one for consumers to choose.

This graph and the previous example regarding the effect of changing accounting treatment need to be viewed in concert. When we changed utility accounting treatments, we demonstrated that the after-tax cost of money was the effective rate at which the utility could borrow and lend funds on behalf of consumers. And the extent to which such borrowing takes place can be determined by the PUC acting on behalf of consumers. The graph, I think, demonstrates that the rate at which consumers can borrow and lend funds is the appropriate rate to be used in judging alternative generating options. A combination of these two results demonstrates that the after-tax cost of money is the appropriate discount rate at which to evaluate these generating options.

Q. What about Mr. Chernick's argument that the delay in Limerick's construction schedule led to excessive costs?

A. Mr. Chernick argues that my analysis of the prudence of PECO's decision to delay Limerick is inappropriate because I use too low a discount rate and because the fuel and capital savings resulting from delay are too speculative to be included in the analysis. His argument makes no sense. As I previously discussed, it is clear that the after-tax cost of money, as the rate at which utilities can borrow and lend on behalf of consumers, is the appropriate rate to use in evaluating investment decisions. And, if we are going to evaluate correctly construction scheduling decisions, it makes no sense to include some effects because they occur early while ignoring others simply because they occur later. All of these analyses are somewhat speculative, and effects occurring in the 20th or 30th years, which Mr. Chernick would apparently include, are no more speculative than events occurring in the 31st year, which he would ignore. If Mr. Chernick is genuinely concerned about this problem, he should restrict his analysis to the first ten years of project life as did PECO's original analysis. With this restriction the delay also is prudent.

CAPITAL COST PROJECTIONS

Q. Do you agree with Mr. Falkenberg's contention that the Company could plausibly have expected costs for Limerick to range as high as $2,454 per kilowatt as of 1978?

A. No. My analysis, which I described in my direct testimony, suggests that PECO's estimates were reasonable given the information available at the time.

Q. What are your criticisms of Mr. Falkenberg's analysis?

A. Mr. Falkenberg uses a regression based on plants completed from 1968 to 1978 to forecast Limerick's costs if completed in 1986. I have attempted to replicate his results and the results of this replication are described in Schedule 23. The results of this replication, which are close to, but not exactly the same as Mr. Falkenberg's, yield a predicted cost for Limerick of $2,390 as compared to his $2,454. This Schedule also contains the results of some modifications to his model.

First, while Mr. Falkenberg purports to use data on all nuclear plants completed from 1968 to 1978, he omits ten units built during this period. When these units are added to the data base, the predicted costs of the Limerick plant falls to $2,087 from the $2,454 which he derived.

Second, it is not clear why Mr. Falkenberg has limited his sample to units completed from 1968 to 1978. If his purpose is to show what PECO could have expected Limerick to cost, the best way to do this statistically would be to use all available data. I can see no reason why a prudent planner in 1978 would ignore information about earlier units. When all units completed before 1978 are included in the analysis, the prediction for the Limerick plant based upon Mr. Falkenberg's model is further reduced to $1933 per kilowatt, about 25% below the estimate from his testimony.

Third, Mr. Falkenberg uses both time and time squared variables to represent the historic trend in cost and, consequently, projects a steadily accelerating trend in nuclear construction costs. As a result, he projects a 1986 cost which is very far above the level actually prevailing in 1978. It is not at all clear that it is appropriate to extrapolate past cost trends. Nevertheless, even if such trends are to be extrapolated, there are other means of trend extrapolation which are equally plausible on statistical grounds, and more plausible on heuristic grounds, that produce much lower cost forecasts. Thus, a simple linear time trend would indicate a cost forecast of $1,241 per kilowatt -- half the level suggested by Mr. Falkenberg. This regression fits the data nearly as well as Mr. Falkenberg's and has a smaller standard error of prediction. Since the objective of Mr. Falkenberg's analysis is to predict Limerick's cost, the standard error of prediction is at least as important as the "R^2" value in choosing the best model. Moreover, as the graph in Schedule 24 suggests, viewed from the perspective of 1978, this lower value is considerably more plausible than that suggested by Mr. Falkenberg.

It is important to note, then, that the difference between Mr.

Falkenberg's estimate and the Company's is not simply whether or not you extrapolate the trend in cost, but how you estimate and extrapolate the trend. In fact, a perfectly reasonable estimate based on extrapolating the trends in past cost produces an estimate lower than the Company's value. And, only Mr. Falkenberg's extreme form of trend extrapolation produces higher values.

Also, Mr. Falkenberg uses the commercial operation date as his time-related explanatory variable. However, the commercial operation date (COD) itself is affected by capital costs because units with high capital costs often take longer to build. As the causation between cost and COD runs both ways, it is not appropriate to use the COD as an independent variable; it is not, in fact, independent of costs.

Q. Did you correct this error?

A. Yes. Schedule 23 summarizes the results of reestimating the model using all nuclear units completed prior to 1978 and replacing the two COD variables with time and time squared variables based on the construction permit date. This avoids the bias implicit in Mr. Falkenberg's model because a unit's capital cost cannot cause its construction permit date to change one way or the other. This modified regression yields a predicted cost of only $1,292 per kilowatt for Limerick, roughly $300 per kilowatt less than what PECO was predicting during the 1978 period. Thus, if Mr. Falkenberg had limited his consideration to truly independent variables, even with his extreme form of trend extrapolation he would have produced a cost estimate below that of PECO. It is hard to see, then, why extrapolation of past trends should have caused the Company to impute greater risks to the decision to build.

Limerick than it did. In addition to producing a lower estimate, the use of the construction permit date also results in a much lower standard of error of prediction. Thus, the standard error of prediction for Mr. Falkenberg's estimate is $241 per kilowatt whereas the standard error that we obtain using the construction permit date is only $132 per kilowatt. In addition to being a more correct specification, therefore, the use of the construction permit date produces a more reliable estimate.

Q. Mr. Falkenberg has argued that PECO could have anticipated that Limerick would cost $2,454 per kilowatt in 1978. If PECO had anticipated such a cost should it have cancelled the investment in the project?

A. No. The results of the analysis contained in my direct testimony in this proceeding indicate that as of 1978, even if Limerick's expected cost were $2989 per kilowatt, it would be economic to complete the project. This result is more fully described in Schedule 3 of my direct testimony, which indicates that as of 1978 Limerick's real direct costs (in 1984 dollars) would have to have been more than $2,525 per kW to make cancellation economic. This estimate of directs translates into a booked cost of $2,989 per kW.

<u>COST OF CONSTRUCTION DELAY</u>

Q. What is your understanding of Mr. O'Brien's calculation?

A. Mr. O'Brien alleges that decisions taken by PECO management resulted in a 27 month delay in completing the unit. He calculated that this 27 month delay increased the cost of Limerick 1 by $740 million, exclusive of the effects on PECO's indirect costs. This includes $564 million for the effect of delay on escalation and AFUDC, and $172 million for additional Bechtel indirects. However, it excludes his estimate of $101 million of increased

PECO indirects because, under cross examination, Mr. O'Brien could not produce support for this estimate and the Company views it as being unrealistic.

Q. What is wrong with this calculation?

A. Several things. First, Mr. O'Brien presents no evidence that the delay in the Limerick schedule was the result of imprudent decisions on the part of PECO management. Unless the decisions which led to the delay were imprudent given the facts available at the time, there is no basis for disallowing cost increases resulting from the delay.

Second, Mr. O'Brien measures only the effect of delay on the nominal capital cost of the Limerick project. However, the appropriate criterion for measuring the cost of delay is to examine its impact on the cost of electricity to consumers. And while the booked cost of Limerick is <u>related</u> to its costs to consumers, it does not translate directly into costs to consumers. In particular, while the effect of delay is to increase the nominal cost of Limerick, it also delays the time period when these costs must be paid. Since these delays reduce the present value of revenue requirements, a rise in nominal booked cost of Limerick will certainly not result in a dollar for dollar increase in the present value of revenue requirements.

NERA has estimated that the effect on revenue requirements of a 27 month delay, which caused a $740 million increase in booked cost, would <u>raise</u> the present value of the capital portion of the revenue requirements by $102 million.

Q. With this correction, does the disallowance described above constitute an appropriate compensation for the effect on consumers of a 27 month delay?

A. No. Mr. O'Brien's assessment ignores two important effects of delay:

1. Fuel and operating costs of the Limerick system. During the initial period of delay there is an increase in system fuel costs since the system does not obtain the benefits of Limerick's low operating costs. Later, the delay reduces fuel costs because Limerick operates over a longer period of time.

2. Capital expenditures for Philadelphia Electric. While the delay increases the construction costs of Limerick, it also reduces system capital costs by delaying the date at which the unit must be replaced.

Q. Have you tried to assess these effects of delay?

A. Yes. I have calculated the effect on system revenue requirements of a 27 month delay in Limerick's on-line date. It is my estimate that this delay increases the present value of system revenue requirements by $4 million.

Q. Please describe the components of this calculation.

A. The delay reduces the present value of PECO's capital related revenue requirements by $19 million. This includes the higher cost of Limerick (which increases revenue requirements), the delay in the time period in which the consumers must pay the capital cost of Limerick, and the delay in building the unit's replacement (both of which reduce the revenue requirements).

The delay increases the present value of fuel, and operating and maintenance (O&M) expenditures by $22 million. It includes higher fuel costs during the period of delay and lower fuel costs late in the delayed unit's operating life.

The combined effect of delay is to increase the present value of revenue requirements by $4 million (The difference between the $22 million of reduced capital cost and the $19 million of added fuel cost does not equal $4 million because of rounding).

Q. What disallowance in Limerick's cost would leave customers unaffected by the effects of the delay?

A. A disallowance of $2 million would reduce the present value of the revenue requirements by the $~~2~~4 million present value figure that I have calculated above. The disallowance is smaller than the increase in revenue because the disallowance reduces taxes, the benefits of which have been assumed to flow through to consumers. 3-11-86

Q. Do you believe that such a disallowance would represent an appropriate treatment of PECO's decisions to delay the project?

A. No. My own analysis suggests that the decisions to delay were prudent, hence, there should be no disallowance. In addition, my own analysis of Limerick's construction time compared to those of other units makes it appear highly implausible that financial constraints could have delayed construction time by 27 months. If built to Mr. O'Brien's schedule, Limerick would have been completed in 9.43 years and, once standardized to Limerick's characteristics, only two units would have shorter construction times while 32 would have longer times. Further, the company contends that building the project on the accelerated schedule suggested by Mr. O'Brien would have raised borrowing costs. If this is the case, any increases in borrowing costs should be deducted from the disallowance described above.

ECONOMIC IMPACT OF RATE INCREASE

Q. What are your comments on Dr. Schinnar's cross-examination testimony regarding the employment consequences of Limerick-related rate increases?

A. Dr. Schinnar, in his cross-examination testimony suggested that my analysis of employment effects in the Lukens Steel case, Re Lukens Steel Company, 58 Pa. P.U.C. 256 (1984), is supportive of his estimate as to the employment consequences of Limerick-related rate increases. I do not agree that my analysis can be used to support this claim.

First, my analysis was designed to analyze the effect of price increases occurring for the entire Commonwealth of Pennsylvania. Since the base of activity is much smaller in the PECO service territory, the employment consequences of any price increase would necessarily be much smaller. The manufacturing labor force in metropolitan Philadelphia, for example, is 36% of that in Pennsylvania.

Second, the increased electric price elasticity which I used to evaluate the impact of Lukens-related price increases was based on an average elasticity for all manufacturing industries. But this is an average of relatively high elasticity in a very small number of industries--steel, chemical, and paper for example--and elasticities are very low in other industries. Since the percentage of employment in electric intensive industries is smaller in the Philadelphia MSA than in the Commonwealth as a whole, the employment elasticity would also be much smaller. In particular, I find it entirely implausible that there could be high employment elasticities with respect to electric price in the service sector as suggested by Dr. Schinnar's model.

Third, in my model I made use of multiplier effects for the Pennsylvania economy which were suggested for use by Luken's consultants, ADL. These multipliers depend upon the percentage of consumer expenditures on goods and services produced in the areas being analyzed. Since Pennsylvania consumers spend a relatively large percentage of their disposable income on goods and services produced in the Commonwealth, the multipliers are fairly large--1.5 indirect employment losses for each direct employment loss. Philadelphia MSA residents spend a much smaller percentage of disposable income on goods and services produced in the Philadelphia MSA and consequently the multipler effects are proportionately smaller.

For all of these reasons I do not believe that the model used to assess employment consequences in the Commonwealth can be simply extrapolated for use in addressing such effects in the Philadelphia MSA.

Q. Does this conclude your rebuttal testimony?

A. Yes.

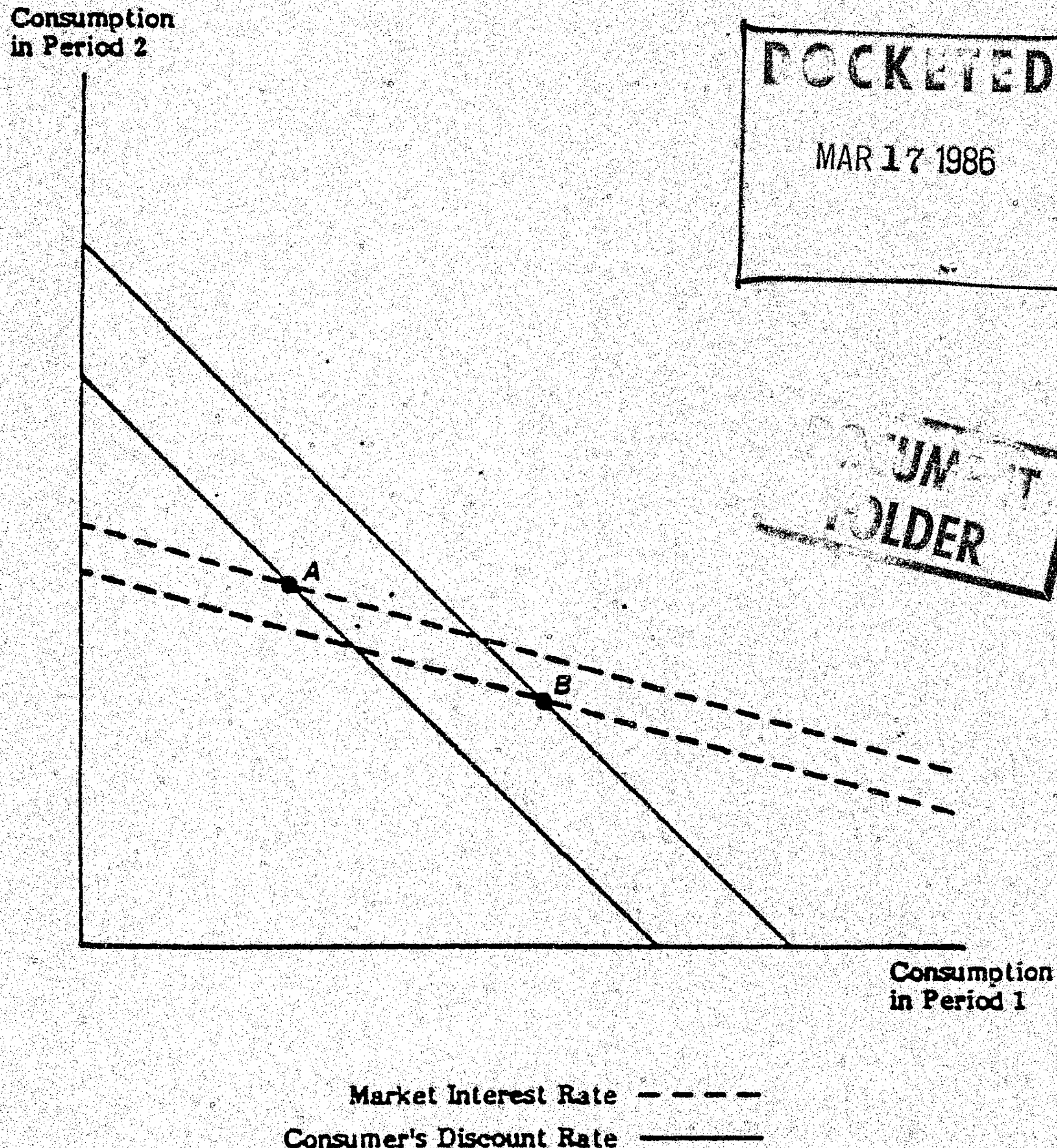
EXAMPLE OF THE DERIVATION OF THE AFTER-TAX COST OF MONEY AS THE DISCOUNT RATE BASED ON ONE YEAR OR TWO YEAR BOOK LIFE

	One Year Depreciation		Two Year Depreciation	
	First Year (1)	Second Year (2)	First Year (3)	Second Year (4)
Equity Return	$ 7.50	-	$ 7.50	$ 3.75
Interest Cost	5.00	-	5.00	2.50
Taxes	7.50	-	-42.50	53.75
Depreciation	100.00	-	50.00	50.00
Total	$120.00	-	$ 20.00	$110.00
Difference in Revenue Requirements			-100.00	110.00
Implicit Interest Rate on Borrowed Funds				10.0%
After-Tax Cost of Money				10.0%

Assumptions

Debt Rate	10.0%
Equity Rate	15.0
Equity Share	50.0
Debt Share	50.0
Tax Rate	50.0
Tax Depreciation	1 Year, Straight-Line
Construction Cost	$100.00

EVALUATING ALTERNATIVE GENERATING OPTIONS AT THE CONSUMERS' DISCOUNT RATE AND THE MARKET INTEREST RATE



FALKENBERG'S REESTIMATED CAPITAL COST REGRESSION EQUATIONS[1]

	Regression Coefficients[2] (t-Statistic)[3]					
	Falkenberg Regression					
	As Reported (1)	As Replicated (2)	All Data 1968-1978 (3)	All Pre-1978 Data (4)	Excluding Time Squared (5)	Time Trend Based on CPD (6)
Constant	41,191.260 -	38,911.843 -	28,084.342 -	21,713.408 -	-5,421.182 -	31,508.789 -
Commercial Operation Date[4]	-1,185.239 (4.955)	-1,123.525 (5.490)	-829.094 (4.490)	-656.623 (9.621)	78.472 (13.313)	- -
Commercial Operation Date Squared[5]	8.544 (5.298)	8.131 (5.896)	6.135 (4.916)	4.970 (10.356)	- -	- -
Construction Permit Date[6]	- -	- -	- -	- -	- -	-1,012.707 (9.143)
Construction Permit Date Squared[7]	- -	- -	- -	- -	- -	8.116 (9.488)
First Unit Indicator[8]	132.500 (5.365)	113.382 (4.774)	134.752 (5.751)	134.463 (5.325)	135.615 (4.868)	41.624 (1.322)
Northeast Indicator[9]	75.071 (3.298)	79.743 (3.785)	81.280 (3.723)	93.157 (4.098)	96.811 (3.759)	109.232 (3.847)
Unit Size[10]	-0.1267 (1.595)	-0.162 (2.198)	-0.208 (3.081)	-0.215 (2.970)	-0.238 (2.990)	0.061 (0.754)
Adjusted R^2	0.8604	0.8841	0.8454	0.8159	0.7815	0.7149
F-statistic	62.611	77.300	66.645	56.838	54.651	32.591
Predicted Cost	2,454	2,390	2,087	1,933	1,241	1,292
Standard Error	241	207	197	138	113	132
Number of Observations	51	51	61	64	61	64

FALKENBERG'S REESTIMATED CAPITAL COST REGRESSION EQUATIONS

Sources and Notes

[1] The dependent variable in the regression is the total booked capital cost in as-spent $/kW, including allowance for funds used during construction. The data are from a September 1985 TVA survey, or from a NERA survey of individual utilities if TVA did not report costs for a unit.

[2] The regression coefficient measures the effect of a one-unit change in the independent variable on the dependent variable.

[3] A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 2.01 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.68 or higher indicates significance at the 10 percent level.

[4] This variable is the commercial operation date minus 1900.

[5] Commercial operation date, as defined above, times itself.

[6] The construction permit date minus 1900.

[7] Construction permit date, as defined above, times itself.

[8] The indicator equals 1 if the unit is the first unit of a series built at a site or if the unit is part of a single-unit plant and 0 otherwise.

[9] The indicator is equal to 1 if the unit was built in the northeast and 0 otherwise.

[10] This variable equals the unit's net design electrical rating in megawatts.

PREDICTED AND ACTUAL NUCLEAR CAPITAL COST