Ex. WHH-30 through WHH-52

PECO STATEMENT NO. 15A

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PENNSYLVANIA PUBLIC UTILITY COMMISSION
V. PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

REBUTTAL TESTIMONY

OF

DR. WILLIAM H. HIERONYMUS

RATE TREATMENT PRINCIPLES APPLICABLE TO LIMERICK,
ECONOMIC BENEFITS OF LIMERICK

FEBRUARY 19, 1986

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

Q. Please state your name and business address.

A. My name is William H. Hieronymus. My business address is Putnam, Hayes and Bartlett, 124 Mount Auburn Street, Cambridge, Massachusetts.

Q. Dr. Hieronymus, have you testified previously in this proceeding?

A. Yes. My direct testimony was PECO Statement No. 15.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will respond to specific aspects of the direct testimony of a number of intervenor witnesses. The general topics I will cover are the ratemaking standards implicit or explicit in the ratemaking treatment of Limerick Unit No. 1 proposed by some parties; the quantification of the schedule effects of the 1976 and 1978 delays as proposed by Staff and OCA; the excess capacity assertions of Mr. Chernick and, at least by implication, Messrs. Knudsen, Lanzalotta and Falkenberg; the import and content of OCA, PAIEUG and UUC/UP's Limerick cost-benefit analyses; and proposals that PECO be required to guarantee the Limerick Unit No. 1 capacity factor or fuel savings.

INTERVENOR WITNESSES' LIMERICK COST RECOVERY PROPOSALS

Q. Have you reviewed the proposals of the various intervening parties concerning how PECO should be permitted to recover its investment in Limerick 1?

A. Yes I have.

Q. Would you please provide an overview of your comments on these proposals within the context of the regulatory policy and economic issues which you discussed in your direct testimony in this proceeding?

A. The proposals fall into five groups: reductions in allowed ratebase due to asserted imprudence; reductions in revenue requirements due to asserted excess capacity; phase-ins and related accounting issues; reductions in revenue requirements as a form of "risk-sharing" and avoided-cost pricing of the output from Limerick.

Q. Do you have any comments on the prudence related disallowances?

A. To the extent that the present value of costs to ratepayers were raised by imprudent acts, disallowance of related costs is appropriate. A later section of my testimony deals with the factual issue of the reasonableness of the schedule delay quantification; I have no quarrel with the abstract regulatory principle underlying the proposal to insulate ratepayers from the burden of paying imprudently incurred costs.

Q. Do you have any comments on the excess capacity-related reduction in revenue requirements?

A. Again, a later section of my testimony deals with factual issues concerning excess capacity. I have nothing to add to what I have already said in my direct testimony concerning the relationship between the used and useful doctrine and penalties for temporary excess reserves.

However, I would like to comment on Mr. Falkenberg's testimony at pages 34 to 41 where he discusses the implications of my testimony regarding regulatory policy. At p. 36 he states that I have misread the unwritten contract between ratepayers and investors "at least as it has been interpreted in the Commonwealth of Pennsylvania." He notes that the Pennsylvania Commission has, since 1979, disallowed recovery of prudent costs on "used and useful" grounds and specifically on grounds of excess capacity. He then asserts that by proposing a return to a "prudence only" standard it is I who is seeking to change the rules of the game.

To a degree Mr. Falkenberg is correct, though I would amend his statement by noting that it was only at the time of the Susquehanna 1 discussion that the old rule changed in a manner which investors were likely to consider important and indicative of an increase in the risk of future loss. Since by that time there was reason for investors to be reasonably confident that PECO would not be subject to a finding of excess capacity when Limerick 1 was completed, this reversal was somewhat mitigated in terms of its effect on investor expectations.

In any event, the meat of Mr. Falkenberg's testimony begins on page 38. He first uses what even he conceeds is an "reductio ad absurdum" argument to point out that "some limit must exist on the application of the prudence standards" (emphasis in original). He then asserts, and it is no more than an assertion, that those limits have been exceeded. However, he provides no criteria for what those limits should be nor does he provide any evidence whatsoever that this limit has been reached. His assertion is simply one man's unsupported opinion.

He then goes on to argue that under a "prudence only" standard "stockholders face no business risk on their investment," and that the only risk they face is that of interest rate fluctuation. On this basis, he asserts that the cost of debt is a business risk-free rate of 9.28 percent and the cost of equity is the adjustable rate on savings bonds, 8.36 percent.

I will assume for purposes of my rebuttal that Mr. Falkenberg is not being facetious. He is simply incorrect that if utilities are safe from a risk of "used and useful" deductions or "risk sharing" of putative losses on prudent investments, they lack business risks. Anyone who has studied the financial performance of the utility industry knows that for virtually all of the period of Limerick construction, utilities failed by wide margins to earn their Commission - mandated fair rates of return. Many observers would also argue that during that period, allowed rates of return were below market; the risk of a below market allowance is thus another form of business risk.

Mr. Falkenberg, in asserting that government bond rates are reasonable measures of utility risk under a "prudence only" standard, ignores miscellaneous other factors, including the fact that utility-earned rates of return are not adjusted automatically on 6-month intervals as his analysis would require, that financial leverage creates an equity risk premium, that federal bond interest is not taxed by states, and that the quoted savings bond rate is a retail rate, not a market rate for large amounts of capital. Finally, the flawed nature of his analysis is demonstrated by the cost of capital for utilities which are not engaged in major generating plant construction and hence are not exposed to the excess capacity penalty risk which Mr. Falkenberg regards as the primary reason for a risk premium on utility securities. None exhibits a cost of capital as low as he believes would apply to PECO.

Q. You indicated that "risk-sharing" had been proposed as a basis for determining the recoverable costs of Limerick. What was the basis for that proposal?

A. Mr. Falkenberg asserts that in undertaking to build Limerick, PECO was "pursuing a risky course of action" and should be made to bear at least part of the consequence of that risk, the consequence being an alleged life cycle net loss due to construction and operation of Limerick 1. The asserted cost to be shared is \$1.2 billion present value dollars. He utilizes this "risk-sharing" argument to support his specific proposal to limit the recoverable first year revenue requirement increase to \$404 million, phased in beginning with a \$135 million rate increase.

Initially, I note that the $404 million figure was not derived based on "risk-sharing" but was ostensibly a limit required to keep PECO from over-recovering its full Limerick 1 revenue requirement. The use of the "risk-sharing" argument is, to me, convincing evidence that Mr. Falkenberg himself recognizes that the derivation of the $404 million number was bogus. Second, while Mr. Falkenberg at page 56 seems to espouse risk-sharing on the grounds that PECO could not remain viable if it had to absorb the cost of Limerick, the reduction in revenue requirements which he proposes are at least sufficient to fully pass to shareholders the responsibility for the supposed $1.2 billion loss.

Q. What is your primary objection to Mr. Falkenberg's proposal?

A. Mr. Falkenberg is proposing a "quasi-prudence" test. He concedes that his evidence does not demonstrate that PECO was imprudent in its load forecasting in the mid-1970s nor does it demonstrate that PECO was imprudent in forecasting a lower Limerick 1 completion cost than he contends they might have. Nor does he demonstrate, or even try to demonstrate, that had PECO adopted the load and plant cost forecasts he presents it would or should have cancelled the plant. The use of his "risk-sharing" proposal as a basis for imposing large losses on shareholders seems to require only 3 ingredients: first, a showing that a course of action was risky; second, a showing that there existed some basis, not necessarily compelling, that some of the assumptions favoring the adopted course of action were potentially optimistic; and third, an after-the-fact calculation which shows that a future net loss from having built the plant is possible.

His first test is too easily failed. Any course of action in the mid-1970s was risky, especially including the "action" of doing nothing. His second test is likewise too easily failed. I simply cannot think of a single real world example of a decision which arguably had a bad ultimate outcome which someone with the benefit of hindsight could not contend should have been decided differently. What divorce(e) lacks old acquaintances who cannot now recall the warning signs that the marriage was a mistake?

What Mr. Falkenberg is really doing is seeking a relabeling of the prudence test which allows him to shear it of the restrictions against the use of hindsight and the defense by the utility that its actions were reasonable. Were his standard to be adopted, no utility would be able to defend investments which were not such clear winners that an assertion of a future loss would not stand the "blush test." Even for an undurable winner, the logical extension of Mr. Falkenberg's proposal would be the imposition of "risk-sharing" losses on the grounds that the gold mine would have been richer had the utility staked the adjacent claim.

Q. The final category of proposal you mentioned was avoided-cost pricing of the output of Limerick Unit No. 1. Please explain this proposal.

A. Mr. Chernick proposes that Limerick 1 not be ratebased. Rather PECO would be paid for Limerick output on a hypothetical avoided cost basis. Avoided cost pricing is also discussed by PBUUG witness King who, to his credit, provides a balanced view of some of the serious problems with the approach. Unlike Mr. Chernick, Mr. King does not specifically propose avoided cost pricing and appears to prefer other options.

Q. Is Mr. Chernick's proposal is sound?

A. No, it is not. First, it is improper on many of the grounds I discussed in my direct testimony: it is an after-the-fact attempt to avoid compensating investors for prudent investments (and, I might add, would apply irrespective of whether the plant is used and useful). Under his proposal, investors who were told that they were investing in a rate of return regulated enterprise, and have been compensated on that basis, are suddenly to be told that they have invested in an enterprise far riskier than the typical unregulated business. Even if Mr. Chernick's proposal were to prove lawful, it would be a shamefully opportunistic abuse of the trust of investors in the fairness of the regulatory system.

Q. Why would PECO become far riskier than a competitive enterprise?

A. Primarily because while a competitive firm faces market prices for its output, and will make profits or losses to the extent that its revenues exceed its costs, PECO would face a quite different and more risky future. This brief statement includes three elements which distinguish the condition of the competive firm from the condition of PECO under Mr. Chernick's proposal. First the competitive firm faces market prices. Mr. Chernick's proposal would compensate PECO based on hypothetical prices: reliability payments would be based on the cost of life extensions not made or peakers not purchased and energy savings on fuel not burned.

Second, those market prices are applied to a firm's entire output. In contrast, Mr. Chernick does not propose to apply avoided cost pricing to PECO's output, only to that of Limerick 1. Competitive firms may not, in each year, fully cover the accounting cost for each of their plants individually, especially their new plants. However, the fact that the firm has a portfolio of plants, some of which are greatly over-recovering their book costs, means that they still may be earning at least market rates of return. It is no accident that the proposal to base revenues on avoided costs is applied by Mr. Chernick only to a plant which he believes is worth far less than it costs and not to plants on which PECO might make a profit greater than it would earn on the plants' depreciated book value.

Third, competitive firms achieve losses <u>or</u> <u>gains</u> depending on the relationship of their costs to market prices. Mr. Chernick is unwilling to offer this arrangement to PECO even on a Limerick-only basis, much less on a company-wide basis. He merely offers the suggestion that the Commission may wish to consider at a later date whether and to what extent PECO should be permitted to keep some of the later supra-market profits as compensation for the large losses his scheme would impose during the first years of the plant's life.

Q. Have you other comments on Mr. Chernick's proposal?

A. Yes. First, Chernick's proposal obviously would severely affect PECO's financial condition, a problem which he states he has not studied. Under the revised FASB-71 as currently drafted, a very substantial equity writeoff would result from his proposal. Second, an alternative to avoided cost pricing which Mr. Chernick also advances would require that the Commission now decide the year to year value of Limerick 1 based on prospective avoided costs. As later sections of my testimony make clear, such an exercise would be highly speculative even on an aggregated life cycle basis, and even more speculative on a year-to-year basis. Third, both rates and net revenues to common shareholders would be quite unstable. Ratepayers would be deprived of the benefits of fuels diversification and, specifically, of reductions in oil use. Since Limerick avoided costs would be priced based on oil much of the time, an increase in the oil price would raise rates to reflect both the cost of oil actually burned and the avoided cost of power from Limerick 1. Conversely, shareholders who thought they were investing in the electric utility business would find themselves speculating in oil futures.

In addition to these obvious failings of Mr. Chernick's proposal, I note simply that what he is proposing is tantamount to deregulation (albeit unfair deregulation) of a major portion of PECO. Such a proposal has far reaching implications for utility regulation in the Commonwealth of Pennsylvania and is not a decision which could or should be made within the confines of a single company's rate case.

LIMERICK CONSTRUCTION DELAY

Q. In your summary, you stated that you would comment on Trial Staff and OCA testimony concerning the effects of decisions to delay Limerick completion in 1976 and 1978. From what perspective will you address this issue?

A. Other witnesses are addressing in detail the specifics of the cost of delay based on factors peculiar to Limerick and to PECO. This approach might be charactized as applying a "micro" perspective to quantification. By contrast, my intent is to apply a "macro" perspective to the issue of quantification. Through time, PHB has compiled extensive databases on nuclear plant construction schedules and schedule estimates. I will use that data to attempt to answer the following question: "In the 'but-for' world in which the specific delay decisions in 1976 and 1978 were not made at that time or were not made based on the reasons complained of in the I-80100341 decision, when would Limerick have been completed?" I should caution that my testimony on this issue is primarily contextual in that it looks at the schedule performance of other units without adjusting for any Limerick or PECO-specific considerations. I hope, however, to provide the Commission with a useful frame of reference to evaluate whether Trial Staff's and OCA's claims as to the consequences of the delay decisions are even superficially reasonable. More precisely, the purpose of my testimony is to show what standard of prudence the Commission would be adopting if it found to be reasonable the testimony sponsored by Trial Staff and OCA as to the quantification of the delay decisions.

Q. In your direct testimony, you stated that on an adjusted basis the Limerick schedule was essentially average for plants in its cohort, and four months longer than average on an unadjusted basis. You indicated that subsequent schedule slippage for units not yet complete would improve this relative performance still further. Has that forecast proven correct?

A. Yes. Since September when my direct testimony was filed, several units have slipped while Limerick has maintained its schedule. On an unadjusted basis, overall Limerick schedule performance is now essentially identical to the average plant in its cohort. Currently forecasted commercial operation dates are shown in Exhibit WHH-30.

Q. How does Limerick's schedule performance compare so far to units in its cohort which have loaded fuel?

A. Compared to other units with construction start dates within plus-or-minus two years of Limerick's, and which have loaded fuel and either have gone commercial by now or were projected to do so at last report, Limerick's schedule is approximately 13 months longer than the average. Of course, this comparison cannot provide direct guidance with respect to Limerick's completion duration under "typical" schedule management conditions. Limerick is being compared only to the plants which have finished the race; those still out on the course will take longer and in some cases substantially longer. This can be readily demonstrated. If instead of comparing Limerick 1 to plants started contemporaneously with it and which are already complete, I simply compare its schedule to that of plants which have come on-line in the past two years, the comparable average rises to 140 months, identical to the Limerick performance.

Q. Isn't it true that some of these plants have had schedule-related prudence disallowances?

A. Yes. Three of the plants -- Wolf Creek, Callaway, and Shoreham -- have had schedule-related disallowances by utility Commissions, and one more, Fermi, has had an ALJ-proposed disallowance. However, these are different in causation, and much shorter in duration, than the schedule disallowance proposed by Trial Staff and OCA. The disallowance proposed by Trial Staff and OCA are predicated on an alleged imprudent decision to extend the schedule. No such assertion was made in any of the four referenced cases. In Callaway and Wolf Creek, the Commissions found imprudence in construction management leading to excessive direct labor manhours and materials. The Commissions found in those cases that with less direct labor, the schedules could have been compressed. In Shoreham and Fermi, the schedule disallowances were more direct in that lengthy delays in the latter stages of construction and testing were held to have resulted from imprudence. It is instructive that the proposed prudent construction period for each of these two plants was longer than the Limerick period. Conversely and curiously, the essentially mechanistic approach taken by the Kansas and Missouri Commissions in Callaway and Wolf Creek resulted in schedule reductions for two plants which were already the most rapidly completed single or first units in the 1980s.

Q. Taking into account these schedule-related imprudence findings, and restricting your sample to units which have completed their ratecases, what is the typical schedule duration which has been found prudent in cases which which have been completed?

A. The range in schedule length runs from Shoreham at 150 months to Wolf Creek at 88.5 months. The average is 128.5 months, 11.5 months less than Limerick 1. I should note, however, that leaving in the Fermi and Shoreham schedule disallowances, but taking out the Callaway and Wolf Creek disallowances which were not really causally related to schedule issues, raises the average to 131 months.

Q. Turning specifically to Trial Staff's proposed quantification, does your data indicate that the commercial operation date used in its analysis is reasonable?

A. No, not remotely. Exhibit WHH-31 shows the schedule duration of all plants completed in the 1980s. With the exception of Arkansas Nuclear One 2 (which loaded fuel prior to the TMI accident) and St. Lucie 2, none even come close to the 82-month schedule which Trial Staff was proposed be found reasonable for Limerick 1.

Staff's proposed quantification is based on the presumption that, but for the complained-of acts, Limerick would in fact have been completed on the schedule set in 1974. Staff makes no attempt to employ any real world analysis or comparisons to justify the reasonableness of this assumption. As is well known, no nuclear plant of Limerick's vintage managed to adhere to its 1974 schedule. Exhibit WHH-32 shows the planned fuel load dates for all plants that, at the end of 1974, were projecting fuel load in 1979, 1980, or 1981. Not one of these units slipped less than 24 months. Thus, even had Limerick achieved the best schedule maintenance performance in the industry from 1974 forward, its <u>fuel load</u> date would have slipped to October of 1982, 18 months after Trial Staff's proposed <u>commercial operation</u> date.

Moreover, the best performance in the industry is not a reasonable standard for quantifying imprudence. Only three of the stations listed in WHH-32, Susquehanna, San Onofre, and Grand Gulf, maintained their fuel load schedules appreciably better than did Limerick 1. In actuality, the Grand Gulf experience should not be counted since the very long start-up schedule and very high post-fuel load construction expenditures demonstrate that Grand Gulf was not truly complete. By comparison, a much larger number of utilities were unable to maintain their construction schedules as well as did PECO. Even if we ignore Watts Bar and Bellefonte, the only units of which I am aware that were deliberately and substantially slipped in order to better match the need for capacity, the average slippage for the group is 57 months -- 8 months longer than Limerick Unit No. 1. These data strongly suggest that delays in fuel load subsequent to 1974 were due to conditions general to the industry and not to PECO-specific actions.

I cannot conclude from these data that, but for the complained-of-acts, Limerick 1 might not have been able to hold to its April 1974 schedule sightly better than it did. I can conclude, however, that absent the complained-of acts, Limerick could not reasonably be expected to have held to its April 1974 schedule as Staff's quantification requires.

Q. Are the same data and conclusion pertinent to the OCA quantification?

A. Yes, though OCA's position is somewhat less extreme. OCA bases its quantification analysis on a fuel load date of July 1982. This is 21 months later than the October 1980 date forecasted in April 1974. Thus, Mr. O'Brien appears to concede a 21-month slippage from the 1974 forecast even absent the complained-of acts. However, while less extreme than Trial Staff's case, OCA is nevertheless basing its quantification on a schedule adherence that is better than the best performance achieved by anyone in the industry.

Q. Mr. O'Brien justifies the reasonableness of his schedule estimation on the grounds that LaSalle 1 and Susquehanna 1 loaded fuel by July of 1982 and that they purportedly were effectively started no later than Limerick 1. Assuming that Mr.

O'Brien's facts are correct, does this make the OCA's July 1982 fuel load date reasonable absent the complained-of acts?

A. No, it does not. The Commission has found that the 1974 schedule slippage was reasonable and prudent. Absent information to the contrary, I infer from this that Limerick's 1974 schedule for fuel load was reasonable given the then-status of construction, PECO's financial capacity, and the state of expectations as to future construction time requirements then commonly held in the industry. As of 1974, LaSalle and Susquehanna may have been further along, their constructing utilities may have been financially able to proceed more rapidly, or their plants may then have been known to require less labor or materials. Whatever the basis, PECO had a 1974 schedule it believed it could meet, as did Commonwealth and PP&L, and as did the other utilities whose actual schedule performance I have discussed. I have already demonstrated that, despite the complained-of acts, PECO was better able to adhere to its schedule than the average utility. PP&L's schedule adherence performance was, for whatever reason, materially better than Limerick's. While Commonwealth's was not. As of 1974, LaSalle 1 was scheduled to load fuel in August 1978. In fact, it loaded fuel in April 1982, 44 months later. LaSalle's twin was also scheduled to load fuel prior to Limerick 1, in June 1979. In fact, it slipped 54 months to December 1983. Thus, Limerick 1's schedule delay of 49 months was within one month of the average delay for LaSalle, one of Mr. O'Brien's two reference units.

I am also somewhat surprised that OCA sets forth LaSalle 1 as a paradigm for estimating a prudent Limerick schedule given that OCA witness Komanoff, who has considerable familiarity with the unit, does not appear to believe that the unit was in fact completed on the schedule utilized by Mr. O'Brien. In testimony filed before the Illinois Commerce Commission in July, 1984, Mr. Komanoff stated:

> Edison declared LaSalle 1 to be in-service for accounting purposes as of October 20, 1982. However, the plant has been troubled by a variety of operating problems until at least March of 1984, and Edison did not declare it in operation until January 1, 1984 [reference omitted]. Its capacity factor during 1983 was only 17%; from October 20, 1982 through the end of 1983, it generated no power at all for 243 days.... In the case of LaSalle, Edison has stated that during 1982-1983, Unit 1 was 'operating but was still in startup testing.

EXCESS CAPACITY

Q. Some of the intervenor witnesses contend that PECO has substantial excess capacity now that Limerick Unit No. 1 is on line. The essence of most of their arguments is that retirements which have or will take place would not have taken place but for the existence of Limerick 1, and that a combination of adding Limerick 1 and retaining that retired capacity would result in excess capacity. Please comment.

A. I note first that these testimonies raise issues of fact concerning the age and condition of these units and, perhaps, issues of prior Commission rulings which are discussed by other Company witnesses more familiar with the relevant facts than am I. While I will not comment directly on specific excess capacity claims, I believe it is important to examine the regulatory policy standards implicit or explicit in the positions taken by these witnesses. I will focus in particular on the testimony of Mr. Chernick at pages 96 and 97 of UUC/UP Statement No. 1. That testimony states explicitly ratemaking standards that are only implied in the testimony of others in this proceeding and, as such, generally subsumes the positions of these other parties.

Q. What is the ratemaking standard espoused by Mr. Chernick?

A. The recommendation on page 97 of his testimony amounts to the proposition that once a utility embarks on constructing a unit which, as a result of subsequent events, creates a condition of temporary excess capacity on a reliability basis, (including but not limited to lower than expected load growth), then the company should be discouraged or even foreclosed from taking measures to mitigate the damage. This presents a stunning tour de force of proposed regulatory perversity. Among the utility actions which would either be forbidden or simply ignored for penalty purposes under Mr. Chernick's view would be delaying plant completion so as to better match needs and resources, load building programs intended to better utilize available capacity, retiring plants which become unneeded once the new plant is completed, selling temporary capacity to other utilities, or even discouraging construction of further excess capacity by third party power producers such as cogenerators. Mr. Chernick's position seems to be that excess capacity penalties should serve "gotcha" rather than incentive purposes: Once a situation of potential excess capacity begins to develop, regulators should make sure that the utility acts in total disregard of it, avoiding all actions which lessen the degree and duration of the excess.

Q. Is it not the case that Mr. Chernick carefully hedges his proposals to exclude only those actions which are uneconomic?

A. That is what his testimony seems to say at first glance. However, what emerges upon examination of his whole capacity value discussion is that he would define whether the action was economic or uneconomic with reference to a non-existent world in which the newly completed capacity, the need for which is contested, does not exist. To suggest that a utility building a large baseload unit should behave in all respects as if it were not doing so is illogical.

Q. Can you give a specific example of this illogic?

A. Yes. Mr. Chernick and some other intervenor witnesses have focused on the 458 MW of combustion turbines which PECO is retiring. The thrust of their testimony is that since these CTs could have been retained, and presumably would have been retained in the "but for" world in which Limerick 1 did not exist, at least 458 MW of Limerick 1 is excess. It is important to note, however, that none of these witnesses suggest that the CTs should be retained in the actual world in which

Limerick 1 does exist.

My understanding is that these CTs were added to the system back in the early 1970's to meet a grave capacity deficit. This was not uncommon in that period. Many utilities found themselves facing brownouts or worse, and only CT's could be added to their systems in time to avert potential calamity. It was recognized at the time that the economic lives of the CTs would be short; once enough additional baseload and cycling capacity could be added, these units would run rarely if at all. Despite their shot period of economic usefulness the short run reliability value of the units was deemed sufficient to justify their costs. Some 15 years later, PECO has finally reached a point where it believes it can safely give up these units.

Consider in this context the implications of Mr. Chernick's policy prescriptions and the incentives implicit in the capacity penalty testimony of other witnesses holding similar positions with respect to alleged excess capacity. What they are saying is that once PECO added this capacity, it should remain saddled with it until it crumbles into dust. As long as it exists, PECO would be penalized for constructing the very baseload and cycling capacity the temporary shortage of which forced the peakers to be built. Under such a policy, if a utility is forced to add non-optimal amounts of peaking capacity to meet a temporary emergency, it will be penalized for rectifying the imbalance at any time in the next 25 years. What is even more perverse is that the more uneconomic the temporary capacity is to run, the longer it will last, and hence the longer will be the period during which the utility would be penalized for replacing it.

Q. At several points in your testimony, you have made reference to the incentive effects of excess capacity penalties. Why do you focus on these incentive effects?

A. Because I do not believe that the reason for imposing excess capacity penalties is for "gotcha" purposes -- a way of opportunistically imposing losses on shareholders. Rather, I assume that when a Commission makes it known that it will impose excess capacity penalties, it has concluded that excess capacity is undesirable and that the utility should take steps to avoid it. Regulatory penalties (and rewards) are incentives and, as with speeding tickets, their purpose is to influence behavior, not collect fines.

Q. Do you have any other comments on the intervenors' excess capacity penalty testimony?

A. Yes. I would simply note that in computing the amount of excess capacity the focus of each of the intervenor witnesses has been on the <u>minimum</u> reserve required to meet reliability standards. Not even in passing has one of these witnesses addressed the issue of what should be the maximum capacity allowed for ratemaking purposes. As I discussed at length in my direct testimony, a standard which sets the minimum and maximum reserves at the same level is unreasonable. All parties must acknowledge that load forecasting is an unexact science and that physical realities preclude adding capacity in blocks which precisely match load on an after-the-fact basis. To penalize the Company for "excess" capacity for a condition which is as a practical matter unavoidable would be quite inequitable.

LIMERICK LIFE CYCLE BENEFITS

Q. Before proceeding to a detailed discussion of the areas of controversy regarding Limerick life cycle benefits, can you summarize the general nature of the intervenor studies?

A. Yes. Exhibit WHH-33 summarizes the OCA, PAIEUG and UCC/UP life cycle net benefit comparisons. All parties except UCC/UP agree that at sometime in the 1990's Limerick 1 is likely to begin to provide net benefits, though these intervenors dispute that Limerick 1 will ever provide cumulative on a present value basis net benefits. I should point out three important facts concerning this Exhibit. First, while several of the intervenors make more than one computation, the case shown is generally the most adverse to Limerick. Second, the cases are not consistent in their treatment of Limerick common plant: the OCA and UUC/UP and PAIEUG include 100 percent of common which PECO does not. Third, revenue requirements for all cases ignore the parties' phase-in proposals and any losses the party would impose on shareholders due to their proposed prudency disallowances, excess capacity penalties or phase-in plans.

Q. What are the major components of the difference of opinion regarding Limerick 1's net benefit?

A. Major differences exist with respect to both benefits and costs. Exhibit WHH-34 displays the benefit summaries. On the benefit side, major areas of dispute are capacity factors (OCA and UCC/UP) and fuel costs (OCA, adopted also by UCC/UP) and the capacity value of the plant.

The cost differences are more dramatic. As shown on Exhibit WHH-35, both PECO and PAIEUG forecasts costs which are relatively flat in nominal dollars while UUC/UP and OCA show starkly rising costs. In addition to the differing treatment of the second half of common, major differences are O&M and capital additions. Exhibit WHH-36 shows that it is a forecast of runaway escalation in O&M which drives UUC/UP's cost forecast. Exhibit WHH-37 shows that OCA's cost forecast is driven by dramatice future growth in capital additions.

Present value differences are also significantly affected by differences in discount rate assumptions.

The differences in benefit expectations are very substantial. They arise from two general areas of dispute. The first disputed area concerns how we interpret the past. The second concerns how we use the past to predict the future. In some instances I shall contend that history has been misinterpreted by these witnesses and/or misapplied in predicting the future costs and benefits of Limerick. Some key intervenor forecasts I regard as not only unlikely but implausible.

Nevertheless, it must be acknowledged that the $2.0 to $4.0 billion of net benefit from Limerick 1, the estimate which I sponsored in my direct testimony, is not certain. The actual benefit may be less, it may be more. It could conceivably be negative, since some elements of the forecast could prove optimistic, just as elements of the intervenor forecast could prove overly conservative. Any sober and reflective forecaster must recognize the very substantial band of error in 40 year forecasts, especially under today's confusing conditions. Perhaps in a few years we shall have a better fix on the future economics of nuclear plants like Limerick, though even that is not certain. Thus, while I continue to believe that the forecasts which I sponsored are quite reasonable, I recognize that the magnitude, and even the existence, of a net life cycle benefit is uncertain. However, whatever uncertainty inheres in PECO's forecast of net gain is at least as present in the intervenors' forecast of net loss.

Q. Can you give a concrete example of how sensitive the forecast of Limerick economics is to changes in forecast expectations?

A. Yes. A key element affecting nuclear plant economic performance is fuel savings. In recent years, PECO's forecast of the savings anticipated from the plant has declined; indeed, Mr. Komanoff argues that it has not declined enough. Mr. Chernick points to a lower PECO net benefit forecast for Limerick 1 than PP&L forecasted for Susquehanna 2 as a reason why the Commission should deal "more sympathically" with ratepayers than did the Susquehanna 2 decision.

The apparent difference in the value of the plants arises largely from differing estimates of future fuel savings, estimates which have clearly proven to be badly wrong (in both directions) in the relatively recent past. Substituting the PP&L Susquehanna 2 fuel savings estimate for PECO's adds $3113 million in present value to the PECO estimate, raising the net savings to the 5 to 7 billon dollar range. Exhibit WHH-38 replicates Mr. Chernick's Table 3.9 based on substituting the Susquehanna 2 full plant fuel savings from his Table 3.2 for the Limerick 1 fuel savings from his Table 3.1. Susquehanna first produces significant net savings in 1991, six and a half years after operation; Limerick first produces net savings in 1992, seven years into the life of the plant. Limerick's savings based on Susquehanna 2 fuel savings assumptions exceed Susquehanna's net savings beginning in 1997 and substantially exceed them in every subsequent year.

Finally, whether Limerick produces a net "profit" in lower present value of costs of "only" 50 to 125 percent of the investment or, as Susquehanna 2 fuel savings would imply, a substantially greater savings is of no obvious relevance even to the generally irrelevant (for regulatory purposes) question of whether Limerick 1 will prove to have been a good investment. Any positive net savings means that the investment is beneficial.

CAPACITY PAYMENTS

Q. A number of intervenor witnesses have criticized the portion of your economic analysis of Limerick 1 life cycle benefits which assumes higher capacity payments to PJM than those implied by the current formula. Please explain briefly your understanding of those criticisms.

A. The criticisms are, first, simply that the presumption of capacity charges by PJM which exceed the current formula is speculative and, second, that if PJM were to raise the capacity charge above the cost of a peaker, the charge could be evaded by simply purchasing peakers.

Q. Why did you assume in your analysis that capacity charges to PECO were likely to be increased if Limerick were not built?

A. The primary foundation for this assumption is the PJM Interconnection Agreement itself. Article 6.2 of that Agreement, of which relevant portions were provided in response to IR-OCA-15-1, states:

> ... The purchase of capacity by any Party Hereto from other Parties Hereto in accordance with Schedule 2.01 (d)(3) shall be for the purpose of meeting capacity deficiencies caused by unpredicted changes in load or capacity availability and for incidental deficiencies in capacity due to the impossibility of exactly matching capacity installations to load growth. It is not intended that any Party Hereto shall persistently purchase such capacity to fulfill its obligation hereunder.

Given the manifest intent of the parties to the PJM Agreement that its members be self-supporting in terms of capacity, it is highly unlikely that had PECO embarked on a deliberate program of becoming a "PJM junkie" the other utilities would continue to make capacity and energy available on favorable terms. It is far more likely that rates would be raised to a penalty level sufficient to induce PECO to add capacity or, failing that, to more fully compensate other members for the capacity provided.

The second foundation for this assumption is simply the change in the basic economics of power supply. At the time that the split savings concept was adopted, the cost of baseload generating facilities relative to the cost of peakers was much lower than it is today. The profits on split savings plus a peaker-based capacity charge at that time substantially compensated the selling utility for its costs. Today, split savings profits plus a peaker-based capacity charge yields revenues far short of the cost of new baseload and intermediate facilities, at least in the near term. While a long-term strategy of relying on PJM for large amounts of energy is not in the interests of a utility's customers, as our Limerick 1 analysis shows, it does allow the purchasing utility to avoid the risks of building new capacity and to avoid the rate increases attendant upon bringing new economic capacity into ratebase. Given the stated intention of a number of utilities to avoid new capacity construction and to rely instead on the shrinking pool of capacity available from their neighbors, it is unlikely that an arrangement on terms as favorable to dependent buyers as the PJM agreement could long survive.

Q. In your direct testimony, you sponsored cases which included 50 and 100 percent increases in the PJM capacity charge. Some intervenor witnesses have contended that no price higher than the carrying cost of a peaker could be sustained since PECO could avoid it by simply buying peakers. Isn't this correct?

A. It would be if the sole issue addressed by the PJM agreement were literal deficiencies in capacity. However, as my answer to the previous question indicates, the problem extends beyond simple capacity deficiencies to the economics of being a "PJM junkie" -- a term which describes a utility that may have capacity sufficient on a pro forma basis to satisfy the PJM agreement, but which actually relies on PJM to meet substantial energy needs over an extended period. While it is true that in my direct testimony, I simply changed the dollar cost of capacity deficiencies, my intent in so doing was to illustrate the magnitude of the dollars involved. I did not mean to imply that a reformed PJM agreement would concern itself solely with simple capacity deficiencies as opposed to deficiencies in energy and economic capacity.

Q. Have you analyzed the form that a PJM agreement which dealt with long-term deficiencies in energy and economic capacity might take?

A. Yes. While I obviously cannot say what precise form a PJM capacity charge would take if PECO were to knowingly and permanently go short by 1,055 MW of baseload capacity, the primary attribute of a reasoned PJM response should be to make capacity payments dependent upon the type of capacity used from other utilities. This is the logical equivalent of split savings on energy. Split savings on energy depend on the production cost of energy taken from PJM and the avoided production cost of the buying utility. A split savings capacity rate would likewise split the savings between the cost of the buying and selling utility.

To determine the cost of not having Limerick under this formula, I had PECO determine the types of facilities (baseload, intermediate, and peaking) from which the PJM make-up energy would be taken. The capacity cost is derived based on the levelized carrying cost of new facilities of this same mix. Capacity charges to PECO are derived by splitting between these costs and the cost of capacity not used by PECO. For the portion of energy obtained from PJM peaking plants, this cost is simply the carrying cost of a peaker -- there is no additional carrying capacity-related cost to be split. For energy from PJM intermediate plants, the cost is the carrying cost of the peaker plus one-half of the difference between the carrying cost of a peaker and the carrying cost of an intermediate unit. For baseload units, the computation is similar.

Exhibit WHH-38 shows the results of this set of computations. The present value of capacity costs avoided by Limerick 1 is $1,849 million.

Q. How does this estimate of the capacity charge savings for Limerick 1 compare to the cases included in your direct testimony?

A. In my earlier analyses, the present value of capacity charges if the present rate were doubled was $2,312 million, while a 50 percent increase above levels under the current formula was $1,734 million in present value. The figure described in the above testimony and summarized in WHH-38 is between the two; specifically, it is the present value equivalent of a 60 percent increase above a rate based purely on the carrying cost of a peaker.

Q. During cross-examination of your direct testimony, it was pointed out that PJM failed to file an upwardly revised capacity payment for 1986. Do your current computations reflect this fact?

A. Yes. Indeed, I assumed that PJM would never catch up for the lost year of inflation. Future capacity charges reflect the 1985 real value with no escalation from 1985 to 1986.

THE AVAILABILITY OF CAPACITY FROM OUTSIDE OF PJM

Q. Beginning at page 9 of his testimony, Mr. Komanoff disputes your cases which show a decline of 50 percent or 100 percent of capacity available from ECAR beginning in 1994. He states that this reduction is unsupported and is implausible in view of ECAR's current excess capacity. What is your response?

A. These adjustments were based on a study performed by the ECAR/MAAC Coordinating Group for the U.S. Department of Energy in June 1985.

In our life cycle analysis, it was assumed that 2,300 MW of ECAR capacity was available to PJM, all of which was low variable cost baseload capacity. The availability rate for this capacity was assumed to be 75 percent. However, since no forced outages were assumed, this was equivalent to 1725 MW at 100 percent availability. That is, it was assumed to be available year round at prices designed to assure it would be dispatched. My understanding is that this estimate of availability is consistent with recent experience; the referenced report states that MAAC imports from Western systems ranged from 1,300 to 3,900 MW in 1984; 70 percent of the time imports were between 1,650 and 2,950 MW.

Between 1986 and 1994, ECAR loads are forecasted to grow significantly faster than capacity. Appendix B of the referenced report indicates that ECAR currently has a surplus of economic capacity (coal, nuclear, and hydro) of 8,131 MW at the time of summer peak, 7,409 MW at winter peak, and 8,338 MW at the average spring and fall peaks. By 1994, this surplus is anticipated to decline to 2,650 MW, 696 MW, and 3,372 MW, respectively. Thus, depending on the season, between 60 and 93 percent of the current surplus will be eliminated.

Q. Do these figures indicate the amount of power available to PJM?

A. No. They represent the total ECAR surplus. PJM would have to compete with other systems, several of which are projected to be shorter in baseload capacity than PJM.

Q. Based on these numbers, how did you decide that a decrease of availability of economic capacity from ECAR of 50 to 100 percent was reasonable?

A. Obviously, in view of the 60 to 93 percent decrease in on-peak availability of economic power from current levels, a significant decrease was called for. In reality, this decrease would be gradual, with on-peak availability reduced beginning around 1990 and off-peak availability declining somewhat later. A 50 percent decline in 1994 (with continuing availability of the remaining amount through the life of Limerick 1) is a quite conservative estimate of the effect.

The 100 percent reduction case was motivated by the warning in the referenced report that any one of several circumstances would completely eliminate the surplus by 1994. An increase in ECAR load growth of but 0.5 percent per year above 1985 forecasts would wipe out the surplus of on-peak economic interchange power during all seasons. A decline in the availability rate of baseload capacity from the 75 percent used in the study to the 70 percent level experienced in the late 1970s would also eliminate all of the surplus. Acid rain legislation would so reduce the capacity in ECAR as to turn it into a net importer. Finally, the report assumes that all capacity projected for completion by 1994 will in fact be completed. Any cancellations would further reduce export capacity.

Q. In your response, you have focused on the availability of ECAR energy during peak conditions for the four seasons. Wouldn't economy power be available off-peak even if the surplus of ECAR capacity were to go away?

A. To some degree, yes. What is less certain is whether, given the amount which PJM would import off-peak even with Limerick 1 in service, additional incremental ECAR generation and PJM transmission capacity would be available. If not, the availability of off-peak energy is irrelevant to the Limerick net benefit calculation.

OPERATION AND MAINTENANCE EXPENSE FORECASTS

Q. Messrs. Komanoff, Falkenberg and Chernick all dispute PECO's O&M forecast for Limerick 1. Beginning with Mr. Komanoff, is his dispute with PECOs O&M forecast significant?

A. No, it is not. Indeed, Mr. Komanoff's results support the reasonableness of PECO's forecast. Mr. Komanoff's forecast is based on averaging the forecasts produced by two separate regression equations which he derives from historic data. His linear equation produces a forecast which is below PECO's. His exponential forecast, which extrapolates the historic growth rate compounded for 40 years without surcease, is higher. The averaged forecast which he adopts is 12.6 percent higher than PECO's in present value. It is important to note that his forecast is below PECO's through the mid-1990s, and lower than PECO's in present value until 2008. Hence, the validity of his 12.6 percent difference depends upon the assumption that data from the period ending in 1984 are a valid predictor of cost escalation occurring more than 20 years later, a heroic assumption at best.

Q. What about Mr. Falkenberg's forecast?

A. Mr. Falkenberg's technique is curious. He bases his forecast on a Peach Bottom database. His equation, shown in his Exhibit 9a, actually produces a forecast of Limerick 1 O&M costs which is well below PECO's. He does not use his equation, however, to forecast the starting point for Limerick's O&M cost, but instead accepts PECO's 1986 O&M forecast, then applies only the trend growth rate derived from his equation. This is a highly questionable procedure: if his Peach Bottom-based forecast is appropriate, the forecast should be at least as valid with respect to the 1986 level of expenditures as it is with respect to the 40 year growth rate. In any event, even ignoring the problem with this methodology, the range of dispute is still small. His escalation from 1986 through 1990 is slightly below PECO's; thereafter the divergence remains relatively small and totals only 55 million present value dollars.

Q. Finally, what about Mr. Chernick's forecast?

A. Mr. Chernick simply assumes that O&M will grow at the geometric rate he derives from the 1970's and early 1980's data. Depending on whether he uses his full dataset or one restricted to units larger than 300 MW, his forecast rises to $54 Billion or $132 Billion dollars per year by the end of the plant's life. Apparently, a forecast, 166 times greater than PECO's, did not pass the "blush test" -- it implies a company town of roughly 250,000 people dedicated to running Unit 1. Instead, he rather arbitrarily used the 1986-87 growth from his exponential model and assumed a linear growth at the 1986-87 rate for the life of the plant. This *ad hoc* procedure reduced his forecast to "only" 500 to 700 percent of PECO's forecast. This forecast begins with a real growth rate of 11 percent per year, declining in percentage terms as the base amount rises.

Mr. Chernick provides no basis for why growth at these rates should continue over the next 40 years; indeed, with commendable (and justifiable) modesty, he asserts only that by 2024 O&M cost at Limerick 1 will be somewhere between $800 million and $132 billion.

The fragility of the Chernick result is readily shown by demonstrating that any one of several quite plausible regression specifications run on his data give dramatically different results. These results are shown on WHH-40(a) through WHH-40(c). WHH-40(a) is Mr. Chernick's regression. In WHH-40(b) the TMI dummy variable used by Mr. Komanoff is added. The variable is highly significant, improving the explanatory power of the regression. Even without halving the value of the TMI coefficient for forecast purposes, a procedure adopted by Mr. Komanoff, the final year forecast drops from 5.34 to 1.70 Billion, a decline of 68 percent. Halving the TMI coefficient would reduce the forecast still further to $1.44 Billion. Merely taking the fact of TMI into account reduces the forecast by roughly 70 percent and exposes the absurdity of 40 year geometric growth extrapolations.

Exhibit WHH-40(c) explores another simple change in equation structure, in which the year to year growth is assumed to be linear as Mr. Chernick assumes for his forecast but not in his model. With this change, the forecast falls well below PECO's forecast in the early years and rises to only slightly above PECO's by the end of plant life.

Q. What do you conclude from this analysis?

A. Depending on whether TMI is taken into account and depending on if the relationship is assumed to be linear or logarithmic, an enormous range of present values of O&M forecasts, ranging from below PECO's to more than an order of magnitude higher, can be produced with equal plausibility. The trend extrapolation methodology cannot tell us anything about the future. PECO's method, which is based on a thorough understanding of the Limerick plant, or Mr. Komanoff's method, which is at least based on an explicit consideration of factors likely to affect the relationship of future to past O&M levels, is far superior.

I should also point out that since Mr. Chernick's main conclusion concerning the substantial net cost of Limerick is derived primarily from his explosive O&M growth, it fails if his O&M extrapolation is rejected.

CAPITAL ADDITIONS

Q. Turning now to the issue of capital additions, can you first comment on Mr. Chernick's testimony?

A. Mr. Chernick forecasts Limerick 1 capital additions costs based on a constant dollar average of 28 1983 dollars per KW (MGN), rising at 1.4 percent per year in real terms. The base year number is approximately the 1980-1984 average for large single units; the escalation rate is based on the real escalation in the NRC Region 1 nuclear Handy-Whitman index over the 1970 to 1983 period.

I concur with Mr. Chernick's observation that there is no substantial evidence of an upward trend in capital additions for large BWRs and therefore do not disagree with the general concept of extrapolating a constant level of real capital additions based on recent experience. However, the Commission should be aware that recent "average" experience is heavily influenced by very substantial capital additions at a small number of stations. Relying on these averages is equivalent to assuming that Limerick 1 will need a major rebuild with considerable frequency.

Q. Can you illustrate this dependence of the averages on extreme values?

A. Yes. I have examined Mr. Chernick's data for 1983 and 1984. The sample I have used, stations with units of over 800 MW, is slightly different than Mr. Chernick's sample, but the results would be similar. The average expenditure in 1983 was $22.5/KW; in 1984 it was $30.7/KW. However, the median or typical expenditures were only $15/KW and $20/KW respectively. Indeed, in 1983, 19 of 28 observations had expenditures below Mr. Chernick's $28/KW estimate and in 1984, 18 were below $28/KW. Half of the average expenditure in 1983 is attributable to four plants which were undergoing major repairs. Those 4 stations -- Beaver Valley 1, Brunswick, Hatch, and Palisades, had expenditures of over $50/KW. In 1984, 7 stations, Beaver Valley 1, Brunswick, Hatch, Davis-Besse, Rancho Seco, and Fitzpatrick experienced repairs of more than $50/KW. These stations accounted for more than half of the average expenditure. Six of the 8 units with large expenditures were PWRs (three of which are B&W units), and the bulk of these expenditures were associated with PWR-specific steam generator repairs. Fitzpatrick, Hatch, and Brunswick are BWRs which required repairs due to IGSCC problems. The likelihood of Limerick 1 suffering IGSCC problems is an issue best discussed by others, and is indeed addressed in the rebuttal testimony of Mr. Helwig (PECO St. No. 5A). However, I am aware that Limerick incorporates features not present in the older Fitzpatrick, Hatch, and Brunswick units which are designed to substantially reduce the likelihood and magnitude of IGSCC problems.

The fact that these 55 datapoints contain 11 major repair years means that implicit in the use of the recent historic average is the presumption that Limerick 1 will require significant and relatively frequent retrofits to correct design problems. I am not aware of any basis for that presumption and none is given by Mr. Chernick.

Q. Does Mr. Chernick have a valid basis for forecasting an increase in the Handy-Whitman deflator, and hence real escalation in capital additions, of 1.4 percent per year?

A. No, he does not. The real escalation in the Handy-Whitman that Mr. Chernick observes was peculiar to the period of rapid expansion in the nuclear industry during the early 1970s. During that period, 1970 to 1976, the Handy-Whitman escalated by 3.6 percent a year in real terms. In 1964 to 1970, it had escalated at only 0.1 percent per year. Since 1976, it has escalated at only 0.3 percent per year. Given the excess capacity in the nuclear supply industry which has existed in recent years, this reduction in real escalation is to be expected. A continuation of this more recent and more typical relative price behavior is also likely for the future given the poor prospects for recovery of the nuclear construction industry.

Q. Can you summarize your comments on Mr. Chernick's capital additions assumptions?

A. PECO's capital additions forecast is based on the expectation that Limerick 1 will not require major repairs to correct design flaws. Its forecast is consistent with historic capital additions costs for units which have not required major repairs. Mr. Chernick's use of recent average expenditures implies either that Limerick will have the same problems as older plants or that, despite the extensive operating history of nuclear plants, as yet unforeseen design problems will develop. His real cost escalation forecasts are clearly without a valid foundation. If PECO's expectation concerning the quality of Limerick's design is correct, Mr. Chernick's capital additions forecast is likely to be overstated by a factor of 2 to 3.

Q. Please comment on Mr. Komanoff's capital additions forecast.

A. Mr. Komanoff forecasts capital additions-related revenue requirements of $26.8 billion dollars, seven times larger than the PECO forecast. This difference accounts for $1.8 billion of the life cycle benefit difference between PECO and the OCA. In constant 1986 dollars, his forecast is for expenditures of $46 million in 1986 rising steadily to $119 million in 2024.

The basis for his forecast is essentially a time trend drawn through the historic data. Moreover, his equation fits the data quite poorly: it explains only 21.6 percent of the variation in capital additions and the 95 percent confidence interval is plus-or-minus $61/KW per year. This is, to say the least, an unimpressive achievement. Since the mean expenditure in his database is $25/KW per year, a confidence interval of plus-or-minus $61/KW per year means that we have learned little even about the historic data from his model.

Q. Why does the model fit the data so poorly?

A. Other than a wage variable, which is not statistically significant, his model contains no variables which are causally related to capital additions costs. While some capital additions are due to new regulations, the largest ones are due to design problems which impact plant output, maintainability and safety. Neither age nor vintage — his principal explanatory variables -- are good predictors of the effects of such problems though they may have been correlated in the historic data.

Q. Can you put Mr. Komanoff's forecast for Limerick capital additions into context?

A. Yes. First, as Exhibit CK-5 shows, his forecast is that capital additions at Limerick will average roughly $75/Kw per year. In his data base, however, only 8 percent of his observations incurred costs that were this high. Thus, he is forecasting that in the average year, repairs and retrofits of Limerick 1 will cost more than the historic annual costs for 92 percent of reactor years -- including those years in which major retrofits were made. This forecast is reasonable only if one believes that the repair cost for Limerick will be worse than all but the worst reactor in his historic data base. Yet this forecast is ostensibly consistent with this same historic data.

Exhibit WHH-41 provides a somewhat more detailed review of the reasonableness of his forecast. It compares the forecasted cost of Limerick capital additions, year-by-year, with the cost for other reactors at the same age. Even in constant dollars, under Mr. Komanoff's forecast, Limerick 1 is expected to cost far more in every year than the historic average would project. For example, the average reactor required capital additions of $30/KW in its first year while KEA's forecast for Limerick is $42/KW. In the fifth year the historical average is $12/KW while KEA's forecast for Limerick is $50/KW. In the tenth year, the historical average is $39/KW while KEA's forecast for Limerick is $59/KW.

Q. Does not WHH-41 confirm Mr. Komanoff's contention that repair costs grow with age?

A. In a sense, yes. Average capital additions turn up sharply in year 7 and remain at that higher level. However, that higher average primarily reflects the large expenditures required to deal with steam generator retubing and replacement at PWRs and IGSCC problems at BWRs. These problems have tended to appear beginning around age 7, or soon thereafter for reactors where they have occurred.

This phenomenon led Mr. Komanoff into a logical error which can best be demonstrated by looking at the data for a plant which has had problems requiring major repairs. To illustrate, Exhibit WHH-42 shows the historic data for the Surry station. For the first six years for which data are available (years 2 through 7) the plant operated with little need for capital additions. However, due to a combination of design and water chemistry, it was necessary to completely replace the steam generators in years 8 and 9. Since that time, capital additions have fallen back sharply and continue to decline.

Because of the major expenditures in years 8 and 9 --$240/KW -- Surry is one of the relatively few plants for which Mr. Komanoff's equation underpredicts capital additions. Through the eleventh data year (1984), he forecasts $236/KW whereas actual expenditures are $299/KW. However, his forecast continues to rise. Even if we were to assume that Surry would only run for six years before requiring a two-year shutdown to again replace the steam generators, his forecast would (assuming only moderate capital additions in the "good" years) accumulate enough through overforecasting to pay for the second replacement. By the time of the third replacement six years later, his forecast has risen to a level sufficient to pay for replacing the steam generators on continuous two-year cycles. Simply stated, Komanoff's forecast is consistent with Surry's history only if one assumes that after approximately 20 years of life, the steam generators will be replaced every other year.

The point of this example is to demonstrate that by drawing a trend through the historic capital additions data, Mr. Komanoff is assuming not only that Limerick 1 will experience the problems of the problem plants historically, and not only that those problems will then recur cyclically, but also that as they recur the "fixes" will either become more expensive (in constant dollars) or last less and less long. Quite simply, this forecast is not justified by his data.

LIMERICK CAPACITY FACTOR

Q. Both Messrs. Komanoff and Chernick criticize PECO's capacity factor forecasts as being excessively optimistic relative to historic data. Are they correct?

A. They are correct that PECO's forecasts exceed the historic average capacity factor performance of BWRs. That fact is not in dispute. The question is, to what extent, if any, will the Limerick capacity factor performance exceed this historic average. Mr. Chernick implicitly assumes it will be worse; Mr. Komanoff believes it will be slightly better, and PECO believes it will be substantially better. These differences stem from different beliefs about the quality of the Limerick plant or about the nature of the operating environment. Mr. Chernick's straight reliance on historic data as he interprets it implies that he believes the operating environment (e.g. the regulatory climate) will not change and that Limerick is not slightly more prone to failure than the average plant. Mr. Komanoff believes that the environment will improve slightly from post-TMI conditions and that Limerick may be a marginally superior plant. PECO believes that the regulatory climate will be more favorable to plant operation. However, the primary basis for PECO's 65 present capacity factor forecast is its belief that Limerick will be less subject to prolonged repair outages than has been the case with either Peach Bottom or the average historic BWR.

Q. You agree that PECO's forecast is above the historic average. Does that mean that it is reasonable in comparison to that history only if one believes that conditions will change?

A. No. Historic capacity factors for nuclear plants have been extremely variable. As a consequence, simplistic statistical analyses which fail to explicitly take into account the direct causes of outages are very inexact predictors of nuclear capacity factors. Exhibit WHH-43 compares PECO's forecast to Mr. Chernick's. Of course, PECO's forecast is higher than the Chernick point estimate. However, it is well within his confidence interval. This broad confidence interval and equivalently poor explanatory power of the regression give little credence to projections based on such models. Clearly, capacity factor performance is so dominated by repair outages and non-routine shutdowns mandated by the NRC that models like Mr. Chernick's are of little help except in describing historic averages.

Q. Is there any basis in the historic data to support PECO's belief that newer BWRs like Limerick will outperform the older reactors on which historic data are based?

A. Yes. While it is obviously too soon to tell for certain if these reactors will avoid the major problems, such as IGSCC, which have contributed to the disappointing performance of the past, the data which do exist suggest at a minimum that Limerick is likely to outperform Mr. Chernick's forecast in the near term. The performance of large new reactors -- both PWRs and BWRs -- has exceeded historically based forecasts at least in their early years. This is less clear for BWRs due to their small numbers and specific factors affecting some units such as the low capacity factor for WPN-2 due to surplus hydro conditions and the perhaps premature declaration of LaSalle in commercial operation.

Q. Have you reviewed the 1985 data on capacity factors?

A. Yes, preliminary data for the full year are now available. For the industry as a whole, the year was the best in the past several; the average capacity factor was nearly 64 percent. BWRs did not have a particularly good year; the average capacity factor which in previous years had closely tracked PWRs failed to keep pace with the improvement. In substantial part, this was due to the prolonged outages at Peach Bottom and at Browns Ferry. While average performance of BWRs did not improve, the performance of older BWR reactors, Mr. Komanoff's "over-12" group, improved dramatically. This improvement was noted by Mr. Komanoff in his testimony. However, he incorrectly forecasted that his "over-12" effect would persist despite a single good year.

Q. Can you demonstrate this fact?

A. Yes. Exhibits WHH-18 and WHH-19 show Mr. Komanoff's forecast with his regression rerun after adding 1985 data to his database. His "over-12" coefficient had been 28.6 percentage points implying a 28.6 percent poorer performance than would be forecasted without the "over-12" characteristic. When 1985 data are added, it drops to 6.5 percentage points and ceases to be significant. As a consequence, despite the rather poor 1985 performance of BWRs generally, the good performance of the older reactors, nearly 75 percent on average, raised his 20-year forecast by 5 percentage points.

Q. How can one year of data make such a difference to the "over-12" effect?

A. Quite simply, Mr. Komanoff's "over-12" effect was extrapolated from very little data. As time passes, more units reach that age. One year of data adds substantially to these data.

Q. What do you conclude from these data?

A. While I will not put words into Mr. Komanoff's mouth, I do note that he believed a 60 percent capacity factor for Limerick was optimistic but plausible based on his analysis of the historic data. With the 20 year forecast based on his equation form now 5 percentage points higher, the 65 percent forecast is now plausible at a no higher level of optimism.

FOSSIL FUELS PRICE FORECASTS

Q. A major source of the difference in the OCA and PECO valuation of Limerick life cycle benefits is the cost of replacement fuel. Mr. Komanoff forecasts substantially lower escalation rates for both coal and oil than does PECO. Do you have any comments on these fossil fuel price forecasts?

A. Other Company witnesses, Mr. Hogan (PECO St. No. 37) and Mr. English (PECO St. No. 32), are more able than I to forecast future fuel prices, particularly oil prices. However, I do have considerable familiarity with eastern coal markets and will comment on Mr. Komanoff's use of historic data on coal prices and mine productivity to support his forecasts of coal escalation rates.

Q. What is your basis for that familiarity?

A. I studied Eastern coal markets and, specifically the history of mine mouth price formation and labor productivity in work which I directed for the Environmental Protection Agency. I contributed to a seminal EPRI study, published under the self-explanatory title, <u>Coal Price Formation</u>. I am also a former member of the Coal Task Force of the New England Regional Commission.

Q. Have you reviewed the coal price projections that are contained in Mr. Komanoff's direct testimony?

A. Yes.

Q. What are your conclusions with regard to Mr. Komanoff's coal price projections?

A. Mr. Komanoff's coal price projections are based on a selective and misleading use of historical data on delivered and mine mouth coal prices and on coal productivity. Because Mr. Komanoff has undertaken an incomplete review of historical data, his coal price forecast of zero percent real escalation through 1990, 0.5 percent per year of real escalation from 1990-2000, and one percent real escalation thereafter are unfounded.

Q. Can you elaborate on your assertion concerning Mr. Komanoff's misuse of historical data on delivered and mine mouth coal prices?

A. Yes. On page 33 of Mr. Komanoff's testimony he states: "Between 1950 and 1984, the average price of coal delivered to U.S. electric utilities has increased at a compound average rate of 0.7 percent a year above the general rate of inflation." For a number of reasons, these data on the average price of coal delivered to all electric utilities in the U.S. cannot be used to predict future prices to PECO's coal plants. First, Mr. Komanoff has not taken into account the fact that the average Btu content of coal consumed by electric utilities has decreased by approximately 18 percent over the past 30 years. If this change in Btu content is taken into account the average national delivered price per million Btu to electric utilities has increased at 1.5 percent per year in real terms. Second, since 1950 there has been a dramatic change in the regional distribution of coal production. For example, the percentage of production in the Appalachian region, where PECO buys its coal, has declined from 74 percent in the 1950s to only 49 percent in 1984. Thus, the use of national data on delivered coal prices is not a proper basis for projecting the cost of coal from a particular region to a particular utility.

Q. Are there other historical price data that you feel Mr. Komanoff should have considered in developing his price forecast?

A. Yes. I believe that Mr. Komanoff should have looked at historical data on FOB mine mouth prices from the districts from which PECO is buying coal, namely Districts 1, 2, and 3. As shown in WHH Exhibit 46, over the period from 1953 (the earliest year for which price data are available at the district level) to 1984, prices in these districts have increased at a rate of between 1.5 and 1.9 percent a year above the rate of inflation.

Of course, these data mask a number of distinct sub-periods. From before 1953 to the late 1960's, coal was in constant oversupply, due principally to a decline in coal's share of the industrial and utility boiler fuels markets. Excess supply was not the only factor that put pressure on the market price. The gradual implementation of new technology, particularly the replacement of conventional mining by continuous mining technology in underground mines, and upsizing of equipment in surface mines led to dramatic improvements in productivity. In the late 1960's oversupply ended, tending to raise coal costs toward the cost of newly opened mines. The Federal Coal Mine Health and Safety Act ("FCMHSA") precipitated substantial declines in labor productivity, and this trend was reinforced by extremely serious labor strife, morale and absenteeism problems. Costs began to rise, but were not always reflected in prices due to the existence of unescalated long term contracts. In the period following the oil embargo of October, 1973, it was widely perceived that coal prices would follow the price of oil. Spot prices rose dramatically and many long term contracts were renegotiated or abrogated. Prices rose above the level of new mine costs, prices which could not be sustained in the long run. Since the mid-seventies, a return of relative labor peace, experience with FCMHSA and, especially since 1982, the emergence of a "soft" coal market have caused prices to decline significantly.

In the long run, minemouth coal prices are driven by two phenomena. The first is labor cost per ton and the second is gradual depletion of the most cheaply mineable reserves. While it is difficult to pick a reference starting and ending point for observing the joint effects of these two phenomena, the 1953-1984 period is a roughly reasonable and perhaps even slightly optimistic period for measuring historic mine mouth price growth. Both the starting and ending points were characterized by glutted markets. Productivity in the intervening period reflected a truly major change in technology only partly offset by regulatory change. In addition, the time span is long enough to show the effects of depletion.

Q. Mr. Komanoff also uses data on the delivered price of coal to Pennsylvania utilities generally, and PECO plants in particular, to support his forecast. Do you believe these data to be representative of future trends?

A. No. Mr. Komanoff's use of price data only for the period 1975-1984 for coal delivered to Pennsylvania utilities, and for the period 1976-1983 for coal delivered to PECO's plants, results in a biased assessment of historic price trends. For example, if Mr. Komanoff had gone back to 1972, which was the first year for which the electric utilities were required to submit price data to the federal government, he would have reached an entirely different conclusion. Exhibits WHH-47, WHH-48, and WHH-49 show the prices of coal delivered to utilities in Pennsylvania, and to PECO's four coal plants, Keystone, Conemaugh, Cromby, and

Eddystone, over the 1972-1984 period. As the Exhibits demonstrate, coal prices during this period increased at rates far above the two percent per year escalation assumed by PECO in its projections.

Q. Are you proposing that these 1972-1984 trends should be used to project the future?

A. No. I do not believe that increases of the magnitude implied by these data will occur. My purpose is simply to show that the historic data are subject to extremely varying interpretations depending on one's choice of a starting point. By picking a starting point at the peak of the market, and an ending point in a severely glutted market, Mr. Komanoff has painted a quite misleading picture of historical coal price trends.

Q. Do you agree with Mr. Komanoff's use of historic productivity data?

A. Mr. Komanoff has taken productivity data from 1977-1984 for Districts 1, 2, and 3. Mr. Komanoff said he did this because it was the earliest data for which he had productivity data. However, as shown in Exhibit WWH-50, if Mr. Komanoff had used coal productivity data (which was available from similar government sources) all the way back to the year 1953, he would have seen that over the 1953-1984 period there were times when coal productivity increased considerably and then decreased considerably. The average increase in productivity over the 1953-1984 period is 2.5 percent per year for District 1, 2.2 percent per year for District 2 and 2 percent per year for District 3. This growth in productivity is lower than the numbers that Mr. Komanoff cites on pages 34-35 of his direct testimony. Again, by choosing a non-representative period, Mr. Komanoff has created an unjustifiably rosy picture of our future.

Q. Has Mr. Komanoff failed to consider any historical data on transportation costs?

A. Yes. In Exhibit WHH-51, data for the index of railroad charge-out-prices for the eastern district are presented. For the 1950-1984 period the real increase in the index has been approximately 2 percent per year, which is the same escalation rate assumed by PECO in developing its coal price forecasts.

Q. What are your conclusions regarding the validity of Mr. Komanoff's assumptions concerning escalation of coal prices?

A. For the reasons discussed above and for the reasons discussed in the testimony of Dr. Hogan and Mr. English, I feel Mr. Komanoff's projections are not supported by the historical data upon which they are based. Therefore, they should not be relied on in forecasting Limerick 1 life cycle benefits.

PECO INFLATION RATE

Q. Have you examined Dr. Schinnar's references to PECO's assumed inflation rates found in note 3 to Dr. Schinnar's direct testimony and at transcript p. 3419, lines 5-9?

A. Yes.

Q. Would you please comment on Dr. Schinnar's references?

A. Note 3 of Dr. Schinnar's testimony refers to numbers that appear in the direct testimony of Albert J. Solecki. These numbers are not PECO's assumed inflation rates but rather are inflation factors developed in the budget preparation process to be used only in the absence of known cost changes (See PECO Statement No. 19, p. 7, lines 10-12).

Q. What are PECO's actual corporate inflation assumptions?

A. PECO's actual corporation inflation assumptions as used in PECO's economic analyses are found in response to IR-OCA-2-25 and are as follows:

<u>Inflation</u>	
1986	4.5%
1987	5.0%
1988 and beyond	6.0%

DISCOUNT RATE

Q. Both Mr. Falkenberg and Mr. Chernick criticize PECO for using its net of tax discount rate in evaluating the value of Limerick. Please comment on their criticism.

A. Let me begin by making clear what the role of the discount rate is in the Limerick 1 cost effectiveness analysis. The purpose of discounting is to answer the question, "is the present value of savings generated by the capital investment in the Limerick plant sufficient to return the cost of that investment?" Implicit in this statement of the appropriate issue is the recognition that what the analysis does not seek to answer is the question of whether ratepayers would prefer to pay the cost of Limerick sooner or later.

Having stated the issue, there are two questions raised by the analyses of Messrs. Falkenberg and Chernick. First, is the discount rate the cost of capital or some other (i.e. social) rate and, if it is the cost of capital, is it PECO's or the ratepayers'? Second, should the cost of capital be net or gross of tax shields on debt?

The second question is most easily answered: discount rates should always be net of the tax effects. As stated in a recent draft EPRI report, <u>Choice of Discount Rates in Utility Planning: The Revenue Requirements Method</u>:

> "The discount rate may also include an adjustment for financing side effects. An example of a financing side effect is the tax shield provided by interest expense. Debt financing may generate project value over and above net operating cash flows because interest payments are deductable for corporate tax purposes. This side effect can be reflected directly, by adjusting cash flows, or indirectly, by adjusting discount rates. The "weighted averge cost of capital" is an opportunity cost of capital adjusted to account for interest tax shields."

The commonsense of this statement applies to any investment. Suppose I am considering spending $80,000 to buy a house, with a $20,000 down payment. Suppose further that my opportunity cost of equity capital is 12 percent (however determined), the interest rate is 10 percent and my marginal tax rate is 35 percent. My cost of funds is:

Equity		20,000 x .12 = 2400
Interest	+	80,000 x .10 = 8000
tax savings - from interest deduction		8,000 x .35 = (2800)
		7,600 or 7.6%

The situation for PECO is similar. Since raising capital to build and carry the capital cost of Limerick generates tax shields, these should be figured into the cost of capital used in evaluating the investment.

Why should the utility's, rather than ratepayers cost of capital be used in evaluating Limerick? In part, it is because that is the cost of the capital which is used to build the plant. Suppose, in the alternative, a higher cost of capital -- for example -- a credit card rate were used to evaluate utility investments. An investment with an internal rate of return of, say, 16 percent would not be made. Yet if the utility were to make the investment at a financing cost below 16 percent, the cost of power could be reduced, and the customer would miss out on an opportunity to save money. The fact that the utility can borrow money at rates below customer rates makes the customers' cost of money irrelevant. I should also note that high consumer rates like credit card rates are in no sense a good proxy for a relevant market rate of interest. They contain large transactions costs as well as a premium for a significant non-payment risk.

More generally, the finance literature is unanimous on one basic point: the cost of capital relevant to evaluating an investment is the market cost of capital for a project with its risk characteristics. It simply does not matter who supplies the capital.

Finally, even were it the case that consumers' rates were relevant, it is not evident that they are materially higher than PECO's net of tax incremental cost of capital. Current money market yields are below 8 percent and subject to tax; given average marginal tax rates for state and federal taxes, the after tax rate is probably below 6 percent. Mortgage rates are currently around 11 percent. However, mortgage expenses are deductable, yielding an after tax cost of around

8 percent. While some customers unquestionably have higher opportunity costs of capital, it is quite inappropriate to use the highest discount rate for any customer to represent ratepayers as a group.

Q. Mr. Chernick cites the "hurdle rates" of his customers as demonstration that they have discount rates of 20 percent or more. Why is this evidence not compelling?

A. "Hurdle rates" are notoriously unreliable measures of the opportunity cost of capital. In many cases, hurdle rates are used to evaluate returns on a pre-tax basis and/or before allocation of corporate overheads. High hurdle rates are used to counter optimism in forecasting project cash flows. Mr. Falkenberg's sample is fairly typical; the usual hurdle rate in American business is 25 percent or more. If hurdle rates were meaningful measures of the opportunity cost of capital, no investments yielding after tax returns below 25 percent would be made and the average return on capital invested in U.S. business therefor would be at least 25 percent. Of course, this is not the case.

Q. Mr. Falkenberg cites an EEI survey to demonstrate that most utilities use a cost of capital which is not adjusted for the tax shield on interest in evaluating projects. Does not this suggest that, correct or not, most utilities use the pre-tax weighted average cost of capital for a discount rate?

A. I was quite puzzled by this result since most of the utilities I work with use a net of tax discount rate. Upon reviewing Mr. Falkenberg's Exhibit 7, I noted that the words "discount rate" were never used. I then reviewed the questionnaire upon which the EEI report was based and found that the questionnaire simply asked the respondent to list the incremental cost of capital used for internal economic evaluations by component. The "cost of capital" has the specific meaning in regulated companies of the weighted average pre-tax cost of capital. It is a "thing", i.e. a quantity, not a "use". As typically used by utilities in internal economic evaluations, it is an input to a revenue requirements model. It is not a discount rate and would not be unless utilities used pre-tax weighted costs of capital as their discount rates. By assuming that in answering this question respondents were specifying their discount rates, Mr. Falkenberg is assuming the answer he is trying to prove. In fact, I am surprised that any utilities at all answered the pair of questions shown on the questionaire by stating that they use a net of tax rate, since those utilities probably did interpret the question as inquiring about discount rates, though they might also have answered in this way if they interpreted it as asking whether the carrying charges used in levelized-cost economic studies were net of deferred tax and ITC effects. In any event, the survey result relied upon by Mr. Falkenberg reflects only the vagueness of the question and not the practice of utilities. Finally, I would point out that at least the incremental cost of debt would be much lower today than in 1984 since the market yield of utility bonds has fallen quite substantially. Thus, even if his interpretation of the EEI survey were right, his discount rate would still be too high.

This point is critical to Mr. Falkenberg's supposed $1.2 billion net cost of Limerick. His analysis begins with my lowest forecast of net savings, ($2.0 billion based on no change in capacity charges and a substantial remaining access to ECAR power on peak after 1993). He then reduces the savings by $55 million for his O&M forecast and by approximately $1 billion in present value for the second half of common. Thus even with his O&M forecast changes and inclusion of the second half of common -- which he proposes should <u>not</u> be recovered as a Limerick 1 revenue requirement -- only his use of the 14.3 percent discount rate creates the "loss" which he proposes to impose on PECO's shareholders.

FUEL SAVINGS AND CAPACITY FACTOR GUARANTEES

Q. Some witnesses have proposed that PECO be required to guarantee the first two years of Limerick fuel savings and at least one witness, Mr. Falkenberg, has proposed a separate guarantee of the projected 65 percent capacity factor for Limerick 1. In addition, Dr. Wilson, a GEC witness, has proposed a specific incentive plan targeting nuclear plant capacity factors, also based on PECO's 65 percent projection. Can you place these proposals into a utility regulatory policy context?

A. Yes. These proposals appear to be defended on either of two grounds. One could be termed the "clairvoyance standard" of ratemaking in which a utility is held to its performance projections, irrespective of whether they are reasonable, whether their non-achievement could have been forecasted, or whether the failure to achieve these performance expectations is due to matters outside the utility's control. The second goal, which is explicit in Dr. Wilson's testimony, is to provide incentives for efficient operation. In my view, the "clairvoyance standard" is poor ratemaking policy, especially if it is applied to fuels costs. The incentive purposes espoused by Dr. Wilson have merit, though I believe that his specific proposal is seriously flawed.

Q. Why is the clairvoyance standard with respect to fuel savings poor ratemaking policy? Isn't it true that future test year ratemaking always bases rates on forecasts of costs?

A. Yes. However, most elements of test year costs are predictable within relatively narrow limits, especially given that the test year is partly historic. However, fuel costs forecasts are the least reliable element of cost, especially for utilities that burn significant amounts of oil or purchase power which is priced based in part on the cost of oil. Essentially all public utility commissions recognize this fact, as is reflected in the ubiquity of fuel adjustment clauses, of which PECO's ECR is an example. What Mr. Falkenberg and Mr. Knudsen are proposing is nothing other than the abolition of the ECR mechanism for Limerick 1.

Q. What is the economic consequence of abolishing the ECR mechanism for Limerick?

A. The effect is to transfer the fuels market price risk from ratepayers to shareholders. Of course, this risk is substantially magnified by that shift: a fuel price change resulting in plus-or-minus 1 percent change in rates translates into a substantially larger variation in the earned return on common equity. The consequence of this shifting is to make utility investments far more risky and, in the extreme circumstance, could dry up access to capital markets. We have already experienced one instance in the 1974-75 period in which utilities were hit with major changes in fuel costs without the protection of fuel adjustment clauses. Mr. Pacquette's direct testimony in this proceeding demonstrates the severe adverse consequences that followed from that event.

Q. Is the value of Limerick fuel savings in the rate effective period uncertain?

A. Yes, it is. Currently, forecasting oil prices for the near term is more political than purely economic. The Saudi's and their allies are punishing both OPEC members who have cheated on their allocations and non-OPEC oil producers who have taken advantage of the OPEC pricing umbrella. Their goal is to re-establish discipline within OPEC and to reach formal or informal allocation agreements with nonmembers. The whole purpose of the recent Saudi actions is to teach the lesson that high prices can be achieved only if the cartel is strong; the carrot which they hold out is a rapid return to higher prices. If the Saudi's succeed -- and certainly the economic incentive is there -- oil prices should rise significantly. If they fail, prices will not rise significantly.

There is an ironic difference between the circumstances of 1974-1975 and the effects of abolishing the ECR for Limerick 1 in 1986-1988 as proposed by Messrs. Falkenberg and Knudsen. In the earlier period, shareholders were hurt by a rise in fuels prices. This at least had the virtue of temporarily shielding ratepayers from the effects of higher prices. Under the OCA and PAIEUG proposal, it is a <u>decline</u> in fuels prices which would hurt shareholders. Benefits from that same decline would be passed through the ECR to ratepayers since the cost of purchased power and power from oil-fired units would fall. Under the OCA and PAIEUG proposal, ratepayers would benefit doubly from a fuels price decline, both for the fuels cost reduction actually experienced and for the phantom decline in the high cost of fuel which is no longer used due to the completion of Limerick 1.

Q. You made the statement that at least some parties would hold PECO responsible for its fuels savings forecast irrespective of whether it is a reasonable forecast. Are you suggesting that it is not?

A. No. My point is that OCA does not believe it is reasonable. OCA witness Komanoff forecasts a Limerick capacity factor of 60 percent and lower fuels prices than does PECO. Under the circumstances he projects, the fuels savings forecasted by PECO would not be achieved. Hence, OCA seeks to hold PECO to a standard which it does not believe to be reasonably achievable.

Q. Turning now to Dr. Wilson's proposal, do you have the same criticisms?

A. No. Dr. Wilson's proposed incentive plan does not hold PECO responsible for fuels prices. The intent of his plan is to provide an incentive for more efficient performance of PECO's nuclear plants, a goal which, in itself, is unobjectionable.

Q. If Dr. Wilson's goal is unobjectionable, why do you disagree with his proposal?

A. Because I believe that utility efficiency incentives should meet several criteria. First, they should not create unintended perverse incentives -- for example, to "gold plate" plant for higher reliability or to defer safety-related maintenance. Second, they should apply only to matters within the utility's control -- otherwise there is no point in the incentive. Third, they should not unnecessarily increase the variability of shareholder returns; this only serves to increase market risk and increases the cost of capital with no offsetting benefit to ratepayers. Fourth, they should provide the utility a fair opportunity to earn its allowed rate of return. Fifth, while (as Dr. Wilson states) an incentive must have a significant likelihood of impact if it is to be effective, the reward or penalty should only be large enough to give management the proper incentive. I will assume, but do not concede, that Dr. Wilson's proposal meets the first three criteria (it assuredly does not meet the third) and concentrate my comments on the fourth and fifth criteria.

Dr. Wilson proposes a deadband of plus-or-minus 5 percentage points around a 65 percent capacity factor; he and PECO agree that 65 percent is a reasonable expected average performance for Limerick 1. PECO would be permitted to keep 50 percent of the savings from higher output, but would pay for 100 percent of the cost of output falling below the band.

If we assume that annual capacity factors are symmetrically distributed around the 65 percent average, this proposal is clearly unfair. If PECO meets the target on average, it will not, on average, get compensated for its fuel cost. At a minimum, therefore, the reward and penalty must be symmetric unless the purpose of the incentive is to systematically deny PECO a fair opportunity to earn its allowed rate of return.

Q. Can you demonstrate that point?

A. Yes. If one excludes the TVA units which were all taken off-line due to a TVA-wide management problem, the average nuclear capacity factor in 1985 was 65 percent. Exhibit WHH-52 shows the distribution of capacity factors. Of the 75 unit years of data, a surprisingly small number -- less than 20 percent -- fell within Dr. Wilson's deadband of 60 to 70 percent. This fact suggests the likelihood that Dr. Wilson's deadband is unnecessarily narrow. Thirty-four of the plants achieved higher capacity factors, 28 lower.

The average unit which fell below the deadband would have been penalized for 15.6 capacity factor shortfall points. The average unit which achieved above the deadband would be rewarded for 12.6. Because more plants were above than below, the total rewards and penalties nearly exactly would balance under a fair incentive plan. However, under Dr. Wilson's proposal, the rewards and penalties would not balance. At the Limerick fuel savings value of 3.2 million per percentage point, the aggregate of losses would be 1,351 million dollars. With 50 percent sharing of gains, the aggregate gain would be 686 million dollars. Thus, had Dr. Wilson's incentive scheme been adopted industrywide, the aggregate loss to the utilities would have been 665 million dollars, despite the fact that, on average, it achieved the target capacity factor.

Q. Your fifth criteria was that penalties should not shift more risks than necessary to achieve the desired incentive effect. Does Dr. Wilson's proposed sharing meet that criteria?

A. No, it does not. In the example I just described, the average penalty would be 50 million dollars while the average reward would be 20 million dollars. The maximum and minimum would of course be larger; the maximum penalty is $145 million for a single unit. Penalties of that magnitude are not necessary to give utilities incentives to pay close attention to reactor performance. They are, however, large enough to tempt management to defer needed maintenance out of refueling years, or invest more than is really needed in reliability-enhancing retrofits. These computations instead suggest that the 80:20 split incorporated in the existing ECR mechanisms is an adequate, and indeed, superior performance incentive.

Q. Does that complete your rebuttal testimony?

A. Yes, it does.

EXHIBIT WHH-30

CONSTUCTION DURATION FOR ALL PLANTS
UNDER CONSTRUCTION OR WITH CONSTRUCTION
PERMITS AS OF DECEMBER, 1974.

PLANT	ACTUAL OR FEBRUARY '86 ESTIMATED COMMERCIAL OPERATION DATE	SEPT. '85 TVA NUCLEAR REPORT CONSTRUCTION START DATE	CALCULATED CONSTRUCTION DURATION (MONTHS)
ARK NUCLEAR ONE 2	Mar-80	Jul-71	104
BEAVER VALLEY 1	Apr-77	Jun-69	95
BEAVER VALLEY 2	Oct-87	May-74	162
BELLEFONTE 1	Jan-94	Sep-74	233
BELLEFONTE 2	Jan-96	Sep-74	257
BROWNS FERRY 3	Mar-77	Aug-68	103
BRUNSWICK 1	Mar-77	Sep-69	91
BRUNSWICK 2	Nov-75	Sep-69	74
CALVERT CLIFFS 2	Apr-77	Feb-68	110
CATAWBA 1	Jun-85	Jun-74	133
CATAWBA 2	Jun-87	Jun-74	157
COMANCHE PEAK 1	Jan-86	Dec-74	134
COMANCHE PEAK 2	Jul-87	Dec-74	152
COOK, D.C. 2	Jul-78	Sep-68	118
CRYSTAL RIVER 3	Mar-77	Sep-68	103
DAVIS-BESSE	Sep-77	Sep-70	85
DIABLO CANYON 1	May-85	Jun-68	204
DIABLO CANYON 2	Nov-85	Mar-71	177
FARLEY, JOSEPH 1	Dec-77	Sep-70	87
FARLEY, JOSEPH 2	Jul-81	Apr-72	112
FERMI, ENRICO 2	Oct-85	Jun-70	185
GRAND GULF 1	Jul-86	May-74	146
HARRIS, SHARON	Oct-86	Jan-78	105
HATCH, EDWIN H. 2	Sep-79	Feb-72	91
HOPE CREEK	Dec-86	Mar-76	129
INDIAN POINT 3	Aug-76	Oct-67	107
LASALLE 1	Oct-82	Oct-73	109
LASALLE 2	Jun-84	Oct-73	129
LIMERICK 1	Feb-86	Jun-74	141
MCGUIRE, WM 1	Dec-81	Apr-71	128
MCGUIRE, WM 2	Mar-84	Apr-71	155
MILLSTONE 2	Dec-75	Nov-69	73
MILLSTONE 3	May-86	May-74	145
NINE MILE POINT 2	Jan-87	Jun-75	140
NORTH ANNA 1	Jun-78	Jul-69	107
NORTH ANNA 2	Dec-80	Jul-69	137
SALEM 1	Jun-77	Jan-68	114
SALEM 2	Oct-81	Jan-68	166

EXHIBIT WHH-30 (Continued)

CONSTUCTION DURATION FOR ALL PLANTS
UNDER CONSTRUCTION OR WITH CONSTRUCTION
PERMITS AS OF DECEMBER, 1974.

PLANT	ACTUAL OR FEBRUARY '86 ESTIMATED COMMERCIAL OPERATION DATE	SEPT. '85 TVA NUCLEAR REPORT CONSTRUCTION START DATE	CALCULATED CONSTRUCTION DURATION (MONTHS)
SAN ONOFRE 2	Aug-83	Mar-74	113
SAN ONOFRE 3	Apr-84	Mar-74	121
SEQUOYAH 1	Jul-81	Apr-69	147
SEQUOYAH 2	Jun-82	Apr-69	158
SHOREHAM	Oct-85	Sep-72	158
ST. LUCIE 1	Dec-76	Jul-70	77
SUMMER, VIRGIL C.	Jan-84	Apr-73	129
SUSQUEHANNA 1	Jun-83	Nov-73	115
SUSQUEHANNA 2	Feb-85	Nov-73	136
THREE MILE ISLAND 2	Dec-78	Jan-69	119
TROJAN	May-76	Oct-70	68
VOGTLE, ALVIN 1	Jun-87	May-74	157
VOGTLE, ALVIN 2	Sep-89	May-74	185
WASHINGTON NUCLEAR 2	Dec-84	Mar-73	141
WATERFORD 3	Sep-85	Dec-75	118
WATTS BAR 1	Oct-85	Dec-72	155 *
WATTS BAR 2	Sep-87	Dec-72	178

* Data for Watts Bar 1 are the last reported before TVA deemed the schedule indefinite.

EXHIBIT WHH-31

CONSTRUCTION DURATION FOR ALL PLANTS
WITH COMMERCIAL OPERATION DATES
AFTER JANUARY 1, 1980.

PLANT	ACTUAL OR FEBRUARY '86 ESTIMATED COMMERCIAL OPERATION DATE	SEPT. '85 TVA NUCLEAR REPORT CONSTRUCTION START DATE	CACULATED CONSTRUCTION DURATION (MONTHS)
ARK NUCLEAR ONE 2	Mar-80	Jul-71	104
BEAVER VALLEY 2	Oct-87	May-74	162
BELLEFONTE 1	Jan-94	Sep-74	233
BELLEFONTE 2	Jan-96	Sep-74	257
BRAIDWOOD 1	May-87	Aug-75	141
BRAIDWOOD 2	Sep-88	Aug-75	157
BYRON 1	Sep-85	Jun-75	123
BYRON 2	May-87	Jun-75	143
CALLAWAY	Dec-84	Apr-76	105
CATAWBA 1	Jun-85	Jun-74	133
CATAWBA 2	Jun-87	Jun-74	157
CLINTON	Nov-86	Mar-76	129
COMANCHE PEAK 1	Jan-86	Dec-74	134
COMANCHE PEAK 2	Jul-87	Dec-74	152
DIABLO CANYON 1	May-85	Jun-68	204
DIABLO CANYON 2	Nov-85	Mar-71	177
FARLEY, JOSEPH 2	Jul-81	Apr-72	112
FERMI, ENRICO 2	Oct-85	Jun-70	185
GRAND GULF	Jul-86	May-74	146
HARRIS, SHARON	Oct-86	Jan-78	106
HOPE CREEK	Dec-86	Mar-76	129
LASALLE 1	Oct-82	Oct-73	109
LASALLE 2	Jun-84	Oct-73	129
LIMERICK 1	Feb-86	Jun-74	141
MCGUIRE, WM 1	Dec-81	Apr-71	128
MCGUIRE, WM 2	Mar-84	Apr-71	155
MILLSTONE 3	May-86	May-74	145
NINE MILE POINT 2	Jan-87	Jun-75	140
NORTH ANNA 2	Dec-80	Jul-69	137
PALO VERDE 1	Feb-86	Nov-76	111
PALO VERDE 2	Oct-86	Jun-77	113
PALO VERDE 3	Oct-87	Apr-79	103
PERRY 1	Nov-86	Oct-74	145
RIVER BEND	Apr-86	Aug-79	80
SALEM 2	Oct-81	Jan-68	166
SAN ONOFRE 2	Aug-83	Mar-74	113
SAN ONOFRE 3	Apr-84	Mar-74	121

EXHIBIT WHH-31 (Continued)

CONSTRUCTION DURATION FOR ALL PLANTS
WITH COMMERCIAL OPERATION DATES
AFTER JANUARY 1, 1980.

PLANT	ACTUAL OR FEBRUARY '86 ESTIMATED COMMERCIAL OPERATION DATE	SEPT. '85 TVA NUCLEAR REPORT CONSTRUCTION START DATE	CACULATED CONSTRUCTION DURATION (MONTHS)
SEABROOK 1	Oct-86	Jul-76	124
SEQUOYAH 1	Jul-81	Apr-69	147
SEQUOYAH 2	Jun-82	Apr-69	158
SHOREHAM	Oct-85	Sep-72	158
SOUTH TEXAS 1	Dec-87	Sep-75	148
SOUTH TEXAS 2	Jun-89	Sep-75	166
ST. LUCIE 2	Aug-83	Jun-77	74
SUMMER, VIRGIL C.	Jan-84	Apr-73	129
SUSQUEHANNA 1	Jun-83	Nov-73	115
SUSQUEHANNA 2	Feb-85	Nov-73	136
VOGTLE, ALVIN 1	Jun-87	May-74	157
VOGTLE, ALVIN 2	Sep-89	May-74	185
WASHINGTON NUCLEAR 2	Dec-84	Mar-73	141
WATERFORD 3	Sep-85	Dec-75	117
WATTS BAR 1	Oct-85	Dec-72	155 *
WATTS BAR 2	Sep-87	Dec-72	178
WOLF CREEK	Sep-85	Feb-77	103

* Data for Watts Bar 1 are the last reported before TVA deemed the schedule indefinite.

Exhibit WHH-32

FUEL LOAD DATE SLIPPAGES FROM THE END OF 1974: ALL PLANTS THEN SCHEDULED TO LOAD FUEL IN 1979-1981

	1974 FLD Forecast	FLD as of 2/86	Months Slippage
Bellefonte 2	3/80	7/95	184
Bellefonte 1	6/79	7/93	169
Watts Bar 2	3/79	10/87	103
Comanche Peak 1	6/79	2/87	92
Vogtle 2	10/80	3/88	89
Vogtle 1	10/79	12/86	86
Beaver Valley 2	2/81	5/87	75
Comanche Peak 2	6/81	8/87	74
Sharon Harris	9/80	6/86	69
Waterford 3	6/79	12/84	66
Hope Creek	6/81	3/86	57
Catawba 2	8/81	3/86	55
LaSalle 2	6/79	12/83	54
Limerick 1	10/80	11/84	49
Catawba 1	8/80	6/84	46
Grand Gulf 1	3/79	8/82	41
San Onofre 2	8/79	2/82	30
Susquehanna 2	11/81	3/84	28
Susquehanna 1	5/80	7/82	26
San Onofre 3	11/80	11/82	24

Exhibit WHH-33

COMPARISON OF NET BENEFIT ESTIMATES

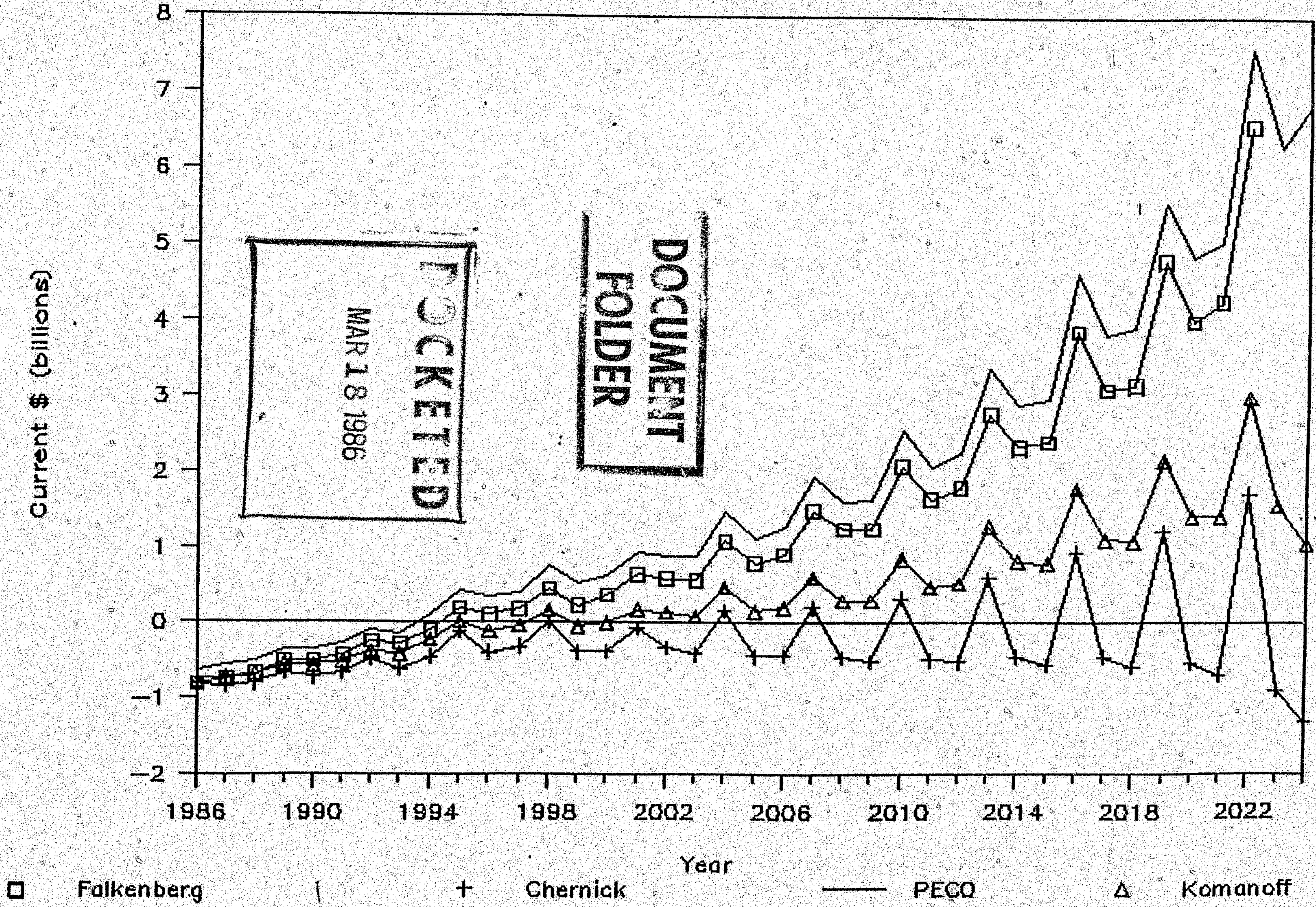


Exhibit WHH-34

COMPARISON OF TOTAL BENEFIT ESTIMATES

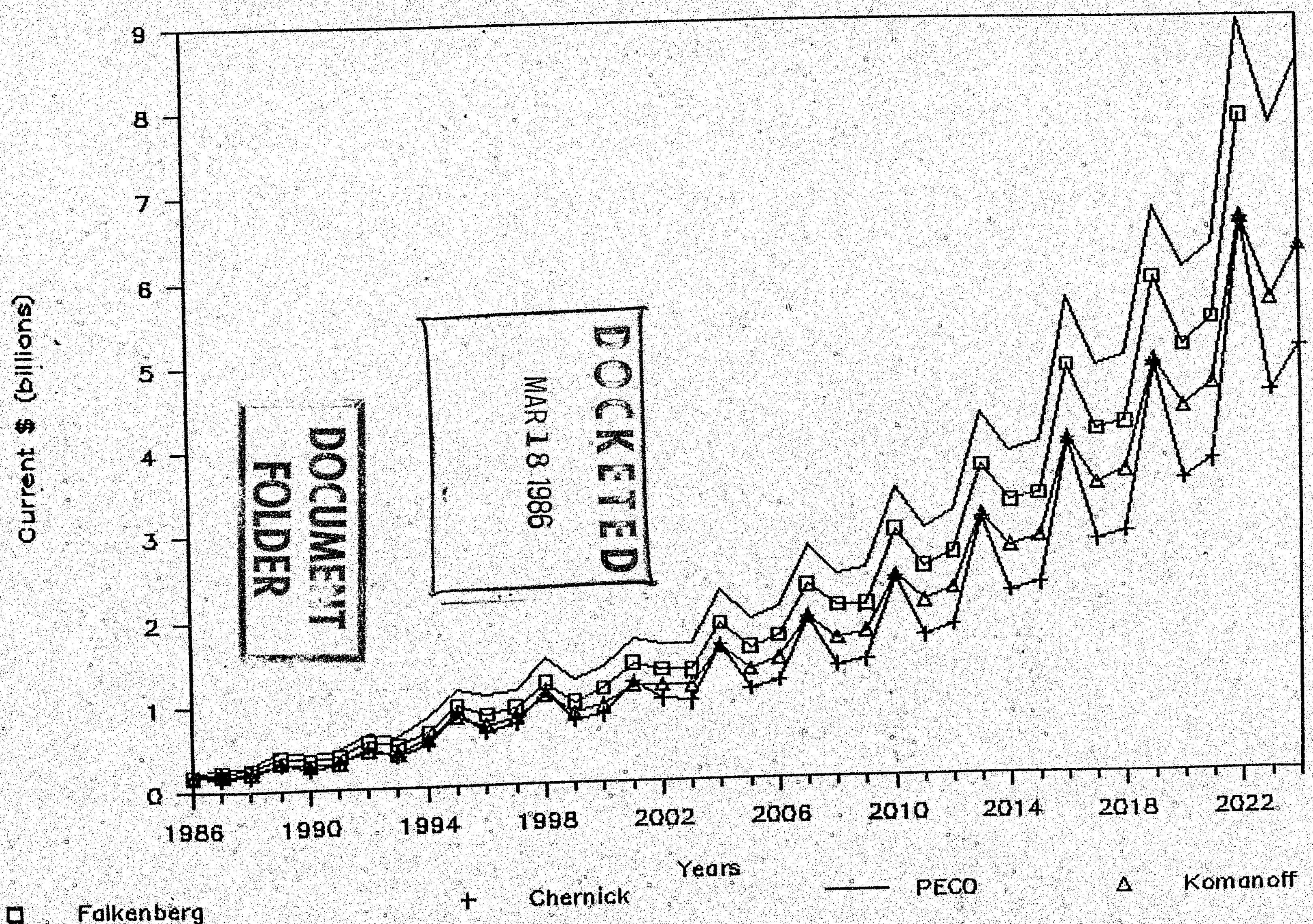


Exhibit WHH-35

COMPARISON OF TOTAL COST ESTIMATES

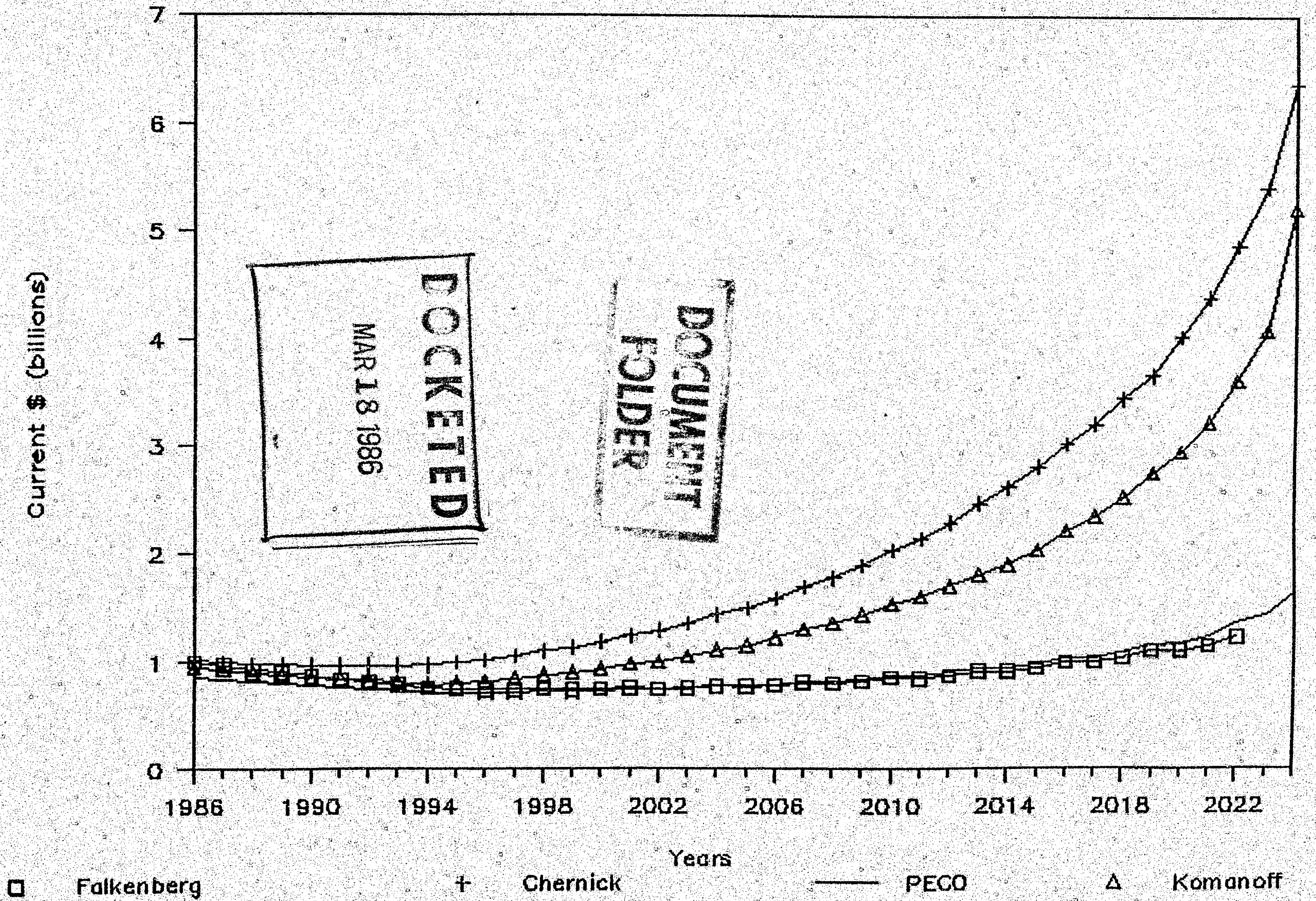
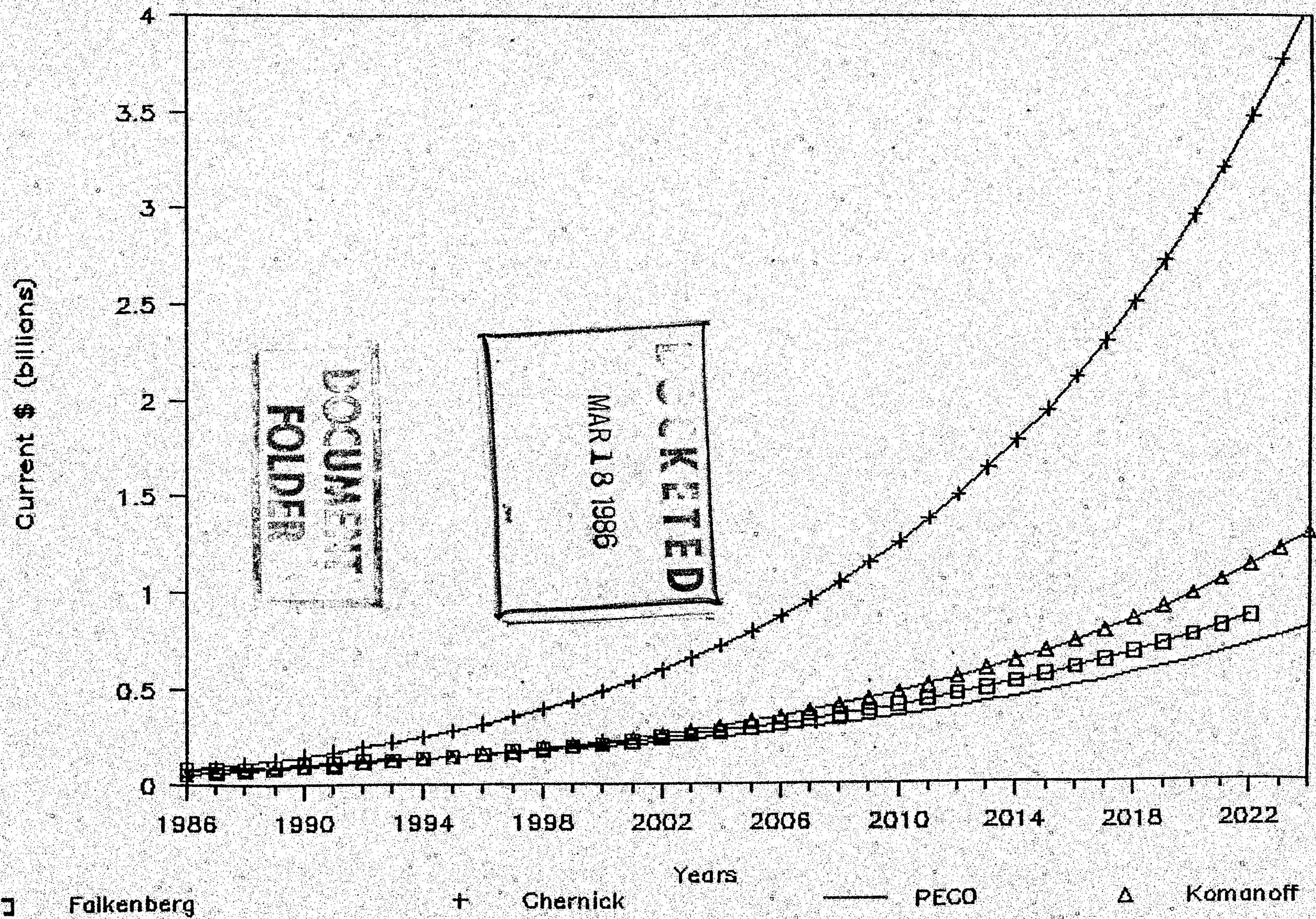


Exhibit WHH-36

COMPARISON OF O&M COST ESTIMATES



COMP. OF CAP. ADDITIONS COST ESTIMATES

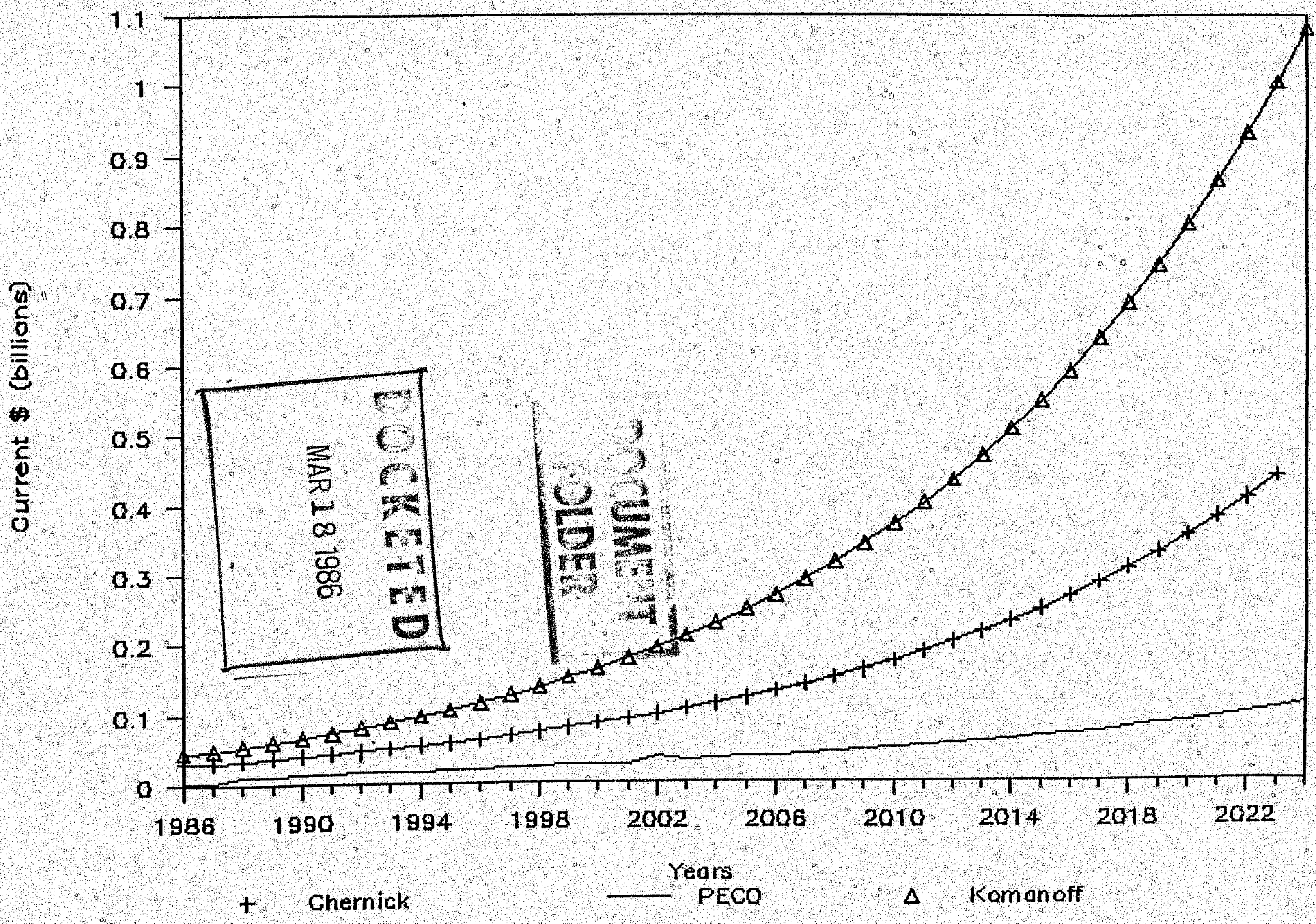


EXHIBIT WHH-38

Computation of Split-Savings Capacity Charges

Year	Mix (%) Coal	Intermediate	Peaker	Composite Cost $/KW
1990	27.8	60.1	12.1	121.2
1995	16.5	58.7	24.8	144.8
2000	23.3	54.0	20.4	210.8
2005	26.5	54.1	19.4	281.5
2010	22.4	56.9	20.7	365.9
2015	19.2	62.0	18.8	482.5
2020	21.0	59.3	19.7	651.5

EXHIBIT WHH-39

IMPACT OF SSES-2 RATECASE FUELS SAVINGS VALUES ON LIMERICK NET BENEFIT ESTIMATE

	Limerick Fuel Savings ($ million)	
Year	Valued at SSES-2 Ratecase Value *	Correct PECO Estimate
1986	138.8	150.8
1987	184.1	186.0
1988	268.4	209.5
1989	352.3	322.4
1990	432.7	282.4
1995	984.1	843.1
2000	1680.9	979.39
2010	3078.0	2684.5
2020	5358.2	4658.7
Present Value	11,792.0	8,679.3

*Retail savings grossed up to total plant.

Equation #5 from Chernick Table 4.6 (All plants in dataset).

	Equation 5	
	Coef	t-stat
CONSTANT	-2.1896	-8.77
ln(MW)	--	--
ln(UNITS)	0.6970	15.34
YEAR	0.1130	31.24
UNITS	--	--
ln(MW/unit)	0.4828	20.23
NE	0.2811	8.78
Adjusted R-sq.		0.87
F statistic		904.3

DEPENDENT VARIABLE=LN('83 O&M) (THIS IS CHERNICK'S EQ 5 PLUS POST-TMI FOR ALL PLANTS)

Regression Output:	
Constant	-0.2555
Std Err of Y Est	0.3194
R Squared	0.8853
No. of Observations	535
Degrees of Freedom	529

	LN(UNIT)	YEAR	LN(MW/UNIT)	NE	POST-TMI (a)
X Coefficient(s)	0.6840	0.0835	0.5193	0.2719	0.3363
Std Err of Coef.	0.043	0.005	0.023	0.030	0.043
T-Statistic	15.864	16.306	22.473	8.952	7.771

	O&M, 1983$ (Millions)		O&M, 1983$ (Millions)
1986	71.10	2006	377.78
1987	77.30	2007	410.68
1988	84.03	2008	446.45
1989	91.35	2009	485.33
1990	99.30	2010	527.60
1991	107.95	2011	573.55
1992	117.35	2012	623.50
1993	127.57	2013	677.81
1994	138.69	2014	736.84
1995	150.76	2015	801.01
1996	163.90	2016	870.77
1997	178.17	2017	946.61
1998	193.69	2018	1029.06
1999	210.56	2019	1118.68
2000	228.89	2020	1216.11
2001	248.83	2021	1322.03
2002	270.50	2022	1437.17
2003	294.06	2023	1562.34
2004	319.67	2024	1698.41
2005	347.51		

(a) POST-TMI equals 1, if year is 1980 or later; otherwise equals 0.

PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR LIMERICK 1 ($ million)

Year	PECO Projections	Using Eq. from Page 1 of this Exhibit.				Using Eq. #5 from Chernick Table 4.6.			
		Compund real growth		Linear real growth		Compund real growth		Linear real growth	
	nominal	1983$	nominal	1983$	nominal	1983$	nominal	1983$	nominal
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1986	$79	$71	$79	$71	$79	$73	$81	$73	$81
1987	$85	$77	$91	$77	$91	$81	$96	$81	$96
1988	$93	$84	$104	$83	$104	$91	$113	$90	$112
1989	$101	$91	$120	$90	$118	$102	$135	$99	$130
1990	$111	$99	$139	$96	$134	$114	$160	$108	$150
1991	$117	$108	$160	$102	$151	$128	$190	$116	$172
1992	$124	$117	$184	$108	$170	$143	$225	$125	$196
1993	$132	$128	$212	$114	$190	$161	$267	$134	$222
1994	$140	$139	$244	$121	$213	$180	$317	$142	$251
1995	$148	$151	$282	$127	$237	$201	$376	$151	$282
1996	$157	$164	$325	$133	$263	$225	$446	$160	$317
1997	$166	$178	$374	$139	$292	$252	$530	$169	$354
1998	$176	$194	$431	$145	$324	$283	$629	$177	$394
1999	$187	$211	$497	$152	$358	$316	$746	$186	$439
2000	$198	$229	$572	$158	$394	$354	$886	$195	$487
2001	$210	$249	$659	$164	$435	$397	$1,051	$203	$539
2002	$222	$271	$760	$170	$478	$444	$1,248	$212	$596
2003	$236	$294	$875	$176	$525	$497	$1,481	$221	$658
2004	$250	$320	$1,009	$183	$576	$557	$1,757	$230	$725
2005	$265	$348	$1,163	$189	$631	$623	$2,086	$238	$797
2006	$281	$378	$1,340	$195	$691	$698	$2,475	$247	$876
2007	$298	$411	$1,544	$201	$756	$782	$2,938	$256	$961
2008	$315	$446	$1,779	$207	$826	$875	$3,487	$264	$1,053
2009	$334	$485	$2,050	$214	$902	$980	$4,139	$273	$1,153
2010	$354	$528	$2,362	$220	$984	$1,097	$4,912	$282	$1,262
2011	$376	$574	$2,722	$226	$1,072	$1,229	$5,830	$291	$1,379
2012	$398	$624	$3,136	$232	$1,168	$1,376	$6,919	$299	$1,505
2013	$422	$678	$3,614	$238	$1,271	$1,540	$8,212	$308	$1,642
2014	$447	$737	$4,164	$245	$1,382	$1,725	$9,747	$317	$1,790
2015	$474	$801	$4,799	$251	$1,502	$1,931	$11,568	$325	$1,949
2016	$503	$871	$5,530	$257	$1,631	$2,162	$13,730	$334	$2,122
2017	$533	$947	$6,372	$263	$1,771	$2,421	$16,296	$343	$2,308
2018	$565	$1,029	$7,342	$269	$1,921	$2,711	$19,341	$352	$2,508
2019	$599	$1,119	$8,461	$275	$2,083	$3,035	$22,955	$360	$2,725
2020	$635	$1,216	$9,750	$282	$2,258	$3,398	$27,245	$369	$2,958
2021	$673	$1,322	$11,235	$288	$2,446	$3,805	$32,336	$378	$3,209
2022	$713	$1,437	$12,946	$294	$2,649	$4,261	$38,378	$386	$3,480
2023	$756	$1,562	$14,918	$300	$2,867	$4,770	$45,550	$395	$3,772
2024	$801	$1,698	$17,190	$306	$3,101	$5,341	$54,062	$404	$4,087
NPV @ 9.7% to 1985	$1,725		$8,260		$3,585		$18,409		$4,443

DEPENDENT VARIABLE='83 $ O&M, (THIS IS CHERNICK'S EQ 5
WITH LINEAR DEPENDENT VARIABLE PLUS POST-TMI FOR ALL PLANTS)

Regression Output:

Constant	-109406
Std Err of Y Est	15290
R Squared	0.636
No. of Observations	535
Degrees of Freedom	529

	LN(UNIT)	YEAR	LN(MW/UNIT)	NE	POST-TMI (a)
X Coefficient(s)	27260.0	1058.4	6310.9	8164.0	18192.7
Std Err of Coef.	2063.83	245.13	1106.16	1454.04	2071.21
T-Statistic	13.21	4.32	5.71	5.61	8.78

	O&M, 1983$ (Millions)		O&M, 1983$ (Millions)
1986	52.18	2006	73.35
1987	53.24	2007	74.40
1988	54.29	2008	75.46
1989	55.35	2009	76.52
1990	56.41	2010	77.58
1991	57.47	2011	78.64
1992	58.53	2012	79.70
1993	59.59	2013	80.75
1994	60.64	2014	81.81
1995	61.70	2015	82.87
1996	62.76	2016	83.93
1997	63.82	2017	84.99
1998	64.88	2018	86.05
1999	65.94	2019	87.10
2000	66.99	2020	88.16
2001	68.05	2021	89.22
2002	69.11	2022	90.28
2003	70.17	2023	91.34
2004	71.23	2024	92.40
2005	72.29		

(a) POST-TMI equals 1, if year is 1980 or later; otherwise equals 0.

PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR LIMERICK 1 ($ million)

Year	PECO Projections	Using Eq. from Page 1 of this Exhibit.				Using Eq. #5 from Chernick Table 4.6.			
		Compund real growth		Linear real growth		Compund real growth		Linear real growt	
	nominal	1983$	nominal	1983$	nominal	1983$	nominal	1983$	nominal
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1986	$79	$52	$58	$52	$58	$73	$81	$73	$81
1987	$85	$53	$62	$53	$62	$81	$96	$81	$96
1988	$93	$54	$67	$54	$67	$91	$113	$90	$112
1989	$101	$55	$73	$55	$73	$102	$135	$99	$130
1990	$111	$56	$79	$56	$79	$114	$160	$108	$150
1991	$117	$57	$85	$57	$85	$128	$190	$116	$172
1992	$124	$59	$92	$59	$92	$143	$225	$125	$196
1993	$132	$60	$99	$60	$99	$161	$267	$134	$222
1994	$140	$61	$107	$61	$107	$180	$317	$142	$251
1995	$148	$62	$115	$62	$115	$201	$376	$151	$282
1996	$157	$63	$124	$63	$124	$225	$446	$160	$317
1997	$166	$64	$134	$64	$134	$252	$530	$169	$354
1998	$176	$65	$144	$65	$144	$283	$629	$177	$394
1999	$187	$66	$155	$66	$155	$316	$746	$186	$439
2000	$198	$67	$167	$67	$167	$354	$886	$195	$487
2001	$210	$68	$180	$68	$180	$397	$1,051	$203	$539
2002	$222	$69	$194	$69	$194	$444	$1,248	$212	$596
2003	$236	$70	$209	$70	$209	$497	$1,481	$221	$658
2004	$250	$71	$225	$71	$225	$557	$1,757	$230	$725
2005	$265	$72	$242	$72	$242	$623	$2,086	$238	$797
2006	$281	$73	$260	$73	$260	$698	$2,475	$247	$876
2007	$298	$74	$280	$74	$280	$782	$2,938	$256	$961
2008	$315	$75	$301	$75	$301	$875	$3,487	$264	$1,053
2009	$334	$77	$323	$77	$323	$980	$4,139	$273	$1,153
2010	$354	$78	$347	$78	$347	$1,097	$4,912	$282	$1,262
2011	$376	$79	$373	$79	$373	$1,229	$5,830	$291	$1,379
2012	$398	$80	$401	$80	$401	$1,376	$6,919	$299	$1,505
2013	$422	$81	$431	$81	$431	$1,540	$8,212	$308	$1,642
2014	$447	$82	$462	$82	$462	$1,725	$9,747	$317	$1,790
2015	$474	$83	$496	$83	$496	$1,931	$11,568	$325	$1,949
2016	$503	$84	$533	$84	$533	$2,162	$13,730	$334	$2,122
2017	$533	$85	$572	$85	$572	$2,421	$16,296	$343	$2,308
2018	$565	$86	$614	$86	$614	$2,711	$19,341	$352	$2,508
2019	$599	$87	$659	$87	$659	$3,035	$22,955	$360	$2,725
2020	$635	$88	$707	$88	$707	$3,398	$27,245	$369	$2,958
2021	$673	$89	$758	$89	$758	$3,805	$32,336	$378	$3,209
2022	$713	$90	$813	$90	$813	$4,261	$38,378	$386	$3,480
2023	$756	$91	$872	$91	$872	$4,770	$45,550	$395	$3,772
2024	$801	$92	$935	$92	$935	$5,341	$54,062	$404	$4,087
NPV @ 9.7 to 1985	$1,725		$1,495		$1,495		$18,409		$4,443

Exhibit WHH-41

HISTORIC AVERAGE AND KEA FORECAST
LIMERICK 1 CAPITAL ADDITIONS
(1984 $/KW)

Plant Age	Historic Average	Limerick Forecast	KEA Difference (Percent)
1**	30.12*	40.09	+ 33
2	13.87	41.77	+ 201
3	16.35	43.47	+ 166
4	13.64	45.15	+ 231
5	12.34	46.84	+ 280
6	16.57	48.53	+ 193
7	25.41	50.21	+ 96
8	26.79	51.89	+ 94
9	26.39	53.58	+ 103
10	39.50	55.27	+ 67
11	33.07	56.96	+ 72
12	50.34	58.64	+ 16

** First-year capital additions were sometimes substantial, especially for reactors declare to be in commercial operation in the fourth quarter of the preceding year, suggestin that these reactors were not quite complete. Some nonessential construction was als deferred to the first refueling outage which, for 12-month reactors, occurred in the firs full calendar year of operation.

Exhibit WHH - 42

KEA FORECAST OF CAPITAL ADDITIONS:
THE SURRY EXAMPLE

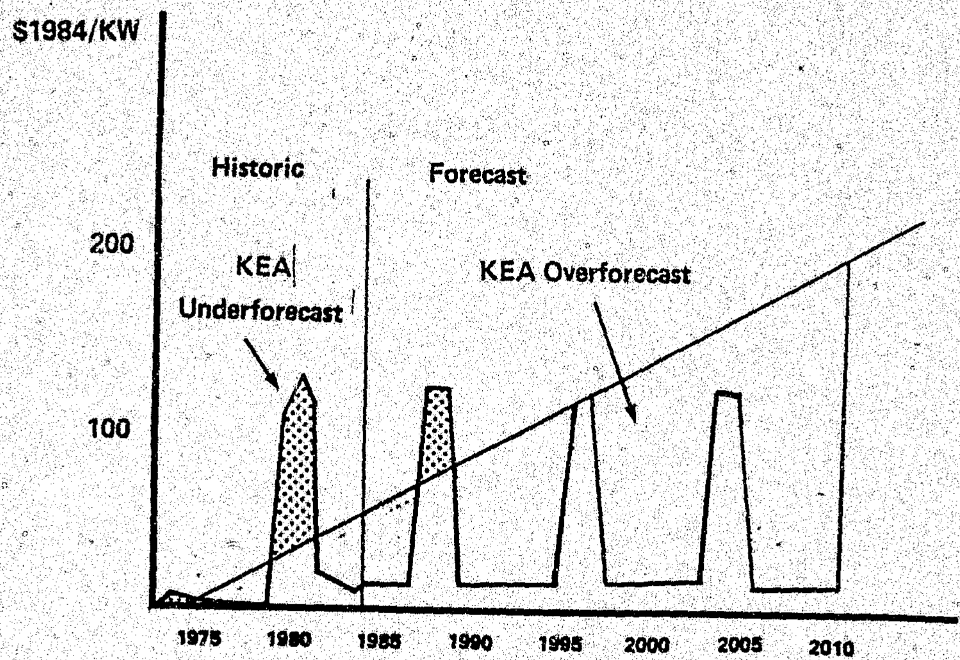


Exhibit WHH-43

TABLE BWR CAPACITY FACTOR PROJECTIONS FOR LIMERICK 1
CHERNICK PROJECTIONS WITH 95% CONFIDENCE INTERVALS

YEAR	Calendar Year of Experience	PECo Point Forecast	Chernick Point Forecast	Conf. Interval Upper	Conf. Interval Lower
			[1]	[2]	[3]
1986	1	65.0%	48.8%	79.6%	18.0%
1987	2	65.0%	40.8%	71.6%	10.0%
1988	3	65.0%	44.3%	75.1%	13.5%
1989	4	65.0%	59.3%	90.1%	28.5%
1990	5	65.0%	51.3%	82.1%	20.5%
	Mature Average	65.0%	56.8%	87.6%	26.0%

Notes: [1] From Chernick Table 4.4. Chernick averages his forecasts using Equations 2 and 4, and makes a -0.27% adjustment based on his interpretation of 1985 BWR performance. (See Chernick text, p.58-59, and Table 4.4,fn. [3].)
[2] Chernick point forecast + (1.96* std. error), with std. error = 0.157 (see text).
[3] Chernick point forecast - (1.96* std. error).

REPLICATE KEA CF MODEL, BWR'S ONLY, 1984 DATA

Regression Output:

Constant	56.77
Std Err of Y Est	15.52
R Squared	0.262
No. of Observations	237
Degrees of Freedom	229

	AGE	OLDER12	SMALL	SALT	BFFIRE	YEAR7475	POSTTMI
X Coefficient(s)	1.20	-28.59	6.15	-9.53	-41.30	-7.38	-9.57
Std Err of Coef.	0.44	5.47	2.45	2.58	9.18	3.57	2.85
T-Statistic	2.73	-5.23	2.51	-3.69	-4.50	-2.07	-3.36

LIM 1 CF

1	48.40		21	43.75	
2	49.60		22	44.95	
3	50.80		23	46.14	
4	51.99		24	47.34	
5	53.19		25	48.54	
6	54.39		26	49.73	
7	55.58		27	50.93	
8	56.78		28	52.13	
9	57.98		29	53.33	
10	59.17		30	54.52	
11	60.37	12 YEAR AVG	31	55.72	
12	61.57	54.99	32	56.92	
13	34.17		33	58.11	
14	35.37		34	59.31	
15	36.57		35	60.51	
16	37.77		36	61.70	
17	38.96		37	62.90	
18	40.16		38	64.10	39 YEAR AVERAGE
19	41.36	20 YEAR AVG	39	65.29	51.35
20	42.55	48.34			

KEA REGRESSION RUNS FOR CAPACITY FACTOR

KEA CF MODEL, BWR'S ONLY, 1985 DATA

Regression Output:

Constant	57.83
Std Err of Y Est	17.41
R Squared	0.16
No. of Observations	263
Degrees of Freedom	255

	AGE	OLDER12	SMALL	SALT	BFFIRE	YEAR7475	POSTTMI
X Coefficient(s)	0.76	-6.51	7.29	-8.46	-41.61	-7.88	-9.95
Std Err of Coef.	0.45	4.86	2.62	2.76	10.29	4.00	3.03
T-Statistic	1.69	-1.34	2.78	-3.06	-4.05	-1.97	-3.28

LIM 1 CF

1	48.65		21	57.36	
2	49.41		22	58.12	
3	50.17		23	58.88	
4	50.93		24	59.64	
5	51.69		25	60.41	
6	52.45		26	61.17	
7	53.22		27	61.93	
8	53.98		28	62.69	
9	54.74		29	63.45	
10	55.50		30	64.21	
11	56.26	12 YEAR AVG	31	64.97	
12	57.02	52.83	32	65.74	
13	51.27		33	66.50	
14	52.03		34	67.26	
15	52.79		35	68.02	
16	53.55		36	68.78	
17	54.31		37	69.54	
18	55.08		38	70.30	39 YEAR AVERAGE
19	55.84	20 YEAR AVG	39	71.07	58.60
20	56.60	53.27			

Exhibit WHH-46

AVERAGE MINE PRICE BY USBM DISTRICT
(1972 Dollars per Short Ton)1/ 2/

Year	District 1	District 2	District 3
1953	8.74	9.84	7.82
1958	7.50	8.98	7.50
1963	5.82	7.72	6.31
1968	5.48	7.38	5.84
1973	8.77	10.80	8.54
1974	16.37	19.56	14.09
1975	17.36	23.14	18.01
1976	19.14*	19.14*	22.76**
1977	18.28*	18.29*	22.16**
1978	17.17	20.91	17.85
1979	16.48	20.73	17.32
1980	15.88	19.31	16.16
1981	16.19	18.69	16.28
1982	15.27	17.47	16.63
1983	14.18	17.26	15.58
1984	13.86	16.24	14.09
% per year increase 1953-1984	1.5	1.6	1.9

1/ Source: DOE/EIA-0118. "Coal Production" (annual editions) U.S. Bureau of Mines, minerals yearbook, 1953-1925

District 1 comprises west-central Pennsylvania and very small portions of West Virginia and Maryland.

District 2 comprises far-western Pennsylvania.

District 3 comprises most of northern West Virginia.

2/ Deflated with GNP deflator. Source: Economic Report of the President, 1985, p.60.

* All Pennsylvania, district data not available.
** All of West Virginia, district data not available.

Exhibit WHH-47

COST OF COAL DELIVERED TO PENNSYLVANIA COAL PLANTS

Year	Average Delivered Cost $/MMBTU Nominal Dollars			Average Delivered Cost $/MMBTU 1982 Constant Dollars		
	Total	Contract	Spot	Total	Contract	Spot
1972	0.395	0.394	0.395	0.817	0.815	0.817
1973	0.441	0.445	0.433	0.867	0.871	0.847
1974	0.784	0.703	0.910	0.408	1.256	1.636
1975	0.955	0.933	1.005	1.571	1.534	1.653
1976	0.976	1.000	0.913	1.526	1.563	1.427
1977	1.009	1.041	0.925	1.490	1.538	1.366
1978	1.163	1.195	1.097	1.600	1.644	1.509
1979	1.201	1.275	1.171	1.520	1.614	1.482
1980	1.329	1.360	1.226	1.541	1.577	1.422
1981	1.556	1.576	1.514	1.650	1.671	1.605
1982	1.535	1.680	1.507	1.635	1.680	1.507
1983	1.531	1.588	1.268	1.469	1.524	1.217
1984	1.592	1.627	1.443	1.472	1.526	1.336
Cummulative Percent per year real increase 1972 to 1984				5.7%	5.3%	4.2%

Notes and Sources:

All coal data are from DOE/EIA-0191. "Cost and Quality of Fuels for Electric Utility Plants," annual.

GNP Deflator used to adjust to constant dollars.

Exhibit WHH-48

COST AND SULFUR CONTENT OF COAL
RECEIPTS BY PECO'S COAL PLANTS [1]
(Cost of Coal Receipts, Cents per Million Btu)

Year	Cromby		Eddystone	
	Non.	72$	Non.	72$
1972	48.3	48.3	53.4	53.4
1973	53.4	50.5	55.7	52.7
1974	125.5	109.1	103.1	89.6
1975	133.5	106.1	128.2	101.9
1976	121.3	91.7	124.1	93.8
1977	116.4	83.1	116.6	83.3
1978	135.5	90.1	131.5	87.4
1979	142.8	87.4	145.7	89.2
1980	163.0	91.4	163.3	91.5
1981	183.1	93.8	186.4	95.1
1982	184.9	89.4	194.1	93.8
1983	161.1	74.7	162.4	75.3
1984	172.2	77.1	180.1	80.6
Avg. Annual Real Increase 1972-1984	4.0%		3.5%	

1/ All coal data are from DOE/EIA-0191, "Cost and Quality of Fuels for Electric Utilit Plants." annual. The GNP Deflator was used to adjust to constant dollars.

Exhibit WHH-49

COST AND SULFUR CONTENT OF COAL
RECEIPTS BY CONEMAUGH AND KEYSTONE[1]
(Cost of Coal Receipts, Cents per Million Btu)

Year	Conemaugh		Keystone	
	Non.	72$	Non.	72$
1972	49.0	49.0	33.0	33.0
1973	55.7	52.7	39.9	37.7
1974	77.0	66.9	54.7	47.5
1975	106.1	84.3	71.0	56.4
1976	121.9	92.1	83.8	63.3
1977	131.7	94.0	96.0	68.5
1978	138.0	91.7	111.1	73.9
1979	144.6	88.5	111.3	68.1
1980	137.6	77.1	100.6	56.4
1981	152.6	78.2	109.2	56.0
1982	166.4	80.4	117.3	56.7
1983	128.3	59.5	114.9	53.3
1984	144.0	64.4	121.1	54.2
Avg. Annual Real Increase 1972-1984	2.3%		4.2%	

1/ All coal data are from PECO. All data from 1973-1983 are from DOE/EOA-D1 "Cost and Quality of Fuels for Electric Utility Plants." annual. The GNP Deflator w used to adjust to constant dollars.

Exhibit WHH-50

COAL MINING PRODUCTIVITY
(Avg. Tons Per Miner/Hour)

Year	District 1 All Mines	District 2 All Mines	District 3 All Mines
1953	.84*	.83*	1.27*
1958	1.61*	1.23*	1.60*
1963	1.65*	1.69*	1.93*
1965	1.82*	1.89*	2.17*
1973	1.69*	1.46*	2.05*
1974	1.80	1.51	1.87
1975	1.50	1.28	1.61
1976	1.49	1.16	1.57
1977	1.49	1.27	1.48
1978	1.51	1.16	1.41
1979	1.49	1.13	1.49
1980	1.61	1.18	1.63
1981	1.69	1.26	1.53
1982	1.63	1.36	1.73
1983	1.73	1.42	2.02
1984	1.81	1.61	2.30

* Data in average tons per day converted to tons per hour by deviding by eight hours.

Notes and Sources: DOE/EIA-0118. Coal Production (annual editions).
U.S. Bureau of Mines, Minerals Year Book 1953-1975.

Exhibit WHH-51

INDEX OF RAILROAD CHARGE-OUT PRICES
EASTERN DISTRICT
(1947-1948 AVERAGE = 100)

Year	Fuel (Coal & Oil)	Materials and Supplies (Except Fuel)	Wage Rates	Combined
1950	105.10	108.60	120.00	116.4
1951	110.10	122.00	133.80	129.2
1952	111.90	125.80	140.30	138.3
1953	116.20	129.30	143.80	138.3
1954	112.10	131.40	148.00	141.4
1955	111.30	134.30	149.70	143.1
1956	118.30	144.00	161.90	154.3
1957	125.70	151.40	173.90	165.1
1958	114.80	153.10	187.50	174.1
1959	117.20	155.90	194.90	180.2
1960	111.20	158.60	199.50	183.4
1961	113.24	158.87	204.13	186.84
1962	110.02	158.11	298.76	190.473
1963	109.31	157.64	210.99	191.857
1964	103.47	159.18	215.99	195.49
1965	106.92	161.33	227.49	204.659
1966	109.66	163.17	235.64	211.233
1967	114.91	169.46	248.99	222.651
1968	118.72	174.07	263.64	234.588
1969	121.82	178.83	281.81	249.12
1970	125.50	185.44	305.96	268.7112
1971	132.51	191.88	340.06	293.4228
1972	135.27	200.86	373.42	319.0250
1973	157.79	207.13	412.01	349.9702
1974	311.91	237.48	436.16	390.7110
1975	372.13	318.67	476.24	446.3678
1976	403.16	335.62	528.02	488.8897
1977	455.91	356.98	374.82	532.3020
1978	477.34	376.25	638.62	581.8061
1979	682.50	415.52	693.93	652.6022
1980	1019.88	469.07	777.73	761.7241
1981	1257.41	491.91	861.08	849.0217
1982	1183.10	493.34	940.98	894.2673
1983	1034.47	474.78	1016.28	920.8824
1984	1027.63	471.57	1043.87	937.3838

Source: Association of American Railroads Series OMPW and RCR.

Increase per annum in index, 1950-1984 = 5.3%

Increase per annum in GNP deflator, 1950-1984 = 4.3

Source: Association of American Railroads Series OMPW and RCR.

1985 ACHIEVED CAPACITY FACTORS
(EXCLUDING TVA UNITS)

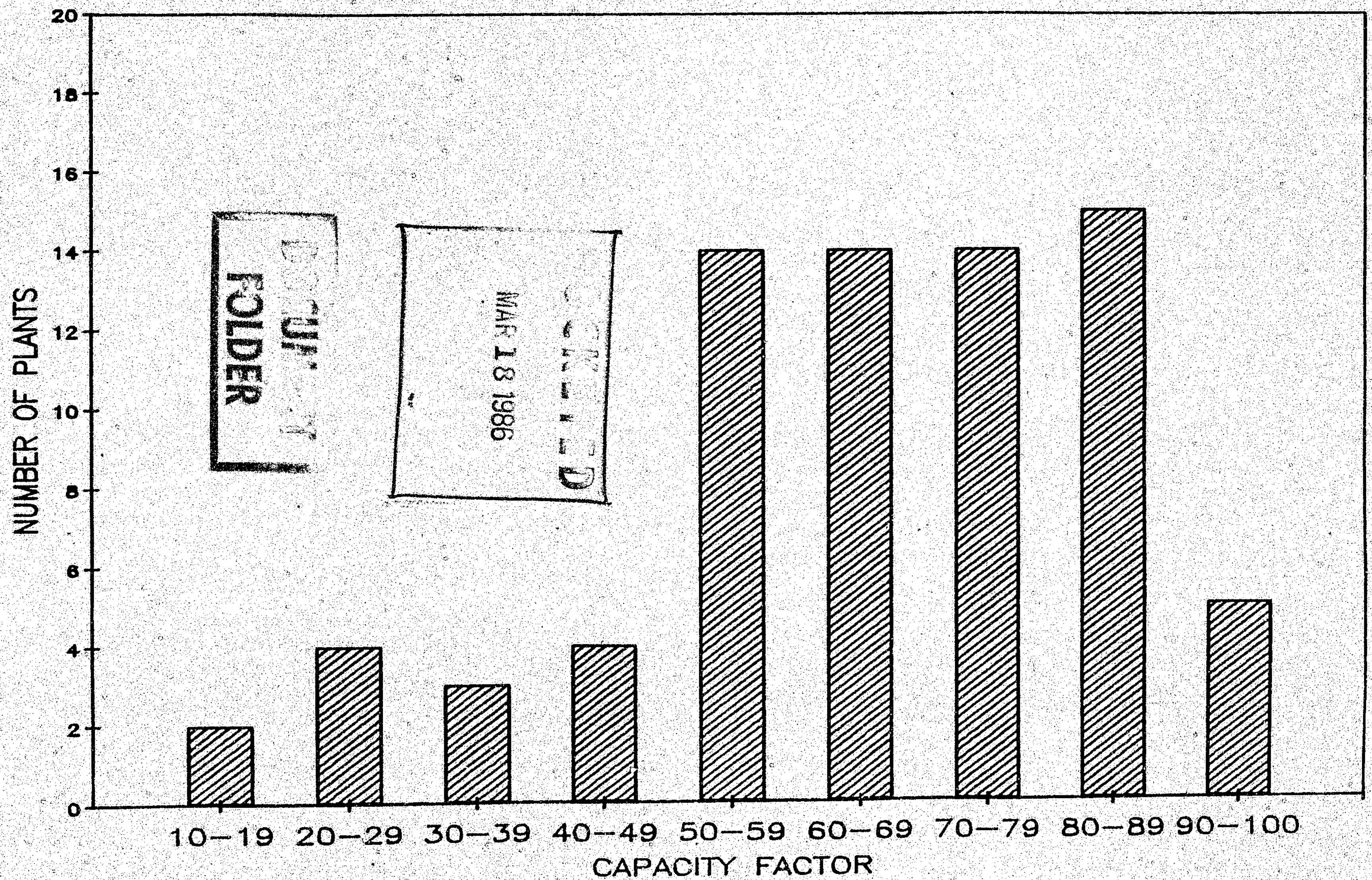


Exhibit WHH-52