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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Limerick Nuclear Generating Station

Investigation, Docket No. I-80100341

Rebuttal Testimony of
Richard A. Rosen
on Behalf of
The Pennsylvania Office of the Consumer Advocate

June 1, 1981

scenarios involving cancelling one or both of the Limerick units are charged substantially more for purchased power in the years before an alternative plant can be built, than it actually costs the PJM Pool to generate that power. From a social cost point of view, generation planning ideally should be done on the basis of the actual cost of the purchased power (including an allowance for fixed and capital costs).

Fifthly, as alluded to above, Mr. Lawrence did not analyze the economics of the Company initiating a major conservation investment program to determine whether such investments would in fact result in a much lower cost way of providing the power required by PECO's customers than would one or both Limerick units.

HISTORY OF PECO PLANNING FOR LIMERICK

Q. SINCE THE TIME THAT THE LIMERICK PLANT WAS ORIGINALLY PROPOSED BY THE COMPANY, WHAT HAS PECO DONE TO RE-EVALUATE THE NEED FOR THIS PLANT AS CONDITIONS HAVE CHANGED DURING THE 1970's?

A. In Mr. Boyer's Exhibit VSB-2, it is stated that in May, 1972 the Limerick power plant was estimated to cost $329 per kw, or about $694 million. One initial fact that I wish to point out is that between then and the Forecast #5 estimate of $4.12 billion in December 1980, PECO's own estimate of the capital cost increased by about 23% per year. By 1976 the Company knew that the cost of Limerick

would be much higher than the original estimate. Given the record of capital costs escalations for Limerick, prudent management would have initiated an intensive re-analysis on an annual basis of the decision to build at least one, if not both Limericks. While the Company seems to have done some limited analyses during this period, both the methodology of the analyses and the assumptions used were unreasonable in light of nuclear capital cost escalations, reduced load growth and the financial constraints faced by the Company. At a minimum, such an analysis should have involved doing the type of analysis that Mr. Lawrence and I have performed in our direct testimony in this proceeding, using a production costing and financial model to compare Limerick with alternative coal baseload alternatives. To my knowledge no such analysis was performed by the Company of this nature until Mr. Lawrence's testimony appeared in this proceeding.

An example of the limited analysis done is contained in Mr. Boyer's Exhibit VSB-3. Examining Exhibit VSB-3 we find that it was a presentation to the Governor's Energy Council on October 28, 1977. This presentation indicates that nuclear power was cheaper than coal-fired power for a plant placed in service in 1974. This was, in fact, generally true at that time.

On page 12 of this exhibit, however, we find Boyer's 1977 comparison of the costs of power from 2400 MW of new

coal plants versus new nuclear plants scheduled for a 1988 on-line date. The first thing to notice about this 1977 comparison is the low estimate assumed for the capital cost of the new nuclear plant of $1340 per kw in 1988 dollars. At this time Limerick was expected to cost about $900 per kw for an on-line date in the early 1980's. Thus even if the costs of nuclear plants were expected to stay constant in real dollars, at 7% inflation (about the average for 1970-77), the cost of a new nuclear plant in 1988 would have been about $1500 per kw. If PECO had studied the actual historic trend of nuclear plant capital costs in late 1977, they would have discovered, as I have found in Appendix C to my direct testimony, and as Dr. Perl has found, that the real costs of nuclear power plants had escalated by about 15% per year above the inflation rate during the period 1970-77. Articles such as those by Irvin Bupp of Harvard University had been published by this time, pointing out that the capital costs of nuclear plants had been increasing at a far greater rate than inflation, and at a greater rate than the capital costs of coal plants. In fact, including data through 1976, William Mooz of the Rand Corp. showed in a volume published in June, 1978 that the cost of nuclear power plants was increasing at $140 per kw per year in 1976 dollars, just for direct construction costs (without AFUDC). Mr. Mooz derived this result by doing basically what Dr. Perl and I have done in our direct

testimony.

The important point is that PECO could have performed this same analysis in the 1977-78 period and discovered approximately the same 15% annual rate of capital cost increases for nuclear plants in real dollars as both Dr. Perl and I have testified to here. Yet in 1977, PECO's planning did not seem to reflect an awareness that the cost of nuclear power plants generally was increasing at a much more rapid rate than the utilities' architect-engineers were then projecting. On page 14 of Exhibit VSB-3, Mr. Boyer states that "plant capital costs have increased dramatically (11% per year) since 1965 for both coal and nuclear facilities, but the costs on a relative basis have remained fairly constant." Mr. Boyer did not at the time (October, 1977) cite how he derived these figures. But as shown in detail below, the average escalation in real dollar costs even without AFUDC (which would tend to increase the escalation rate with inflation) was 15% for nuclear and 4% for coal during the 1970's. The 11% per year cited by Mr. Boyer would only be about 5% real during the period 1965-77, and would therefore have been close to correct for coal plants but about 10% per year too low for nuclear.

Q. WERE THERE ANY OTHER WAYS IN WHICH THE COMPANY'S 1977 ANALYSIS OF THE ECONOMICS OF COAL VERSUS NUCLEAR POWER CONFLICTED WITH THE DATA THAT EXISTED BY 1977?

A. Yes. By 1977 it became clear that the average capacity factors for large (800 MW and over) BWR power plants like Limerick had been less than 55%, and that there was no clear evidence to date of improvement with age. These results were cited by J.M. Fowler, et al., in a SIPI report published in the April, 1978 issue of Environment magazine entitled "Power Plant Performance." Yet, PECO persisted in assuming a 70% capacity factor for both Limerick and other new nuclear units, as they have continued to do in Mr. Boyer's direct testimony. However, even using Mr. Boyer's other unrealistic estimates, on p. 26 of his 1977 document (Exhibit VSB-3) Mr. Boyer shows that coal power would become cheaper than nuclear if the nuclear capacity factor fell below 56.5%. Thus if in 1977 Mr. Boyer had used accurate historical data, he would have had to conclude that new coal plants might be less expensive to build than new large BWR nuclear plants. Perhaps this finding would have led the Company to more seriously reconsider continuing with the Limerick facility which clearly seemed to be costing relatively more for that time period (1977) than the generic 1988 nuclear plant costs assumed by Mr. Boyer in his comparative analysis. Equally importantly, the Company's basic methodology in studying the economics of Limerick, as portrayed in VSB-3 and other planning documents in the mid and late 1970's, was severely flawed for the same reasons given below for criticizing Dr. Perl's

general methodology of comparing two different kinds of power plants without a dispatch model.

In conclusion, it appears that before proceeding in 1978 with what was rapidly becoming a multi-billion-dollar investment, i.e., the Limerick plant, the Company should have performed a considerably more careful study of the alternatives to Limerick. This was especially true once the 1978 delay to 1983-85 was announced for the Limerick on-line dates, and once it became clear in that year that demand was continuing to grow at a much lower rate than the Company was actually forecasting at the time.

Q. WOULD YOU PLEASE COMMENT ON THE APPROACH THAT THE COMPANY'S CONSULTANT DR. PERL TOOK IN EVALUATING THE ECONOMICS OF THE LIMERICK POWER PLANT.

A. I believe that Dr. Perl's methodological approach to evaluating the economics of the Limerick power plant, as opposed to the Company's in this case, is extremely flawed and is not a legitimate approach at all. First, in his Monte Carlo analysis (not his 1990 PJM optimization) Dr. Perl does not utilize a production costing/dispatch model in order to capture the generation system-wide costs and benefits of proceeding with a given construction program. Without running a dispatch model, as PECO and ESRG do for each year, he cannot calculate the complex trade-offs over time between, for example, purchased power and building a new plant. Because Dr. Perl does not utilize a dispatch

PECO Statement No. 1b
Docket No. I-80100341

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PHILADELPHIA ELECTRIC COMPANY

ELECTRIC OPERATIONS

Direct Testimony
of
Vincent S. Boyer

February 1981

TESTIMONY OF VINCENT S. BOYER

Q. Please state your name for the record.

A. Vincent S. Boyer.

Q. Mr. Boyer, you have previously testified in Statement 1a as to the initial planning decisions and construction activities at the Limerick Generating Station through the grant of the construction permit in 1974. What is the purpose of your present testimony in PECO Statement 1b?

A. This statement describes the organizational structure by which the Company's management supervises the Limerick project as well as certain aspects of Company decisions in the mid-1970's to defer completion of the plant. I will also describe the various analyses which we performed in the 1974 to 1980 period which indicated to us the desirability of continuing with the plant's construction during that period. Further, I will explain the reasons for selection of the alternatives to Limerick, nuclear and coal plant capacity factors, and nuclear fuel escalation rates employed by Mr. Lawrence in the economic analysis presented in his prepared statement. Finally, I will describe the current status of water supply projects associated with the Station.

Q. Please provide a brief overview of the Company's management structure for the Limerick Project.

A. Responsibility for planning, scheduling and cost control of the construction of new generating facilities is assigned by corporate management to the Engineering and Research Department. Thus, following the Limerick committment decision and the selection of General Electric and Bechtel, the E&R Department created an organization to manage future Limerick planning and construction activities.

The objective of our management process is to monitor the cost, schedule and quality of the design and construction of the plant. To that end, information concerning the project status is distributed on a wide basis. Department management holds weekly meetings with the Division heads to discuss significant activities. The individual divisions have biweekly meetings at which Limerick activities are reviewed. A Departmental report is prepared and sent monthly to the Chairman of the Board for his use in keeping the Board members abreast of Limerick activites. In addition, the Department Vice President reports significant events to top management at the weekly corporate authorization meeting and at the biweekly chairman's staff meeting.

A major project coordination meeting is held monthly, usually at the site but occasionally in San Francisco, and is attended by PE and Bechtel engineering, construction and project personnel. These meetings begin with a site tour and take up the entire day with a thorough review of all project activities, from Procurement and Quality Assurance to design, cost and construction status. Special meetings on specific subjects needing resolution may be held on the days preceding or following the project meeting.

Additional periodic meetings are held between General Electric, Bechtel and PE management groups to review the overall project status or discuss particular aspects of the work. These meetings include the appropriate Vice Presidents and project personnel and, while not held on a regular schedule, number about three a year.

The E&R Department is made up of six divisions, each having responsibility for specific activities related to the project. The overall coordination and administration of the project resides in the

Mechanical Engineering Division, and the designated Project Manager, Richard A. Mulford, is located here. This division follows the mechanical design aspects of the plant, reviews and interacts with the piping and instrument system diagrams and plant layouts prepared by Bechtel, reviews and approves equipment specifications and drawings, and reviews bidders lists and equipment purchase recommendations. The division also performs a similar monitoring function for General Electric, who is the vendor of the nuclear steam supply system. Following the start of construction, a PE Resident Project Manager was assigned to Bechtel in San Francisco, and his staff now numbers three people.

The Electrical Engineering Division follows the electrical aspects of the plant's design. Personnel in this division perform functions parallel to their counterparts in the Mechanical Engineering Division, working through an electrical project Engineer who coordinates his activities and reports through Mr. Mulford.

The Construction Division is responsible for monitoring the construction of the project and as such, works closely with Bechtel. A Project Manager--Construction, James Clarey, is assigned to directly supervise site activities. In addition, home office Construction Division personnel work closely with Mr. Clarey and the other divisions of the department in analyzing job costs and schedules.

The System Planning Division includes the Budget and Cost Section which issues periodic reports on costs, prepares and updates budgets, reviews capacity needs and makes economic evaluations pertaining to the generation of electricity by various methods.

The Design Division reviews drawings, maintains records and files and prepares itself to take over the many thousands of drawings and job related items at the completion of the job.

The sixth division, Research and Testing, performs special reviews as requested, monitors metallurgical activities, and tests and calibrates plant instrumentation.

The activities of the various divisions relating to Limerick are coordinated through the Project Manager or the Department Management as appropriate. All communications between Bechtel, General Electric and PE and channeled through the Project Manager who assigns, records and monitors the progress of the requests. To date, there have been about 30,000 letters from Bechtel to PE covering job related items and about 2500 from GE to PE.

In addition to its monthly meeting at which a presentation is made covering job status and cost expenditures compared to budget, the Board of Directors receives complete reviews of the cost of the project on two occasions each year. In May, a full presentation is made of major Company projects and their costs (including Limerick) for a five-year forecast period. In January, the project costs are up-dated and presented in written form to the Board. If significant project cost changes are recognized between budget periods, as, for example, when a Bechtel Annual Forecast is revised, the Board of Directors is informed at this time.

Bechtel, in addition to the voluminous reports prepared for the monthly project review meetings, also prepares a monthly summary report highlighting job progress and costs which is distributed throughout the Bechtel and PE organizations at the management level.

Q. During Limerick's construction, did the Company continue to examine the plant's economics and necessity as compared to alternative capacity additions?

A. Yes, the Company has continuously conducted such analyses. At least one review of the comparative economics of nuclear and fossil generation was made in each of the years 1974, 1975, 1976 and 1977. Both oil and coal-fired generation were compared to nuclear. The analyses were both prospective (i.e. comparing Limerick or generic nuclear to a hypothetical coal plant for installation in the same time period) and retrospective (i.e. comparing experienced Peach Bottom costs with costs from a hypothetical coal unit installed in place of the Peach Bottom units). Each of these studies indicated nuclear capacity was more economic than fossil for both present and future service periods. An example of such an analysis is provided in Exhibit VSB-3.

The results of our own analyses, I should note, were consistently confirmed by independent industry studies available at that time. One recent report (1979) published by the National Academy of Sciences entitled Energy in Transition 1985 - 2010 is representative of these studies. In this report, the National Research Council's Committee on Nuclear and Alternative Energy Systems stated:

> National policy should support the continued use of nuclear power for the next few decades. The rationale for such support rests on the availability of nuclear power as a domestic energy resource whose risks are at worst comparable to those of other energy sources, its competitive economics, and the undesirability of relying too heavily on coal or nuclear power, to the exclusion of the other, until the risks of each are better understood.

Q. Mr. Boyer, have you any comment as respects the Company's several decisions to defer completion of Limerick?

A. Yes, I do. Decisions prior to 1974 to postpone Limerick's service dates were necessary to parallel delays in obtaining the construction permit, which was not granted until 1974. Decisions to defer plant completion made in 1974 and 1976 were reached for a number of reasons as explained by Mr. Paquette.

From a construction manager's point of view, the principal effect of those decisions was a failure to provide the cash requested for the plant's construction. Obviously, the pace of construction slows as the level of funds available for the purchase of labor and materials is reduced. As construction managers, the role of the E&R Department was to develop construction schedules and programs which would implement management's funding and completion date directives. In performing this function, consistent with management's objectives, we sought: 1) to minimize funding requirements in the early years of construction as required by financial constraints and 2) to retain the option of accelerated completion of the project as compared to announced completion dates in the event additional funding became available and such completion were to appear desirable. Of course, we also sought to construct the plant as efficiently and promptly as possible with the funding which management was able to provide.

Q. Mr. Boyer, how many dollars had the Company invested in Limerick at the time of its 1974 and 1976 decisions to defer the plant's completion?

A. In 1974, we had expended $223 million and in 1976 $417 million, excluding AFUDC. A measure of the cost of deferring plant completion is the additional carrying charges which will be experienced on this existing

investment as the result of the deferral. Employing the AFUDC rate in effect in early 1976 as representative of the carrying cost rate, the addition to the plant's completion cost is but $36.6 million as a result of the 1974 decision and $68.4 million as a result of the 1976 decision.

Q. Mr. Boyer, have you any comment as to the 1978 and 1980 schedule alterations?

A. With regard to the 1978 announced schedule alteration, I would like to emphasize that that particular alteration was never actually implemented in the form of a funding reduction. In each of the years 1978 to 1980, Company management authorized and spent the money which our analyses indicated was required to complete the plant upon a 1983/1985 schedule. Accordingly, the construction schedule in effect throughout this period to which we and Bechtel were working provided for plant completion in 1983 and 1985.

This schedule was viewed as achievable during the early years of this period. However, a number of factors combined such that in early 1980 we realized that this schedule could not be achieved. It became clear at that time that manpower availability and labor productivity in the installation of bulk commodities such as conduit and pipe were not meeting the target values. The manhours to install the seismic design of pipe hangers and restraints proved greater than estimated, and interferences introduced by these hangers to duct work and cable trays also required additional manhours to resolve. Finally, as the NRC action items resulting from Three Mile Island were issued, significant additional manhours of job effort were added such that a lengthened project schedule became necessary.

Accordingly, in July 1980 the project schedule was updated and evaluated, and Bechtel estimated that the previous field commercial operation dates could no longer be met and that the earliest dates the field construction schedule could support would be commercial operation in April 1984 for Unit #1 and April 1987 for Unit #2. This represented a one-year slip in Unit #1 and a two-year slip in Unit #2. The estimate for total cost of the project based on these service dates was calculated to be $3.4 billion.

In view of the cost increase and revision in field construction schedule, a meeting was held in Philadelphia with Bechtel Power Corporation at which the background and basis for the revisions were presented and discussed. This meeting was held on July 15, 1980, and in attendance were the Vice Presidents of the Bechtel Power Group, Project Management, and Construction as well as their staff representatives. Philadelphia Electric Company was represented by the Sr. Vice President, Nuclear Power, the Vice President of Engineering & Research, the Project Manager, and appropriate Construction and Engineering personnel. A presentation and summary was presented to our President, Mr. Everett, in the afternoon. During the meeting, it was brought out that much of the additional effort resulting from Three Mile Island required the work of electricians. Most of the changes were associated with instrumentation and the running of cables to new locations such as the new technical support center and emergency operations facility which fell into the electricians' work area. The expected resolution of some of the major outstanding generic items such as the review of the Mark II containment design loadings and the anticipated transients without scram considerations were also coming into clearer focus with resulting ability to estimate manpower needs to accommodate the design requirements.

In September 1980, the trended cost report further analyzed the additional work effort. It was estimated that 100,000 feet of additional conduit would be required which, when added to the base of 260,000 feet for Unit No. 1 and Common, made the scheduled date for No. 1 Unit unattainable. Commercial operation dates of April 1985 and April 1987 thus were predicted with an associated plant cost of $3.7 billion.

In October 1980, Forecast 5 was developed and presented to PE by Bechtel. This forecast considered the latest cash flow projections and incorporated updated quantities and commodity installation rates. In this Forecast it was necessary to extend the commercial operation date of the second unit to October 1987, with the resulting estimated cost of the plant increased to $4.12 billion. Following the issuance of this Forecast, a complete review of the Limerick costs and schedules was presented by Bechtel and the E&R Department to the Company President and Executive Vice President on December 19, 1980. The meeting was attended by the appropriate PECO Vice Presidents and Project Managers as well as the Bechtel Project Manager and scheduling personnel. Reasons for the schedule extension and projected plant cost increase were the subject of detailed inquiry and a number of questions were answered.

To emphasize the Company's concern over the schedule extensions and cost increases, in January 1981, the Board of Directors visited Bechtel in San Francisco and General Electric in San Jose. A full day's program was presented to the Board by the responsible personnel of Bechtel, Philadelphia Electric and General Electric. Corporate management of both Bechtel and General Electric participated in the meetings. In addition to a review of the project, the Board received a thorough discussion of the work schedules and costs for the effort remaining to place the plant in

commercial operation. Emphasis was placed upon the Company's concern that completion of the project be expedited and that costs be held to the minimum possible level.

Q. Have other companies in the industry similarly deferred completion of planned nuclear facilities already under construction?

A. Yes. Table A attached, which has been compiled from the Nuclear Regulatory Commission's Construction Status Report (December 1980), demonstrates that decisions deferring completion of nuclear projects already under construction for financial and/or load growth reasons are the norm rather than the exception. Such deferrals have occurred in the case of 21 out of 34 projects which have reported reasons for delays. Almost half of these projects were delayed by three years or more for these reasons.

Q. Mr. Boyer, what would Limerick have cost if PECO had constructed the plant to an optimum construction schedule for completion upon the presently scheduled dates in 1985 and 1987?

A. I have requested that Mr. Kob conduct such an analysis which is described in PECO Statement 14. As he explains in that statement, a generating station built on an optimum schedule for completion in 1985 and 1987 would have cost $3.98 billion, or approximately $140 million less than the $4.12 billion cost estimate based on Forecast 5. This analysis indicates that the actual cost of Limerick now forecasted is comparable to a project of the identical scope and complexity built upon an optimum construction schedule developed with the objective of reducing total project cost. This occurs because the lower AFUDC costs under the optimum schedule are offset by the lower materials and labor cost in the Limerick cost forecast, especially for major equipment such as the nuclear fuel supply

system obtained at the lower prices of the early 1970's. In reaching its decisions to defer completion of the Limerick plant, PECO management was cognizant of this fact.

Q. Mr. Boyer, do you believe that the current Forecast 5 cost of $4.12 billion and schedule of 1985/1987 is achievable?

A. Yes, I do. Based upon my background in the construction of nuclear facilities combined with the analyses of Bechtel and Philadelphia Electric staff and of Forecast 5, I am confident that the schedule and cost estimates of Forecast 5 are achievable.

Q. In view of the increase in the projected completion cost of the Limerick Station, is it still your opinion that completion of the Station is the economic choice for the Company and its customers?

A. Yes, it is. To keep the cost of electricity to the consumer at a minimum, Limerick Nuclear Plant should be put in service as scheduled in 1985/1987.

Q. How did you arrive at that conclusion?

A. My conclusion is based both upon the economic analyses prepared by Mr. Lawrence, which I have reviewed, and other analyses which I have periodically had prepared.

Q. What alternatives to completion of the Limerick plant have you considered in your analyses?

A. These alternatives, which have also been employed by Mr. Lawrence at my direction, are as follows:

Scenario 1: Complete Limerick Nuclear Plant as planned.

Scenario 2: Convert Limerick to a coal-fired plant of equivalent capacity.

Scenario 3: Cancel Limerick and install equivalent coal-fired capacity at Chester and Hendricks Island as soon as possible.

Scenario 4: Cancel Limerick and do not construct a new plant until 1994.

Q. What are the significant features of Scenario 1?

A. Scenario 1 involves the completion of Limerick as planned with two 1055 mw units; the first having a service date of 4/85, and Unit No. 2 a date of 10/87. As is obvious, this is the Company's present capacity planning program. Based on the recently completed review of the progress of construction by Bechtel Power Corporation in October 1980, the direct cost for completion of construction on these dates is $2.5 billion. With allowance for funds used during construction (AFUDC) added, the total cost is estimated to be $4.12 billion.

Q. What are the features of Scenario 2?

A. Scenario 2 assumes the conversion of Limerick to a coal-fired plant with two 1130 mw units, the first having a service date of 1989 and the second in 1990. These service dates were determined from the construction schedule developed by Gilbert Associates and an assumed January 1, 1982 project start date. On the basis of these assumptions, which I view as unrealistically optimistic but have employed in order to be conservative, the 1989 and 1990 service dates are the earliest possible. Gilbert's cost estimate for the coal conversion has been adjusted to reflect the approximate one year's delay and resulting greater escalation experienced prior to the start of construction (i.e. in 1985) as well as various PECO overhead costs not fully reflected by Gilbert. The resulting direct costs of converting the station to coal are $2.9 billion. Adding the AFUDC, additional investment required to complete facilities which are assumed to be available by Gilbert but are outside the scope of their cost estimate and that portion (one-half) of the sunk investment costs of Limerick through December 31, 1981 which are required for use with the converted plant the total cost of the converted plant, is estimated to be $5.5 billion.

Q. Please explain Scenario 3.

A. Scenario 3 assumes that all construction on Limerick Station would be terminated as of the end of 1981 and that the plant would not be completed. Thereafter, an equivalent amount of coal-fired capacity is installed as soon as possible. This capacity consists of two 615 mw units at Chester and two 450 mw units at Hendricks Island. The cost of these plants are determined from a study prepared by Gilbert Associates. Optimistic service dates (unrealistic, I believe) for the two Chester 615 mw units based upon the Gilbert Study are 1989 and 1990. Their direct costs would total $1.73 billion and with AFUDC would be $2.2 billion. The Gilbert costs have been adjusted to reflect a January 1, 1982 project start date rather than the 1981 date employed by Gilbert and for certain PECO overhead costs omitted by Gilbert.

Service dates for the two 450 mw units at Hendrick Island were assumed to be 1991 and 1992. These service dates are the earliest possible in light of the earlier Chester units. Their direct costs were estimated to be $1.67 billion and with AFUDC would be $2.1 billion.

Q. What are the significant features of Scenario 4?

A. Scenario 4 assumes that all construction on Limerick Station would be terminated as of the end of 1981 and that the plant would not be completed. Thereafter, no new capacity would be added to the PECO system until 1994. Between 1982 and 1994, it is assumed that existing PECO units now scheduled for retirement could be kept in service at no additional capital cost. No capital costs, other than payments to PJM for contractual capacity deficiencies, are incurred in this plan, but high operating and maintenance costs would be incurred. The treatment of such investment costs of the Limerick nuclear plant which the Company believes is appropriate is developed by Mr. Lawrence.

Q. Why did you select the three alternatives you have just described as the proper basis for an economic comparison with Limerick?

A. Scenario 4, i.e. cancel Limerick without replacement until 1994, was chosen as a control case to demonstrate what would happen if we attempted to reduce capital expenditures to the bare minimum for as long as possible. The year 1994 has been chosen as the ending point in each analysis because beginning with this year, regardless of load growth, additional new capacity, either as a replacement for or in addition to Limerick, must be installed. Scenario 2, convert Limerick to a coal plant of equivalent capacity, was selected because it would make maximum use of the existing investment, would facilitate obtaining regulatory approvals associated with new capacity and would permit use of the proposed economic transmission outlets planned for Limerick.

Option 3, cancel Limerick and install equivalent coal-fired capacity at Chester and Hendrick Island, was chosen to obtain a comparison of Limerick with generation at the other most likely sites in our territory. Coal-fired generation was chosen because coal is the current economic fossil fuel alternative.

Q. For Scenario 2, you indicated that 50% of the nuclear sunk costs represent facilities whose use is required by the converted coal plant. How did you reach that conclusion?

A. We looked at the plant components whose cost is included in the 1981 year-end sunk cost total. This included a review of costs for such major plant items as the reactor and rad-waste facilities, the structures and site facilities, the turbine plant equipment, electric plant equipment and miscellaneous equipment. Based on this review, it was determined that plant items, including the reactor and rad-waste facilities, having a sunk cost of approximately 50% of the total plant sunk investment could not be used.

Q. Do you have any additional comment as to the capital cost of the Limerick alternatives which you have just described?

A. It should be emphasized that the capital costs of the capacity addition alternatives to the Limerick Nuclear Plant would be subject to substantial uncertainties not imposed by Limerick. Construction of Limerick Unit 1 and the common plant, which together comprise 60% of total projected direct construction expenditures, will be essentially complete by late 1983. The remaining period prior to the unit's commercial operation in April 1985 will be spent principally in testing plant systems. Thus, exposure to the uncertainties of cost escalation or, at least to a degree, additional regulatory requirements is far less for Limerick Nuclear than it is for Limerick converted to coal or for the alternative site coal plants. Construction at these facilities would not begin until 1985 and, of course, they cannot be completed until much later.

Q. What escalation rate is used in determining the cost of nuclear fuel in the Company's analyses?

A. For the ten-year period 1985-1994 an effective escalation rate of 9% per year was employed.

Q. How was this determined?

A. It is a rather complex process requiring the use of computer programs. One program is used to analyze the depletion behaviour of the Limerick reactors through the desired period.. The process provides a rapid evaluation of potential loading patterns, control rod patterns, fuel shuffling schemes, etc. to calculate the end-of-cycle exposure distribution, cycle length and number of fuel assemblies in each fuel loading cycle.

Such data is then used as input into another computer program along with unit cost data for uranium ore, conversion, enrichment and fabrication. This program then computes nuclear fuel costs for the given reactor on a yearly basis. Results for nuclear fuel cost escalation calculated from this data will vary in percent yearly. The figure of 9% per year given above was determined by taking the fuel costs in cents per million btu for 1985 and calculating the compound rate which would effectively produce the fuel cost calculated by the program for 1994.

Q. What capacity factor do you expect to experience at the Limerick nuclear plant?

A. 70%.

Q. What has the industry experience been?

A. The cumulative capacity factor for all U. S. reactors larger than 600 mw in service for five years or more was 60%, for both BWR's and PWR's. The actual capacity factors for the year 1979 were 60% for all reactors, which breaks down to 65% for BWR's and 58% for PWR's.

Q. What has been the trend in nuclear capacity factor?

A. According to industry data, continuous upward trend in capacity factor as the age of the units increases has been established for units which began commercial operation after 1967, for both BWR's and PWR's.

Q. What has been the PE experience at Peach Bottom?

A. The lifetime capacity factor for Peach Bottom #2 has been 63.4% (7-1/2 yrs), with a low of 43.7% in 1977 and a high of 93.1% in 1979. The lifetime capacity factor for Peach Bottom #3 has been 66.9% (7 years), with a low of 52.7% in 1977 and a high of 79.6% in 1979.

Q. Why does PE expect the Limerick capacity factor to be 70%?

A. Retrofitting at Peach Bottom resulted in outages which should not occur at Limerick. If the most significant of these outages are subtracted from the total outages, the resulting lifetime capacity factors at Peach Bottom would have been 73% for Peach Bottom #2 and 72% for Peach Bottom #3.

We expect that Limerick, with the same type of reactor as Peach Bottom but with the modifications made at Peach Bottom already in place, will achieve a cumulative capacity factor of at least 70%. Based on experience gained during the construction of Peach Bottom, the application of a more sophisticated degree of quality assurance than existed through much of the construction of Peach Bottom, the increase in the refueling cycle from 12 months as employed during the early years at Peach Bottom to 18 months as now employed and as will be employed at Limerick, and the application of a rising level of technology to the design and specifications for Limerick, we believe a 70% average capacity factor will be achieved during the initial 10 years of Limerick operation.

Q. What capacity factors did you assume for new coal-fired units?

A. Capacity factors were not assumed for the new coal-fired units. Unlike the minimum operating cost nuclear units the capacity factors for coal-fired units are a result of the economics of operation and assumed availability factors.

Q. What availability factor did you assume for new coal-fired units?

A. The outage parameters assumed for new coal-fired units are equivalent to an availability factor of 70%.

Q. What availability factor did you assume for new coal-fired units?

A. We used a 70% availability factor, which we feel is conservative.

Q. What availability factor did you assume for the Limerick coal-converted units?

A. The same 70% availability factor was used for the 1100 mw Limerick coal-converted units as for the smaller units. The limited experience of large coal-fired units in the 1100 mw range would indicate a lower availability factor. Lower availability factors would have been examined if the Limerick coal-conversion was economically competitive.

Q. With the 70% equivalent availability factors, what were the resultant capacity factors?

A. The capacity factors of the new coal-fired units and the Limerick coal-converted units were approximately 62%.

Q. Mr. Boyer, what will be the sources of the water needed to supply the Limerick Generating Station?

A. The sources of water supply for Limerick will be the Schuylkill River and the Perkiomen Creek as augmented by water from the Delaware River.

Q. What regulatory approvals have been obtained or are necessary before these water sources can be utilized?

A. Responsibility for water supply and water quality matters concerning the Delaware River and its tributaries is vested in the Delaware River Basin Commission (DRBC), a regional agency created by intergovernmental compact. Under the terms of the Compact, the DRBC has jurisdiction over both the requirement for and development of water storage facilities to augment the water supply in the Basin during periods in which the natural flow of fresh water is reduced, and the allocation of water to approved projects within the Basin. DRBC regulates the supply and use of water in the Basin through a Comprehensive Plan which it has developed.

That plan establishes water supply and water quality standards based upon the DRBC's forecasts of the future supply of and demand for Basin water. On the supply side, the DRBC looks at the anticipated natural flow

of water in the Basin as augmented by existing and proposed storage facilities. The projected demand stems from those customers who have received a DRBC authorization to draw water or who have been guaranteed a specified minimum amount of water.

On November 7, 1975, the DRBC in taking final action, included the Limerick project in its Comprehensive Plan for the Basin; approved the use of waters from the Schuylkill River and a water intake structure; approved the use of waters from the Perkiomen Creek, a water intake structure, and a pipeline to Limerick; and approved the use of waters from the Delaware River. The Pennsylvania Department of Environmental Resources issued permits for the construction of the Schuylkill and Perkiomen intake structures on July 16, 1976.

On February 18, 1981, the DRBC approved the Point Pleasant intake structure on the Delaware River and a combined transmission main to Bradshaw Reservoir. These facilities will be constructed, operated and owned by the Neshaminy Water Resources Authority, an agency of Bucks County. On the same date, the DRBC also approved Bradshaw Reservoir and the pipeline from the Bradshaw Reservoir to the East Branch of the Perkiomen Creek. This pipeline will be used to transport water to the creek where it will flow to the Limerick intake structure.

Routine applications for minor encroachments and/or stream crossings associated with constructing the water pipelines, together with an application for a permit authorizing the Bradshaw Reservoir have been prepared and filed with the Pennsylvania Department of Environmental Resources.

PECO is not required to obtain any further permits or approvals from the U.S. Corps of Engineers with respect to the water supply system discussed above.

Q. Will the approved water sources provide sufficient water for year round operation of Limerick?

A. In answering that question, I first want to state that prior to the in-service date for Limerick #1, the Company expects to have available a reservoir storage facility to supplement the flows of the Delaware River during low flow periods. The DRBC has authorized the Company to use water from the Delaware River with the limitation that such use will not reduce the flow as measured at the Trenton gauge below 3,000 cfs. The Company projects that without augmentation by an upstream reservoir, there would be insufficient water to operate Limerick on an average of 41 days a year by the year 1990. To assure the water supply needed for consumptive use by Limerick during periods of low flow, the Company, in cooperation with Public Service Electric and Gas Company and five other electric companies will build a reservoir at Merrill Creek, Warren County, New Jersey. I should emphasize that construction of this reservoir is essential to virtually all new generation projects of the Company and other utilities in the Delaware River Basin. Of the 7 new projects planned, all rely upon construction of this reservoir to assure an uninterrupted water supply, as do certain plants already in service.

An application for DRBC approval of the Merrill Creek Reservoir was filed in December 1977. A preliminary Environmental Impact Statement was issued by the DRBC in February 1979. PECO anticipates that the necessary regulatory approvals, construction and filling of Merrill Creek Reservoir will be accomplished in sufficient time that commercial operation of Limerick will not be interrupted due to water limitations even with the drought conditions of the worst year on record.

Q. Does this conclude your Statement 1b?

A. Yes, it does.

TABLE A

NRC Construction Status Report ("Yellowbook")
December 1980
Tabulation of Delays in Nuclear Construction Programs*
For Financial and/or Load Growth Reasons

Period of Delay	Number of Projects
Less Than 1 Year	3
1-3 Years	9
3 Years or More	9
Total	21

* After receipt of construction permit

April 8, 1981

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Philadelphia

IR-2

1-1
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IR-6
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Q.30

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Q.8-12. Was any or all of this data gathered and reviewed in 5/75, 5/76 or 5/78 when the plant's construction schedule was delayed due to reduced load forecasts and financial constraints and $223, $284, and $417 million respectively, in direct costs had been expended. If not, explain why not considered.

A.8-12. See response IR-2, 8-10.

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Q.8-10. Provide actual data available in 1968 as to operating and capital costs of nuclear plants (for experimental, turnkey, other under 800 mw and other over 800 mw, stated separately), e.g.,

(a) megawatt years operating experience
(b) number of plants
(c) actual capital cost per kW
(d) actual escalation rates of capital costs
(e) actual life capacity factors

A.8-10. The requested data will be discussed in the Direct Testimony of Company witness Vincent S. Boyer. The data utilized by the Company in the decision to construct a nuclear station was discussed in response IR-2, 1-1, and as stated in that response these documents are available for inspection, upon request, at the Company's main office.

Q.1-1. Provide a copy of any or other document relied upon by PECo management in their initial decision to construct Limerick, including the assumed energy and demand growth rate.

A.1-1. The decision to build the Limerick plant may be categorized under the following three headings: (1) determination of the need for capacity; (2) selection of the type of plant; (3) choice of the site. Each category is discussed briefly below:

1. The Need for Capacity

Philadelphia Electric Company annually makes a forecast of generating capacity requirements. That process involves estimating future annual usage, peak demands and the reserve capacity needed to reliably supply such needs. Each annual forecast compares, for each year in the forecast (5 to 15 years), (i) the total generating capacity required (demand plus reserve); and (ii) installed generating capacity (reflecting the occurrence of retirements and additions). Where installed capacity falls below the capacity required, plans are developed to eliminate the gap by acquiring sufficient additional generating capacity and decisions are based on the magnitude and duration of the deficiency. Conversely, if installed capacity exceeds demand and reserve requirements, adjustments are made in so far as practical in future additions and retirements to bring installed capacity and generation requirements into line.

The decision to build the two units, eventually located at Limerick, was made in 1968, with estimated service dates of 1975 and 1977 for units 1 and 2, respectively. The relevant capacity forecasts were compiled in the mid-1960's showing that, even with Peach Bottom 2 and 3 and Salem 1 and 2 being placed in service between 1971 and 1974, reserve capacity would fall to unacceptably low levels in the later years of the forecasts. The addition of Limerick brought installed capacity for those years back into an acceptable range.

The annual capacity forecasts from 1968 to the present are available for inspection upon request at the Company headquarters. A summary of the 1968 capacity forecast is attached as Attachment IR-2, 1-1(a).

An integral part of the capacity requirements forecasts is Philadelphia Electric Company's load growth forecasts. For many years prior to the decision to build Limerick, and for several years thereafter, the Company experienced consistent, long term load growth of approximately 6% per year. The process of forecasting load growth involves considering data beyond historical trends and includes projections of the U.S. Gross National Product, local demographic statistics, anticipated economic conditions, studies of national and local demand characteristics, other electric growth rate forecasts and other information. In the late 1960's and early 1970's there was strong regulatory pressure upon the Company to plan for a higher growth rate than the Company's own forecasts indicated was appropriate.

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ESTIMATED MAY 1968: PLANNED - LIMERICK UNITS, COMBUSTION TURBINES, RETIREMENTS

PHILADELPHIA ELECTRIC COMPANY LOAD AND CAPACITY 1968-1977

	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977
PE Peak System Load - Mw	4150	4420	4720	5040	5360	5680	6010	6340	6670	7010
PE Installed Capacity - Mw										
Available for 1968 peak *	4939	4989	4989	4989	4989	4989	4989	4989	4989	4989
Retirements		-90	-90	-504	-504	-504	-504	-504	-504	-504
Combustion Turbines (CT's)		160	160	420	420	420	420	420	420	420
Conemaugh Nos. 1 and 2			186	373	373	373	373	373	373	373
Peach Bottom No. 2				452	452	452	452	452	452	452
Salem No. 1					416	416	416	416	416	416
Peach Bottom No. 3						453	453	453	453	453
Salem No. 2							474	474	474	474
Limerick No. 1 **								895	895	895
Limerick No. 2 **										895
Total	4939	5059	5245	5730	6146	6599	7073	7968	7968	8863
PE Reserve Capacity										
Actual - Mw	839	639	525	690	786	919	1063	1628	1298	1853
Actual - %	20.2	14.5	11.1	13.7	14.7	16.2	17.7	25.7	19.5	26.4
Design Standard - Mw	623	663	755	932	965	1051	1082	1046	1067	1157
Design Standard - %	15.0	15.0	16.0	18.5	18.0	18.5	18.0	16.5	16.0	16.5
Surplus (Deficit)	216	(24)	(230)	(242)	(179)	(132)	(19)	582	231	696
Without Limerick Units										
Actual - Mw								733	403	63
Design Standard - Mw								1046	1067	1157
Surplus (Deficit)								(313)	(664)	(1094)

* Actual at time of peak was 4800 mw; Keystone No. 1 (189 mw) was delayed until after summer peak.
** Initially 160 mw of each unit was to be sold to ACE and DPL

2. Selection of the Type of Plant

In the mid-1960's, nuclear power became a viable alternative to fossil fuel for the generation of electricity. In 1965, after extensive study, PECo decided to participate with other companies in the construction of 2 large nuclear generating stations, one to be located on the PE system at Peach Bottom and the other on the PS system which ultimately became the Salem plant. In a joint study by Public Service Electric and Gas Company and Philadelphia Electric Company, which was the basis of that decision, a comparison was made between the economics of fossil fuel and nuclear powered generating plants to meet generation needs in 1971-1975. A copy of this study, which describes the types of plants studied, capital costs, operating economics evaluations and other relevant matters, is available for inspection upon request at the Company's headquarters.

In reaching its decision that the Limerick units should be nuclear fueled, PECo relied upon the earlier joint study, which it reanalyzed and updated to the extent required to take into account changed circumstances or additional data. Included in this additional analysis was consideration of optimal plant size, cost proposals from reactor manufacturers and other relevant matters. When PECo determined to employ BWRs manufactured by General Electric Company in the Peach Bottom project, it also obtained an option from General Electric on two additional BWRs. Based on its further analysis at the time of the Limerick decision, it was determined that the G.E. options should be exercised. The analyses which supported that decision are available for inspection upon request at the Company headquarters.

3. Choice of the Limerick Site

Extensive studies were undertaken by Philadelphia Electric Company and its consultants to determine the most appropriate site for the nuclear plant which eventually was built at Limerick, PA. After investigating various sites, the studies focused on five sites: "Sanatoga Crossing" (Limerick), "Washington Crossing", "Buckingham", "Tohican Creek" and "Pine Forge". These studies are available for inspection upon request at the Company headquarters.

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Limerick Nuclear Generating
Station, I-80100341
OCA Exhibit No. 20

IR-2:

1-3, 4, 6, 7, 24, 25, 26, 28, 29, 30, 31, 41, 42, 58;
3-12;
4-8;
5-9;
6-6, 7, 8, 9, 16, 17;
7-1, 2, 9, 10, 11, 19, 23, 25, 26, 28, 31, 32, 33, 34, 35, 57;
8-2, 3, 12, 15;
9-11, 15, 27, 19, 20;
10-1, 2, 3, 5, 8, 10, 19, 21, 29, 32, 33;
11-11;
12-12, 13, 14;
14-1, 2, 5, 6, 9, 10;
16-1, 5;
17-3, 6, 7, 17, 24;
18-2, 3, 5, 6, 7, 8, 9;
19-1, 2, 3, 19, 20; and
20-1, 4, 5, 6, 7, 9, 10, 14, 17, 18.

TR-2:

3, 4, 11, 12, 13, 16, 19, 24, 25, 27, 28, 29, 30, 31, 33, 34, 35, 36, 37, 38, 47, 49, 52, 53, 54, 55, 56, 59, 60, 61, 62, 64, 67, 69, 73, 74, 75, 76, 77, 78, 79, 81, 82.

Schedule 1, PECO Statement 1B, R.I.D. 865.

Q.1-3. Provide all of the cost estimates made by PECO and/or the architect/engineer of the total cost of construction of Limerick, direct and AFDC stated separately, and the date of each estimate.

A.1-3. The information requested is provided in the table below.

Limerick Cost Estimates
(Costs are in Millions of Dollars)

Date of Estimate	Limerick Service Dates	Direct Cost	AFDC	Total Limerick Cost
5/68	1975-77	$289	$37	$326
2/70	1975-77	425	60	485
1/71	1975-77	620	96	716
7/72	1978-80	923	286	1209
10/74	1981-82	1295	443	1738
10/75	1981-83	1497	505	2002
5/77	1983-85	1857	721	2578
8/78	1985-87	2007	1175	3182
2/80	1985-87	2113	1245	3358
9/80	1985-87	2317	1457	3774
10/80	1985-87	2559	1561	4120

Note: Overhead and Taxes are included in Direct Cost.

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Limerick Nuclear Generating
Station, I-80100341,
OCA Exh. No. 23

TR-1:

7, 8, 9, 11,

TR-2:

18, 41, 69, 92, 94, 96, 97

IR-2:

1-63, 19-2, 20-15, 20-18, 21-4, 21-5, 21-6, 22-1, 22-3, 22-9, 22-10, 22-11, 22-12, 22-13, 22-14, 22-16, 22-17, 23-3,

IR-3:

4-1, 7-8

IR-5:

1-6, 2-1, 2-2, 2-8, 4-4, 4-5, 11-1, 12-1

IR-6:

4-3

IR-1: RR-1 through 4 (R.I.D. 1225)

Q. Isn't it correct that PECO actually spent as many dollars in the period up to 1981 as it intended to spend under the schedule as it existed before the announcement of the 1978 delay?

A. The statement that PECO actually spent as many dollars as it intended to spend under the schedule existing before the 1978 delay was announced is not correct. Actual expenditures in the 1978-1980 period (direct costs) amounted to $479 million compared to the $529 million that had been scheduled for the same three-year period prior to the delay. Comparing these two figures is a theoretical exercise since changes in inflation rates, plant design, retrofits and post-TMI changes would also have to be taken into consideration in determining whether the pre-1978 schedule could be maintained.

Appendix A

PHILADELPHIA ELECTRIC COMPANY
from the PUBLIC INFORMATION DEPARTMENT (215) 841-4000
2301 MARKET STREET • PHILADELPHIA, PA. 19101

FOR RELEASE IMMEDIATE (May 24, 1976)

Distribution:
Financial; Karl Abraham;
AIF; Pottstown Mercury

Contact: W. R. Taylor, 841-4320

PE ANNOUNCES REDUCTION IN CONSTRUCTION EXPENDITURES

Philadelphia Electric Company today released a new forecast which calls for a reduction of $750 million in construction spending through 1980.

John H. Austin, Jr., PE's vice president for finance and accounting, reported that the Company presently contemplates reducing construction expenditures to $1.75 billion for the four years 1977-80, compared to the previous estimate of $2.5 billion. Budgeted construction expenditures for 1976 have been reduced to $437 million compared to the previous forecast.

"Our near-term policy is to reduce financing requirements to an absolute minimum until earnings rise to a level that will be adequate to support the high cost of obtaining money," Austin explained.

The Company expects to obtain about 43 percent of its revised construction budget from internal sources. The remainder will come from the sale of securities.

-more-

If you desire additional information, we shall be glad to supply it.

add one: PE ANNOUNCES REDUCTION IN CONSTRUCTION EXPENDITURES

As a result of construction budget revisions, the schedule for Limerick Generating Station, PE's largest project, has been extended by two years. Construction work is about 20 percent complete on the two 1.1 million kilowatt nuclear units near Pottstown. The first unit is now scheduled for service in 1983 and the second in 1985.

"Our construction program will maintain minimum economic work on our Limerick generating plant," Austin added. "We hope that the two-year delay in Limerick's availability will not affect PE's ability to meet future customer needs.

"Our latest estimate indicates that electric peak load will grow at an annual rate of about 5.2 percent, which is lower than predicted a year ago. The cumulative effect of this reduced growth rate will be to lower our estimated 1980 peak load from 8,000 megawatts to 7,140 megawatts. This revised estimate has been prompted by a slower business recovery than previously predicted and continued energy conservation by our customers," Austin concluded.

#

PHILADELPHIA ELECTRIC COMPANY
From the PUBLIC INFORMATION DIVISION (215) 841-5555
2301 MARKET STREET • PHILADELPHIA, PA. 19101

NEWS RELEASE - Immediate (May 11, 1978)

Contact : Ron Harper, 841-4122

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Suburban Dailies
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Financial Organizations

PE To Spend $2.5 Billion For Construction from 1978 to 1982

Philadelphia Electric Company today released a new five-year forecast which calls for construction spending of approximately $2.5 billion through 1982. The Company also announced that the completion dates of its two nuclear units at Limerick, Pa. are being rescheduled from 1983-85 to 1985-87.

Joseph F. Paquette, Jr., PE's Vice President of Finance and Accounting stated, "As a result of continued energy conservation by our customers and sluggish economic growth, the Company has reduced its projected electric sales and peak load growth rates for the forecast period from 5 percent annually to 3 percent. The stretch-out in completing Limerick, which will reduce construction spending by about $270 million in the next 3 years, is consistent with these reduced growth estimates and is in keeping with the Company's policy of holding near-term capital spending to the lowest possible level that will permit completion of generating capacity as needed in the 1980's".

The Company expects to obtain almost half of its forecasted construction expenditures from internal sources, primarily depreciation and deferred income taxes. Approximately $1.7 billion of new capital must be raised from the sale of securities during the next five years.

If you desire additional information, we shall be glad to supply it.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

LIMERICK NUCLEAR GENERATING

STATION INVESTIGATION

I-80100341

INITIAL DECISION

OF

JOSEPH J. KLOVEKORN

Administrative Law Judge

March 26, 1982

over 10.8 million shares of common stock in 1975 at an average price of $12.31 per share. This increased the number of shares outstanding by 20% in just one year.

No party disputes that these events occurred. The OCA notes, however, that the company should have been aware then of the quagmire of direct construction cost escalations and in-service delays experienced by PECO at its other principal construction sites. (OCA M.B., p. V-11). The cost of this delay has been estimated at $36.6 million by the company. (PECO Statement 1B, pp. 6-7)[7/] and $372 million by the OCA.[8/]

Trial Staff argues that PECO should have either cancelled the units at this time or built the plant as quickly as possible. Instead, it criticizes the company for choosing the worst possible path-not cancelling before the bulk of construction was begun, but not pressing forward to get the plant finished in light of optimistic economic forecasts for 1976-1978. (OCA Ex. 23, Tr-1, 9; T.S. M.B. pp. 8-9).

1976 Extension

In 1976 PECO announced a further delay in the commercial operation of Limerick. Unit I was now to start in April 1983 and Unit II

7/ This is the additional carry-charge which would be experienced on the existing investment as the result of the deferral. It neglects, however, to reflect inflation in the costs of construction due to the delay.

8/ This is arrived at by comparing the July 1972 PECO estimates of total direct Limerick cost ($923 million) with the October 1974 estimate of $1.295 billion (OCA Ex. 1, IR 2, 1-3). This rough approximation cannot be relied on, since, of course, it reflects all post-July 1972 inflation, not just that portion related to the delay.

in April 1985. According to PECO, this rescheduling was made primarily to match growth in capacity additions with a new lower load forecast which was made in the spring of 1976. According to the company Witness Paquette, the rescheduling was desirable from a financial standpoint. The company had not been able to improve its financial performance to a satisfactory level and, therefore, any lightening of the construction program enabled it to reduce the financing burden that it was facing.

During 1974 and 1975, PECO's return on common equity was in the range of 8.9% to 9.4%, its SEC interest coverage decreased further to 2.3-2.4 times and the price of its stock remained in the area of $10 to $15 per share, which was only 50% to 70% of book value. Also, in 1976, Standard & Poor's reduced its bond rating again, this time to A-.

In the summer of 1975 PECO's electric peak load was 5,530 megawatts, again below the 1973 record. This gave PECO further indications that energy conservation was having a significant effect and that it could expect a permanent adjustment in customers' usage of energy. Therefore, at that time the company changed its forecasted growth rate from its pre-1974 level of 7% per year down to 5%. The effect of this reduced growth rate was to lower its estimated 1980 peak load by almost 1,000 megawatts. This meant that it could reduce its capacity accordingly. Therefore, it delayed the Limerick units by two years, which lowered its projected capacity by 1,055 megawatts in the years 1981 to 1984 inclusive.

PECO had filed for another rate increase in November 1975 for a total of $95 million, or 10%. It requested $47 million to go into effect on January 19, 1976 on an interim basis, but the Commission allowed only $24 million of the increase, a 2.5% increase, to go into

effect in February 1976. Another $23 million increase became effective in August of that year on an interim basis.

In the spring of 1976, PECO lowered its five-year construction program by about $750 million. On average, PECO was able to reduce its outside financings in those years by about $60 million per year, or about 20%.

Mr. Paquette also testified that in evaluating the 1976 postponement, "it is also important to appreciate the context within which these decisions were being made". (PECO Statement No. 9, p. 10).

When growth forecasts began to level off and it became apparent that it would not need Limerick's capacity in 1981 and 1983, Mr. Paquette stated, it was entirely consistent with corporate and regulatory policy to slow down the construction of that plant in order to avoid bring it on line in advance of its need. This concern about excess capacity came to the surface in the company's 1975 and 1976 rate proceedings, when questions were raised by the Commonwealth of Pennsylvania concerning reserve margins and the possibility that the company then had "excess capacity" which should be eliminated from its rate base. Although the PUC rejected the Commonwealth's arguments in that case, it did indicate that the company would be required to justify its installed capacity in the next rate case. According to Mr. Paquette, in such an environment the company concluded that the public interest did not warrant a speedy completion of Limerick. Indeed, the company felt that there was some risk that if it brought on the Limerick units in 1981 and 1983, this Commission might exclude it from rate base with very dire financial consequences to the Company (PECO Statement No. 9, p. 11).

According to the testimony the company recognized that such a delay could result in a higher cost for Limerick, although the amount of this increase could not be accurately determined. PECO stated that balancing these factors, it was clear that rates would be greatly reduced in the short term from a postponement of Limerick since customers would not have to pickup the carrying costs for the plant in 1981 and 1983.

PECO believed, based on a review of Commission actions at that time, that the Commission's preference would be to have lower rates in the short term, even though that might result in some long term increases. During the proceeding, PECO estimated the cost of this delay at $68 million. (PECO Statement 1B, p. 7).

The OCA is highly critical of PECO's 1976 decision to slip Limerick's construction schedule, stating that it evidences a corporate attitude to react to load growth by building more and more capacity and not attempting to control such growth. (OCA M.B., p. V-15). It also criticized the company for failing to analyze what capacity would be needed if load growth continued to deescalate. It rejects the company's expressed concern about excess capacity. Under such circumstances, OCA maintains, the appropriate consideration, if not necessarily, would be whether it was reasonable, possible and responsible to stockholders and ratepayers to cancel one or both units. OCA notes that no analysis of this type was made. The only generation planning analysss during this period were plant-to-plant, coal versus nuclear, studies. Furthermore, OCA argues, PECO's load forecasts were fundamentally flawed in their methodological failure to capture the changing consumption patterns. In May of 1976, $284 million direct construction costs had been expended on Limerick. (OCA Ex. No. 6, IR-2, 8-12). The delay announced in 1976

added, according to the OCA, some $202 million to the direct cost of Limerick. (OCA Ex. No. 20, IR-2, 1-3).

Trial Staff was also highly critical of the 1976 delay. It estimated the cost of this postponement to be approximately $506 million (T.S. Ex. REN-1A, Sch. 2, p. 1). Trial Staff's witness Dr. Donald L. Birx, noted that PECO's originally stated reason for the delay was reduced load forecast. (T.S. Statement DLB-1, pp. 3-4). A press release issued at the time, however, also referred to financial constraints. (PECO Statement 11-B, App. A).

Trial Staff Witness Donald H. Muth testified, that according to the company, the 1976 delay reduced PECO's financing requirements by $56 million (1976), $44 million (1977) and $76 million (1978). (PECO Statement No. 9, Table C).

Mr. Muth concluded that PECO would have been able to issue sufficient additional mortgage bonds in 1976-1978 to eliminate the reason for this postponement. (T.S. Statement DHM-2, pp. 2-3). Although these debt issues would have increased rates by increasing the cost of debt, Trial Staff admits, this is true whenever any debt is issued at greater than the embedded cost. It should also be noted that long term bond rates were lower in 1976-1978 than in 1974-1975 (Tr. 509).

Mr. Muth, however, would have had the company using some debt mixed with equity issues to finance the additional capital investment. In 1977 and 1978, according to the witness, PECO passed up an unparalleled opportunity to issue more common stock at close to book value. In fact, he noted such an issuance would have been closer to book value than the stock has attained since 1974 (T.S. Statement DHM-2, pp. 4-5 and T.S. Ex. DHM-2A, Sched. 8). In 1978, when the proceeds/book ratio was 90.6%

(Sched. 8), PECO did not even make a stock issue. The 1.9 million shares issued during this time were only through the ongoing dividend reinvestment and employee stock ownership programs (Tr. 510). Trial Staff argues that PECO should have been eager to issue common stock in 1978 after observing conditions in 1977, during which the average proceeds/book ratio was 101.5% (T.S. Ex. DHM-2A, Sched. 8). The increase in equity ratio would also have tended to increase rates in R.I.D. 438 and R-79060865, thus further improving PECO's interest coverage. Trial Staff maintains that PECO could have financed the construction in a variety of ways. In 1976, PECO's mortgage coverage ratio was 2.5 times. If PECO had not reduced its 1976 construction expenditures by $56,000,000 and had financed these additions with first mortgage bonds, its mortgage coverage ratio would have only been reduced to 2.4 times. (T.S. Statement No. DHM-2, p. 4).

Trial Staff argues that PECO could also have financed the $56,000,000 of construction on an interim basis through short-term debt. PECO reduced its short-term debt by $100,728,000 during 1976 and there was only $7,226,000 of short-term debt outstanding on its balance sheet at December 31, 1976.

According to Trial Staff, PECO could also have issued additional common stock during 1976. Although its common stock was still selling below book value at an average price of $16.68 per share, this price was substantially higher than the 10,866,340 shares it issued in 1975 at $12.31 per share.

Trial Staff also argues that PECO could have financed the additional $44 million needed to maintain its construction schedule in 1977 through the issue of more common stock. However, this construction could also have been financed by first mortgage bonds or, on an interim

basis, with short-term debt. In 1977, PECO issued 5,317,952 shares of common stock at an average price of $19.54, or 101.5% of book value. If PECO had issued another 2,300,000 shares it would have had sufficient funds to cover the $44,000,000 of additional construction expenditures. Common stock issued in 1977 would have totaled 7,617,952 shares or substantially less than the 10,866,340 shares issued in 1975 (at $12.31 per share) or the 9,749,355 shares issued in 1980 (at $14.14 per share).

PECO's mortgage coverage ratio was 2.35 times in 1977. If PECO had issued an additional $44,000,000 of first mortgage bonds in 1977, its interest coverage would have been reduced to 2.28 times (assuming that the $56,000,000 of additional construction expenditures in 1976 had not been financed with mortgage bonds). The issuance of an additional $44,000,000 of first mortgage bonds in 1977 would therefore not have had a material effect on its interest coverage. Even if the 1976 and 1977 construction expenditures had both been financed with mortgage bonds, the mortgage coverage ratio would have only been reduced from 2.5 times to 2.2 times.

Trial Staff argues that PECO could also have financed the $44,000,000 of additional 1977 construction through short-term debt. PECO only increased its short-term debt by $7,649,000 in 1977, meaning there was only $14,875,000 of short-term debt outstanding on its balance sheet at December 31, 1977.

PECO could have financed its 1978 construction expenditures by issuing additional common stock. PECO had no public stock offering in 1978. The shares that it issued in 1978 were sold through its Dividend Reinvestment and Stock Purchase Plan, its Employee Stock Purchase Plan and its Tax Reduction Act Stock Ownership Plan. The stock issued through

these plans was sold at an average price of $17.46 or 90.6% of book value. If PECO had held a public sale of stock during the first quarter of 1978, its per share price would have been even greater than $17.46.

PECO's mortgage coverage ratio was 2.37 times in 1978. If PECO had issued an additional $76,000,000 of first mortgage bonds in 1978, its interest coverage would have been reduced to 2.26 times (assuming no additional mortgage bond issues in 1976 or 1977).

If the postponed 1976 and 1978 construction of $56,000,000 and $76,000,000, respectively, had been financed with mortgage bonds and the 1977 construction of $44,000,000 with common equity, the 1978 mortgage coverage ratio would have been 2.18 times.

Short-term debt outstanding at December 31, 1978, totaled only $16,129,000. This balance provided sufficient leeway for PECO to finance some or all of the $76,000,000 of 1978 postponed construction with short-term debt if it had chosen to do so.

PECO argues that Trial Staff's position is not supportable. First, it claims Trial Staff employs hindsight to construct a set of hypothetical financings allowed by circumstances about which the company could not have known when faced with the need to make its decision. Trial Staff is able to construct this hypothetical financing program because, as Trial Staff points out, long term bond rates were at a lower level between 1976 and 1978 than they were in 1976, because the rate of inflation decreased in the period 1976 through 1978, and because the value of PECO common stock increased between 1976 and 1978.

According to PECO, the second deficiency of Trial Staff's hypothetical financing program is that, even with the benefit of hindsight, it is impractical. Trial Staff insists that, while PECO common was still selling below book in 1976, the company could have sold $56 million of common to finance Limerick since the 1976 market price exceeded the 1975 market price. In addition, common stock sales of $44 million in 1977 and $76 million in 1978 were recommended. As an alternative, Trial Staff suggested that PECO could have issued $56 million in mortgage debt in 1976 because the company's coverage ratio was 2.5 times, that PECO could have issued $44 million in mortgage debt in 1977 with a coverage ratio of 2.35 times, or that PECO could have issued $76 million in 1978 because the company's mortgage ratio stood at 2.37 times. If sales of common stock or mortgage debt failed, Trial Staff suggests the use of short term debt "on an interim basis" to finance $56 million in 1976 and/or $44 million in 1977, and/or $76 million in 1978.

PECO maintains that Trial Staff's hypothetical financing program is not fiscally sound. If its suggestions were added to the amounts actually issued by the Company through the same period, PECO would have been left with an indenture coverage below 2.0 times in 1979, and further mortgage bond financing would have been precluded. (PECO Statement 11D, p. 5).

PECO claims that in the 1975 to 1979 period it could only have issued a total of about $30 to $40 million in additional mortgage bonds while maintaining a 2.0 times mortgage coverage ratio in 1979 (PECO Statement 11B, p. 6).

Trial Staff also hypothesized common stock offerings in 1976 ($56 million), 1977 ($44 million), and 1978 ($76 million), but PECO claims, ignored the cumulative effect of such offerings. If as Trial Staff suggested, PECO had issued an additional $176 million in common stock, the company would have been left with earnings of $1.70 per share in 1978, an amount insufficient to cover the company's common stock dividend. (PECO Statement 11D, p. 5).

Trial Staff's suggestion that PECO could have financed all or some of their 1976-78 requirements through short-term debt, PECO claims, ignores the fact that short term debt must be constantly refinanced. It also ignores the fact that use of large amounts of short term debt for immediate construction needs would sacrifice all of the financial flexibility inherent in short term debt reserves which are necessary to protect against capital market disruptions and unanticipated operating needs. (PECO Statement 11D, p. 5).

1978 Extension

In May 1978 PECO announced a decision to reschedule Units I and II from 1983-85 to 1985-87. PECO Witness Mr. Paquette testified that PECO did not in fact change the critical path of the construction schedule from 1978 through 1980, and that in those years PECO authorized and spent the additional dollars to maintain the 1983-85 service dates in the event that it became desirable to complete the units earlier than 1985-1987 (PECO Statement No. 9, p. 12; Tr. 495). The record shows, however, that PECO reduced its direct expenditures from 1978-1980 from the budgeted amount of $529 million to $479 million (OCA Exh. 23, Tr-1, 7). PECO explains, however, that it funded all major construction activities

required to maintain the earlier completion dates, but not activities of lesser importance (PECO R.B., p. 96, fn. 7).

The reasons for announcing a delay in 1978, according to PECO witness Paquette, were similar to those which were involved in the 1976 decision. In other words, by 1978 there were two more no-growth years. PECO's load forecasters lowered peak load estimates from 5% to 3% per year. In addition, PECO claims, the Commission permitted inadequate rate relief during this period. One important factor in this decision to postpone was apparently the recommendation of Administrative Law Judge Joseph Matuschak at R.I.D. 438 that an adjustment be made to PECO's rate base for "excess capacity." This was viewed as a message to the company not to optimize installed capacity but to minimize current costs and rates.

PECO, however, continued to preserve its options to maintain the earlier timetable due to the fact that escalating oil costs now made it appear that completion of Limerick at an early date might be advantageous to customers even if the capacity was not required, since the fuel cost savings resulting from Limerick's operations would more than offset the carrying costs of the plant (PECO Statement No. 9, p. 14).

Unlike the 1976 delay (Tr. 502), however, PECO this time performed an analysis to determine the level of short-term savings vs. long-term costs attributable to deferring completion of the plant. In 1978 PECO estimated that a one-year delay would reduce revenue requirements in the first year by $190 million. This would come about through a $350 million savings in base rates offset by higher operating expenses of about $160 million due to continued energy purchases. However, beginning in the second year and every year thereafter for the life of

the plant customers' bills would be approximately $47 million higher so that it would take approximately five years before the savings would be offset. No present value analysis was made (Tr. 502-503).

OCA points out, in response, that Judge Matuschak's decision in R.I.D. 438 came months after the decision to delay was announced. OCA also claims that the company failed to adequately analyze the economic and financial implications of the delay and the possible cancellation of at least one unit (OCA M.B., p. V-24-26).

Trial Staff estimates the cost of the 1978 delay to be $597 million (T.S. Ex. REN-1A, Sch. 2, p. 1).

1980 Schedule Extension

In 1980 PECO abandoned its option of maintaning the earlier 1983/1985 completion dates. This was made necessary when it became obvious that manpower availability and labor productivity in the installation of bulk commodities such as conduit and pipe were not meeting the target values. The manhours necessary to install the seismic design of pipe hangers and restraints turned out to be greater than estimated, and interferences introduced by these hangers to duct work and cable trays also required additional manhours to resolve. In addition, the NRC action items resulting from Three Mile Island were issued, adding additional manhours of job effort (PECO Statement 1B, p. 7).

Reasonableness of the Delays

Having discussed the various delays in the Limerick construction schedule, we now turn to the reasonableness of PECO management's various decisions to postpone the commercial operation dates of these units.

Initial consideration should be given to the standard of prudence against which these decisions should be measured. PECO argues (PECO M.B. pp. 296-299), that Trial Staff has actually ignored the legal standard establishing the requirements for a showing of management imprudence. PECO notes that the "prudent investment" theory is not new to the regulatory process. It was first articulated by Justice Brandeis nearly sixty years ago in Missouri ex. rel. Southwestern Bell Tel. Co. v. Missouri Public Service Commission, 262 U.S. 276, 67 L.Ed. 981 (1923). In defining the appropriate standard to be applied by regulatory agencies in their review of utility expenditures, Justice Brandeis stated as follows:

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgement, unless the contrary is shown. Southwestern Bell, supra (dissenting opinion), 262 U.S. at 289, n. 1. (Emphasis added).

An assessment of management's prudence is not properly premised upon hindsight. As stated by the Michigan Public Service Commission in Re Consumers Power Co., 14 P.U.R. 4th 1 (Mich. P.S.C. 1976):

> It has also become well established that in applying the prudent investment theory to particular management decisions, the commission must determine that there existed a reasonable need and basis for the utility to commit funds for the construction of utility plant in light of the circumstances which prevailed when the decisions were made and, further, that the expenditures were reasonably incurred. . . . [T]he Commission reviews these questions, not with hindsight, but based upon the circumstances that existed at the time those decisions were made. (At pp. 15-16). (Emphasis added.)

Accord, Wisconsin Telephone Co. v. Public Service Commission, 232 Wis. 274, 287 N.W. 122, 148 & 157 (1939).

According to PECO mere speculation as to potential cost savings will not support a finding of managerial imprudence. Re Consolidated Edison Co., 54 P.U.R. 3d 43, 103-114 (N.Y.P.S.C. 1964); Re Consolidated Edison Co., 96 P.U.R. NS 194 (N.Y.P.S.C. 1952). Nor will evidence that certain claimed expenditures are unusually high alone justify their disallowance. Boise Water Corp. v. Idaho Public Utility Commission, 578 P.2d 1089 (1978).

Further, it is not sufficient that such testimony simply question the wisdom of management's decision. As stated by the New York Public Service Commission in Re Consolidated Edison Company, 54 P.U.R. 3d 43, 112 (N.Y.P.S.C. 1964):

> A determination of prudence of imprudence calls for an inquiry into the reasonableness of management's judgment, i.e. whether there was a rational basis for it, but not an inquiry into its wisdom. In short, it is not for a commission to determine prudence by reference to what it would have done if it had been exercising the powers of management. (Emphasis added.)

Also, it is not sufficient that opponents to rate base inclusion of the claimed investment show that management could have made other decisions which would have had equal economic or other decisions which would have had equal economic or other benefit. As stated by the Supreme Judicial Court of Maine in Central Maine Power Company v. Public Utilities Commission, 405 A.2d 153, 178 (Me. 1979):

> Where, as here, the road chosen by management is arguably at least as economical as any alternative, and the benefit (i.e. cost) does not clearly appear to be 'excessive, or unwarranted, or incurred in bad faith,' management's judgment must be respected.

PECO argues that the Courts of this Commonwealth have applied these same principles as the legal standard which must be satisfied before a ratemaking disallowance may be justified on the basis of "management imprudence." Pennsylvania Power & Light Co. v. Public Service Commission, 128 Pa. Super. 195, 210, 216-17, 193 A. 427, 433-34 & 436-37 (1937); Pittsburgh v. Pa. P.U.C., 370 Pa. 305, 318 (1952); Pittsburgh v. Pa. P.U.C., 173 Pa. Super. 87, 92 (1953).

PECO concludes that an analysis of its various scheduling decisions relative to Limerick, demonstrates that, at the time and in the circumstances, its decisions were prudent. It claims that only by ignoring the circumstances surrounding each of its decisions and by using instead hindsight and strained comparision that one is able to argue otherwise.

The standard by which PECO seeks to have its actions measured appears to this administrative law judge to be inappropriate. In effect, the company is saying that as long as there is a rational basis for its action, any decision that it makes cannot be criticized. While that may have been the rule in the past, more recent decisions by regulatory agencies have held that:

> ...the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company. Case 27123, Consolidated Edison Company of New York, Inc. (Opinion 79-1, issued January 16, 1979, pages 5-6). (N.Y.P.S.C.) See also, Case 27565, Niagara Mohawk Power Corp. (Opinion 80-25 issued June 24, 1980), Case 27869, Consolidated Edison Company of New York, Inc. (Opinion 82-2, issued January 21, 1982, pp. 11-14).

This standard of "reasonable care" rather than "rational basis" appears to be more appropriate here, primarily because it reflects the need to recognize the economic impact of delays in construction on the company's ratepayers. The rational basis standard might well be appropriate where one is dealing with a single routine item of plant which may cost several millions or the selection of one transmission line route over another. Certainly, this Commission should not take it upon itself to review every management decision. But where, as here, a company decision will have a substantial, if not overwhelming impact on rates for many years, this Commission must judge that action by some standard other than its rationality. PECO's conduct in delaying construction shall be judged on the basis of how reasonable people would have responded to the events of 1974-1978 and whether PECO's response was satisfactory in light of all those conditions and circumstances.

On this basis PECO's action in 1974 was reasonable by any standard. The oil embargo of late 1973 resulted in higher energy prices and recessionary economic conditions throughout the country. For the first time since World War II, energy sales and peak loads decreased. In addition the market for utility securities was poor due to the omission of Consolidated Edison's dividend. Under these circumstance, the company's decision to slip its construction schedule by two years was a reasonable response to an extraordinary series of events.

By 1976, however, the reduced load and financial constraints experienced by the company two years earlier continued. PECO's decision in the Spring of 1976 to delay Limerick for another two years might well have been reasonable, had it been based on a thorough evaluation of

economic consequences, not only to it but also to its ratepayers. The record, however, indicates that no such thorough evaluation was made.

As Trial Staff and OCA noted, PECO witness Paquette did not recall any analysis of the long-term economic costs to customers of this delay (Tr. 502). Although an exact determination of this increased cost could not be made, some sort of analysis should have been done. Similarly no analysis of alternatives to Limerick was made, neither did the company analyze its capacity requirements if load growth continued to decline.

In 1978 PECO did analyze the effect of its schedule extension on ratepayers and computed that a one-year postponement would reduce revenue requirements by $190 million for the first year, but would increase bills by $47 million per year the second year and each year thereafter for the life of the plant. Whether this was a good bargain for ratepayers is subject to discussion.

Although there can be no doubt that these postponements were caused in large part by financial factors, Mr. Paquette has offered another insight into management thinking when he testified (PECO Statement No. 9, pp. 10-13):

> In evaluating the 1976 postponement based on capacity and financial factors, it is also important to appreciate the context within which these decisions were being made. A public utility such as Philadelphia Electric has a duty to provide service and to build the facilities which are necessary to do so. Conversely, it has been historically recognized that no utility should build additional facilities which will not be useful within a least a reasonable time following their completion. Based on such an historic regulatory concept, it was clearly the view of the Company that Limerick should not be completed well in advance of the need for it. Accordingly, when our growth forecasts began to level off and it became apparent that we would not need Limerick's capacity in 1981 and 1983, it was entirely consistent with corporate and regulatory policy to slow down the construction of that plant in order to

avoid bringing it on line in advance of its need. This policy appeared to be confirmed when in the rate proceedings of 1975 and 1976 questions were raised by the Commonwealth of Pennsylvania concerning reserve margins and the possiblity that the Company then had "excess capacity" which should be eliminated from its rate base. Although the PUC rejected the Commonwealth's arguments in that case, it did indicate that the Company would be required to justify its installed capacity in the next rate case. In such an environment the Company concluded that the public interest did not warrant a speedy completion of Limerick. Indeed the questions concerning the Company's "excess capacity" indicated that there weas certainly some risk that if the Company brought on the Limerick plant in 1981 and 1983, the Public Utility Commission might exclude it from rate base with very dire financial consequences to the Company.

Offsetting all of these factors dictating a delay in the Limerick construction schedule, there was, of course, recognition by the Company of the possibility that such a delay could result in a higher ultimate cost for the Limerick station. The amount of this increased cost could, of course, not be accurately determined on any of the postponement dates. However, there was little question that additional AFUDC would be accrued as a result of the postponement, and it was also clear that the maintenance of the construction staff for a longer period at the site would increase overhead costs.

Balancing these factors, it was clear that the cost to the customers would be greatly reduced in the short term from a postponement of Limerick since they would not have to pick up the carrying costs for the plant in 1981 and 1983 but would have these costs postponed for at least two years. In other words, the delay decision involved clear short-term benefits to customers offset by possible long-term burdens, although the exact amount of those long-term burdens could not be precisely determined at the time.

In evaluating this question, the Company was of the view that the Pennsylvania Commission's preference would be to have lower rates in the short term even though that might result in some increases long term. Our judgment in this respect was based on a review of Commission actions and orders at that time. For examples, the Commission had refused the Company's request in include some CWIP in rate base and to normalize additional deferred taxes. Each of these PUC actions produced lower rates in the short

term, but higher rates in the long term and delay of Limerick seemed to fit in with this concept.

Because of continuing high inflation and low earnings, we requested another increase of $119 million in August 1977. We requested that approximately $50 million be allowed as interim rate belief to permit recovery of the carrying charges on Salem #1 which went into service on July 1977. However, the PUC granted an interim increase of only $11.8 million in March 1978. The final order for this case was not issued until March 1979, 19 months after we filed, and it granted an additional $67 million increase retroactive to July 4, 1978.

In the decision of the ALJ in connection with this rate increase, theres was a recommendation that the Commission adjust rate base for "excess capacity". We viewed this as another "message" from the public sector directing us not to optimize the installed capacity of our generating facilities, but to minimize current costs and rates. The regulatory philosophy for constructing additional capacity and the preference of short-term cost savings over long-term cost increases discussed in connection with the 1976 delay were all present in causing the delay announcement which was made in 1978.

It appears therefore that PECO's decision to postpone construction was influenced in part by the fear of an excess capacity adjustment by the Commission in a subsequent rate case. Rather than run the risk of such a revenue loss, the company chose to delay construction while at the same time continuing to accrue AFUDC on this plant-costs that will eventually be borne by the ratepayers.

In the past this Commission has held that there should be some sharing of the risk associated with bringing large plants on line and the resultant excess capacity which typically results. See Pa. P.U.C. v. Pennsylvania Power Co., R-77110521; Pa. P.U.C. v. Philadelphia Electric Co., R-79060865. This risk should not be effectively placed entirely on the ratepayer by permitting a utility delay the commercial operation of

a plant until the optimal time, while still allowing the company to earn a return, albeit non-cash, on its investment during this interregnum.

In summary, it appears that the company's action in postponing Limerick in 1976 and 1978 was made without careful analysis of the impact of such delay on its ratepayers.

In addition, the record shows that a factor in these decisions was the potential impact of Limerick on the company's capacity and reserve margins[9/] and the adverse effect this would have on the company's rate allowances. Consumers should not be expected to pay for delay which results form a conscious management decision to protect its own interests without adequate weight being given to its ratepayers' interest.

Trial Staff, although arguing that some adjustment is warranted as a result of PECO's decisions to postpone Limerick in 1976 and 1978, recommends that no final decision on this subject be made by the Commission at this time for the following reasons:

(1) A prospective rate base adjustment is arguably not within the Commission's power when PECO has not yet claimed the plant in rate base.

(2) A prospective rate base or other adjustment such as a four year stoppage of AFDC would give the consumers no immediate benefits in terms of lower rates; such a decision at this time might well lead to a bond downrating or higher cost of debt or equity which would have a

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9/ If Limerick were in service in 1981, PECO would have a summer reserve margin of 66% (PECO Statement No. 9, p. 18).

short range negative impact both on PECO and its ratepayers. Trial Staff suggests that this issue should therefore be considered again and more fully at the time PECO seeks to include Limerick in rate base. (T.S.M.B. p. 11).

I agree with Trial Staff that any decision now would be advisory only. This Commission cannot bind the future Commission that must decide PECO's claim for rate base treatment of these plants when they become commercially operable. Furthermore, this proceeding is a fact-gathering one. For purposes here, it is sufficient to note that the decisions to postpone Limerick were, in part, the result of management's discretion as well as financial circumstances. In a subsequent proceeding consideration can be given to the extent to which these delays were caused by financial and other external constraints and the extent to which management's fear of Commission sanctions entered into these decisions. Such a proceeding would also be an appropriate forum to quantify the effects of these delays. Such a record does not exist at the present time.

MANAGEMENT OF THE LIMERICK CONSTRUCTION PROJECT

Having followed the progress of Limerick up to the present it might be appropriate to discuss the management of the project as detailed on this record.

As noted earlier Bechtel Power Corporation was selected as the architect/engineer and constructor for Limerick, and General Electric was selected to provide the steam generator. Following the selection of these companies, PECO assigned responsibility for planning, scheduling

Staff Exh. #2
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TABLE 1

EDDYSTONE STATION

UNITS 1 & 2

Responses to Cross Examination Questions
Re: Mod Justification (Economics) and
Job Status (Work in Progress)

TABLE 1

EDDYSTONE UNITS 1 AND 2

JOBS TO BE COMPLETED WITHIN 3 YEARS:

1. Replace superheater outlet headers (Unit 1).
2. Develop and implement program to assess high pressure piping integrity.
3. Wastewater treatment modifications.
4. Feedwater, steam temperature, CC, PD and H.P. boilerfeed pump controls.
5. Water induction protection (Units 1 and 2).
6. Soot blower control panel replacement.
7. ATC (combustion air) drive and control replacement.
8. Auxiliary boilers (convert from No. 6 fuel oil to gas firing).
9. Replace igniters (Units 1 and 2).
10. Replace air tempering coils.
11. Replace feedwater heaters (Unit 2).
12. Air dryers.
13. Vibration Monitoring.

Eddystone Station

1. Replace Superheater Outlet Headers (Eddystone Unit 1)

A leak developed in the 4A header on 6/29/85. Extensive repairs and heat treatment were performed. Other headers were nondestructively examined. Numerous visual indications were identified on almost every inspected header; and limited radiographic examinations showed faint (questionable) indications in every inspected header.

The Metallurgical Engineering Group and Combustion Engineering agreed that remaining life of these headers is limited, but continued operation until the replacement material becomes available is acceptable because of the proven properties of stainless steel.

No formal economic justification for complete planned replacement vs. continuing piecemeal repairs involving forced outages was made, due to a major concern for long range safety as well as unit reliability and availability.

Status -

Materials are being shipped. Installation is planned for the Spring, 1986 outage.

2. Develop and Implement a Program to Assess High Pressure Piping Integrity (Preliminary Engineering)

Due to continuing piping and pipe support problems and the need to assure safe operation of the older fossil units, Mechanical Engineering Division undertook a program to assess such critical piping systems. This is a safety issue, therefore no cost/benefit analysis was done.

Status -

Initial phase (Eddystone 2) completed for cost listed. The report has been issued and the findings are being reviewed. Studies will follow for other fossil units at an additional $2-4,000,000. Actual repair/replacement program (scope, schedule, cost, justification) to be developed.

3. Wastewater Treatment System Modifications

The Pennsylvania Department of Environmental Resources has established limits on the concentration of materials that may be discharged into the river. The waste water treatment system processes the waste water from various sources within the station to comply with these restrictions. The modifications are being made to the system to increase its reliability and thereby reduce the number of violations to the discharge water quality limits.

Status -

Engineering and construction in progress.

4. Feedwater, Steam Temperature, Combustion, Pressure Differential and H.P. Boilerfeed Pump Controls

The Unit 1 and 2 combustion controls and Unit 2 feedwater/steam temperature controls are vacuum tube type. These controls are obsolete and spare parts are no longer available. The Unit 1 feedwater and steam temperature controls are hydraulic type. These controls, due to their age, are no longer capable of safely and reliably controlling the feedwater and steam temperature on Unit 1. Spare parts lead time for the hydraulic system is approaching two years. Final cost of the initial phase of this work is reported at $1,200,000. Subsequent phases will cost almost $9,000,000. No formal economic analyses were made. The units simply cannot be operated without these control system replacements.

Status -

Replacement of Unit 2's feedwater, P.D., and H.P. boilerfeed pump controls (initial phase) is complete.

Replacement of Unit 2's steam temperature and combustion controls is now in progress and will be completed by Fall, 1986.

Replacement of Unit 1's feedwater, steam temperature, combustion, P.D. and H.P. boilerfeed pump controls is now in progress and will be complete by Fall, 1987.

5. Units 1 and 2 Water Induction Protection

Modern large steam turbines are designed for efficient, reliable operation at high pressures and temperatures, requiring heavy metal sections in early stages, moderate clearances between stationary and rotating parts, and long buckets in later stages. Accidental introduction of water into any of these turbine areas will cause serious damage to high pressure shells, rotors, buckets and thrust bearings, resulting in costly outages and repairs/replacements.

The water induction prevention systems will detect and remove any water in steam leads to or from the steam turbine before any appreciable amount of liquid collects in the lines. Sources of water include the steam generator as well as various steam lead attemperating sprays. Installation of these systems will maintain unit reliability and prevent costly turbine damage.

No formal economic evaluation was made. However, based on industry experience for comparable units, replacement power for one outage due to this problem could amount to $7.5 million, more than justifying the capital expenditure.

Status -

Job is in the 1986 Budget but has not yet been authorized or firmly scheduled.

6. Sootblower Control Panel Replacement

The existing sootblower control systems on Units 1 and 2 have been in service for twenty-five years. They consist of stepping switches, timers, relays, jumper plugs and jumper plug sockets. The reliability of this equipment is poor and it requires continuous maintenance. The manufacturer of the original control panels has indicated that spare parts are becoming obsolete and has recommended replacement by 1986.

Lack of proper sootblowing has contributed to poor unit performance, as well as increased maintenance costs. Poor unit performance is caused by lack of boiler cleanliness because additional fuel must be burned to achieve rated conditions. This, in turn, results in higher dry flue gas losses. The increased cost of fuel due to dry flue gas losses in 1984 was $329,000 for Unit 1 and $349,000 for Unit 2. The increased cost values are based on Electric Production Department performance records. No formal cost/benefit analysis was performed, but the economic justification is obvious.

Lack of proper sootblowing can also lead to corrosion of waterwall tubes and superheater and reheater platens and pendants. Fly ash buildup can cause air flow restrictions, opacity excursions, and problems with induced draft fans and air heaters. In addition, fly ash buildup on furnace slopes and clinkers on platens and pendants cause outage extensions because these areas must be cleaned before safe access can be made to the steam generator for inspection and repairs.

Status -

Replacement is scheduled to be complete within 3 years.

7. ATC (Combustion Air) Drive and Control Replacement

The existing drives and controls are difficult to maintain due to parts obsolescence and age and are becoming increasingly unreliable. Recent boiler tests conducted by station technical personnel and Combustion Engineering, the boiler manufacturer, revealed that the poor condition of the ATC drives is contributing to accelerated boiler tube wall erosion in the burner area and a loss of boiler efficiency due to carryover of unburned fuel into the convection pass of the furnaces.

The ability to position the auxiliary and fuel air dampers in the desired position is critical to the reliable and efficient operation of the boilers. The operators must be able to maintain sufficient air velocity behind the coal nozzles to create adequate turbulence and mixing of fuel and air in the combustion zone and to maintain the flame at a sufficient distance from the burner nozzles to avoid overheating them. Lack of adequate air velocity also leads to a tangential fireball covering a larger furnace area and increased impingement on furnace wall tubes.

This condition increases wear due to erosion and adversely impacts the life of these tubes and, thus, the availability of the unit. In addition to the above condition, improper positioning of fuel and air dampers decreases boiler efficiency. As a result of poor mixing and incomplete combustion, unburned fuel is carried into the convection pass. The quantity of unburned fuel is directly proportional to a loss of thermal efficiency and dollars in terms of increased fuel cost per megawatt hour. Based on the above mentioned tests, combustion efficiency improvements alone were calculated to save $95,000 per unit per year.

Status -

This replacement is now in progress and will be completed by Fall, 1986.

8. Convert Auxiliary Boilers from No. 6 Fuel Oil to Gas Firing

The net annual savings in fuel costs, reduced maintenance, and costs associated with other operating problems, was estimated to exceed $1,120,000, which easily justified the required capital expenditure.

Status -

Equipment bids are being evaluated. Field work is scheduled to begin August, 1986.

9. Replace Igniters

Since inclusion in original testimony, job has been undergoing re-evaluation and change of scope. In addition to availability and efficiency improvements cited previously, support for coal firing is now being considered, which would include additional upgrading to meet NFPA operational safety requirements.

Status

Although not yet authorized, job is still being planned for 1987 installation.

10. Replace Air Tempering Coils

Restoration of adequate air tempering will result in an estimated annual savings in air preheater operating and maintenance costs of $1,000,000 per unit, more than justifying the required capital expenditure.

Status -

12 of 16 units have been complete. Remaining 4 to be done during forthcoming outages.

11. Replace Feedwater Heaters 5A, 5B, 6A and 6B

The number of plugged tubes in each heater ranges from 16.6% to 24.7% of the tubes. The reduction of tubes in service causes a deterioration in performance. Based on the budgeted net generation for calendar year 1986 this heat rate penalty amounts to an annual cost of $30,000 in increased fuel burn.

In addition to the heat rate penalty the tube leaks have resulted in partial forced outages for tube plugging. To repair a leak in any one heater, one heat cycle must be taken out of service which reduces unit capacity from 300MW to 180MW. Based on the average annual outage time for tube pluggings over the last five years, the cost of replacement power is estimated to be $173,000 annually. As more tubes are plugged, the frequency of additional tube leaks usually increases which will further increase the annual forced outage time and therefore the annual cost of replacement energy.

If the heaters are not replaced, we will ultimately have to bypass the 5th and 6th heaters. Based on the budgeted generation for calendar year 1986, the heat rate penalty for bypassing the heaters would amount to an additional annual cost of $300,000 in fuel burn.

Status -

Authorization Request being prepared. Job is in 1986 Budget.

12. Air Dryers

The preliminary engineering for this job is complete and its justification is now being reviewed. The job might be cancelled.

Status -

On hold.

13. Vibration Monitoring

The existing equipment has become a maintenance problem; the equipment is no longer manufactured and spare parts are no longer available. Because of the condition of this equipment, spare parts will likely be needed in the near future. The units should not be run without an operable turbine supervisory instrumentation system monitoring the machine variables which indicate overall mechanical integrity of the machine. The new equipment will provide reliable instrumentation for vibration monitoring.

Although no formal cost/benefit analysis was made, the turbine damage potential is great compared to the small cost of this supervisory equipment, and our investigations indicate that one vibration caused outage would result in replacement power costs of $300,000.

Status -

This job has been authorized and engineering is in progress.

EAC/mtk/02278605

TABLE 2

CROMBY STATION

UNIT 1

Responses to Cross Examination Questions
Re: Mod Justification (Economics) and
Job Status (Work in Progress)

TABLE 2

CROMBY UNIT 1

PROJECTED TO BE COMPLETED WITHIN 3 YEARS:

1. Chlorine injection system - job complete - response not required.
2. Demineralizer regeneration pump suction modifications.
3. Fire protection modifications.
4. Coal pile run-off system.
5. Purchase of replacement L.P. rotor.

2. Demineralizer regeneration pump suction modifications.

The demineralizers purify the water needed for plant operation. They must be regenerated periodically, by pumping acid and caustic through them, to restore their purifying ability. The regeneration pumps, used for this purpose, have experienced operational problems which impact the availability of this system. Modifications are being made to correct these problems.

Status -

Field work in progress.

3. Fire Protection Modifications

Sprinkler protection is being provided for the Unit 1 boiler fronts, turbine lube oil reservoir, and hydrogen seal oil unit. The improvements are being made to provide increased fire protection and therefore increased plant reliability while at the same time providing hazard protection consistent with that necessary to obtain favorable hazard insurance rates.

Status -

The installation of sprinkler systems is complete for the turbine lube oil reservoir and hydrogen seal oil units. Installation of boiler front sprinklers is 20% complete.

4. Coal pile runoff system modification.

The coal pile runoff system was installed to comply with PA D.E.R. regulations that require rain water runoff from coal piles be collected and treated before being discharged to the river. The system is experiencing low flow problems.

Status -

The problem is under review to determine the cause and solution.

5. Low pressure turbine rotor replacement.

Bore cracks in the LP rotor were found during the 1981 borosonic examination. At this time, the manufacturer recommended rotor replacement due to questions on the integrity of the rotor. The money was then budgeted for the purchase of the rotor following inspection in the last outage. During the last outage the bore was enlarged, and the subsequent borosonic examinations showed all crack indications have been removed. The rotor will not require replacement at this time. This budget item will be removed.

TABLE 3

PEACH BOTTOM ATOMIC POWER STATION

UNITS 2 AND 3

Responses to Cross Examination Questions
Re: Mod Justification (Economics) and
Job Status (Work In Progress)

Table 3

PEACH BOTTOM UNITS 2 & 3

JOBS TO BE COMPLETED WITHIN 3 YEARS

1. Replace all three L.P. turbine rotors (Unit 3).
2. Reactor feed pumps recirculation valves.
3. Increase capacity of spent fuel racks.
4. Install new recirculation and RHR piping (Unit 3).
5. Replace 1 of 3 L.P. turbine rotors (Unit 2) (Combined with write-up for item 1).
6. Replace feedwater heater - job completed - response not required.
7. Control room instrumentation modifications
8. Plant simulator.
9. Replace plant process computer.

1 & 5 Low Pressure Turbine Rotors

Stress Corrosion Cracking of the Peach Bottom Low Pressure Turbine rotors (3 per unit) has resulted in increased probability of turbine in service failure. All six rotors will be replaced. Replacement of these rotors will decrease maintenance costs and increase unit availability. Replacement power costs alone for one failed in service rotor replacement could reach $110 million.

The first two rotors (2A and 2B) were placed on order in 1982 and installed in 1984.

For the remaining four rotors (2C, 3A, 3B & 3C), five options were evaluated in 1984. Technological advances allowed for the use of a monoblock shaft which extends inspection intervals. In addition the refurbished buckets from the original rotors are being reused. The attached table contains the alternatives considered, and shows GE retrofit monoblock rotors as the clear economic choice for these necessary replacements.

Status -

The four monoblock shafts have been ordered, on which the existing refurbished buckets will be reused. The 3A and 3B rotors are planned to be replaced during the 1987 Unit 3 outage. The remaining two are planned to be replaced during the earliest subsequent outages.

Table of Alternatives

Economic Evaluation of Peach Bottom Low Pressure Turbine Rotors.

1.	New GE Monoblock Rotor	$14,000,000
2.	GE Retrofit Monoblock Rotor*	$ 3,500,000
3.	GE Retrofit Wheel-Bore Tab Rotor*	$ 5,000,000
4.	GE Rebuild Costs per Rotor	$ 4,250,000
	New Bldg. Req'd.	$ 3,600,000***
5.	BBC Brown Boveri Welded Retrofit Rotor*	$ 5,350,000

The costs are based on manufacturers prices. Installation and transportation are not included.

* Costs include removal, refurbishment and installation of original buckets.

*** One time cost/re-use for each rotor.

2. Reactor Feedpump Recirculation Valves

Six Reactor Feedpump Recirculation valves are required for the protection of the reactor feedpumps against low flow damage. The valves and associated piping failures have compromised the systems' integrity.

Based upon the experience of past outages, the estimated expenditures during future outages if the valves are not replaced, would be as follows:

1)	Ultrasonic Inspection	$15,000 per outage
2)	Maintenance & repairs of the valves	$ 8,000 per outage
3)	Repair or replacement of downstream piping	$30,000 per outage

The projected costs if a pump fails are as follows:

A.	Replacement of one pump	$1,200,000
B.	New pump may require larger recirculation valve and line	$ 700,000
C.	10% load reduction is required due to loss of one RFP. At least one year is required for a typical replacement	$ 45,000 per day

Failure of the valves and adjacent piping has been a continuous problem. Replacement of the valves will maintain the feedwater systems' integrity, reduce the probability of RFP failure and resulting load reduction, as well as minimize personnel exposure.

The economics are obvious so a more detailed cost/benefit analysis is not necessary for justification of the job.

Status -

The six replacement valves are currently on order for 10/86 delivery. Design work is in progress. The new valves are scheduled to be installed during the next Unit 2 and Unit 3 outages.

3. Increase Capacity of Spent Fuel Racks

The loss of the capability of discharging additional spent fuel while maintaining Full Core Discharge Reserve (FCDR) at Peach Bottom Station Units 2 and 3 will occur in 1987/88 respectively.

PECo is proceeding to rerack both fuel pools with tighter cavity pitched stainless steel storage racks capable of storing consolidated fuel. This approach is the lowest cost interim alternative to PECo's spent fuel storage problem, it meets our storage requirement needs in a timely fashion, and provides additional storage capacity without rod consolidation until 1992 and 1993 for Units 2 and 3 respectively. In the ultimate, by consolidating spent fuel in a 2:1 ratio, the storage capability of the spent fuel pools will be sufficient to provide FCDR until 2004 for Unit 2 and 2005 for Unit 3. A federally owned repository is expected to be available to store spent fuel generated after these dates.

Status -

New racks have been fabricated and are being shipped and stored on site. Field preparations are nearly completed and installation of new racks has begun. Installation should be completed by late 1986.

4. Replace Recirculation and RHR Piping

PECO Management is planning to replace this piping during the next Unit 3 fueling outage; and various alternatives are being economically evaluated. Unit 2 replacement was completed in view of the many cracks being found distributed throughout the system, and the fact that NRC was permitting operation of only one fuel cycle for weld overlay repairs. It was felt that eventual complete replacement was inevitable for assurance of reliable continuous operation of Unit 2.

Status -

Engineering is in progress and material has been purchased

7. Control Room Design Review and Instrumentation Mods

This work is a NRC requirement to be completed at all nuclear plants (licensed or license applicants) per NUREG-0737 Supplement No. 1.

Status -

Required survey completed with report by NRC soon to be issued.

During next two refueling outages, changes identified during review will be implemented.

8. Plant Simulator

The Peach Bottom Plant Reference Training Simulator is being procured to satisfy the upgraded operator qualification requirements that the NRC is imposing through the implementation of NUREG-0585 "TMI-2 Lessons Learned Task Force Final Report" and Reg. Guide 1.149. Improved operator training will provide greater operator efficiency, and reduce potential errors, thereby improving unit availability and performance. This simulator will be leased.

Status -

A contract was signed with Singer in July 1985 to provide the Peach Bottom Simulator on a 30-month schedule.

9. Plant Process Computer

The plant process computer is being replaced because it is beyond its expected life, no longer supported by the manufacturer, maintenance and spare parts availability is becoming difficult, and no new features or improvements can be added. In addition, PECo has committed to the NRC to provide a Safety Parameter Display System (SPDS) at Peach Bottom to satisfy NUREG-0800. This required SPDS system will be part of the process computer replacement. These systems will be leased.

Status -

A specification is in the final stages of preparation and will be released for proposals within a month. A contract will be awarded later this year with scheduled service dates of 1989 for Unit 3 and 1990 for Unit 2.

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TABLE 4

SALEM GENERATING STATION

UNITS 1 AND 2

Responses to Cross Examination Questions
Re: Mod Justification (Economics) and
Job Status (Work in Progress)

TABLE 4

SALEM 1 & 2

PROJECTS TO BE COMPLETED WITHIN 3 YEARS:

1. Replace Moisture Separator Tube Bundles.
2. Replace RHR Sump Pumps.
3. Upgrade Circulating Water Pump Bearing Lubrication Pump.
4. Reactor Vessel Head Quick Disconnect Tensioner
5. Replace Service Water Strainer - Cancelled - Response not Required.
6. Replace Chiller Condensers.
7. Replace Primary System Flow Transmitters - Job Completed - Response not Required.
8. Replace Turbine Area Sump Pumps.
9. Upgrade Plant Simulator.
10. Upgrade Circulating Water Pump Internals.
11. Replace Service Water Piping to Component Cooling Heat Exchanger.
12. Turbine-generator Supervisory Instrumentation.

Salem Units 1 & 2

1. Replace second stage tube bundles in all moisture separator reheaters (MSR's)

Present tube failure rate exceeds 10% yearly and is rapidly incressing due to excessive vibration. The vibration is caused by support failures and other material and design problems, all of which are being corrected with the tube bundle replacements. Because of the tube failures, reheat temperatures have been running 20°F below design corresponding to an energy replacement cost of $550,000 per year per MSR. Each bundle was estimated, at the time of cost/benefit analysis, to cost $950,000 for a pay back period of about 21 months.

Status -

Design complete. Equipment ordered. Construction scheduled for next two outages.

2. Replace RHR Sump Pumps

These pumps transfer seal leakage from the RHR pumps and other sump water to the waste hold-up tanks. The pumps are vital to unit operation; servicing is difficult because they must be removed from the sump which is in a high radiation area. They have been subject to unanticipated excessive amounts of debris and silt clogging the internal cooling passages, overheating the motors, and damaging the bearings. The failure rates have been three to four times per year; and three times only one of four pumps per unit was in service.

The replacement pumps and controls will be of an upgraded design to better provide for the service encountered. No formal economic evaluation was performed; but the relatively small replacement cost is justified by improved reliability of this important equipment.

Status -

Design complete. Equipment ordered.

3. Replace two main circulator bearing lube pumps

The new pumps will be of an upgraded design and materials to resist the severe erosion experienced by the original bowl and impeller due to the unanticipated amount of silt in the river water. By eliminating the inefficient operation and high maintenance costs (pumps have had to be repaired at a rate of one every three months), upgrading with the new pumps will result in a payback period of about one year.

Status -

Design complete. Construction is about 5% complete.

4. Reactor vessel head quick disconnect tensioner

Existing tensioners are screwed on manually by two men, requiring about 12 minutes per stud. The new, quick disconnect, air activated tool requires only one man to operate at about 1/16 of the time. The result is a savings of 10-12 man-rem and about 30 hours of outage time for each refueling. Including replacement energy costs, the annual savings were estimated at $330,000 more that justifying the job.

Status -

Three tensioners have been received. 54 new studs scheduled for delivery by August, 1986.

6. Replace chiller condensers

The original chiller condensers, with 90/10 copper/nickel tubes, were replaced in 1979 with two-pass, straight tube condensers using titanium tubes. However, increasing fatigue failures have occurred due to unanticipated excessive vibration in unsupported spans whose natural frequency was found to be close to that of nearby mechanical equipment. The resulting tube leaks allowed river water to enter the compressor causing high maintenance costs.

The new units will be of a four-pass, U-tube design with shorter spans, also using titanium tubes.

Based on maintenance cost savings, a pay back of about two years is estimated for the condenser replacements.

Status -

Equipment is on order.

8. Replace Turbine Area Sump Pumps

The original vertical turbine pumps have carbon steel internal parts which have corroded and eroded badly over the years. Mechanical failures have occurred repeatedly. These pumps are no longer manufactured, and parts are very difficult and time consuming to obtain. The replacement pumps for this important service will be of a different manufacturer and upgraded design. They will be submersible, slurry type pumps with cast bodies and stainless steel internals.

Status -

Equipment is on order.

9. Upgrade plant simulator

The simulator is located in the Nuclear Training Center. NRC NUREG 1.149 requires that all control room changes be duplicated on the simulator within 12 months of such changes. The job included here was authorized in 1985. It is anticipated that there will be similar updating authorizations annually for the next few years.

Status -

Design and component procurement are in progress.

10. Upgrade circulating water pump internals

The pumps, of ductile iron construction, have experienced severe graphitization resulting in wall thickness being reduced to less than code minimum. Some upgrading and rebuilding has already been completed. This work item includes modifications to deflector support flanges, deflector blades, pump cover with manway and pipe assembly, upper and lower bearing brackets, and stuffing box spargers, all with improved materials, design, and/or maintenance access provisions.

Improved fuel efficiency, lower operating and maintenance costs, and avoidance of load reductions due to pump unavailability result in a pay back period of 22 months.

Status -

Design is complete and field work is about 60% complete.

11. Replace service water piping to component cooling heat exchanger

Existing stainless steel piping to the heat exchanger is often in a low flow condition causing severe pitting and corrosion. This piping will be replaced with polyethylene coated carbon steel pipe. The emergency auxiliary feedwater piping, due to its configuration and location of an isolation valve, is normally stagnant, resulting in build-up of silt and marine growth causing pitting and corrosion. This piping will be rerouted with an isolation valve located so as to eliminate the dead legging. Economic evaluation of the described fixes showed a pay back of two years. Two other alternatives (spray coating without redesign, and repair as problems arise) were also evaluated and found less economical. Avoidance of forced unit outages due to failure of this piping, and the successful use of polyethylene coated pipe in other similar applications, provide further justification for this project.

Status -

Installation not started (being scheduled).

12. Replace turbine generator supervisory instrumentation

The existing monitoring systems (vibration, expansion, eccentricity, differential, etc.) designed in the 1960's have become inaccurate, unreliable, and subject to excessive maintenance costs. Parts are no longer available, and false indications could lead to unnecessary unit shutdowns.

The economic analysis justifying this project showed a pay back of less than two years.

Status -

Installation not started (to be scheduled).

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TABLE 5

KEYSTONE UNITS 1 AND 2

AND

CONEMAUGH UNITS 1 AND 2

Responses to Cross Examination Questions
Re: Mod Justification (Economics) and
Job Status (Work In Progress)

JOBS TO BE COMPLETED WITHIN 3 YEARS:

Keystone

1. Replace economizers
2. Convert boilers to balanced draft
3. Replace station computers
4. Develop additional ash disposal sites
5. Electrostatic precipator modification
6. Replace L.P. feedwater heaters
7. Purchase spare boiler circulating pump
8. Replace intermediate reheaters
9. Wastewater treatment system improvements
10. Purchase spare boiler feed pump coupling elements

Conemaugh

11. Replace H.P. and L.P. feedwater heaters
12. Replace station computers
13 Develop additional ash disposal sites
14. Electrostatic precipitator gas flow improvements
15. Purchase spare boiler circulating pump - Job cancelled - See Keystone Item 7.
16. Heat rate monitoring equipment.

KEYSTONE 1 AND 2

1. Replace Economizers

The economizers were a source of increasing high maintenance costs and outage rates.

By replacing the economizers, recovery of generation loses will save an estimated $\$11.3 \times 10^6$/year, resulting in a payback period of 21 months.

Status -

The installation is about 60% complete. Remaining work is being coordinated with other work scheduled during forthcoming planned unit outages.

2. Convert Boilers to Balanced Draft

Continual operation of the boilers with pressurized furnaces entails serious equipment failure risks and operating hazards due to hot pressurized furnace gas and flyash leaks. Various modifications and operating limitations were considered to improve operation in the pressurized mode, but none of these were felt to insure long term service life. No attempt was made to evaluate these risks, the only economic analysis being to compare the present worth of capital investment plus annual operating costs of each option, including continuing as is. The lowest cost (using 30 year expected life to maximize use of the locally available coal supply), even without a cost assessment of pressurize operation risks, was clearly conversion to balanced draft, as follows:

$\$ \times 10^6$

Alternative	Capital Cost	Annual Cost	Present Worth
1. Convert to Bal. Dr.	48	4.0	131.8
2. Press. Oper w/Mods.	72.7	4.2	159.0
3. Press. Oper. as-is	-	49.2	1005.5

Status -

Unit 1 is virtually complete and Unit 2 is about 60% at this time.

3. Replace Station Computers

A. The existing computers are approaching the end of their useful life and computer down-time will increase significantly.

B. The new computers will be capable of displaying controllable losses in dollars/hour, BTU/KWH, and megawatt-hours/hour, which is beneficial in improving the units' heat rate. Shift performance logs can also be generated on the new computers.

C. Through turbine start-up assistance, lockout/permissive analysis and enhanced data display capabilities unit start-up time can be reduced using the new computers.

D. The historical storage and retrieval function and the high speed sequence of events function of the new computers can reduce forced outage time by quickly identifying the cause of the forced outage and returning the unit or the lost equipment to service.

E. The turbine startup/shutdown assistance function, the enhanced data processing capabilities and the historical storage and retrieval function will extend the equipment life by not subjecting the turbines to excessive thermal stresses during startup and shutdown, trending to detect gradually-developing problems and to aid in troubleshooting changes in unit performance.

F. The features described above, besides contributing to increased equipment life, will improve personnel safety by detecting problems before they result in destructive failure.

G. The new computer systems will support the Production Department staff in their attainment of corporate goals related to heat rate improvement, capacity factor improvement, personnel safety and plant longevity.

H. Many of the required spare parts for the existing computers are no longer available for purchase, making system maintenance and repairs increasingly difficult.

Recoverable losses were calculated for improved control of steam temperatures and excess air, plus reduced start-up fuel and replacement power costs, totalling $435,000 per year. As described above, the overall benefits far exceed these calculated savings.

Status -

Design work is in progress.

4. Develop Additional Ash Disposal Sites

Additional site development is required to provide continuous ash and mine refuse storage for Keystone Station and maintain the disposal site in compliance with PaDER's Solid Waste Disposal Permit No. 300837 and Coal Refuse Disposal Area Permit No. 03820701.

Additional underdrains and liner are required in 1986 to provide necessary disposal site capacity to mid-1987. Because the amount of liner required to complete the Stage I area is relatively small (approximately 14 acres total), the installation will be completed in 1986.

Construction of the final east peripheral drainage facilities is being delayed until 1986 pending approval of an amendment to the station's two PaDER permits. The amendment is required due to a combined ultimate East/West Valley site development plan modification intended to gain additional storage volume for Keystone Station at no increase in site development costs.

This in an environmental project; therefore, no economic analysis is required.

Status -

This work was authorized in September 1984 and is now approximately 70% complete.

5. Electrostatic Precipitator Mods

The electrostatic precipitator modifications were necessitated by the recent changes in State Air Quality regulations and, thus, no economic analysis was required for their justification. The benefits obtained by these modifications were as follows:

A. Optimized voltage control would permit the precipitator to operate at a higher efficiency.

B. Improvement in stack opacity. As of April 1, 1983, continuous stack opacity monitoring is required by the PaDER. This will require the precipitators and control systems to operate at their maximum efficiency to insure compliance with required opacity levels.

C. Maintenance costs would be reduced using the new solid state controls.

D. An ability to obtain spare parts for the new controls, since the existing equipment is obsolete.

Status -

The modifications were authorized in February of 1983 and are now approximately 90% complete.

6. Replace L.P. Feedwater Heaters

Tube failures have been increasing and are expected to continue doing so. To prevent turbine water injection, a heater with significant tube leakage must be isolated which requires removing a whole heater string from service and operating on a by-pass and the other string. An increase in heat rate and loss of generating capacity results from such operating mode. These losses were estimated at $575,000 annually for both units. If the faulty heaters were to be simply removed from the cycle and the units run permanently without them, the annual loss was calculated to be almost 10 times that of occasional by-passing. In either case, replacement of the heaters was easily justified.

Status -

New feedwater heaters are on order.

7. Purchase a Spare Boiler Circulating Pump (for use on either unit)

Repair time for these extremely critical boiler circulating pumps has been 2-3 months on an emergency basis and 4-6 months on routine basis. Repair costs have ranged from $70,000 to $150,000 per pump. The cost of a forced outage due to pump failure for loss of generation is $400,000/day which is approximately the cost of a spare pump. It is proposed to purchase a spare pump/motor assembly which will be a common spare for both units.

Status -

This work was authorized in January 1984, however difficulty has been experienced in obtaining a new pump.

Note -

This spare will also back-up Conemaugh Station.

8. Replace Intermediate Reheaters

Tube failures in the intermediate reheaters of both units have resulted in a 1.0 to 2.0% loss of generation averaged over a recent 3-year period. The present worth of levelized estimated annual replacement energy and capacity losses over a projected 25 year period for both units exceeds $\$6.4 \times 10^6$. The present worth of the levelized capital charge for the same period for both units equals only $\$2.4 \times 10^6$, easily justifying the total replacement of these reheaters.

Status -

The work has just recently been authorized.

9. Waste Water Treatment System Improvements

The Pennsylvania Department of Environmental Resources determined that the existing treatment lagoon cannot be utilized as a part of the station's treatment facilities, due to a stream flowing through the lagoon and entering Crooked Creek through the station's NPDES discharge point. The lagoon, although it is not to be used as a treatment facility, does bring the discharge waters closer to compliance with regard to thermal limits set by PaDER. The lower water temperature of the stream mixes with the station discharge and thus significantly reduces the overall temperature of the water entering Crooked Creek.

A study was performed which determined that a cooling tower alone would not meet regulations. The cost of this cooling tower would be approximately $2,682,000.

Based on these facts, PaDER will permit Penelec to divert a portion of the stream and use the lagoon for thermal treatment, allowing Keystone to exceed thermal discharge limits until Crooked Creek recovers. It is less expensive to install a 24" diameter bypass pipe ($1,560,00) than a cooling tower. Tests on Crooked Creek waters for the past four years have shown improvement in its water quality, but it is not likely to recover fully for some time.

An economic analysis was performed to determine how long construction of a cooling tower could be delayed by constructing the bypass pipeline now, using 25 years of remaining life for Keystone Station.

The present worth of the pipeline levelized fixed carrying charges and O&M costs totaled $1,776,124, compared to $3,757,559 for the cooling tower, a difference of $1,981,435.

The next step was to determine how long construction of a cooling tower could be delayed to break even. The break-even point was found to be 5 years, so that it becomes cost effective to construct the bypass pipeline now if the cooling tower would not be required for 5 years.

Status -

The pipeline is now 60% complete.

10. Purchase Spare Boiler Feed Pump Coupling Elements (for use on either unit)

In service failure of a BFP coupling could result in a 40% load reduction on the affected unit for a minimum of 8 to 10 months while a replacement is being manufactured. Continued maintenance experience indicates a high probability of such a failure occurring, at an estimated cost of $55x10^6$ which more than justifies the cost of this spare equipment which will be available for either unit.

Status -

Parts are on order.

CONEMAUGH 1 AND 2

11. Replace HP and LP Feedwater Heaters

Justification similar to Keystone Item 6.

Status -

Job in 1986 budget. Schedule to be developed.

CONEMAUGH STATION

12. Replace Station Computers

Justification similar to Keystone Item 3.
Savings totalling $871,000 per year were calculated. As in the case of keystone, the overall benefits are much greater.

Status -

Engineering is in progress.

13. Develop Additional Ash Disposal Sites.

The station burns 4×10^6 tons of coal per year, creating a coal ash and mine waste transportation and disposal requirement which can only be met with new facilities. Public sites are far away and extremely costly. The site to be developed is close to the station, is similar to a site recently completed for Keystone, and will comply with all State and Federal regulations. The only alternative for compliance would be shut down of the station.

Status -

Work is in progress.

14. Electrostatic Precipitator Mods

Justification similar to Keystone Item 5.

Status -

Unit 2 complete. Unit 1 30% complete.

16. Heat Rate Monitoring Equipment

The existing station computer is being used to its maximum capability, and long-range modifications and upgradings are being investigated. In the meantime this mini-computer will suffice, providing on line monitoring of controllable heat rate parameters such as steam temperature, pressure, excess air, condenser back pressure, flue gas temperature, etc. The expected heat rate gain is 50 BTU/KWH/UNIT resulting in annual savings of $\$723 \times 10^3$, more than justifying this very small capital expenditure.

Status -

Installation is 80% complete.

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3/17/86 JC

PHILADELPHIA ELECTRIC COMPANY

RECEIVED
MAR 19 1986
SECRETARY'S OFFICE
Public Utility Commission

PAIEUG et al Response to the
Utility Users Committee/University of Pennsylvania
Transcript Request of February 19, 1986

REQUEST: Please provide the percent increases to PAIEUG et al members under Mr. Pollock's recommended rate spread and rate design. Also provide the corresponding load factors.

RESPONSE: Per the agreement between Counsel, the percent increases and corresponding load factors are as follows:

PAIEUG Recommended Tail Block
(JP-1, Schedule 8, Column 2)

	Base	Nonfuel	Load Factor*
Low	8.2%	52.9%	147%
High	35.2%	67.4%	43%
Average	18.5%	61.0%	89%

DELETED
MAR 24 1986

Equal Percent Increase
(JP-1, Schedule 8, Column 3)

	Base	Nonfuel	Load Factor*
Low	12.0%	61.6%	147%
High	33.3%	64.5%	43%
Average	20.2%	64.4%	89%

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

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Surrebuttal Testimony and Exhibits of

James J. O'Brien

ACCOUNT FOLDER

Linerick I and Common

Construction Delay and Consequent Cost Increases

DOCKETED
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O'Brien-Kreitzberg & Assoc., Inc.
2 South Centre Street
Merchantville, New Jersey 08109

SURREBUTTAL TESTIMONY OF JAMES J. O'BRIEN

Q. Are you the same James J. O'Brien that previously filed OCA Statements No. 1 and 1A in Docket No. R-850152?

A. Yes.

Q. What is the purpose of this surrebuttal testimony?

A. This surrebuttal testimony is filed to respond to various rebuttal testimony submitted in response to my direct testimony. I have reviewed all of the testimony and associated exhibits of the following PECO witnesses:

Vincent S. Boyer (Statement No. 1A)

James J. Clarey (Statement No. 4A)

David R. Helwig (Statement No. 5A)

H. William Vollmer (Statement No. 31)

Roger J. Mattson (Statement No. 9A)

James R. Coughlin, Bechtel Power Corp. (Statement No. 33)

James O. Love and

Basil P. Kononetz, Theodore Barry & Assoc. (Statement No. 8A)

Some of the above-named witnesses have prepared new analyses allegedly based upon my direct testimony, and have also commented on the analyses of the other PECO witnesses. Other witnesses have apparently served in an advisory/review role, and have commented as to their opinions regarding the results obtained by others. In

order to avoid repetitious testimony, I have organized this surrebuttal into topical areas.

First I will discuss what I believe to be the issues in this matter. With that discussion as a basis, I will next attempt to group and summarize the various positions taken by the parties in this matter with a primary focus upon those represented by the schedule analyses of Dr. Mattson, and Messrs. Coughlin and Love/Kononetz. Based upon these analyses, I shall demonstrate why I am more convinced than ever that my original testimony was correct, and that Limerick Unit 1 should have been ready to load fuel by July 1982. Finally, I will re-address the excess funds expended by PECO as a consequence of its delay in loading fuel.

In addition, I note that Dr. Stephen H. Hanauer is filing separate testimony regarding Mark II and licensing issues.

Q. Would you please state what you believe to be the issues in this case?

A. For nearly all of the time that Limerick Unit 1 was under construction, PECO announced publicly that it was intentionally delaying the completion of this plant because of a reduced demand for electric power and an inability to finance construction. It was only while Limerick was actually loading fuel that PECO said that <u>even if</u> it had chosen to proceed on its 1974 completion schedule, Limerick

could not have been completed any sooner. As a justification for this position, PECO has offered reasons running the gamut from the close proximity of casino construction to the allegedly immutable demands of the NRC.

As a professional construction manager, I have worked on numerous complex projects in an effort to complete them timely, and have further dedicated myself to the study, development and broad dissemination of state-of-the-art project management systems to aid the construction industry accomplish that goal. I have never heard of a project that was completed earlier than the owner's stated intentions and funding limitations. Thus, in spite of all of PECO's "even if" speculations, the simple fact is that Limerick was not completed sooner because PECO did not try to complete it sooner.

It seems to me that the issue here is whether or not it cost more to complete Limerick as an intentionally delayed project. The answer is admitted by PECO witness David R. Helwig when comparing the first units at Limerick, Susquehanna and La Salle. He has testified to the following (at PECO Statement No. 5A; page 18, line 11):

> Many of the differences between the plants, <u>even though contributing to higher costs and a longer schedule at Limerick</u>, should also result in additional reliability, operability and safety benefits. (Emphasis added)

Q. Mr. O'Brien, doesn't Mr. Helwig also state that you and Dr. Hanauer have, ". . . misstated the comparative value of these plants to the ratepayers." Have you?

A. No, I have not attempted to put a value on any of the three plants. I simply noted in my direct testimony that La Salle and Susquehanna were completed earlier than Limerick. I will now add that both La Salle and Susquehanna cost substantially less than Limerick. I should caution, however, that PECO's assumed correlation between better reliability, operability and safety, and higher cost and longer schedule is tantamount to counting chickens before they are hatched. Among all of the nuclear plant owners I have interviewed, there has been a universal claim of the same benefits. I do not doubt their intent, but the achievement of these benefits has been less than universal. Thus, regardless of speculations about potential benefits, it is admitted by PECO that Limerick Unit 1 took longer to build and cost more than it need have.

Even Messrs. Love and Kononetz found the following "intuitively credible" (at PECO Statement No. 8A; page 44, line 43):

> . . . because PECO reduced then-scheduled funding levels, <u>schedule delays and increased project costs resulted</u>. (Emphasis added)

Messrs. Love and Kononetz did not necessarily agree that such cost increases would result from delay. However, I

firmly believe that the consequences of intentionally delaying construction are more than merely "intuitively credible" - they are provable, quantifiable facts. Further, the cost consequences of delaying construction were known to be considerable and rapidly trending upward at the time PECO made the decision. As such, the Commission was well-justified in finding that it was an unreasonable and imprudent decision. Thus, I believe that the only issue for consideration is the quantification of the cost of delay. Doing so requires a determination of when Limerick Unit 1 could have been completed.

Q. What do you perceive to be the positions of the various parties with regard to that determination?

A. The Pennsylvania Public Utility Staff Witness Dougherty has used an April, 1981, in-service date for Limerick 1 as the basis of his quantification. I know of one post-TMI nuclear power facility that achieved commercial operation around that date (North Anna 2 - 12/14/80).

Chronologically, the next group of plants to gain operating licenses after TMI are given by Dr. Mattson at Schedule 1, PECO Exhibit RJM-1. These were Salem 2, Farley 2, McGuire 1, and Sequoyah 2. All achieved operating licenses in 1980-81, and although I have not performed the investigation, it is possible that Limerick might have been among these plants but for the fact that it had a Mark II

containment. Again referring to Dr. Mattson's Schedule 1, it is noted that by August of 1982, an additional five plants gained operating licenses bringing the total to 10. Among these, of course, were La Salle 1 and Susquehanna 1, as well as Grand Gulf 1, San Onofre 2 and Summer. As I stated in my previously submitted testimony, the inclusion of La Salle and Susquehanna in this last-cited list demonstrates that the Mark II problem could have been resolved to permit an early 1982 fuel load.

I also stated in my previous testimony that I agreed with Dr. Hanauer that the Mark II problem appears to have been the critical path to fuel load. Mr. Vollmer comes very close to conceding this point also when he states (at page 8, line 25) the following:

> This [the Mark II problem] was the most complex issue to face the BWR owners.

It would appear that the only reason that Mr. Vollmer did not consider resolution of the Mark II problem to be the critical path to fuel load is given on the following page 9, at line 31 where he says the following:

> . . . Contemporaneous plant construction schedules did not necessitate such risk taking.

Thus, "the most complex issue to face" PECO could have been resolved by early to mid-1982 (albeit with some risk of rework) but was not because the construction schedule had been intentionally delayed by PECO management.

Q. Would you please briefly address the critical path analysis presented by Dr. Mattson.

A. Yes. Dr. Mattson has testified that the critical path to fuel load was not at Limerick at all, but at the offices of the NRC. Dr. Mattson has stated the following (at PECO Statement No. 9A; page 36, line 23)

> . . . The PRA [Probabilistic Risk Assessment] and the licensing process were critical path items to OL receipt, not the Mark II containment as alleged by Dr. Hanauer. . . . (and continuing at page 39, line 33) preparation, review and litigation of the PRA were additional limiting activities on any accelerated path to low power licensing, and the licensing activities associated with the PRA could not have been accomplished sooner than mid-May of 1984.

Q. How do you respond to that assertion?

A. Dr. Hanauer will respond more specifically. However, it is inconceivable to me to suggest that if Limerick Unit 1 had been properly completed in conformance with the then-existing NRC regulations, including the requirement for documentation, by early to mid-1982, the NRC would nonetheless have forced the plant to remain idle for two years before issuing an operating license. Even in the immediate wake of TMI, the licensing moratorium only lasted just over a year as described above regarding North Anna.

Q. Did Dr. Mattson perform an investigation in an effort to prove that the earliest possible licensing schedule could not have been completed prior to May of 1984?

A. Yes he did, and it is seriously flawed.

Q. Why is that?

A. The basis for Dr. Mattson's conclusion is given at Schedule 4 (Exhibit RJM-1) entitled "Hypothetical Earliest Possible Licensing Schedule For Limerick Unit 1." The problem is that it is only half "hypothetical". It demands that we accept a great deal of history as it actually transpired. For example, Dr. Mattson's Schedule 3 gives the As-Built Licensing Schedule, and shows that the NRC requested a Probabilistic Risk Assessment on May 6, 1980, informed PECO early in 1981 that the PRA had to accompany PECO's license application, and that the PRA printing was complete and submitted with the application in March, 1981.

Compare the beginning of this string of activities with Dr. Mattson's Schedule 4: it shows PECO's hypothetical application being submitted at the end of the third quarter of 1978, but it maintains the same actual date for the PRA request as shown at Schedule 3.

Q. Why was the PRA not required to accompany the hypothetical application back in 1978?

A. Dr. Hanauer has addressed this at length but the simple answer is that the NRC did not require PRA's in the pre-TMI era.

Dr. Mattson would have us believe, however, that even if the plant had been completed earlier, the consequences of

the PRA could have been satisfied only in the way that they were, regardless of how much that delayed operations. I contend that the matter was handled as it was because it was assured that it would not delay the construction critical path to Fuel Load.

The Company's approach on this issue demands that we accept the hypothesis that the sense of the NRC would have been the same in 1977-78 with regard to a plant scheduled for completion in 1982 as it was in 1980-81 for a plant scheduled to be completed in 1984. It most certainly would not.

In sum, I cannot accept the constant insistence by PECO licensing witnesses that history as it was negotiated or transpired would have been precisely the same three years earlier.

Q. Do TBA and PECO construction witnesses also rely heavily on as-built analyses?

A. Yes. This is precisely the same position taken by PECO's construction witnesses, i.e., that I must accept construction as it actually transpired. For example, this position is expressed by TBA as follows (Statement No. 8A; page 22, line 27):

> . . . An 'as-built' schedule inherently incorporates the licensing and regulatory requirements and their impact on the project completion date.

Obviously, an as-built schedule also inherently incorporates the impact of all delays regardless of their cause, including those caused by unreasonable and imprudent decisions, mismanagement or a discretionary action. But, there is no analysis by PECO demonstrating that the regulatory actions equal the delaying effect. Certainly, TBA did no independent analysis, but instead chose to interpret and amplify the results of Mr. Coughlin.

Q. Does TBA present a construction schedule analysis?

A. Yes. TBA's sole contribution appears to be the creation of an as-built network, and the allegation that this network reveals that the Bechtel Schedule I used (issued the same month as the Construction Permit) is missing "several construction activities and numerous activity sequence modifications" (at page 24, line 29).

Q. Did the TBA network reveal any as-built construction realities you failed to reflect?

A. Technically, yes, but practically it did not. First, let me point out that TBA's as-built network was done on the basis of a 900 activity schedule which is far more summary in nature than the schedule that I used. Nonetheless, TBA's exercise revealed a hold on containment concrete placement from April 9 until May 28, 1975. Further, there was a concurrent strike which lasted until June 9, 1975. Therefore, the combination of the containment hold and the

strike added exactly two months to the critical path.

Q. What effect would that have had on your analysis?

A. It would have extended my projected fuel load date from December 11, 1981 until February 11, 1982.

Q. Is there anything else you became aware of as a result of the submission of PECO's rebuttal testimony?

A. Yes. TBA states that the setting of the Reactor Pressure Vessel was delayed because of delays experienced in the precedent concrete placement activities. TBA says the following (at Statement No. 8A; page 25, line 1):

> . . . The actual project schedule issued April 9, 1976 projects RPV set to occur on September 3, 1976. Thus, exhibit JJO'B-4 erroneously shows the setting of the RPV occurring five months earlier than projected.

While that lone statement represents the extent of the proof offered by TBA, based upon my own research, I will accept that delay.

Q. Would the acceptance of the concrete placement delay change the conclusion expressed in your direct testimony?

A. No, it would not. The effect would be to extend the fuel load date from that accepted immediately-above (February 11, 1982) six weeks until the end of March, 1982 as I will discuss below. Since my original testimony included an

extension of construction until July, 1982, this change has no effect on my ultimate conclusion.

As an explanation of its position, TBA offers Schedule 5 (at St. No. 8A, pg. 29b). The TBA AS-BUILT SCHEDULE shown at the top of the page shows only two activities not included in my schedule analysis. These are:

CONTAINMENT HOLD - 7 weeks

ADDITIONAL REBAR - 6 weeks

Every other activity shown on that line is included in my network. Thus, the sum of the only two new activities is 13 weeks. As I noted on page 11 above, I have already extended my December, 1981, fuel load date to February, 1982, to allow for the containment hold. Thus, the only other delay which would need to be accounted for is the six week rebar delay. In the TBA testimony noted above, however, we are urged to accept without explanation two months for the containment hold and strike, and five additional months for the concrete placement delay - a total of seven months. I believe that my schedule analysis provides appropriate recognition of the containment hold and the additional rebar delay.

Moreover, it should be noted, that all PECO witnesses agree that the Reactor Pressure Vessel was not set until December 8, 1976 (see for example TBA Statement No. 8A; page 20a). This additional delay was due to construction

problems at the site and not increased regulation. Thus, this activity is admitted by the Company to have occurred three months late against the contemporaneous construction schedule cited above.

Q. Mr. O'Brien, can you explain why this and other activities highlighted by TBA were late, even compared to a contemporaneous construction schedule?

A. Yes, the simplest explanation was given by Dr. Parkinson in his now-famous "law" which I will paraphrase as follows:

> The quantity of work always expands to fill the available time.

Thus, tasks were not completed timely with reference to the so-called "target schedules" because they were unrealistic - the targets could not be met because PECO had already announced that it did not intend for the targets to be met, and would not fund construction so that the targets could be met.

PECO believed in 1976 that it had six years until fuel load, and in 1978, PECO delayed fuel load again so that there were still six years of construction ahead. Had PECO been at all serious about meeting its target schedules, everybody--craft labor, subcontractors, supervision, and management-would have approached the job very differently.

Q. Your analysis has been criticized because of your use of a June 1974 MSCS schedule which was later revised as to scope and activity sequences. Do these modifications affect your analysis in any way?

A. No, they do not. I added two years plus 7 1/2 months to the 1974 schedule which allows for all additional scope changes and the manpower to install them. I will show when I discuss Mr. Coughlin's Case 1 and 2 analyses that by the addition of this time, as reflected in JJO'B-13, activity durations were sufficiently expanded to embrace all as-built, installed commodities and manpower. Moreover, I reject the assertion that just because the Baseline BPC Schedule was created in June 1974 it is somehow flawed. For example, much has been made of the fact that while this BPC Baseline Schedule (JJO'B-3) shows Containment work as a single activity, it was later separated into two activities, thereby splitting work in the Drywell and Wetwell. This change does not render the original network wrong or less useful. PECO admits that the Wetwell would have been completed relatively quickly and that the overall duration of my Containment activity would have been controlled by work in the Drywell. Either way, the critical path was exactly as shown at JJO'B-13 - in Containment. Further, I will show that when the activities in Containment are split by PECO, sufficient time <u>is</u> available to complete the critical Drywell work under reasonable manpower density limitations.

Q. Are you aware of the fact that Mr. Coughlin has done a study which suggests that even if sufficient funding had been available, the project still could not have been completed by July of 1982?

A. Yes I am.

Q. Please summarize your understanding of how that study was performed?

A. Mr. Coughlin started with my Mark II impacted Schedule as appended to my original testimony (Exhibits 5C and JJO'B-13). Mr. Coughlin then made two unwarranted and in my opinion incorrect changes which I shall address momentarily. However, now I would like to address the substance of his analysis. He says he resource loaded the as-built manhours for all scheduled mechanical/electrical activities into my schedule, as follows (at Statement No. 33; page 10, line 37):

> This adjustment assures that the schedule analysis reflects as-built increases in the quantities of material and equipment installed on the project and related manhour expenditures. As-built direct manual manhours were obtained from our field records which recorded these manhours by facility and commodity, and were directly transferred to the appropriate activity and facility/elevation in the schedule.

In effect, Mr. Coughlin divided the amount of time allowed for each activity on my schedule by the total number of manhours actually spent to install the final as-built quantities, and found the number of craft laborers that

would have been necessary on each day of construction to complete the work according to my schedule.

Q. What was the result of that analysis?

A. Mr. Coughlin claims that the results proved that for some areas of the plant, more manpower would have been required than the physical space could hold. In fact, Mr. Coughlin stated the following (at page 12, line 34):

> The OKA assumed manpower densities exceed the maximum sustainable level in the containment by more than 100 percent, and manpower densities in two elevations in the reactor building are also substantially greater than the maximum sustainable. Moreover, this table indicates the containment and two elevations in the reactor building would require greater than full double shifting in the work forces in the entire duration in order to meet OKA's schedule at even this unrealistic manpower level. However, as described in our Case 2 analysis, such shifting would not have been possible . . . this analysis does not analyze drywell and wetwell manpower density separately . . . the drywell is the actual critical path, and it has more stringent manpower density limits than does the wetwell. When the combined drywell/wetwell density of 170 is separated . . . the OKA required density will exceed the achievable density by a significant additional increment.

Q. Do you agree that in order to complete the plant by July of 1982, PECO would have had to stuff more manpower into certain critical spaces than could physically be done?

A. I do not agree at all. PECO's conclusion is based upon a study apparently done for the sake of the Limerick 2 proceedings, and is in direct contradiction to the figures

published barely four months previously as part of Forecast 7, Part 2, dated November 30, 1984. I have appended the entire appropriate section entitled SCHEDULE DEVELOPMENT to this testimony as JJO'B-27. The following chart compares Forecast 7 with the current PECO testimony regarding Case 1.

Containment

Peak Manpower Density

Forecast 7 (Part 2), page 28	
Reasonable limit	400
Limerick 2 (Forecast 7)	360
Limerick 1	340
Project B	450

PECO Statement No. 33, page 12	
OKA Assumed Manpower to Achieve July 1982 Schedule	379**
Coughlin Maximum	170

It is obvious from this chart that even the inflated OKA figure computed by Mr. Coughlin is nonetheless entirely reasonable in comparison with those presented at Forecast

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** Not based upon JJO'B-13 as submitted. Figure would be less.

7. Conversely, it is Mr. Coughlin's rebuttal figure that appears starkly inappropriate.

As I have previously stated and mentioned in the footnote above, Mr. Coughlin made changes to my Exhibit JJO'B-13 for his Case 1 analysis which artificially inflated the manpower requirements in Containment. Mr. Coughlin states at page 10, line 23, the following:

> Employment of actual startup activities and logic increased the startup length from the originally scheduled 21 months employed by OKA to the actually achieved duration of 27 months (i.e., as measured from initial energization to fuel load). This had the effect of reducing the amount of time available for mechanical/electrical work, but accurately reflected the proper time required for startup testing. (Emphasis added)

In addition, however, Mr. Coughlin states he made other changes as follows (at page 9, line 9):

> Adjustments were then made to reflect the July 1982 fuel load date proposed by OKA . . . the adjustment from the OKA MSCS December 11, 1981 fuel load date to the July 1982 fuel load date proposed by OKA was developed by extending the completion date for critical path activities in OKA's schedule by 7 1/2 months. This was accomplished by adding . . . one month to startup and preoperation and testing activities.

The sum of these statements indicates that the actual as-built duration of startup was imposed upon my network, plus an additional month, but CASE 1 shows energization as February 23, 1980, and fuel load as July 28, 1982. Thus, Mr. Coughlin scheduled over 29 months for startup and not the as-built duration of 27 months. For Case 2, Mr.

Coughlin imposed actual as-built durations on all activities up until June of 1976, and I have already noted that this included unexplained and avoidable delays. Thus, the civil/structural phase at the front of the network was expanded, the startup and testing phase at the back of the network was expanded, and the pinch in the middle severely reduced the amount of time Mr. Coughlin asserts would have been available for mechanical/electrical work. This, in turn, significantly inflated the apparent size of the daily work force which was then compared to suddenly-reduced maximum density limits. I believe that Mr. Coughlin's manipulation of my schedule in this fashion is wrong.

Q. Are there other instances where the scenario you just described was employed?

A. Yes, as I quoted earlier, Mr. Coughlin described in some detail the criticality of the Containment Drywell at his Case 2 analysis. Forecast 7 (at page 27) addressed the very same Containment Drywell (control area 14) along with the Reactor Elevation 253 (control area 7) as MANAGEMENT AREA A. The "MAXIMUM PERSONNEL MANAGEABLE" and "FORECAST CRAFT DENSITY" are both listed as 420.

Q. What does Mr. Coughlin give as the "Maximum Sustainable Manpower Density Limits" for these two areas?

A. At page 17, Mr. Coughlin shows the limit for Containment Drywell to be 120, and the Reactor Building at elevation

253 to be 100, for a total of 220 craftsmen. Similar unexplained manpower density reductions can be demonstrated in other Management Areas, although some increases are noted at specific locations in the Turbine Building.

Q. Were the manpower density limits you cited from Forecast 7 qualified in any way?

A. Yes, they were. Forecast 7 says the following at page 26:

> Manpower up to these limits can be managed without degradation of productivity for conventional operation.
>
> Manpower above these limits can be accomplished, but with reduced productivity and increased manhours.
>
> For maximum productivity, manpower levels below these limits should be targeted.
>
> Manpower loading for HVAC subcontract in the critical areas has been included.

Q. Do any of those qualifications limit the applicability of the manpower density limits in your study?

A. No, to the contrary, it is the "new" figures whose applicability is questionable. Mr. Coughlin states (at page 11, line 25) the following:

> Maximum sustainable manpower density limitations were developed from a study recently performed on the project for the purpose of organizing manpower resource application to achieve the schedule needed to complete Limerick 2 within the PPUC imposed cost containment cap.

Thus, the new Bechtel/PECO study was done for a very limited purpose having little to do with Limerick Unit 1 as

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Thus, the new Bechtel/PECO study was done for a very limited purpose having little to do with Limerick Unit 1 as

it was actually man loaded, or as it might have been man loaded had the various target schedules been real targets.

Q. What conclusions do you draw from your manpower density analysis?

A. The simple result is that it shows that reasonable manpower density limits would not have prevented the completion of Limerick Unit 1 by July 1982. Because that is true, however, it also shows that JJO'B-13 was properly expanded to include all of the as-built direct manhours it actually took to build the plant. Direct manhours are expended to install commodities. Therefore all of the commodities that manpower installed are also embraced in my network. And, once again it is proven that if you don't try to complete your facility, you won't. The means, however, were available.

Q. Has Mr. Coughlin performed any other analyses in an effort to rebut your schedule analysis?

A. Yes. Mr. Coughlin states the following at Statement No. 33; page 20, line 43:

> To demonstrate how quantity differences would have prevented Limerick from achieving the Susquehanna fuel load date, an analysis was performed incorporating the greater Limerick quantities into the Susquehanna construction schedule. (Emphasis added)

Mr. Coughlin then concludes the following (at page 22, line 9):

> . . . Because of its greater quantities, Limerick could not have been completed within the same time frame as Susquehanna . . . (and at page 21, line 19) the results of this analysis are contained in Exhibit JRC-2.

First, it is important to note that Mr. Coughlin's analysis is not based, as alleged, on ". . . the Susquehanna construction schedule" or any Susquehanna construction schedule.

The referenced Exhibit JRC-2 is in fact a 16 construction activity barchart created by Mr. Coughlin on a personal computer. The scope of the activities shown thereon are so broad that one cannot even determine the date of major milestones, such as the date the Reactor Pressure Vessel was set. Comparisons with Limerick are impossible because no similar document was created for Limerick - as I previously noted, the TBA as-built schedule was a 900 activity network and my OKA Schedule included over 3700 activities.

In sum, Exhibit JRC-2, even as explained at PECO Statement No. 33 is virtually useless as an analytic tool for the purpose offered. Accordingly, at IR-OCA-25-9, I asked for all of the backup documentation to this study, and the data offered is far more interesting. For example, Attachment IR-OCA-25-9(c)(1) (revised) (appended as JJO'B-28) gives the monthly installation rate for various commodities at both Susquehanna and Limerick for the period during which

10 percent through 90 percent of each bulk commodity was installed. The results are as follows:

Concrete	27 percent better at Susquehanna
Large Pipe	38 percent better at Susquehanna
Large Pipe Hangers	17 percent better at Susquehanna
Small Pipe	12 percent better at Susquehanna
Cable Tray & Gutter	8 percent better at Susquehanna
Conduit	40 percent better at Susquehanna

Only in the areas of Wire and Cable, and Connections did Limerick produce higher sustained monthly installation rates. Thus, in six out of eight bulk commodities compared, Susquehanna bettered Limerick installation rates by significant amounts, despite the fact that accelerated schedules are supposed to lead to decreased productivity.

Q. What do you mean when you say that Susquehanna was on an accelerated schedule?

A. Susquehanna was, in effect, a lead Mark II plant, and working very hard to complete as soon as possible. This inevitably led to higher manpower densities and consequent inefficiencies, and more rework for which no credit is earned. Yet, productivity was still better at Susquehanna than at Limerick. In my opinion, this is striking testimony to the result of announced construction slowdowns

at Limerick, regardless of the existence of unfunded target schedules showing earlier completion dates.

Along the same lines, PECO witness Clarey has criticized my direct testimony with regard to the same Limerick/ Susquehanna comparison. He states (at Statement No. 4A; page 18, line 41) the following:

> Mr. O'Brien has ignored the earlier construction permit issuance dates at . . . Susquehanna . . . the construction permit date for Susquehanna was November 1973 - a full seven months ahead of Limerick 1. . . .

What Mr. Clarey has declined to mention is that construction at Limerick actually started in August 1970, years before the issuance of a Construction Permit in 1974. Reference to the previously discussed Coughlin Exhibit JRC-2, along with Attachment IR-OCA-25-9(c)(3) (revised) is particularly revealing of the head-start this afforded Limerick. Attachment IR-OCA-25-9(c)(3) (appended as JJO'B-29) gives the dates on which 10 percent and 90 percent of various bulk commodities were actually installed at Limerick. A comparison of those two documents reveals the following:

- While JRC-2 alleges that only 10 percent of structural concrete could have been theoretically placed at Susquehanna by the end of August 1975, Limerick actually achieved that same milestone 10 months earlier in October of 1974.

- o While Structural Concrete is shown on JRC-2 to be 90 percent theoretically completed at Susquehanna at the end of September 1981, this milestone was achieved at Limerick nearly a year earlier in November of 1980.

- o While Large Pipe is shown on JRC-2 to be 10 percent complete for Susquehanna at the end of February 1977, this happened at Limerick a full year earlier in February of 1976.

Q. What do these figures show about PECO Exh. JRC-2?

A. PECO Exh. JRC-2 purports to show that if Susquehanna Unit 1 had had to install Limerick Unit 1 commodities, that plant would have taken many months longer to complete. However, JRC-2's results are inconsistent with its stated underlying assumptions. While using better productivity rates for Susquehanna 1 than at Limerick 1, the schedule has completion milestones for concrete and large pipe at Susquehanna occurring almost a year later than they actually occurred at Limerick Unit 1. It does not make sense that Susquehanna would be behind Limerick in these commodities if the Susquehanna productivity rates were so much better.

Q. What else does the JRC-2 analysis show?

A. JRC-2 also shows that Limerick was in a far better position than Susquehanna to "hit the ground running" when its

construction permit was issued, and this momentum is clearly evident in the early construction activities and through the time period until Limerick's funding was cut back. For example, even a quick review of JRC-2 indicates over one full year for mobilization at Susquehanna 1, while Limerick had mobilized in 1970 and again in 1973, and as noted above, had achieved 10% concrete poured within 5 months of receipt of its Construction Permit. If this unnecessary year of mobilization is removed from Mr. Coughlin's JRC-2 schedule, his fuel load date would be reduced from April, 1984, to March, 1983.

Q. Apart from the flaws in PECO Exh. JRC-2 you have just discussed, do you have any other comments on PECO's Susquehanna/Limerick commodity comparisons?

A. Yes. I have prepared the following table to illustrate what we are discussing.

Commodities	Monthly Instal. Rate at Susquehanna Compared to Limerick	Commodity Diff. at Limerick Compared to Susq.
Concrete	+27%(SSES better than LGS)*	+10%**
Large Pipe	+38%	+30%
Large Pipe Hangers	+17%	+36%
Small Pipe	+12%	+18%
Cable Tray & Gutter	+ 8%	- 7%
Conduit	+40%	-17%
Wire & Cable	-14%	-15%
Connections	-29%	+ 2%

---

* from IR-OCA-25-9-(c)(1)rev.

** from PECO St. 5A Sch. 2 rev.

Q. What does this table reveal?

A. This table compares the Susquehanna and Limerick installation rates and commodities. As noted previously, and as seen above, Susquehanna had monthly commodity installation rates which were substantially better than Limerick. Thus, even though Limerick had increased quantities for some commodities, I believe that if Limerick's construction performance had matched Susquehanna's, Limerick's fuel load would have been achieved substantially earlier than PECO suggests was possible.

Q. Are there any other comments contained in the PECO Rebuttal Testimony on which you would like to comment?

A. There are many things, but due to time limitations I will restrict myself to one more issue which I believe to be important. TBA has attempted to highlight what it believes is an inconsistency in positions taken between Dr. Hanauer and myself. PECO Statement No. 8A (at page 18, line 3) extracts two statements from our previous testimony at Callaway, and says the following:

> In summarizing the O'Brien-Hanauer review basis, Mr. Hanauer states:
>
> > Our review properly concentrated on the results achieved . . . it is the results rather than the process by which prudence should be judged, in our opinion.
>
> In contrast, OCA witness O'Brien in this proceeding testified that:

> I don't believe that looking at the bottom line is an appropriate comparison as to whether something is prudent or imprudent.

These two statements are not at all inconsistent. My statement was made with reference to comparing the "bottom line" of plant costs. Dr. Hanauer has never testified on the subject of total plant costs and was referring here to the "results achieved" with reference to engineering and licensing issues.

Q. Finally, Mr. O'Brien, has any of the PECO Rebuttal Testimony caused you to reconsider your position with regard to excess expenditures as a result of the 27 month delay in completing Limerick Unit 1?

A. I have reconsidered all of my testimony, but my position remains unchanged.

Q. What cost increase in Limerick was incurred because of the Mark II errors?

A. In my direct testimony, I gave a simple answer to this question. I used the Company's number of $136.1 million as the direct cost, right out of PECO Exhibit No. 2. Actually, in response to an early OCA data request PECO supplied a Mark II cost estimate of $162 million. Now, company witness Mr. Vollmer says in rebuttal that neither figure is correct. He gives a listing of the cost

breakdown. The result of his analysis is that only $24.8 million of the $136.1 million of the Mark II cost at Limerick would have been incurred if the plant loads had been specified correctly to start with.

Q. Have you reviewed Mr. Vollmer's allocation?

A. Yes, I have.

Q. What did you use for comparison?

A. I reviewed the items in Mr. Vollmer's list against their detailed descriptions in the Company's response to data request OCA-4-45, which is a detailed set of documents backing up Items A-D in Mr. Vollmer's list.

Q. Are the cost breakdowns given in the Company's response to OCA-4-45 actual costs?

A. No, they are not. They are taken principally from Forecasts and Trends. Both of these were predictions of the cost of the plant or individual items. I have learned on many other plants that Bechtel does not go back and review the cost estimates it has previously supplied for Trends and Forecasts after the work is done to see whether the actual expenditures were equal to the forecasted amounts. The principal reason for this is that Bechtel does not accumulate costs in such a way as to identify work items separately in the cost reports. Therefore, we are

looking at forward-looking estimates of certain pieces of work.

Q. How do you feel about the accuracy of these estimates?

A. I have no data directly telling whether these particular estimates were accurate. However, the history of the Limerick job is a history of cost overruns in both engineering and field work. Therefore, I would have to believe that these cost estimates are most likely lower than the actual cost incurred for these items.

Q. What were your objectives or criteria in reviewing the allocation of these costs?

A. My objective was to try to find out, within the limitation that these weren't actual costs at all, which of these costs would have been incurred if the Mark II loads had been specified correctly from the start.

Q. How did you assess the original cost of the design and construction of the containment?

A. I couldn't. No such data were given. I don't know whether any field work had to be torn out and thrown away. I suspect it was small, based on the description given. However, the design, construction and installation of about 1000 pipe hangers was wasted and had to be done entirely over because of the Mark II error. (PECO Statement No. 8A, p. 12)

Much of the design work on the containment structure and related structures had to be done over again even though the structures themselves may not have required very much modification. Therefore, much of the design work on the original containment, an amount we don't specifically know, was wasted and should be included with the total cost that would have been avoided if the Mark II loads had been specified correctly to start with.

Q. Have you reviewed Mr. Vollmer's allocations?

A. Yes, as best I could. Some of the descriptions aren't very informative.

Q. Do you agree with his result?

A. No. There are many things that I think are wrong with it.

1. The cost figures are taken from estimates made before the work, and are therefore probably too low.
2. AFUDC must be added.
3. As discussed earlier, the amount of the original analysis and construction which had to be thrown away is not included.
4. Mr. Vollmer's figure also excludes the cost of the delay in plant completion calculated from 1981 when reasonably built non-Mark II contemporaneous plants were completed.
5. The items which involved field work (Items J, K, L, M, N and O) are all (except J1) allocated 50-50 between

Units 1 and 2. This is consistent with the idea that all the Trends and Forecasts (up to Forecast 7) are for both units, undifferentiated. It is not consistent with the facts. The equipment dealt with in these Trends and Forecasts has not yet been installed in Unit 2. Therefore, it can be done right the first time and there will be, one hopes, no rework and no low productivity due to shoehorning changes in at the last minute. Either the estimation (which is all that we have) of these changes was done incorrectly, by imputing the shoehorning and poor productivity incorrectly to Unit 2 as well as Unit 1, or it was divided incorrectly and the lion's share of the cost should go to Unit 1 rather than half as was done by the Company's reckoning.

6. Many of the analytical and engineering tasks (Items A-I) read like the same work. Examples are Item B, "Engineering to perform Mark II containment analysis" and Item E, "Mark II analysis." Some of the other analytical items also look similar. They do come from different Forecasts, so maybe this is the usual continual ballooning of analytical costs. However, there seems not to have been adequate consideration of how much of these costs were for work which later had to be thrown away.

7. The cost of delay during the 2 month Containment Hold and subsequent placement of additional rebar is not included.

8. The distributable costs are not correctly calculated, as Mr. Vollmer has acknowledged in the Company's response to Data Request OCA-25-6.

Q. What do you conclude?

A. As I have testified under cross-examination, my belief is that the total cost of Mark II changes at the Zimmer plant would have exceeded $400 million had that plant been completed. The utilities which own Zimmer have in fact sued GE for at least $360 million as a result of Mark II containment problems. Given that, as well as for the reason set forth above, it is my belief that the $136.1 million figure given by PECO for Limerick represents a conservative estimate of excess costs that need not have been spent had the Containment been properly designed in the first place.

Q. Do you propose to make any changes with respect to your calculation of Bechtel and PECO Indirect costs of delay?

A. No, it is my belief that the figure I provided for excess Bechtel Power Corporation Indirect Costs is understated, and does not include Home Office Overhead which has never been revealed.

As to the PECO overhead figures, Mr. Clarey states (at Statement No. 4A; page 16, line 37) the following:

> . . . Public Notification costs relate to design and installation of the NRC-mandated Emergency Notification System at Limerick, and would all have been incurred regardless of the completion date.

Mr. Clarey continues at page 16, line 43) as follows:

> . . . Training costs are related to the training and qualification of the plant operating staff and would all have been incurred earlier if the plant was completed in July 1982.

I am not willing to accept these assertions without additional proof. The fact is that PECO was repeatedly asked by OKA to supply annual overhead figures from which it would have been possible to determine when charges for these items were started. It would then be possible to correlate charges with events so as to assess what excessive costs might have been incurred. For example, the plant operating staff is usually deeply involved in startup and testing activities as part of their training. The Staff is generally brought to the plant when it is about 50% complete. This completion point was recorded in Limerick Forecasts beginning in 1979; at which point Bechtel was projecting an October, 1982, fuel load date. It is not very likely that the plant operating staff was reassigned elsewhere or laid-off when the fuel load date was officially slipped until October, 1984. It is very likely that this large group remained at the plant and continued doing something for that additional two years at

considerable cost. Likewise, Plant/ Start-up Staff and Maintenance costs were also accumulated during the delayed startup phase. Excess power costs were incurred during the 27 month delay period. In any event, these are insignificant matters when compared with PECO's failure to divulge the entirety of Bechtel Power Corporation's overhead and indirect costs during the 27 month period.

Q. Mr. O'Brien have you adjusted any of your delay cost calculations.

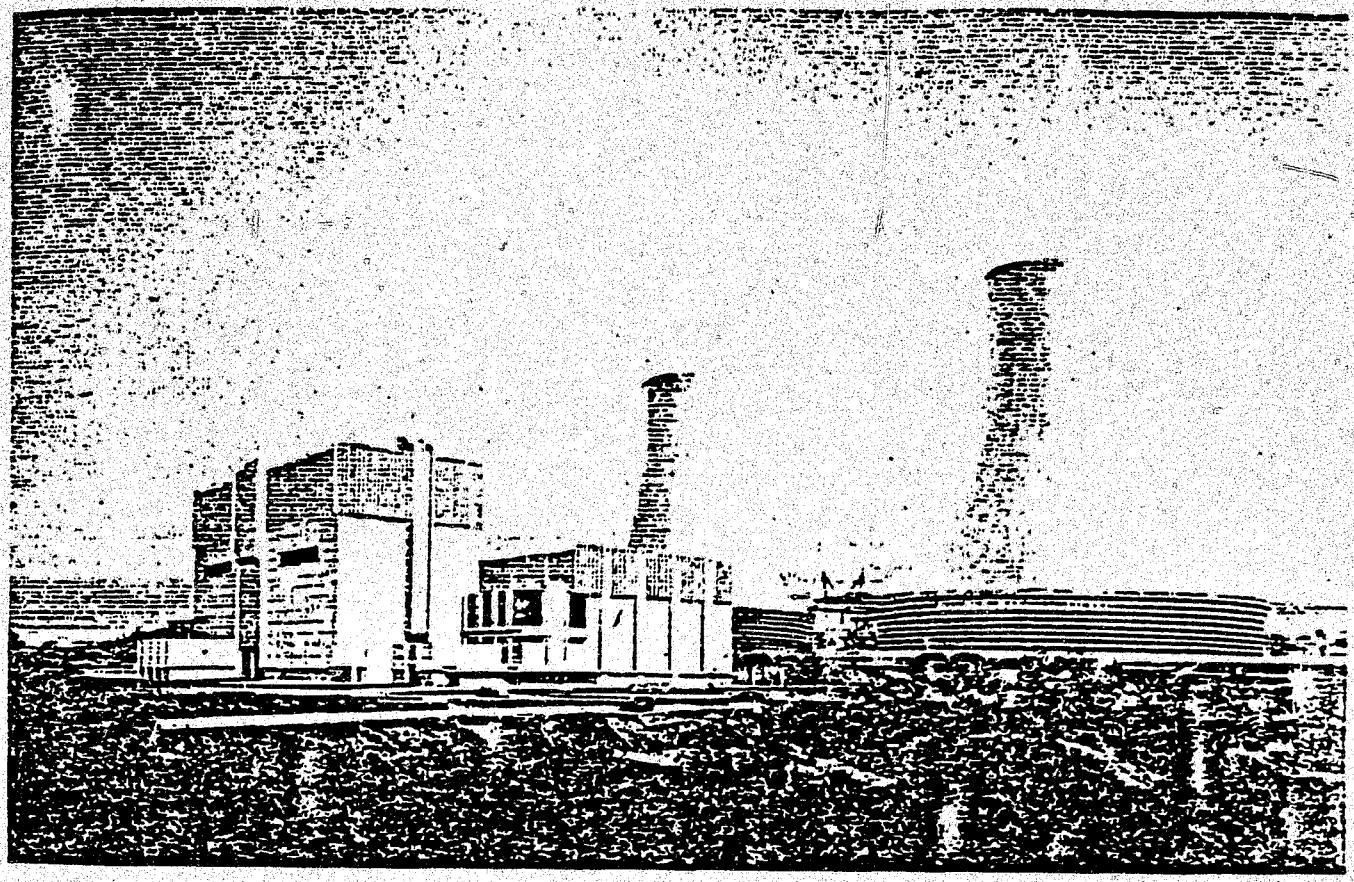
A. Yes. As shown in Exh. JJO'B-30, I have adjusted my calculations to take into account PURTA taxes and overheads where necessary. My final calculations show that if the PUC adopts an adjustment for the 27 month delay and the Indirect Costs, the total would be a) at 50% of Common, $652.4 million and b) at 100% of Common, $792.7 million. If the PUC also adopts my Mark II quantification the total would be a) at 50% of Common, $804.4 and b) at 100% of Common $944.7 million.

Q. Does that conclude your testimony?

A. Yes it does.

Limerick Generating Station

Units 1 & 2
Philadelphia Electric Company



FORECAST 7

PART 2

NOVEMBER 30, 1984

Bechtel Power Corporation

3.0

SCHEDULE DEVELOPMENT

3.0 SCHEDULE DEVELOPMENT

There are two methods for schedule evaluation

I. Manpower Densities (Primary method)

1) Manpower density by management area
2) Availability of critical craft - fitters/welders
3) Overall manpower on site.

II. Comparison of Installation rates at other plants.

3.1 Manpower Density Evaluation

Several schedule analysis runs were made for this case, each with different durations and hence different installation rates and manpower densities. The resultant manpower curves were compared to first the density limits of each management area, and then to the job overall. The specific limits are listed on Attachment 3.1-1 (following). A description of the schedule runs is outlined below:

Run	Shift Format	Labor Productivity	Restart to F/L Duration	S/U Duration
A-4-3	5x8	10% better than Unit 1	4 yrs. 3 mos.	16 mos.
A-3-6	5x8	10% better than Unit 1	3 yrs/ 6 mos.	16 mos.
A-3-6'	5x8	10% better than Unit 1	3 yrs/ 6 mos.	16 mos. constn slip into S/U by 3 mos.

After a project management review of the various runs, it was decided to forecast the project on the basis of run A-4-0 with a 3 month extension for unavailability of craft during two outages of Unit 1. This yields a 4 year 3 month schedule.

3.0 SCHEDULE DEVELOPMENT

3.1 Manpower Density Evaluation (Cont'd)

- This schedule analysis is at a master schedule level. Upon approval of a specific schedule, a detailed construction schedule will be developed.
- "Phasing" between commodity curves reflects the Limerick program.
- The manpower density limits listed on Attachment 3.1-1 represent manageable upper limits as opposed to optimal limits.
  - Manpower up to these limits can be managed without degradation of productivity for conventional operation.
  - Manpower above these limits can be accomplished, but with reduced productivity and increased manhours.
  - For maximum productivity, manpower levels below these limits should be targeted.
- The profile commodity installation curve used in this analysis is not the standard "S" curve, but a slightly convex curve in the 10% to 90% range. This reflects the assumption of unrestricted rates of progress early in the bulk construction stage.
- The unit-rate curve ("Focus" curve) is based upon Unit 1.
- Manpower loading for HVAC subcontract in the critical areas has been included.

LIMERICK GENERATING STATION
UNIT 2
FORECAST 7, PART 2

3.0 SCHEDULE DEVELOPMENT (Cont'd)

3.1. Manpower Density Evaluation (Cont'd)

Manual Craft Density

(Includes all actitivities except distributables)

MANAGEMENT AREA	DESCRIPTION	MAXIMUM PERSONNEL MANAGEABLE	"FORECAST" CRAFT DENSITY
A	Reactor EL' 253 and containment drywell (Control area 7 & 14)	420	420
B	Core spray and RHR (Control area 1, 2 & 3)	150	150
C	HPCI, RCIC, Elev 177', 201' & 217' and wetwell (Control area 4, 5, 6 & 7)	300	300
D	Fuel pool cooling, RWCU, EL 283', 313, 352, & steam chase (Control area 8,9,10,11,12)	330	330
E	Turbine cond pump, air ejector, iso phase, north of condensor (Control area 15, 16, 17, 18)	130	240
F	South of condensor, east of condensor, air compressor, lube oil area (Control area 19, 20, 21, 22)	150	
G	Turb deck, turb aux El' 269 & 302 (Control area 23, 27, 28)	180	
H	Turb Aux El' 200, 217, 239 (Control area 24, 25 & 26)	200	180
I	Diesel Generators (Control area 29 & 30)	110	80
	Total	1,970	

Reasonable build rate per month: 400 total crafts
160 filters
48 welders

Reasonable overall site maximum peak: 2,000
(excluding distributables)

3.0 SCHEDULE DEVELOPMENT

3.1 Manpower Density Evaluation (Cont'd)

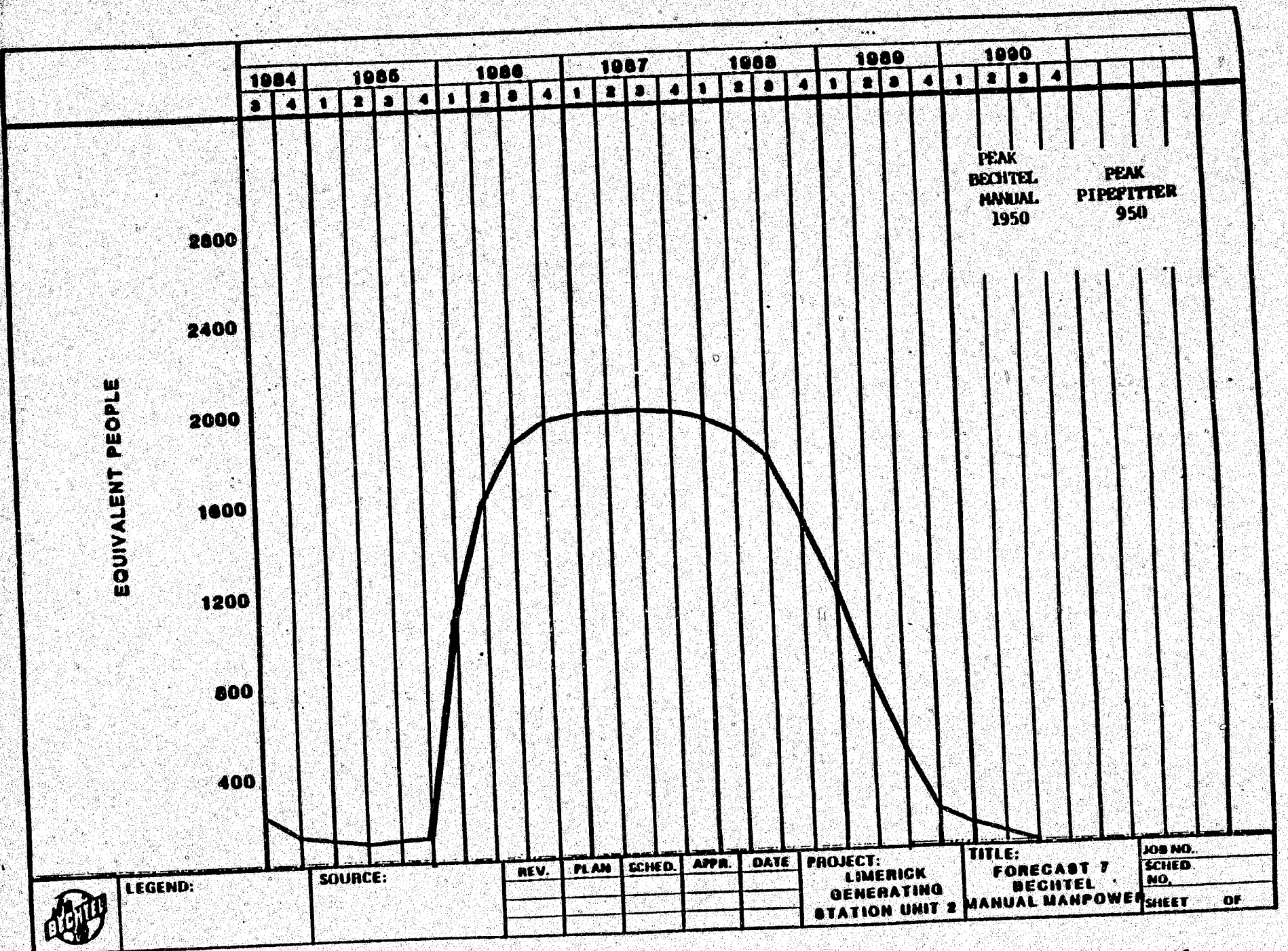
Peak Manpower Density

	Containment	Reactor Blg.	Turbine Blg.	Total Project
Reasonable limit	400	800	660	2,600
Limerick 2 (Forecast 7)	360	680	350	1,950
Limerick 1	340	750	320	2,660
Project A	250	550	370	2,700
Project B	450	340	650	2,975
Project C	310	620	550	3,410

3.0 SCHEDULE DEVELOPMENT (Cont'd)

3.2 Installation Rate Evaluation

Commodity	Installation Rate (per month)	Period (months)	90% to F/L (months)
Large Pipe	4,410	17	34
Small Pipe	4,740	24	20
Cable Tray	1,570	14	34
Conduit	8,680	20	21
Wire & Cable	200,000	16	17
Terminations	6,200	16	14
LP Hangers	315	17	29



SFPD/DTS/D800)

Installation Rate Information
SSES Unit 1 & C vs. LGS Unit 1 & C

Commodity		LGS Duration	10% to 90% Sustained Installation Rate per Mo. SSES	LGS	SSES Duration	Duration for Exhibit JRC-2 (1) LGS Qty/ SSES Rate
Concrete (Composite)	cy	73	2800	2200	53	73(2)
Large Pipe	lf	67	5800	4200	37	48
Large Pipe Hangers	ea.	75	175	145	46	62
Small Pipe (Mech. & Instr.)	lf	46	4800	4300	32	42
Cable Tray & Gutter	lf.	49	1400	1300	44	42
Conduit	lf.	51	8800	6300	44	36
Wire and Cable	lf.	26	146K	170K	36	31
Connections	ea.	26	3600	5100	36	37
Connections 90% to Fuel Load		11			10	

(1) LGS Q/SSES Rate = 0.8 x LGS Quantity/SSES Installation Rate (Bulk Installation Only). This represents the duration from 10% - 90%.

(2) Concrete LGS Quantity/SSES Installation Rate is based on a composite of concrete, rebar, formwork, and embeds, which results in a 1.38 factor appllied to the SSES Q for concrete.

NOTE: Durations are in months.

Limerick Unit 1 and Common

Commodity	FC/7 Total	10% Qty.	Date	90% Qty.	Date
Concrete [1]	203000	20265	10/74	182381	11/80
Large Pipe	349519	34699	2/76	312287	9/81
Small Pipe [2] and Instrument Pipe	248876	24896	6/79	224065	4/83
LP Hangers	13506	1350	11/76	12240	2/83
Cable Tray and Gutter	73728	7373	12/77	66355	1/82
Metallic Conduit	395000	39500	4/79	355500	7/83
Wire & Cable [3]	5934874	593359	8/81	5340231	10/83
Connections [4]	186210	18621	9/81	167589	11/83

NOTES: 1) Excludes lean concrete

2) Excludes Control Rod Drive Piping

3) Includes security wire and cable

4) Includes security connections

GENERAL NOTE: The above table was used to develop the 10% points and 90% points of each commodity and the resultant duration for the work. The installation rates in Attachment IR-OCA-9(c)(1)(Revised) for LGS were derived by using the quantities in PECO Statement 5A Schedule 2 for Limerick.

Derivation of AFUDC Accruals on Nominal Direct Construction Expenditures
For Limerick 1 and 50% of Common Facilities
Assuming 31 July 1982 Fuel Load

(In Millions of Nominal Dollars)

INCLUDING TAXES AND OVERHEADS ON ACTUAL PECO EXPENDITURES
AND PRORATED ADDITIONAL PURTA ON OKA DIRECTS

	ANNUAL DIRECTS						AFUDC					Cumulative Totals	
	OKA			PECO		AFUDC Rates		ACCRUALS				OKA	PECO
								OKA		PECO			
Year	Annual	Semi	Cum	Annual	Semi Cum	Nominal Effectiv	Semi	Annual	Cum	Annual	Cum		
1971				26.5	26.5	8.00% 8.00%	1.1	1.1	1.1	1.3	1.3	27.6	27.8
1972				28.6	28.6 55.05	8.00% 8.00%	3.5	3.5	4.6	3.4	4.7	59.6	59.7
1973				50.1	25.1 105.15	8.00% 4.00%	2.9	6.8	11.4	5.9	10.6	87.6	115.7
					25.1	7.50% 3.75%	3.8					116.5	
1974				61.3	30.6 166.45	7.50% 3.75%	5.0	11.4	22.8	9.7	20.2	152.2	186.7
					30.6	7.50% 3.75%	6.4					189.3	
1975	105.9	53.0	272.4	70.2	236.6	8.00% 4.00%	8.7	20.3	40.5	16.2	36.5	248.3	273.1
		53.0				8.25% 4.13%	11.6					312.9	
1976	124.1	62.0	396.5	92.3	328.9	8.20% 4.10%	14.4	32.4	72.9	22.2	58.7	389.3	387.6
		62.0				8.40% 4.20%	18.0					469.4	
1977	140.6	70.3	537.1	99.0	427.9	8.60% 4.30%	22.2	48.7	121.6	29.7	88.4	561.8	516.3
		70.3				8.70% 4.35%	26.5					658.7	
1978	136.4	68.2	673.5	78.0	505.9	7.10% 3.55%	25.0	54.3	175.9	40.1	128.5	752.0	634.5
		68.2				7.30% 3.65%	29.2					849.4	
1979	173.9	86.9	847.4	97.5	603.4	7.40% 3.70%	33.7	72.4	248.3	51.8	180.3	970.0	783.7
		86.9				7.50% 3.75%	38.7					1095.7	
1980	255.1	127.5	1102.5	147.9	751.3	7.50% 3.75%	44.3	100.0	348.3	69.4	249.7	1267.5	1001.0
		127.5				8.20% 4.10%	55.7					1450.8	
1981	310.6	155.3	1413.1	182.3	933.6	8.30% 4.15%	64.8	145.3	493.6	92.2	341.9	1670.9	1275.5
		155.3				9.00% 4.50%	80.5					1906.7	
1982	316.7	158.4	1729.9	262.1	1195.8	9.10% 4.55%	92.5	198.9	692.5	129.8	471.6	2157.6	1667.4
		158.4				9.30% 4.65%	106.5					2422.4	
1983	90.0	45.0	1819.9	332.1	1528.0	9.30% 4.65%	116.4	212.4	905.0	171.2	642.8	2583.8	2170.7
		45.0				9.30% 3.62%	96.0					2724.8	
1984				329.9	1857.8	9.40%				223.5	866.2	=======	2724.0
						9.40%							
1985				116.0	1973.8	9.50%				270.3	1136.5		3110.2
1986				8.0	1981.8					62.2	1198.8		3180.5
DIFFERENCE IN TOTAL MCG:				$455.7				Per DR-Staff-LIM-14					3180.5
				=======									=======

Derivation of AFUDC Accruals on Nominal Direct Construction Expenditures
For Limerick 1 and 50% of Common Facilities
Assuming 31 July 1982 Fuel Load

Adjusting for Disallowance of PECO and Bechtel Indirects

(In Millions of Nominal Dollars)

INCLUDING TAXES AND OVERHEADS ON ACTUAL PECO EXPENDITURES
AND PRORATED ADDITIONAL PURTA ON OKA DIRECTS

	ANNUAL DIRECTS						AFUDC						Cumulative Totals	
	OKA			PECO			AFUDC Rates			ACCRUALS				
										OKA		PECO	OKA	PECO
Year	Annual	Semi	Cum	Annual	Semi	Cum	Nominal	Effectiv	Semi	Annual	Cum	Annual Cum		
1971				26.5	26.5		8.00%	8.00%	1.1	1.1	1.1	1.3 1.3	27.6	27.8
1972				28.6	28.6	55.05	8.00%	8.00%	3.5	3.5	4.6	3.4 4.7	59.6	59.7
1973				50.1	25.1	105.15	8.00%	4.00%	2.9	6.8	11.4	5.9 10.6	87.6	115.7
					25.1		7.50%	3.75%	3.8				116.5	
1974				61.3	30.6	166.45	7.50%	3.75%	5.0	11.4	22.8	9.7 20.2	152.2	186.7
					30.6		7.50%	3.75%	6.4				189.3	
1975	101.7	50.8	268.1	70.2		236.6	8.00%	4.00%	8.7	20.1	40.3	16.2 36.5	246.1	273.1
		50.8					8.25%	4.13%	11.4				308.4	
1976	120.4	60.2	388.5	92.3		328.9	8.20%	4.10%	14.2	31.9	72.2	22.2 58.7	382.8	387.6
		60.2					8.40%	4.20%	17.7				460.7	
1977	135.8	67.9	524.2	99.0		427.9	8.60%	4.30%	21.7	47.7	119.9	29.7 88.4	550.3	516.3
		67.9					8.70%	4.35%	26.0				644.1	
1978	129.6	64.8	653.8	78.0		505.9	7.10%	3.55%	24.5	52.9	172.8	40.1 128.5	733.4	634.5
		64.8					7.30%	3.65%	28.5				826.6	
1979	162.9	81.5	816.7	97.5		603.4	7.40%	3.70%	32.7	70.2	243.0	51.8 180.3	940.8	783.7
		81.5					7.50%	3.75%	37.5				1059.8	
1980	229.4	114.7	1046.1	147.9		751.3	7.50%	3.75%	42.7	96.0	339.1	69.4 249.7	1217.1	1001.0
		114.7					8.20%	4.10%	53.3				1385.2	
1981	269.7	134.9	1315.8	182.3		933.6	8.30%	4.15%	61.6	137.5	476.5	92.2 341.9	1581.6	1275.5
		134.9					9.00%	4.50%	75.9				1792.3	
1982	263.6	131.8	1579.4	234.6		1168.2	9.10%	4.55%	86.5	185.4	661.9	129.2 471.1	2010.6	1639.3
		131.8					9.30%	4.65%	98.9				2241.3	
1983	90.0	45.0	1669.4	250.6		1418.8	9.30%	4.65%	107.8	196.8	858.7	164.5 635.5	2394.1	2054.3
		45.0					9.30%	3.62%	89.0				2528.1	
1984				260.6		1679.4	9.40%					208.3 843.8	=======	2523.2
							9.40%							
1985				116.0		1795.3	9.50%					250.3 1094.1		2889.4
1986				8.0		1803.3						59.6 1153.6		2957.0
DIFFERENCE IN TOTAL MCG:				$428.8										2957.0
				=======										

Derivation of AFUDC Accruals on Nominal Direct Construction Expenditures
For Limerick 1 and 50% of Common Facilities
Assuming 31 July 1982 Fuel Load

Adjusting for Disallowance of PECO and Bechtel Indirects
And Mark II Rework

(In Millions of Nominal Dollars)

INCLUDING TAXES AND OVERHEADS ON ACTUAL PECO EXPENDITURES
AND PRORATED ADDITIONAL PURTA ON OKA DIRECTS

	ANNUAL DIRECTS						AFUDC						Cumulative Totals	
	OKA			PECO			AFUDC Rates		ACCRUALS				OKA	PECO
										OKA		PECO		
Year	Annual	Semi	Cum	Annual	Semi	Cum	Nominal	Effectiv	Semi	Annual	Cum	Annual	Cum		
1971				26.5	26.5		8.00%	8.00%	1.1	1.1	1.1	1.3	1.3	27.6	27.8
1972				28.6	28.6	55.05	8.00%	8.00%	3.5	3.5	4.6	3.4	4.7	59.6	59.7
1973				50.1	25.1	105.15	8.00%	4.00%	2.9	6.8	11.4	5.9	10.6	87.6	115.7
					25.1		7.50%	3.75%	3.8					116.5	
1974				61.3	30.6	166.45	7.50%	3.75%	5.0	11.4	22.8	9.7	20.2	152.2	186.7
					30.6		7.50%	3.75%	6.4					189.3	
1975	101.4	50.7	267.9	69.9		236.3	8.00%	4.00%	8.7	20.1	40.3	16.2	36.4	246.0	272.8
		50.7					8.25%	4.13%	11.4					308.2	
1976	119.4	59.7	387.3	91.4		327.7	8.20%	4.10%	14.1	31.8	72.1	22.2	58.6	382.0	386.3
		59.7					8.40%	4.20%	17.7					459.4	
1977	134.0	67.0	521.3	97.3		425.1	8.60%	4.30%	21.7	47.5	119.6	29.6	88.2	548.1	513.2
		67.0					8.70%	4.35%	25.9					640.9	
1978	125.7	62.9	647.0	74.2		499.2	7.10%	3.55%	24.3	52.5	172.2	39.8	128.0	728.1	627.2
		62.9					7.30%	3.65%	28.2					819.2	
1979	157.5	78.8	804.6	92.2		591.4	7.40%	3.70%	32.4	69.4	241.6	51.1	179.1	930.3	770.5
		78.8					7.50%	3.75%	37.1					1046.1	
1980	218.2	109.1	1022.8	137.0		728.4	7.50%	3.75%	42.1	94.5	336.1	68.0	247.0	1197.3	975.4
		109.1					8.20%	4.10%	52.4					1358.9	
1981	246.9	123.5	1269.7	160.0		888.4	8.30%	4.15%	60.2	134.1	470.1	89.1	336.2	1542.5	1224.6
		123.5					9.00%	4.50%	73.9					1739.8	
1982	226.5	113.2	1496.2	197.7		1086.1	9.10%	4.55%	83.6	178.5	648.6	123.2	459.4	1936.7	1545.5
		113.2					9.30%	4.65%	94.9					2144.8	
1983	44.5	22.3	1540.7	205.1		1291.2	9.30%	4.65%	102.6	186.7	835.3	153.6	613.0	2269.7	1904.1
		22.3					9.30%	3.62%	84.0					2376.0	
1984				252.1		1543.3	9.40%					193.5	806.4	=======	2349.7
							9.40%								
1985				116.0		1659.2	9.50%					233.4	1039.9		2699.1
1986				8.0		1667.2						55.8	1095.6		2762.8
	DIFFERENCE IN TOTAL MCG:			$386.8											2672.8
				=======											

Derivation of AFUDC Accruals on Nominal Direct Construction Expenditures
For Limerick 1 and 100% of Common Facilities
Assuming 31 July 1982 Fuel Load

(In Millions of Nominal Dollars)

INCLUDING TAXES AND OVERHEADS ON ACTUAL PECO EXPENDITURES
AND PRORATED ADDITIONAL PURTA ON OKA DIRECTS

	ANNUAL DIRECTS						AFUDC						Totals	
	OKA			PECO			AFUDC Rates			ACCRUALS			OKA	PECO
										OKA		PECO		
Year	Annual	Semi	Cum	Annual	Semi	Cum	Nominal	Effectiv	Semi	Annual	Cum	Annual	Cum		
1971				31.2	31.2		8.00%	8.00%	1.3	1.3	1.3	1.5	1.5	32.5	32.7
1972				33.9	33.9	65.1	8.00%	8.00%	4.1	4.1	5.4	3.9	5.4	70.5	70.5
1973				56.2	28.1	121.3	8.00%	4.00%	3.5	7.9	13.3	6.8	12.2	102.1	133.5
					28.1		7.50%	3.75%	4.4					134.6	
1974				71.9	35.9	193.2	7.50%	3.75%	5.8	13.3	26.6	11.3	23.5	176.4	216.7
					35.9		7.50%	3.75%	7.4					219.8	
1975	125.2	62.6	318.4	82.2		275.4	8.00%	4.00%	10.1	23.6	47.1	19.0	42.5	289.4	317.9
		62.6					8.25%	4.13%	13.5					365.5	
1976	145.4	72.7	463.8	107.2		382.6	8.20%	4.10%	16.8	37.9	85.0	26.3	68.8	455.1	451.4
		72.7					8.40%	4.20%	21.1					548.8	
1977	164.5	82.3	628.3	116.9		499.5	8.60%	4.30%	25.9	57.0	142.0	35.3	104.1	657.0	603.6
		82.3					8.70%	4.35%	31.0					770.4	
1978	162.8	81.4	791.1	94.0		593.5	7.10%	3.55%	29.3	63.6	205.6	47.4	151.5	881.1	745.0
		81.4					7.30%	3.65%	34.3					996.7	
1979	206.3	103.1	997.4	110.0		703.5	7.40%	3.70%	39.5	85.0	290.6	61.2	212.7	1139.4	916.2
		103.1					7.50%	3.75%	45.5					1288.0	
1980	300.6	150.3	1298.0	167.0		870.5	7.50%	3.75%	52.1	117.6	408.2	81.6	294.3	1490.4	1164.8
		150.3					8.20%	4.10%	65.5					1706.2	
1981	384.6	192.3	1682.6	227.1		1097.6	8.30%	4.15%	76.4	171.7	580.0	109.7	404.0	1974.9	1501.6
		192.3					9.00%	4.50%	95.3					2262.6	
1982	395.7	197.9	2078.3	325.7		1423.3	9.10%	4.55%	110.0	237.0	817.0	153.4	557.4	2570.4	1980.7
		197.9					9.30%	4.65%	127.1					2895.4	
1983	118.4	59.2	2196.7	399.7		1823.0	9.30%	4.65%	139.2	254.3	1071.3	203.6	761.0	3093.8	2584.0
		59.2					9.30%	3.62%	115.1					3268.0	
1984				408.7		2231.7	9.40%					266.9	1027.9	=======	3259.6
							9.40%								
1985				149.7		2381.4	9.50%					323.7	1351.6		3733.0
1986				12.7		2394.1						74.7	1426.3		3820.4
DIFFERENCE IN TOTAL MCG:				$552.4						Per DR-Staff-LIM-14					3820.4
				=======											=======

Derivation of AFUDC Accruals on Nominal Direct Construction Expenditures
For Limerick 1 and 100% of Common Facilities
Assuming 31 July 1982 Fuel Load

Adjusting for Disallowance of PECO and Bechtel Indirects

(In Millions of Nominal Dollars)

INCLUDING TAXES AND OVERHEADS ON ACTUAL PECO EXPENDITURES
AND PRORATED ADDITIONAL PURTA ON OKA DIRECTS

	ANNUAL DIRECTS						AFUDC							Totals	
	OKA			PECO			AFUDC Rates		ACCRUALS					OKA	PECO
										OKA		PECO			
Year	Annual	Semi	Cum	Annual	Semi	Cum	Nominal	Effectiv	Semi	Annual	Cum	Annual	Cum		
1971				31.2	31.2		8.00%	8.00%	1.3	1.3	1.3	1.5	1.5	32.5	32.7
1972				33.9	33.9	65.1	8.00%	8.00%	4.1	4.1	5.4	3.9	5.4	70.5	70.5
1973				56.2	28.1	121.3	8.00%	4.00%	3.5	7.9	13.3	6.8	12.2	102.1	133.5
					28.1		7.50%	3.75%	4.4					134.6	
1974				71.9	35.9	193.2	7.50%	3.75%	5.8	13.3	26.6	11.3	23.5	176.4	216.7
					35.9		7.50%	3.75%	7.4					219.8	
1975	120.2	60.1	313.4	82.2		275.4	8.00%	4.00%	10.1	23.4	46.9	19.0	42.5	286.9	317.9
		60.1					8.25%	4.13%	13.3					360.3	
1976	141.0	70.5	454.3	107.2		382.6	8.20%	4.10%	16.6	37.3	84.2	26.3	68.8	447.3	451.4
		70.5					8.40%	4.20%	20.7					538.5	
1977	159.0	79.5	613.4	116.9		499.5	8.60%	4.30%	25.4	55.8	140.0	35.3	104.1	643.4	603.6
		79.5					8.70%	4.35%	30.4					753.3	
1978	154.9	77.4	768.2	94.0		593.5	7.10%	3.55%	28.6	62.0	202.0	47.4	151.5	859.4	745.0
		77.4					7.30%	3.65%	33.4					970.2	
1979	192.6	96.3	960.8	110.0		703.5	7.40%	3.70%	38.4	82.5	284.4	61.2	212.7	1104.9	916.2
		96.3					7.50%	3.75%	44.1					1245.2	
1980	268.7	134.4	1229.5	167.0		870.5	7.50%	3.75%	50.2	112.8	397.3	81.6	294.3	1429.8	1164.8
		134.4					8.20%	4.10%	62.7					1626.8	
1981	334.3	167.1	1563.8	227.1		1097.6	8.30%	4.15%	72.5	162.3	559.5	109.7	404.0	1866.4	1501.6
		167.1					9.00%	4.50%	89.8					2123.3	
1982	330.3	165.1	1894.1	291.9		1389.5	9.10%	4.55%	102.7	220.5	780.0	152.7	556.7	2391.2	1946.3
		165.1					9.30%	4.65%	117.8					2674.1	
1983	118.4	59.2	2012.5	300.0		1689.5	9.30%	4.65%	128.7	235.3	1015.2	195.4	752.2	2862.0	2441.7
		59.2					9.30%	3.62%	106.5					3027.7	
1984				324.0		2013.5	9.40%					248.3	1000.5	=======	3014.0
							9.40%								
1985				149.7		2163.2	9.50%					299.2	1299.7		3462.9
1986				12.7		2175.9						71.4	1371.1		3547.0
	DIFFERENCE IN TOTAL MCG:			$519.3											3547.0
				=======											

Derivation of AFUDC Accruals on Nominal Direct Construction Expenditures
For Limerick 1 and 100% of Common Facilities
Assuming 31 July 1982 Fuel Load

Adjusting for Disallowance of PECO and Bechtel Indirects
And Mark II Rework

(In Millions of Nominal Dollars)

INCLUDING TAXES AND OVERHEADS ON ACTUAL PECO EXPENDITURES
AND PRORATED ADDITIONAL PURTA ON OKA DIRECTS

	ANNUAL DIRECTS						AFUDC						Totals	
	OKA			PECO			AFUDC Rates		ACCRUALS				OKA	PECO
										OKA		PECO		
Year	Annual	Semi	Cum	Annual	Semi	Cum	Nominal	Effectiv	Semi	Annual	Cum	Annual	Cum		
1971				31.2	31.2		8.00%	8.00%	1.3	1.3	1.3	1.5	1.5	32.5	32.7
1972				33.9	33.9	65.1	8.00%	8.00%	4.1	4.1	5.4	3.9	5.4	70.5	70.5
1973				56.2	28.1	121.3	8.00%	4.00%	3.5	7.9	13.3	6.8	12.2	102.1	133.5
					28.1		7.50%	3.75%	4.4					134.6	
1974				71.9	35.9	193.2	7.50%	3.75%	5.8	13.3	26.6	11.3	23.5	176.4	216.7
					35.9		7.50%	3.75%	7.4					219.8	
1975	119.9	59.9	313.1	81.9		275.1	8.00%	4.00%	10.1	23.4	46.9	19.0	42.5	286.7	317.6
		59.9					8.25%	4.13%	13.3					360.0	
1976	140.0	70.0	453.1	106.3		381.4	8.20%	4.10%	16.5	37.2	84.1	26.3	68.8	446.5	450.2
		70.0					8.40%	4.20%	20.7					537.2	
1977	157.3	78.7	610.4	115.2		496.6	8.60%	4.30%	25.3	55.6	139.7	35.2	103.9	641.2	600.5
		78.7					8.70%	4.35%	30.3					750.1	
1978	151.0	75.5	761.4	90.2		586.8	7.10%	3.55%	28.5	61.6	201.3	47.1	151.0	854.1	737.8
		75.5					7.30%	3.65%	33.2					962.8	
1979	187.2	93.6	948.6	104.7		691.5	7.40%	3.70%	38.1	81.7	283.0	60.5	211.5	1094.4	903.0
		93.6					7.50%	3.75%	43.6					1231.6	
1980	257.6	128.8	1206.2	156.1		847.6	7.50%	3.75%	49.5	111.2	394.2	80.2	291.7	1410.0	1139.3
		128.8					8.20%	4.10%	61.7					1600.5	
1981	311.5	155.7	1517.7	204.8		1052.4	8.30%	4.15%	71.1	158.8	553.1	106.6	398.3	1827.3	1450.7
		155.7					9.00%	4.50%	87.7					2070.8	
1982	293.2	146.6	1810.9	255.0		1307.4	9.10%	4.55%	99.8	213.6	766.7	146.7	545.0	2317.2	1852.5
		146.6					9.30%	4.65%	113.8					2577.6	
1983	72.9	36.4	1883.7	254.5		1561.9	9.30%	4.65%	123.6	225.1	991.8	184.6	729.6	2737.6	2291.5
		36.4					9.30%	3.62%	101.5					2875.6	
1984				315.5		1877.4	9.40%					233.6	963.1	=======	2840.5
							9.40%								
1985				149.7		2027.1	9.50%					282.3	1245.5		3272.6
1986				12.7		2039.8						67.6	1313.1		3352.9
	DIFFERENCE IN TOTAL NCG:					$477.3									3352.8
						=======									

Q. DR-OCA-6-1. a. Please provide the actual total BPC costs for Limerick 1 and Common on either an annual or semi-annual basis.

b. Provide the 1984 AFUDC rates.

c. Provide the 1985 costs when available as of the commercial operation.

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A. DR-OCA-6-1. a. Actual BPC costs for Limerick 1 and Common on either an annual or semi-annual basis are not available. These costs were tracked on a total project basis, that is, with Unit 1, Common and Unit 2 combined.

Recently, the total actual costs associated with the total Limerick project were separated into two categories: 1) Limerick 1 and Common, and 2) Limerick 2. As of 12/31/84, the total actual BPC direct cost for Limerick 1 and Common was $1.768 billion. These data are not available by years.

Please refer to the response to DR-OCA-6-2 for a discussion of available annual data.

PE calculates AFUDC on the cost of the entire project, not separately for the BPC and PECo costs. The AFUDC costs being accrued on the Limerick Project are calculated on a monthly basis. They are computed on a base consisting of all direct construction costs, overhead charges, capitalized taxes, and prior AFUDC. The direct and overhead costs are added to the base each month, while the AFUDC calculated each month is accumulated for six months and added to the base in July and January (compounding of AFUDC is semi-annual). Before 1/1/78, prior AFUDC was not included in the base used in calculating the monthly AFUDC accruals.

b. An AFUDC rate of 9.4% is applicable to the first six months of 1984 and to the last six months of 1984.

c. The 1985 costs will be provided when available.

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Q.DR-OCA-7-2. DR-OCA-6-1(a) shows a total actual BPC direct cost for Limerick 1 and Common of $1.768 billion as of 12/31/84. DR-OCA-6-2(a) shows a total actual PE direct cost for Limerick 1 and Common of $427.2 million as of 12/31/84. Attachment DR-OCA-6-2(a) shows annual cost data on a combined BPC and PE basis by year separately for Limerick 1 and Common. While DR-OCA-6-1 and 2 state that actual annual data are not available for BPC and PE, some estimate must be available in order to have developed Attachment DR-OCA-6-2(a). Therefore, please provide the derivations of the separate BPC $1.768 billion and PE $427.2 million totals, by year, on a basis comparable to that set out in Attachment DR-OCA-6-2(a), for Limerick 1 and Common, and also show taxes and O.H., and AFUDC associated with each year's direct costs.

A.DR-OCA-7-2. As previously stated in response to DR-OCA-6-2, actual project expenditures for Limerick Unit #1 and Common facilities on either an annual or semi annual basis are not available.

The estimating process used to develop Attachment DR-OCA-6-2(a) did not require a further breakdown of annual expenditures into the requested Bechtel and PECo expenditure categories. Consequently, no such breakdown was performed. However, one method for arriving at this breakdown is to assume that the annual relationship of these direct costs was identical to the relationship that existed on a cumulative basis at 12/31/84. It should be noted, however, that such an approach could be subject to significant inaccuracy in certain years.

The Company's response to DR-OCA-7-3 provides the latest available actual data together with estimated expenditures to completion for Limerick Unit #1 and common facilities on a combined Bechtel and PECo basis.

Q: DR-OCA-IV-8: Provide a weekly listing, by craft, of the following data for Unit 1 and Unit 2, separately:

(a) Regular hours worked
(b) Premium hours worked
(c) Regular earnings
(d) Premium earnings

A: DR-OCA-IV-8: The requested information is available for both units only on a combined basis and will be provided for review upon request at the offices of Morgan, Lewis & Bockius, 2000 One Logan Square, Philadelphia, Pennsylvania 19103.

PECO STATEMENT NO. 33

R-850152
3/17/86

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PENNSYLVANIA PUBLIC UTILITY
COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY,
DOCKET NO. R-850152

DOCKETED
MAR 24 1986

REBUTTAL TESTIMONY OF
JAMES R. COUGHLIN

DOCUMENT
FOLDER

EARLIEST ACHIEVABLE SITE CONSTRUCTION
SCHEDULE OF LIMERICK 1 AND COMMON PLANT

FEBRUARY 19, 1986

REBUTTAL TESTIMONY OF JAMES R. COUGHLIN

Q. Please state your name and business address.

A. My name is James R. Coughlin and my business address is Bechtel Power Corporation, P.O. Box 3965, San Francisco, CA 94119.

Q. Please describe your involvement with the Limerick project.

A. I have been directly involved with the Limerick project for a substantial portion of its construction and startup/preoperational testing. My principal involvement has been in the area of cost and schedule control.

In September 1978, I was assigned as the Project Planner in Bechtel's San Francisco offices with responsibilities which included the scheduling of all phases of the project. This included maintenance and revision of the Management Scheduling and Control System ("MSCS") and the development and implementation of a system-related construction completion/startup system test schedule. Also, I participated in development of the Intermediate Construction Scheduling ("ICS") system which eventually replaced the MSCS schedule when the project entered the bulk installation phase.

In April 1981, I became the Cost/Schedule Supervisor at the Limerick construction site. I was responsible for supervising a staff of 70 Bechtel personnel who handled all cost and scheduling activities during construction and startup. I held that position until August 1985 when I was promoted to my current position as Deputy Project Manager for all work contracted for between Bechtel and Philadelphia Electric Company. My current primary areas of management responsibility include engineering, computer services, startup and support for PECO's Electric Production Department in the operation of the Peach Bottom and

Limerick nuclear facilities.

Q. Please describe your educational background and professional experience.

A. In 1967, I received a Bachelor of Science degree in Civil Engineering from the University of Illinois, and in 1971 I was awarded a Masters of Business Administration degree from the University of Florida. For the past 17 years, I have been employed with Bechtel, of which 15 have been principally in the areas of cost and schedule control on nuclear and other major construction projects. A listing and brief description of my work experience, including my activities at Limerick, is attached as Schedule 1.

Q. Do you belong to any professional organizations or have any professional registrations?

A. Yes. I am a registered professional civil engineer in the state of California and I am a member of the American Society of Cost Engineers.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to describe the analysis undertaken jointly by PECO and Bechtel to correct significant errors and omissions in the schedule analysis presented by OCA Witnesses O'Brien-Krietzberg & Associates, Inc. ("OKA"). I will also correct certain misstatements made by OKA about the Limerick plant and Bechtel scheduling assumptions. Finally, I will present a Susquehanna-based schedule analysis for Limerick which demonstrates that, due to differences in scope between the plants, Limerick could not have been completed in July 1982 as OKA assumed.

Q. Please briefly describe the schedule analysis performed by OKA?

A. OKA's analysis was performed in three steps. First, OKA obtained an MSCS construction schedule for Limerick prepared in May 1974, i.e. prior to issuance of

the construction permit, loaded it into a computer and, through the use of MSCS software, recreated the logic, activities and durations contained in that early schedule. This schedule projected an April 9, 1979 fuel load and is contained in Exhibit JJO'B-3.

As a second step, this schedule was purportedly adjusted to reflect the project's late 1974 to early 1976 cash constraints. OKA purports to have made such an adjustment by expanding the duration of those construction activities falling wholly within the cash restricted period and adding a proportional amount to the activities that were only partially within that period. The results of these adjustments are set forth in Exhibit JJO'B-4.

Finally, OKA purports to adjust its Limerick schedule for the schedule related effects of the necessity of resolving the Mark II loads issue at Limerick. This adjustment was effected by uniformly increasing each of the activities falling within the containment structure by 34%. This final effort, which is contained in Exhibit JJO'B-13, produced a fuel load date of December 11, 1981. Recognizing that no boiling water reactor contemporaneous with Limerick achieved completion before 1982, OKA adopts a Limerick fuel load date of July 1982 based upon the fact that Susquehanna 1 and LaSalle 1 were completed by that date.

Q. Have you identified any errors in OKA's schedule analysis?

A. Yes. OKA's analysis contains a number of errors which when corrected significantly alter the date upon which construction could have been completed.

First, by relying on a 1974 MSCS schedule as the basis for its analysis, OKA fails to reflect a number of unavoidable as-built construction realities. These realities include the omission of certain as-built critical path activities, the construction related effects of new or changed NRC imposed safety requirements

and additions in the necessary duration of all critical path activities due to these same factors. For example, the OKA analysis does not accurately recognize the substantial increase in quantities of materials and equipment not anticipated in 1974 which had to be installed to construct a licensable plant. These increases were imposed, in large part, because of changing regulatory requirements and required the expenditure of substantial additional manhours. This omission is significant in that the additional hours of required work impacted the required cash flow, manpower levels and productivity of the labor force, and these items in turn significantly delayed the fuel load date. Another significant error is the omission of any consideration of manpower density limitations throughout the plant. Only a certain number of people can be productively employed in a given area at any one time. To the extent that optimum density limitations are exceeded, productivity will decline and the schedule will be extended.

OKA's analysis also incorrectly reflects and oversimplifies the critical path for the project. It asserts that the project critical path ran through the mechanical and electrical bulk installation activities for the containment structure. However, the containment structure consists of two very separate areas - the drywell and wetwell. As described further below, the true critical path went only through the drywell and not the wetwell. Because OKA treated these plant areas on a combined basis, the critical path and its duration were not accurately presented. Finally, the cash flows implied by OKA's analysis are unrealistic, could not have been anticipated and would not have supported a July 1982 completion.

Q. Mr. Coughlin, is there a central factor which, in your judgment, has led to many of these substantial OKA errors?

A. Yes, there is. A principal feature in all the errors described above is the fact that OKA has conducted a very superficial analysis and has ignored fundamental requirements for accurate project schedule development. For example, a determination of project schedule requires an analysis of limitations on the amount of resources that can be efficiently employed, i.e., manpower density limitations and use of shift work, etc. This is referred to as resource loading and is the fundamental base upon which a project schedule is developed. What had to be done (i.e. installation of specific equipment, feet of large pipe, pipe hangers, etc.) and how it could be accomplished (size and type of craft force) must first be determined to establish specific activity durations, which durations along with activity interrelationships (i.e. the first floor concrete structure must be completed before the second floor can be started, etc.), determine construction logic, annual construction activities and schedule length. OKA's purported Limerick schedule evaluation fails entirely to conduct this necessary resource loading analysis. For this reason, based upon OKA's analysis, there is no reason or basis to believe that the OKA schedule could have been achieved at Limerick. Indeed, as I will demonstrate below, the OKA schedule was entirely unachievable.

Also, OKA's failure to perform a resource loading analysis implicitly assumes that unlimited resources were available to staff the project and that these resources could be applied without limit to any activity. As I will demonstrate, OKA's analysis thus assumes that more work could have been completed at Limerick than physically achievable within its assumed activity durations. Since OKA's conclusion that Limerick could have achieved a July 1982 fuel load rests upon a purported project schedule which was simply not physically feasible, clearly those conclusions are in error. Moreover, as I will also

demonstrate below, the OKA schedule could not have been achieved due to various NRC safety requirement changes made later in the project.

I should note that, unlike OKA, our schedule analysis is supported by detailed resource loading, including analyses of craft staffing levels, overtime, manpower density limits and a cash flow consistent with the scheduled construction activities.

Q. Have you performed an analysis of the effects of the above identified OKA errors upon the results of their schedule analysis?

A. Yes, I have. Through the combined efforts of PECO and Bechtel personnel, the errors of OKA's schedule analysis were identified and then corrected in four stages. These four analysis stages have been designated Case 1, Case 2, Case 3 and Case 4, and their results are set forth in Exhibit JJC-1/JRC-1.

In Case 1, the database for OKA's Mark II adjusted schedule contained in Exhibit JJO'B-13 was obtained and recreated through the use of the MSCS computerized schedule program. A one to one check was performed for each activity to ensure that the OKA schedule had been accurately copied. The completion date was then extended in this case by 7 1/2 months in order to reflect the difference between the December 11, 1981 fuel load actually shown in OKA's Mark II adjusted schedule, and the July 1982 fuel load which OKA ultimately adopted. Next, to permit analysis of the feasibility of the OKA schedule employing the realities of construction site management, the OKA adjusted schedule (i.e. July 1982 fuel load) was resource loaded. This was accomplished by distributing actual project manhours into the individual critical path activity durations for mechanical/electrical work in the schedule. Finally, the as-built startup logic and durations were entered into the analysis. In making these

necessary adjustments, the July 1982 fuel load date was held constant.

Our Case 1 evaluation demonstrated that manpower levels in the containment drywell and the reactor building required to achieve the July 1982 schedule substantially exceeded maximum manpower density limitations sustainable for these critical and near-critical path areas of the project. This fact alone establishes that the OKA schedule is not achievable. The results of Case 1 are presented in Exhibit JJC-1/JRC-1, Section 3.

Case 2 was developed by making adjustments to Case 1. First, as-built schedule logic and durations for the civil/structural phase were added for the period January 1975 through May 1976. This was done to accurately reflect the cash constrained condition of the project through May 1976. Second, the remaining drywell civil/structural logic from June 1, 1976 through the initiation of mechanical/electrical work was examined and modified to show a best possible schedule. Third, maximum sustainable manpower density limitations were applied for areas on the critical and near-critical paths, i.e., the drywell and wetwell areas in containment and each elevation of the reactor building. This was done to permit a realistic determination of the durations of the mechanical/electrical bulk installations in those critical and near critical path areas. Fourth, critical path activity durations were adjusted so that the schedule resource loading employed a maximum sustainable two-thirds second shift in addition to a full first shift. As shown in Exhibit JJC-1/JRC-1 Section 4, Case 2 results in a fuel load date of July 2, 1984 and reflects a more realistic level of manpower required to complete the project.

Case 3 was developed by modifying Case 2 to reflect annual project cash requirements foreseen during the period 1975-1979 which were then believed to be

adequate as shown by project documentation to produce a desired mid-1982 or earlier fuel load. In other words, the level of cash required for each year was determined to be that amount of cash which PECO and Bechtel believed was necessary during the 1975-1979 time period in order to complete the plant by 1982 or sooner. Since there were no cash constraints beginning in 1980, as required cash levels were assumed from that point forward. The result of this last case is a schedule which incorporates all required manhours reflecting the increased scope of the project, maximum sustainable manpower density limitations in critical path areas of the project, actual startup logic and duration, and foreseeable annual anticipated cash flow requirements. As shown in Exhibit JJC-1/JRC-1, Section 5, Case 3 results in the same fuel load date as Case 2, principally because work in the drywell remains on the critical path. However, the manpower and cash flow requirements are somewhat different in that they peak at a later time period, which is more representative of what actually happened at Limerick and other plants. This case demonstrates that the construction of Limerick 1, when plant-specific conditions have been reflected, could not have been completed any earlier than July 2, 1984.

Case 4 was developed by modifying Case 3 to reflect the impact of regulatory and licensing restraints as discussed in the testimony of Messrs. Helwig, Sproat and Mattson. Several items described by these witnesses could not be completed to support a fuel load date any earlier than October 1, 1984. In addition, the manpower and cash flow requirements in Case 4 are shifted to a slightly later time frame in the project from those in Case 3. The results of Case 4 are set forth in Exhibit JJC-1/JRC-1, Section 6.

Q. Please describe in greater detail the Case 1 analysis.

A. The basis for Case 1 is OKA's Mark II adjusted schedule contained in Exhibit JJO'B-13, which was recreated through the use of the MSCS computer program. The logic networks produced by the schedule were reduced to their essential elements, namely the critical path for each elevation in the containment and reactor building. Adjustments were then made to reflect the July 1982 fuel load date proposed by OKA, the actual startup logic and duration employed at Limerick, and the substantial increase in manhours required to install the quantities of materials and equipment during the mechanical/electrical phase, the total scope of which were not anticipated in 1974.

The adjustment from the OKA MSCS December 11, 1981 fuel load date to the July 1982 fuel load date proposed by OKA was developed by extending the completion date for critical path activities in OKA's schedule by 7 1/2 months. This was accomplished by adding 2 months to civil/structural activities, 4 1/2 months to mechanical/electrical activities and 1 month to startup and preoperational testing activities. This allocation is based upon the relative contribution of each of these project phases to the overall schedule duration as shown in JJO'B-13.

Schedule logic for the construction of a nuclear power plant typically pursues the following sequence of events: civil/structural activities, mechanical/electrical activities and then startup activities ending with fuel load. The first principal category of schedule logic errors and activity omissions of the OKA schedule analysis is in the civil phase of construction. These errors include the omission of upper elevation structural steel in the drywell, omission of a 5-week strike by Operating Engineers in 1975 and omission of the 2-month hold on containment activities also in 1975 as a result of Mark II related containment

integrity evaluations. These activity omissions have clearly resulted in an understated schedule duration in the OKA analysis. However, due to time constraints, these errors were not corrected in our Case 1 analysis, but were rather reflected in our analyses beginning with Case 2. This renders the Case 1 analysis conservative and more favorable to the OKA position than it should be.

Major changes were also made in the startup and pre-operational testing logic and duration as-built at Limerick as compared to that estimated in the 1974 MSCS schedule employed by OKA. Unlike the civil/structural phase, errors in startup and preoperational testing logic and duration were corrected in the Case 1 analysis. Changes to reflect as-built logic included the resequencing of blue tag testing and the substitution of the core spray system for the emergency service water system as the critical path startup activity in containment. Employment of actual startup activities and logic increased the startup length from the originally scheduled 21 months employed by OKA to the actually achieved duration of 27 months (i.e. as measured from initial energization to fuel load). This had the effect of reducing the amount of time available for mechanical/electrical work, but accurately reflected the proper time required for startup testing.

Finally, we resource loaded the as-built manhours for all scheduled mechanical/electrical activities into the OKA 1982 schedule (i.e. Case 1). This adjustment assures that the schedule analysis reflects as-built increases in the quantities of material and equipment installed on the project and related manhour expenditures. As-built direct manual manhours were obtained from our field records which recorded these manhours by facility and commodity, and were directly transferred to the appropriate activity and facility/elevation in the schedule. As-built indirect manual manhours which were not recorded on a

facility/commodity basis were allocated in proportion to the number of manual manhours directly assigned. Examples of activities resulting in the expenditure of indirect manual manhours include the installation of scaffolding, material handling and subcontract activities.

Q. Mr. Coughlin, what were the results of your Case 1 analysis?

A. As described above, manpower density limitations are an important factor in determining construction project schedule duration. These limitations, in conjunction with the total manhours required to be expended to complete a given facility and plant elevation, determine the schedule duration required for each activity. As we held the July 1982 fuel load date constant, the purpose of the analysis was to determine the manpower requirements needed to meet the OKA schedule, both total and at specific plant locations where manpower density limitations are most severe. Maximum sustainable manpower density limitations were developed from a study recently performed on the project for the purpose of organizing manpower resource application to achieve the schedule needed to complete Limerick 2 within the PPUC imposed cost containment cap. These developed maximum manpower densities were checked for reasonableness against manpower densities achieved at other Bechtel projects, including specifically Susquehanna. The following table compares the OKA required manpower densities and the maximum sustainable densities employed in our analysis:

Plant Location	As-built Manhours (1000's)	OKA-As-Built July 1982 Activity Schedule Durations (wks)	OKA Assumed Manpower Densities to Achieve July 1982 Schedule	Maximum Sustainable Manpower Densities	OKA Manpower Shifts Assumed to Compute Manpower Densities (Basis)
Containment	2598	171	379	170	2.23
Reactor Bldg. 177	1048	263	100	80	1.25
201	838	259	81	95	1
217	1187	226	131	125	1.05
253	1466	180	204	100	2.04
283	1258	138	228	185	1.23
313	838	117	180	90	2.00
352	349	104	84	90	1
Total Reactor Bldg.	6984		1008	765	

As this table demonstrates, the OKA assumed manpower densities exceed the maximum sustainable level in the containment by more than 100% and manpower densities in 2 elevations in the reactor building are also substantially greater than the maximum sustainable. Moreover, this table indicates that the containment and two elevations in the reactor building would require greater than full double shifting of the workforces for the entire duration in order to meet OKA's schedule at even this unrealistic manpower level. However, as described in our Case 2 analysis, such shifting would not have been possible and certainly would not have been desireable. Also, this analysis does not analyze drywell and wetwell

manpower densities separately. This is an additional conservatism significantly favoring the OKA analysis. As described below, the drywell is the actual critical path, and it has more stringent manpower density limits than does the wetwell. When the combined drywell/wetwell density of 170 is separated, as will be shown below, the OKA required density will exceed the achievable density by a significant additional increment. The significance of these manpower density comparisons is that they demonstrate quite clearly that achievement of the OKA proposed July 1982 schedule is quite impossible.

In addition to the physical impossibility due to manpower density constraints, the OKA schedule cannot be achieved as it is not supported by the OKA assumed cash flow. As indicated in Exhibit JJO'B-17.3, OKA's projected annual cash requirements are based on a reallocation of post-1982 direct costs according to the as-built March 29, 1977 to October 26, 1984 cash expenditure pattern at Limerick. This pattern, however, is substantially different than the pattern required to support the 1974 MSCS construction sequence and timing employed by OKA to purportedly demonstrate the achievability of a July 1982 completion date.

A revised version of the cash flow required to support OKA's schedule, as adjusted by the corrections described above, was therefore developed. This analysis employed a number of assumptions favorable to OKA respecting shift work, ramp-up rates, drop-off rates and other matters (See Exhibit JJC-1/JRC-1, Section 3). Unlike the unrealistic OKA cash flow, this "adjusted" OKA cash flow was developed from manpower curves which permit the identification of annual cash requirements needed to achieve the OKA adjusted schedule analysis assumed construction activities.

The analysis shows that an additional $207 million in direct cost over and above the OKA projected cash flow would be required for the years 1975 through 1979 to fund the assumed July 1982 completion schedule. This further demonstrates the unreasonableness of the OKA proposed schedule. Moreover, as explained in conjunction with Case 3 described below, as the need for cash flows of this magnitude were not foreseeable during this time period, the OKA adjusted cash flows for 1975-1979 exceed by $383 million in direct cost the total cash requirements foreseen as needed during that time period to achieve a 1982 or earlier completion date.

Q. Mr. Coughlin, please now describe the details of your Case 2 analysis.

A. The starting point for Case 2 was the schedule created in Case 1. This schedule was adjusted to correct for certain logic errors and omissions in the civil/structural phase prior to June 1976 as described above. As described by Mr. Clarey, the durations for several key activities on the critical path were understated by OKA because earlier than actual completion dates were employed. OKA also failed to fully reflect the actual scope of work for civil/structural activities. Civil/structural commodities in the containment and reactor building actually increased by 50% and 25%, respectively, and therefore, the durations for activities in these areas should have also been increased.

A further adjustment was made to incorporate reasonable manpower density limitations in each area of the containment and reactor building during the mechanical/electrical installation phase. As stated previously, there are practical limitations on the number of workers which can be effectively used in any particular area of the project, especially in the containment and reactor building where the number of workers was severely limited by space constraints and

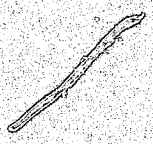
congestion.

Q. Are there any other matters significant to proper schedule development which you have reflected and OKA has not?

A. Yes, there are. I have adjusted the OKA analysis to employ maximum sustainable double shifting to achieve maximum schedule reduction. In Case 2, all mechanical/electrical activities were resource loaded with actual manual manhours. Durations for these activities were then developed to reflect maximum sustainable double shifting. Based on Bechtel's experience at Limerick, as well as at the Susquehanna and Hope Creek nuclear facilities, a full second shift over the entire duration of a project is not achievable on a sustained basis. The difficulty of having two full shifts work efficiently in a congested area is that the second shift staffing is significantly lower than first shift staffing due to logistics problems in shift turnover and project support of the workforce. Reflecting these considerations and Bechtel's actual job experience, a maximum <u>average</u> sustainable second shift size equal to two-thirds of the the size of the first shift was applied. Mechanically, in our schedule analysis, we reflected this second shift by employing a manpower density restraint equal to 167% of the single shift density restraint in determining mechanical/electrical activity durations on the critical path. Smaller second shifts were employed elsewhere as appropriate. I should note that our use of a two-thirds average second shift sustained over the entire mechanical/electrical activity duration period (i.e. a period of approximately 5 years) significantly exceeds the actual experience at Susquehanna and Hope Creek.

Finally, as described above, OKA treats the work in containment as a single activity in its schedule analysis. In fact, the containment is comprised of two

separate areas, i.e. the wetwell and the drywell. Important to schedule analysis, each of these areas has very different work scopes and manpower density limitations. The more severe limitations and the greater work scope are involved with the drywell, which was in fact the critical path activity at Limerick. The OKA erroneous combined treatment of these areas assumes that the higher density limitations of the wetwell will be applied to work in the drywell once the smaller wetwell scope of work is completed. In other words, it applies the higher combined containment manpower limitation to drywell activities after the completion of the wetwell despite the much lower actual density limitation in the drywell. To correct this OKA error, separate density limitations and double shifting assumptions were developed for both the drywell and the wetwell. A summary of these assumptions is set forth in the table below:



Location	As-built Manhours (1000's)	Case 2 Developed Activity Duration (wks)	Case 2 Developed Manpower Density	Maximum Sustainable Manpower Density Limits	Manpower Shifts Employed T Compute Manpower Densities (Basis)
Containment					
Drywell	2090	261	200	120	1.67
Wetwell	508	344	37	50	1
Total Containment	2598		237	170	
Reactor Bldg.					
177	1048	328	80	80	1
201	838	326	64	95	1
217	1187	318	93	125	1
253	1466	292	126	100	1.26
283	1258	230	137	185	1
313	838	197	106	90	1.18
352	349	208	42	90	1
Total Reactor Bldg.	6984		648	765	

As this table indicates, Case 2 results in a realistic and reasonable application of manpower in contrast to the OKA analysis. Since activities within the drywell are on the critical path, a two-thirds second shift (i.e. 1.67% of a single shift) is assumed for the entire 261 week duration for drywell activities. As a result, manpower requirements do not exceed and are in fact equal to the maximum density limitations (i.e. 120 x 1.67% = 200). Similarly, manpower requirements in the wetwell and reactor building, since they are not on the critical path, do not require use of a two-thirds second shift, and also do not

exceed maximum sustainable manpower density limitations.

Q. Mr. Coughlin, please describe the results of your Case 2 analysis.

A. Case 2 results in an earliest achievable fuel load date of July 2, 1984. This extension of the OKA schedule is attributable to the reflection of proper manpower density limits, achievable sustained shift work levels and civil/structural logic.

Q. What is shown in your Case 3 analysis and why was it prepared?

A. Case 3 is a modification of Case 2 to constrain annual cash flows to the level projected as necessary to achieve a 1982 Limerick 1 completion during the years 1975-1979. In other words, Case 3 construction logic and activity levels have been constrained to those levels which were believed adequate during the 1975-1979 period to achieve a 1982 or earlier project completion. These cash requirements were taken from project forecasts and other documents. They were developed in the late 1970s as part of the forecasting process to indicate Bechtel's/PECO's best estimate of annual cash required to meet a desired mid-1982 or earlier project completion date. As a subsequent step in the forecasting process, these cash requirement projections were adjusted downward to reflect PECO cash constraints on the project. However, in performing our Case 3 analysis, we have used only the contemporaneous projection of unconstrained required cash flows to achieve the OKA proposed or an earlier project completion date.

Specifically, three historic cash projections were used. Expenditures for 1976 were obtained from an early 1976 cash flow which forecasted an August 1980 Limerick 1 fuel load. The 1977 expenditure is based on a cash flow forecasting a December 1980 fuel load, and the 1978 and 1979 expenditures were taken from the Forecast 3 Case I projections for an October 1981 Limerick 1 fuel load. These

historic cash projections were then adjusted to include forecasted PECO costs.

As a result of these cash flow assumptions, non-critical mechanical/electrical activities were delayed due to cash insufficiency. Because the schedule is still controlled by activities in the containment drywell, which are double shifted as described above, employment of these "foreseeable" cash flows does not alter the Case 2 fuel load date. However, the shifting of more work to later in the project due to cash flow restraints more closely corresponds to the pattern of activities actually experienced at Limerick and other post-TMI nuclear projects. I should note that if these "foreseeable" cash flow assumptions were imposed without consideration of manpower density limitations or the use of second shifting in specific plant areas, the end date would still extend substantially beyond the July 1982 date proposed by OKA because of limitations on total manpower which could be employed on the project.

Q. Do you have any additional comments regarding OKA's schedule analysis?

A. Yes, I do. There are two additional errors which should be corrected. First, OKA states that the August 27, 1981 Monthly Status Report indicates that Unit 2 was in 1981 staffed with 713 pipefitters and 462 electricians. This is incorrect. The referenced report establishes that this is total project staffing, not that of Unit 2. A correct reading of the report indicates that only 111 pipefitters and 16 electricians were assigned to Unit 2.

Second, OKA states that it was Bechtel's judgment as late as June 1980 that a 1982 fuel load date was achievable. This also is incorrect. A review of documentation prior to and just after June 1980 demonstrates Bechtel's belief that even an October 1982 fuel load was probably not achievable. For example, the March 21, 1980 letter transmitting Forecast 4A from Bechtel to PECO states:

"The 10/82 Fuel Load date for Unit 1 continues to result in a

high risk schedule, which requires continued improvement in many areas."

Indeed, an October 1983 fuel load date was projected only a few months later with the issuance of Forecast 4B on September 2, 1980, and the letter transmitting that forecast to PECO suggested that even that date may not be achievable:

> "The 10/83 Fuel Load Date Schedule for Unit No. 1 contains significant risk, considering: 1) key manual manpower availability with our existing work rules, 2) our ability to achieve F/C 4B unit rates, 3) an unrealistically short licensing schedule, 4) completing technical resolution of certain major issues (i.e., Mark II and ATWS), 5) cash availability in the $200 million range in 1981 and 1982, and 6) the quantity of conduit to be designed and installed over the next 2 years."

Q. Have you performed any additional analyses to demonstrate the error of OKA's schedule analysis?

A. Yes. OKA has relied in substantial part upon a comparison between Limerick 1 and Susquehanna 1 in concluding that a July 1982 fuel load could have been achieved. This comparison, however, is inappropriate. OKA has failed to adjust for scope and other differences between the plants. As explained by Mr. Helwig, significant differences exist in the levels of bulk commodities at Limerick and Susquehanna, and thus render these plants substantially uncomparable for schedule analysis purposes. These greater commodities and the associated greater manhours needed to install them, plus the differing impacts of NRC safety requirement additions and licensing, are the reasons for Limerick's longer schedule duration as compared to Susquehanna.

To demonstrate how quantity differences would have prevented Limerick from achieving the Susquehanna fuel load date, an analysis was performed incorporating the greater Limerick quantities into the Susquehanna construction schedule. Specifically, this was accomplished by plotting the actual bulk

installation curves for Susquehanna and determining the point at which each bulk commodity was 10% complete and 90% complete. An installation curve is a graphical depiction of the quantities of installed commodities over time. In addition, the Susquehanna installation rates for all commodities, i.e. the quantities installed per month, and the timing or phasing relationships between commodities, i.e. when the installation of each commodity began in relation to the percent completion of other preceding or succeeding commodities, were developed. Next, by using the actual rates of installation and the timing relationships between the commodity curves experienced at Susquehanna, and the actual quantities installed at Limerick, a revised construction schedule was developed. The results of this analysis are contained in Exhibit JRC-2.

Q. Would you please explain in greater detail the significance of this analysis and its results?

A. The use of installation rates for Susquehanna reflects the speed with which commodities were actually installed under as-built conditions at that plant. Further, the use of phasing relationships reflect the timing of installation of major commodities in relation to each other at Susquehanna. These data are critical factors which control the duration needed to install plant commodities and thus total project schedule. Holding these Susquehanna based factors constant while adding the higher level of commodities at Limerick provides an approximation of the effect that higher commodity levels would have had upon the schedule at Susquehanna.

As shown in Exhibit JRC-2, the substantially greater commodity levels at Limerick when applied to Susquehanna resulted in a schedule duration, i.e. measured from construction permit to fuel load, of 118 months versus the actual

Susquehanna schedule of 104 months. The actual Limerick schedule was 124 months or only 6 months longer than the adjusted Susquehanna schedule. Had Susquehanna been faced with the significantly greater commodities required at Limerick, it would not have been able to achieve a July 1982 fuel load. Thus, because of its greater quantities, Limerick could not have been completed within the same time frame as Susquehanna and an unadjusted comparison of schedule duration, as presented by OKA, is meaningless.

Q. Do the results of this analysis indicate that Limerick 1 could in fact have been completed 6 months earlier than it actually was, i.e. in April 1984?

A. No, it does not. The above analysis only attempts to reflect the schedule effect of commodity differences between Susquehanna and Limerick. Other differences, such as engineering, procurement and licensing restraints upon the schedule, were not considered here.

Q. Does that conclude your testimony?

A. Yes, it does.

Professional Experience of James R. Coughlin

Griffith Mine, Red Lake, Ontario 5/67 - 3/68

Field Civil Engineer with responsibility for subcontractor administration, conveyor system erection and tank erection.

Turkey Point Nuclear Power Plant, Homestead, Florida 3/68 - 9/70

Field Civil Engineer with responsibility for the construction of the Reactor Auxiliary Building for one year. The next one and a half years were spent as the Field Scheduler. Primary responsibility in this assignment was the preparation of short term construction schedules and overall construction summary schedules to interface with the system-oriented startup schedules.

Engineering Planning Assignment - San Francisco, CA 2/72 - 2/73

Developed the Engineering Work Planning and Control System for the Power Division Projects in San Francisco. This system consisted of activity related bar charts that were man loaded and provided for progress reporting and performance monitoring.

Arkansas Nuclear One - Unit 2 - San Francisco, CA 2/73 - 7/76

Lead Engineering Planner for one year. Supervised a group of four engineering planners in the preparation of detailed engineering work schedules and the integration of these schedules with the construction schedules. Balance of the assignment was spent as the Lead Project Planner with responsibilities for scheduling work for all phases of the project. This included the development and implementation of a system related construction completion/startup system test schedule.

Seawater Project, Dahran, Saudi Arabia 8/76 - 8/78

Lead Field Cost Engineer for Seawater Treatment Plant and distribution system project. Developed field labor budget, estimated change orders, and supervised all cost reporting and performance monitoring.

Limerick Generating Station, San Francisco, CA 9/78 - 3/81

Project Planner in San Francisco for the Limerick Project. In addition to the duties shown on the Arkansas Nuclear One Assignment, worked on the development of ICS scheduling system which replaced the MSCS schedule that had been used on Limerick.

Limerick Generating Station, Pottstown, PA 4/81 - 7/85

Cost/Schedule Supervisor for the construction effort at the Limerick site. Supervised a group of 70 personnel that handled all cost and scheduling activities including scheduling of startup and preoperational testing activities. Startup scheduling at Limerick utilizes the PREMISE program which is similar to MSCS.

PECO Contract Work, San Francisco, Ca 8/85 - Present

Deputy Project Manager for all work contracted between Bechtel and PECO. Specific areas of responsibility are engineering, computer services, startup, support to PECO's Electric Production Department.

& ASSOCIATES, INC.

CALCULATED BY J. O'BRIEN DATE 3-16-82

CHECKED BY _____ DATE _____

SCALE JOB-32

From COUGHLIN JCC-2/JRC-2 pg 5

Adjusting the Company's single shift sustainable densities for the Containment to reflect comparable multiple shift peak density levels (assuming a 2/3 second shift), would result in the following:

	Maximum Single Shift Sustainable Densities 1/		Maximum Sustainable Two Shift Densities 2/		Pea Tw Shi Densit
Drywell	120	+ 2/3 (120) =	200	200 X 1.5 =	30
Wetwell	50	+ 2/3 (50) =	84	200 X 1.5 =	12

PECO CLAIMED MAX: 284 42

SCENARIO: 2 SHIFTS: 4 x 10 HR/DAY
2 SHIFTS: 3 x 12 HR/DAY

DRYWELL 120 x 2 = 240
120 x 2 x 36/40 = 216
456 x 1.5 = 684

WETWELL 50 x 2 = 100
50 x 2 x 36/40 = 90
190 x 1.5 = 285

OKA

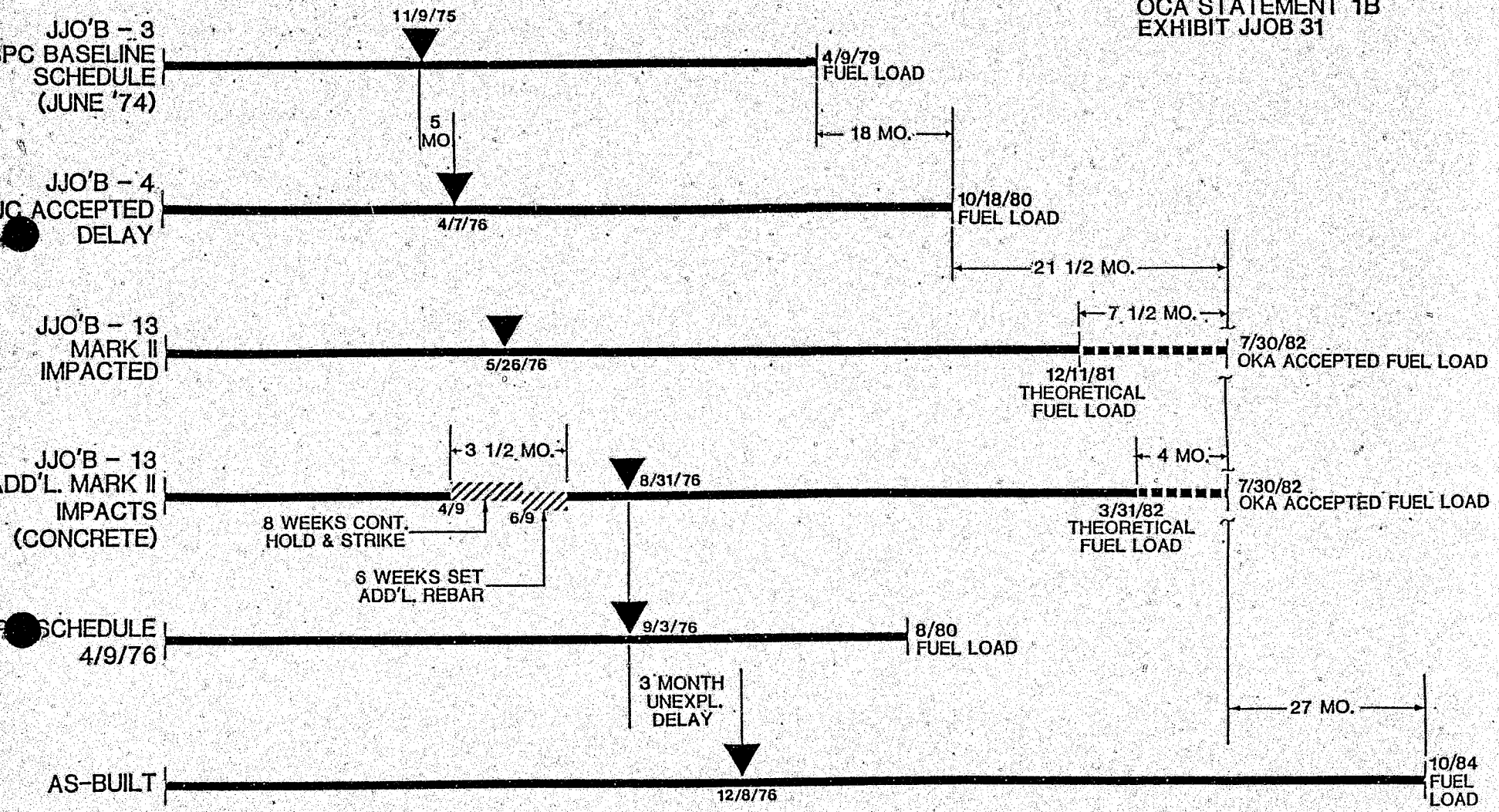
REASONABLE MAX: CONTAINMENT TOTAL 646 969
SUSTAINED PEAK

PECO STATEMENT OF OKA MAX: 379 566

SCENARIO Use 2/3 on 2d SHIFT

DRY WELL	SUSTAINED	PEAK
WEEK		
1 SHIFT × 4 × 10 M/D =	120	
2/3	80	
WEEKEND		
1 SHIFT × 3 × 12 M/D =	108	
2/3	72	
	390	585

OCA STATEMENT 1B
EXHIBIT JJOB 31



SCHEDULE COMPARISON

LEGEND
▼ SET REACTOR PRESSURE VESSEL
NOT TO SCALE

PECO STATEMENT NO. 33A

R-850152
317-81

RECEIVED
MAR 19 1986
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY
COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

DOCKETED
MAR 21 1986

SUR-SURREBUTTAL TESTIMONY OF
JAMES R. COUGHLIN

ERRORS IN OCA CRITICISMS OF COMPANY ANALYSES CONTAINED IN EXHIBITS JJC-1/JRC-1 AND JRC-2

DOCUMENT
FOLDER

March 13, 1986

Sur-Surrebuttal Testimony of
James R. Coughlin

Q. Please state your name and business address.

A. My name is James R. Coughlin, and my business address is Bechtel Power Corporation, P.O. Box 3965, San Francisco, CA 94119.

Q. Are you the same James R. Coughlin who previously submitted testimony in this proceeding?

A. Yes, I am. I have previously filed rebuttal testimony which has been identified as PECO Statement No. 33.

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

A. The purpose of my testimony is to comment upon and respond to various criticisms of the Company's analyses in Exhibits JJC-1/JRC-1 and JRC-2 which are contained in the surrebuttal testimony of OCA witness James J. O'Brien.

Q. Have you assessed the qualifications of Mr. O'Brien as they relate to the schedule analysis and criticisms of Company testimony that he has presented in this proceeding?

A. Yes, I have. Although Mr. O'Brien has admittedly retrospectively reviewed the construction of nuclear generating facilities in connection with several litigated proceedings, his background indicates no direct experience in managing either the engineering or construction of such a facility. I believe that this lack of direct hands-on experience may account for Mr. O'Brien's failure to fully understand and reflect in his schedule analysis and in his criticisms of the Company's analyses, the practical realities of nuclear power plant construction which would have precluded a Limerick 1 completion by July 1982.

As shown in his resume in Exhibit JJO'B-1 and as admitted during cross-

examination, Mr. O'Brien and his firm were never engaged as an architect-engineer with responsibility for design management or as a constructor or construction manager with responsibility for directly managing the construction of a nuclear power plant. Mr. O'Brien's only experience in this area appears to be in proceedings such as this where he has been hired to retrospectively review a nuclear project in support of a particular party's position in litigation. In addition, to the best of my knowledge, Mr. O'Brien and his firm have had very little, if any, direct involvement in actually managing the engineering or construction of any significant non-nuclear project that approaches the size or complexity of Limerick. Where he has been involved in such projects, his role seems to have been as an administrator or coordinator of cost and schedule matters, rather than as a manager of engineering or construction activities.

Moreover, the statement in Mr. O'Brien's direct testimony that OKA "is listed 37 nationally by Engineering News - Record among professional construction management firms" (OCA Statement No. 1, p. 1) is misleading. Engineering News-Record (EN-R) publishes annual rankings of the top 400 contractors and the top 500 design firms. The top 500 design firms are ranked according to their billings for design and construction management services, exclusive of contracts where they have a financial liability exceeding $500,000. OKA is included in this category and was ranked only 166th for 1984 and 178th for 1983, with billings in both years between $10 million and $15 million (this includes significant OKA billings for rate case work). As a subset of the design firm rankings, EN-R also ranks these firms according to their construction management billings only. Using this criterion, OKA ranked 24th in 1984 and 25th in 1983. The important point to note here is that OKA's ranking, based on construction management billings within

the selected subset of design firms, is exclusive of firms such as Bechtel, Stone & Webster, Fluor, Brown & Root, etc., who contract to perform significant amounts of construction management services but whose liability under these contracts exceeds $500,000. If all firms who performed construction management services, regardless of liability limits, were grouped together (no such ranking exists), OKA's relative postion would be very substantially reduced.

In contrast, and as explained by Mr. Soppet (PECO Statement No. 7, p. 3), Bechtel is a worldwide leader in the construction of all types of electrical generating facilities, including in particular, nuclear power plants. Bechtel's extensive experience includes direct involvement in managing and performing engineering and/or construction activities on over 300 non-nuclear and 150 nuclear power projects, including over 80 of the latter which have been completed. As a result of this experience, Bechtel has accumulated extensive knowledge and understanding of factors which affect the time needed to complete nuclear construction, including restraints imposed by manpower density limitations, changing regulatory requirements, unanticipated cash requirements, etc. Further, for the years 1983 and 1984, EN-R ranked Bechtel 1st and 3rd, respectively, out of the 400 top contractors and construction management firms. Total work contracted for by Bechtel in those years equalled $8.2 - 13.8 billion, with approximately $2.8 - 4.9 billion related directly to construction management activities.

Q. Have you prepared an exhibit which demonstrates the errors and misunderstanding of Mr. O'Brien concerning manpower densities?

A. Yes, I have. In conjunction with PECO's Construction Division and with assistance of other Bechtel personnel, I have developed Exhibit JJC-2/JRC-2 which

demonstrates the errors contained in Mr. O'Brien's criticism of the density levels used in our analysis in Exhibit JJC-1/JRC-1. My role was to assist in the development of the exhibit and to review all the material for corrections.

Q. On page 14 of his surrebuttal testimony, Mr. O'Brien states that separating the Containment into two activities, i.e. the Wetwell and Drywell, would not affect his schedule analysis. Do you agree?

A. No, I do not. Mr. O'Brien completely misunderstands the significance of separating the Containment into the Drywell and Wetwell for determining the earliest date that Limerick could have been completed. As explained in my and Mr. Clarey's rebuttal testimony, the separation of the Containment into the Drywell and the Wetwell is significant to the analysis of the manpower required to support Mr. O'Brien's July 1982 Fuel Load Schedule. The Drywell requires four times more manhours for its construction than the Wetwell - approximately two million versus five hundred thousand - and has its own separate maximum sustained manpower density. The Wetwell, on the other hand, requires far less manhours than the Drywell and its own maximum sustained manpower density, and thus can be completed in a shorter duration. Therefore, treating total Containment manpower limitations and manhours as a single activity would allow the higher combined manpower limitation to be applied to the Drywell once the smaller scope of work is complete in the Wetwell, despite the lower density limitations in the Drywell. Such an approach understates the impact of manpower density limits in the Drywell, and thus is obviously in error.

The effect of Mr. O'Brien's treatment of the Containment as a single activity is demonstrated in Exhibit JJC-2/JRC-2.

Q. How do you respond to the apparent contradiction in manpower density numbers

for Containment that Mr. O'Brien displays on page 17 of his testimony?

A. The reasons for this apparent contradiction are fully explained in Exhibit JJC-2/JRC-2, which I have jointly prepared with Mr. Clarey. As demonstrated in this Exhibit, Mr. O'Brien incorrectly compared a single shift Maximum Sustainable Manpower Density for the Containment (Wetwell and Drywell) used in the Company's case analyses contained in Exhibit JJC-1/JRC-1, with multiple-shift peak manpower density information contained in Forecast 7, Part 2. As a result of these differences, the data relied upon by Mr. O'Brien are simply not comparable. If adjustments are made to make the data comparable, the Company's manpower density assumptions are shown to be comparable to the data contained in the Forecast and consistent with our Case 1 analysis, and Manpower density levels required to complete the plant by July 1982, as proposed by Mr. O'Brien, are shown to be unrealistically high and unachievable.

I would note that Mr. O'Brien further states that the 379 density level required to achieve the July 1982 schedule, as shown in the Case 1 analysis, is not based on JJO'B-13 and that the proper figure would be less. This is incorrect. As explained in my rebuttal testimony, the Case 1 analysis is based on Mr. O'Brien's Mark II adjusted schedule contained in Exhibit JJO'B-13. The 379 figure represents the maximum sustainable manpower density required for the completion of the mechanical/electrical installations in the Containment when the JJO'B-13 schedule is properly corrected to reflect scope increases and other unavoidable as-built conditions. As shown in Exhibit JJC-2/JRC-2, this number significantly exceeds the achievable maximum sustainable manpower density.

Q. At the bottom of page 19 and at the top of page 20 of OCA Statement No. 1B, Mr. O'Brien again claims to point out a discrepancy in the Manpower Density Number

presented in your analysis and in Forecast 7, Part 2. Is he correct?

A. No. The 420 number that Mr. O'Brien refers to was taken from Forecast 7, Part 2. However, the density limits utilized in all the cases shown in PECO Statement No. 33 were based on the study supplied in the response to IR-OCA-25-1. This more recent study was a more in-depth review that examined the density limits for smaller areas of the plant and supersedes the more summary level study prepared at the time of the Forecast.

Mr. O'Brien, however, has totally misused the information supplied to him. He compares single shift and sustained maximum numbers (120 and 100) to a number that is clearly defined as a peak number and that includes multiple shifting. In fact, the more recent study that was utilized in our Unit 1 analysis results in a "Maximum Personnel Manageable" of 550 for the two referenced control areas. Therefore, the use of this study produces a more conservative result in analyzing Unit 1 than would have been the case if the 420 number basis had been used.

Q. Do you agree with Mr. O'Brien's contention, on page 18 of his testimony, that you incorrectly reflected the as-built start-up duration in your Case 1 analysis?

A. No, I do not. Mr. O'Brien states that in Case 1 we used over 29 months for startup, and not the as-built duration of 27 months. This statement is incorrect. The Case 1 schedule does indeed show energization as February 23, 1980 and fuel load as July 28, 1982, for a total elapsed time of 29 months. However, included in this duration are 2 months of weather allowance, an activity completely unrelated to startup but which was included in the startup phase solely for administrative convenience in preparing our analyses. In his criticism, Mr. O'Brien seems to have overlooked the fact that this very same activity had also been reflected during

startup activities in his schedule analyses. The fact is, we did use exactly 27 months for the as-built startup duration.

Q. On Page 22 of OCA Statement 1B, Mr. O'Brien criticized the Schedule Comparison between Limerick and Susquehanna as not based on the Susquehanna construction schedule and too broad based to determine significant milestones. Do you believe that criticism is accurate?

A. No. Mr. O'Brien totally misses the point. The Susquehanna/Limerick schedule study was presented as a summary level comparison between the projects and as an "independent" validity check of the premise that the construction of the Limerick Plant would require more time than Susquehanna due to the differences in scope between the plants. This analysis ignores additional key parameters such as regulatory impact items, site specific design differences, plant congestion and manpower density limits that would need to be considered to determine a reasonable Limerick Fuel Load Date.

A comparison between plants is best prepared at a summary level in order to be able to analyze the major relevant parameters and not get drawn into an ever increasing and complex web of detail and plant specific differences that result in "missing the forest for the trees". Going to a greater level of detail, such as trying to compare the schedule of two plants building level by building level or system by system, would involve too many adjustments to properly account for the myriad of specific plant differences that always exist. The comparison would also involve tremendous amounts of detailed research that adds nothing to the accuracy of the results.

This summary level study does compare the plants at a reasonable level of detail which, I should point out, is a level of detail substantially greater than Mr.

O'Brien when he stated (OCA Statement No. 1, Page 25):

> "Based upon the circumstance reconstruction techniques used in this study, it is my opinion that Fuel Load could have been achieved at Limerick anytime within the window bounded by my Impacted Schedule projection (12/11/81) and the issuance of an Operating License at Susquehanna (7/17/82)."

Mr. O'Brien's actual analysis produces the ridiculous result that Limerick should have loaded fuel earlier than Susquehanna, and he then merely "arm waves" the difference by calling it a "window" without any attempt to compare the plants at any level of detail.

The analysis presented in Exhibit JRC-2 is most definitely based on actual Susquehanna data for the relevant parameters (i.e., installation rates, milestone dates, etc.). In my opinion, the study contains an entirely proper level of detail for its purpose.

Q. Mr. O'Brien makes the following assertion (OCA Statement 1B; page 26, line 8):

> "If this unnecessary year of mobilization is removed from Mr. Coughlin's JRC-2 schedule, his fuel load date would be reduced from April, 1984 to March, 1983."

Do you agree?

A. No. First of all, the term mobilization, in this context, includes a myriad of activities and is meant to include all work done at the site up to the point where the structural concrete is 10% complete. This would include such things as site clearing, excavation, piping, embedded raceway, and all work required to get structural concrete work up to 10%. The most significant of which could not be started until the CP was issued.

Secondly, Mr. O'Brien is making one job specific adjustment to a summary study which is based on very valid, but also summary parameters. Once you make one such adjustment, you have to look at other site specific differences between the plants, such as differences in complexity, productity, etc., and then you end up

with a very detailed but also very difficult, almost impossible task. In fact, the additional detail generally does not add to the accuracy of such a study. That, again, is an example where Mr. O'Brien picks one detail which suits his goals but disregards other details which might be detrimental to his effort.

Q. On page 23 of OCA Statement 1B, Mr. O'Brien points out that, in 6 of the 8 commodities shown, Susquehanna had higher installation rates than Limerick. Does this in anyway discredit the analysis or result contained in Exhibit JRC-2?

A. No. Mr. O'Brien only wants to look at part of the picture and not the whole. The main point is that using the actual Susquehanna installation rates and phasing between the commodities and Limerick commodities produce a significantly later Fuel Load than July 1982. Mr. O'Brien ignores entirely how these commodities must be interfaced and sequenced to produce an overall adjusted duration.

Mr. O'Brien also inaccurately states, in two places on page 23, that Susquehanna had better productivity than Limerick. He apparently does not understand the concept of productivity. Productivity is the measure of the amount of work (i.e., manhours) required to install a given amount of quantity (e.g., manhours per lineal foot of pipe, etc.). Productivity is not total production per unit of time, as Mr. O'Brien suggests. This is an error in the use of one of the most basic concepts in Construction Management and another example of how Mr. O'Brien has misused and/or misunderstood information which was previously provided (see interrogatory response IR-OCA-4-28).

Q. Could you please summarize your comments on Mr. O'Brien's criticisms of the Limerick/Susquehanna Schedule Comparison in Exhibit JRC-2?

A. Yes. Basically, Mr. O'Brien wants only to choose comparisons that are favorable to his case and does not present an entire analysis using all the relationships. He

particularly ignores the phasing between the various commodities and how these relationships are combined to produce a comprehensive analysis.

The most significant error, however, is that he chooses to miss the point that this particular analysis is not the central analytical tool to be used in evaluating the Limerick schedule. The proper approach is contained in Exhibit JJC-1/JRC-1 and includes a number of factors such as foreseeable cash flow needs, regulatory and licensing issues, and manpower density limits that are not considered here. This analysis was done to demonstrate the error in Mr. O'Brien's comparison of Limerick and Susquehanna and to counter his assertion that Limerick should have loaded fuel no later than Susquehanna's date of July 1982.

Q. Does this conclude your testimony?

A. Yes it does.

PECO STATEMENT NO. 4A

R-850152
3/17/86

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY,
DOCKET NO. R-850152

RECEIVED
MAR 19 1986
SECRETARY'S OFFICE
Public Utility Commission

REBUTTAL TESTIMONY
OF
JAMES J. CLAREY

DOCKETED
MAR 24 1986

ERRORS IN OKA SCHEDULE ANALYSIS
LIMERICK ON SUSQUEHANNA SCHEDULE COST ANALYSIS
REBUTTAL TO WITNESS DOUGHERTY

DOCUMENT
FOLDER

FEBRUARY 19, 1986

Rebuttal Testimony of James J. Clarey

Q. Please state your name and business address.

A. My name is James J. Clarey and my business address is P.O. Box A, Sanatoga Branch, Pottstown, Pennsylvania 19464.

Q. Are you the same James Clarey who has previously filed testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to comment upon and criticize the analyses presented in the testimony of OCA Witness James J. O'Brien and to support portions of the joint PECO/Bechtel analysis to correct major errors contained in Mr. O'Brien's schedule analysis. In addition, I will describe an analysis of the cost to complete Limerick if it were to have been built to the same duration as Susquehanna 1, assuming a February 1986 commercial operation date. I will also update the industry cost and schedule comparison presented in my direct testimony. Finally, I will comment upon and respond to Trial Staff Witness Dougherty's quantification of the costs of the 1976 and 1978 construction deferral announcements.

Q. Have you reviewed the schedule analysis presented by OCA witness O'Brien?

A. Yes, I have

Q. What were the results of your review?

A. Our review indicates that the schedule analysis prepared by Mr. O'Brien has many fundamental errors, is unrealistic and cannot be relied upon in this proceeding. That analysis completely ignores the many as-built conditions and events which affected Limerick costs and contributed to the project's schedule duration. The

reason for this is his reliance on a 1974 construction schedule which was prepared at a time when many as-built events and conditions could not be anticipated. As a result, the following major errors were identified:

1. Failure to reflect the actual level of quantities and manhours which were required because of regulatory requirements and other reasons;

2. Failure to incorporate as-built schedule and cash flow information through June 1, 1976, as accepted by Mr. O'Brien;

3. Failure to consider manpower density limitations for specific work areas which reflect the scope of work and congestion at Limerick;

4. Failure to separately assess the scope of work in the drywell and wetwell within the Containment structure;

5. Failure to assess the impact of near-critical path activities, such as those in the Reactor Building;

6. Failure to incorporate the actual startup logic and duration;

7. Failure to reflect the impact of engineering, procurement and licensing restraints upon the schedule as a result of regulatory requirements.

8. Failure to develop a cash flow based on the needs of the schedule.

As this list indicates, and as further described below, Mr. O'Brien's analysis is replete with errors and omissions, is extremely superficial and does not reflect a reasonable or accurate assessment of when Limerick 1 could have been completed.

Q. Please discuss Mr. O'Brien's failure to reflect actual quantities and manhours in his schedule analysis.

A. The Limerick project scope increased substantially from the time of the original schedule in 1974 to that which was built for a commercial operation date of February 1, 1986. The principal reason for this was changing regulatory requirements as demonstrated in prior Company testimony. This increased scope of work, when allocated to the appropriate areas of the plant, requires the expenditure of many more manhours to complete construction than initially anticipated and significantly changes the duration of scheduled activities. Mr. O'Brien has failed to add these manhours to the appropriate areas of the job and thus assumes a July 1982 fuel load could have been achieved without evaluating the effects of these scope additions.

By adding these scope changes to appropriate areas and applying necessary manpower density limitations, Mr. O'Brien's schedule would be substantially extended. However, adjustment for increased scope alone only touches the surface of the schedule effect caused by the multitude of changes experienced at Limerick. As described in PECO Exhibit 2, regulatory requirements above and beyond the Mark II additions resulted in increased engineering and procurement requirements, disruption of construction activity sequencing and reduced labor productivity, all of which also substantially contributed to the project's duration.

Q. Please explain the failure of Mr. O'Brien to reflect the as-built schedule and cash flow conditions through June 1, 1976.

A. In his testimony (page 5), Mr. O'Brien states that he has accepted the revised construction schedule as announced by the Company in 1974. From 1974 through May of 1976, the construction schedule's fuel load date supported the 1974

announced fuel load date of October 1980 accepted by Mr. O'Brien. During that period, PECO applied necessary resources to the critical areas of the job to maintain an October 1980 or earlier fuel load date. In March 1976, the project was on schedule for a target fuel load date of July 29, 1980. Because critical areas were always manned and the project was on schedule, the as-accomplished schedule and actual cash expenditures through May of 1976 should be reflected in Mr. O'Brien's analysis. After May 1976, critical path activities continued to be manned but cash constraints caused non-critical areas of the job to slip. Moreover, the 1976 deferral announcement was not made until late May 1976 and, therefore, all as-built conditions through that date should be incorporated.

Nevertheless, Mr. O'Brien has failed to reflect these conditions. As shown on Exhibit JJO'B-17.4, as-built cash requirements were used by Mr. O'Brien only through the end of 1974. Moreover, he has similarly failed to reflect as-built schedule logic and activities. For example, Mr. O'Brien's analysis does not include the Operating Engineers strike which occurred in 1975. This strike resulted in a 5-week delay in Reactor Building activities, and as discussed further below, would have directly impacted the critical path under an assumed July 1982 completion. Likewise, Mr. O'Brien's analysis ignores the 2-month hold on containment concrete work in 1975 due to the Mark II loads problem. This delay directly affected critical path activities and should have been reflected in Mr. O'Brien's analysis. In addition, Mr. O'Brien's schedule analysis incorrectly adopts completion dates for certain critical path activities during the pre-June 1976 period which are earlier than actually achieved. For example, Mr. O'Brien's schedule indicates that the pouring of reactor building concrete walls to elevation 217 was completed on February 16, 1975, when in fact this concrete was not

placed until September 12, 1975, or 7 months later. This incorrect reflection of as-built conditions directly affects the critical path in Mr. O'Brien's analysis, assumes that more work was completed than actually occurred prior to June 1976 and thus does not accurately reflect as-built progress of the project during that period. Additional errors of this type contained in Mr. O'Brien's analysis are set forth in Schedule 1.

Q. Please explain the significance of Mr. O'Brien's failure to assess and establish manpower density limitations which would reflect the actual scope of work and congestion at Limerick?

A. In IR-OCA-5-1, information regarding the manpower density limitations and manpower requirements utilized in Mr. O'Brien's schedule analysis were requested. Mr. O'Brien responded that these items were not considered. Failure to do so is a serious and fundamental error as it reflects the assumption that work could be accomplished regardless of the manpower required in a particular plant area.

One of the major considerations for schedule development is the evaluation of the number of workers that can be effectively utilized in a building area based on the configuration, scope, and congestion of the work. This is done very carefully in order to ensure that the work proceeds in an effective, efficient, and coordinated manner. Also, the correct number of manhours including subcontracted work must be allocated to the specific areas of the job in order to properly apply the manpower limitations. Mr. O'Brien's failure to address manpower density limitations creates a situation where work is unattainable in the duration assumed because fewer workers than scheduled can be utilized. Thus, the schedule is unrealistically short.

Indeed, based on the Case 1 analysis, as described by Mr. Coughlin, if Mr. O'Brien's schedule is adjusted to reflect increased quantities and the actual startup duration, manpower levels would be more than 50% higher than maximum density levels in the drywell area. Correction of this error through application of proper density limitations would add more than 90 weeks to Mr. O'Brien's overall schedule duration.

Moreover, evaluation of the manpower limitations in the Reactor Building shows that Mr. O'Brien's scheduled manpower exceeds the density limits at elevation 253 by 22%. Correcting for this error alone would add 40 weeks to Mr. O'Brien's overall schedule duration. Similarly, Mr. O'Brien's assumed manpower level at elevation 313 exceeds the maximum density limit by 20%. If this error were corrected, Mr. O'Brien's schedule would be extended 23 weeks.

Q. Please explain Mr. O'Brien's failure to separately assess the scope of work in the drywell and wetwell within the Containment.

A Because of his reliance on a 1974 MSCS schedule, Mr. O'Brien adopts the logic in that schedule which treats the drywell and wetwell as a single activity within containment. This is inappropriate. These areas must be separated for proper development of an "as should have been" schedule. Each area has highly different work scope and density limitations due to the congestion, configuration, and access to them. Thus, it is necessary to revise the logic and separate the scope of work into two distinct areas. When this necessary change is accomplished schedule durations are significantly affected and lengthened. Mr. O'Brien should have recognized the need for these modifications in order to present an accurate work product. Failure to do so results in a significant understatement of the scheduled duration which could reasonably have been met. As discussed above,

correction of this error adds 90 weeks to Mr. O'Brien's schedule.

Q. Please explain Mr. O'Brien's failure to address work in near critical path areas of the project.

A. Failure to evaluate work performed in near critical path activities represents a serious flaw in Mr. O'Brien's analysis, as it may result in the derivation of an erroneous completion date when evaluating the reasons for schedule growth. Specifically, where critical path activities are adjusted, as Mr. O'Brien has done in his analysis, near critical path activities, i.e., activities which could take more time to complete than scheduled before impacting the critical path, may become critical if the durations of critical path activities are sufficiently reduced. Thus, in order to provide an accurate analysis, all critical and near critical path activities must be considered in the analysis.

An example of a near critical path activity not considered by Mr. O'Brien is the Reactor Building at Limerick. This facility surrounds the primary containment area, houses most of the mechanical and electrical safety features of the plant and thus was subject to many changes caused by regulatory imposed items, including Mark II work. Any schedule evaluation must include the proper civil and electrical/mechanical work for each area and elevation of this building. These areas must be evaluated based on the manhours required to finish the work and applicable manpower density limitations in order to quantify the factors affecting the schedule at Limerick. In fact, as shown in Case 1 (i.e. Exhibit JRC-1, Section 3), activities on elevations 253 and 313 in the Reactor Building are actually on the critical path when Mr. O'Brien's schedule is adjusted to reflect increased mechanical/electrical work scope and the as-built startup duration. Thus, in order to provide an accurate schedule assessment, an analysis of all near

critical path activities should have been performed.

Q. Please explain the significance of Mr. O'Brien's failure to recognize the actual startup logic and duration.

A. First, let me point out that the Limerick startup program for Unit 1 had the shortest duration of all comparable first unit plants. This is illustrated in Schedule 2, which contains a comparison of startup durations (i.e. as measured from first energization to fuel load) for other contemporaneous plants. The actual startup duration at Limerick was 27 months as compared to the 21 months projected in the 1974 schedule used by Mr. O'Brien. The major reason for this difference was the rigorous regulatory environment in which the project had to be completed and the required extensive documentation of all startup test work. Thus, Limerick 1 startup could not have been completed in any shorter duration than was actually achieved.

Moreover, the actual detailed startup schedule used at Limerick required significant construction sequence changes from the logic contained in the 1974 MSCS schedule. Mr. O'Brien failed to recognize these changes in his analysis. For example, Mr. O'Brien's logic requires containment to be completely finished in order to support the testing of Startup System 54 which is Emergency Service Water. However, Startup System 54 is not required for containment; Mr. O'Brien should have used Startup System 51 which is the Core Spray System as the activity which determines when containment should have been finished. Also, Mr. O'Brien failed to schedule an activity called Blue Tag Testing which had in fact been rescheduled to a duration prior to system turnover to allow for construction testing of plant systems at that time. This revised logic represents a significant change to the startup program at Limerick and was a principal reason why startup

activities took only 27 months to complete.

Incorporation of the actual startup logic and durations in the critical path areas of Mr. O'Brien's schedule alone would extend it by 35 weeks. Thus, Mr. O'Brien has erred by failing to analyze the startup period more thoroughly and, as a result, has falsely concluded that Limerick's startup could have been sooner and accomplished in 21 month (energization to fuel load), a duration not achieved by any contemporaneous first unit plant.

Q. Please explain the failure of Mr. O'Brien to include the effects of engineering, procurement and licensing restraints upon the schedule.

A. Mr. O'Brien did not reflect the impact of engineering and procurement restraints upon the schedule which were caused by regulatory requirements other than Mark II. Instead, he blindly assumes that all additional work caused by these requirements could have been accomplished before July 1982. As discussed in other PECO rebuttal testimony, Limerick's fuel load could not have been achieved earlier than October 1, 1984 as a result of requirements such as ATWS, fire protection, equipment qualification and others. Mr. O'Brien's failure to recognize the Limerick requirements for completion of regulatory items renders his analysis unrealistic and without merit. Similarly, Mr. O'Brien has failed to address the difficulties which PECO had to overcome to obtain an operating license at Limerick. Failure to recognize and address these items further illustrates the superficiality and lack of merit in Mr. O'Brien's analysis.

Q. Please discuss Mr. O'Brien's failure to develop a cash flow based on his schedule analysis.

A. In order to have a realistic cost and schedule estimate for a project, cashflows must be developed from information contained in the schedule in order to ensure

that sufficient financial resources are available to support the requisite level of manpower and activities needed to complete the project on time. In Mr. O'Brien's analysis (Exhibit JJO'B-17.3), annual cash flows were redistributed according to the actual pattern of real expenditures at Limerick. However, this methodology of estimating cash requirements is erroneous because it does not actually support the schedule developed by Mr. O'Brien. In order to develop appropriate cash flows, Mr. O'Brien's analysis should have examined the scope of work to be performed and manpower required to meet the needs of the schedule, and then calculated cash requirements on the basis of this information. Thus, Mr O'Brien's cash flows and schedule are inconsistent.

In the Case 1 analysis presented by Mr. Coughlin, a revised cashflow based on Mr O'Brien's schedule (i.e., assuming a July 1982 fuel load) was developed after adjustment to reflect the as-built conditions through May 1976 and startup duration. This analysis indicates that the cash flows required to meet a mid-1982 fuel load are substantially higher than those projected in Mr. O'Brien's schedule analysis. Indeed, Mr. O'Brien's cash flows through 1979 closely follow the Case 2 analysis which projects a July 2, 1984 fuel load. Thus, Mr. O'Brien's cash flow is inconsistent with the higher level of work required to meet an earlier schedule. Furthermore, given the erroneous nature of Mr. O'Brien's cash flow, all subsequent calculations based on it are flawed.

Q. Have you attempted to adjust Mr. O'Brien's schedule analysis in order to correct the errors described above?

A. Yes. At the direction of Mr. Boyer, the Company's Construction Division in conjunction with Bechtel developed a multiple-stage analysis to correct the above-referenced errors in Mr. O'Brien's analysis. My role was to provide

assistance in the overall direction, supervision, and coordination of the analysis. All major aspects of the analysis were reviewed and evaluated by my staff to assure reasonableness and accuracy. A detailed description of this analysis is contained in Mr. Coughlin's testimony. Documentation of the analysis is presented in Exhibit JJC-1/JRC-1.

Q. Would you please briefly describe this analysis and its results.

A. First, PECO acquired Mr. O'Brien's Mark II adjusted schedule through the use of the MSCS computer program at McDonnel Douglas Corporation. Computer tapes were transferred to Bechtel to allow reproduction and analysis of Mr. O'Brien's schedules. After confirming the correctness of program operability, we used the MSCS program to develop the several stages of our analysis.

The first stage of our analysis is labelled Case 1. Because of Mr. O'Brien's failure to prepare a schedule for the fuel load date of July 1982, it was necessary to take proper steps to adjust Mr. O'Brien's schedule from the fuel load of December 11, 1981 to July 28, 1982. This end date was then held constant. In addition, the as-built startup logic and duration and actual manhour requirements for mechanical/electrical activities were added to the schedule to reflect the actual scope of work required to complete the job. The result of this first analysis is shown in Exhibit JJC-1/JRC-1, Section 3 and demonstrates that Mr. O'Brien's assumed cash flows do not support a July 1982 schedule, and manpower density requirements to meet such a schedule were unreasonably high. Thus, Mr. O'Brien's schedule duration is unrealistic and unsupportable.

Next, Case 2 was prepared as shown in Exhibit JCC-1/JRC-1, Schedule 4. This analysis added several items, including:

1. The as-built schedule and cash expenditures through May 1976, as

accepted by Mr. O'Brien but totally omitted from his analysis.

2. The as-built civil/structural logic and scope of work.

3. Appropriate manpower density limitations including the use of double shift work.

4. Separation of containment activities into two areas, i.e., drywell and wetwell.

The result of these additional adjustments was a scheduled fuel load date of July 2, 1984 being the earliest date achievable based on the scope, complexity, and congestion of the Limerick plant.

We then developed Case 3 which adjusted the Case 2 analysis to reflect yearly cash requirements as then foreseen to complete the project as early as possible. While Case 3 resulted in the deferral of some work until the later years of the schedule, the achievable end date was not affected. The results of this case are presented in Exhibit JJC-1/JRC-1, Section 5.

Finally, in order to illustrate the effect of regulatory and licensing restraints upon the schedule, Case 4 was prepared based on data contained in the testimony of Messrs. Helwig, Sproat and Mattson and in Exhibit RJM-1. Inclusion of critical licensing and regulatory issues shows that the earliest fuel load would have been October 1, 1984. The results of Case 4 are presented in Exhibit JJC-1/JRC-1, Section 6.

Q. Please describe your role in developing the maximum sustainable manpower densities used in the Case 2 and 3 analyses.

A. My role was to review the reasonableness of the maximum sustainable manpower density limitations adopted in these analyses. As stated previously, manpower density limitations must be considered in order to realistically assess when

Limerick could have been completed. The density limitations used in the analyses were derived from a very detailed study for the completion of Unit 2 and were reviewed for reasonableness by my staff. These densities were developed using the following information:

1. Limerick 1 manpower densities actually utilized in specific areas of the plant.

2. Detailed walkdowns by Bechtel management in conjunction with my staff to identify maximum manpower limitations based on access, congestion and possible sequencing of activities within specific plant areas.

3. Bechtel's comparisons prepared for Limerick Forecasts, particularly Forecast 7, Part 2, which compares Limerick to other plants.

Employment of these major items demonstrate that the densities used in the analyses were indeed maximum sustainable density levels, were reasonable limits to impose upon the use of manpower in specific areas of the plant, and would result in the shortest schedule duration possible under realistic construction conditions.

Q. Have you prepared an Exhibit which illustrates the reasons for manpower density limitations at Limerick?

A. Yes, I have. Exhibit JJC-2 contains photographs of various elevations within the containment drywell. Its purpose is to show the limited space conditions and massive amounts of mechanical and electrical commodities, i.e. large and small pipe, pipe hangers, HVAC duct, cable tray and conduit, which have caused extreme congestion, complexity and therefore restrictive density limitations in the drywell and other plant areas.

Q. Please describe the significance of the double shift assumptions used in Cases 2

and 3 and your role in the development of those assumptions.

A. An important factor in scheduling construction activities is the extent to which more than one shift of craft laborers can be effectively employed to complete construction activities. Double shifting refers to a situation when one group of laborers works in a particular plant area for a full shift, i.e. typically 8 hours, and is followed by a second shift of workers to continue construction activities in that same area. The benefits of shift work are that it avoids the significant loss of productivity which generally results if extensive overtime is used and compensates for the restrictive manpower density limitations found in many plant areas. As a result, construction activities may be completed in a shorter duration.

In the Case 2 and 3 analyses, it was assumed that a maximum average second shift equal to two-thirds of the first shift could be employed on a sustained basis. This assumption was developed from the collective experience of Bechtel and PECO on the Limerick project and their knowledge of shift work employed at other plants. Specifically, my contribution to this assumption is based on over 15 years experience at the Limerick project, my direct involvement in the construction of the Company's Peach Bottom nuclear units and knowledge of construction activities at other nuclear plants, including Susquehanna, which we monitored for most of Limerick's construction duration.

Based on my experience, I believe that the use of a fully staffed second shift could not have been achieved on a sustained basis, principally because of practical difficulties in coordinating and managing the interface between shifts. For example, a work shift which is installing large pipe hangers must develop extensive measurements in order to fabricate, fit-up and install the hangers. This information would then have to be communicated to the second shift if work were

to continue. Because of the complexity and detailed nature of these measurements, such communication is extremely time consuming and generally not attempted. Moreover, second shifts typically work after normal business hours when engineering and other nonmanual support is not as readily available as it is on the first shift. Thus, the amount of work which a second shift can effectively accomplish is limited and this reduces the level of staffing which can be effectively employed.

As a result of these practical difficulties, we determined that a full second shift could not have been used on a sustained basis. Indeed, our experience at Limerick indicates that where fully staffed second shifting was attempted in the Containment and Reactor Building, where at most a second shift of approximately 50% could actually be used because of the problems identified above, and this occurred only in certain plant areas. Thus, I believe that an assumed two-thirds second shift is entirely reasonable and adds a measure of conservatism to the analyses. I would also note that this assumption is consistent with experience at other plants, including Susquehanna, which were unable to maintain even a consistent two-thirds second shift as assumed in our analyses.

Q. What was your role in developing separate manpower density and shift assumptions with regard to the drywell and wetwell areas of containment?

A. As noted above, our review of Mr. O'Brien's analysis indicated that he had incorrectly treated the containment as a single activity. Through my direct experience at Limerick, I was very familiar with the differences in scope and complexity between the drywell and wetwell structures within that facility. Specifically, the drywell has a much greater work scope and more complicated design than the wetwell, which resulted in a greater amount of congestion and

more restrictive manpower density limitations in that area. Because of the wetwell's smaller work scope, it would require less time to complete than the drywell. Therefore, treating these areas on a combined basis effectively applies the greater total containment density limitations to the drywell area after wetwell activities are complete, and thus results in an unrealistically short schedule.

As a result, separate manpower densities were developed for the drywell and wetwell, and these areas were separately reflected in the Case 2 and 3 analyses. This adjustment to Mr. O'Brien's analysis was necessary to accurately reflect the realities of construction at Limerick. Indeed, the containment scheduling for Limerick 1 was in fact divided between the drywell and wetwell during the latter part of the project, principally due to the scope and complexity differences described above.

Q. Are there any other errors in Mr. O'Brien's testimony?

A. Yes. On pages 31-32 of his testimony, Mr. O'Brien identifies certain PECO indirect costs which he believes would not have been incurred if Limerick's schedule was advanced. Mr. O'Brien's assumption that these costs were incurred as a result of the schedule duration is incorrect. To the contrary, many of these costs are not time-related. For example, Public Notification costs relate to the design and installation of the NRC-mandated Emergency Notification System at Limerick, and would <u>all</u> have been incurred regardless of the completion date. Similarly, Training costs are related to the training and qualification of the plant operating staff and would <u>all</u> have been incurred earlier if the plant was completed in July 1982. Power costs are also not time-related as they were incurred primarily for construction welding and startup testing activities, <u>all</u> of

which would have had to be performed to meet an accelerated completion. Finally, Plant/Start-up Staff and Maintenance costs are associated with startup activities, which also would all have to be performed regardless of when the plant was completed. Adjusting for these errors would reduce Mr. O'Brien's adjustment for indirect costs by $25.7 million and $29.8 million with AFUDC.

The remaining indirect costs disallowed by Mr. O'Brien are also not entirely time related, as he admitted during cross-examination. For example, some additional Construction Supervision and Engineering costs would have been incurred because of the larger amount of work which would be performed if an earlier completion date were achieved. At least 54% of these costs, however, are not time related, and Mr. O'Brien's adjustment should be reduced by an additional $28.1 million and $32.6 million including AFUDC. This figure was calculated on the assumption that time related indirect costs would have increased in the same proportion as reflected in Mr. O'Brien's reallocation of direct costs for the pre-July 1982 period.

Q. Do you have any other comments regarding Mr. O'Brien's testimony?

A. Yes, I do. In his comparison of Limerick to Susquehanna and LaSalle, Mr. O'Brien relies on differences in start dates for certain construction activities. Specifically, Mr. O'Brien uses the information contained in Exhibit SHH-3 to show that Large Pipe Hanger installation started 3 years before LaSalle and 1 year before Susquehanna. The data contained in Exhibit SHH-3 is based on the NRC Yellow book. However, the correct start date from the NRC Yellow book for Large Pipe Hangers is March 1976 for LaSalle (SHH-3 shows April 1979) and August 1975 for Susquehanna (SHH-3 shows August 1977). Using these corrected dates, Mr. O'Brien's testimony should be changed to indicate that Large Pipe

Hangers at LaSalle started only 2 months after Limerick and Large Pipe Hangers at Susquehanna started 5 months ahead of Limerick.

Mr. O'Brien also only uses those comparisons which favor his conclusion. For example, he states that Structural Concrete at Limerick started two months earlier than at Susquehanna, but fails to point out that LaSalle started Structural Concrete one month earlier than Limerick. Likewise, O'Brien states that Large Pipe installation at Limerick started 10 months earlier than LaSalle, but fails to point out that Susquehanna started Large Pipe one year and 5 months ahead of Limerick. Following Mr. O'Brien's logic suggests that if a comparison were made between LaSalle and Susquehanna, Susquehanna should have finished 2 years and 3 months ahead of LaSalle based on the start of Large Pipe installation (i.e. August 1974 at Susquehanna versus November 1976 at LaSalle).

Furthermore, it should be noted that comparisons using NRC Yellow Book information may be misleading as a result of construction and reporting differences between plants. Start and finish dates as used in the NRC Yellow Book do not allow any meaningful comparison between plants since a start date could mean either that the very first piece of a commodity was installed or that construction was substantially underway.

Q. Has Mr. O'Brien considered the differences in construction permit dates for Limerick, Susquehanna and LaSalle?

A. No, he does not. Mr. O'Brien has ignored the earlier construction permit issuance dates at LaSalle and Susquehanna in comparing Limerick to those plants. The construction permit date for Susquehanna was November 1973 - a full 7 months ahead of Limerick 1, while fuel load at Susquehanna was July 1982, the same date projected by Mr. O'Brien as an achievable date for Limerick 1. Likewise, the

construction permit date for LaSalle was September 1973 - a full 9 months ahead of Limerick 1, yet LaSalle 1 loaded fuel in April 1982, or 3 months before July 1982. As shown by these dates, the durations from construction permit to fuel load for Susquehanna and LaSalle were 104 and 101 months, respectively. However, under Mr. O'Brien's analysis, Limerick 1 should have been completed in 97 months. Given the significantly greater commodities which were required at Limerick, as described by Mr. Helwig, such a result is clearly unreasonable.

Q. Have you updated the cost and schedule comparison of Limerick 1 with plants of similar design which was presented in your direct testimony?

A. Yes. The updated comparison is set forth in Schedule 3.

Q. Please describe the updated comparison.

A. The updated comparison is in the same format and includes the same units as described at pages 36-37 of my direct testimony.

Q. Please summarize how the cost and schedule of Limerick 1 now compare with the updated information for the other BWR's included in your comparison group.

A. The cost of Limerick remained the same at $2234/Kwe, and is now 12% lower than the average of $2502/Kwe. The 12-plant average cost/Kwe has increased more than 7% since my original testimony. We anticipate that additional increases will occur because some utilities would not provide cost or schedule updates due to estimate reevaluations.

The 12-plant average schedule duration increased 1 month and, therefore, there is minimal change in the schedule comparison since my original testimony.

Q. As explained in your direct testimony, the cost and schedule of BWRs constructed in the Northeast are influenced by factors which in whole or in part do not affect those built elsewhere. Please describe how Limerick 1 compares to the updated