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PENNSYLVANIA PUBLIC UTILITY COMMISSION
PHILADELPHIA ELECTRIC COMPANY,
Docket No. R-850152

DIRECT TESTIMONY OF
JAMES J. CLAREY

LIMERICK 1 AND COMMON PLANT
CONSTRUCTION SITE MANAGEMENT
PREPARATION OF PECO EXHIBIT 2

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Direct Testimony of James J. Clarey

Q. Please state your name and business address.

A. James J. Clarey, P. O. Box A, Sanatoga Branch, Pottstown, Pennsylvania 19464.

Q. By whom are you employed and in what capacity?

A. I am employed in the Construction Division of the Philadelphia Electric Company. My position for the last 15 years has been the Project Manager - Construction at the Limerick Generating Station construction site. The title of my position has recently been changed to Superintendent - Limerick Section.

Q. Please briefly state your educational and employment background.

A. I received my Bachelor of Civil Engineering degree from Villanova University in 1955. Following graduation from college and a relatively short period of field engineering work for a heavy construction contractor, I joined PECO in 1957. In my 28 years with PECO, I have been consistently involved in major construction project management and my responsibilities have included managing overall field construction progress, schedule development, procurement, contract bidding, awarding and administration, estimating and monitoring project costs, quality assurance, acting as coordinator between various PECO divisions and major contractors and reporting regularly to PECO senior management. The major projects in which I have held management positions include construction of Eddystone Station Units 1 and 2 (1957-1962), additions and improvements to PECO's steam heating distribution system (1962-1964), construction of PECO's underground Independence Mall Substation (1964-1965),

construction of Muddy Run Pumped-Storage Generating Station (1965-1969) and, since 1969, construction of Limerick Generating Station.

Q. Do you belong to any professional societies or organizations?

A. Yes. I am a member of the American Society of Civil Engineers and the Project Management Institute. In addition, I am a registered professional engineer in the Commonwealth of Pennsylvania.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the construction site management organization established at Limerick, to describe the site management tools used to control cost, schedule, labor effectiveness and quality, and to explain the impact of changing regulatory requirements and other external forces on construction activities. In addition, my testimony will present the results of two studies which I have performed: 1) a comparison of Limerick 1 and common plant costs and schedule duration with similar data for a group of comparable nuclear projects, and 2) a comparison of Limerick 1 and common plant commodities and unit rates with data at other plants.

1. Limerick Construction Site Management Organization

Q. Please briefly describe your role as Project Manager - Construction at the Limerick Project.

A. My role encompassed three major categories of activities. First, I was in charge of the day-to-day supervision and direction of the PECO Construction Division team at the

Limerick site. Second, I conducted PECO's coordination efforts with the site management teams of Bechtel Power Corporation ("Bechtel") and General Electric Company. Third, I regularly communicated with and reported to PECO senior management and worked with other PECO division personnel represented at the site, including the Station Superintendent, the Quality Assurance Engineer, the Electrical Engineering Division Field Engineer, the Testing Section Engineer, internal auditors and other administrative personnel. As part of my duties, I participated in regular and special PECO management meetings, including the Monthly Project Status Review Meeting chaired by the Vice President for Engineering and Research, and the Monthly Construction Review Meeting with Bechtel Construction which I chaired and which was attended by the General Superintendent of Construction and his assistant.

I was also responsible for preparing a number of major reports on the status of construction activities which were submitted for review by senior PECO management. These reports included the Construction Activities Report, the Schedule Analysis Report and the Monthly Cost Report. A further description of these reports and how they were used in managing cost and schedule is set forth later in my testimony.

Q. Please briefly describe the history of PECO's Limerick site management organization?

A. My field office was established at the Limerick site in 1970 and I have worked at the site since that time, with the exception of the period January 1972 to May 1973 when

construction was suspended as a result of NRC licensing delays. Prior to the receipt of a construction permit, the Company's site forces were relatively small, consisting of five engineers. The small size of PECO's construction management organization was appropriate since only limited construction activities, such as clearing and site preparation, could be performed at that time. By the time the NRC construction permit was issued in 1974, the site team had grown to 13 PECO engineers and 1 field supervisor. This increase was due primarily to the anticipation of the start of construction activities. As the number and variety of field operations increased (i.e. civil, mechanical, piping, electrical), the staffing, in turn, increased to its peak size of 25 engineers, 10 senior mechanical and electrical field construction supervisors and 4 administrative assistants. A chart depicting this site management organization is attached to my testimony as Schedule 1.

This site management organization had been successfully used in prior construction projects, including in particular the construction of the Peach Bottom units between 1968 and 1975. Our engineers and field construction supervisors were highly experienced in appropriate engineering and construction activities. Much of this experience came from direct involvement with construction at Peach Bottom. Stated broadly, the role of the site team was to assure fulfillment of the Project's cost, schedule, quality and procurement requirements and to assure that contractor activities were carried out in an

effective and efficient manner.

Q. Describe the roles and responsibilities of the various members of PECO's site management team.

A. Referring to Schedule 1, I have labeled the major branches of the organization with five functional headings: Technical Analysis, Schedule and Progress Review, Subcontract Monitoring, Cost Analysis and Quality Control. The activities of these functional groups are described below.

Technical Analysis: PECO mechanical, electrical and civil engineers reviewed the Project drawings and specifications, commenting on them or approving them in accordance with responsibilities established by the PECO Project Manager; monitored the construction activities in their discipline; recommended changes to improve the construction process or to enhance quality; and analyzed and responded to NRC inquiries regarding field activities.

Schedule and Progress Review: PECO engineers were assigned to complement the Bechtel system of dividing the Project into several geographic areas (hence the name Area Engineer or Area Superintendent) and closely followed field construction activities to assess fulfillment of Project schedule goals, field management effectiveness and the quality and completeness of the various schedules.

Subcontract Monitoring: PECO engineers reviewed and approved the various activities leading to award of subcontracts for field construction work not performed by Bechtel, including participation in pre-bid meetings, bid

package preparation and selection and approval of bidders. Following award, the administration of the subcontracts and construction progress were closely monitored through to completion. This team was actively involved in reviewing and monitoring change orders and claims resolution.

Cost Analysis: PECO engineers reviewed the field labor and material quantities portions of periodic Bechtel cost estimates (called Forecasts), monitored and evaluated field labor performance, and reviewed Bechtel's field procurement practices.

Quality Control: A specially established group, using a formal Quality Assurance program developed by PECO management, performed daily inspections of selected construction activities for quality of workmanship and completeness. The scope of their work included inspection of key plant systems which were important to reliable plant operation, thus reducing unscheduled outages for repair of equipment.

In summary, the site team monitored and controlled all functional areas of Project construction. Principal regular activities performed by the site management organization included monitoring construction activities for compliance with design requirements, reviewing construction drawings, attending construction meetings, witnessing completion of significant construction activities and assessing the effectiveness of field supervision and manpower utilization. Through the performance of these functions and utilization of the management control processes described later in my testimony,

the site organization effectively and efficiently controlled the construction process.

2. Cost, Schedule and Labor Control Systems

Q. Please describe the control systems employed in managing Limerick's construction.

A. The principal systems were the Limerick Resource Management System ("LRMS") and the Forecast and Control Updating System ("FOCUS"). LRMS is a computerized management control system that tracks actual materials and equipment installed and develops projections of required further quantities (i.e. "to go" installations). FOCUS is a computerized labor monitoring system which calculates actual and projected unit rates.

LRMS maintains data on quantities installed to-date as well as to-go quantities. It was a unique system and was a fore-runner of the data-tracking systems later developed on other projects. It was first developed by Bechtel with PECO support from experience gained during the construction of Peach Bottom Units 2 and 3. To-date quantities were obtained from weekly construction progress reports prepared by construction supervisors. To-go quantities were developed from engineering drawings and were revised as plant design was refined. In addition, LRMS provided computerized procurement systems for the procurement of major materials, engineered equipment and field purchases of bulk commodities. The information contained in LRMS was updated on a weekly basis and could be recalled in various forms depending upon the users' needs, i.e. total project equipment/commodity installation status, status of a

particular commodity or equipment installation or status of equipment/commodity installation at a particular plant location or within a particular startup system.

FOCUS combines actual manhours expended in the field as taken from craft time sheets with quantity data obtained from LRMS to develop actual unit installation rates (i.e. manhours per unit of material installed) for each commodity. FOCUS also provides comparisons of actual and budgeted unit rates and projects to-go unit rates for each commodity. The FOCUS program was used by Bechtel at a number of its projects during the same time frame as Limerick and, as discussed later in my testimony, was the major management tool used to monitor and control labor effectiveness.

Q. What other control systems were utilized?

A. In addition to the above systems, computerized systems for the control of payroll, the payment of invoices for equipment and commodity purchases, and craft manhour expenditures were also maintained.

Q. Please describe how construction costs and progress were measured and controlled.

A. In order to control costs and measure progress, it is necessary to develop a construction plan. This was accomplished through the Project Forecasts, initially prepared by Bechtel but thoroughly reviewed and approved by PECo management. Both PECO home office and site personnel, drawing upon their experience with oversight and monitoring of actual engineering and construction activities, participated in this review and

approval process. Forecasts were developed employing the LRMS and FOCUS. Estimated to-go quantities for each commodity were obtained from LRMS and combined with appropriate unit prices to develop estimated material costs. Forecasted unit rates derived from the FOCUS program were reviewed and adjusted appropriately by construction management, and then applied to the to-go quantities to calculate estimated labor manhours. Total manhours were combined with appropriate wage rates to develop total labor costs. Activities required to install the forecasted commodities were assigned a duration based on labor availability, effective work crew size and other construction practicalities, and were sequenced in a long-term Project schedule. More detailed intermediate and short-term schedules were then developed.

Progress against the cost Forecasts and schedules was monitored through a Trend Program, review of FOCUS reports, review of schedule analyses and commodity installation projections, meetings with Bechtel and direct observation of construction activities. The Trend Program was a mechanism by which Bechtel advised us of significant variations of actual design and construction from the Project plan, i.e. variations with a significant likelihood of affecting either total Project cost or schedule. Trend reports were generally supplied monthly and were carefully reviewed both by my organization and by home office personnel. FOCUS reports were supplied weekly. These reports permitted us to evaluate commodities installed, unit rates experienced and other significant measures of

construction progress against the Project plan. Often, the variances were the result of regulatory or other uncontrollable factors and could not be corrected. When cost estimate changes were required, the Project plan was revised via approval of a cost trend.

One of the functions of my organization was to make a detailed analysis of the field cost portion of each Forecast, monthly trend reports and weekly FOCUS reports. Major items analyzed included material quantities, installation rates, unit rates, distributable manual labor, non-manual labor and contingency allowances. For example, material quantities were reviewed for reasonableness by comparisons with other projects and by consideration of quantities of materials used to-date at Limerick. Similarly, unit installation rates proposed by Bechtel were also compared with industry data as well as with to-date performance at Limerick. Assessments of unit rates necessary for accomplishment of the remaining work were made with consideration given to industry performance data based on the physical completion status of each commodity. Similar evaluations were regularly performed on the remaining field cost categories. The results of the site organization's evaluation of the monthly/weekly cost and scheduledata were supplied to PECO Senior Management in separate monthly cost and schedule reports which I describe further below.

Q. Please describe the schedules used by Project management.

A. There were three principal types of schedules used to manage construction activities at Limerick. First, at the

lowest level, a three to four week rolling schedule was prepared and used by superintendents and area foremen to plan daily activities for their crews. These schedules were extremely detailed, containing specific information at the pipe spool, pipe hanger, etc., level. Their purpose was to insure that activities were statused and scheduled so that craft manpower would be used effectively. These schedules were reviewed and updated at weekly Bechtel field meetings attended by PECO construction engineers at which the discussions would focus on problem resolution, coordination between work crews and ways to improve schedule progress.

A second type of schedule was the 12-month schedule prepared by field supervisors and planners in order to provide mid-range planning and coordination of engineering, procurement and construction activities. This schedule was specific to each section of each plant elevation and facility, and was updated every three months to reflect completed items and remove them from the schedule, to reschedule incomplete items and to reflect the latest three months of activities. Each revision of this schedule was distributed throughout the site management organization and was reviewed by PECO Construction Division and compared to the long-term schedule. Progress was monitored by PECO through review of Bechtel prepared reports, i.e. the Monthly Earned Manhour Report, Weekly Bulk Commodity Analysis Report and Monthly Construction Management Report,

through weekly and monthly meetings with Bechtel field management, through daily site tours and through informal communication with Bechtel superintendents and field engineers.

The final type of schedule employed at Limerick was for long-range planning. During the construction of Peach Bottom, it was recognized that improved schedule control was needed. As a result, we hired a consultant to develop a critical path method ("CPM") schedule for primary containment construction. In addition, we later encouraged and supported Bechtel's use of a computerized critical path scheduling system called Management Scheduling and Control System ("MSCS") at Peach Bottom. We requested that Bechtel use this same scheduling method at Limerick.

MSCS was a scheduling program developed by McDonnell-Douglas Company which provided scheduling for 3,000 to 4,000 activities on a facility/elevation and systems/commodities basis. Logic diagrams were prepared based on planning by construction supervisors and schedulers. Using the quantity information available from LRMS, the unit rates available from FOCUS and crew sizes and manpower densities established by construction supervisors, the schedulers prepared program input. Through an iterative process, final activity durations and manpower loadings were combined to yield start and completion dates for all construction activities. Further calculation yielded float information, i.e. available slack

time for each activity. Activities with the least or no float constituted the critical path. Engineering and procurement activities were separately scheduled based on MSCS need dates, and MSCS construction activities were, in turn, scheduled to meet the requirements of the Project startup schedule. Thus, all phases of the Project were coordinated.

As construction shifted to the installation of bulk mechanical and electrical commodities in 1978, we recognized the need for a scheduling method that was more appropriate for this phase of the Project. Working closely with Bechtel, we developed what became known as the Intermediate Construction Schedule ("ICS"), a scheduling methodology better adapted to the dynamic nature of bulk installation activities. Regular monthly review meetings attended by the General Superintendent of PECO's Construction Division or his assistant and my group were held with Bechtel site management to review progress against the MSCS/ICS and 12-month schedules. Moreover, PECO construction engineers monitored bi- weekly Bechtel on-site meetings at which craft supervisory personnel and Bechtel site management discussed the progress of all areas of the Project in detail.

When combined with the forecasting program, these schedules completed the overall management system by which construction cost and schedule control was achieved.

Q. Please describe in greater detail why you decided to change

from MSCS to ICS in 1978.

A. MSCS had served the Project well through the civil/structural and major equipment installation phases. However, we recognized that a critical path methodology such as that used by MSCS would not be appropriate in the bulk commodity/system completion phase. The reason for this was the traditional use by CPM of "hard" logic which is inflexible in that it demands a certain sequencing of construction activities. The civil/structural phase of the Project, by its very nature, required that a predetermined construction sequence be followed, i.e. that a certain structure or piece of equipment be installed before another. Therefore, the hard logic underlying the MSCS program was well suited for scheduling this type of work.

However, mechanical and electrical commodity installation was not benefitted by this "hard logic, rigid sequence" approach to activity planning. Unlike civil/structural work, there are an infinite variety of methods and sequences for efficient commodity installation with the most efficient often depending upon external forces which cannot be known until construction proceeds. For example, hard planning logic for the installation of piping is not appropriate because it cannot reflect the realities of spool problems, scaffolding, access, deliveries of hangers, fitting and valves, foreman preferences and hundreds of other real-life factors that determine the best method of installation on a day-to-day

basis. As a result, MSCS was simply not the best method for scheduling this phase of the Project.

Q. What problems would arise from using the hard MSCS logic for the scheduling of bulk commodity installation?

A. The most serious problem was that MSCS could not be used to accurately evaluate progress or report Project status. Where departure from the established hard logic was required for proper installation of a particular commodity, the MSCS schedule would often show a negative schedule impact, i.e. negative float, until the logic was revised to reflect this change. If these activities were on or nearly on the critical path, a schedule delay of a Project milestone would be unnecessarily reported. This misinformation interfered with management evaluation of Project status and needs.

Q. What was the ICS schedule methodology and why was it more appropriate than MSCS?

A. ICS was developed by Bechtel in response to our continuing insistence that a better schedule tool was necessary to plan, schedule, assess and evaluate progress. ICS covered the same scope as MSCS, i.e. construction, testing and startup, and it was similar in format to MSCS in that work was divided by facility/elevation and the commodities in those locations were included. All remaining work was quantified and displayed in a series of line items, similar to bar charts, which had calculated calendar durations.

These line item activities had two basic logic ties.

First, detailed analyses were performed to schedule commodity completion and testing to support system turnover to startup. Second, analyses of the commodity activities at each location were made so that these activities could be scheduled to reflect interrelationships of space and time. That is "soft", rather than "hard", logic was established, i.e. goals rather than outright demands were stated. At this level of scheduling, direction as to which specific portion of the line items should be installed first, last or otherwise was not stated. Thus, construction supervision had the necessary flexibility to cope with routine day-to-day problems. They did, however, commit to meeting the goals established by the soft logic and were monitored accordingly.

In addition, ICS provided a better assessment of progress because it employed the earned value concept of schedule attainment. The earned value method assigns quantity credit on the basis of degree of difficulty and complexity with each major commodity installed to accurately status segments of the job and then the total job on a value-of-work accomplished basis. This concept provided a more accurate picture of actual progress and avoided the illusion of, for instance, faster progress resulting from accomplishment of easier work. Thus, ICS provided management with the ability to better assess electrical/mechanical commodity progress and, on a summary basis, assess total Project progress.

Q. Were there any special purpose work schedules employed at Limerick?

A. Yes. A number of special purpose work schedules were used to supplement those described above. Where work in a particular area of the plant was especially difficult or critical to meeting the overall Project schedule, a specific schedule for that work was generally prepared. These schedules provided a level of detail similar to that used in the three to four week schedules, but for a substantially longer period of time. Their purpose was to provide additional detailed scheduling for those activities which required a higher level of planning effort in order to ensure that Project completion would not be impacted. Typically, PECO construction engineers were assigned to the items covered by special purpose schedules to monitor progress and ensure that slippages in schedule were promptly addressed by Project management.

The most important of the special purpose schedules employed at Limerick was for work performed in the primary containment. Because of the complexity and limited work space in this part of the plant, construction interferences caused by regulatory design changes threatened to slow construction progress and delay overall Project completion. Regulatory changes which impacted the primary containment design and construction included Mark II modifications, Class I seismic requirements, pipe whip restraints and TMI modifications. The primary containment

special schedule was used to provide detailed planning of activity sequencing in order to meet major milestones, such as the hydrostatic test of the reactor vessel and connecting piping, the structural integrity tests and the integrated leak rate test.

A number of other such schedules were developed, including specific schedules for 1) completion of systems needed for turnover to the startup group which were prepared and updated weekly; 2) systems heavily impacted by regulatory change, including control room panel modifications, installation of interior and exterior security equipment, TMI additions, etc; and 3) other miscellaneous activities, such as control rod drive installation, reactor vessel internals installation, refueling floor construction, thermal insulation of piping and the application of special coatings to walls and floors.

Q. Please describe how work force effectiveness was managed.

A. As previously discussed, quantities installed, manhours expended and unit rates for all commodities were maintained in LRMS and FOCUS. These data were then summarized and compared with forecasted unit rates through the FOCUS program. Forecasted unit rates for the various commodities were presented in the form of performance curves developed from productivity information at other nuclear construction projects in which Bechtel was involved and to-date performance at Limerick. These curves reflected the relationship between unit rate and completion progress.

Unit rate comparisons were the principal tool used to monitor labor effectiveness. These comparisons were reported and summarized in Weekly Labor Cost Reports (produced by FOCUS) which were reviewed by a PECO cost engineer who would then prepare a monthly report to PECO management presenting performance analyses for major commodities on a cumulative, annual and monthly basis. The cost engineer, in concert with the schedule engineers, would also calculate installation performance for the most recent three month period. These data were then compared with forecast unit rates. If significant deviations were revealed, the effect on schedule (i.e. installation durations) was estimated and corrective action was studied. Management was alerted to possible schedule slippage if corrective action could not be taken or was ineffective.

In addition, a number of other programs were established in order to enhance worker productivity and morale. A description of the most important of these programs follows.

Work Sampling - A special program of field study of work activities was established using statistical sampling to identify nonproductive time, i.e. time not yielding direct or indirect work. Under this program, the plant was divided into survey routes which would take approximately 30 minutes to cover, and PECO engineers were assigned to each of the routes to observe and record results on standardized survey forms of the specific activities of

workers in various construction areas. The focus of this program shifted to areas of the plant where work was progressively more difficult to perform. Data were compiled, concerns of observers were summarized, and results were reviewed with contractor management on a daily and weekly basis.

Production Engineering - Where normal control procedures did not readily produce desired production rates, a group of industrial engineers were assigned to study the problem and recommend corrective action.

Industry/Academic Interface - PECO participated in a number of programs sponsored by the academic community to identify areas for improving the construction of nuclear plants. The results and recommendations from these programs were reviewed and analyzed for applicability to Limerick.

Employee Suggestion Program - We have always held a strong belief in the value of employee suggestions and have maintained such a program within the Company. During the Limerick Project, a similar program was extended to non-PECO site personnel as well.

Quality Circles - Bechtel developed a program under which non-manual employees met weekly to discuss problems and select significant items for referral to management.

Finally, PECO attempted to enhance productivity through efforts designed to improve and maintain employee morale. Examples of our efforts in this regard included

the publication of a monthly job site newspaper which provided individual recognition of worker performance and human interest stories involving construction personnel; a project open-house which allowed workers to share their accomplishments with their families; and an annual series of afternoon meetings with all craft foremen, superintendents and lead-nonmanual personnel which provided an opportunity to direct questions to upper level PECO management, including the Vice President for Engineering and Research, about Project goals and other matters related to Limerick.

Q. Please describe any other management tools used to monitor and control construction costs and schedule.

A. The primary tool used to monitor and control all aspects of the Project was the Monthly Project Status Review Meeting. This meeting provided a forum in which the status of each functional area of the Project was communicated to upper management. Information on construction activities was generally provided through two sources. First, the Bechtel Project Construction Manager provided a construction report which explained the status of all construction activities and discussed major construction items in detail. As the representative of the PECO construction site team, I would comment on the various matters presented by the report and provide clarification as to the site team's position on these matters. Second, the PECO site team developed analyses of cost and schedule performance during the

previous month which would be given to PECO management in advance and discussed at the meeting as necessary. As a result, potential problems in the construction area were raised and reviewed by all management groups, the impact on other areas of the Project was analyzed, and corrective measures were formulated and implemented.

Cost and schedule were also monitored through a number of regular reports prepared under my direction and supervision. One of the most important was the Construction Activities Report which was issued monthly in preparation for the Monthly Project Status Review Meeting. This report informed Construction Division Management in Philadelphia of the site team's immediate efforts and recommendations. Areas of coverage included construction status, subcontracts and procurement, PECO quality control and numerous miscellaneous items. Appendices to the report included a detailed numerical summary of PECO quality control activities and a detailed construction status report which provided completion percentages for major structural components and commodities in each facility. This report was a continuation of a method of regular communication with upper management which was instituted during the construction of Peach Bottom Units 2 and 3 in the early 1970's.

A second major report developed by my unit was the Philadelphia Electric Schedule Analysis Report ("PESA"). Each month prior to the Project Status Review Meeting, the

Construction Division prepared this report, which contained a detailed analysis of construction progress. This report was distributed to the Vice President of Engineering and Research, the Superintendent - Construction Division and the Station Superintendent - Limerick Generating Station. The PESA typically included a statement of Project status, commodity status, facility status, subcontract status, system status, critical path analyses and an areas of concern section. The report was used to provide management with the site team's independent assessment of the Project based on the data received from Bechtel and our continual involvement with work progress. As a result, our management was well-informed of problem areas prior to the Project Status Review Meeting so that proper attention could be focused on major items.

The last major report prepared by the site team was the Monthly Cost Report which was developed by the Construction Division Cost Engineer and circulated to the Vice President of Engineering and Research and the Construction Division General and Assistant Superintendents. This report provided a summary of trends since the last Forecast, manual and nonmanual manpower levels, a comparison of actual versus budgeted cash flows and a summary of the unit rate comparisons developed through FOCUS. The report also included a projection of total plant costs based on trend, FOCUS, staffing and cash flow information. The final section of the report was for

special studies and covered a wide range of topics, such as potential cost increases not identified by the Trend Program, various alternatives to reduce overall plant costs (i.e. split unit security), analyses of the causes and possible solutions to less than anticipated labor performance, comparisons of Project costs and unit rates with similar data from other plants, analyses of the Project Forecasts, analyses of work sampling results and corrective action to improve labor effectiveness, and miscellaneous reviews of overtime, absenteeism, distributable costs and backcharges.

Q. Did the Limerick Project make use of scale models to facilitate design and construction activities?

A. Yes. A scale model of the Limerick power block, which included large pipe, HVAC, cable tray, equipment, structural steel, and critical small pipe was built from design drawings in order to locate and correct potential commodity interferences before the design drawings were released for construction. Bechtel's Plant Design Model Shop Group ("PDMSG"), located in San Francisco, coordinated the modelling program. The various design disciplines at Bechtel routed their design drawings to the PDMSG where they were incorporated into the model. When interferences were identified, the PDMSG notified the affected discipline to revise the design drawings to eliminate the interferences. The model was then updated to incorporate the revised design.

In addition, photographs of the model taken at various stages of its production were transmitted to the field, where they were used to assist with planning, scheduling and installing large commodities. The photographs were also distributed to the various design groups, where they were used to improve and simplify future design. The photos proved invaluable and saved both time and money. The model itself, which consisted of some ten sections, was then set up in the field for consultation and study by construction personnel.

The power block model enhanced all aspects of the project. It improved communication among plant design disciplines and between plant design and field engineering, simplified design - particularly in congested areas, simplified preparation of layout drawings, improved sequencing of commodity installation, aided field scheduling, and, most importantly, the model eliminated more than 4200 interferences. The resulting savings in cost and schedule were significant.

Apart from the power block model, several additional structural models were also prepared:

- A primary containment reinforcing steel model was developed as a design and constructibility aid. Interferences with primary containment liner plate embedments were identified and resolved. Assembly sequencing was developed and refined during model development and then duplicated during actual construction

for optimal schedule and manpower efficiency.

- Full scale mock-ups of the primary containment conical wall sections were constructed to trial fit the complex geometric curves of the 2-1/4-inch diameter reinforcing steel prior to actual erection. Fabrication inaccuracies and deformation of prefabricated shapes during shipping were identified early and corrected, thus permitting continuity of the erection sequence.

- A scale model of reinforcing steel and sheathing for the post-tensioned fuel pool support girders was constructed to determine optimal assembly sequencing and constructibility. Field supervision and engineering used the model in conjunction with the design drawings to plan and schedule construction activities.

These civil engineering/construction models contributed greatly to the superior performance of the Limerick Project in these areas of work.

Q. PECO implemented an expanded quality program under which quality inspections of non-safety systems were performed. Would you please describe this program.

A. In order to enhance reliability of the plant's non-nuclear systems and components, PECO management directed that a field inspection quality control program similar to the safety-related quality assurance program be developed to perform quality inspections on certain identified non-safety items. Systems and components to be included in the program were identified by PECO engineering. The

inspection program was prepared and implemented by PECO construction engineers. Staffing of the program included a Lead Quality Control Engineer, Mechanical and Electrical discipline engineers and, at peak, nine inspectors. Inspection work was performed in accordance with the detailed procedures and checklists developed in the quality assurance program manual and scoped on system drawings. The inspectors were all PECO foremen, each with a minimum of twenty years of construction experience. The experience and training of the inspectors proved invaluable in assisting Bechtel and the craftsmen in efficiently performing their work.

As a result of this program, several significant concerns were detected and corrected. For example, during the erection of the main condensers, an inspector recognized a missing vendor shop weld, an item that would normally not be inspected and would not have been discovered until a hydrostatic test was performed during startup. The immediate correction of this item resulted in the savings of hundreds of manhours to perform rework and delays in the testing program. Also, while performing the required cleanliness inspection of the reactor feed pumps, a high wear area identified from previous experience was closely inspected. The inspection revealed linear indications in the casing which would have caused premature maintenance downtime. As a result, the pumps were sent back to the vendor for repair under warranty prior to final

installation.

Ultimately, the group inspected several thousand hangers, pipe spools, valves and pieces of equipment and thereby substantially assisted in increasing construction efficiency, acceptability of work and system reliability. Nine years after its start, the program was completed with the turnover of systems to plant operations staff. The overwhelming success of the program with minimum manpower and expense was seen in the efficient startup and testing of Unit 1.

3. Impact of Changing Regulatory Requirements and Labor Unavailability Upon Construction Activities

Q. Please describe how changing regulatory requirements impacted the construction process.

A. As a general matter, changing regulatory requirements have made the construction process much more difficult, costly and time consuming. Regulatory imposed design changes have added substantial additional commodities and manhours to the Project. These changes have also added to the complexity of the construction effort and increased the congestion in work areas, which, in turn, has resulted in increased costs, reduced labor effectiveness and schedule delays.

Q. An explanation of how regulatory changes adversely impacted the cost and schedule of the Limerick Project is presented in PECO Exhibit 2. Did you participate in the preparation of that Exhibit?

A. Yes, I did. I participated in the preparation of Section III of that Exhibit along with other Company personnel. I provided the description of the effect ofthe regulatory changes discussed in that Section upon construction and startup activities. Section III has been drafted to be self-explanatory, and I will be happy to answer questions respecting the analyses contained therein.

Q. Please summarize your portion of the analyses as presented in Section III of PECO Exhibit 2.

A. Section III of PECO Exhibit 2 contains two separate analyses. The first, which is set forth in subsections A and B of Section III, is an analysis of the time durations required to identify, design and construct major plant additions or modifications required by new or changing regulatory requirements. This analysis identifies in detail the additional engineering and construction activities required because of major regulatory changes and their impact upon the project schedule, particularly during the late stages of the project when construction was being completed and startup testing performed. The second analysis is set forth in subsection C and provides additional detail as to increases in project commodities and manhours (i.e. both craft and engineering) required as a result of new or revised regulatory requirements.

The preparation of subsections A and B of Section III of PECO Exhibit 2 reflects the combined efforts of several PECO witnesses. I was responsible for providing

information on the timing and extent of construction activities required because of regulatory changes. This included detailed information on the duration of construction activities, increases in commodity levels, interferences in the field and disruption of construction sequencing, and the effects of regulatory changes on startup and preoperational testing activities. Detailed information as to the timing and identification of new or revised regulatory requirements and the level and duration of engineering required in response thereto, has been provided by witnesses Boyer, Helwig and Sproat, and is described in greater detail in their testimony. I prepared subsection C and am prepared to answer all questions with respect to its contents.

Q. What are your conclusions based on the analyses set forth in Section III of PECO Exhibit 2?

A. These analyses demonstrate that new and changing regulatory requirements had a substantial impact upon the project, especially during the construction completion and startup testing phases. Because of the timing of these requirements, substantial additional engineering and construction activities were required at the end of the project to modify existing systems or design and install new systems. These changes substantially increased the level of commodities and manhours beyond that which was originally anticipated. The cumulative effect of these changes was a substantial reduction in labor productivity

due to field congestion and installation complexity, and delay in the turnover of completed systems to startup and completion of startup and preoperational testing. As a result, project management could not have completed construction and startup testing activities much earlier than was actually achieved.

Q. Please discuss further the higher than expected unit rates experienced at Limerick.

A. One of the major effects of regulatory change was higher than projected unit rates, i.e. a measure of labor effectiveness. By this I mean that the amount of labor required to perform specific functions on the Project was greater than anticipated.

As a result of monitoring labor effectiveness at other nuclear projects, the construction site team noticed a trend of higher unit rates (i.e. more manhours needed to install one unit of material) in the late 1970s than those budgeted at Limerick. Through analysis of these data, we realized that the budgeted goals used at Limerick, which were based on experience at Peach Bottom and other plants prior to 1975, did not adequately account for the regulatory caused increase in complexity experienced at more modern plants. As a result, the FOCUS system consistently underestimated unit rates, especially for large pipe hangers, small pipe and electrical conduit.

To remedy this problem, we requested that Bechtel reevaluate the performance models used in the FOCUS

program. This reevaluation disclosed that factors affecting labor effectiveness, i.e. work space, access to work location, number of workers in the same area and congestion with other commodities, all were severely impacted by post-1975 regulatory changes. Those regulatory changes which had the greatest impact on field labor performance included TMI, fire protection requirements, ATWS, ALARA, equipment qualification, seismicity and concrete expansion bolt testing. As demonstrated in Section III of PECO Exhibit 2, these changes required the replacement or modification of commodities and equipment in areas already congested due to the relatively late stage of construction. The cumulative effect of these changes substantially increased the complexity and difficulty of the installation process and caused less than optimal construction sequencing, thus resulting in higher than anticipated unit rates. The performance models were subsequently modified to reflect the current regulatory environment, which enabled management to more accurately estimate unit rates and, therefore, control labor effectiveness.

However, even after revising the FOCUS performance models, it was determined that unit rates were still being underestimated as a result of 1) the post-TMI changes and other regulatory requirements which were issued in the 1980s, and 2) greater than anticipated adverse effects from earlier changes. As a result, and as shown in Schedule 6

of PECO Exhibit 2, we were forced to continually increase our estimates for manual manhours needed to complete construction. This resulted in further adjustments, i.e. increases, to budgeted unit rates reflected in the performance models. In making such adjustments, we recognized that a significantly greater effort (manhours per unit) would be required during the late construction and startup testing period to incorporate final changes on systems which were complete, quality control accepted, as-built, and possibly in the pre-operational testing phase. Access to systems was necessarily delayed while testing was in progress and work on tested systems was hampered as a result of increased documentation and inspection requirements to ensure that work did not cause deterioration of nearby systems. Thus, the combination of increased regulatory requirements and the timing of resolution and implementation of such requirements, i.e., causing out of sequence construction work, substantially increased unit rates at Limerick. Additional data demonstrating this effect is contained in Section III of PECO Exhibit 2.

We recognized this impact and sought to minimize it through detailed scheduling of systems, revised performance models, and programs for improvement of labor effectiveness, all of which I have previously described.

Q. Was labor unavailability experienced during the construction of Limerick 1 and, if so, how was the problem

resolved?

A. During the late 1970s and early 1980s, Limerick, like many other large scale construction projects, experienced several craft labor shortages. The craft shortages were primarily among the mechanical trades, i.e. principally the pipefitter and sheetmetal welders in 1979 and the asbestos workers in 1983.

The shortage of qualified pipefitter and sheetmetal welders was unforseeable and occurred because the increasing construction of oil and petrochemical plants, nuclear power plants, the Atlantic City Casinos and fossil fuel plants resulted in an unprecedented increase in demand for those possessing these skills. For example, major construction projects in Pennsylvania and surrounding states which competed with Limerick for craftsmen included PSE&G's Salem and Hope Creek Stations, major Peach Bottom and Eddystone plant modifications, PP&L's Susquehanna Station and Atlantic Electric's Beasley Point Station. Moreover, six of the major oil refineries located in the New Jersey - Delaware - Pennsylvania area engaged in substantial construction programs during Limerick's construction, and five Atlantic City Casino Hotels were constructed during that period.

All of these projects required large numbers of pipefitter and sheetmetal welders. Consequently, the available pool of qualified welder manpower was substantially reduced.

In an effort to assist in the orderly and timely manning of the Limerick Project, several innovative plans for addressing the demand for manpower were developed and implemented. These included: 1) development of weekly welder reports which tracked and monitored the number of welders on payroll, the number terminated, the number hired and the estimated manpower needed; 2) advertisements for welders in local/regional newspapers; 3) establishment of programs to train, qualify and upgrade welders for employment at Limerick; 4) daily/weekly communication with the local and international unions concerning this problem; 5) use of subjourneymen and non-union welders; 6) increase in travel pay to attract and retain qualified welders; 7) Regional Manpower Surveys conducted to assist in estimating peak levels of manpower availability in a given region during corresponding Limerick manpower requirements; 8) development of a comprehensive file of individuals who participated in the Limerick welder training/upgrading program to ensure a back-up supply of qualified welders should the unions be unable to satisfy manpower requirements; and 9) the use of automatic welding equipment and additional training programs to enhance welder productivity.

Beginning in May 1983, Asbestos Workers Local #14 went on strike until September 8, 1983 due to the expiration of its contract. As a result of the strike's duration, coupled with the pressure to meet the fuel load schedule,

each contractor at the jobsite employing asbestos workers was forced to increase original manpower estimates. A manpower shortage thus resulted, but was addressed by 1) communication with the local and international unions for assistance in resolving this problem; 2) implementation of two-shift operations, overtime and 10-hour day schedules to avoid schedule impact; and 3) development of daily and weekly manpower activity logs and charts, similar to those established during previous welder shortages, in order to assess the ongoing site manpower requirements in view of the availability of qualified asbestos workers in the region.

4. Comparative Cost and Schedule Analyses

Q. Have you performed an analysis comparing the cost and schedule of Limerick 1 with plants with similar design and licensing requirements.

A. Yes, we have prepared a cost and schedule comparison with all boiling water reactor ("BWR") nuclear generating units which had or will have commercial operation dates in 1982 or later. This comparison is set forth in Schedule 2.

Q. Please describe this comparison.

A. In general, Schedule 2 shows the direct costs and schedule duration for all stand-alone and first unit BWRs with commercial operation dates between January 1, 1982 and December 31, 1989, inclusive. In all cases, each unit includes 100% of the cost of common plant. There are a total of 12 units (including Limerick) in the comparison

group. These plants are identified by code letter in column (1). Column (2) shows the NRC region responsible for inspection, design review and final licensing of each plant. The net electrical output of each unit in megawatts is in column (3). Column (4) shows the month/year each plant received its construction permit. The actual or scheduled fuel load for each unit is shown in column (5). Column (6) is the schedule duration, in months, based on the period from issuance of the construction permit to the actual or scheduled fuel load for each unit. The commercial operation date, actual or scheduled, of each unit is shown in column (7). The direct cost of each unit, including 100% of common plant is stated in column (8). This cost is exclusive of AFUDC, general overheads and realty taxes. Finally, Column (9) is the direct cost per kilowatt for each plant. This is derived by dividing column (8) by column (3) and multiplying by 1000. Column (9) is the basis for our comparisons of plant direct costs, while column (6) is the basis for comparing schedule duration.

Q. Why have you limited the comparison group to nuclear facilities with boiling water reactors that have actual or anticipated commercial operation dates of 1982 or later?

A. The comparison group was so limited to include only those plants with construction costs that were affected by the same factors present at Limerick, i.e. principally plant design and regulatory environment. Only BWRs were included

because differences in design have increased their costs relative to plants having a pressurized water reactor ("PWR") design. For example, the BWR containment design has resulted in greater congestion within the primary containment and in more equipment being exposed to radioactive materials.

This, in turn, has resulted in higher costs associated with reduced labor effectiveness and additional engineering and materials needed to meet ALARA (i.e. As Low As Reasonably Achievable) radiation concerns. Moreover, design differences have caused BWRs to experience different technical problems, different regulatory-mandated backfits and other changes which have had different effects upon their schedule and costs than upon PWRs. Examples of these BWR-unique technical problems include the Mark II phenomenon and Intergranular Stress Corrosion Cracking.

Finally, the time limitation for commercial operation, i.e. the post-1981 period, was chosen because it ensured that all units in the comparison group were affected by approximately the same regulatory changes that impacted Limerick.

Q. Please summarize how the cost and schedule of Limerick 1 compares with the 11 other BWRs included in your comparison group.

A. The cost of Limerick compares very favorably with the other plants. Limerick 1, at $2,234/kwe, is 4% less expensive than the average of $2,329/kwe, and is the fifth least

expensive of the 12 BWRs in the study. The schedule duration of Limerick 1 at 124 months is only slightly longer (4%) than the average of 119 months.

Q. What other comparisons does Schedule 2 permit?

A. Analysis of the data shows that plants in the Northeast United States with a cost of $2,605/kwe are approximately 20% more expensive than plants outside that area ($2,132/kwe). In addition, durations for Northeast plants average 15 months (13%) longer than other non-Northeast plants. A review of similar data for PWRs indicates that Northeast PWRs also cost more to build and take longer to construct than PWRs located elsewhere in the country.

Q. Please explain why there are significant differences between plants located in the Northeast and those located in other parts of the country.

A. We believe some of the differences are the result of 1) labor rates and conditions in the northeast which result in higher costs, and 2) additional costs associated with winter construction. However, we feel that the major reason for higher costs at Limerick and perhaps other Northeast plants is the regulatory environment. Plants in the Northeast are located closer to major population centers than are plants in other regions, and have therefore received a higher degree of NRC regulatory scrutiny. Moreover, our experience at Limerick and knowledge of other plants indicates that Northeast plants have generally been subjected to a greater level of

intervention by opponents to their construction. Such intervention complicates licensing, creates uncertainty, increases pressure for regulatory imposed design changes and lengthens project durations.

Q. How does Limerick compare to the other Northeast plants.

A. The direct cost of Limerick 1 and common plant of $2,234/kwe is significantly less (14%) than the average of all 5 Northeast plants at $2,605/kwe. The Limerick 1 schedule is slightly shorter (i.e. 3%) than the average of all Northeast plants. Furthermore, both Limerick's cost and schedule are the second best of the five Northeast BWRs.

Q. What conclusions have you drawn based on these comparisons of Limerick 1 to other BWRs of the same vintage?

A. Despite adverse conditions specific to BWRs located in the Northeast United States generally, and to Limerick in particular, the direct costs associated with constructing Limerick 1 are lower than the industry average and the schedule is, at worst, only slightly longer than the average for all BWRs in this study. This demonstrates, in my opinion, that when evaluated against projects constructed under similar conditions, we have been able to effectively control cost and schedule, and the management team at Limerick has performed well.

Q. Have you prepared a comparison of Limerick 1 and Common Plant commodity quantities and unit rates with industry data?

A. Yes, I have. Schedules 3 and 4 present a comparison of

Limerick 1 and Common Plant commodity quantities and unit rates with industry data compiled under my supervision. The data in this comparison were compiled from a questionaire sent to utilities representing 11 single and first unit BWRs with commercial operation dates between 1982 and 1989, inclusive. This sample was selected based on regulatory environment and design similarity as I described above. Responses were received for 10 units on a confidential basis. I should note that comparisons such as those presented in these schedules are of limited value in evaluating nuclear plant construction parameters. Although the greatest possible care was taken in obtaining and tabulating the data, differences in plant configuration and utility accounting systems render the data substantially uncomparable. All that can be said of this presentation is that a particular utility's data may be generally within the range of industry experience. This is the case for the Limerick 1 and Common data as Schedules 3 and 4 demonstrate.

As these schedules show, Limerick is below or approximately equal to the average for nine of eleven commodity quantity levels and for nine of eleven unit rates. Where Limerick is above the average for these data, the differences can generally be attributed to Limerick unique design requirements and/or differences in site accounting systems.

For example, Limerick 1 is above the average for quantities of large and small pipe. There are many reasons

for quantity differences between plants such as plant size, location, design preference, operational reliablity, unit availability, radiation exposure and maintainability. The design at Limerick incorporated many features which enhanced reliability, availability and maintainability, and reduced radiation exposure (ALARA enhancement), including 1) sixth stage feedwater heaters, 2) separate drainage systems for clean and dirty liquid radwaste, 3) a second steam jet air ejector, 4) dual instrument air headers, 5) demineralized water piping to more areas in the plant, and 6) more extensive piping of equipment vents and drains. These requirements all resulted in additional piping at Limerick which was not included in the design of all plants in the survey. Thus, while Limerick 1 has higher quantities of pipe, the reliability, availability and maintainability of that unit should be better than average. In addition, radiation exposure to plant workers should be below average.

Similarly, unit rates for Limerick 1 are above the average for large pipe hangers and conduit. Differences in large pipe hanger unit rates are the result of several factors, including 1) spacing and complexity of hangers, 2) seismic requirements at each site and the site-specific soil characteristics, and 3) quantity accounting practices. Conduit unit rates are also determined by several factors, including 1) seismic requirements (hangers are included in the unit rate), 2) size of conduit used,

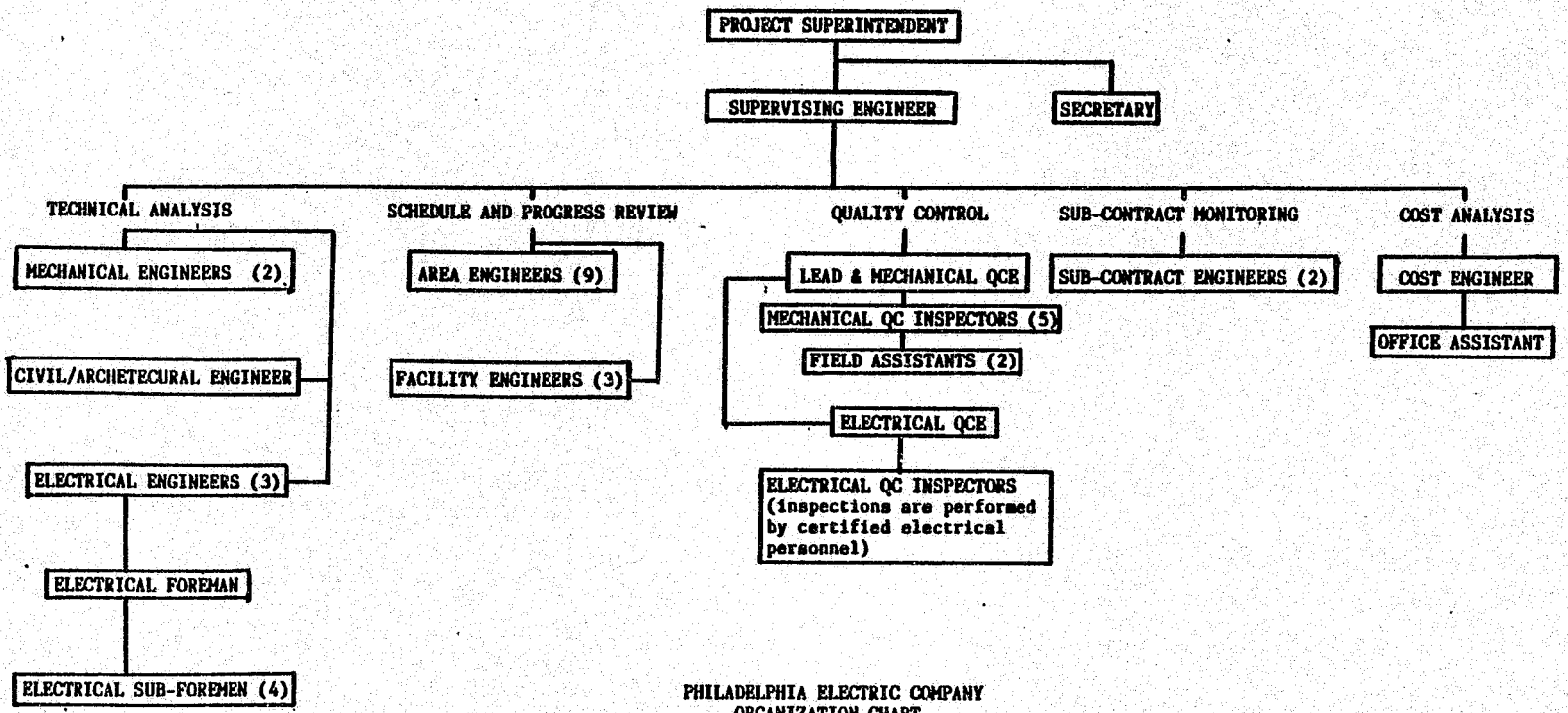
and 3) plant complexity and congestion. However, without performing a detailed analysis of each plant's cost tracking system and design criteria, a total explanation of differences in unit rates is not possible.

In summary, Schedules 3 and 4 demonstrate that the Limerick 1 quantities are generally less than those of the average BWR designed and constructed under today's regulatory environment. Similarly, Limerick 1's unit rates are generally less than or the same as the average achieved by the other units in the sample. In addition, I should note that this comparison is biased by an indeterminant degree against Limerick. Approximately 25% of the units contained within this comparison have substantial construction yet to be completed. Based on the history of recent nuclear project construction, their total reported commodities are virtually certain to rise and their unit rates increase as they advance towards completion. From a construction standpoint, Limerick is already complete and its data thus already reflects this phenomenon.

Q. Does that conclude your testimony?

A. Yes, it does.

LIMERICK GENERATING STATION



PHILADELPHIA ELECTRIC COMPANY
ORGANIZATION CHART
CONTRUCTION DIVISION
JUNE 1984

Schedule 1

Schedule 2

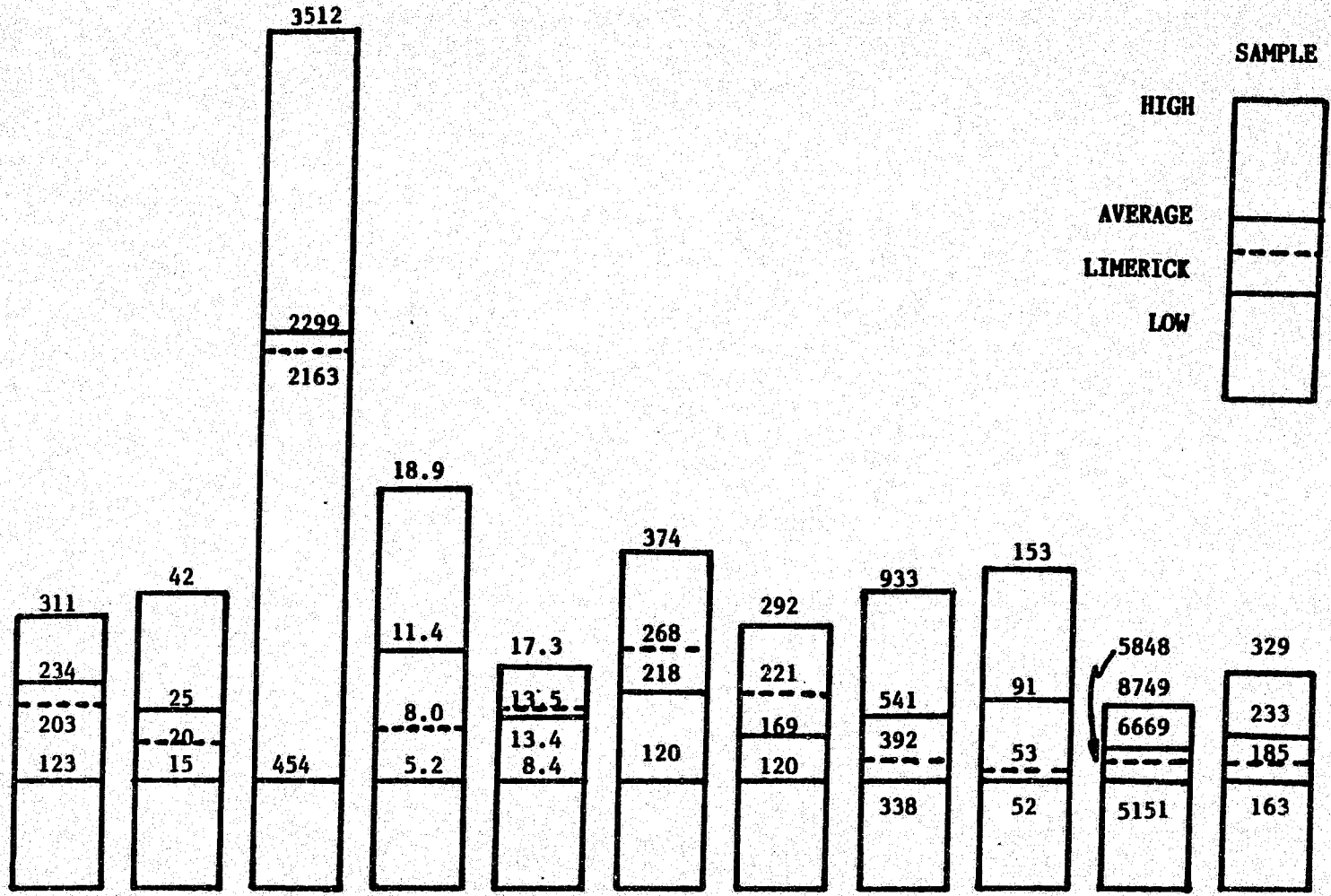
PHILADELPHIA ELECTRIC COMPANY
LIMERICK GENERATING STATION
CONSTRUCTION DIVISION

COMPARISON OF BWRS WITH COMMERCIAL OPERATION DURING 1982 TO 1989
(EXCLUDING AFUDC)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
PLANT	NRC REGION	NET MW	DATE CP ISSUED	FUEL LOAD	DURATION C.P. TO F.L. (MONTHS)	C.O.	TOTAL DIRECT COSTS (MILLIONS)	COST PER KW
A	3	1078	9/73	4/82A	103	10/82A	1043	968
B	1	1050	11/73	7/82A	104	6/83A	1611	1534
C	2	1250	9/74	6/82A	93	2ndQTR/85S	2028	1622
D (LIMERICK)	1	1055	6/74	10/84A	124	2/86S	2357	2234
E	3	1139	9/72	3/85A	150	10/85S	2543	2233
F	5	1103	3/73	12/83A	129	12/84A	2500	2267
G	3	1205	5/77	6/85S	97	12/85S	2762	2292
H	3	950	2/76	1/86S	119	7/86S	2502	2634
I	1	1067	11/74	1/86S	134	12/86S	2865	2685
J	4	934	3/77	6/85S	99	12/85S	2720	2912
K	1	809	4/73	11/84A	139	10/85S	2650	3276
L	1	1084	6/74	2/86S	140	10/86S	3570	3293
				12 PLANTS	1431		29122	27922
ALL BWRS				AVERAGE	119		2429	2329
				7 PLANTS	790		16098	14927
NON - NORTHEAST BWRS				AVERAGE	113		2300	2132
				5 PLANTS	641		13024	12995
NORTHEAST BWRS				AVERAGE	128		2611	2605

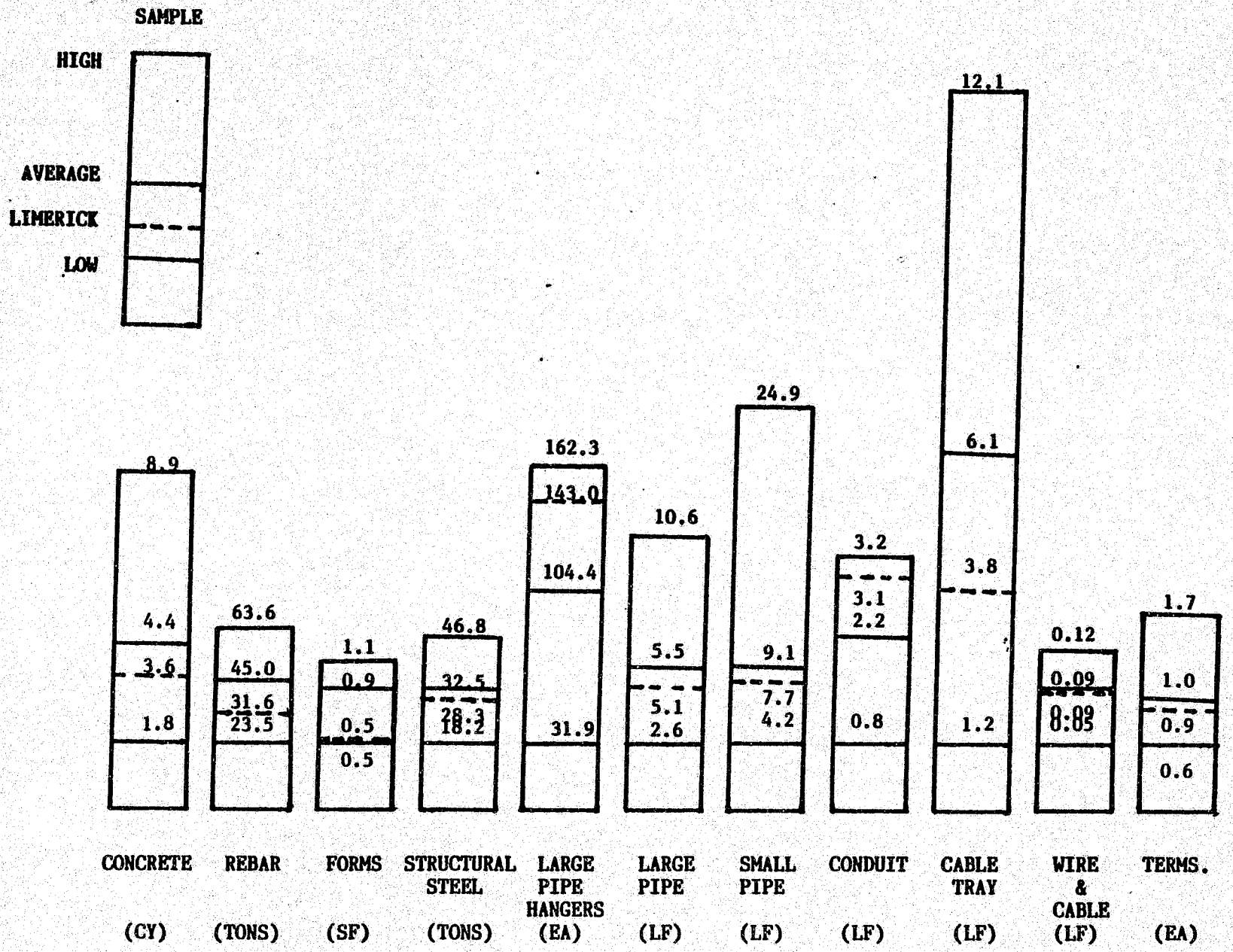
BWR COMMODITY COMPARISON

(ALL VALUES X 1000)



Schedule 3

BWR UNIT RATE COMPARISON



Schedule 4

ORIGINAL

PECO STATEMENT NO. 6

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Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION v.
PHILADELPHIA ELECTRIC COMPANY,
Docket No. R-850152

DIRECT TESTIMONY OF EDWARD F. SPROAT, III

LIMERICK 1 AND COMMON PLANT
PREPARATION OF PECO EXHIBIT NO. 2

September 27, 1985

SEP 27 1985

DIRECT TESTIMONY OF EDWARD F. SPROAT, III

Q. Please state your name and business address.

A. Edward F. Sproat, III, 2301 Market Street, Philadelphia, Pa.

Q. By whom are you employed and in what capacity?

A. I am the Supervising Engineer of the Nuclear Generation Branch of the Electrical Engineering Division in the Engineering and Research Department of Philadelphia Electric Company.

Q. What is your educational background?

A. I received my Bachelor of Science Degree in Electrical Engineering from the University of Pennsylvania in 1973. I have currently fulfilled approximately one-third of the academic requirements for a Master of Science Degree in Management Science at the University of Pennsylvania.

I have also attended a number of continuing professional education courses including:

- Fundamentals of Nuclear Power
- Engineering Economics
- Quality Assurance
- BWR Simulator Training
- Qualification of Nuclear Safety-Related Equipment
- Modern Power Plant Practices

Q. Please describe your work experience at PECO, including your duties and responsibilities in your current position.

A. I joined PECO in June 1973 as an Assistant Electrical Engineer and was assigned to the Limerick Project Group in the Electrical Engineering Division. In this position,

I reviewed and approved electrical schematic and single line diagrams, and specifications and requisitions for certain major Limerick electrical equipment. I also coordinated the in-house review of bid evaluations for these electrical purchase orders, and was responsible for the electrical construction criteria drawings which covered the installation of grounding, raceway, wire and cable, lighting, communications systems and the fire alarm system. In this position, I had extensive communications with the Architect/Engineer (Bechtel) and the Nuclear Steam Supplier (General Electric Company).

I continued in this position from 1973 until August 1978, during which time, I was responsible for reviewing and developing responses to U.S. Nuclear Regulatory Commission Regulatory Guides which affected the electrical design of the plant. Regulatory Guides which caused extensive redesign in the electrical area during this period and with which I was personally involved included R.G. 1.75, "Physical Independence of Electrical Systems", R.G. 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems", R.G. 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants", R.G. 1.29, "Seismic Design Classification", R.G. 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," and R.G. 1.106, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves." For each of these Regulatory

Guides, I directed the development of electrical design changes required to bring Limerick into compliance with this NRC guidance.

From September 1978 to August 1980, I was temporarily assigned to Gas-Cooled Reactor Associates in LaJolla, California. In this position, I performed a number of market and economic analyses of the High Temperature Gas-Cooled Reactor (HTGR). In September 1980, I returned to my former position in the Limerick Project Group. At that time, I was given oversight responsibilities for the development of electrical design changes that were responsive to late regulatory requirements. These areas included Startup Transient Test Monitoring, Plant Security, Emergency Response Facilities and Fire Protection.

In February 1982, I was promoted to the position of Limerick Electrical Project Engineer. In this position, I was responsible for the completion and licensing of the electrical design of Limerick and directly supervised four engineers and one technical assistant in the Limerick Project Group. I also coordinated and monitored the activities of approximately fifteen other PECO electrical engi neers working on Limerick as well as the efforts of the Bechtel and General Electric engineers working on the electrical design.

As part of my responsibilities at PECO, I wrote numerous responses to NRC requests for additional information and conducted several meetings with NRC

reviewers and management. These meetings were generally on topics where the Limerick design provided a cost effective alternative to the standard NRC requirements. Specific topics covered by such meetings included fire protection shutdown capability, internal control panel wiring separation and redundant raceway separation criteria. In all of these cases, the PECO alternative was ultimately accepted.

In addition to the above licensing activities, I was also directly involved in two major technical areas: Fire Protection Shutdown Capability and Electrical Separation. In both cases, I developed the strategy upon which the Limerick design is based. For the former, I developed the methodology used to determine which cables were to be fireproofed. This resulted in a reduction of approximately 9,000 feet in the amount of raceway which would have required fireproofing due to the original Bechtel analysis. For the latter, I developed and managed two test programs which advanced the state of the art in electrical separation criteria and justified the Limerick unique criteria to the NRC, thereby avoiding the rework that would be needed to comply with NRC standard criteria. These test programs have received industry-wide recognition and several utilities have expressed interest in their purchase and use.

Finally, in October 1984, I was promoted to my present position of Supervising Engineer of the Nuclear Generation Branch. In this position, I directly supervise fourteen

engineers, a technical assistant and one clerk. My responsibilities include supervising the Limerick Electrical Project Engineer and his group, the Peach Bottom Electrical Project Engineer and his group, and the Equipment Environmental Qualification Group.

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

A. I am a Registered Professional Engineer in the Commonwealth of Pennsylvania. I am a member of the Institute of Electrical and Electronics Engineers (IEEE) and three societies of that organization, including:

- Power Engineering Society (PES)
- Nuclear and Plasma Sciences Society
- Engineering Management Society

I am also active in the nuclear standards writing activities of the IEEE. I served on the working group which wrote IEEE Standard 649-1980, "Standard for Qualification of Class 1E Motor Control Centers for Nuclear Power Generating Systems." I am currently Chairman of the working group which is revising this standard. I am also a member of the Nuclear Power Engineering Committee (NPEC) of the PES and a member of NPEC Sub-Committee 2, Equipment Qualification.

Q. Do you have any prior experience in presenting testimony before the NRC or other regulatory bodies?

A. Yes, I testified before the Atomic Safety and Licensing Board (ASLB) during the Limerick Operating License hearings concerning a contention on the adequacy of the Limerick

environmental qualification program. The contention was found to be without merit.

I have also made a presentation to and answered numerous questions from the Advisory Committee on Reactor Safeguards (ACRS) during its review of the Limerick design. My presentation covered the electrical system designs and their reliability under degraded conditions. The Limerick design was found to address all of the Committee's concerns.

I have also made numerous presentations to NRC Staff members in meetings as outlined in my testimony above.

Q. What is the purpose of your testimony?

A. The purpose is to describe my role in developing the analyses contained in Section III of PECO Exhibit 2.

Q. Please describe that role.

A. Section III of PECO Exhibit 2 provides engineering and schedule details on major regulatory requirements which occurred late in the construction schedule. Because of my personal involvement with a number of these items and my position on the Project management team, I was able to provide details of the integration of these changes into the existing design and to analyze their effects on overall project schedule. This information was then used in the generation of parts of Section III of PECO Exhibit 2.

Q. Please provide a description of the major regulatory requirements listed in PECO Exhibit 2, Section III with which you were involved.

A. As Electrical Project Engineer, I was involved in the

implementation of all requirements which affected the electrical and control systems of Limerick. As described in PECO Exhibit 2, not only did TMI and many other electrical system regulatory changes occur late in the Project, but some continued to be changed and refined into 1983.

After their issuance, PECO analyzed each requirement. Engineering of design changes began immediately and the required number of engineering manhours were estimated. The engineering schedule was coordinated with the construction schedulers so that the final design would arrive at the site in a pre-arranged, optimal sequence along with the required materials. These schedules were met in practically all cases.

The specific design changes with which I was most intimately involved are listed below.

Emergency Response Facility Data System (ERFDS). I coordinated the selection of the system supplier and design of system installation. The installation was extremely complex and costly because it required connections into several hundred existing instrument loops in numerous panels. Each of these connections required that several drawings be revised.

The system was installed primarily in response to NUREG-0737 to provide a Safety Parameter Display System, but it also was utilized to provide the transient recording capability required by Regulatory Guide 1.68. It eliminated the need for a separate startup transient recording system

which was estimated to cost several million dollars uninstalled.

Fire Protection. I devised the methodology utilized by Bechtel to analyze and document Limerick's compliance with the safe shutdown capability requirements of BTP CMEB 9.5-1. My involvement peaked after Bechtel's preliminary analysis showed that approximately 12,000 feet of raceway would require fireproofing. This quantity could not have been completed to support an October 1984 fuel load. As the result of the revised methodology, total fireproofing was reduced to approximately 2,700 feet which was completed in August 1984. The fireproofing cost approximately $1,000 per foot installed.

I also defended the methodology before the NRC during their fire protection audit in August 1984 in which Limerick was found to have no violations of NRC criteria. Limerick was one of the first plants to successfully pass this NRC audit.

Control Room Panel Modifications. Panel modifications resulted from a number of late design changes required by regulatory changes, as described in PECO Exhibit 2. The design changes for separation criteria required to complywith Regulatory Guide 1.75 were minimized by PECO's efforts to develop Limerick unique separation criteria through the use of test results and analysis. As mentioned earlier in my testimony, I developed a test program and authored a test report which was accepted by the NRC as an

innovative method of justifying lesser separation requirements than those listed in the Regulatory Guide. Compliance with the current NRC requirements would have required essentially a complete redesign of the Control and Auxiliary Equipment Rooms at significant cost and schedule delay. The test methodology and results avoided this.

Equipment Qualification (EQ). The EQ effort was managed by PECO Electrical Engineering with work conducted at Bechtel and General Electric. Through our involvement in IEEE Standards activities and our leadership roles in other industry groups, we were able to complete the qualification effort prior to fuel load as compared to numerous operating plants which have still not completed their EQ efforts. This was accomplished through maximizing the use of data bank or shared information with other utilities and by our knowledge of the requirements to eliminate unnecessary testing and analysis. Because this item was the subject of a licensing contention, slippage of this effort most certainly would have caused a delay in issuance of the Operating License. Moreover, by completing this effort, we have eliminated the need for such expenditures after commercial operation as has occurred at some other plants.

Other modifications described in PECO Exhibit 2 which I have had experience with and provided information on are those associated with Security, Anticipated Transients Without Scram (ATWS), Safety Relief Valve Position Indication, the Radiation and Meteorological Monitoring

System (RMMS) and the electrical aspects of the Emergency Response Facilities. The discussion of these items in PECO Exhibit 2 is fully explanatory, and I am available to answer any questions which relate to these matters.

Q. Does this conclude your testimony?

A. Yes, it does.

ORIGINAL

PECO STATEMENT NO. 7

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Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION v. PHILADELPHIA ELECTRIC COMPANY, Docket No. R-850152

DIRECT TESTIMONY OF
CHARLES K. SOPPET

LIMERICK 1 AND COMMON PLANT PROJECT ORGANIZATION, EXPERIENCE AND PROCEDURES OF BECHTEL POWER CORPORATION; EFFECTS OF NRC CHANGING DESIGN AND QUALITY ASSURANCE REQUIREMENTS

September 27, 1985

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TESTIMONY OF CHARLES K. SOPPET

Q. Please state your name and business address.

A. My name is Charles K. Soppet and my business address is 50 Beale Street, San Francisco, California, 94105.

Q. By whom and in what capacity are you employed?

A. I am employed by the Bechtel Power Corporation ("Bechtel") as a Project Manager, and am currently serving as Project Manager for the design and construction of the Limerick Generating Station in Limerick, Pennsylvania.

Q. Please describe your educational background and business experience.

A. These are set forth in detail in my curriculum vitae which is attached to this testimony as Schedule 1. The highlights of my professional career are as follows.

I graduated from the Michigan State University with a Bachelor of Science degree in mechanical engineering in 1950 and since that time I have been continuously employed in the nuclear energy field. Upon graduation, I joined the Argonne National Laboratory, a national center for nuclear research and development, where I was responsible for the design, fabrication and installation of nuclear reactor components, fuel and fuel handling equipment.

In 1958, I accepted a position with the General Nuclear Engineering Corporation to manage the design and construction of nuclear research reactors and experimental power station reactors. In this capacity, I was responsible for directing the design of systems, and managing all construction performed by subcontractors and fabrication of vendor-supplied equipment. My duties with General Nuclear were similar to my current responsibilities as Project Manager of Limerick, although the experimental projects were of a smaller scale.

In 1962, I joined the Aerojet General Corporation where I was involved in the "NERVA" project, a joint Atomic Energy Commission and National Aeronautic and Space Administration project, aimed at developing rocket vehicles powered by nuclear engines. At Aerojet, I initially served as Nuclear Operations Department Design Manager, and I managed the nuclear reactor design and reactor test program. Thereafter, I was appointed Manager of Engine Test Operations with responsibility for the engine test facility construction, operational modifications of that facility including any needed redesign, and the conduct of all test operations. I held this position until 1970 when I joined Bechtel as Project Manager.

As Project Manager at Bechtel, I was initially assigned responsibility for the design and construction of Limerick Generating Station Units 1 and 2, and I have retained responsibility for this project since that time. In addition, in 1973, I was appointed Senior Project Manager responsible for all PECO work performed by Bechtel in the nuclear energy field.

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

A. Yes, I am a member of the American Nuclear Society where I serve as Chairman of the Standards Committee, as Power Division Secretary and as an Executive Committee member. I am also a registered professional engineer in both nuclear engineering and quality assurance in the state of California.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the management organization employed by Bechtel at the Limerick project and the management tools and processes implemented to monitor and control construction quality and project

cost and schedule. In addition, I will briefly describe and illustrate the effects of NRC requirement changes and quality assurance requirements upon the project.

Q. Please describe Bechtel Power Corporation.

A. Bechtel Power Corporation, a subsidiary of the Bechtel Group Inc., is a leading company in the worldwide construction of power generating stations, including nuclear, fossil fuel and geothermal power plants, ancillary electrical transmission equipment and distribution facilities. Bechtel Power Corporation employs over 6,800 full-time employees in permanent offices in six states of the United States as well as Brazil, Spain, Indonesia, Saudi Arabia, England, Kuwait, Australia, Japan, Mexico, Canada and France. Bechtel's experience in the power industry includes management and performance of engineering and/or construction services for over 300 non-nuclear and 150 nuclear power plants. Of the latter, over 80 have been completed.

Bechtel has engineered and constructed fossil-fueled plants ranging in capacity from 8 to 800 mw, including the first computer-controlled turbine roll of a power plant and the first 1,500 ton per hour automatic coal handling system. In the nuclear generation of power, Bechtel pioneered the application of nuclear energy for the generation of electrical power with the construction, in 1949, of an experimental breeder reactor and the first nuclear reactor from which useful electrical power was produced. In addition, Bechtel constructed Dresden I, the first large-scale commercial nuclear plant in the United States, and San Onofre, one of the largest nuclear power generating stations in the United States today. We are also continuing work in the development of advanced fast breeder and fusion technologies.

Q. Please describe your position as Project Manager for Limerick.

A. As Project Manager, I have had and continue to have broad oversight responsibilities for managing, coordinating and administering the project from the conceptual stage through planning, engineering, procurement, contracting, construction, startup and closeout. I discharge these responsibilities subject to the overall direction and control of both my own management and of the Philadelphia Electric Company, our client. I supervised the preparation of project plans, budgets and schedules for submission to Philadelphia Electric personnel for review and approval. Moreover, I monitored project progress and took action to maintain schedules and obtain appropriate staffing to perform the work on budget and within schedule where possible.

Q. Please describe the project organization employed by Bechtel at Limerick.

A. The Bechtel project organization was divided generally into six discrete functional areas: Quality Assurance, Engineering, Construction, Technical Services, Administration and Procurement. Bechtel maintained an organization at both its home office in San Francisco and on-site to attain the objectives of cost effective quality design and construction. At the peak of the project's activity, Bechtel employed approximately 2,800 permanent engineering, clerical and supervisory personnel, with approximately 800 located in San Francisco and 2,000 on-site who were devoted full-time to both units of the Limerick Project. In addition, Bechtel employed slightly in excess of 2,600 manual craft workers on-site during the peak period.

The Bechtel home office Limerick project organization consisted of five functional groups: Engineering, Technical Services (Cost and Scheduling), Administration, Procurement and Quality Assurance ("QA"). The Project

Engineering group, which was organized into six areas of responsibility, including management, civil/architectural, mechanical, plant design, quality engineering and electrical/control systems, was responsible for the Limerick design and any needed engineering support of construction functions. The Technical Services group was responsible for planning, scheduling and cost estimating. This group, with input from each Bechtel project functional area, was also responsible for the preparation of project Forecasts and trends. The Administration group maintained all Limerick records and correspondence, and the Procurement group was responsible for bidding, purchasing and subcontracting. The Limerick Quality Assurance (QA) group, located in both the home office and on-site but functionally separated from the rest of the Bechtel Limerick organization, performed or monitored the performance of those functions necessary to comply with the NRC's QA regulatory requirements. Apart from these groups, there were approximately 75 additional off-project employees at the home office who, on a part-time basis, provided support services for the design and construction of Limerick.

The on-site Limerick organization was supervised by the Project Field Construction Manager, who had six functional groups reporting to him, including Field Engineering, Construction Superintendents, Services (including Contract Administration), Finance and Accounting, Field Procurement, and Cost and Scheduling. Field Engineering consisted of engineers whose design efforts directly supported construction at Limerick. The Construction Superintendents were in charge of labor relations and general craft labor supervision. The Cost and Scheduling group performed a service similar to that in the home office. Contract Administration managed subcontracts, while Finance and Accounting acted as a local financial agent. Field Procurement purchased field materials and managed

the warehouse and stores. Finally, the Quality Control (QC) group was also located at the site but reported independently to the Bechtel Quality Control organization. This group was responsible for inspecting the safety-related systems at the plant.

Bechtel employed a matrix management organization which permitted each of the various project functional groups to receive technical direction and information, based on experience at other Bechtel projects, from the larger functional organizations within Bechtel, while receiving project direction with respect to budget, schedule and project objectives from my project operations organization. An organization chart which illustrates this matrix organization is set forth in Schedule 2.

Q. Please describe the project control system utilized at Limerick.

A. The project control system consisted of three parts: 1) a project plan communicated throughout the Bechtel and PECO project organizations, reflecting the planned scope, schedule and cost; 2) a monitoring system that measured progress and performance against an established baseline; and 3) a reporting system that identified deviations from the cost and schedule plan and provided analysis to facilitate decisions by the project team, as well as Bechtel and PECO management.

The project plan defined the technical scope of work and Bechtel's services and responsibilities. Based upon this technical and service scope of work, an estimate and schedule were developed which formed the basis for the project budgets. The monitoring and reporting of progress and performance were achieved through an integrated system of computerized and manual cost and

schedule programs. Schedule 3 graphically displays the primary components of this cost and schedule control system.

Q. Would you please describe some of the more important cost and schedule control programs shown on Schedule 3.

A. Yes. The following description sets forth those control tools and systems which were the most significant to Bechtel's activities in controlling cost and schedule at Limerick.

Estimate and Milestone Summary Schedule

Estimates of the technical scope and services to be performed were prepared and budgeted in the framework of the approved project code of accounts. The code of accounts categorized and identified all labor, materials and services for the project.

The milestone summary schedule reflected the project plan in terms of significant schedule dates and established the master schedule for the total project. The more detailed intermediate engineering and construction schedules were developed within the constraints imposed by this schedule. The milestone summary schedule was intended to give a complete yet simple picture of the overall project schedule. It was used to status progress in a summary fashion for both Bechtel and PECO senior management.

Project Forecasts

Project forecasting was a technique used to systematically re-evaluate the project plan to avoid cost and schedule surprises, allow replanning of project activities and provide a basis for continuous project control. Forecasting consisted of the identification of actual "to date" costs and a comprehensive evaluation of project "to-go" costs at a detailed level for quantities of bulk

materials, items of equipment, engineering, craft and field non-manual manhours, and a re-evaluation of the schedule in light of any changes in these variables. The forecasted costs of Limerick were divided into six basic categories: 1) engineering and other home office costs, 2) material and subcontract costs, 3) field installation costs, 4) PECO costs, 5) allowance for funds used during construction ("AFUDC"), and 6) overhead and tax costs. Taken together, these components determined the total cost of the project.

Estimates of engineering and other home office costs were obtained from a knowledge of the status of engineering design, necessary engineering support to construction activities, and other home office costs. These estimates were based upon Limerick experience to date and Bechtel's experience with similar projects.

Material quantities were estimated by reviewing project drawings. These estimates included quantities of pipe, conduit, concrete, reinforcing steel, structural steel, pumps, valves, wire, electrical switchgear, and other materials which had to be installed. Subcontract costs were derived from a review of the specifications controlling the work scope, and our current experience with the costs of similar work at Limerick and at other Bechtel projects. A comparison with other projects was especially necessary during the early stages of the project, because firm "project-unique" costs and experience were not yet available. This comparison with other projects continued throughout the life of the project, but diminished in importance as more Limerick-specific information, developed from on-going project experience, was compiled.

Similarly, field manual and non-manual construction costs were estimated from the quantities of material to be installed and the time required for installation, and were based in part on experience at other projects, our Limerick

experience and our knowledge of labor conditions at the site. Projections of wage rates in the local construction area over the life of the project were applied to the estimates of construction hours to determine the field construction costs. These costs were added to the home office costs and material quantity costs (which were also adjusted for escalation over the life of the project) to derive Bechtel's "direct" costs. PECO costs, AFUDC, overhead and taxes were developed by PECO and added to Bechtel costs to obtain the total project cost forecast.

Trend Program

An integral part of the project control system was the trend program which provided a mechanism for identifying changes in the scope of services to be provided (i.e. changes in design, material quantities, labor productivity, etc.) and the project schedule. The key activities of the trend program included establishing an initial control budget immediately after award of the Limerick contract, holding regularly scheduled project team trend meetings to discuss potential or actual deviations from the plan, documenting all potential or actual deviations through the participation of all project entities, and providing a periodic summary report of all trends. These activities enabled the project team to avoid cost and schedule surprises and minimize plant cost through a continuous review of the project's evolution and its causes. The trend program also continuously analyzed, reported and reviewed project status through the various control systems as design, procurement and construction progressed. Any significant deviation from the established budget was considered a trend and a rough estimate of the cost and schedule impact was determined, as well as any indicated corrective action to eliminate or minimize this impact.

Limerick Resource Management System

One of the most important components of our project control system was the Limerick Resource Management System ("LRMS"), a computerized system originally developed in the early 1970's and modified throughout the project to reflect changing project needs and technological advances. This system or data base utilizing those home office and field based computers identified discrete work activities (e.g. concrete placements, cable tray runs, etc.) and components (e.g. pumps, valves, equipment, etc.) by individual identifiers or tag numbers, and tracked the status of all necessary design, procurement, installation, and inspection activities associated with each individual activity or component. For example, data associated with a specific pump such as drawing number, purchase order number, installation status, area/elevation and startup system were available within LRMS by tag number. By simply querying LRMS, numerous status reports were generated on a regular basis for use by the various project groups. This system provided the primary source of project data used by all Bechtel and PECO management groups to develop forecasts and monitor and report the status of cost and schedule performance.

Quantity Tracking

Quantities were the "leading indicators" of the project's status. Quantity tracking was an integral part of the LRMS and was initiated when engineering design parameters were established. This aspect of the system was utilized to identify and quantify equipment and material needs and the progress of their installation, based on data obtained from the LRMS. The quantity estimates and takeoffs were the basis for the project reporting and control system.

Permanent plant equipment and uniquely identified bulk materials, such as pipe spools and reinforcing steel, were taken off drawings and tracked from project inception through design, procurement, receipt at the construction site and installation. Estimates of bulk quantities were initially developed in Bechtel's home office based upon historical information, from similar plants or systems, and replaced with actual quantities as the design, procurement and construction progressed. This "offsetting" of estimated quantities with actuals permitted a continuous review of the project's total scope, not just that designed at the time of the review. The major material items tracked were concrete bulks, mechanical equipment, piping, valves, pipe hangers, instruments, electrical equipment and electrical bulks.

Bulk commodities were the thread that tied the cost and schedule reporting systems together to provide the basis for progress measurement. Each entity of the project team i.e. Engineering, Procurement, Construction, Startup, etc., required that information be oriented in the manner in which its work was performed. For example, Startup was oriented by startup system, Construction by facility and module, Procurement by specification/purchase order, and Engineering by system and facility.

Engineering Budget and Schedule Control

Limerick's engineering control program provided the project team with specification/drawing status and engineering task information used to develop and update engineering schedules to support construction schedule requirements and to identify internal design restraints. All specification, task, and engineering drawing schedule release dates were derived from the engineering and construction schedules. Thus, engineering schedules were directly tied to the

construction schedules and were responsive to construction/startup needs for materials, procedures, drawings and specifications.

As in the case of construction material and equipment, the number of specifications and drawings to be developed was estimated at the time of project award, using data from similar plants. This early identification of specifications, tasks, or drawings allowed engineering group supervisors to establish priorities within their groups. The use of standard numbering designations facilitated the early identification of specifications and drawings. The project team used the output from the various engineering control system reports to status the engineering schedule. The use of established control points for each type of drawing and specification enabled the team to accurately determine (using earned value techniques) the progress and performance of each engineering activity and identify deviations from the established plan in the cost and schedule trend program.

Procurement Controls

The procurement group initially utilized "heckle sheets" to track and control procurement and subcontract information. During the project's latter stages, these "heckle sheets" were superseded by the Procurement Status Report ("PSR") or "buck sheet" which gave an expanded picture of the procurement/engineering interface.

The heckle sheet and later buck sheets were issued monthly and were used by supervisors to monitor in detail the various processes required to purchase major equipment, including significant project/vendor milestones and completion data for each procurement package. After purchase orders were placed, fabrication and delivery status was reported on "buck sheets."

Field Cost/Schedule Control System

The Limerick field cost/schedule control system revolved around three main elements: 1) the project forecasts, 2) the LRMS data bases and 3) the Monthly Project Status Review Meeting. Each of these in turn had many interrelated sub-elements which combined to form an integrated project control system.

Each forecast contained key base-line data against which construction was managed. These data included the cost projection for each code account including craft hour estimates for the labor accounts. The basis for the cost projections was also provided and included a detailed listing of all bulk commodities and estimates of material pricing and wage rates. Along with the cost data, each forecast contained a summary level schedule describing key dates and installation rate targets for bulk commodity installations. Both the cost projections and schedule were used to develop forecasted cash flows.

The second main element of the control system was the LRMS. Early in the project and partially as a result of experience gained at the Peach Bottom plant, the LRMS was set up to identify and track all material used in constructing the plant. This system contained a series of computer files or data bases that provided a listing of each item of material along with important reference information (i.e. plant location, system designation, cost code, etc.) and current status (i.e. designed, fabricated, installed, etc.). The creation and maintenance of these data established the need for an organization to catalogue and manage all the information and a system to monitor and provide the status on each item as it progressed through the various steps from design to testing.

An organization was set up within project Technical Services in the home office and the Cost and Scheduling group in the field to maintain the accuracy of

the files by reviewing revisions to project documents and changing the computer files as needed. A card system, utilizing a field engineer's "sign off" following inspection indicating completion of installation, was used to monitor completion status. As a result, the data base files contained the latest information from drawing inception through construction completion and generated reports displaying current status information at varying levels of detail and summarization up to and including total plant scope. This information was then used to measure schedule progress, control cost and provide forecast information.

The third main element of the field cost/schedule control system was the Monthly Project Status Review Meeting, and additional related meetings. At these meetings project progress was discussed and difficulties were resolved.

Q. Were there any other management tools used to control field activities?

A. Yes. A number of additional cost/schedule control tools were used to manage specific areas of the project from time to time. A brief description of each of the key scheduling tools that were employed during project construction are listed below:

1. The Management Scheduling and Control System ("MSCS") was a 3000 to 4000 activity computerized critical path model ("CPM") schedule used for long-range planning. MSCS provided the overall construction schedule logic for both critical path and non-critical path activities, early and late start dates, and activity float. This schedule provided the basis for the 12-month construction schedule described below.

2. The Intermediate Construction Schedule ("ICS") replaced the MSCS in 1978. This schedule consisted of 1500 activities organized by facility/elevation and displayed scheduled construction of major commodities. Starting in mid-1982,

commodities were grouped by startup system to facilitate the scheduling of completed system turnover to the startup organization. The ICS was similar in function to the MSCS but with the added ability to compare "earned" to "actual" manhours expended.

3. The construction 12-Month Schedule was a rolling schedule which provided detailed construction logic for the next 12-month period and was updated on a quarterly basis. At each update, the schedule was reviewed and approved by all affected project entities. This schedule was organized by facility/elevation with quantity and duration data shown for all commodities. In mid-1981, commodities were grouped by startup system and provided the basis for manpower histograms and commodity installation curves.

4. Commodity curves for installation of bulk commodities were also used to show scheduled and actual cumulative monthly installation rates.

Several types of construction detail schedules were also prepared. The 3-week rolling schedule, which was updated weekly, contained detailed planning of work activities for a 3-week period and was used primarily during the bulk commodity installation phase of the project. Work operations were scheduled by craft and components to be worked were identified by spool, valve, equipment/instrument number, etc. This schedule was used by superintendents for coordinating activities between crafts and as notification to field engineering to provide required construction support.

Special topic logic schedules were prepared for various items, such as facility/elevation completion, subcontracts, etc., which required more detailed planning than the 12-month schedule. These schedules generally covered durations of one month to two years and were updated as required. For example, a number

of special schedules were prepared to facilitate planning of system completion and turnover to the startup organization. Facility and system turnover schedules were prepared and organized by system and facility to show interdiscipline logic and the pacing activities required to complete either or both systems and facilities for turnover. The intermediate startup schedule utilized both a bar chart and computer schedule to detail the individual milestones to be accomplished. The milestones included acceptance of each system by the startup group, preparation and acceptance of startup test procedures, completion of preoperational and acceptance tests, and review and approval of test results packages. Individual detailed schedules were also prepared for each preoperational test describing prerequisites, restraints and test logic. In addition, detailed special schedules were prepared for all major startup tests or plant operations which required coordination of activities between startup, construction and/or engineering activities. Examples include code hydrostatic testing, integrated leak rate testing, loss of air testing, and operational hydrostatic testing.

To manage field costs, a number of additional control tools were used. The Weekly Labor Cost Report ("WLCR") was a device used to monitor and control the expenditure of manual craft hours. Craft hours were collected daily through the field labor distribution system. On a weekly basis the hours were grouped by cost code and fed into the Forecast and Control Updating System ("FOCUS"). This program produced a series of productivity reports which compared the manhours expended, quantities installed, and the hours spent per unit of installation, to the original budget and the latest forecast. The reports were generated in cost code sequence and the cost code structure was set so that accounts were grouped to match the project organization structure. This system also produced a series of

performance, trend projection, and percent complete calculations and reports. A weekly reporting cycle was observed and included a review of problem areas and assignment of corrective actions by site management to the implementing site organizations. As a result of this review cycle, trends or revised craft hour projections for specific accounts were included in the project trend program.

The control of subcontract costs used an approach similar to that used to control manual craft hours. In addition to a "FOCUS" approach, each subcontract was reviewed for changes as part of the normal trending and forecasting process.

Nonmanual labor was not as directly related to the production measurement goals as was manual labor and, therefore, the cost control approach for these manhours was somewhat different. Each department prepared time oriented bar charts (i.e. "work plans") which displayed the tasks to be performed and the required staffing levels to achieve them. The actual manpower levels were monitored against these plans and deviations were identified and corrective action taken through the monthly meeting reporting process.

Finally, material costs were collected by cost code and controlled through the cost and commitment program. This program formed a part of the forecasting process and established a "forecast" or "budget" value for each account. Actual dollars committed and spent were collected on a monthly basis for each account and were compared to both the total forecast and cash flow forecast for each account. Deviations from either comparison were investigated as part of the monthly reporting and trending cycle and reported to management via the trend program.

Q. Mr. Soppet, please now explain how the implementation of NRC required design changes concurrent with plant construction affects cost and schedule?

A. In an ideal engineering and construction sequence, the design information needed for construction is provided early in the project. An ideal sequence permits construction to continue in a straightforward fashion unhampered by missing information or materials. Engineering performed over the last several years of the project following this ideal sequence consists of field support, as-built verification, and support of startup activities. The implementation of new design late in the project disrupts this ideal sequence and thereby adversely effects project cost and schedule.

The adverse effect on project cost and schedule is due to a variety of factors. Any change to a portion of a system requires that the performance of the entire system be re-evaluated, which may necessitate additional changes to other parts of the existing system. The addition of new systems, or changes to existing systems, late in the project frequently occurs in areas already congested with other systems and components. In these cases, the modifications typically impact the other systems and components in the area, requiring relocation of existing equipment and rework of existing piping, hangers, valves, conduits, etc. Because of the need to design around existing systems, pipe routing, cable routing, etc., design of the required new system cannot be achieved as efficiently as otherwise would be the case, which results in increased commodity levels and delay. In addition, new core bores through existing walls are frequently required. Electrical changes often necessitate modification of control room panels, which are highly congested. Changes to these panels typically necessitate rewiring of existing circuits to provide room for the added instrumentation and associated circuits. The time required for installation of items such as electrical tray, conduit, and cable is increased due to interferences and congestion in work areas, and the

changes frequently disrupt startup activities, resulting in delays in the test program.

The implementation of the new requirements resulting from the Anticipated Transients Without Scram (ATWS) issue at Limerick 1 is an example of a regulatory-mandated design change that disrupted the ideal project sequence. An anticipated transient is an occurrence which is expected to occur once or more during the life of the reactor and to interrupt its normal operation. For some transients it is important that the control rods be rapidly inserted into the reactor core (a reactor scram) to shut down the chain reaction. If there is a potentially severe "anticipated transient" and the reactor shutdown system does not "scram" as desired, then an "anticipated transient without scram," or ATWS, has occurred.

The ATWS design features at Limerick, adopted as a conceptual design change in late 1980 in response to then still on-going NRC rule-making procedures, are as follows:

1. Redundant Reactivity Control System (RRCS)

The redundant reactivity control system (RRCS) determines that a transient is underway and exceeds expected operating parameters. The RRCS uses transient detection sensors for high vessel dome pressure and low vessel water level and the actuation logic to initiate the ATWS mitigation actions (ARI, RPT, SLC injection, and feedwater runback) discussed below.

The RRCS consists of two completely redundant divisions. Each division is initiated automatically by the ATWS detection sensors, which are independent of the reactor protection system (RPS) sensors, or manually by switches that require the same type of operator actions as manual scram. Installation of the RRCS required mounting new level and pressure sensors on instrument racks, installing

new instrument cabinets in the already congested auxiliary equipment room, routing cables to maintain adequate separation and control room panel modifications. Also, an uninterruptable power supply had to be added to the average power range monitors (APRM) to ensure complete independence from the RPS.

2. Alternate Rod Insertion (ARI)

The ARI is designed to provide a parallel path for actuation of the scram valves, which results in control rod insertion. ARI consists of the redundant valves on the scram valve pilot air headers that are actuated by the RRCS logic. The RRCS logic is designed so that successful ARI performance will avoid subsequent ATWS mitigation action (feedwater runback and SLCS initiation). Installation of the ARI required mounting new solenoid valves in existing air lines and routing cables between the auxiliary equipment room and the CRD control area.

3. Recirculation Pump Trip (RPT)

The recirculation pump motors are tripped by the RRCS logic. The purpose of the RPT is to reduce core flow and create core voids to decrease power generation, thus reducing the steam discharge to the suppression pool. Installation of the RPT required finding space for additional switchgear cabinets and routing power cables from the motor generator sets to the switchgear, and from the switchgear to the recirculation pump motors.

4. Feedwater Runback

Upon receipt of a high-pressure signal from the RRCS and after a specified time delay, if core power is not reduced as evidenced by the Average Power Range Monitors (APRMs) reading downscale, feedwater flow would be auto-

matically limited by the RRCS, thereby reducing power and steam discharge to the suppression pool. The system provides for manual operation to be returned to the operator after a time delay to allow an increase in feedwater flow if needed. Installation of the feedwater runback required routing cable from the RRCS cabinets to the feedwater control cabinets.

5. Standby Liquid Control System

The standby liquid control system (SLCS) is automatically actuated by the RRCS or manually initiated by an operator in the main control room upon indication of a failure to scram and in accordance with plant operating procedures. The system is designed to inject sodium pentaborate solution through a core spray sparger. Major modifications of the SLCS system were required to ensure that each pump in the system was as independent as possible. A third SLCS pump was also added, requiring additional power and control cables.

6. HPCI Flow Split Modification

The HPCI system has been modified to incorporate two injection paths to the reactor vessel. About one-half of the flow goes into the core spray sparger, and the remaining portion is routed to the feedwater sparger. Also, as mentioned above, the SLCS flow is injected via the core spray sparger. The flow split modification maintains proper natural circulation flow mixing within the reactor core during an ATWS event.

Installation of the above systems also required the addition of a third standby liquid control pump, valves, major piping and supports, new power supplies, switchgear, control cabinets and instrumentation. It also required modifications to existing piping (i.e., adding a tee and modifying pipe hangers),

power supplies and panels. Possible locations within the plant had to be evaluated to accommodate the additional equipment and piping. Modifications to existing systems were evaluated to identify the options for adding the new ATWS equipment with the least impact to existing systems while complying with design requirements. The effects of potential hazards such as pipe break, fire, radiation and missiles associated with the addition of the new systems and the modification of existing systems were assessed and documented. New foundations for the additional equipment were designed. Routing for the new piping and electrical raceway for both ATWS and existing systems which were affected by the inclusion of ATWS modifications was selected and the design for these commodities was finalized.

The addition of this new ATWS equipment and associated commodities required that the delivery of the new equipment and access to facilities for its installation be factored into construction planning with consequent construction impact. Installation of the new piping, valves, and hangers also resulted in rework to systems already installed in the affected areas. In addition, the installation of those commodities which occurred late in the construction sequence, such as electrical tray, conduit, cable and terminations, was also adversely impacted in these locations. Greater time was required for such installations due to interferences and congestion in work areas. Moreover, craft manpower had to be obtained and brought back to the project unexpectedly. Delays occurred in fabrication of needed equipment and commodities. In sum, engineering, procurement and construction to satisfy these late imposed regulatory requirements substantially and adversely affected Project cost and schedule, particularly because such activities had to be performed out of the normal

construction sequence. This rendered their performance more time consuming and costly, and disrupted the performance of other scheduled activities during the period in which they had to be performed.

In addition to the specifics just discussed, there were peripheral effects associated with the backfit. Various documents had to be revised to identify the new ATWS system, including the Final Safety Analysis Report, drawings and calculations. Also, revisions had to be made to the plant training manuals and startup test and operating procedures, plant operators had to be retrained and testing of the new ATWS system was required.

The implementation of new regulatory requirements was not limited to ATWS. Many more regulatory-imposed modifications of similar complexity or scope occurred over the life of the project. As backfits overlapped each other, negative synergistic effects started to appear, especially with respect to common plant support systems such as power supplies, heating and ventilation systems and cooling water systems. These multiple overlapping backfits complicated the design process resulting in the redesign of some already installed primary plant systems and their support systems up to and through the startup phase. The consequent disruption of construction and startup activities as a result of implementing these many new requirements imposed upon Limerick had a serious detrimental impact upon both project cost and schedule.

Q. Please describe the effects of changing NRC quality assurance requirements upon the Limerick project.

A. Of the NRC requirements imposed during the Limerick construction period, the most significant in terms of cost and schedule was the nuclear QA program. The imposition of 10 CFR 50 Appendix B, the NRC Quality Assurance rule, in 1970,

had a profound effect upon all aspects of the nuclear power industry. Appendix B set forth the criteria which had to be met if acceptable nuclear power plant quality was to be demonstrated. Written in general rather than specific terms, the rule has been subject to increasingly more stringent NRC interpretation since its adoption.

Limerick was committed to conform to Appendix B, both in its engineering and construction by PECO's executive management, as early as 1971. The project was not only a proponent of quality workmanship, but a leader in complying with regulatory QA mandates. The project consistently received the highest ratings given by NRC inspection and compliance personnel. In short, it is a high quality plant designed and built by people who placed quality at the top of the list. This, however, was not achieved without cost. The escalation of quality-related requirements can be illustrated by a comparison to the earlier and quite acceptable Peach Bottom Project.

At Peach Bottom, Quality Control (QC) was the responsibility of field engineering. Five persons were devoted exclusively to QC activities and reported to the project field engineer. After Appendix B was issued, a QC group was established as a separate Peach Bottom entity and was expanded to 55 personnel. Its scope of work was increased to include receipt inspection and subcontractor surveillance as well as responsibility for final installation inspections and product acceptance. The inspections at that time were based on past construction practice and individual judgment and used a minimum of inspection tools. In certain areas, only a simple review of paperwork was required for acceptance.

During the time span covered by the construction of Limerick, the number of QA/QC functions and the degree of involvement by QA/QC organizations, in all

aspects of the project from initial engineering through final acceptance, greatly increased. This impact was most clearly seen in the number of engineers required to staff and to support the QA and QC functions, the development of extensive training and qualification programs, and the millions of documents which were collected to demonstrate quality.

In this regard, the QC department at Limerick peaked at 270, compared to the 55-man peak staffing at Peach Bottom Unit 2. The collection and verification of documentation on all nuclear quality related components and construction at Limerick, estimated at three and one quarter million documents, added a workload for all field nonmanual personnel unprecedented at earlier generation plants. The increased level of QA/QC activity also resulted in increased staffing levels in both the design engineering and field engineering functions. To this latter point, the Limerick field engineering forces of approximately 700 contributed 20% of their time to the performance of redundant pre-QC inspections to ensure timely completion of the work under the existing QA rules.

From a project engineering standpoint, there were more than 10 times the number of calculations at Limerick than at Peach Bottom. In addition, the process of specification preparation underwent periodic redefinition of acceptance standards for the fabrication and installation of components as the NRC acceptance criteria changed. For example, commercial grade specifications on piping or steel fabrication and installation would typically include a statement that excluded weld splatter and arc strikes as a basis for finding workmanship unacceptable. The equivalent nuclear quality related specifications went through several sequential engineering evaluations, each of which defined more precisely and quantitatively the amount of weld splatter and arc strikes that could be

accepted under then-current NRC inspection rules. The thoroughness of the field inspection of installed components was also significantly strengthened in order to demonstrate that the increased or more precisely defined acceptance criteria had been achieved.

The actual construction process was impacted by the increasing QA/QC level of activity in several ways. The acceptance standards that were imposed exceeded those in all other types of construction and previous nuclear construction experience. This increased the number of field craft hours required to complete a work item to these new standards. Also, the evolving nature of the acceptance criteria resulted in the application of new standards to previously completed work with a consequent expenditure of craft and nonmanual hours to bring previously constructed work into compliance with the latest acceptable criteria. This also caused work to be performed in a less than optimal sequence.

In response to these problems, extensive training programs were set up for both craft and nonmanual personnel to instruct them in the standards and to help them develop needed additional skills. The inefficiencies that resulted from this moving quality target significantly impacted the project's ability to maintain a motivated workforce and to achieve projected levels of productivity.

Compliance with mandated changes to design rules in the name of increased safety produced additional complications. For example, more stringent seismic requirements necessitated increased quantities of reinforcing steel in Seismic Category I structures. This quantity increase resulted in more complex designs and installation procedures for Limerick and in more quality control and quality assurance to ensure that the constructed plant reflected the design. As a second example, in 1979, as a part of the project's response to IE Bulletin 79-14, as-built

drawings and analyses had to be reverified to be in close agreement with very tight installation tolerances. These tight tolerances also required a significant increase in quality control.

Q. Does this conclude your testimony?

A. Yes, it does.

PERSONAL RESUME OF CHARLES K. SOPPET

PROFESSIONAL LICENSES AND SOCIETIES

ANS - Power Division Treasurer, Executive Committee and Program Committee, Ch. Standards Steering Committee
Registered Professional Engineer - State of California

EDUCATION AND PERSONAL DEVELOPMENT PROGRAMS

B.S.M.E. Michigan State University, Mechanical Engineering 1950
Various graduate studies

OTHER SIGNIFICANT INFORMATION

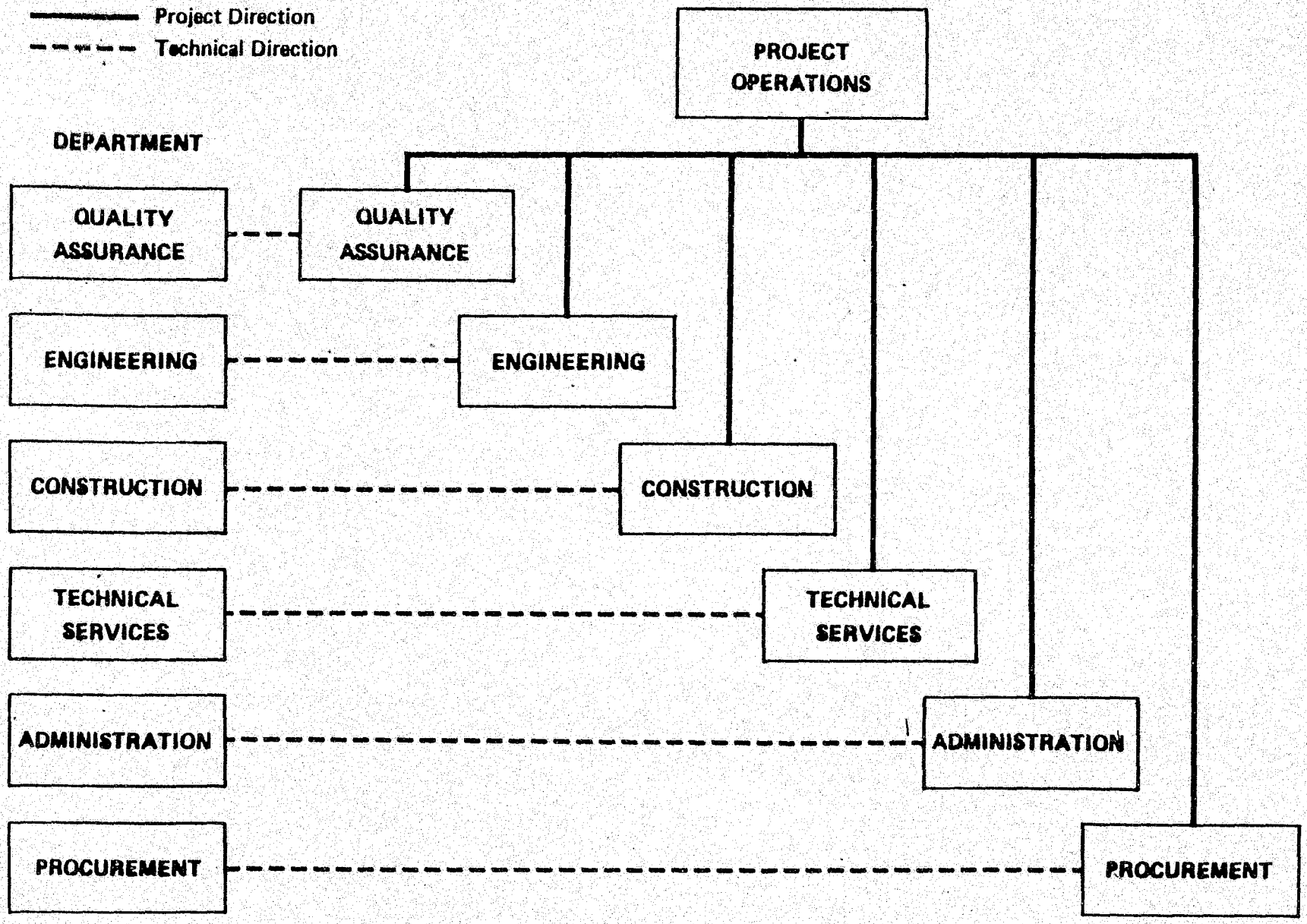
ACHIEVEMENTS: Three patents for nuclear fuel fabrication and design when with Argonne - assigned to Government; number of publications at Argonne and General Nuclear

WORK HISTORY

DATES FROM	DATES TO	COMPANY, DIVISION OR DEPARTMENT, LOCATION AND SUPERIOR	POSITION HELD, SUMMARY OF RESPONSIBILITIES AND SIGNIFICANT ACCOMPLISHMENTS
1950	1957	Argonne National Laboratory	Staff Engineer and Engineering Group Supervisor. Resp. for design and Fab. of reactor internals, control system & fuels
1957	1963	General Nuclear Engineering Corp.	Staff engineer and Project Manager - Directed and managed design and construction of nuclear research reactors and experimental central station nuclear power plants
1963	1970	Aerojet General	Manager Nuclear Operations Dept.; Manager Engine Test Operations; Mgr. New Product Development and Marketing. Directed and managed nuclear activities for both Aerospace and Civilian Commercial application.
3/70	5/70	Power & Industrial Bechtel Corp. - SF H.O. Reinsch	Project Manager
5/70	10/71	Bechtel Power Corp. S. F. Power Division San Francisco R. D. Allen F. A. Hollenbach	Project Manager - Limerick Project
10/71	8/84	Bechtel Power Corp. S.F. Power Division San Francisco, CA F. A. Hollenbach	Lead Project Manager - Peach Bottom and Limerick Projects
9/84	Present	Bechtel Power Corp. Western Power Division San Francisco, CA J. H. Battin	Same as above

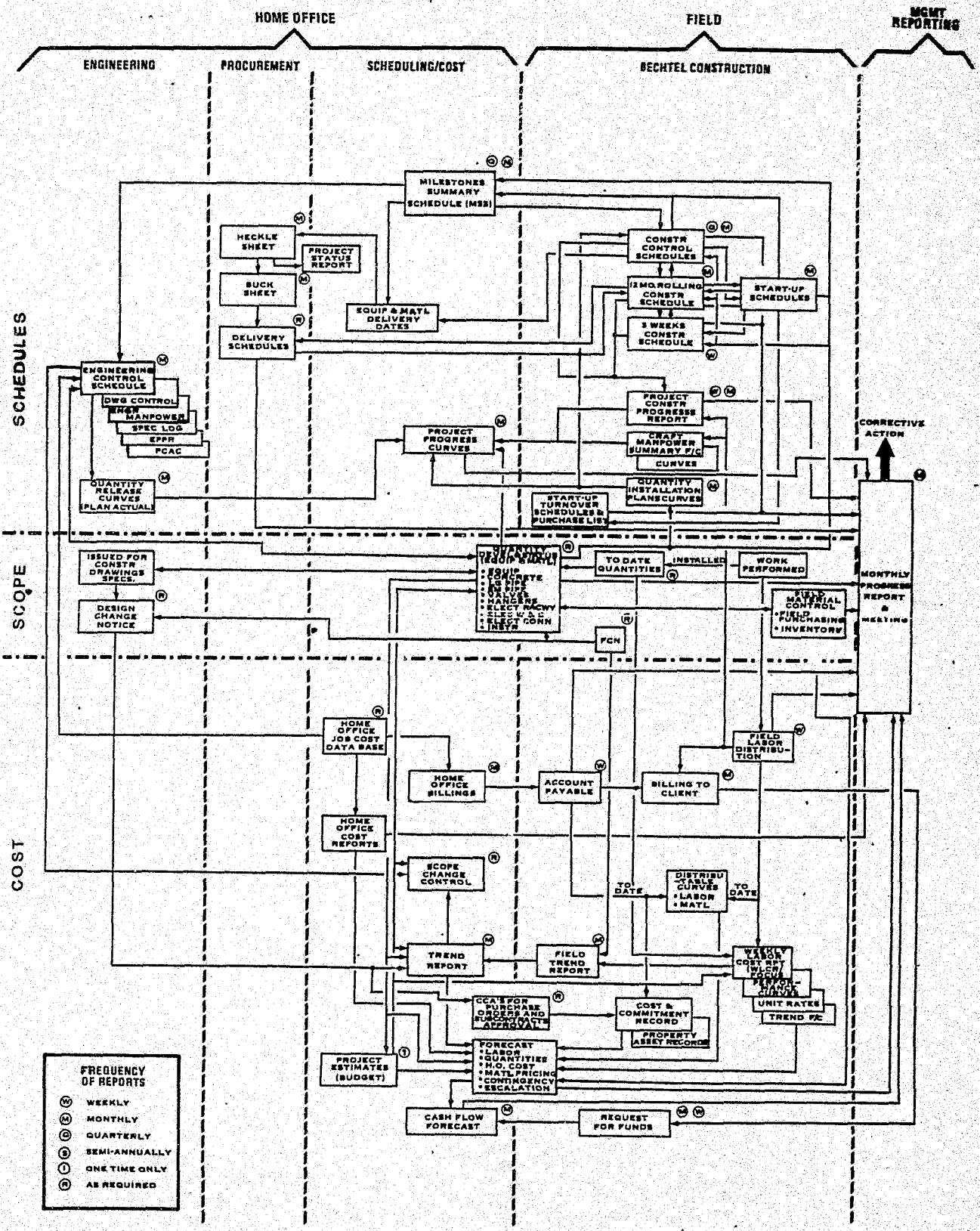
LIMERICK GENERATING STATION
JOB 8031

PROJECT MATRIX ORGANIZATION



Schedule 2

LIMERICK COST & SCHEDULE CONTROL PROGRAM FLOW DIAGRAM



PECO STATEMENT NO. 9

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION V.
PHILADELPHIA ELECTRIC COMPANY,
Docket No. R-850152

DIRECT TESTIMONY OF
ROGER J. MATTSON

LIMERICK 1 AND COMMON PLANT
EFFECTS OF CHANGING NRC LICENSING
REQUIREMENTS AND PREPARATION
OF PECO EXHIBIT NO. 2

DOCKETED
SEP 27 1985

SEPTEMBER 27, 1985

DIRECT TESTIMONY OF ROGER J. MATTSON

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

A. I am Roger J. Mattson, and my business address is:

2600 Virginia Avenue, N.W., Suite 1000, Washington, D.C. 20037.

Q. By whom are you employed, and in what capacity?

A. I am Vice President of Nuclear Safety and Operations Services for International Energy Associates Limited.

Q. Please summarize your professional qualifications and experience.

A. I am a mechanical engineer by training and hold a Ph.D. in that field from the University of Michigan. My early engineering experience was in test reactor design and construction at Sandia Laboratories. My principal qualification for this testimony consists of 17 years of experience in the development and implementation of nuclear power plant safety regulations. I served with the U.S. Atomic Energy Commission (AEC) and then the Nuclear Regulatory Commission (NRC) from 1967 through early 1984. In the early years I had

responsibility for emergency core cooling and other reactor safety systems, and later I had more general responsibility including the development of NRC's technical licensing requirements. My last seven years at the NRC were spent in a senior management position where I was responsible for the majority of the technical review of utility applications for construction permits, operating licenses, and license amendments. The bulk of the technical review of the Limerick Unit Nos. 1 and 2 operating license application was performed under my direction. I was the manager responsible for determining most of the licensing requirements for these units. I also had a number of more general responsibilities. For example, I directed the NRC's regulatory reform efforts for the first year following the accident at Three Mile Island Unit No. 2 (TMI-2). I served on NRC's Regulatory Requirements Review Committee from 1977 to 1980 and its successor, the Committee for the Review of Generic Requirements, from 1983 to 1984. In various capacities, I managed the development and implementation of NRC's regulatory requirements from 1974 to 1984. My other experience and current employment are summarized in the resume contained in Schedule 2.

Q. What is the purpose of your testimony?

A. My testimony describes the NRC licensing process, traces the growth and change in NRC licensing requirements through the 1970s and into the early 1980s, describes generally the effects of changes in requirements on the design and

construction of Limerick 1, and ascertains the validity of the cost effects attributed to new or revised NRC requirements in PECo Exhibit 2. Specifically, my testimony (1) presents a chronology of changes in licensing requirements from the time Limerick received its construction permit to when it was licensed and (2) evaluates PECo Exhibit 2 to ensure that the NRC requirements described therein were in fact imposed by the NRC and had the general effects described by PECo.

Q. How is your testimony organized?

A. The testimony initially provides background on the NRC licensing process. It identifies sources and methods of imposition of NRC licensing requirements; discusses the timing of imposition of NRC licensing requirements; and describes the effect of new and revised licensing requirements on Limerick.

Findings on the causes of cost increases attributed by PECo to NRC are presented. This final part of the testimony affirms that (1) new or changed NRC requirements had the general effect described in PECo Exhibit 2 and (2) the PECo responses to these new or changed regulatory requirements were reasonable.

My testimony also describes how the changes in NRC licensing requirements and the increase in NRC inspection requirements led to increased plant complexity, increased costs and longer construction times for Limerick relative to earlier plants and relative to original estimates for Limerick.

1. NUCLEAR REGULATORY COMMISSION LICENSING PROCESS

Q. Please begin by describing the NRC licensing process.

A. The licensing of a nuclear power plant by the NRC is conducted in two stages. Initially, a utility must receive a construction permit (CP) before beginning any major construction activity. The NRC decision to issue this permit is based on its technical review of design and site information contained in the preliminary safety analysis report (PSAR) prepared by the utility. The review culminates in a public hearing held before an Atomic Safety and Licensing Board (ASLB) and, if necessary, before an Atomic Safety and Licensing Appeals Board (ASLAB). Additionally, an independent review is conducted by the Advisory Committee on Reactor Safeguards (ACRS).

Once a CP is issued, the utility proceeds with constructing the plant. During this time and until an application for an operating license (OL) is filed, the NRC typically has little direct licensing interaction with the utility. During

this period of construction, new requirements or regulations may be promulgated by the NRC and backfit to plants under construction. If a utility adopts these new items and adds them to the plant before applying for an OL, there usually is no evaluation by the NRC. Hence, the CP holder is proceeding with implementation of these new requirements at some financial risk. However, by proceeding in this manner a utility can avoid later, more costly rework because the utility is implementing the NRC backfit before construction has been completed on the parts of the plant that will be affected by the new requirement. The state of licensing uncertainty that exists between the CP and the OL application continues until the plant is approximately two to three years from being ready to operate. At that time, the utility applies for an OL, and a close interaction with the NRC licensing staff is resumed.

Applications for an OL are supported by a final safety analysis report (FSAR) which describes the completed plant design. After the FSAR is filed with the NRC, a technical review similar to the one performed for the CP application is undertaken by NRC. Issuance of the OL will occur when construction is complete, the final design receives NRC staff approval, the ACRS completes its second evaluation of the plant, and any hearing related matters are resolved. Receipt of the OL permits the licensee to begin fuel loading and operation up to five percent power. Approval from the

Commission itself is required before higher power operation can commence.

Q. What are the principal issues covered in the NRC licensing review?

A. The main consideration in the NRC licensing process is the assurance that the operation of a nuclear power plant does not endanger the public health and safety. This is accomplished by employing a three-party review, consisting of the NRC staff, the Advisory Committee on Reactor Safeguards (ACRS) and the ASLB.

The review by the NRC staff covers the plant design; quality assurance (QA) during construction and operation; operational philosophy and procedures; and utility personnel and experience. This evaluation determines if (1) the design is safe and consistent with NRC requirements, (2) the plant is constructed using sound practices and in accordance with the design, and (3) the plant is operated in a safe and reliable manner. In addition, the NRC reviews the environmental aspects of the plant in accord with the National Environmental Policy Act.

When a Safety Analysis Report (SAR) is received by the NRC, an acceptance review is conducted by the Staff to ensure that it contains sufficient information to permit a proper

evaluation. Once this preliminary review is complete, the NRC officially accepts (dockets) the SAR for review, and the technical review of the design by the NRC is begun. The first step in the technical review is to issue a set of questions requesting additional information in areas where more details are needed to understand the design. The additional information is provided in the form of amendments to the SAR and is reviewed by the Staff. The Staff then issues a draft Safety Evaluation Report (SER) to describe the course and conclusions of its review. The draft SER may contain as many as 400 open items that are unresolved between the applicant and the NRC technical Staff. It is made available to the applicant and the public. The applicant responds to the open items and an SER is issued by the Staff when there are only 10 to 20 open items remaining. After this, supplements to the SER are published which identify any new items, report on the ACRS review, and finally resolve all of the open items.

Once the NRC Staff issues the SER, the ACRS performs a review of the same areas and meets with the Staff and applicant to discuss any safety concerns. Following this meeting the ACRS sends a letter report to the NRC Chairman presenting the findings of its independent evaluation and the ACRS recommendations on whether the CP or OL should be issued. Parallel to the NRC Staff and ACRS reviews, the ASLB conducts mandatory hearings at the CP stage and further

hearings at the OL stage if a member of the public petitions to intervene in the operating license process. The opportunity for a hearing is provided to accord due process to the individuals who will be affected by the plant. Most of the contentions adjudicated by the ASLB deal with utility or site-specific concerns such as quality assurance, emergency planning, or site location. In addition to petitions from the public, the ASLB can investigate issues of safety significance sua sponte. Participants in a hearing can appeal ASLB decisions to the ASLAB, to the Commission, and to the Federal Courts.

2. SOURCES OF NRC LICENSING REQUIREMENTS

Q. What are the principal sources of NRC licensing requirements?

A. There are three principal sources of "official" NRC licensing requirements used in OL reviews. In addition, during the late 1970s and early 1980s, there were a number of additional "informal" sources of licensing requirements imposed by the NRC Staff.

Of the "official" sources, the first, and most important is the Code of Federal Regulations, Title 10 (10 CFR). A regulation is adopted in 10 CFR only after a formal rulemaking

proceeding has been completed. Compliance with the terms of 10 CFR is mandatory unless an exemption is obtained.

As I will describe below, the requirements of 10 CFR are very broad and general, providing little guidance as to how the prescribed assurance of safety is to be achieved. The other two "official" sources of licensing requirements are the Standard Review Plan (SRP) and Regulatory Guides. These are guidance documents issued by the NRC Staff. They are added to or changed following a formal review process that includes an opportunity for public input.

In addition to these three official sources of requirements, a fourth set of documents, called NUREG Reports, began to contain licensing requirements after the TMI accident. Finally, there are numerous additional documents generated by the NRC Staff, which, either because of their incorporation into an "official" licensing requirement or because of NRC Staff insistence, have been imposed as licensing requirements upon all or specific nuclear projects. Examples of these documents are: Branch Technical Positions (BTPs), Generic Letters, The Office of Inspection & Enforcement Bulletins and Circulars, and Industry Standards.

Q. Dr. Mattson, please expand upon your statement as to the differences in purpose and contents of the official and unofficial sources of licensing requirements you have identified.

A. 10 CFR sets forth the standards of safety assurance that an applicant must satisfy to obtain an operating license. The SRP and Regulatory Guides provide guidance as to the design, construction or operating approaches that the NRC Staff has found acceptable for meeting the requirements in 10 CFR. The SRP is an organized, written guide prepared by NRC Staff and approved by senior management for use by the Staff in reviewing license applications to determine their compliance with 10 CFR. The SRP refers to Regulatory Guides, Branch Technical Positions, NUREGs and the other licensing requirement source documents which I have referenced above, thereby giving all of them a perception of official NRC requirements. This is unfortunate because not all of the documents have been accorded that status. This allows individual NRC staff reviewers, on a significant number of occasions, to enforce licensing requirements from the unofficial documents. The NUREG Reports and other licensing requirements are not NRC requirements in the strictest sense. Rather they reflect NRC Staff positions and not the Commission's official positions as to how the required safety assurance standards of 10 CFR must be satisfied.

Q. Please provide more detail on the differences between 10 CFR, the SRP, and Regulatory Guides.

A. The two characteristics which differentiate these documents are the extent to which compliance with their terms is required and their degree of specificity.

Compliance with 10 CFR is mandatory. If a utility cannot meet the criteria in 10 CFR, it must receive a formal exemption from the NRC. There are no other options. In contrast, Regulatory Guides and the SRP serve as guidance documents to the industry and to the Staff, respectively, on how to meet the mandatory regulations in 10 CFR. As noted in the introductions of these guidance documents, they are not, at least in theory, the only alternatives that may be acceptable. License applicants may propose alternative ways of meeting the regulations, and NRC will review them.

The other characteristic that differentiates the regulations in 10 CFR from the other regulatory requirements is the degree of technical detail. The regulations in 10 CFR are very general. The Regulatory Guides, the Standard Review Plan, and the other standards that they endorse are much more detailed.

Q. Can you give an example of the difference between a mandatory requirement in 10 CFR and alternative methods of meeting that requirement that have been specified in the guidance documents and found acceptable by NRC?

A. Yes. A good example is the emergency core cooling system. General Design Criterion 35 of Appendix A to 10 CFR 50 provides the mandatory requirement, as follows:

> Criterion 35-Emergency core cooling. A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.
>
> Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Pursuant to this very general requirement, the NRC Staff has issued a number of Regulatory Guides and Section 6.3 of the Standard Review Plan to provide guidance on alternative designs of emergency core cooling systems (ECCS). Using these guidance documents, alternative designs have been found acceptable. For example, in the case of boiling water reactors, some plants have an ECCS comprised of high pressure coolant injection, automatic depressurization system, redundant core spray, and redundant low pressure coolant injection (e.g., Limerick). Other boiling water reactors have an ECCS comprised of high pressure core spray, automatic depressurization system, low pressure core spray, and redundant low pressure coolant injection (e.g., GESSAR II). Both of

these approaches have been approved by the NRC Staff as meeting the abundant cooling and redundancy requirements of General Design Criterion 35.

It should be noted that the general requirements of 10 CFR were issued first, and the acceptable approaches described in the SRP and Regulatory Guides came along later. This later guidance reflected what was actually approved by NRC in the licensing process for the earliest power reactors pursuant to the general requirements of 10 CFR.

Q. To further illustrate the difference between regulations and guidance, can you give an example of the difference in detail between the mandatory regulations of 10 CFR and the optional guidance in the SRP or the Regulatory Guides?

A. Yes. A good example of the difference in technical detail is the fire protection program. General Design Criterion 3 of Appendix A to 10 CFR 50 provides the mandatory requirement, as follows:

> Criterion 3-Fire protection. Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that

their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

This requirement is very general. After the fire at the Browns Ferry Nuclear Plant in 1975, more detailed guidance was developed by the NRC Staff for implementing this general design criterion. The details were published in Branch Technical Position 9.5-1. It was subsequently revised, and the current version in the Standard Review Plan is 53 pages long. The detailed requirements of the SRP Section on fire protection cover fire hazards analysis, fire suppression system design, alternative shutdown systems, administrative controls, fire brigades, quality assurance, safe shutdown criteria, control of combustibles, smoke detectors, sprinkler designs, portable extinguishers, lighting, ventilation, separation of equipment, storage of hazardous materials, and a host of other specific details for protecting various aspects of a nuclear plant against fires. This example clearly indicates that guidance documents are much more detailed than the mandatory regulations.

Q. When did the SRP begin to be used in licensing reviews?

A. The use of the SRP in the licensing process was approved in Office Letter No. 2 issued August 12, 1975 by NRC's Office of Nuclear Reactor Regulation (NRR). Office Letters are used by the Director of NRR in implementing general procedures. In

Office Letter No. 2, the Office Director advised the NRR Staff to use the SRP to assure a consistent evaluation of all license applications. In Office Letter No. 9 (June 18, 1976), the Director identified the need to document deviations from the SRP for those plants that had already received a Construction Permit but had not been reviewed against the SRP. The cutoff date for this requirement was set in a January 31, 1977 internal memorandum from the Office Director in NRR to upper-level NRR managers. According to this memorandum, the NRC Staff began to use the SRP in its review of OL applications docketed after January 1, 1977.

Q. What was the SRP's specific application to Limerick?

A. From 1975 to 1977, while construction was in its early stages, there was no active licensing review of Limerick and, hence, no application of the SRP to the design. However, in Enclosure 2 to the January 31, 1977 internal NRC memorandum, Limerick Units 1 and 2 were identified as plants which would have to meet the SRP or have their deviations justified by the NRC Staff. This was communicated to PECo in a letter from Karl Kniel of the NRC to Edward Bauer of PECo dated July 26, 1977. Later, new or revised SRP criteria affecting 55 SRP sections were backfitted to Limerick Unit Nos. 1 and 2 by a letter from Roger Boyd of NRC to Edward Bauer of PECo dated November 20, 1978. These changes affected areas of plant design such as the methods used to analyze the thermal

hydraulic stability of the reactor core, the protection from internally generated missiles afforded safety-related equipment, including reorientation of potential missile sources and the addition of missile shields, the addition of a second level of voltage protection for the onsite power system, and a revision of pump operability requirements, including pump redesign in some cases.

Q. Did the SRP remain stable or was it constantly changed by the NRC Staff?

A. It was constantly changed. The only time the SRP remained stable was from 1979 to 1981 while NRC was occupied with the accident at Three Mile Island Unit 2 (TMI-2) and resultant backfits. The NRC did not find time in that period to maintain the SRP. Then, in July 1981, the entire SRP was revised to incorporate new and revised Regulatory Guides, Branch Technical Positions, the lessons learned from the TMI-2 accident, and other technical guidance, such as that contained in NRC technical reports (the so-called NUREG Reports).

Q. Please explain how Regulatory Guides were adopted and their purpose in the licensing process.

A. Regulatory Guides are developed by the Office of Research in NRC. It is separate from either the licensing office (NRR)

or the inspection office (IE). The Guides are intended to codify good engineering practices as developed and approved on earlier plants so as to speed the review of later plants and to ensure consistently high standards of design and operation.

Some Regulatory Guides delineate techniques used by the Staff to evaluate specific situations. Others provide guidance to applicants concerning the information needed by the Staff in its review of applications for permits and licenses. Many Regulatory Guides reference or endorse national standards (also called consensus standards or voluntary standards) that are developed by recognized national organizations under the aegis of the American National Standards Institute, often with NRC participation. NRC makes use of a national standard in the regulatory process only after an independent review of the standard has been made by the NRC Staff and after public comment on NRC's planned use of the standard has been reviewed.

The NRC Staff encourages people to make suggestions for improvements in Regulatory Guides. The NRC Staff issues each Guide for public comment in draft form before Staff review is completed and before an official NRC Staff position on implementation of the Guide has been established. Copies of draft Regulatory Guides, together with assessments of their costs and benefits, are mailed for comment to many individuals and

organizations. The cost/benefit assessment indicates the objective of the Guide, its expected effectiveness compared to alternative ways of achieving the objective, and expected impacts on other safety systems, NRC operations, other government agencies, the industry, and the public.

Once a Regulatory Guide has been formally endorsed by the Staff, it is implemented on plants. This can occur in the licensing review or by specific order of the NRC. In some cases, Regulatory Guides have been backfitted by less formal means, such as letters.

Q. Please explain what a BTP is and its purpose.

A. Prior to issuance of the Standard Review Plan by the NRC in 1975, the Atomic Energy Commission (AEC) Staff used Branch Technical Positions to provide information, recommendations, and guidance to its license application reviewers and to applicants as to what constituted an acceptable design that met the safety requirements in 10 CFR. BTPs could be issued by Branch Chiefs or mid-level NRC management, and they contained the branch technical position on generic issues. Generic issues are issues which are applicable to all plants or all plants of a specific design (e.g., boiling water reactors). When the SRP was developed, BTPs were combined with Regulatory Guides, Industry Standards, and other NRC requirements to form the SRP Acceptance Criteria.

One purpose of the Standard Review Plan was to assemble in one document all of the licensing criteria which would be applied by the NRC Staff in its licensing reviews. Thus, all BTPs and all changes to BTPs were to be contained in the SRP. Changes were made to the SRP in a controlled manner, as described above, and they were only made if they involved a significant safety concern, provided additional clarification of a staff position, or corrected an error. Some revisions of BTPs were interpreted as providing only minor clarification, and some NRC branches continued to issue them on their own authority even after the SRP was issued. In 1978, NRC management recognized that this practice, in effect, altered the Acceptance Criteria of the SRP and thus imposed substantial new regulatory requirements upon licensees and applicants without the requisite management review. Therefore, the NRC procedures on BTP issuances were changed to require a review by the Regulatory Requirements Review Committee before any further changes were made. This procedure resulted in a decrease in the number of new and revised BTPs being issued. By about 1981, the NRC Staff had stopped issuing new BTPs altogether and no longer used them in its safety review unless they were already a part of the SRP.

Q. What are NUREGs and when did the NRC begin to impose them as licensing requirements?

A. NUREGs are reports prepared by the NRC Staff or its contractors to address a particular safety issue or to share information of interest to the nuclear industry, the technical community, or to the public. Although NUREG reports are not supposed to contain licensing requirements, NRC began to impose specific reports as licensing requirements in the aftermath of the accident at TMI-2 in 1979. This practice then spilled over into other areas, such as the Mark II containment loads definition, equipment qualification, and control room design reviews.

Q. How many NUREGs have been issued by the NRC?

A. Today the NRC Staff issues approximately 1,200 NUREG reports per year in four different categories. First, there are the NUREGs that contain technical information. Examples of these include NUREG-0660, the TMI Action Plan; NUREG-0510, the identification of Unresolved Safety Issues; and NUREG-1000, Staff findings on the Salem ATWS event. The NUREGs in this category were the ones sometimes imposed by the Staff as licensing requirements. Another type of NUREG report is a NUREG/CR. These are contractor reports which discuss research results or describe work performed by a contractor for the Staff. NUREG/CR-3028, the Limerick PRA review, is an example of this category. The remaining categories are: NRC brochures (NUREG/BR), such as the guide for use of the public

document room, and conference proceedings from professional meetings (NUREG/CPR).

Even though the majority of NUREG reports are issued for information only, substantial effort must be expended by an applicant in order to determine if the subject matter of the reports affects its plant. If this is the case, the applicant may choose to take corrective actions. The NRC imposed some NUREGs as licensing requirements by referencing them in Generic Letters, the SRP or 10 CFR. This was usually done only if the NUREG report addressed a significant safety concern in a dispositive manner.

Q. Were any other types of requirements imposed by NRC?

A. Yes. Following the accident at Three Mile Island, the Office of Nuclear Reactor Regulation in NRC began to use Generic Letters as a means of identifying issues that were applicable to a number of plants, such as all boiling water reactors. Generic Letters are issued pursuant to 10 CFR 50.54(f) which requires the response from the utility to be signed under oath or affirmation. In each Generic Letter, NRC states some new licensing problem and usually present a method for its resolution. The Generic Letters are intended to inform utilities of deficiencies discovered at other plants and to suggest solutions; however, NRC has used them as an additional means of imposing new requirements.

Examples of areas covered by Generic Letters include safety concerns with pipe breaks in BWR scram systems, new or revised Technical Specifications, inspections of BWR stainless steel piping, clarification of compliance to 10 CFR 50.49 on equipment qualification, and guidance for quality assurance of equipment used for protection against anticipated transients without scram (ATWS). When a Generic Letter identifying a safety concern is sent to utilities, the NRC requires that each utility describe why its plant does not have this problem or describe the corrective actions to be taken. In many cases, plant changes are required. For example, Generic Letter 82-33 transmitted Supplement No. 1 to NUREG-0737 and contained requirements on the design of the plant safety parameter display system, emergency support facility, meteorological data collection system, and the application of Regulatory Guide 1.97 to emergency response systems. These requirements were different than those imposed in NUREG-0737 and, therefore, resulted in more work.

Q. Besides NRR, were there any other offices which issued documents that were imposed as requirements upon applicants?

A. Another part of NRC which is involved in oversight of nuclear plants is the Office of Inspection and Enforcement (IE). IE ensures that plants are designed, constructed, and operated in accordance with their CP or OL and with the NRC regulations. As part of its functions, IE performs routine

inspections on site during construction and operation. IE also provides resident inspectors. In addition, it issues Bulletins, Information Notices, and Circulars which discuss such items as component failures, deficiencies in the design of components, inadequate qualification of electrical equipment, installation errors, verification of installed pipe hangers, and structural integrity of masonry walls having seismic category I piping attached to them. These documents are sent to utilities to provide information about occurrences at other plants and to describe corrective actions which should be taken in order to address any problems that might be associated with such occurrences. Although many of these documents from IE are, in theory, intended only for information, the resident inspectors, the regional inspectors, and the inspectors from IE headquarters review the utility actions taken to address them. Hence, through its normal inspection process, the NRC often imposes Bulletins, Notices, and Circulars as additional requirements.

For example, some Bulletins prescribe actions to be taken only by holders of operating licenses, and they are often issued "for information" to holders of CPs. However, Chapter 92717 of the NRC Inspection and Enforcement Manual describes the actions to be taken by the NRC resident inspectors to ensure utility compliance with IE Bulletins and Information Notices sent for information. This is demonstrated in Schedule 3.

Schedule 3 lists representative reports of NRC inspections of Limerick in Column 1. Columns 2 and 3 list the Bulletins and Circulars provided to Limerick "only for information." Compliance with the suggested retrofits in these Bulletins and Circulars was confirmed by NRC in the Inspection Reports identified in Column 1.

Q. Previously, you mentioned that the NRC also used industry standards as licensing requirements. What role does the NRC have in the development and growth of industry standards?

A. The role of NRC in developing industry standards is at two levels, management and technical staff. Senior management participates in the process by serving on the various committees of the American National Standards Institute (ANSI) that design and manage the overall body of nuclear standards. Mid-level managers serve on committees of the various engineering societies responsible for producing nuclear standards. Such societies include the Institute of Electrical and Electronics Engineers, American Society of Mechanical Engineers, American Society of Testing and Materials, American Nuclear Society, and about a dozen others.

At the technical staff level, individual engineers participate on particular standards writing committees that are critical to nuclear safety. There have been more than 100 such committees. Pursuant to the guidelines of the Federal

Government, these engineers serve as individuals and can exercise their own judgment, but they are knowledgeable of NRC interests and intentions in their technical disciplines.

Once an important national standard is finished, NRC may endorse it in a Regulatory Guide. This brings the standards into the licensing arena. Sometimes, NRC takes exception to national standards by adding conditions in the Regulatory Guides that endorse them. When this occurs, generally the NRC imposes conditions that are more stringent. Thus, the NRC has a significant role in both the development and contents of industry standards that affect the design and construction of nuclear power plants. In addition to the standards directly endorsed by NRC, there are a number of indirect uses of industry standards for nuclear plants. All told, hundreds of national standards are relied on.

3. METHODS OF IMPOSITION OF NRC LICENSING REQUIREMENTS

Q. Dr. Mattson, please describe how these various sources of licensing requirements were imposed upon OL applicants such as PECo.

A. As I have noted, 10 CFR requires that there be an adequate assurance of safety at a plant prior to licensing, and the criteria in 10 CFR are mandatory. The specifics as to what constitutes adequate assurance of safety in the view of the

NRC Staff (as defined by specific design, construction or operating practice) are set forth in the SRP, Regulatory Guides, BTPs and other documents which I have described above. These requirements were imposed by the Staff through the OL review process. On some occasions, individual Staff reviewers would impose their own interpretations of what constituted adequate assurance of safety, including imposition of BTPs, other licensing documents or Industry Standards as the only acceptable alternatives. They did this through the leverage provided them by the licensing review process.

Q. Please explain this leverage.

A. As described above, compliance with the SRP, Regulatory Guides, and less formal licensing requirements was not technically required in order to obtain an OL. A utility could achieve the requisite assurance of safety through design or operating approaches different than those spelled out in the SRP or Regulatory Guides. However, in practice, compliance with the specific engineering or other approaches of the SRP and the Regulatory Guides was generally required. Through force of will or threat of delay, alternative methods of achieving the objectives of 10 CFR were discouraged.

This discouragement of alternatives begins with a statement in the Introduction of the SRP under a section entitled

"Acceptance Criteria." In this section, the NRC Staff notes that the SRP Acceptance Criteria are based on Regulatory Guides, the General Design Criteria in Appendix A to Part 50 of 10 CFR, various engineering codes and standards, BTPs, and SRP Section Appendices. The SRP then states:

> Like Regulatory Guides, the Branch Technical Positions and Appendices represent solutions and approaches that are acceptable to the staff, but they are not required as the only possible solutions and approaches. However, applicants should recognize that, as in the case of Regulatory Guides, substantial time and effort on the part of the staff has gone into the development of the Branch Technical Positions and Appendices and that a corresponding amount of time and effort will probably be required to review and accept new or different solutions and approaches. Thus, applicants proposing solutions and approaches to safety problems or safety related design areas other than those described in the Branch Technical Positions and Appendices must expect longer review times and more extensive questioning in these areas.

Thus, the NRC Staff in effect stated that if applicants do not provide designs which are in conformance with Regulatory Guides and the SRP, more extensive and longer OL reviews should be expected. Since the length of OL review can have significant cost consequences for a utility, and since the schedule loss and retrofit cost of proposing an alternative which the staff does not accept can be prohibitive, this approach obviously discourages a utility from offering alternatives. This formal guidance served as the basis for NRC Staff to implement the guidance documents as rigid requirements. This practice was legitimized when Section

50.34 of 10 CFR was amended to require applicants to identify and justify all differences relative to the SRP for all applications filed after May 17, 1982. In practical terms, this mandatory requirement had been imposed by NRC Staff for OL applications filed prior to that time as well.

Q. How did this occur?

A. Initially, a reviewer asked an applicant to describe how its design met a particular SRP section, BTP or Regulatory Guide. If the applicant proposed an alternative approach, the reviewer asked a set of detailed questions. If questions were not answered by the time the safety evaluation report (SER) was issued, the reviewer would identify the issue as an open item which required resolution prior to issuance of the license. If the alternative was still preferred by the applicant and the questions were answered, a dissatisfied reviewer would still identify it as an open item requiring more detailed evaluation.

Further evaluation led to more questions and further delay. Each question that was answered produced a new question. In this way, reviewers kept controversial items unresolved until late in the license review process where the threat of delay and associated cost penalties added to the incentive for the applicant to conform the design of the plant to the SRP, BTP, or Regulatory Guide in question.

Schedule 4 contains several samples of the approximately 1200 questions asked by the NRC Staff about the FSAR for Limerick Unit Nos. 1 and 2. These questions and doubtless others imposed adherence to the SRP, BTPs and Regulatory Guides in the manner which I have described.

Q. Dr. Mattson, can you cite any documentary support for the proposition that NRC and its Staff imposed new licensing requirements upon nuclear projects during the period from 1974 to 1984 through a number of formal and informal procedures as you have described above?

A. Yes, I can. In fact, this documentation makes clear that I have limited my discussion to the principal sources of requirements. There were others. The document I am referring to is a report by NRC's Executive Director for Operations who identified about 80 different ways that NRC has imposed new requirements. The ways range from telephone calls to rulemaking. They are listed in Schedule 5 which is a set of three tables that have been retyped from an NRC report numbered SECY-82-39A of April 29, 1982.

Q. How does the imposition of new licensing requirements by informal means differ from the more formal procedure of rulemaking, and how does this difference affect utilities constructing nuclear power plants?

A. In the rulemaking process, there are a number of steps which are followed before the rule becomes effective and compliance is required. Initially, an issue will be identified by the NRC as one which requires rulemaking. The issue is then discussed by the Commission at an open meeting and arguments, both pro and con, are presented. If the Commission decides that the subject warrants rulemaking, it then drafts a proposed rule. It is printed in the Federal Register, and public comments are solicited. Once the public comments are received, the Commission may chose to (1) enact the rule as written, (2) modify the rule and issue it, or (3) retract the rule.

When the rulemaking process is followed there are a number of advantages. These include: (1) an opportunity for the public and nuclear industry to comment on the proposed rule; (2) forewarning to the industry of new requirements; (3) the ability of the industry to present arguments, using engineering analysis, risk assessment or cost-benefit analysis, to persuade the NRC to abandon or modify the rule; (4) sufficient time for utilities to assess implementation costs and incorporate these into their budgets; (5) insight into the likelihood of the original or some modified rule being adopted; and (6) reasonable time to make the necessary design and construction changes.

On the other hand, the implementation of new requirements through new staff interpretations or other means, such as Generic Letters or Bulletins does not offer the same benefits as rulemaking. Through these less formal processes, utilities are less able to predict the nature of new requirements nor can they accurately predict the costs. During the NRC review of Limerick Units 1 and 2, almost all of the new requirements were imposed through these less formal means.

4. TIMING OF IMPOSITION OF NRC LICENSING REQUIREMENTS

Q. From what you have said, it appears that there were many types of requirements levied by NRC on PECo for the Limerick plant and that these requirements changed often. Is that the case?

A. Yes. By 1972, the AEC had put in place the general rules applying to nuclear power plants, including the radiation protection standards of Part 20, the siting criteria of Part 100, the General Design Criteria of Appendix A to Part 50, and the quality assurance rules of Appendix B to Part 50 (i.e., the mandatory provisions of 10 CFR). Then a myriad of changes began to occur. Schedule 6 is a table which illustrates the changes in regulatory requirements during the 1970s and up to 1984. The five columns in the table represent the number of Technical Rules, Regulatory Guides, Generic Letters, Bulletins, Information Notices and

Circulars issued during that period. As can be seen from this table, during the mid and late 1970s and early 1980s the number of NRC requirements drastically increased. In the ten years beginning with 1975, the year NRC was formed, through 1984, the year Limerick was licensed, the NRC issued 23 new technical rules, made 354 revisions to its other regulations, and issued 213 new or revised Regulatory Guides, 287 Generic Letters, 109 Bulletins, and 396 Information Notices. As I described above, the NRC also imposed new licensing requirements through new and revised BTPs, NUREGs, and individual staff interpretations. Some 90 new requirements were levied on each plant in connection with the accident at TMI-2. As Schedule 6 shows, a significant number of other changes occurred in the post-TMI period, (i.e., after 1979), late in the construction of Limerick.

In addition to the constant stream of new requirements, PECo also had to comply with changing NRC interpretations of old requirements. For utilities like PECo, many of the changes in NRC requirements occurred after the CP was issued and prior to the OL application. Because of this, utilities were at some disadvantage in understanding the scope of the changes, and it was only after the FSAR was submitted that the utilities were indirectly told (through questions, staff positions, or unresolved issues in the SER) of the extent to which the new criteria or new staff interpretations were

being implemented. This further delayed recognition of the requirements and increased the difficulty of retrofitting.

Additionally, NRC attention to the details of construction increased steadily over the years of Limerick's construction. The increased number of areas inspected by the NRC is demonstrated by the growth of the IE Manual. In 1974, the year the Limerick CP was issued, there were eight Manual Chapters for use by IE inspectors. In 1975, the year NRC was formed, the number of chapters had increased to 93. By the time PECo received an OL for Limerick Unit No. 1 in 1984, there were 547 Manual Chapters. Thus, there was a six-fold increase over the number in existence during the first year of NRC and nearly a factor of 70 increase over those in use by the AEC at the time the Limerick CP was granted. This increase in inspection effort also opened up more areas where new or different interpretations of NRC licensing requirements among IE inspectors and NRR technical reviewers could occur. Schedule 7 traces the rate of issuance of new chapters in the IE Inspection Manual.

Q. Dr. Mattson, what is the IE Manual and why is the growth of Manual Chapters significant?

A. The IE Manual contains the policies of the NRC Office of Inspection and Enforcement (IE), its organization, the expected conduct of employees, the use of contractors,

guidance on construction and operations inspections, and other matters. The Manual is divided into Parts which are subdivided into Chapters. Each Part covers a general policy area while each Chapter covers specific topics within that area. The principal purpose of the Manual is to identify inspection areas and procedures to be used by NRC inspectors. Many Manual Chapters contain inspection modules that NRC inspectors use during plant construction or operation to guide their inspections. For example, Part 7200 of the Manual covers startup testing, and the 36 Chapters in this Part describe the inspection program for startup testing. The majority of the inspections in the Manual are to be conducted on plants prior to operation. These have increased approximately in proportion to the increase in size of the total Manual. As shown in Schedule 7, Manual Chapters, and thus inspection areas and procedures, increased substantially throughout Limerick's construction (i.e., 1975 to 1984), with major increases in 1979 and 1980.

Q. Can you provide any other evidence of the increase in detail of NRC's inspection program applicable to Limerick and other plants built during the late 1970s and early 1980s.

A. Yes I can. Through most of the 1970s and until the TMI accident, the NRC performed several inspections a year using staff from either its Regional Offices or from its IE headquarters. After TMI, the NRC placed a resident inspector at

each site whose duty was to inspect the plant construction or operation on a day-to-day basis. This new inspection effort was further augmented by increased regional and IE headquarters inspections. This is demonstrated by the fact that the average, annualized number of inspection hours expended for Limerick Unit 1 by NRC for the 12 months prior to its licensing was more than 3½ times greater than the amount expended for Peach Bottom Unit 2 in the comparable time frame.

Not only did the NRC have more inspectors at a site on a more frequent basis, but the role of the inspectors also changed. Previously, the inspectors would review the progress and quality of construction to ensure that the plant was being built in accordance with the SAR and NRC regulations. After about 1979, the NRC became less content with the review of documentation of quality assurance and began to address the quality of work in progress and the finished product.

Q. Why were there so many new or changed licensing requirements during the 1974 to 1984 period?

A. A principal cause of change was the shift in responsibility for nuclear power plant safety between the government and the licensed utilities.

The primary responsibility for safety has always rested with the utility. However, through the years of safety regulation there have been different expectations of what role the AEC, and then the NRC, would play in assuring that the primary responsibility was fulfilled. In February 1984, the

Congressional Office of Technology Assessment observed that nuclear safety regulation as envisioned in the 1954 Atomic Energy Act was initially expected to involve very little control by the Atomic Energy Commission.

> The basic notion underlying the first regulatory scheme was to allow industry the discretion to choose plant designs and build them using its own judgment on how best to satisfy the legal requirements for a "reasonable assurance that the health and safety of the public will not be endangered." The assumption at that time was that the industry would be able to handle the technology well, and regulation would entail only a brief design review of safety-related components and periodic inspections.

By the late 1960s, the AEC Regulatory Staff began to codify nuclear plant design practices in General Design Criteria (10 CFR 50, Appendix A) and Quality Assurance requirements (10 R 50, Appendix B). These practices had been developed in the licensing review of the early plants before AEC adopted them as required features for later plants. Their subsequent interpretation and still later reinterpretations by the AEC and NRC Staff eventually led to a shift in responsibility for the details of safety away from the utilities and toward the regulators. The regulators simply took over some of the decision making authority of the utilities on many of the design details. The growth in detailed technical requirements that I described earlier in connection with Schedule 6 is exemplary of this shift. Another example of how the NRC became more prescriptive can be seen in the way Technical Specifications have evolved. In materials provided earlier this year to a subcommittee of the House Committee on Appropriations, NRC

stated that for a plant licensed in 1972, there were 390 surveillance tests per year required to demonstrate that six limiting conditions for operation (LCOs) were met. In contrast, NRC went on to say that a plant of similar design licensed in 1984 required 14,000 surveillance tests per year to demonstrate that the same six LCOs were met.

A second reason for there being so much change in the licensing requirements was organizational. In 1975, the AEC was reorganized into two separate agencies, the Energy Research and Development Agency, now the Department of Energy (DOE), and the NRC. The NRC quickly moved to establish itself as an independent regulator of safety. Its first annual report reflects that NRC placed high priority on improving regulatory efficiency, stabilizing its licensing requirements, reducing regulatory uncertainty, and shortening the time required for licensing reviews. Despite its attention to such objectives, NRC performance in all of these areas worsened compared to the AEC. Instead of greater licensing efficiency, there were large increases in the number of licensing requirements and in the depth of review compared to that performed by the AEC. The NRC acquired staff members for every facet of nuclear technology. This increased attention to detail is illustrated by the growth of NRC resources. In its first year of operation, NRC had a staffing level of 2,006 employees and issued 10 limited work authorizations, 14 CPs and 9 OLs, a total of 33 significant

licensing actions. At that time there were about 230 nuclear plants planned, under construction, or in operation. In 1984, the year Limerick Unit No. 1 was licensed, the NRC had 3371 full-time equivalent positions and issued no LWAs, no CPs, and only six full-power licenses. The effort expended in a typical OL review by NRC grew from about 7 professional staff-years in the mid 1970s to about 20 in the early 1980s. By that time, only about 130 plants were under construction or in operation. Schedule 8 presents a chronology of NRC staffing and licensing issuances. The increase in NRC staffing level per license application did not produce shorter review times. Rather, it resulted in increased review effort which yielded more design changes, longer review times and longer construction times. This can be seen in Schedule 9 which lists the year of CP issuance and the plant construction time in months for BWRs with CPs issued by 1974.

What is evident from Schedule 9 is that the time it took to complete construction and receive a license under the AEC was about six years. For those plants that received a CP from the AEC but performed plant construction under NRC inspection and were eventually licensed by the NRC, construction times increased significantly, ranging from nine to twelve years. These figures are consistent with the thesis that expanded resources correspond to closer scrutiny of designs and construction, and the greater review effort added significantly to the time required to complete the licensing process.

A third principal source of change in regulatory requirements was the new information gained from operating experience. From 1960 through 1970, the nuclear power industry was in its infancy. During the early 1960s, small prototype reactors were constructed and operated. From the late 1960s to the early 1980s the power rating and size of reactors increased significantly. Operating experience that was accumulated from the earlier plants gave NRC and industry valuable information. This was subsequently incorporated into the larger designs either by the nuclear industry itself or through backfitting of new requirements by the NRC.

A fourth source of new information that led to changes in reactor regulation was safety research.

Q. How did the accident at TMI-2 affect the NRC licensing process?

A. The accident at TMI-2 affected the licensing process in two ways. First, it led to a number of new requirements directly related to the accident. Second, it led to a virtual moratorium on licensing that created a backlog of applications.

Following the TMI accident, the NRC established various internal review groups such as the Lessons Learned Task Force, the Bulletins and Orders Task Force, the Special Review

Group of the Office of Inspection and Enforcement, and the NRC Emergency Preparedness Task Force. There were also four major reviews of the accident by quasi-independent groups, namely, the Presidential Commission on TMI, the NRC Special Inquiry Group, and investigations by the NRC oversight committees of the U.S. House and Senate. All of these groups reviewed the accident and made recommendations for improvements in NRC regulation of nuclear plants. These recommendations were then published in numerous reports which were distributed to the industry and eventually led to new NRC regulatory requirements.

Many of the changes resulting from TMI-2 were in human factors areas, but there were hardware changes too. These included instrumentation, electrical power, leakage detection, and engineering analysis. Of greatest significance for capital costs were the addition of a post-accident sampling system, computer hardware and software and instrumentation for post-accident radiation monitoring and dose assessment, emergency response facilities and data systems, improved emergency communications and planning, and a human-factors review of the control room.

In addition, from March 1979 until August 1980, the NRC did not issue any new OLs. The reasons for this were: (1) a majority of the NRC Staff was participating in the task force efforts to investigate the accident while the

remainder supported activities at operating reactors, such as license amendments and requalification of operators, and (2) as a result of the accident and task force findings, the NRC identified the need to change its concept of and approach to nuclear safety. Because of these two factors, it was not until early 1981 that the NRC fully returned its attention to the backlog of OL applications that needed to be reviewed. By that time the Staff was so far behind in its OL reviews that the Office Director of NRR required mandatory overtime for the NRR Staff and there was a shift in agency resources from other offices to NRR so that the reviews could be completed.

The overtime and shifting of personnel did little to speed the review process. There were poor communications between the NRC Staff and utilities; more authority was assumed by individual reviewers who would impose their own interpretations of design requirements; many of the reviewers who came from other offices did not fully understand the NRR review process and clogged the system rather than helping to speed up the reviews; and the NRC had issued new requirements, based on the TMI task force findings, that were not understood by either the industry or the Staff. It was in this type of review climate that approximately 1,200 questions were asked about the Limerick OL application.

Q. Were there any controls on the regulatory changes imposed by the NRC?

A. Yes, and they have become more effective in recent years. In the pre-TMI era, the Regulatory Requirements Review Committee (RRRC) served as an internal review board to coordinate new safety requirements issued by NRC. However, the Committee required little analysis of costs or benefits, and there was no assessment of the effect on overall plant safety of individual changes in narrow technical areas. Most of the proposed changes or additions to the regulations passed through the Committee unaltered, and some did not even go through the Committee. This is illustrated by a November 20, 1978 letter from Roger Boyd of NRC to PECo. In this correspondence the NRC required PECo to backfit 35 Regulatory Guides, four Branch Technical Positions and new SRP criteria that affected 55 SRP Sections. Enclosure 4 of the letter listed items which had not been reviewed by the RRRC but were to be directly implemented because the Director of NRR had determined that they warranted immediate incorporation into the staff review. The Director thus bypassed the RRRC. Included in Enclosure 4 of the Boyd letter were the 55 SRP Sections and 12 new or revised Regulatory Guides.

Immediately following the TMI accident, the issuance of requirements increased substantially and the RRRC was barely

consulted. Although each of the changes in requirements individually resulted in some improvement to safety, the changes were issued in an undisciplined way that actually detracted from safety in some cases by overwhelming the resources of operating plants. The lack of discipline spread to other areas not directly related to TMI, and from 1979 through 1981 new requirements were implemented in a "leap-before-you-look" mind frame at the NRC. When the safety implications of this approach were realized, NRC formed the Committee to Review Generic Requirements (CRGR). It replaced the old RRRC, had much broader powers, and has brought greater discipline to the backfitting process.

5. EFFECT OF NEW AND REVISED LICENSING REQUIREMENTS ON LIMERICK

Q. Based on your knowledge of the NRC regulatory process, can you summarize the conditions that existed during the construction and licensing of Limerick Unit No. 1?

A. In summary, the regulatory climate at the NRC between 1975 and 1981 can be best described as highly unstable. The NRC issued and backfitted several hundred new requirements. It reacted to new information from research, operating experience, and licensing experience. The review process grew in scope and depth and was poorly coordinated.

The problems were at their worst in the immediate aftermath of the accident at Three Mile Island. This led upper NRC management to survey a sample of representative licensees to ascertain the depth and scope of any negative safety impact which may have resulted from the backfit process. The survey is documented in NUREG-0839. The general finding from the survey was that the imposition of requirements was "out of control." No single requirement was considered burdensome or unsafe; but there was a lack of integration of requirements. Also, because of the lack of coordination of the several organizational elements within NRC, there was a lack of appreciation within the agency of the number, scope, and overall effect on utility resources of the new requirements. The utilities noted that they were not provided authoritive positions or interpretations on technical issues and that the Staff was unresponsive to comments or to proposals of technical alternatives. This approach was found to result in an unnecessary expenditure of utility funds, in some instances significantly increasing the costs because of NRC schedule requirements. The survey concluded that:

> It is the finding, notwithstanding the competence and good intentions of the staff, that the pace and nature of regulatory actions have created a potential safety problem of unknown dimensions.

From another vantage point, the Surveys and Investigations staff of the House Committee on Appropriations found in its 1984 report that:

> Backfits can and have been imposed by many different levels of the NRC, from the on-site NRC inspectors, to regional inspectors and management officials, and most often by staff reviewers. Collectively, these staffers have imposed personal interpretations of licensing requirements and their own criteria as conditions for operation. To suggest there is a legitimate appeal process for utilities to oppose staff-imposed backfits is another fiction. The term "reviewer blackmail" has been used by utilities to describe the intimidation present when an NRC official recommends a backfit. According to utility representatives, a utility must balance the cost of a backfit, vis-a-vis the cost of a licensing action or refueling delay, which generally translates into a utility cost of about $1 million per day for loss of full operation.

There have been other studies of the overall effects of backfitting. At President Reagan's initiative, a group of private sector executives was asked to study the federal government's cost effectiveness. The purpose was to discern whether agencies would be aided through the application of cost-control techniques successfully used by the private sector. In its analysis of NRC, the President's Private Sector Survey (known as the Grace Commission) reviewed the cost impact of NRC actions or lack of actions on the construction and operation of nuclear power plants. The information included in the survey covered (1) the cost impact attributable to the unpredictability of changes in NRC requirements, (2) the cost impact attributable to the delay caused by NRC actions, and (3) the cost of backfitting after an OL is issued. The Grace Commission had difficulty quantifying the cost impact of NRC actions. The data did not permit reasonable quantification. The complications, the Grace

Commission report contended, are amplified by the licensing process, which can be illustrated using a "snowball analogy."

> The very first regulatory change after a construction permit is issued starts the snowball at the top of the regulatory change hill, causing design changes, time delays, higher costs paid with funds invested at high interest rates, and exposure to additional changes because of the time delays, which cause the cycle to repeat with the snowball becoming larger and more uncontrollable as it progresses through the changing regulatory system.

In short, the Grace Commission concluded that the process of regulation had been out of control. Although some plants were able to better cope with a changing regulatory environment, it was concluded that the unpredictability of NRC actions and regulatory changes were major contributors to licensing delays and cost increases.

Other groups such as the Atomic Industrial Forum, the NRC's Regulatory Reform Task Force, and the Department of Energy's Regulatory Reform Task Force reached similar conclusions.

Q. What effect did the changes in licensing requirements have specifically on Limerick?

A. By constantly adding and revising the licensing requirements, the NRC was forcing PECo to design the Limerick Station to a moving target. PECo would receive a new

requirement and incorporate it into the design. Sometime later, the NRC would revise this requirement, PECo would change the Limerick design, and, in some instances, PECo would rework a system or component at the plant. Schedule 10 is a chronology of Limerick Unit No. 1 from the December 1970 cost estimate to issuance of the OL. It lists the major NRC requirements cited by PECo as sources of cost escalation. What this table shows is that, during the construction process, the plant was constantly subject to design change. New design features were added, and some of those already included in the plant were changed. Sometimes features were changed on a yearly basis.

Q. Can you provide a detailed example of how this occurred?

A. Yes. For example, Regulatory Guide 1.97 was first issued in December 1975 and identified plant parameters which needed to be monitored in order to assess plant and environmental conditions following an accident. Revisions to the Regulatory Guide subsequently were issued in 1977, 1980, and 1983 when the plant was 37%, 63%, and 90% complete. With each revision, except the last, new parameters were added and, in many instances, the new parameters required new detectors, cables and indicators.

Compliance with these new requirements was difficult and expensive because of their late imposition. For example,

the detectors, cables and connectors had to be qualified and qualification packages had to be prepared. This process entailed performing costly qualification tests if the components had not been previously qualified. Sufficient room had to be available in the electrical penetrations to allow the new instrument cables to exit the containment. The routing of cables had to be reviewed to ensure that the separation requirements were maintained, and isolation devices had to be added to prevent electrical feedback effects between safety and non-safety equipment. Additionally, procurement problems such as availability of parts could easily make a single instrument a critical path item. Some instruments required by Regulatory Guide 1.97 did not exist and had to be designed. Also, in the control room, adequate separation had to be maintained, and sufficient space had to be available in the cabinets to accommodate the control boards and cables.

The revisions to Regulatory Guide 1.97 caused significant design and construction changes. This problem is amplified when one considers the number of other new requirements issued during the construction of Limerick Unit No. 1.

There are other examples of where changes in regulatory requirements caused the plant design to become more complex, the layout to become more congested, and the construction

work to be performed out of sequence or repetitively. One example is provided by the changes in seismic design basis, seismic analysis methods, and seismic qualification methods imposed on Limerick after the CP was issued. These led to new pipe hangers, cable trays, ceilings, snubbers, etc. Some of them had to be installed several times. Fire protection and electrical separation are other examples. While Limerick was under construction, the Browns Ferry fire led NRC to toughen its fire protection requirements and to backfit them to Limerick. Then, very late in the construction, NRC became quite inflexible in allowing deviations from the new fire protection requirements. This led to rework of completed construction at Limerick. These and other examples cited by PECo in Exhibit 2 were typical of the indirect effects of backfitting that were experienced at all other plants under construction in the time period from 1974 to 1984.

Q. Were there any special circumstances surrounding the licensing of Limerick Unit No. I that made implementation of changes in NRC requirements more difficult or costly for PECo relative to other plants recently coming on line?

A. Yes. The Limerick OL proceeding was highly contested. In my experience with licensing, I have observed that an OL case like Limerick with many intervening parties and many contentions, each alleging that Limerick fails to comply with NRC

requirements, combined with the likelihood of many weeks of hearings extending over several years will cause the licensing process to become quite prescriptive. The NRC Staff technical reviewers are less willing to accept departures from the Standard Review Plan, and the NRC regional inspectors are more likely to be narrow in their interpretations of inspection modules. Also, the NRC Staff management is less likely to defer open or confirmatory items in the review to later resolution; i.e., there will be fewer conditions allowed to be placed in the license. These effects are attributable to the hearing process. It is a natural tendency of the NRC Staff and regional personnel, in preparing for a contested hearing, to assemble the most defensible case they can present to the Atomic Safety and Licensing Board. The fewer departures from standard procedures and conditions that are allowed by the Staff, the easier will be the defense against attack by intervenors in the proceeding. This in turn forces a utility to accept and implement prescriptive SRP criteria or other NRC requirements as a prerequisite to issuance of an operating license. The end result is a cleaner license with fewer exceptions but higher costs to the utility. It has been my observation that this general situation prevailed in the case of Limerick, and this is borne out by the low power license which is relatively free of conditions in areas that have been troublesome to other recent license applicants, e.g., fire

protection, environmental qualification of safety related equipment, and implementation of TMI backfits.

Q. Was it possible in 1974 to foresee the extensive new and revised licensing requirements imposed by the NRC?

A. No. One of the primary objectives in forming the NRC was to establish an independent agency that would be devoted to the regulation of nuclear power plants. By doing this, both Congress and the Executive Branch hoped to reduce the average time required to construct and license the plants. The new Commission tried to reduce licensing time and improve regulatory efficiency by eliminating unnecessary requirements. In its first annual report in 1975 the NRC states:

> A major Commission objective during the first year was careful examination of NRC programs, procedures and requirements to determine the extent of their contributions to effective and efficient regulation.... [This] meant taking steps to eliminate or reduce requirements that were shown to be unnecessary. While the paramount NRC goal is assurance of full protection of the public and the environment, the Commission has taken the position that neither the public nor the regulated industry should be required to bear costs and inconveniences resulting from unjustifiable regulatory burdens.

As can be seen, the expectations of the NRC and nuclear industry in 1975 were that there would be a reduction in the licensing time of nuclear power plants and the number of licensing requirements. Ten years later, this is not the

case. The number of requirements has multiplied many times over while the time it takes to construct a nuclear power plant has nearly doubled. Not only was this not anticipated in 1975, but the 1979 accident at TMI-2 was also unanticipated. After 1979, the imposition of new requirements was expected because of the accident at TMI-2, but the actual number of new requirements and their effect on plant construction were not within the realm of reasonable expectations. This was because the changes in attitude at NRC (caused by the accident at TMI-2 and the public reaction related to it) led to new requirements in areas with no direct relationship to the accident at TMI-2.

Q. Have you reviewed Sections II and III of PECo Exhibit 2?

A. Yes, I have. The purpose of my review was to evaluate the accuracy of the description of NRC requirements and their revisions and to determine the general reasonableness of the effects upon the Limerick Project asserted to have been caused by new or changed NRC requirements.

Q. What did you conclude as the result of this review?

A. I reviewed Exhibit 2 and the NRC documents that it references. I determined that the descriptions of the effects of new or changed NRC regulations are accurate. I was able to

confirm from my knowledge of these requirements and from my knowledge of nuclear plant design and construction, as well as records in the NRC Public Document Room, that the effects attributed by PECo to NRC requirements in fact stem from NRC requirements.

Q. In your opinion, did PECo respond in a reasonable manner to new NRC requirements, and, if so, in what way?

A. Yes, PECo did respond in a reasonable manner to new and revised NRC requirements. I have reached this conclusion having considered both the design changes made by PECo and the manner in which PECo managed its relationship with the NRC in understanding, appealing, and finalizing the requirements for Limerick. PECo had only two basic options on any of these matters. The company could either incorporate an NRC requirement into the Limerick design or appeal to NRC management in an attempt to be exempted from the new requirement. In some areas, such as the TMI Action Plan and the ASME Code, it was far better to make the necessary design changes than to appeal them. They did not detract from safety, and NRC was not interested in cost considerations, so there were no viable counter arguments. Furthermore, it is unlikely that an appeal would have resulted in a reversal of the requirements, and it very well might have further delayed construction. In other instances, PECo did appeal NRC positions and obtained relief. An example of this

occured when PECo questioned the need to coat the steel columns in the turbine building with fire resistant foam.

Another way PECo demonstrated good management of its relationship with NRC was its work with owners groups to resolve licensing problems which were generic to Limerick and other plants. By being a part of the owners groups, PECo and the other members of the owners group paid less for resolution of the licensing problems because costs were spread over a number of utilities. The owners also presented a united front to NRC, thus giving greater weight to their technical arguments and protecting themselves from the vagaries of individual NRC reviewers. An area in which PECo worked with an owners group to resolve a licensing concern was the Mark II containment loads. As a result, PECo was able to reduce its costs for the generic portion of the work, and the only unique problems that arose for Limerick were a few confirmatory items concerning plant-specific analyses.

A third way PECo demonstrated good management was in the licensing of Limerick. The following items show what PECo did to ensure that licensing was properly handled:

(1) PECo took full responsibility for licensing;

(2) An organization was established to monitor and control licensing;

(3) PECo developed an automated status summary tracking program for licensing activities;

(4) Information received by PECo from Peach Bottom was, if appropriate, applied to Limerick;

(5) PECo used interdisciplinary teams of in-house and contractor experts to prepare thorough responses to NRC questions; and

(6) Letters were used to respond to staff questions, thus eliminating the delay of waiting for the SAR amendments.

In my opinion, these points show that PECo was dedicated to achieving the best possible licensing practices. Overall, I find that PECo handled licensing in an exemplary manner.

Q. Are there others who have reviewed PECo's management and licensing performance on Limerick and what did they conclude?

A. Yes, the NRC regularly performed such reviews, and it rated PECo quite highly. The NRC Staff, in its Systematic Assessment of Licensee Performance (SALP), has given consistently high marks to quality assurance and other construction activities at Limerick. For example, the January 16, 1984 SALP report contains the following overview statement for the Limerick Generating Station:

> The licensee has continued to manage the construction program for Units 1 and 2 well. By providing knowledgeable staffs, and by effectively controlling the Constructor and Architect-Engineer, the licensee has achieved a requisite level of quality. Additionally, the technical knowledge and expertise of the licensee's construction Quality Assurance organization has contributed substantially to the overall effort.

The NRC Staff reached similar conclusions about PECo's licensing activities as exemplified by the following quote from the April 26, 1985 SALP report:

> The licensee's management consistently exercised firm control over the licensing activities performed by its contractors and maintained effective communications between its contractors, its own staff, the NRR staff and the NRR staff's contractors.
>
> The success of the licensee's effort to assure quality is evident in that the many submittals made during this period have been virtually always submitted in a timely manner, have been complete and thorough (requiring very few revisions for correction of errors) and is reflective of a power plant design that is well controlled and verified by licensee personnel prior to submittal to NRC.
>
> The licensee's management and staff have consistently demonstrated a thorough understanding of technical issues. Participation in a variety of industry working groups contributes to this understanding as does the extensive experience of much of the licensee's staff in operating the Peach Bottom Atomic Power Station for more than a decade. The licensee's strengths in this area were particularly evident in the resolution of power systems, electrical and instrumentation systems, and containment systems issues during the rating period.
>
> On occasions, when the licensee deviated from staff guidance, the licensee has consistently provided good technical justification for such deviations. Examples included several fire protection program issues, seismic/dynamic equipment qualification, lifting of leads for surveillance testing and separation criteria for electrical cable trays, panel meters and terminal blocks. The licensee's response to these and other similar issues was virtually always set forth in a technically sound and thorough manner.
>
> A noteworthy aspect of the licensee's performance in this area has been the lack of hesitation to develop and submit additional information and to support meetings whenever required to resolve issues. The licensee has also cooperated with the staff in response to several inquiries related to generic issues (e.g., USI-A45 Decay Heat Removal).

Q. Are there examples of where decisions by PECo resulted in significant cost savings in implementing new NRC requirements?

A. Yes, an effective means by which PECo controlled cost was to anticipate design problems before they became licensing issues for Limerick. An example of this is the decision to change reactor coolant system piping because of experience with intergranular stress corrosion cracking (IGSCC). An option would have been to wait for it to become an NRC requirement. Worse yet, PECo might have chosen to wait for the plant to operate. Then the design change would have become much more expensive. Instead, PECo observed the experience of operating BWRs, correctly sensed the direction that NRC was heading in regulating this area, realized the money that could be saved by an early change, and made the decision to change the piping at Limerick. Subsequently, between 1982 and 1984, a large number of cracks were experienced at BWRs in the U.S. and the NRC issued requirements to resolve the problem before it led to a safety problem.

Not only did the PECo action result in savings of money and worker exposure, but the craftsmen and material were available to do the job. Once the NRC took action on this problem, there was a rush of utilities, both foreign and domestic, to obtain the hardware and craftsmen needed to perform the work. Because of this, there has been delay in

completing the work at other plants. Also, PECo's early initiative in responding to this issue demonstrated to the NRC that PECo was willing to address significant issues in a timely and responsible manner. Such actions serve to enhance PECo's reputation at NRC as a technically sound and well managed utility.

Q. Dr. Mattson, will you summarize your testimony?

A. I have shown how NRC changed its licensing requirements almost continually between the time it issued a CP and the time it issued an OL for Limerick Unit No. 1. The changes occurred in ways and to degrees that could not have been reasonably expected. This is supported by the following:

(1) the NRC issued the SRP in 1975 and backfitted it to Limerick in 1977, issued and backfitted new SRP criteria that affected 55 SRP sections in 1978, then revised the SRP in 1981 and backfitted the revision;

(2) the NRC began to use Generic Letters, Bulletins, Information Notices, and Circulars as additional means of issuing new requirements and issued nearly eight hundred of them from 1974 to 1984;

(3) the NRC issued about 90 new licensing requirements in connection with the accident at TMI-2;

(4) the number of Manual Chapters used by the NRC inspectors increased from eight in 1974 to 547 in 1984; and

(5) the NRC issued and revised 213 Regulatory Guides in the period from 1975 to 1984.

These new requirements led to longer construction times, more equipment, and more complex plants. Increased NRC inspection levels were also imposed upon utilities during this period.

I have reviewed the approach taken by PECo to implement the new NRC requirements and have concluded that PECo was reasonable and prudent. Further, I have reviewed NRC evaluations of PECo management of the Limerick project and, drawing upon my experience at NRC, it is my opinion that these reviews reflect a favorable evaluation by the NRC of PECo's effort.

Finally, I have reviewed the descriptions of NRC mandated design changes and their effects upon the Limerick Project as described in PECo Exhibit 2 and, based upon my experience at the NRC and my knowledge of the requirements involved, find them to be accurate.

Q. Does this conclude your testimony?

A. Yes, it does.

SCHEDULE 1

REFERENCES

(1) Boyd, Roger S. (NRC), letter to Edward G. Bauer, Jr. (PECo), "Subject: Implementation of Staff Review Requirements - Limerick Generating Station, Units 1 and 2," November 20, 1978.

(2) Kniel, Karl (NRC), letter to Edward G. Bauer, Jr. (PECo), "Subject: Documentation of Deviations from the Standard Review Plan - Limerick Generating Station, Unit No. 1 and 2," July 26, 1977.

(3) Rusche, Ben C., "NRR Office Letter No. 2, Subject: Standard Review Plans for Safety Evaluations," August 12, 1975.

(4) - - -, "NRR Office Letter No. 9, Subject: Documentation of Departures from Standard Review Plan," June 18, 1976.

(5) - - -, Memorandum for: R. Boyd, R. Heineman, V. Stello, H. Denton, "Subject,: Revised Procedure for Documentation of Deviations from the Standard Review Plan," January 31, 1977.

(6) U.S. Nuclear Regulatory Commission, NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," Vols. 1 and 2 May 1980; Revision 1, August 1980.

(7) - - -, NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

(8) - - -, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition," July 1981.

(9) - - -,NUREG-0839, "A Survey by Senior NRC Management to Obtain Viewpoints on the Safety Impact of Regulatory Activities from Representative Utilities Operating and Constructing Nuclear Power Plants," November 1981.

(10) - - -, NUREG-0991, "Safety Evaluation Report related to the Operation of Limerick Generating Station, Units 1 and 2," August 1983.

(11) - - -, NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plants, Generic Implications," April 1983.

(12) - - -, NUREG/CR-3028, "A Review of the Limerick Generation Station Probabilistic Risk Assessment," February 1983.

(13) - - -, Regulatory Guide 1.21, "Measuring Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants," Revision 1, 1974.

(14) - - -, Regulatory Guide 1.23, "Onsite Meteorological Program," February 1972.

(15) - - -, Regulatory Guide 1.29, "Seismic Design Classification,: Revision 3, September 1976; Revision 2, February 1976; Revision 1, August 1973; Revision 0, June 1972.

(16) - - -, Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection System," May 1973

(17) - - -, Regulatory Guide 1.46, "Protection Against Pipe Whip Inside Containment," May 1973.

(18) - - -, Regulatory Guide 1.48, "Design Limits and Loading Combinations for Seismic Category I Fluid Components," May 1973.

(19) - - -, Regulatory Guide 1.60, "Design Response Spectra For Seismic Design of Nuclear Power Plants," Revision 1, December 1973.

(20) - - -, Regulatory Guide 1.68, "Initial Test Program For Light-Water-Cooled Nuclear Power Plants," Revision 2, August 1978; Revision 1, January 1977; Revision 0, November 1973.

(21) - - -, Regulatory Guide 1.70, Revision 3, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," November 1978.

(22) - - -, Regulatory Guide 1.75, "Physical Independence of Electric Systems," Revision 2, September 1978; Revision 1, January 1975; Revision 0, February 1974.

(23) - - -, Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants," April 1974.

(24) - - -, Regulatory Guide 1.78, "Assumptions For Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," June 1974.

(25) - - -, Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems For Multi-Unit Nuclear Power Plants," Revision 1, January 1975, Revision 0, January 1974.

(26) - - -, Regulatory Guide 1.93, "Availability of Electric Power Sources," December 1974.

(27) - - -, Regulatory Guide 1.96, "Design of Main Steamline Isolation Valves Leakage Control System For Boiling Water Reactor Nuclear Power Plant," June 1978.

(28) - - -, Regulatory Guide 1.97, "Instrumentation For Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3, May 1983; Revision 2, December 1980; Revision 1, August 1977; Revision 0, December 1975.

(29) - - -, Regulatory Guide 1.100, "Qualification of Electrical Power Equipment For Nuclear Seismec Power Plants," August 1977.

(30) - - -, Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems," Revision 1, August 1977; Revision 0, August 1976.

(31) - - -, Regulatory Guide 1.109, "Calculation of Annual Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance With 10 CFR 50, Appendix I," Revision 1, October 1977; Revision 1, March 1976.

(32) - - -, Regulatory Guide 1.117, "Tornado Design Classification," Revision 1, April 1978; Revision 0, June 1976.

(33) - - -, Regulatory Guide 1.120, "Fire Protection Guidelines for Nuclear Power Plants," Revision 1, November 1977 (Issued for Comment); Revision 0, June 1976.

(34) - - -, Regulatory Guide 1.127, "Inspection of Water Control Structures Associated With Nuclear Power Plants," Revision 1, March 1978; Revision 0, April 1977.

(35) - - -, Regulatory Guide 1.133, "Loose-Parts Detection Program for the Primary System of Light-Water-Cooled Reactors," Revision 1, May 1981; Revision 0, November 1972.

(36) - - -, Regulatory Guide 1.136, "Materials, Construction and Testing of Concrete Containment", Articles CC-1000, -2000, and -4000 through -6000 of the "Code for Concrete Reactor Vessels and Containments," Revision 2, June 1981; Revision 1, October 1978; Revision 0, November 1977.

(37) - - -, Regulatory Guide 1.141, "Containment Isolation Provision for Fluid Systems," April 1978.

(38) - - -, "Title 10 to the Code of Federal Regulations."

(39) Diricks, William, EDO, to Commissioners, "Procedures for Controlling Generic Requirements on Reactor Licenses," SECY-82-39A, USNRC, April 29, 1982

SCHEDULE 2

RESUME OF ROGER J. MATTSON

NAME: Roger J. Mattson

EDUCATION:

1972	University of Michigan, Ph.D., Mechanical Engineering
1966	University of New Mexico, M.S., Mechanical Engineering
1964	University of Nebraska, B.S., Mechanical Engineering

EXPERIENCE:

6/84 - International Energy Associates Limited, Washington, D.C.
present - Vice President, Nuclear Safety and Operations Group

Vice President and Manager of Nuclear Safety and Operations Group, serving clients in industry and government in projects ranging from safety analysis, licensing assistance, quality assurance, plant operations, and systems engineering to energy policy analysis, advanced reactor design, power plant management, and regulatory reform. Current projects of personal involvement include advanced light-water-reactor design and licensing, systems safety review, backfit controls, and organization for nuclear safety assurance.

4/81 to - U.S. Nuclear Regulatory Commission
6/84 - Director of Systems Integration, Office of Nuclear Reactor Regulation

Directed a Division of 175 persons and $10 million of contractual assistance. The Division performed technical reviews of operating reactor license amendments, construction and operating license applications, standardized nuclear power plant designs, and generic safety issues. The scope of the Division included the reactor and balance of plant, including associated electrical and fluid systems and all radiation protection matters.

Developed NRC policy on severe accidents and new plant licensing requirements for future light water reactors; utilized decision analysis techniques for complex generic safety issues; motivated NRC support of international consortium to operate the Loss of Fluid Test Facility; and directed agency task force after the failures of the automatic scram system at the Salem Nuclear Plant in 1983. Also responsible for motivating closure of controversial licensing issues, including: PWR coolant pump trip criteria, emergency procedure guidelines, instruments to follow the course of accidents, anticipated transients without scram, diesel generator reliability, and vital area definition for sabotage protection in nuclear power plants.

Served on NRC's Committee to Review Generic Requirements, represented the U.S. in international forums dealing with reactor safety (including CSNI, France, Germany, and People's Republic of China), and directed NRC's Protective Measures Team for response to accidents at licensed facilities.

8/80 to 4/81 - U.S. Environmental Protection Agency
- Director of Radiation Surveillance and Emergency Preparedness, Office of Radiation Programs

Responsible for developing EPA plans for monitoring and regulating low-level radioactive waste disposal at sea, standards on nonionizing radiation, monitoring of radioactivity in the environment, and response to radiological emergencies. Initiated a technical publications of public awareness program on radiation effects.

7/77 to 8/80 - U.S. Nuclear Regulatory Commission
- Director of Systems Safety (later, Safety Technology), Office of Nuclear Reactor Regulation

Administered a safety review program of essentially the same size and scope as the position described above with the NRC Division of Systems Integration. Work also involved seismic design, materials engineering, chemical engineering, and environmental qualification; radiation protection was, however, outside the scope. Overcame growing and embarrassing staff dissent with a program for recognizing and resolving differing professional opinions.

Initiated several programs including NRC's program for solution of Unresolved Safety Issues and NRC's program and organization for utilization of probabilistic risk assessment and reliability engineering techniques in the licensing review of nuclear power plants. Directed NRC's Lessons Learned Task Force after the accident at Three Mile Island. Developed NRC's Action Plan for responding to the recommendations of the Presidential Commission on TMI and other legislative and regulatory groups that investigated the accident. Served on NRC's Regulatory Requirements Review Committee.

8/74 to 7/77 - U.S. Nuclear Regulatory Commission
- Director of Siting, Health and Safeguards Standards, Office of Standards Development (1975 to July 1977); Assistant Director (1974 to 1975)

Directed a Division of about 60 persons and $5 million of contractual assistance developing regulations and other standards in implementation of the Atomic Energy Act and the National Environmental Policy Act. The scope of the Division included nuclear power plant siting, land use and regional planning, environmental surveillance and modeling, effluent control, emergency preparedness, earth sciences, meteorology, occupational exposure control, radiobiology, and safeguarding of nuclear materials and facilities.

Directed the development of 10 CFR 73.50 and 73.55, the primary federal regulations for safeguarding reactors and special nuclear materials, respectively. Initiated NRC effort at Sandia National Laboratories with a group of industry experts to define specific system vulnerabilities to acts of sabotage in typical commercial power plants. Negotiated an agreement with EPA on 40 CFR 190 to avoid duplication with 10 CFR 50 Appendix I and save NRC and its licensees millions of dollars with no decrease in safety. Managed NRC's implementation of the Federal Water Pollution Control Act. Represented the United States on the Technical Review Committee on Siting under the IAEA's Program for Nuclear Safety Standards, producing the first of a series of international Codes of Practice.

2/74 to 8/74 - U.S. Atomic Energy Commission
- Technical Assistant to Atomic Energy Commissioner William O. Doub

2/72 to 2/74 - U.S. Atomic Energy Commission
- Nuclear Engineer and Section Leader, Reactor Systems Branch, Office of Regulation

Performed thermal, hydraulic, and safety system reviews of nuclear power plant license applications and administered contracts in support of criteria development. Served on panel of expert witnesses, coordinated preparation of testimony, and conducted technical area cross examination in AEC rulemaking to establish criteria for emergency core cooling systems, 10 CFR 50, Appendix K.

9/69 to 2/72 - University of Michigan
- Graduate Student and Research Assistant, Department of Mechanical Engineering

Published a thesis on experiments with nucleate boiling crisis in freon simulating core conditions in large pressurized water reactors. Completed Ph.D. in Mechanical Engineering.

6/67 to 9/69 - U.S. Atomic Energy Commission
- Reactor Engineer, Reactor Technology Branch

Performed technical review of nuclear power plant safety systems and accident analysis.

3/64 to 6/67 - Sandia Corporation, Albuquerque, N.M.
- Technical Staff Member

Designed components for irradiation effects experiments and advanced test reactors and other facilities simulating nuclear

weapon environments. Conducted in-core transient heat-transfer experiments supporting the design of an advanced test reactor, now called the Annular Core Research Reactor.

PUBLICATIONS, SPEECHES, AND TESTIMONY:

Published articles in technical journals, laboratory reports, and government reports from 1966 to present, covering a range from heat transfer and systems engineering to environmental protection and regulatory policy.

Invited to speak on reactor safety, environmental, and safeguards topics before industry, environmental, social, religious, and foreign regulatory groups. Represented NRC on difficult technical and policy subjects with print and electronic media.

Testified as an expert or agency representative before committees of the House of Representatives and the Senate, EPA, NRC, the Advisory Committee on Reactor Safeguards, Licensing and Rulemaking Hearing Boards, state organizations, regional planning commissions, and international organizations.

AWARDS:

NRC Distinguished Service Award, 1980, for work on TMI accident
NRC Meritorious Service Award, 1976, for leadership in standards
NRC and AEC letters of commendation for work on various task forces
Senior Executive Service Bonus in 1980, 1982, and 1983
Nomination for Presidential Rank of Meritorious Executive in 1980, 1983, and 1984
National Science Foundation Research Assistantship, 1971

MEMBERSHIPS:

Sigma Xi (Science)
Pi Tau Sigma (Mechanical Engineering)
Pi Mu Epsilon (Mathematics)
Sigma Tau (Engineering)
American Nuclear Society

SCHEDULE 3

INSPECTION REPORTS AND IE BULLETINS AND CIRCULARS

INSPECTION REPORT	BULLETINS	CIRCULARS
84-01	80-14, 80-17	
84-33	74-08, 75-04 75-04A, 76-06 79-01B, 79-24, 80-02	78-07, 78-08 79-05, 79-20 80-10, 80-11 81-01, 81-06
84-36	78-14, 79-08, 79-10, 79-18, 79-27, 80-24, 81-01, 82-03, 83-02, 84-01	79-11, 80-01 80-18, 80-21
84-49	80-12, 80-25, 83-03	79-18, 80-07
84-65	78-03	

SCHEDULE 4

NRC QUESTIONS
ON LIMERICK FSAR

QUESTION 270.6 (SRP 3.11)

Verify that your EQ program includes, without exception, all Regulatory Guide 1.97, Rev. 2 Category 1 and 2 equipment in a harsh environment which is currently installed or which will be installed prior to fuel load.

QUESTION 280.10

Provide a design description of the types of penetration seals used, including materials of construction. Verify that tests have been conducted to qualify the resistance of the seals in accordance with BTP CMEB 9. 5-1 Section C.5.a. Verify that the seals will be installed in accordance with the manufacturer's instructions.

QUESTION 280.13

Identify those areas of the plant that will not meet the guidelines of Section C.5.b of BTP CMEB 9.5-1 and, thus alternative shutdown will be provided. Additionally provide a statement that all other areas of the plant will be in compliance with Section C.5.b of BTP CMEB 9. 5-1.

QUESTION 410.1 (Section 5.2.2)

Per the requirements of Regulatory Guide 1.70, discuss the relief protection provided to the emergency and auxiliary systems connected to the reactor coolant system.

QUESTION 410.76 (Section 9.3.3)

In accordance with Standard Review Plan Section 9.3.3, Part III, demonstrate that a failure of the non-seismic Category I, non-safety grade portion of the equipment and floor drain system (EFDS) will not compromise the capability for safe shutdown

because of failure of more than one redundant safety related train due to flooding for the following reasons:

QUESTION 420.1 (Section 3.11.2.1.1)

Provide or reference a discussion showing your compliance with the requirements of NUREG-0588.

QUESTION 421.1 (Sections 7.1 thru 7.7)

Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, indicates that duplication of information required be provided in the principal section and referenced in other portions. Several incorrect references are included in Chapter 7.4.2.4.2.1.2 ref. 7.1.2.6.19, Sec. 7.1.2.5.13 ref. 7.7.2.8.3, etc). Review all references in Chapter 7 of the FSAR, provide a list of corrected references and correct the FSAR in a subsequent amendment. In addition, Sec. 7.1 of the FSAR indicates that detailed discussions are provided in Sec. 7.2 thru 7.7 relating to the degree of conformance to applicable design criteria (e.g., Sec. 7.1.2.5.5 references Sec. 7.6); these detailed discussions are in fact not provided. Identify all areas where details are not provided in the list of corrected references and include the detailed information in a subsequent amendment to the FSAR.

QUESTION 421.5 (Sections 7.3 and 7.5)

Standard Review Plan, Table 7-2, TMI Action Plan Requirements for Instrumentation and Control Systems Important to Safety, provides an applicability matrix to various sections of Chapter 7 and referenced NUREGs. General information is provided in Section 1.13 of the FSAR. Discuss the details using drawings as appropriate, of proposed design modifications, status of effort to date and projected schedules for completion of the following TMI action items:

QUESTION 480.7 (Section 6.2.1.1)

Appendix I to SRP Section 6.2.1.1.C provides criteria designed to upgrade the steam bypass capability of the Mark II containment design and to assure that the bypass leakage is not substantially increased over the life of the plant. Provide the following information to demonstrate compliance with Appendix I to SRP Section 6.2.1.1.C:

QUESTION 610.1 (Section 13.2.1.1)

As per Regulatory Guide 1.70, identify by position the personnel to be trained in the plant staff training program.

QUESTION 640.4 (Section 14.2.7.2)

Modify the listing for Regulatory Guide 1.68 to reflect the required revision, Revision 1, July 1978.

QUESTION 640.5 (Section 14.2.7.2)

Add a description of the extent of compliance with testing prescribed by NUREG-0554, "Single-Failure Proof Cranes for Nuclear Power Plants" and NUREG-0612 "Control of Heavy Loads at Nuclear Power Plants" to your statement in 14.2.7.2 regarding Regulatory Guide 1.104.

SCHEDULE 5

THREE TABLES OF METHODS USED BY NRC TO IMPOSE NEW REQUIREMENTS

Table 1

PRINCIPAL MECHANISMS USED BY NRC STAFF TO ESTABLISH OR COMMUNICATE GENERIC REQUIREMENTS TO REACTOR LICENSEES*

Rulemaking(a)

Advanced Notices of Proposed Rulemaking (ANPRs)
Notices of Proposed Rules
Final Rules
Policy Statements

Other Formal Requirements(b)

Multi-plant orders including show-cause orders and Confirmatory Orders

Staff Requirements(c)

Bulletins
Circulars
Multi-plant letters (including requests for affirmations under 10 CFR 50.54[f] and TMI Action Plan letters)
Regulatory Guides
Standard Review Plan (including Branch Technical Positions)
Standard Technical Specifications
Unresolved Generic Safety Issue NUREGs

(a) Although rulemaking is an action of the Commission rather than the staff, rules prepared or proposed by the staff are subject to CRGR review and require EDO concurrence.

(b) Such documents themselves impose a legal requirement, e.g. regulatory orders and license conditions.

(c) Mechanisms that reflect staff interpretations of requirements or regulatory positions that, unless complied with or accomplished in a satisfatory alternative manner, the staff would impose or seek to have imposed by formal requirement.

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* U.S. NRC, "Procedures for Controlling Generic Requirements on Reactor Licensees," SECY-82-39a, April 29, 1982.

Table 2

MECHANISMS OFTEN USED TO ESTABLISH OR COMMUNICATE INTERPRETATIONS OF GENERIC REQUIREMENTS

Actions on Petitions for Rulemaking Under 10 CFR 2.802

Actions on Petitions to Modify, Suspend, or Revoke a License Under 10 CFR 2.206

Approvals of Topicals

Facility Licenses and Amendments

Safety Evaluation Reports

Preliminary and Final Design Approvals

Inspection and Enforcement Manual

Office of Inspection and Enforcement Positions

NUREG Reports (not addressing Unresolved Generic Safety Issues)

Operator Licenses and Amendments

Single Plant Orders

NRC Staff Positions Provided to Code Committees (e.g., ASME)

Unresolved Issues Resulting from Inspections

Table 3

ADDITIONAL MECHANISMS SOMETIMES USED TO
ESTABLISH OR COMMUNICATE GENERIC REQUIREMENTS

Draft or Final Environmental Statements

Entry, Exit, and Management Meetings Between Licensee and NRC Staff

Information Notices

Licensee Event Reports or Construction Deficiency Reports (sent to other Licensees)

NRC Operator Licensing Staff Contacts with Licensees

Phone Calls or Site Visits by NRC Staff or Commissioners to Obtain Information (e.g., conduct surveys, insure about corrective actions or schedules)

Pleadings

Preliminary Notifications

Press Releases

Proposed Findings

Public Meetings, Workshops, Technical Discussions

Routine Contact Between Resident Inspectors and Licensees

Systematic Assessment of Licensee Performance (SALP) Reports

Commission (SECY) Papers (some utilities apparently sent operators to college based upon a SECY paper on operator qualification)

Special Reports

Speeches to Local Groups or Industry Associations

Plant Technical Specifications

Telephone Calls or Meetings with Licensees, Vendors, Industry Representatives, or Owners' Groups

Testimony

SCHEDULE 6

NRC REGULATORY REQUIREMENTS ISSUED THROUGH 1984

Year	Technical Rules(1)	Regulatory Guides	Generic Letters	Bulletins(2)	Information Notices(3)
1971		13		3	0
1972		16		3	0
1973		40		6	0
1974	3/31	27		16	0
1975(4)	1/13	36		8	0
1976	2/30	45		8	7
1977	4/43	46		8	15
1978	2/38	40	28	14	19
1979	2/27	11	55	28	37
1980(5)	2/41	8	57	25	45
1981	2/46	10	40	3	39
1982	3/51	7	39	4	56
1983	2/38	6	44	8	84
1984	3/27	4	24	3	94

(1) Technical rules are defined here to mean changes in NRC regulations affecting nuclear power plant design in a way to affect the capital costs. The first number listed is the number of technical rules made effective that fiscal year; the second number is the total number of NRC rule changes made effective that year.

(2) Before 1975, these were called Regulatory Operating Bulletins; after 1975 they were Inspection and Enforcement Bulletins.

(3) Prior to 1979, these were called Circulars.

(4) The NRC Standard Review Plan, now NUREG-0800, was issued in 1975.

(5) The backfits specifically associated with the accident at TMI were issued in NUREG-0737 in 1980. They totaled about 90 per plant, depending upon the design.

SCHEDULE 7

DEVELOPMENT OF MANUAL CHAPTERS
CONTAINING NUCLEAR POWER PLANT INSPECTION MODULES

	Number of Manual Chapters		
YEAR	ISSUED	REVISED	CUMMULATIVE TOTAL
1970	1		1
1971	1		2
1972	0		2
1973	3		5
1974	3		8
1975	85		93
1976	46		139
1977	81		220
1978	24		244
1979	104		308
1980	103		411
1981	23		434
1982	31	17	465
1983	14	50	479
1984	68	37	547

SCHEDULE 8

NRC STAFFING LEVEL AND LICENSES ISSUED VERSUS TIME

FISCAL YEAR	STAFFING LEVEL	ISSUANCES LWAs	CPs	OLs+
1975	2,006	10	14	9
1976	2,289	21	16	9
1977	2,499	12	10	3
1978	2,723	6	15	5
1979	2,691	0	2	0
1980	3,041	0	0	2 (4)
1981	3,139*	0	0	4 (4)
1982	3,468*	0	0	6 (4)
1983	3,403*	0	0	5 (5)
1984	3,371*	0	0	6 (6)

*Full-time equivalent, FTE, not total personnel.

+Low-power and (full-power) licenses issued each year.

SCHEDULE 9

PLANT CONSTRUCTION TIMES FOR
BOILING WATER REACTORS

PLANT	CP ISSUED	CONSTRUCTION TIME (MONTHS)
LaCrosse	1963	52
Oyster Creek	1964	56
Nine Mile Point 1	1965	52
Dresden 2	1966	48
Millstone 1	1966	53
Dresden 3	1966	53
Quad Cities 1 and 2	1967	70
Browns Ferry 1	1967	79
Browns Ferry 2	1967	87
Monticello	1967	43
Vermont Yankee	1967	71
Peach Bottom 2	1968	72
Peach Bottom 3	1968	77
Browns Ferry 3	1968	77
Pilgrim 1	1968	46
Copper	1968	67
Hatch 1	1969	60
Brunswick 1	1970	81
Brunswick 2	1970	58
Duane Arnold	1970	44
Fitzpatrick	1970	53
Hatch 2	1972	66

SCHEDULE 9

PLANT CONSTRUCTION TIMES FOR
BOILING WATER REACTORS

PLANT	CP ISSUED	CONSTRUCTION TIME (MONTHS)
Fermi	1972	150
LaSalle-1	1973	103
Lasalle-2	1973	123
Susquehanna 1	1973	104
Susquehanna 2	1973	124
WNP-2	1973	135
Shoreham	1973	140
Hope Creek	1974	112*
Limerick	1974	124
Nine Mile Point 2	1974	132*
Grand Gulf 1	1974	132
River Bend 1	1977	102

*No OL issued yet.

SCHEDULE 10

CHRONOLOGY OF REGULATORY ISSUANCES AFFECTING LIMERICK

END OF YEAR	PERCENT CONSTRUCTION COMPLETE	NRC ACTION
12/70	-0-	
1971	-0-	
1972	-0-	Reg Guides 1.29, Rev. 0, and 1.133, Rev. 0 issued.
1973	Limited site work	Reg Guides 1.29, Rev. 1; 1.45; 1.48; 1.60, Rev. 1; and 1.68, Rev. 0 issued.
1974	Not Available	Reg Guides, 1.21, Rev. 1, 1.76, 1.78, 1.81, and 1.93 issued. CP issued.
1975	19	Reg Guides 1.75, Rev. 1, 1.81, Rev. 1 and 1.97, Rev. 0, issued. SRP backfit to Limerick via NRR Office Letter No. 2

SCHEDULE 10 (cont.)

CHRONOLOGY OF REGULATORY ISSUANCES AFFECTING LIMERICK

END OF YEAR	PERCENT CONSTRUCTION COMPLETE	NRC ACTION
1976	28	Reg Guides 1.29, Rev. 2; 1.96; 1.108, Rev. 0; 1.109, Rev. 0; and 1.120 issued. NRR Office Letter No. 9 issued.
1977	40	Reg Guides 1.97, Rev. 1; 1.100; 1.108, Rev. 1; 1.109, Rev. 1, and 1.127, Rev.0 issued. Karl Kniel Letter backfitting SRP to Limerick sent to PECo.
1978	48	Reg Guides 1.68, Rev. 2; 1.70, Rev. 3; 1.75, Rev. 2; 1.127, Rev. 1, and 1.36, Rev. 1 issued. NUREGs 0460, Vol. I, II, and III; and 0487 issued. Roger Boyd letter backfitting 35 Reg Guides, 4 BTP, and new or revised SRP/criteria affecting 55 SRP Sections sent to PECo.

SCHEDULE 10 (cont.)

CHRONOLOGY OF REGULATORY ISSUANCES AFFECTING LIMERICK

END OF YEAR	PERCENT CONSTRUCTION COMPLETE	NRC ACTION
1979	57	Reg Guide 1.136, Rev. 1 issued. NUREGs 0554; 0578, and 0588 issued.
1980	60	Reg Guide 1.97, Rev. 2, issued. NUREGs 0460, Vol. IV; 0487, Supplement 1; 0612; 0619, Rev. 1; 0654; 0696; and 0737 issued.
1981	69	Reg Guide 1.133, Rev. 1 and 1.136, Rev. 2 issued. NUREGs 0700; 0763; 0783; and 0808 issued. SRP revised.
1982	83	NUREG-0802 issued.
1983	92	Reg Guide 1.97, Rev. 3, SER; DES; and ACRS letter issued.
mid 1984	98	OL issued

ORIGINAL

PECO STATEMENT NO. 10

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION v.
PHILADELPHIA ELECTRIC COMPANY,
Docket No. R-850152

DIRECT TESTIMONY OF
WILLIAM A. ABRAMS

LIMERICK 1 AND COMMON PLANT
FINANCIAL MANAGEMENT

SEPTEMBER 27, 1985

DOCKETED
SEP 27 1985

PHILADELPHIA ELECTRIC COMPANY

DIRECT TESTIMONY OF WILLIAM A. ABRAMS

Q. Please state your name and business address.

A. My name is William A. Abrams, I am Group Vice President of Duff & Phelps Inc., 55 East Monroe Street, Chicago, Illinois.

Q. Describe briefly your educational background and business experience.

A. I received a Bachelor of Science of Commerce degree from Loyola University (Chicago, Illinois) in 1951, majoring in business administration.

From 1951 through 1957, I worked for several firms in industry. I was responsible for various phases of credit analysis and approval for Walter E. Heller Company and Steel Products Engineering Company, Inc. In 1953, I joined Uniroyal, Inc., where I was involved in sales administration, contract cancellation negotiations, production coordination, forecasting and accounting.

In 1958 and 1959, as a principal of Curran, Bayliss & Glasgow, Inc., a management consulting firm, I performed analyses of and made recommendations for improvement of client internal operational systems, evaluated merger-acquisition situations, and consulted on financial planning. From 1960 until 1967, I was engaged in corporate finance, initially as Assistant to the President of Hyman-Michaels Company and subsequently with Benjamin Lewis & Company, investment bankers. I was responsible for negotiating large railroad and other types of equipment lease transactions financed by private placement with institutions, merger-acquisitions, private corporate financing and municipal bond underwriting.

I joined Duff & Phelps in 1967 as a senior financial analyst to

perform special company valuation studies and to analyze the securities of companies principally in the electric equipment industry. From 1969 to the present, I have been in our Utility Research Division. Until 1980, my primary responsibilities had been to analyze a group of individual utility companies particularly in California, the Mid-West and the East Coast. My work included analysis of the earnings potential of these companies, their financing requirements, coverage ratios of interest and preferred dividends, and the cash coverage of the common dividend. From 1974, I was also Chairman of our Utility Fixed Income Rating Committee. I regularly consulted with and advised our clients on public utility fixed income and common stock investment and was a member of the Senior Officer Committee, which reviews and finalizes the Duff & Phelps' Regulatory Rankings.

Since 1980 my responsibilities have been entirely with the Duff & Phelps' Fixed Income Rating Service. I am Vice Chairman of the Duff & Phelps' Fixed Income Rating Committee. As a member of this Committee, I participate in interviewing and analyzing companies and assigning ratings to their fixed income securities.

Q. Have you testified in other regulatory proceedings?

A. I have testified before the California, Michigan, Minnesota, New York, North Carolina, Maine, Mississippi, Nevada, Kansas and Indiana Commissions, the Georgia Legislative Committee on Utility Regulation, and before FERC on the subjects of rate of return, financing, and factors affecting credit ratings.

I have lectured on rate regulation, utility financing, and the analysis of public utility companies and their securities to classes

of graduate students at Northwestern University and as guest faculty member for the Executive Development Center seminars sponsored by the University of Illinois and the University of Notre Dame. I have given speeches and served on panels on utility matters before investor, utility, and expert witness groups; the PUR Financial Conference; Edison Electric Institute conferences; the Iowa State University Regulatory Conference; Merrill Lynch Capital Markets seminars; and the Society of Rate of Return Witnesses. I write articles on utility related subjects for publication in "Credit Decisions," a weekly credit review published by Duff & Phelps.

Q. Are you a chartered financial analyst?

A. Yes. On the basis of my experience and a series of written examinations, I was awarded the professional designation of Chartered Financial Analyst by the Institute of Chartered Financial Analysts in 1971.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Investment Analysts Society of Chicago; the Fixed Income Group of the Chicago Society; and the Utility and Telecommunications Securities Club.

Q. Please describe the business of Duff & Phelps.

A. Duff & Phelps is a large independent investment research organization. The utility division of Duff & Phelps is retained in a professional advisory capacity for advice and consultation on investments in public utilities' securities by more than 250 financial organizations. Our clients include the following types of investors: insurance companies, banks, trust companies, mutual funds, universities, and pension and retirement funds. In addition, we have as clients a

number of investment counseling and securities firms. Thus, directly and indirectly, Duff & Phelps provides independent, objective, professional investment research to a very large cross section of investors of all types. For the purpose of providing our clients with information concerning investment risks, we have for many years rated the fixed income securities of utility, industrial and financial companies. Since 1980, our ratings have been public. In developing these ratings and the factors which influence them, it is our purpose to focus on those factors we consider to be related to risk. Duff & Phelps does not act as broker, dealer, or underwriter of securities.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents my views and those of Duff & Phelps respecting the financial condition of the electric utility industry in the 1970s, the causes of the degrading of the industry's financial condition and the similar experience of Philadelphia Electric Company (PECO) during that period. Further, against the background of the previously presented financial data, I will present my and Duff & Phelps' views about the reasonableness and necessity of the Company's 1976 and 1978 decisions to reduce its capital expenditures from the point of view of the effect of those decisions upon its financial condition and risk. I also will present my judgment as to whether the Company could have raised in excess of $1.0 billion additional capital during the period 1976 to 1981, that amount of capital being the amount which I am advised by the Company would have been required to permit advanced Limerick Project completion absent substantial additional rate relief.

Q. How have you organized your testimony?

A. I begin with a description of how Duff & Phelps evaluates the

financial integrity of electric utilities and then describe the factors which control our assignment of credit ratings. As part of this discussion, I explain the effect which regulation and its decisions respecting specific issues of importance to the investment community has upon those evaluations.

Next, I describe the financial condition of PECO and the electric industry in the 1970s, the substantial forces which changed that condition adversely and the effect of those changes upon investors' perception of the industry.

Finally, I present my and Duff & Phelps' evaluation of PECO's decisions in 1976 and 1978 to reduce its capital expenditures and of whether the Company could have raised the additional capital needed to permit an earlier plant completion.

Q. How do you define financial integrity?

A. Financial integrity refers to the soundness or stability of the enterprise. This means the ability of the business to resist downward financial pressures and the existence of sufficient buffers from unexpected adverse developments so that any distortions can be quickly remedied without impairing either the orderly conduct of the business or the credit quality of the outstanding and future fixed income securities. In other words, we examine the stability and protection of the income stream. It also means the assurance of confidence in the earnings return potential of the enterprise so that capital -- both debt and equity -- can be attracted on a reasonable basis.

Q. What analysis is made to ascertain the financial integrity of a utility company?

A. There are two parts to any analysis of a utility company to determine

its financial integrity. The analysis is both qualitative and quantitative.

Qualitative aspects for an electric utility (on both a current and prospective basis) include the viability of the service area (jobs, industrial diversification, sales outlook, state and local government policies); power supply (reserve margins, age of units, purchase power sources); fuel supply (diversity, cost, availability); regulatory principles (extent of recognition of operating costs, capital costs and cash flow needs, and consistency); management (recognition of problems and development/implementation of solutions, depth); quality of earnings (cash generation), and quality of balance sheet (capital structure, off balance sheet financing, liquidity).

To quantify the financial protection, certain measures are used. For example, we look for coverages, principally excluding AFC, to be steady within a range appropriately reflecting other risks to which the business is exposed. The capital structure must contain sufficient equity support to protect the senior securities. The forward construction program and other funds needs relative to the size of the company are examined to ascertain whether the required capital growth rate will be a strain. Returns allowed and earned must be sufficient to attract capital for the ongoing needs of the company.

Q. Are credit ratings based just on historical data, or are ratings also determined on the basis of anticipated results?

A. The historical financial record of a company and its current status are certainly important to demonstrate how a company has been run, how it has been regulated, and how its problems have been solved. A company with a long record of poor financial performance generally

must demonstrate a long period of sustained improvement before it will be upgraded. This is in contrast to a company with good financial stability that experiences a temporary dip in performance which is quickly corrected.

Business characteristics interact with financial standards, and where there are unfavorable business characteristics, there must be offsetting financial protection. Conditions external to the company can add to risks.

The history of the company is studied to give some perspective to the future. The past record gives credibility to future assumptions. That future view must recognize to what extent ongoing conditions are apt to be different from the past. Naturally, the longer the future period the less clear is the picture. The rating agency attempts to forecast the safety or absence of major problems of quality deterioration over the next year, the next three years, the next five years, etc. It calculates, for example, whether a company can attract from the market the money it will need to finance its construction commitments, or to meet other funding requirements such as debt maturities while achieving or maintaining coverages and other financial ratios satisfactory for its particular quality rating.

Q. What is the role of regulation in the financial integrity of a utility?

A. Investors, investment advisors, and rating agencies such as Duff & Phelps regard regulation as a key factor in assessing a utility company. A utility's financial condition is assessed on many bases all of which are related to the ability of the company to earn a realistic rate of return, the cash quality of those earnings, the

stability of earnings trends, and moderation of the company's need to finance externally. Important considerations are the allowed rates of return; proper recognition of test year sales, expenses, and rate base; the relationship of the test year and timing of the rate increase to the period when those rates will be in effect; and, the recovery of capital. Built into these considerations are the mechanisms in place which enable rates to be adjusted to recognize swings in major costs which might not be capable of accurate forecasting. An example is the fuel clause and the timeliness of its operation. To the extent that rising fuel costs are not offset in their entirety or in a timely manner, business risk is increased and financial risk must be decreased. This requires a stronger capital structure (higher common equity support), and a higher level of interest and preferred stock coverage to maintain the financial integrity of the company. All of these items must be considered in rating a company.

Q. Why is the recognition of rate base considered important by investors?

A. Unlike most other industries, the utility company is required by its franchise to meet the demand of its territory. The plant it builds is highly capital intensive relative to the revenue it can generate. Construction lead time for generating plant is long. The plant is not multi-use, and cannot itself be sold or transported into different markets, although its energy output may be sold. Plant is built under these long lead times based on projections of customer demand growth. Projections of growth are based on past trends and best intelligence of future outlook. Plant also may be started (or built) to diversify fuel sources (e.g., away from oil/gas) and, of course, to

replace aging units. Further, in many cases, the plant must be designed of a size that results in extra capacity when the unit goes into service. Substantial funds must be expended for preliminary engineering, environmental studies and various regulatory approvals before ground is even broken.

A radical decrease in demand patterns can occur during the construction phase. Also, other outside changes can alter the economic feasibility or even prevent the completion of the unit. For example, inflation, rapidly rising capital costs and mandated design changes of the past half-dozen years have raised the cost of nuclear plants far beyond initial estimates. Political opposition may also develop to oppose a construction project on environmental grounds.

If recovery of cost and a return on capital investment in a plant is not permitted, investors will be loath to put new money into utilities in that state. Ratings will reflect the added risk and any funds which may be available for future service of the ratepayer will be at higher cost. Given the importance of the rate base issue in today's investment environment and typical utility involvement with large construction work in progress balances, unfavorable Commission action on this issue alone can precipitate downgrades which cannot be reversed for many years.

Q. Are the investor and the rating agency concerned with utility cash flow and regulatory position on issues which could enhance cash flow in their appraisal of the financial integrity of a utility company?

A. Yes. For example, a current cash return on CWIP is very important. The debt holder is concerned about the protection (coverage) of the company's interest obligation. As mentioned above, interest must be

paid in cash, not AFC which is a non-cash credit. Therefore, to what extent CWIP is included in rate base or some other form of current rate support for construction is provided became, in the early 1970's, one of the key factors considered by Duff & Phelps.

If no current "cash" rate support is provided, increased CWIP balances cause a wider spread between coverages including AFC and coverages excluding AFC. When this happens, investors realize that a large proportion of their utility investment is not earning a cash return and the cash protection of interest payments is less. The financial integrity of a utility company becomes weaker as its non-earning assets become larger unless a compensably higher return is achieved on the earning assets. Investors recognize that where regulatory bodies permit no cash earnings on investment under construction, the financial integrity is in jeopardy and, for that reason, tend to regard such companies as having more risk than would otherwise be the case.

To the extent plant under construction is not in the rate base with a revenue return, the total cost of the plant increases, and higher rates must be charged when the plant goes into service.

Q. You earlier mentioned that debt holders are concerned with the protection of interest obligations as measured by coverages. How does Duff & Phelps assess coverages?

A. Coverages can be calculated on a pre-tax or on an after-tax basis. These are also considered including or excluding AFC. Duff & Phelps uses pre-tax coverages excluding AFC as the primary indicator. Major non-cash earnings effects from accrued revenues and/or expense deferrals are also considered.

Q. Can you explain why this is so?

A. Yes, I would like to explain why we consider coverages excluding AFC as the primary indicator. AFC is an accounting method which recognizes that the capital costs of debt and equity used during construction are part of the total cost of building plant to serve the utility's customers. Thus, these costs have to be added to the construction work in progress asset which ultimately becomes rate base. To accomplish this, reported earnings are credited (increased) by AFC based on a formula designed to compensate for the equity and debt funds used each year for construction. For each accounting period, the amount of AFC increases retained earnings on one side of the balance sheet and the CWIP account on the other side of the balance sheet. The AFC is also compounded. By this, I mean that AFC builds upon AFC as well as on labor and hardware costs during the construction period. The expectation is that the company will earn a future return on the accumulated AFC when the construction project is completed, put into rate base, and is allowed a revenue return. AFC is then depreciated as part of the total plant account.

I said above that AFC is an accounting treatment. There are accounting treatments to record all of a company's transactions. The fact that an accounting treatment is correct from a recording standpoint does not mean that the event or business condition it is recording is desirable. An example I have used is that there is an accounting treatment to record uncollectible accounts receivable. While uncollectible receivables are a fact of business and they must be accounted for, they are not desirable. The larger they are, the less desirable the condition of the company. My point in this example

is that the financial condition which underlies the accounting treatment is what must be analyzed in determining a company's financial integrity.

Until recent years, it was never thought that non-cash earnings would reach the proportion of reported earnings that it has today nor that it would continue as a major part of earnings for such an extended period of time. This condition has been brought about by several factors:

1. the inflation rate (actual and anticipated) which has raised the cost of all capital;
2. the inflation rate and government regulations which have increased the cost and extended the completion time of plant; and,
3. the inadequate levels of earned returns on operations.

The real world expects to be paid in cash. No company can operate for long without impairing its financial integrity when major and ever-increasing portions of its reported earnings are composed of non-cash, bookkeeping entries. The utility company must pay dividends and interest in cash. It has to pay its contractors on a construction project in cash. So, too, it must have cash to pay its suppliers of fuel, its labor, and its taxes. It takes cash to carry the company's accounts receivable. When that cash is not earned, the company has to enter the capital markets for the cash to pay its bills and honor its construction commitments. This process increases capital costs, increases AFC, and reduces real earnings.

Recognizing that interest has to be paid in cash, we use the pre-tax coverage of interest excluding AFC to measure the protection

which cash earnings provide to the debt holder. In our assessment of reported coverages, we also consider deviations caused by major non-cash earnings produced by various revenue accruals, expense deferrals, and off balance sheet obligations.

Q. What were the investor views of the Electric Utility industry during the 1970's when Philadelphia Electric elected to delay the Limerick Nuclear station?

A. Investors were concerned with a number of basic fundamental changes which had and were continuing to affect the electric utility industry.

1. Rapidly rising operating and capital costs.
2. Regulatory changes.
3. The economy and electric utility sales prospects.
4. Financial deterioration.

Q. Could you describe the trend in operating and capital costs?

A. Yes. Through the mid-1960's, the electric utilities were a declining cost industry. New technology and economies of scale enabled the industry to effect unit price reductions. Of course, this had the effect of contributing to sales growth which, in turn, lowered capital costs per unit of Kwh. From 1960 to about 1965, the industry "rode down the reserve" as sales grew rapidly into available capacity.

In the mid-1960's a new building program was initiated by the industry. This was done in response to the outlook for continued rapid sales increases and the national concern for low reserve margins which was highlighted by the New York City blackout of 1963. Remember that, in the 1960's, the industry still had in service many "tea kettles", generating units from the 1920-1940's that were small, relatively inefficient, and aging.

As this new building program got underway, the national economic conditions began to change. Inflation accelerated, and interest rates responded to actual and anticipated inflation, to the rising trend of government and corporate borrowings, and to the surge of electric utility company financings.

In the second half of the 1960's, there developed a national and local concern for the environment. The utility companies, encouraged by price and need to reduce coal emissions, converted older coal units to oil and built large, new oil units. However, by the late 1960's, low sulphur oil was mandated in many areas. This type of oil was in shorter supply, and the higher price drove up fuel costs in the late 1960's and early 1970's. The 1973 Arab oil embargo was a major shock to operating expenses. The quantum oil price increase in 1973-74 was followed by a complete revamping of fuel pricing. Thus, gas and coal followed oil in the upward spiral through 1980. Through this same period, the use of low sulphur coal or scrubbers was mandated, further driving up operating and capital costs.

Of the 95 major U.S. electric utility companies, about 70 became involved in nuclear power plant construction. The capital costs of these units were large relative to imbedded capacity, and grew rapidly with NRC changes and licensing delays.

Q. What regulatory changes affected the electric utilities through the 1965-80 period?

A. The principal regulatory changes occurred in three areas of regulation.

1. Environmental

2. NRC

3. State regulation and FERC

These areas are not entirely separable because the costs imposed by environmental agencies and the NRC must be faced by the state regulatory commissions and the FERC.

In the late 1960's, the national, state, and local concerns for the environment exploded. As mentioned above, SO_2 restrictions locally mandated higher cost fuels and, in many cases, scrubbers. This required higher cost fuel (and/or fuel transport costs) and also reduced the utilities' ability to bargain as successfully in negotiating for fuel supplies. Scrubbers added to capital costs and reduced plant efficiency. So too did environmental impact studies and plant siting requirements. In 1978, the Power Plant and Fuel Use Act moved to set priorities for so-called premium fuels with the electric utilities the lowest priority.

At the same time, nuclear concerns (indeed, anti-nuclear sentiment) surfaced. This led to more and more stringent NRC safety requirements, plant retrofit, redesign and construction delays. Of course, the 1979 TMI incident served to multiply NRC changes for plants nationwide.

These environmental and NRC changes were made with no concern to capital cost or economies of operation. Of course, the bread basket of higher expenses (environmental, NRC, rate base additions, operating and capital) came home to the regulatory commissions in the form of rate requests.

My perception of the state regulatory bodies is that they were ill prepared to handle the surge of rate increase requests that began in the late 1960's. Most important initially were rate lag and

recognition of inflation and cost of capital. Schedule 1 shows the rise in rate cases filed and decided from 1970-80.

Rate cases took one to several years to decide. Most test periods adopted were historic and did not reflect the ongoing rate of inflation. The regulators generally took the position that, even though inflation existed in the test year, it would stop. Similarly, although the cost of money was demonstrably higher in the test year and at the time of the order, regulators tended to look backward. Thus, allowed rates of return were lower than the true cost of capital.

Similarly, the regulators refused to recognize the burgeoning cash needs of the electric utility industry. The quality of earnings became an ever more important issue as the industry struggled to raise depreciation rates, utilize deferred accounting for income tax benefits, and obtain a revenue return on construction work in progress.

Investors had come to realize that the utility companies could not pay their bills with ever mounting AFC credits. These concerns were evident in the drop of the industry's P/E multiple which peaked at 24.7x's in 1961, slipped to 22.7x's in 1964, then dropped to 18.8x's in 1966, and trended downward from 16.3x's in 1967 to 11.9x's in 1972. When Consolidated Edison of New York passed its dividend in March 1974, the investor focus on cash intensified and solidified. The industry P/E multiple dropped to 6.4x's. The industry decline resulting from the Con Ed dividend action was exacerbated by the 1973 oil embargo and the ensuing quantum jump in fuel prices. Investors and their advisors began to calculate interest coverages and dividend

coverages excluding AFC. These data are shown in my Schedule 2.

Rate hikes to cover fuel cost increases (even though some states deferred increases thereby exacerbating the cash problems of the companies) focused greater public and media attention on the utilities. Investors became increasingly concerned whether rate treatment would be adequately responsive. At the same time, various interest groups pushed conservation, alternate energy, no growth scenarios casting a public pall on the concept of new central station generating plants. Regulation in some states reacted by delaying rate cases, switching to elected commissions, abandoning fair value principles, and generally opening hearings to more intervenor groups. Rate design was changed to promote conservation, minimize residential price increases, and often to reduce sales.

It took until the late 1970's for regulation in general to gear up to the press of a far larger number of rate case filings (annually for many companies), to recognize more nearly the cost of money, to update test years, and to provide measures to help halt the erosion in earnings quality.

Q. Did the economic conditions from 1965-80 affect investors' concerns about the electric utilities?

A. Yes. Certainly the persistence of inflationary trends was recognized as having an adverse impact on the capital intensive electric utility industry. Many major investors got out of utility equities. Lower quality securities became more difficult to sell. Some companies avoided (by recourse to banks, for example) selling debt which might lead to a debt rating downgrade.

Q. What was the electric utility industry's performance during this

period of turmoil?

A. The table of selected financial data (Schedule 3) shows the following: Debt ratios slowly began to retreat from the 1970 peak level of 57.1%, reaching the 52% to 53% range by 1978-80 which was the approximate ratio during the early 1960's. Annual capital growth expanded rapidly from 12% in 1970 to 14.2% in 1974. This measure eased in 1975-78 as the industry completed, cancelled, or delayed plant construction.

Average debt interest costs increased steadily with steady borrowings at new debt rates above imbedded rates. Thus, this measure increased from 5.3% in 1970 to 9% by 1980. Returns earned on common equity held near 12% until 1974 when fuel prices and far higher capital costs drove the return down to 10.4%. This measure partially recovered in 1975 and fluctuated upward to 12% again in 1980.

AFC steadily rose, reaching 53% of balance for common by 1980. The income tax rate, a composite measure of earnings quality, declined steadily in 1970-74 as AFC rose. This measure improved for several years through 1978 with increased provisions for income tax deferrals; the subsequent decline reflected the big increases in AFC relative to earnings.

In this environment, coverages excluding AFC declined steadily from 3.1x's in 1970 to 2.2x's in 1974. A four-year partial recovery was reversed in 1979 and coverages returned to 2.2x's in 1980.

The performance of the industry common stock capsulized the attitude of the investor during this period. Thus, the market to book ratios (which were 200 to 280 from 1960-68) had declined to 163 in 1970. The drop to 102 in 1973, as a result of the oil embargo in the fall of that year, was shortly followed by Consolidated Edison of NY

passing its dividend. This action crystalized in the investors' minds the underlying cash strain problems of the industry and the market to book ratio fell to 70. Except for several years again near unity, this ratio retreated in the late 1970's as inflation and interest rates expanded, with the sharp fuel price hikes again in 1979 and (for nuclear companies) the 1979 TMI nuclear accident.

Q. Can you describe Philadelphia Electric Company as it existed in 1970?

A. Yes. Philadelphia Electric entered the 1970's with low reserve margins and sales and peak load growth which, though below the industry average, was high for a mature territory. In 1970, 51% of generating capacity was oil fired. In that year, 56% of the energy generated was by oil.

Q. What was the financial position of Philadelphia Electric Company from 1970 through 1980?

A. The financial position of Philadelphia Electric Company can be quickly ascertained by reviewing certain financial ratios shown in my Schedule 4. Comparison of these data with similar data discussed earlier for the Industry (Schedule 3) gives a perspective of how Philadelphia Electric compared with the Industry in those years.

As with many companies in those years, Philadelphia Electric was pressured to build for unexpectedly rapid growth and for fuel diversification. As noted above, Philadelphia Electric in 1970 derived 56% of its generation from oil.

This building program accelerated rapidly in the late 1960's so that capital growth by 1970 was very heavy at 16 1/2%, more than one-third greater than the Industry average of 12%. Capital growth for the company remained far higher than the Industry through 1973 and was

comparable to the Industry peak in 1974. In the years 1975-80, the Company's capital growth rate was below the Industry average. Average interest cost approximated the Industry through 1973, but gradually increased faster than the Industry so that the Company's debt interest cost in the late 1970's was 50 to 70 basis points higher than the Industry average.

With the strain of construction financing and sub-par returns, Philadelphia Electric's coverages excluding AFC deteriorated rapidly. Thus, they fell from a respectable 4.3x's in 1967 to a very sub-average 2.2x's level by 1970. After a brief and small upturn in 1971-72, coverages resumed their downturn reaching 1.5 times in 1980. Adjustment for non-cash deferred fuel cost accounting showed even more serious deterioration in 1974 and 1979 to 1.6 and 1.2x's, respectively.

Rate relief granted through this period was inadequate to sustain returns near industry levels. In part because of the Company's large oil dependence, fuel cost increases commanded 2.63¢ of the total 1970-80 increase in revenue granted per Kwh. Capital costs including return and all other expenses accounted for only 1.91¢ of the total 4.54¢ increase. With regulatory lag and rate case delays, the earned returns for Philadelphia Electric were low throughout the period. In 1970 and each year 1973 through 1979 (a total of eight years), the return was under 10%. In only one year did the return exceed 11% (1967 @ 12.2%).

Q. Please now present your and Duff & Phelps' evaluation of the reasonableness and necessity of PECO's decisions in 1976 and 1978 to reduce its capital expenditures?

A. In 1976, PECO announced a delay in the completion of the Limerick station by 2 years. The 5-year, 1975-1979, construction forecast was lowered by $504 million to $2.080 billion. Similarly, the 1978 delay announcement again lowered the 3-year 1978-80 forecast by $88 million to $1.278 billion.

It was not uncommon for utilities to reduce construction expenditures during the 1970's. This was especially true of companies that were financially strained and/or where load growth forecast changes suggested later need for the plant. Examples of utilities which adopted this course of action are provided in Schedule 5.

As I explain further below, it is my and Duff & Phelps' opinion that the investor climate for utilities and the financial fundamentals of PECO during the 1974 to 1980 period necessitated this action.

Q. What was Philadelphia Electric's construction program through the 1970's?

A. Schedule 6 shows the 1970-80 Sources & Uses of Funds Statements for Philadelphia Electric. Major projects through the early 1970's were the Peach Bottom units, the Salem units, and the Eddystone units. Internal cash generation was low and annual external financings ranged from $300 million to $500 million in 1970-75. These were large sums for a company with 1970 capitalization under $2 billion, especially when there is no respite. The Company's 1975 forecast showed the same pattern in 1975-79 when $320 to $523 million in annual financings were forecast. This is shown on Schedule 7.

By contrast, with the cuts in construction requirements, actual financings in 1975-79 ranged from $235 million to $370 million. This was shown earlier in my Schedule 6. The level of the reduction of

construction expenditures is set forth on my Schedule 7 and varied from approximately $50 million to $270 million annually.

Q. What was Duff & Phelps' opinion of Philadelphia Electric's construction burden through the 1970's?

A. We were concerned. In our reports on the Company from 1970 through 1980, we noted the large construction budgets, high early 1970's capital growth, the late 1970's changes in this pattern, and the Limerick deferral announcements in 1976 and 1978. Excerpts from these reports are included as Schedule 8.

Q. Referencing these Reports, please provide a further description of Duff & Phelps' evaluation of PECO's financial integrity and assignment of security ratings in the mid to late 1970s, pointing out specifically the effect, if any, which the Company's construction expenditure cuts had upon those evaluations?

A. In these Reports, in explaining the basis of our evaluation of PECO securities, we emphasized pre-tax coverage excluding AFUDC, the size of the Company's construction and external financing program and the responsiveness of Pennsylvania regulation to its rate requests. For example, in our September 30, 1976 Fixed Income Summary, we specifically noted that "Construction forecasts have been revised downward" and that internal funds were expected to provide a greater percentage of future construction requirements. We further noted, as a significant basis of our rating assignment, that "a moderating trend in capitalization growth and in external financing", along with annual sales of common and adequate rate relief, would produce "satisfactory" earnings protection for senior securities in the future.

In our September 27, 1977 Fixed Income Summary, we further

noted:

> "Our ratings reflect the easing of pressures associated with financing of the construction program over the near term. Capitalization growth is expected to be well below the D&P Average through 1979. However, with below-average kwh sales growth forecast for the territory combined with limited growth prospects in the gas area, the Company will still be dependent on periodic rate relief."

Throughout the remainder of 1977 and early 1978, our Summaries continued to refer to the Company's "manageable" and "below average" construction program as a major basis for maintaining the Company's assigned security ratings, i.e. our categories 7 and 8. However, in September 1978, we reduced the Company's ratings for reasons I will describe below.

As noted above, in each of our Fixed Income Summaries and in our Basic and New Financing Reports, we noted, as a major factor in our ratings assignment, our evaluation of Pennsylvania regulation and the results of recent Company rate decisions. During the 1974 to 1980 period, our evaluation of Pennsylvania regulation was average to slightly below average, with the latter evaluation applying in 1976 and 1978. In our September 21, 1978 Basic Report, we reduced the Company's common stock security ratings and stated the following reason:

> "We are lowering our qualitative rating of the Company from D&P-II to D&P-III because of the deteriorating Pennsylvania regulation and the diminished financial flexibility of the Company."

At that time, we noted that:

> "Further generating additions have been rescheduled to 1985 and 1987, thus easing financing pressures in the early 1980s. Combined with adequate rate relief, this could allow for some restoration in per share earnings and returns in the intervening years."

However, we concluded that a downgrading was necessary for the following reasons:

> "We currently rate Pennsylvania regulation in our Group IV category. Recent Commission actions point to a deteriorating atmosphere and this ranking will be carefully reviewed upon receipt of several expected forthcoming orders...
>
> ...Overall, we concluded the Company has been unable to secure rate relief in sufficient amounts on a timely basis...
>
> Earnings for the 12 months ended July 31, 1978 were $1.65 which compared with $2.08 for the prior similar period on 8% additional average shares. The decline principally reflected a full year's operation of the Salem nuclear Unit No. 1 with little offsetting rate relief. As mentioned earlier, the Commission permitted an $11.9 million interim increase amounting to less than 1% of revenues, to become effective April 4, 1978, subject to refund. We anticipate the final order by year-end 1978...
>
> Our expectations for the balance of 1978 are for continued earnings attrition until significant rate relief becomes effective.... Thus, we estimate 1978 earnings at $1.55 per share. The Company has announced deferment of the Common stock offering previously planned for fall of 1978. Based on 7% additional average outstanding shares, a return of around 8.2% on average Common equity is indicated.
>
> The most important factor affecting the level of earnings in 1979 will be the amount of rate relief obtained. The Company will be burdened by costs associated with the installation of the second Salem nuclear unit which is anticipated to be placed in commercial operation at mid-year....Assuming $90 million of rate relief initially reflected during the year, 5% more average shares, and higher financing costs not offset by AFC, we estimate 1979 earnings at $1.80 per share. This estimate would produce a return of about 9.5% on average Common equity."

In our prior ratings of the Company, as reflected in our New Financing Report of September 27, 1977, we had maintained the Company's higher rating in light of our ranking of Pennsylvania regulation as Group III (i.e. average), our perception of the easing of financing pressures due to the 1976 capital expenditure reductions and our expectation of receipt by the Company of adequate and timely

rate relief. We expressed our basis for this expectation in the New Financing report as follows:

> "Per share earnings for the 12 months ended July 31, 1977 were reported at $2.08 versus $1.84 for the similar prior period and $1.91 for calendar 1976. Earnings for the 12 months ended July 1977 benefited principally from an increase in AFC of $10 million since year-end 1976 and rate relief. A slowdown in financing cost increases was also a positive factor. However, as a result of commercial operation of the Salem nuclear unit at June 30, 1977, AFC will begin to decline $2 million monthly and depreciation will rise $900,000 monthly; other fixed charges relating to this generating addition will increase. Less rate relief will also be effective for the balance of 1977. A small offset will be the nuclear fuel savings. Overall, we expect some attrition in per share earnings for the balance of 1977 and until rate relief is received. Thus, we are maintaining our 1977 earnings estimate of $2.00 per share on 8% additional average outstanding shares which equates to a 10.3% return on average equity.
>
> For 1978 our estimate is $2.05 per share. The decision of the Pennsylvania Commission on the Company's recent petition regarding proposed changes in the fuel clause and request for $119 million of annual rate relief--which has been suspended to April 1978--will be the primary determinant of the level of earnings for the year. Assuming reasonable treatment by the Commission, on 7% additional shares, our $2.05 estimate indicates a 10.6% return on average equity. Longer term, with capitalization growth slowing and financing pressures easing, we envision modest earnings progress, assuming rate relief is received on a timely basis....
>
> Previous rate decisions by the Pennsylvania Public Utilities Commission have been based on fair value, end-of-period historical rate bases and the adjusted book Common equity returns have been 14% - 14 1/2%. Interim rate relief has been granted and normalization of accelerated depreciation tax deferrals on post-1969 property was allowed."

Thus, as shown in both our Reports and our Fixed Income Summaries, our downgrading of the Company's securities in 1978 was attributable to the disappointment of our expectations respecting its 1978 and likely future earnings levels, due principally to its failure to obtain interim rate relief and the resulting attrition experienced as it awaited rate base recognition of a major generating plant

addition. Further, we noted the prospect that this process would be repeated in 1979 when a second major unit entered service with additional negative effects to earnings. We were particularly concerned at this time that the Company would in the next several years be unable to meet its mortgage bond coverage test, thus being foreclosed from issuance of mortgage bonds, and with the fact that its earnings per share were not at that time and quite possibly would not in the future support its dividend thus raising concern about the maintainability of that dividend. These concerns were further summarized in our March 11, 1980 Fixed Income Summary (see Schedule 8, first and third paragraphs). By contrast, our decision to maintain the Company's ratings in 1977 and early 1978 reflected our more positive view at that time of Pennsylvania regulation and our expectation of adequate financial performance by the Company in substantial part due to its 1976 and 1978 capital expenditure reductions.

Q. Did the D&P Credit Rating Committee downgrade the Company's securities in 1976?

A. Yes. In late April 1976, the D&P Committee reassessed PECO's credit risks. We lowered the bond rating to D&P-7 (Low Single A) from our previous 2-Medium in our prior rating scale.

Q. How did the 2-Medium in your former rating scale compare with the new scale adopted in 1976?

A. A 2-Medium was the fifth rating category in our former scale. However, in terms of risk comparability, it was equivalent to a strong D&P-6 (Medium Single A) in the revised scale.

Q. What was the reason for the late April 1976 rating reduction of PECO's

securities by D&P?

A. The D&P Rating Committee was concerned about PECO's ability to maintain and improve its financial ratios. Coverages for 1976 were forecast to retreat to the 1974 level, near the bottom for the D&P 5 to 7 (Single A) rated companies. Construction remained very large with the forecast at $437 million in 1976 and totaling almost $2 billion for the four years 1976-79. The Committee was concerned about whether rate increases would be adequate and about the level of external financing which would be necessary to finance PECO's capital program. This downgrading was in advance of the 1976 Limerick delay announcement.

Q. What are the types of reports published by D&P?

A. D&P publishes reports on common stock and on the fixed income securities of companies it rates. The Basic Report discusses the company in depth and addresses especially the common stock. The Common Stock Summary is a periodic update to that report. The Fixed Income Rating Analysis is an indepth report on the credit aspects of the company. The Fixed Income Summary is a synopsis of our credit rating opinion. At the time of each fixed income offering, we publish a New Financing Report describing the proposed issue and the company's credit fundamentals.

Q. You mentioned that Duff & Phelps rates securities. What has been your history of ratings for Philadelphia Electric's senior debt?

A. We currently rate the Company's debt D&P-9 (Medium Triple B). We assigned this rating in April 1980. Our history of rating changes as well as those of Moody's and Standard & Poor's are shown in Schedule 9.

Q. What is your belief as to D&P's rating action had the Limerick schedule not been changed in 1976 and 1978?

A. As Chairman of our Utility Rating Committee from 1974 to 1980, I recall my own and our committee's concern about the Company's large capital spending and low level of coverage and internal cash generation. This was the subject of our quarterly rating review with our analyst following Philadelphia Electric. I recall the construction expenditure reductions and the Company's efforts to reduce its debt ratio as key factors in tempering our reductions in the securities ratings.

The rating reductions we made were primarily because of the continued low earned returns, the Pennsylvania regulatory climate, the declining coverages, and in 1980 the cost effects anticipated on nuclear plants largely as a result of the TMI accident and the PUC denial of CWIP. Had the construction program been on its more ambitious 1975 forecast, the Company's financial ratios would have been lower. Under these circumstances, I believe the D&P ratings would have been lowered earlier and further.

Q. Could you describe your rating system?

A. Yes. Schedule 10 sets forth our numerical rating system and gives generic definitions for each category. We use 17 ratings. D&P-10 is the lowest in the investment grade category. Philadelphia Electric's Bonds are only one level away from that level.

Q. In your opinion, could PECO have raised the needed capital for the pre-1976 construction schedule?

A. It would have required tremendous regulatory support. Coverages were very low. The Mortgage Indenture earnings test limited bonding

capacity. Each new offering would have raised interest expense and pressed coverages down further. In my opinion, the only way this might have been possible is if the PUC had allowed a cash return on substantial construction work in progress. This option was rejected several times by the PUC. For example, this treatment was denied in cases RID 129 and R-811626. Similarly, provisions to enable additional cash generation were denied in case R-80061225.

Q. What bond rating was necessary for utility companies in the 1970's?

A. In the 1970's, a Triple B electric utility was regarded with extreme caution. Those companies which had sunk to that level were often shut out of the market although the Triple B category is regarded as investment grade. There were two reasons for this. First, many institutions are prohibited by law or policy from investing in securities rated below Single A. Second, during a period of concern about the industry such as existed in the 1970's, investors attempted to upgrade their holdings and at times would only buy higher (Double A) quality securities fearing that downgrades of even Single A credits would result in a Triple B holding. There was no utility "junk" bond market such as developed in 1983-84 when companies such as Long Island Lighting or PS New Hampshire were able, by paying a very high price, to sell their debt instruments.

Therefore, utility companies which had to have ready and frequent access to the markets strived to maintain Double A or at least strong Single A ratings. PECO's actions in reducing its construction expenditures, as well as the similar action of numerous other utilities, greatly facilitated this purpose. In my opinion, this was a reasonable and proper action by PECO management, and was

necessary to permit maintenance of an adequate and ultimately marginally adequate financial position by the Company.

Q. Could you summarize your testimony?

A. Yes. I believe that the Limerick schedule deferrals of 1976 and 1978 were financially necessary for the Company at that time. Had they continued full force, the stress of far larger annual financings would likely have resulted in further credit deterioration and reduced ability to handle the increased funding in the 1980's. This would have been damaging to the investors and not in the best interest of the rate payers.

Q. Does this conclude your testimony?

A. Yes, it does.

Schedule 1

PHILADELPHIA ELECTRIC COMPANY

Investor Owned Utilites
Annual Electric Rate Actions
1970-1980

	Cases Filed	Cases Decided
1970	87	97
1971	115	111
1972	110	136
1973	139	131
1974	212	206
1975	192	237
1976	173	217
1977	164	210
1978	155	205
1979	181	219
1980	256	258

Source: Edison Electric Institute - Financial Infomation Tabulation Dated 4/8/85.

Schedule 2

PHILADELPHIA ELECTRIC COMPANY

Investor Owned Utilities
Price/Earnings Multiples
1960-1980

Year	X's
1960	22.9
1961	24.7
1962	21.8
1963	22.3
1964	22.7
1965	21.1
1966	18.8
1967	16.3
1968	16.5
1969	12.8
1970	13.5
1971	12.6
1972	11.9
1973	8.8
1974	6.4
1975	8.4
1976	9.4
1977	8.9
1978	7.6
1979	6.9
1980	6.1

Source: Duff & Phelps Twenty Company Average. (Twenty companies of the major power regions on the basis of total generating capacity and plant investment. The companies are: AEP, C&SW, Com Ed, DE, Dom R., Duke, FPL, IPALCO, MSU, NEES, NMP, NSP, PacifCorp., PS&E, PECO, PSCOLO, PSE&G, SoCo, TU, Union Elec).

Schedule 3

PHILADELPHIA ELECTRIC COMPANY

Investor Owned Utilities
Selected Ratios
1970-1980

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Debt Ratio	57.1	56.9	56.0	54.7	56.8	54.7	53.4	53.2	52.2	52.9	53.0
% Incr. Avg. Cap.	12.0	13.0	13.1	12.7	14.2	11.2	8.5	9.3	8.8	11.7	10.3
Avg. Debt Int. Cost	5.3	5.5	5.7	6.0	6.7	6.9	7.1	7.3	7.5	8.0	9.0
ROE	12.2	12.0	12.2	11.8	10.4	11.5	11.6	11.5	11.8	11.4	12.0
AFC as % Bal. for Common	22	29	35	36	46	36	34	37	44	52	53
Income Tax Rate	29	25	23	23	20	29	31	32	32	26	27
Debt Int. Cvg. Ex AFC	3.1	2.7	2.6	2.6	2.2	2.4	2.6	2.6	2.6	2.3	2.2
Mkt. to Book-Common Stock	163	150	145	102	70	96	106	100	87	77	74
Yield-Common Stock	5.28	5.47	5.61	7.70	12.15	8.42	7.71	8.16	9.85	11.49	12.51

Source: D&P Twenty Company Average

Schedule 4

PHILADELPHIA ELECTRIC COMPANY

Selected PECO Financial Ratios
1970-1980

Year	Int. Cvg. Ex AFC	Int. Cvg. Ex AFC & Def. Fuel	Cap. Incr. %	Debt Ratio %	Avg. Int. Cost %	ROE %
1967	4.3	4.3	8.3	55.5	4.1	12.2
1968	3.5	3.5	9.2	58.2	4.5	10.9
1969	3.0	3.0	11.9	56.7	5.0	10.3
1970	2.2	2.2	16.5	56.8	5.6	9.4
1971	2.4	2.4	16.1	54.0	5.7	10.8
1972	2.4	2.4	15.2	53.3	5.9	10.3
1973	2.2	2.2	14.9	51.0	6.2	9.8
1974	1.8	1.6	14.1	54.4	7.1	8.9
1975	2.0	2.0	10.1	53.2	7.6	9.4
1976	2.1	2.1	5.8	51.6	7.7	9.9
1977	2.0	2.0	5.9	51.8	8.0	9.6
1978	1.9	2.0	5.8	52.1	8.2	9.7
1979	1.6	1.2	7.3	53.2	8.5	9.8
1980	1.5	1.8	7.0	51.8	9.5	10.6

	Avg. Realization Per Kwh	Fuel & Net	All Other
1970 ¢/Kwh	1.78	.44	1.34
1980 ¢/Kwh	6.32	3.07	3.25
1970-80 % Incr.	255	597	142

Source: Company Reports

Schedule 5

PHILADELPHIA ELECTRIC COMPANY

Delayed Generating Plants

Company	Plant
Long Island Lighting	Shoreham
Detroit Edison	Fermi
	Belle River
Public Serv. E&G	Hope Creek
Consumer Power	Midland
Ohio Edison)	Beaver Valley No. 2
Cleveland Electric)	
Toledo Edison)	
Duquesne Light)	
Niagara Mohawk	Nine Mile Point
Georgia Power	Plant Vogtle
	Sherer 1
Pacific P&L	Wyodok 1

Source: Annual Electric Power Survey Report of the Electric Power Survey Committee of the Edison Electric Institute

Schedule 6

PHILADELPHIA ELECTRIC COMPANY

PECO Sources & Uses of Funds
1970-1980

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Net Income	$ 68,376	$ 93,624	$107,974	$122,867	$129,097	$143,925	$164,618	$173,439	$184,861	$194,471	$227,131
Less: Total AFC	18,513	31,691	42,450	58,743	70,841	66,874	77,641	86,078	90,997	113,383	147,550
Fuel Cost Def. (Recovery)	--	--	--	--	21,655	(3,722)	1,921	3,154	(18,781)	79,285	(72,464)
Less:											
Pfd. Div.	8,612	15,320	22,046	28,056	34,272	36,026	39,414	40,712	43,877	44,760	52,973
Common Div.	53,683	60,689	67,735	78,350	86,458	95,439	107,683	124,893	135,687	144,984	157,423
Balance	(12,432)	(14,076)	(24,257)	(42,282)	(84,129)	(50,692)	(62,041)	(81,398)	(66,919)	(187,941)	(58,351)
Plus:											
Non-Cash Exp.	52,293	60,453	69,691	77,468	126,806	124,046	179,550	175,808	193,173	164,901	146,368
Funds From Operations	39,861	46,377	45,434	35,186	42,677	73,354	117,509	94,410	126,254	(23,040)	88,017
(Inc) Decr Other Work Cap	(3,292)	(633)	508	17,122	(68,945)	(1,690)	(38,301)	(20,279)	(5,436)	28,114	36,286
Nonrecurring Item	--	--	--	--	--	18,750	64,000	--	--	--	--
Net Funds	36,569	45,744	45,942	52,308	(26,268)	90,414	143,208	74,131	120,818	5,074	124,303
Construction	351,554	351,514	399,676	494,187	476,696	361,368	380,007	393,134	405,606	421,615	579,802
Less: Total AFC	18,513	31,691	42,450	58,743	70,841	66,874	77,641	86,078	90,997	113,383	147,550
Net Construction	333,041	319,823	357,226	435,444	405,855	294,494	302,366	307,056	314,609	308,232	432,252
Debt Retirement	10,140	34,838	18,130	14,290	69,313	95,193	63,271	38,945	31,422	56,169	140,671
Other	1,704	(1,867)	34,413	(29,240)	(10,093)	9,480	12,971	13,196	9,106	9,629	3,599
Total Requirement	344,885	352,794	409,769	420,494	465,075	399,167	378,608	359,197	355,137	374,030	576,522
Int % of Total	10.6	13.0	11.2	12.4	(5.6)	17.9	20.9	20.6	34.0	1.3	21.6
Int of % of Constr	11.0	14.3	12.9	12.0	(6.5)	24.3	26.2	24.1	38.4	1.6	28.8
External Financing:											
Short-term Debt	(23,262)	(26,247)	54,543	43,922	30,192	(69,970)	(100,728)	7,649	1,344	68,968	(32,597)
Long-term Debt	206,700	160,000	140,000	100,000	375,000	249,000	200,000	173,500	150,000	200,000	275,000
Pfd. Stock	65,000	70,000	75,000	75,000	75,000	--	50,000	--	50,000	--	72,000
Common Stock	59,878	103,297	94,284	149,264	11,151	133,723	86,128	103,917	32,975	99,988	137,816
Total	308,316	307,050	363,827	368,186	491,343	308,753	235,400	285,066	234,319	368,956	452,219

Source: Published Company Reports

Schedule 7

PHILADELPHIA ELECTRIC COMPANY

PECO Construction Forecasts
($MM)

Date	1975	1976	1977	1978	1979	1980
5/28/75	410	469	481	550	674	
5/24/76	361A	437	414	390	478	470
4/19/77		380A	448	434	455	511
5/10/78			393A	483	418	465
4/30/79				406A	406	466
Post 1975 Reductions	49	89	88	144	268	4

1975 External Financing Forecast
($MM)

Date	1975	1976	1977	1978	1979
5/28/75	355	328	320	349	523

A - Actual

Source: Published Company Data

Schedule 9

PHILADELPHIA ELECTRIC COMPANY

Rating Agency Changes

	Duff & Phelps		Moody's		Standard & Poors	
	From	To	From	To	From	To
11/70			Aaa	Aa		
09/74			Aa	A	AA	A
02/76					A	A-
04/76	6*	7				
09/78	7	8				
04/80	8	9			A-	BBB+
06/81			A	Baa	BBB+	BBB
09/82					BBB	BBB-
01/83			Baa2	Baa3		

*Prior D&P rating scale stated as 2-Med.

Source: Agency Announcements

Schedule 10

Duff and Phelps Credit Rating Scale

D&P Rating	Generic Category	Description
1	Triple A	Highest credit quality. The risk factors are negligible, being only slightly more than for risk-free U.S. Treasury debt.
	Double A	
2	High	High credit quality. Protection factors are strong. Risk is modest but may vary slightly from time to time because of economic conditions.
3	Medium	
4	Low	
	Single A	
5	High	Protection factors are average but adequate. However, risk factors are more variable and greater in periods of economic stress.
6	Medium	
7	Low	
	Triple B	
8	High	Below average protection factors but still considered sufficient for institutional investment. Considerable variability risk during economic cycles.
9	Medium	
10	Low	
	Double B	
11	High	Below investment grade but deemed likely to meet obligations when due. Present or prospective financial protection factors fluctuate according to industry conditions or company fortunes. Overall quality may move up or down frequently within this category.
12	Medium	
13	Low	
	Single B	
14	High	Below investment grade and possessing risk that obligations will not be met when due. Financial protection factors will fluctuate widely according to economic cycles, industry conditions and/or company fortunes. Potential exists for frequent changes in quality rating within this category or into a higher or lower quality rating grade.
15	Medium	
16	Low	
17	Substantial Risk	Well below investment grade with considerable uncertainty as to timely payment of interest, preferred dividends and/or principal and sinking funds. Protection factors are narrow and risk can be substantial with unfavorable economic/industry conditions, and/or with unfavorable company developments.
18-20		Reserved for later use.

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REPORT

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September 21, 1978

PHILADELPHIA ELECTRIC COMPANY

Summary

Philadelphia Electric Company provides electric service in Philadelphia and environs which contributed 84% of 1977 revenues and 89% of pre-tax income. Gas service is supplied to suburban areas around Philadelphia (13% of revenues) and steam service accounts for the small balance. In terms of invested capital, Philadelphia Electric is the ninth largest utility in the U.S. Annual revenues approach the $1.5 billion mark. The territory is highly industrialized and diversified. Customer growth is sluggish and kwh growth is projected at a below average 3%-4% annually. Pennsylvania regulation is currently ranked in our Group IV category.

Construction expenditures including nuclear fuel are forecast at $483 million for 1978, $418 million of 1979 and aggregate $2.5 billion for the five years ended 1982. Internal sources are expected to provide 40% for 1978 and around 45% of the required funds for 1979-1982; invested capital will compound at 6% annually through 1982 as compared with a 9% rate recorded in the five years ended 1977. At June 30, 1978, capitalization totaled $4.2 billion and consisted of 52% total debt, 14% Preferred and 34% Common equity. No additional public financings are anticipated until early 1979.

Earnings for the 12 months ended July 31, 1978, were $1.65 per share versus $2.08 for the prior similar period and $1.87 for calendar 1977. The earnings erosion principally reflects commercial operation of the nuclear Salem No. 1 (453-mw) at mid-1977 with little offsetting rate relief. A rate order on the pending $119 million (11.5%) application filed August 1977 is anticipated by year-end 1978. Excluding further rate relief in 1978, we estimate 1978 earnings at $1.55 per share. If the final order is retroactive to the July 1978 suspension date, the Company has indicated 1978 earnings may be restated upward. Assuming $90 million of annual rate relief is reflected in 1979 and commercial operation of Salem No. 2 at mid-1979, we project a recovery in 1979 earnings to around $1.80 per share, equating to a still below average return on Common of about 9.5%. Further generating additions have been rescheduled to 1985 and 1987, thus easing financing pressures in the early 1980s. Combined with adequate rate relief, this could allow for some restoration in per share earnings and returns in the intervening years.

Investment Opinion

Trading at 17-3/4 (latest 52-week market range: 20-1/4 - 16-7/8) and at an approximate 8% discount to book value, the shares sell at 11.5 times our 1978 estimate of $1.55 per share. The yield is 10.1% on the $1.80 dividend established in March 1977. In 1977, 27% of the dividend was considered a tax-free return of capital. Some portion could also be so classified in 1978. We expect this dividend to be maintained at least until receipt of the Pennsylvania rate decision, at which time the situation will be reviewed by the Board of Directors. The cash coverage of the 1978 dividend is estimated at about 1.75 times. This is below average but adequate.

We are lowering our qualitative rating of the Company from D&P-II to D&P-III because of the deteriorating Pennsylvania regulation and the diminished financial flexibility of the Company. We also regard the Common stock as having below average attraction except for those investors able to benefit from the combination of high current yield, partial non-taxability of the Common stock dividend and exemption from personal property taxes for Pennsylvania residents.

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PHILADELPHIA ELECTRIC COMPANY

Territory

Philadelphia Electric Company is a combination electric, gas and steam utility serving southeastern Pennsylvania including Philadelphia and the surrounding suburban area. Electric operations in 1977 accounted for 84% of total Company revenues of $1.39 billion and 89% of pre-tax operating income. Gas contributed 13% of revenues and 10% of pre-tax operating income. The small steam operations provide 3% of revenues and are marginally profitable in most years.

The total service area encompasses 2,475 square miles and a population of 3.9 million or approximately one-third of the state's inhabitants. The City of Philadelphia represents only 5% of the total geographical area but contributes 40% of electric revenues. The gas service area is somewhat smaller in size and generally excludes the City of Philadelphia. The Philadelphia suburban area has shown population gains slightly in excess of those of Pennsylvania and the U.S. but population trends in the City proper have been static. In the five years ended 1977 total customer growth of 5% has been well below the 12% experienced by the electric utility industry. Income levels and growth in per capita incomes have slightly exceeded the U.S. averages.

Philadelphia is the fourth largest U.S. metropolitan area and is a principal financial and commercial center. The economy is well diversified with many basic industries such as metal and machinery, petroleum refining and chemical production, food, rubber and transportation equipment. Commercial and industrial growth nas been sluggish in recent years. Additionally, the heavy industrial mix exposes the service area to cyclical swings in the economy.

Overall, considering the mature urban territory coupled with the industrial base, we regard the service area as below average for the operation of an investor-owned electric utility. We project kwh growth at 3%-4% annually including the use of electricity for heating and as an alternate fuel source.

Business - Electric

Electric operating revenues of $1,178 million (84% of total) in 1977 were derived 36% from residential sales, 14% from commercial, 44% industrial and 6% other. Retail sales accounted for essentially all of total kwh sales. The Company's revenue structure is heavily weighted to the industrial category (nearly one-half of which is non-manufacturing). Conversely, the commercial segment is below average. Electric customers approximate 1.27 million.

Electric sales growth in the 1972-1977 period averaged only 2.1% annually, less than half of that for the industry for the same period. Retail sales expanded at an average 5% annual rate for the five years ended 1973. However, this pattern was sharply interrupted by such factors as the Arab oil embargo, conservation, recession, and mild weather. The industrial sector has been particularly slow to recover and the 1977 level of industrial sales was still 3% below the peak recorded in 1973. Recessions have impacted the area more severely and for a longer period of time than in many other sections of the country because of the industry mix and little industrial expansion.

At the same time both the residential and commercial sales gains also trailed the D&P Averages. This is traceable largely to the sluggish growth in the number of new customers, competition from natural gas, a greater mix of multiple-family low-usage dwelling units and a low (3%) saturation of electric space heating. Average residential usage in 1977 was 7,097 kwh, 6% over 1976, and about 14% under the investor-owned electric utility average. Overall kwh sales registered a 3.5% gain in 1977, largely attributed to relatively hot weather with increased use of air conditioning; the residential category registered a 7% increase.

Reflecting sluggish sales growth, some rate relief and operation of the fuel adjustment clause, Philadelphia Electric's retail revenue growth of 105% compared with a 124% gain for the electric utility industry during the 1972-1977 years. The Company's 1977 residential realization averaged 5.27¢ per kwh versus 4.92¢ for 1976. This realization was higher than the 4.06¢ of the investor-owned utility average but closer to other nearby East Coast utilities such as 5.08¢ for Delmarva Power & Light, 4.29¢ for Baltimore Gas and Electric (incorporating a large nuclear component) and 4.67¢ for Potomac Electric.

Electric Power and Fuel Supply

Net installed electric generating capacity totaled 8,198 mw at year-end 1977 consisting of 1,346 mw of nuclear base load generating units (16%), 3,834 mw of conventional steam (47%), 1,626 mw of combustion turbine peaking units (20%), 512 mw of hydro and 880 mw of pumped storage (17%). Over 800 mw of the conventional steam capability is composed of four relatively old and inefficient stations with heat rates exceeding 13,000 Btu.

The two Peach Bottom nuclear units (the Company's share totals 886 mw) were installed in 1974 and are jointly-owned with other utilities but are operated by Philadelphia Electric. The nuclear Salem unit is also jointly-owned but operated by Public Service Electric and Gas Company. This unit began commercial opeation in June 1977 with 480 mw accruing to Philadelphia. The 400 mw oil-fired Eddystone unit was added in June 1976. These generating units placed in service during the past four years represented a 27% increase in installed generating capability and a 116% increase in the cost of production plant. At the end of 1977 the installed cost was $230 per kw. Reflecting work on four additional nuclear projects underway, construction work in progress was 23% of total electric plant at year-end 1977.

Based on the highest summer peak attained to date--5,888 mw in 1977--and generating capability of 7,954 mw (adjusted for removal of 238 mw from service temporarily), the 1978 reserve margin was 35%. Assuming 3% average annual peak load growth, availability of existing units and addition of a new unit prior to 1980, the reserve margin will be 25% or above through 1982. Additionally, the Company is a member of the Pennsylvania-New Jersey-Maryland interconnection (PJM) which fully integrates the bulk power generating and transmission operations of eleven electric utilities. The 1978 reserve margin of the PJM Pool is estimated at an ample 36%. In recent years Philadelphia Electric has been a net purchaser of power with 20%-30% of its needs purchased on a net interchange basis.

There has typically been a relatively wide 20%-30% variation between summer and winter peaks which we attribute to the weather sensitivity, particularly to summer air conditioning loads, as well as the low saturation of electric space heating. Also, a large part of the industrial sales category represents non-manufacturing with little round-the-clock consumption. These factors in concert with the purchase of relatively large amounts of economy power from the PJM Pool result in a below average load factor generally ranging in the 56%-58% area.

Principally due to slower load growth projections, the Company has stretched out its schedule for new generating additions. The next unit is the nuclear Salem No. 2 being constructed in conjunction with Public Service Electric and Gas Company. The Company's share, 474 mw, is expected to be available at mid-1979. Two wholly-owned Limerick nuclear units, each 1,055 mw, have been rescheduled to 1985 and 1987. The current estimated cost of Salem No. 2 is over $600 per kw and for the Limerick units about $1,500 per kw. Construction permits for the two Limerick units have been received and over one-quarter of the estimated costs has already been expended.

Nuclear will represent a growing portion of the Company's generation. Sources

of electric output for 1978 are estimated at nuclear 28%, coal 29%, oil 18% and other including purchased power and net interchange 25%. With Salem No. 2 in service, nuclear generation will account for about 35% of the power generated.

Most of the coal and oil requirements are contracted for annually on a short-term one to five years basis. Commitments for the nuclear fuel supply cycle have been made for four (Peach Bottom and Limerick) units through 1981-1985 and the two Salem units through at least 1979. Additional arrangements are being sought. Unit fuel costs have escalated sharply in recent years, particularly in 1974, and for 1977 fuel and interchange expense averaged 1.66¢ per kwh sold, somewhat above our D&P Average. The high fuel component represents use of sizeable quantities of imported oil and purchase of interchange power. Cost increases in recent years have been modified by the growing use of nuclear generation.

The Company is subject to Federal, state and local regulation with respect to environmental matters. Use of high sulfur coal does not meet prescribed pollution control standards and certain stations are currently operating under consent orders. The Peach Bottom station has operated under thermal limitations and may be required to install a closed cycle cooling system. The Company estimates approximately $100 million of expenditures could be required for compliance, part of which is included in current construction estimates.

Overall, we view the Company's power generation and fuel supply as satisfactory well into the 1980s. The Company is attempting to comply with regulations or is seeking variances. We think the Company's commitment to nuclear generation is a positive element.

Business - Gas

The Company provides gas service to 271,000 customers in the surrounding suburban area of Philadelphia. Gas revenues of $175 million in 1977 were contributed by residential with heating 48%, residential other 5%, commercial-firm 22%, fndustrial-firm 23%, and other 2%. For the 1972-1977 period, gas revenues rose 87% despite 15% lower sales volume, with rate relief, purchased gas cost adjustments and elimination of the lower realization interruptible industrial sales category. Industrywide, gas revenues increased 122% for the same five year period.

Heating degree days for the service area average 4,945 under normal weather conditions but the 1973-1975 years were all warmer than normal. In calendar 1976, heating degree days registered 5,199 or 5% colder than normal temperatures and in 1977, 5,166 heating degree days were recorded in the territory. Mcf sales of gas decreased 14% in 1975 due to gas curtailments by the major pipeline suppliers. In 1976 gas sales increased 13% resulting from the availability of gas under emergency contracts and increased sendout in the abnormally cold October-December 1976 months. Gas sales were marginally lower in 1977. Residential space heating saturation is about 65%. The Company has not been able to increase the number of customers served in recent years.

Philadelphia Electric purchases nearly two-thirds of its natural gas requirements from Transcontinental Gas Corporation under contracts expiring in 1990 and the other one-third from Texas Eastern Transmission Corporation under contracts expiring in 1987. The Company's contracted supply was curtailed 25% in 1975, 29% in 1976 and 30% in 1977. The 1978 curtailment is anticipated to be similar to that experienced in 1977. Gas service was partially curtailed to large industrial customers January through April 1977. To alleviate curtailments, the Company has 1) obtained additional gas on 60 day emergency contracts, and 2) used SNG and substitute gas from oil. It also received production from several gas wells it has participated in on a joint basis. Gas storage contracts will enable the Company to store about 42% of the anticipated 1978-1979 heating season sendout.

The 1977 residential realization was $3.26 per Mcf, up from $2.91 in 1976, $2.72 in 1975 and $2.39 in 1974. Purchased gas adjustment clauses pass on increased costs of gas but do not fully reflect overhead and basic costs which apply to the reduced unit volume. However, profitability of the gas operation increased from a depressed $16.0 million in 1975 to $22.4 million in 1976 reflecting the higher sales volume coupled with some rate relief which was applicable. In 1977 gas operating income equalled $20.9 million; the attrition was primarily due to minimal rate relief.

Overall, with static to declining gas supplies and substantially higher prices of natural gas together with inflation, these operations appear to offer limited growth and are dependent on periodic rate relief.

Regulation

Previous rate decisions by the Pennsylvania Public Utilities Commission have been based on fair value, end-of-period historical rate bases and the adjusted book Common equity returns have been 14%-14.5%. Interim rate relief has been granted and normalization of accelerated depreciation tax deferrals on post-1969 property was allowed.

Two Pennsylvania statutes adopted in late 1976 and effective for filings dated after October 7, 1977, provide for several modifications. These include: 1) the establishment of a maximum seven month suspension period plus 60 days for the filed effective date of a general rate increase (nine months effectively vs. eleven previously), 2) authorization (not mandated) of the use of a future test year (vs. historical prevously), and 3) prohibition of potential rate retroactivity of multiple rate filings (pancaking) and interim rate relief other than for emergency purposes. An Office of Administrative Law Judge was created to conduct hearings and submit recommendations.

The Pennsylvania Commission adopted a new Energy Rate Clause (ERC) effective July 1, 1978. This fuel clause includes nuclear and the fuel component of purchased power (excluding the demand charge). The base is that established and approved in the last general rate case or the latest 12 months scrutinized by the staff. Philadelphia Electric has received Commission approval for its base to be the 12 months ended October 1977. The new ERC will be a rolling six-month average, updated monthly, with an approximate two-month lag. The Commission has approved a plan for amortization over nine months for recovery of the deferred fuel costs.

In the Company's last rate case concluded in February 1977, the Pennsylvania Commission authorized an electric rate increase of $72 million in response to a $95 million request filed November 1975 in a two-part application. The Company requested the first part--$47 million--not be suspended. In January 1976 the Commission suspended both parts for up to six months but permitted an interim increase of $24.3 million to be effective subject to possible refund. In July 1976 the PUC authorized an additional interim increase of $22.7 million effective August 1976. The $25 million additionally granted in February 1977 was retroactive to October 1976. The February 1977 decision was based on a period-end fair value rate base; the test year was the 12 months ended August 1975; and the overall return allowed incorporated about a 14.15% return on book Common equity. The decision allowed a slightly lower return on book Common equity than the prior March 1975 Order and took 15 months to process but the interims granted partially mitigated the delay.

An Order was received in late 1976 allowing $9.2 million of increased gas rates in two steps. The first part consisting of $6.4 million went into effect June 1975, subject to refund. The additional $2.8 million allowed was retroactive to March 1976. The decision was issued in almost 20 months and, according to the Company, was based on an inadequate rate of return on Common equity and an insufficient allowance for depreciation.

Philadelphia Electric made a two-part electric rate filing August 1977. The first part sought to transfer the existing electric fuel adjustment charges into base rates, eliminate the electric fuel adjustment clause for residential and small commercial customer (30% of kwh sales) and to substitute a new energy adjustment clause for other customers (including nuclear). Part two involved a $119 million increase (11.5%) in electric rates, half of which is designed to recover the additional operating and capital charges associated with the commercial operation of the Salem No. 1 nuclear unit on June 30, 1977. Both parts were suspended until April 4, 1978. In December 1977 an Administrative Law Judge recommended an interim increase of $32.5 million; the Company urged the PUC to grant a $53.6 million increase; and on April 4, 1978 the Commission awarded the Company only $11.8 million, subject to refund, and further suspended the case to July 4, 1978. The opinion of the Administrative Law Judge is expected to be available around October 1978 and we are anticipating receipt of an Order by year-end 1978. If the final Order is retroactive to the July 4, 1978 maximum suspension date as expected, the Company has indicated 1978 earnings may be restated.

The Company filed for a $2.1 million annual increase in wholesale rates with FERC in May 1977; the increase went into effect July 1977 subject to refund. Additional rate increases totaling $4.1 million were placed in effect on September 1, 1978, subject to refund.

We currently rate Pennsylvania regulation in our Group IV category. Recent Commission actions point to a deteriorating atmosphere and this ranking will be carefully reviewed upon receipt of several expected forthcoming orders.

Construction

Construction expenditures including nuclear fuel are currently budgeted at $483 million for 1978, $418 million for 1979, $465 million for 1980, $509 million for 1981, and $604 million for 1982. About 85% of this five-year program which aggregates $2.479 billion is earmarked for the electric department with the majority of the money to be spent on new nuclear generating capacity. This budget compares with $2.1 billion expended in the five years ended 1977. Cost of certain pollution control equipment that may ultimately be required is not included in the preceding forecast.

Financing and Capitalization

Capital requirements for 1978 are estimated at $513 million including $483 million for construction and $30 million for debt maturities and sinking funds. Internal sources are expected to provide about 40% of 1978 construction funds. Financing in 1978 is anticipated to total about $300 million and to consist of approximately $250 million debt including the $100 million of First Mortgage bonds sold on March 7, $50 million of 8-3/4% Preferred privately placed, and the balance bank loans. A contemplated offering of First Mortgage bonds as well as sale of four million shares of Common (around $70 million @ 18) tentatively scheduled for October 1978 have been deferred to the first quarter of 1979. Shareholder Dividend Reinvestment and Employee Plans contribute about $20 million of capital annually.

For 1979-1982 we estimate about 45% of the construction program can be funded from internal sources. In addition, debt maturities will require $51 million in 1979, $126 million in 1980, $130 million in 1981 and $60 million in 1982. We expect sales of debt and Common in each of the years 1979 through 1982; Preferred will be sold every other year.

Capitalization at December 31, 1977 totaled $4.1 billion and consisted of 44.1% Mortgage debt, 51.8% total debt, 13.1% Preferred and 35.1% Common equity. We estimate 1978 year-end ratios to be 52% total debt, 14% Preferred and 34% Common equity. Our calculations indicate total capitalization will

increase about 6% annually in the five years ending 1982 as compared with a 9% compound annual rate experienced for the prior five years ended 1977. At a market price of 17-3/4, the Common currently sells at 92% of its June 30, 1978, book value of about $19.25.

Accounting Practices

Tax deferrals related to accelerated depreciation on property additions since 1970 are normalized; for additions prior to 1971, the resultant tax deferrals are flowed-through to income. Tax deferrals from the use of ADR are normalized. Investment tax credits are amortized over the estimated useful life of the utility plant. Income tax credits applicable to non-operating activities (primarily interest relating to construction work in progress) are reported in other income with an offsetting increase in operating income taxes. For 1977 the income tax rate was 29%, as compared with a 24%-32% rate in last five years.

Depreciation as a percent of average depreciable utility plant in service was 2.99% for 1977. AFC was computed at a net after-tax rate of 8%-8.4% during 1975-1976. On January 1, 1977 a rate of 8.60% was adopted in accordance with the FERC method of accounting; the rate was increased to 8.70% on July 1, 1977. Effective January 1, 1978 the basis for calculating AFC was changed and a 7.1% net after-tax rate is applied to the CWIP base including prior AFC and is will be compounded semi-annually. This rate and application are equivalent to an 8.7% rate previously used when applied to a CWIP base excluding prior AFC. We note AFC has been a relatively high proportion of reported earnings in recent years.

Beginning January 1974 deferred fuel cost accounting was adopted. At December 31, 1977 deferred fuel expense totaled $23 million, as compared with $20 million at year-end 1976. Under the new ECR fuel clause, use of deferred fuel accounting has been discontinued and permission has been received to amortize the balance in this account over nine months beginning July 1978.

We consider the overall quality of reported earnings to be about average. Both the quality of earnings and the level of cash flow have improved in recent years.

Earnings Record

Various statistical tables are presented at the end of this report. Earnings per share have shown no progress in the latest five-year period 1972-1977 nor even in the last ten years. Per share earnings declined 10% during the five years ended 1977 as compared with a 12% gain for the D&P Average. We attribute this record principally to: 1) sluggish sales growth which contributed to below average Company revenue gains, 2) somewhat higher increases in operating and maintenance expenses than the industry partially related to operation of new generating capacity and pollution control equipment, extra costs associated with operating in a major metropolitan area, and high wage rates and increases, and 3) somewhat higher financing costs than the industry.

For the 1972-1977 period, Philadelphia Electric's capitalization growth was 9.2%. The Common equity portion of the capitalization structure compounded at 10% annually and the number of average Common shares outstanding rose 71%. By comparison, invested capital growth of the D&P Average was 11% annually and Common shares outstanding increased 55%. The Common equity component was generally maintained in the 34%-35% area except for 1974 when a Common stock sale was delayed. With a high payout ratio (averaging 89%) earnings retention was low and four of the five Common stock sales were consummated below book value. Thus, book value declined slightly during the five years 1972-1977 from $20.00 per share to $19.26. Returns on average Common equity generally fluctuated in the 9%-10% range during the 1973-1977 years. These returns averaged

about 18% below the D&P Average. Overall, we conclude the Company has been unable to secure rate relief in sufficient amounts on a timely basis.

In 1977 kwh sales rose 3.5% and gas volumes declined 1%. The first Salem nuclear unit, owned in conjunction with Public Service Electric and Gas Company, began commercial operation at mid-year 1977 and added 453 mw to the system. This penalized 1978 earnings by about 20¢ per share. A non-recurring offsetting factor was the conversion of residential and commercial customers from bi-monthly to monthly meter reading and billing which benefited earnings by 11¢ per share. Only a nominal amount of rate relief was effective. On 8% more average shares outstanding, earnings were reported at $1.87 per share, down slightly from the $1.91 recorded for the prior year. AFC was about flat on a per share basis for both years.

Current and Prospective Earnings

Earnings for the 12 months ended July 31, 1978 were $1.65 which compared with $2.08 for the prior similar period on 8% additional average shares. The decline principally reflected a full year's operation of the Salem nuclear unit No. 1 with little offseting rate relief. As mentioned earlier, the Commission permitted an $11.9 million interim increase amounting to less than 1% of revenues, to become effective April 4, 1978, subject to refund. We anticipate the final order by year-end 1978. In the first half of 1978 kwh sales experienced a 2.5% gain, gas sales were up 9.3%, AFC was down about 10%, and maintenance and depreciation charges were up 15% and 13%, respectively. Favorable interchange sales during the coal strike aided the Company's results.

Our expectations for the balance of 1978 are for continued earnings attrition until significant rate relief becomes effective. The 11¢ per share non-recurring benefit from transition to monthly billing in the latter half of 1977 will be phased out during the balance of 1978. Additionally, the new energy clause will eliminate any advantage to the Company from interchange sales or nuclear fuel savings as both of these components are automatically passed through to customers. Thus, we estimate 1978 earnings at $1.55 per share. The Company has announced deferment of the Common stock offering previously planned for fall of 1978. Based on 7% additional average outstanding shares, a return of around 8.2% on average Common equity is indicated.

The most important factor affecting the level of earnings in 1979 will be the amount of rate relief obtained. The Company will be burdened by costs associated with the installation of the second Salem nuclear unit which is anticipated to be placed in commercial operation at mid-year. A large amount of rate relief is required to offset the higher fixed and operating costs of the Salem nuclear units estimated at around $60 million annually for each. We look for a 3%-4% kwh growth and around $30 million in costs related to a half year's operation of the new generating unit. Assuming $90 million of rate relief initially reflected during the year, 5% more average shares, and higher financing costs not offset by AFC, we estimate 1979 earnings at $1.80 per share. This estimate would produce a return of about 9.5% on average Common equity.

In response to a projected 3% annual gain in kwh sales, Philadelphia Electric has stretched out its construction plans with new units now scheduled for 1985 and 1987. Invested capital growth is anticipated to compound at a below average 6% annual rate with around 45% internal cash generation. Beginning in 1980 AFC will rise on a per share basis. Financial pressures could begin to ease somewhat in the early 1980s. However, in view of the very low level of current earnings and returns being achieved coupled with the relatively large size of the Company and the number of outstanding Common shares, large dollar amounts of rate relief will still be required for the Company to restore earnings and returns to acceptable levels.

Dividends

The $1.80 annual dividend was established March 1977, up from $1.64 which had been paid since 1967. Based on a 17-3/4 price for the Common stock, the yield is 10.1%. In 1977, 27% of the dividend was considered a tax-free return of capital. Some portion may also be so classified in 1978. We think the dividend will be paid at the current rate at least until a rate decision is forthcoming, at which time the Board of Directors will review the earnings outlook for the next year or two. The dividend cash coverage for 1978 is estimated at around 1.75 times. This is below average but adequate. The Company has a Shareholders' Reinvestment Plan and a voluntary Employee Stock Purchase Plan.

Management

Mr. Robert E. Gilkinson (61), Chairman of the Board, joined Philadelphia Electric in 1939, held various positions including that of President for six years and was elevated to his present position in 1971. Mr. James L. Everett (52), a mechanical engineer, has been employed by the Company for 28 years and became President in 1971. He was designated the Chief Executive Officer April 1978. A new position was created April 1978 with the advancement of John H. Austin, Jr. (50) to Executive Vice President. He previously held several technical and accounting positions, most recently as Vice President - Finance and Accounting. Eleven Vice Presidents (including Joseph K. Pacquette, Jr. (44), recently named Vice President - Finance and Accounting,) and eight other officers comprise the senior management roster.

The eleven-member Board of Directors is composed of the three top corporate officers plus eight outside leaders from business, financial, government and educational institutions.

In our opinion, management is capable and experienced in utility operations. Management has had to contend with a sluggish territory and an increasingly political and unresponsive regulatory climate which has not enabled the Company to obtain sufficient rate relief to offset the increasing operating, construction and capital costs. Clearly, the principal challenge of management is to improve returns and earnings per share.

Dorothy M. Jelinek, C.F.A.

PHILADELPHIA ELECTRIC COMPANY

Capitalization

	December 31, 1967		1972		1977	
	$1,000	%	$1,000	%	$1,000	%
Debt - Long-Term	701,548	52.0	1,300,759	49.3	2,106,926	51.4
Debt - Other	47,700	3.5	103,810	4.0	14,875	0.4
Preferred Stock	87,472	6.5	337,472	12.8	534,268	13.1
Common Equity	512,599	38.0	894,686	33.9	1,437,202	35.1
Total	1,349,319	100.0	2,636,727	100.0	4,093,271	100.0
Index (1967 = 100)						
Company		100		195		303
D&P Avg.		100		177		298
Shares Outstanding		29,031,919		44,728,691		74,624,517
Book Value per Share		$17.66		$20.00		$19.26

Earnings Record

	Oper. Revenues ($1,000)	Income Before Interest ($1,000)	Earned on Avg. Capitalization %	Balance for Common ($1,000)	Earned on Avg. Com. Equity %	Inc. Tax Rate %
1977	1,394,762	337,067	8.50	132,734	9.6	29
1976	1,224,141	315,781	8.43	125,596	9.9	32
1975	1,134,810	288,317	8.14	107,899	9.4	31
1974	1,011,726	249,560	7.75	95,415	8.9	24
1973	766,658	213,183	7.56	95,267	9.8	25
% Gain 1972-1977						
Company	104	81		54		
D&P Avg.	128	90		71		
1972	685,038	185,759	7.56	86,416	10.3	29
1971	608,134	160,769	7.54	78,304	10.8	27
1970	504,371	126,382	6.88	59,764	9.4	24
1969	440,494	109,277	6.93	58,366	10.3	36
1968	405,231	96,323	6.83	56,424	10.9	36
% Gain 1967-1972						
Company	82	101		45		
D&P Avg.	65	83		45		

Common Stock Data

	Earnings $	Shares Outstanding (1,000)	Dividend Rate $	Payout %
7/31/78	1.65	73,979	1.80	109.1
1977	1.87	70,844	1.80	96.3
1976	1.91	65,606	1.64	85.9
1975	1.86	58,135	1.64	88.2
1974	1.81	52,717	1.64	90.6
1973	1.99	47,847	1.64	82.4
% Gain 1972-1977				
Company	(10)	71	10	
D&P Avg.	12	55	22	
1972	2.08	41,505	1.64	78.8
1971	2.10	37,323	1.64	78.1
1970	1.84	32,556	1.64	89.1
1969	1.97	29,644	1.64	83.2
1968	1.94	29,032	1.64	84.5
% Gain 1967-1972				
Company	(2)	49	0	
D&P Avg.	21	20	16	

	Market				P/E Ratios		Yield	
	High $	Low $	Close $	To Book %	High	Low	Low %	High %
7/31/78	20.2	16.7	17.6	92	12.3	10.2	8.89	10.67
1977	21.2	17.1	19.5	102	11.4	9.2	8.47	10.51
1976	18.0	14.7	17.7	93	9.4	7.8	9.11	11.03
1975	15.4	11.1	15.0	79	8.3	6.0	10.58	14.74
1974	19.4	9.3	10.7	54	10.8	5.2	8.41	17.49
1973	23.4	17.0	18.0	89	11.8	8.5	6,98	9.65
1972	25.0	21.2	22.6	114	12.0	10.2	6.56	7.72
1971	25.1	20.5	23.7	122	12.0	9.8	6.53	7.95
1970	24.7	19.0	22.4	119	13.5	10.3	6.59	8.63
1969	32.1	22.0	24.0	127	16.3	11.2	5.11	7.45
1968	32.4	27.2	31.1	171	16.8	14.0	5.05	6.02

a - Market data for the latest 52 weeks through 9/18/78.

PHILADELPHIA ELECTRIC COMPANY

Operating Data
1977

	Electric ($1,000)	%	Gas ($1,000)	%
Revenues				
Residential	427,622	36.3	93,753	53.6
Commercial	168,435	14.3	38,299	21.9
Industrial	513,383	43.6	42,099	24.1
Other	68,249	5.8	667	0.4
Total	1,177,689	100.0	174,818	100.0
% of Total	84		13	
Net Operating Income	198,606		20,861	
% of Total	89		9	

Growth Trends

	% Increase 1972-1977			
	Electric		Gas	
	Company	Industry	Company	Industry
Customers	5	12	(1)	5
Sales - Retail				
Residential	18	28	1	(7)
Commercial	13	30	68	1
Industrial	6	18	(47)	(22)
Total	11	24	(15)	(17)
Revenues - Retail	105	124	88	122
Residential Usage per Customer	12	13	-	-

Power Supply

Year	Generating Capability* mw	Net Firm Purchases* mw	Total* mw	Peak Load# mw	Annual Growth %	Reserve Margin %
1982E	8,405	-	8,405	6,700	3	25
1981E	8,411	-	8,411	6,500	3	29
1980E	8,428	-	8,428	6,300	3	34
1979E	7,954	-	7,954	6,090	3	30
1978E	7,954	-	7,954	5,888	-	35
1977	8,202	-	8,202	5,888	10	39
1976	7,166	-	7,166	5,346	(3)	34
1975	7,214	-	7,214	5,530	2	30
1974	6,768	200	6,968	5,431	(6)	28

* - At time of peak.

Unit Revenue and Cost Trends

Electric

	1977	1976	1975	1974	1973
Total Operating Revenues					
Mills/Kwh Sold	43.3	39.0	38.6	34.2	24.6
Production & Trans. Exp.					
Mills/Kwh Sold	21.0	17.7	17.9	17.7	10.6
% Revenues	48.6	45.5	46.5	51.9	43.2
Average Fuel Cost					
Cents/Million Btu	140.4	124.2	122.5	142.3	71.0
Mills/Kwh Generated	15.3	13.1	12.9	15.2	7.5
Average System Input Cost					
Mills/Kwh - Net Load	19.3	15.9	16.2	16.1	9.6
Other Operating Exp.					
$/Customer	113.29	99.79	91.55	77.33	72.72
% Revenues	12.2	12.2	11.4	10.9	13.8
Depreciation					
% Avg.Gross Plt.in Serv.	2.9	2.9	2.8	2.4	2.7
% Revenues	8.2	8.5	8.2	7.8	8.9
General Taxes					
% Avg.Gross Plt.in Serv.	2.4	2.4	2.4	2.1	2.3
% Revenues	6.9	7.1	7.2	6.9	7.8
Net Operating Income Before Income Taxes					
% Revenues	24.1	26.7	26.7	22.5	26.3
After Income Taxes					
% Revenues	16.9	18.2	18.3	15.5	20.2
Avg. Net Plt. in Serv.					
Per $1 Revenue	2.14	2.23	2.27	2.18	2.40
Mills/Kwh Sold	92.9	87.1	87.5	74.4	59.0
Net Oper.Inc./Avg.Plt.in Serv.					
% Before Income Taxes	11.2	12.0	11.8	10.3	11.0
% After Income Taxes	7.9	8.2	8.1	7.1	8.8

Gas

Total Operating Revenues					
¢/Therm Sold	28.4	25.7	21.8	17.0	15.1
Production, Trans. Exp. & Storage					
¢/Therm Sold	15.9	13.5	11.3	7.2	6.5
% Revenues	56.1	52.5	51.6	42.1	42.9
Average Purchased Gas Cost					
¢/Therm	16.0	12.4	10.5	6.9	5.9
Other Operating Exp.					
$/Customer	101.67	87.00	81.25	78.17	81.85
% Revenues	15.8	14.9	18.8	19.7	22.4
Depreciation					
% Avg.Gross Plt.in Serv.	2.9	3.0	3.1	3.1	2.2
% Revenues	4.7	5.3	7.0	7.4	5.6
General Taxes					
% Avg.Gross Plt.in Serv.	3.5	3.3	2.7	2.5	2.5
% Revenue	5.7	5.7	6.0	6.1	6.4
Net Operating Income Before Income Taxes					
% Revenues	17.7	21.6	16.6	24.7	22.7
After Income Taxes					
% Revenues	11.9	14.1	13.6	17.1	16.9
Avg. Net Plt. in Serv.					
Per $1 Revenue	1.35	1.48	1.97	2.10	2.25
¢/Therm Sold	38.2	37.9	43.0	35.8	34.0
Net Oper.Inc./Avg.Net Plt.in Serv.					
% Before Income Taxes	13.1	14.7	8.4	11.7	10.1
% After Income Taxes	8.9	9.6	6.9	8.1	7.5

DUFF AND PHELPS, INC.

FIXED INCOME SECURITIES DATA — January 7, 1974

PHILADELPHIA ELECTRIC COMPANY

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	Ratings		
	D&P	Moody's	S&P
Mortgage Bonds	2	Aa*	AA
Preferred Stock	1		AAϕ

* - Downgraded one level in 1970 ϕ - Downgraded one level in 1968

	Pro Forma 1973#	1973#	1972	1971	1970
Times Earned Pre-Tax:					
Total Debt Interest Excl. IDC	2.08	2.24	2.36	2.42	2.23
Incl. IDC	2.66	2.87	2.91	2.90	2.55
Times Earned After-Tax:					
Total Int. & Pfd. Divs.(a)	1.72	1.83	1.87	1.95	1.90
Margin of Safety					
Total Interest - %(a)	20.9	21.8	21.7	20.9	17.8
Capital Ratios - Debt - %	50.9	50.1	53.3	54.0	56.8
- Preferred	13.9	14.1	12.8	11.5	9.7
- Common	35.2	35.8	33.9	34.5	33.5
% Increase Avg. Capital.	15.2E	14.2E	15.2	16.1	16.4
Int. Cost on Avg. Debt - %	6.62E	6.24E	5.91	5.70	5.56
% Earned on Reported Avg. Capitalization	5.69E	5.62E	5.84	6.13	6.06
Common Equity	9.3E	10.0E	10.3	11.6	10.8

(a) - IDC included in Income.

\# - October 31, 1973; Pro forma for $125 million bond offering scheduled January 16, 1974, assumed interest 8%.

Including the unreflected portion of a 9% electric rate increase received in August, 1973, pro forma pre-tax coverages would be closer to 2.65 times excluding IDC and 3.30 times including IDC. Coverages since 1970 have benefited from periodic rate relief and sales of equity. A substantial electric rate increase filing is planned for later in January, 1974. We consider Pennsylvania regulation as reasonable and constructive.

Construction continues relatively heavy geared largely to adding nuclear capacity. About 75% of capital requirements in the five years ending 1977 need to be obtained externally. We project capitalization in these five years increasing about 14% annually, on average. We look for capitalization ratios to remain relatively well balanced and with continued management aggressiveness in seeking rate relief, current debt quality ratings should be maintained.

RJS/mb

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DUFF AND PHELPS

FIXED INCOME SECURITIES DATA

March 2, 1976

PHILADELPHIA ELECTRIC COMPANY

	Pro Forma	% of Cap.	Ratings D&P	Moody's	S&P
Capitalization:					
$3,655 million	Mtg. Bonds	44.5	2-Med	A(1)	A-(2)
Revenues:	Debentures	3.5	3-Med	Baa	BBB
$1,135 million	Pfd.Stock	13.3	2	"a"	BBB(3)

(1) - Downgraded one level in 1970 and again in October 1974.
(2) - Downgraded one level in 1968, October 1974 and again in Feb. 1976.
(3) - Downgraded one level in 1968, April 1974 and again in October 1974.

	Pro Forma 1975	1975	1974	1973	1972
Times Earned Pre-Tax:					
Total Debt Interest					
Excl. IDC	1.91	1.98	1.83	2.16	2.36
Incl. IDC	2.36	2.44	2.42	2.81	2.91
Times Earned After-Tax:					
Total Int. & Pfd. Divs.(a)	1.57	1.60	1.62	1.81	1.87
Margin of Safety					
Total Interest - % (a)	17.9	18.3	16.9	21.3	21.7
% Capital Ratios - Tot.Debt	53.2	53.2	54.4	51.0	53.3
- Preferred	13.3	13.3	14.2	13.7	12.8
- Common	33.5	33.5	31.4	35.3	33.9
% Increase Avg. Capital.	10.1	10.1	14.1	14.9	15.2
Int. Cost on Avg. Debt - %	7.67	7.57	7.08	6.15	5.91
% Earned on Reported Avg.					
Capitalization	8.20	8.14	7.75	7.56	7.56
Common Equity	9.1	9.4	8.9	9.8	10.3

(a) - IDC included in income.

Construction forecasts are $437 million for 1976 and an aggregate of $2,242 million for 1976-1979. We estimate internal funds will provide 30% of 1976 needs and 42% for 1977-1979. Capitalization is expected to increase 10% annually and debt, Preferred and Common sales are scheduled in each of the years through 1979. We anticipate 1976 pretax total debt interest coverages to decline slightly to 1.85 times ex IDC and 2.3 times including IDC. The Company received $24 million (2.5%) of rate relief effective February 1976 and $70 million additional is currently pending. Pennsylvania regulation is subject to uncertainty with recent installation of two new Commission members. With annual sales of additional Common stock and adequate rate relief, we think coverages will be satisfactory to maintain current ratings.

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DUFF AND PHELPS

FIXED PUBLIC UTILITY SECURITIES DATA

April 12, 1976

PHILADELPHIA ELECTRIC COMPANY

	Pro Forma@	% of Cap.	Ratings D&P	Moody's	S&P
Capitalization:					
$3,655 million	Mtg. Bonds	43.3	2-Med	A(1)	A-(2)
Revenues:	Debentures	4.2	3-Med	Baa	BBB
$1,144 million	Pfd.Stock	14.6	2	"a"	BBB(3)

(1) - Downgraded one level in October 1974.
(2) - Downgraded one level October 1974 and again in Feb. 1976.
(3) - Downgraded one level April 1974 and again in October 1974.

	Pro Forma= 1975	1975	1974	1973	1972
Times Earned Pre-Tax:					
Total Debt Interest					
Excl. IDC	1.97	1.98	1.83	2.16	2.36
Incl. IDC	2.43	2.44	2.42	2.81	2.91
Times Earned After-Tax:					
Total Int. & Pfd. Divs.(a)	1.55	1.60	1.62	1.81	1.87
Margin of Safety					
Total Interest - % (a)	18.2	18.3	16.9	21.3	21.7
% Capital Ratios - All Debt	51.9	53.2	54.4	51.0	53.3
- Preferred	14.6	13.3	14.2	13.7	12.8
- Common	33.5	33.5	31.4	35.3	33.9
% Increase Avg. Capital.	10.1	10.1	14.1	14.9	15.2
Int. Cost on Avg. Debt - %	7.66	7.57	7.08	6.15	5.91
% Earned on Reported Avg.					
Capitalization	8.15	8.14	7.75	7.56	7.56
Common Equity	8.9	9.4	8.9	9.8	10.3

(a) - IDC included in income.
= - Pro formed for February sale of $100 million Mortgage Bonds and April sale of Preferred with proceeds used to repay debt.

Construction forecasts are $437 million for 1976 and an aggregate of $1,986 million for 1976-1979. We estimate internal funds will provide 31% of 1976 needs and 42% for 1977-1979. Capitalization is expected to increase 9% annually and debt, Preferred and Common sales are scheduled in each of the years through 1979. We anticipate 1976 coverages to decline slightly from 1975 levels. The Company received $24 million (2.5% of rate relief effective February 1976 and $70 million additional is currently pending. Pennsylvania regulation is subject to uncertainty with recent installation of two new Commission members. We rank Pennsylvania regulation as Group IV, slightly below average in our Group I (highest) to Group VI (lowest) rating system. With annual sales of additional Common stock and adequate rate relief, we think earnings protection for the senior securities will be satifactory to maintain current ratings.

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September 30, 1976

PHILADELPHIA ELECTRIC COMPANY

	Pro Forma ø	% of Cap.	Ratings D&P#	Moody's	S&P
Capitalization:	Mtg. Bonds	43.9	7	A(1)	A(2)
$3724 million	Debentures	4.0	8	Baa	BBB
Revenues:	Pfd. Stock	14.0	8	"a"	BBB(3)
$1164 million					

(1) - Downgraded one level October 1974; (2) - Downgraded one level October 1974 and again February 1976; (3) - Dowgraded one level April 1974 and again October 1974.

	Pro Forma 1976ø	1976ø	1975	1974	1973
Times Earned Pre-Tax:					
Total Debt Interest					
Excl. AFC	1.91	1.99	1.98	1.83	2.16
Incl. AFC	2.38	2.48	2.44	2.42	2.81
Times Earned After-Tax:					
Total Int. & Pfd. Divs. (a)	1.55	1.62	1.60	1.62	1.81
Margin of Safety					
Total Interest - % (a)	18.1	18.6	18.3	16.9	21.3
% Capital Ratios - All Debt	52.0	52.5	53.2	54.4	51.0
- Preferred	14.0	14.4	13.3	14.2	13.7
- Common	34.0	33.1	33.5	31.4	35.3
% Increase Avg. Capital.	8.0	6.5 E	10.1	14.1	14.9
Int. Cost on Avg. Debt - %	7.71	7.63	7.57	7.08	6.15
% Earned on Reported Avg.					
Capitalization	8.17	8.20	8.14	7.75	7.56
Common Equity	8.7	9.6	9.4	8.9	9.8

(a)-AFC in Income E-Estimate ø-12 months ended May 31, 1976

Construction forecasts have been revised downward to $388 million for 1976, $414 million for 1977, and an aggregate of $2,140 million for 1976-1980. Internal funds are expected to provide 55% of 1976 construction requirements and 40% for 1977-1980. Our projected capitalization growth averages 8% annually 1976-1980 as compared to 13% compounded for the five years ended 1975. Rate relief of $24 million (2.5%) became effective February 1976, $23 million (2.3%) in August 1976 and PUC orders pertaining to an additional $59 million are expected by late fall 1976. We rank Pennsylvania regulation as Group IV, slightly below average in our six-step rating system. We estimate year-end 1976 pre-tax total debt coverages at 1.85 times ex AFC and 2.30 times including AFC. With a moderating trend in capitalization growth and in external financing coupled with annual sales of common and adequate rate relief, we think earnings protection for the senior securities will be satisfactory.

Dorothy M. Jelinek, C.F.A.

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FIXED
INCOME
SUMMARY

Duff and Phelps, Inc. | Utility investment research service

March 1, 1977

PHILADELPHIA ELECTRIC COMPANY

	Pro Forma	% of Cap.	Ratings D&P	Moody's	S&P
Capitalization:					
$3,841 million	Mtg. Bonds	44.9	7	A	A-
Revenues:	Debentures	3.8	8	Baa	BBB
$1,224 million	Pfd. Stock	13.6	8	"a"	BBB

	Pro Forma 1976	1976	1975	1974	1973
Times Earned Pre-Tax:					
Total Debt Interest					
Excl. AFC	1.96	2.08	1.98	1.83	2.16
Incl. AFC	2.45	2.59	2.44	2.42	2.81
Times Earned After-Tax:					
Total Int. & Pfd. Divs. (a)	1.59	1.66	1.60	1.62	1.81
Margin of Safety					
Total Interest - % (a)	18.9	19.6	18.3	16.9	21.3
% Capital Ratios - All Debt	52.7	51.6	53.2	54.4	51.0
- Preferred	13.6	13.9	13.3	14.2	13.7
- Common	33.7	34.5	33.5	31.4	35.3
% Increase Avg. Capital.	7.1	5.8	10.1	14.1	14.9
Int. Cost on Avg. Debt - %	7.72	7.70	7.57	7.08	6.15
% Earned on Reported Avg.					
Capitalization	8.44	8.43	8.14	7.75	7.56
Common Equity	9.4	9.9	9.4	8.9	9.8

(a) - AFC included in income.

Electric operations provided 84% of 1976 revenues and 88% of pre-tax operating income; the balance was derived from gas and steam. Construction is budgeted at $414 million for 1977, $390 million for 1978, and $1,752 million for the four years 1977 through 1980. The Company estimates internal sources can provide about 42% of 1977-1980 requirements. Invested capital will compound 8.2% annually as compared with a 10% rate applicable to the prior four-year period ended 1976. We rank Pennsylvania regulation in Group III in our I (highest) to VI (lowest) rating system. Fuel generation in 1977 is expected to be 29% coal, 27% nuclear, 21% oil, 4% hydro, and 19% other. We estimate 1977 pre-tax total debt interest coverages at 1.9 times ex AFC and 2.4 times including AFC. A moderating rate of growth in capitalization coupled with rate relief and sale of Common should allow earnings protection for the senior securities to be satisfactory.

Dorothy M. Jelinek, C.F.A.

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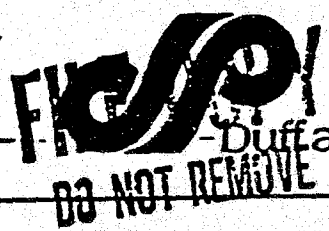
FIXED INCOME SUMMARY



Duff and Phelps, Inc. | Utility investment research service

September 27, 1977

PHILADELPHIA ELECTRIC COMPANY

Fixed Income Securities	Amount $MM	% of Cap.	Ratings D&P	Moody's	S&P
Mortgage Bonds	1,804	44.5	7	A	A-
Debentures	150	3.7	8	Baa	BBB
Preferred Stock	535	13.2	8	"a"	BBB

		Pro Forma 7/31/77	7/31/77	December 31 1976	1975	1974
Total Capitalization	$MM	4,052	4,005	3,841	3,655	3,431
All Debt	%	52.1	53.5	51.6	53.2	54.4
Pfd.	%	13.2	13.3	13.9	13.3	14.2
Common	%	34.7	33.2	34.5	33.5	31.4
Increase Avg. Capital.	%	7.0E	6.3E	5.8	10.1	14.1
Avg. Debt Int. Cost	%	7.8	7.7E	7.7	7.6	7.1
Coverages and Ratios						
Pre-Tax - Tot. Int.						
Excl. AFC	X	2.03	2.11	2.08	1.98	1.83
Incl. AFC	X	2.56	2.67	2.59	2.44	2.42
Aftax-Int. & Pfd. Div.	X	1.68	1.72	1.66	1.60	1.62
Margin of Safety	%	19.3	19.8	19.6	18.3	16.9
Earned on Average						
Total Capitalization	%	8.8E	8.8E	8.4	8.1	7.6
Common Equity	%	10.5E	11.1E	9.9	9.4	8.9
Effective FIT Rate	%	39 E	41 E	42	41	37

Comment: Our ratings reflect the easing of pressures associated with financing of the construction program over the near term. Capitalization growth is expected to be well below the D&P Average through 1979. However, with below-average kwh sales growth forecast for the territory combined with limited growth prospects in the gas area, the Company will still be dependent on periodic rate relief.

The Company filed a two-part electric rate petition August 1977. The first part seeks to transfer the existing electric fuel adjustment charges into base rates, eliminate the electric fuel adjustment clause for residential and small commercial customers (30% of kwh sales) and to substitute a new energy clause for other customers. Part two calls for a $119 million increase (11.5%) in electric rates, part of which covers inclusion of the Salem No. 1 nuclear unit into rate base. Both parts have been suspended to April 1978. In the meantime, most of the nuclear fuel savings accrue to the customers. The Pennsylvania Commission is also studying a new generic fuel clause for the state. Long term coverages are expected to be stable with enhanced cash flow, a below average construction program, annual sales of Common and moderate amounts of rate relief.

Dorothy M. Jelinek, C.F.A.

SUITE 4000 · 55 EAST MONROE STREET · CHICAGO, ILLINOIS 60603 · (312) 263-2610 · TELEX 25-5165

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February 22, 1978

PHILADELPHIA ELECTRIC COMPANY

Fixed Income Securities	Amount $MM	% of Cap.	Ratings D&P	Moody's	S&P
Mortgage Bonds	1,878	45.2	7	A	A-
Debentures	149	3.6	8	Baa	BBB
Preferred Stock	534	12.9	8	"a"	BBB

		Pro Forma 1977	December 31 1977	1976	1975	1974
Total Capitalization	$MM	4,153	4,093	3,841	3,655	3,431
All Debt	%	52.5	51.8	51.6	53.2	54.4
Pfd.	%	12.9	13.1	13.9	13.3	14.2
Common	%	34.6	35.1	34.5	33.5	31.4
Increase Avg. Capital.	%	6.7	5.9	5.8	10.1	14.1
Avg. Debt Int. Cost	%	8.0	8.0	7.7	7.6	7.1
Coverages and Ratios						
Pre-Tax - Tot. Int.						
Excl. AFC	X	1.84	1.97	2.08	1.98	1.83
Incl. AFC	X	2.33	2.49	2.59	2.44	2.42
Aftax-Int.	X	1.59	1.65	1.66	1.60	1.62
Margin of Safety	%	16.6	17.5	19.6	18.3	16.9
Earned on Average						
Capitalization	%	-	8.5	8.4	8.1	7.6
Common Equity	%	-	9.6	9.9	9.4	8.9
Effective FIT Rate	%	-	40	42	41	37

Comment: Our ratings reflect a reasonable capital structure and a manageable construction program. However, sluggish sales growth in the important electric division mandate dependency on periodic rate relief coupled with annual sales of Common.

Coverages slipped in 1977 as a result of the operation of the nuclear Salem No. 1 generating unit at mid-year. Only modest rate relief was reflected in 1977. The Company filed for a $119 million two-part electric increase in August 1977, a portion of which reflects the impact of the Salem unit. The Company requested $53.6 million of interim relief while an Administrative Law Judge recommended $32.5 million in December 1977. A Commission decision is expected February 24, 1978 and a final Order is anticipated around April 1978. In the meantime, almost all of the nuclear fuel cost savings has accrued to customers. The Pennsylvania Commission has proposed a new generic fuel clause (ECR) for the state effective July 1978 which could be detrimental in its present form. Even with substantial rate relief, we expect modest erosion in coverages in 1978.

Dorothy M. Jelinek, C.F.A.

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FIXED INCOME SUMMARY

Duff and Phelps, Inc.

Utility investment research service

September 21, 1978

PHILADELPHIA ELECTRIC COMPANY

Fixed Income Securities	Amount $MM	% of Cap.	Ratings D&P	Moody's	S&P
Mortgage Bonds	1,874	44.4	8	A	A-
Debentures	149	3.5	9	Baa	BBB
Preferred Stock	583	13.8	9	"a"	BBB

		6/30/78	December 31, 1977	1976	1975	1974
Total Capitalization	$MM	4,222	4,093	3,841	3,654	3,432
All Debt	%	52.0	51.8	51.6	53.2	54.4
Pfd.	%	13.8	13.1	13.9	13.3	14.2
Common	%	34.2	35.1	34.5	33.5	31.4
Increase Avg. Capital.	%	6.3	5.9	5.8	10.1	14.1
Avg. Debt Int. Cost	%	7.9	8.0	7.7	7.6	7.1
Coverages and Ratios						
Pre-Tax - Tot. Int.						
Excl. AFC	X	2.0	2.0	2.1	2.0	1.8
Incl. AFC	X	2.5	2.5	2.6	2.4	2.4
Aftax-Int. & Pfd Div.	X	1.6	1.6	1.7	1.6	1.6
Margin of Safety	%	17.2	17.6	19.7	18.3	16.9
Earned on Average						
Total Capitalization	%	8.3	8.5	8.4	8.1	7.8
Common Equity	%	9.2	9.6	9.9	9.4	8.9
Income Tax Rate	%	32	29	32	31	24

Comment: The Company has a reasonable capital structure and a manageable construction program. However, sluggish electric sales growth together with low current returns and coverages indicate the need for both substantial periodic rate relief and annual sales of Common. Sale of Common and bonds has been delayed until the first quarter of 1979; short-term bank loans are being utilized in the interim.

Operations in the latter half of 1977 were impacted significantly by the commercial operation of the nuclear Salem No. 1 generating unit offset in part by a non-recurring gain from the changeover to monthly billing. In early 1978 some benefit was derived from interchange sales during the coal strike and a $10.8 million interim allowed by the Commission in March. A final order relating to the $119 million (11.5%) August 1977 filing is anticipated by yearend 1978.

We expect coverages to remain under pressure until rate relief beyond that currently filed is obtained to offset the increase in fixed and operating costs associated with the mid-1979 commercial operation of the Salem No. 2 nuclear unit. Two wholly-owned Limerick nuclear generating plants have been deferred until 1985 and 1987.

Dorothy M. Jelinek, C.F.A.

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October 8, 1979

PHILADELPHIA ELECTRIC COMPANY

Fixed Income Securities	Pro Forma 7/31/79 SMM	% of Cap.	D&P	Ratings: Moody's	S&P
Mortgage Bonds	1,970	43.9	8	A	A-
Debentures	147	3.3	9	Baa	BBB
Preferred Stock	580	12.9	9	"a"	BBB

		1980E	1979E	7/31/79	1978	1977	1976
Total Capitalization	$MM	4,850	4,600	4,438	4,301	4,093	3,841
All Debt	%	53	53	52.3	52.1	51.8	51.6
Preferred	%	13	12	13.1	13.6	13.1	13.9
Common	%	34	35	34.6	34.3	35.1	34.5
Increase Avg. Capital.	%	6.2	6.0	5.4E	5.8	5.9	5.8
Avg. Debt Int. Cost	%	8.7	8.4	8.4E	8.2	8.0	7.7
Coverages and Ratios							
Pre-Tax - Tot. Int.							
Excl. AFC	X	1.9	1.8	1.8	1.9	2.0	2.1
Incl. AFC	X	2.4	2.4	2.4	2.4	2.5	2.6
Aftax-Int. & Pfd. Div.	X	1.6	1.7	1.7	1.6	1.6	1.7
Margin of Safety	%			17.7	17.6	17.6	19.7
Earned on Average							
Total Capitalization	%			9.0E	8.7	8.5	8.4
Common Equity	%			10.3E	9.7	9.6	9.9
Income Tax Rate	%			24	28	29	32

Comment: Philadelphia Electric provides electric, gas and steam service to areas of southeastern Pennsylvania. The service territory is subject to cyclical economic fluctuations because of the recession-prone heavy industry mix, including metal, machinery and rubber production. Customer and sales growth has been below average, as commercial and industrial growth was sluggish in recent years. Kwh sales growth is forecast to remain below average at 2%-3% annually over the next several years.

Construction is forecast at $406 million for 1979, about equal to 1978. However, after 1979, expenditures should steadily increase, reaching $677 million in 1983. The 1979-83 budget totals $2.8 billion versus $2.0 billion for the previous five years. The Company has a 43% interest in Public Service E&G's 1,115 mw Salem 2 nuclear unit, now expected to be in service by mid-1980. With reserve margins projected to average about 32% through 1983, the Company has agreed to sell Jersey Central Power & Light energy from its 474 mw share of Salem 2 until at least 1984. Philadelphia Electric has two wholly-owned Limerick nuclear units, each 1,055 mw, planned for 1985 and 1987.

Coverages have remained within a narrow range in recent years, declining slightly in 1977 and 1978 with the addition of new capacity and increases in related fixed and operating costs. We look for 1979 and 1980 coverages to remain at about the 1978 levels or slightly lower. A $3 million steam rate increase was recently granted, and a small gas increase is expected by the end of 1979. An order in the pending $123 million (9.8%) electric rate increase is expected in the first half of 1980. AFC should continue to rise until Salem 2 is in operation. Over the longer term, coverages should remain fairly stable assuming periodic rate relief in a below average regulatory climate. Despite annual Common stock sales, we see no significant increase in the Common equity ratio over the next few years. With low returns earned, the Common stock payout ratio has been 90% or above, permitting little plowback.

Byron C. Karzas, C.F.A.
Mary Beth M. Bopp

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FIXED INCOME SUMMARY
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Duff and Phelps, Inc. | Utility investment research service

March 11, 1980

PHILADELPHIA ELECTRIC COMPANY

Fixed Income Securities	Pro Forma 12/31/79 SMM	% of Cap.	Ratings D&P	Moody's	S&P
Mortgage Bonds	1,970	42.7	8	A	A-
Debentures	146	3.2	9	Baa	BBB
Preferred Stock	654	14.2	9	"baa"[a]	BBB

a Lowered one level in February 1980.

		1981E	1980E	1979	1978	1977	1976
Total Capitalization	$MM	5,290	5,015	4,615	4,301	4,093	3,841
All Debt	%	52	53	53.2	52.1	51.8	51.6
Preferred	%	13	13	12.6	13.6	13.1	13.9
Common	%	35	34	34.2	34.3	35.1	34.5
Increase Avg. Capital.	%	7.0	8.0	6.2	5.8	5.9	5.8
Avg. Debt Int. Cost	%	9.1	8.9	8.5	8.2	8.0	7.7
Coverages and Ratios							
Pre-Tax - Tot. Int.							
Excl. AFC	X	1.7	1.7	1.6	1.9	2.0	2.1
Incl. AFC	X	2.3	2.3	2.2	2.4	2.5	2.6
Aftax-Int. & Pfd. Div.	X	1.6	1.6	1.6	1.6	1.6	1.7
Margin of Safety	%			15.2	17.6	17.6	19.7
Earned on Average							
Total Capitalization	%			8.9	8.7	8.5	8.4
Common Equity	%			9.8	9.7	9.6	9.9
Income Tax Rate	%			19	28	29	32

Comment: Coverages declined after 1976 reflecting (1) the addition of new capacity and increases in related fixed and operating costs, (2) lack of adequate rate relief, and (3) continued below average gains in customers and sales. The service territory is subject to cyclical economic fluctuations because of the large industrial mix.

Construction is forecast at $610 million for 1980, 45% higher than in 1979 due to inflation, increased NRC requirements for nuclear plants, and pollution-control additions. After 1980, expenditures should remain large, reaching $677 million in 1983. The Company has a 43% interest in the 1,115 mw Salem 2 nuclear unit, currently expected to be in service around fall 1980. With reserve margins projected at 27%-36% through 1983, the Company has agreed (subject to FERC approval) to sell Jersey Central Power & Light energy from its share of Salem 2 until at least 1984. Philadelphia Electric's two wholly-owned Limerick nuclear units, each 1,055 mw, are planned for 1985 and 1987.

The Company received small gas and steam rate increases in late 1979, and an electric rate order is anticipated in April 1980 on a $123 million (10%) request. The Administrative Law Judge has just recommended a $79.9 million increase. Even with these increases and assuming some additional rate relief late in 1981, we estimate 1980 and 1981 coverages remaining no better than level. In each year, financing costs should be sizeable with sales of debt and Preferred. Over the longer term, we look for coverages to stay under pressure unless rate relief becomes more responsive in meeting increasing operating expenses and capital costs. We see no significant improvement in the Common equity ratio, despite annual Common stock sales over the next few years.

Mary Beth M. Bopp

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Utility investment research service

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April 21, 1980

PHILADELPHIA ELECTRIC COMPANY

Fixed Income Securities	Actual 12/31/79 $MM	Actual 12/31/79 % of Cap.	Security Ratings D&P[a]	Mdy's	S&P[b]	Reg. Rank D&P
Mortgage Bonds	1,970	42.7	9	A	BBB+	IV
Debentures	146	3.2	10	Baa	BBB-	
Preferred Stock	579	12.6	10	"baa"	BBB-	

a New D&P ratings in expanded #1-#11 system: #9-Middle "BBB"; #10-Low "BBB".
b Lowered one level in April 1980.

Total Capitalization	$MM	1981E 5,310	1980E 5,030	1979 4,614	1978 4,301	1977 4,093	1976 3,841
All Debt	%	52	53	53.2	52.1	51.8	51.6
Preferred	%	13	13	12.6	13.6	13.1	13.9
Common	%	35	34	34.2	34.3	35.1	34.5
Incr. in Cap.	%	5.6	9.0	7.3	5.1	6.6	5.1
Avg. Int. Cost	%	9.1	9.0	8.5	8.2	8.0	7.7
Coverages							
Pre-Tax Int.							
Excl. AFC	X	1.7	1.6	1.6	1.9	2.0	2.1
Incl. AFC	X	2.2	2.2	2.2	2.4	2.5	2.6
Aftax-Int. & Pfd. Div.	X	1.6	1.6	1.6	1.6	1.6	1.7
Margin of Safety	%	-	-	15.2	17.6	17.6	19.7

Distinguishing Characteristics

Coverages declined after 1976 reflecting (1) the addition of new capacity and increases in related fixed and operating costs, (2) lack of adequate rate relief, and (3) continued below average gains in customers and sales. The service territory is subject to cyclical economic fluctuations because of the large industrial mix.

Construction is forecast at $610 million for 1980, 45% higher than in 1979 due to inflation, increased NRC requirements for nuclear plants, and pollution-control additions. After 1980, expenditures should remain large, reaching $677 million in 1983. The Company has a 43% interest in the 1,115 mw Salem 2 nuclear unit, currently expected to be in service around fall 1980. With reserve margins projected at 27%-36% through 1983, the Company has agreed (subject to FERC approval) to sell Jersey Central Power & Light energy from its share of Salem 2 until at least 1984. Philadelphia Electric's two wholly-owned Limerick nuclear units, each 1,055 mw, are planned for 1985 and 1987.

The Company received small gas and steam rate increases in late 1979, and an electric rate order is anticipated in April 1980 on a $123 million (10%) request. The Administrative Law Judge has recommended a $79.9 million increase. Even with these increases and assuming some additional rate relief late in 1981, we estimate 1980 and 1981 coverages remaining no better than level. In each year, financing costs should be sizeable with sales of debt and Preferred. Over the longer term, we look for coverages to stay under pressure unless rate relief becomes more responsive in meeting increasing operating expenses and capital costs. We see no significant improvement in the Common equity ratio, despite annual Common stock sales over the next few years.

Mary Beth M. Bopp

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DUFF AND PHELPS, INC.

BULLETIN PHILADELPHIA ELECTRIC COMPANY DATE October 7, 1974

REFER TO Our Summary dated July 17, 1974.

CROSS REFERENCE

NEW SIX AND TWENTY YEAR BONDS

On or about October 17, 1974, Philadelphia Electric proposes to sell two separate bond issues in a negotiated offering through underwriters headed by Drexel, Burnham & Company, Inc., and The First Boston Corporation. The two issues are (1) $50 million First and Refunding Mortgage Bonds, ____% Series, due October 15, 1980 and (2) $75 million First and Refunding Mortgage Bonds, ___% Series, due October 15, 1994. Net proceeds aggregating about $125 million will be used to refund at maturity $65 million 2-3/4% bonds due November 1, 1974 with the balance applied to partial repayment of short-term debt incurred for construction.

The six year $50 million Bond issue will carry a conventional five year non-call provision, i.e., prior to October 15, 1979, none of the new six year Bonds may be redeemed with proceeds of any refunding operation involving borrowed funds having an interest cost to the Company less than ___%. We expect this percentage to be the effective interest cost of the new six year issue. No sinking fund is provided for the six year issue.

For the 20 year $75 million new Bond issue, the non-call provision will be ten years or prior to October 15, 1984 rather than five years. In addition, the new 20 year Bonds will have a 5% annual sinking fund commencing in 1979. The sinking fund, equivalent to $3,750,000 annually, is designed to retire 75% of the new 20 year Bonds prior to maturity. At the Company's option the sinking fund could be doubled annually; this option is non-cumulative.

INVESTMENT OPINION

We carry the Company's outstanding mortgage bonds on our No. 2 Bond List (medium relative quality on that list) where we shall also place the new issues. Early in October 1974, Standard & Poor's downgraded the Company's bonds to single-A from double-A and its Preferred stock to triple-B from single-A. More recently, Moody's announced that it was reducing the rating on the Company's bonds from double-A to single-A.

As computed by us, latest coverages for the 12 months ended July, 1974 were at their lowest levels for quite some time after declining slightly, in general, in recent years. The Company adopted deferred fuel cost accounting earlier

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this year with the result that latest coverages are more liberally stated. Including the annualization of the April 4% rate increase, being collected subject to refund, we compute pro forma pretax coverages for long term debt interest at around 1.8 times excluding IDC and nearly 2.4 times including IDC. The April interim rate relief is the first part of a three part filing seeking $136 million or 21%. We expect a decision early in 1975.

Recently announced construction cutbacks for the five years ending 1978 amount to around 20%. The Company estimates that about 67% of total capital requirements in the five years ending 1978 will be financed externally with the other 33% obtained internally. We estimate total capitalization in these five years increasing slightly less than 10% annually. By comparison, the rate of increase was nearly 15-1/2% compounded annually in the prior five years. Pro forma capitalization ratios would include 44.7% bonds and 8.3% other debt for a total debt ratio 53.0%, 14.8% Preferred stock, and 32.2% Common stock equity.

We think the new six year issue in today's market would probably be offered at a yield around 10.75%. For the twenty year issue, the offering yield would probably be around 11.75%.

SYSTEM OPERATIONS

This utility provides electric service in and around Philadelphia and natural gas service in surburban Philadelphia. The electric department accounts for nearly 90% of after-tax net operating income. About 40% of total revenue is obtained within the city itself. The Company's current projections contemplate that following about a 2% decrease in electric sales for 1974 because of conservation measures and adverse weather, sales growth of about 5-1/2% in 1975 and 6%-7% for several years thereafter could be expected. The Company's projections seem reasonable to us.

Philadelphia Electric received general electric rate increases in 1969, 1971, and 1973. In January, 1974, the Company filed for additional electric rate increases of $136 million annually or about 21%. The filing was divided into three separate parts and was rather innovative inasmuch as, among other things, a forward looking test period is being sought. Part one was designed to increase revenue by $24 million or 4%, was in effect a "make-whole", and was allowed to go into effect subject to refund April 1, 1974. The Commission has suspended to January 1, 1975, the second and third steps amounting to $54 million (8%) and $58 million (9%), respectively, while it conducts an investigation as to the reasonableness of the entire $136 million. If everything goes as presently scheduled, a final decision on this three part filing would be handed down in early 1975.

In the past we have considered Pennsylvania regulation as reasonable and constructive. However, there is a risk that the regulatory climate could change inasmuch as the chairman of the Commission is a Republican whose term expires in 1975. If the present Democratic Governor is re-elected in November, 1974, we think it unlikely that the present chairman will be reappointed for another term with the result that the character of the Commission could change. Currently there is one vacancy on the five-man Commission and already one Governor-nominee has been turned down by the Senate which has the power of confirmation.

Power supply additions over the next decade are strongly oriented to nuclear power. In July, 1974, Peach Bottom No. 2, a nuclear generating unit with a capacity of 1,051 mw began commercial operation. Philadelphia Electric's share of this unit is 447 mw, equivalent to 43%. The Company is also entitled to 447 mw of Peach Bottom No. 3, the nuclear unit planned to go on line later this year.

Recently announced construction cut backs would delay the in service date of the six nuclear units at the Salem, Limerick and Fulton stations. The Salem No. 1 generating unit, of which the Company's portion is 464 mw, has been rescheduled from 1975 to late 1976 and the second Salem unit rescheduled to 1979 from 1976. Four units at the wholly-owned Limerick and Fulton units aggregating 4,430 mw are now scheduled for the 1981 through 1986 period. Also placed in service this 1974 summer were eight combustion turbine generating units with a total capacity of 432 mw. Two oil-fired units of 344 mw each are scheduled for operation in the fall of 1974 and the summer of 1975.

Company-owned generating capability is backed by the PJM Pool interconnection. Through the constant interchange of electricity, this integrated operation affords greater reliability and economy than would be possible if the power systems of the same companies were developed independently. The PJM installed capacity was approximately 37,400 mw on August 31, 1974 which provides a reserve margin of around 22% over the forecasted 1974 summer peak load.

Philadelphia Electric's electric output for 1974 is expected to be obtained 30% from oil-fired generation, 19% from service area coal-fired generation, 12% from jointly owned mine-mouth-fired coal generation, 10% from nuclear capacity, 5% from hydro capacity, 5% from internal combustion capacity, and 19% from net purchases from the PJM Pool, of which around one-half is generated on coal-fired equipment.

Effective January 1, 1974, the Company was allowed by the Pennsylvania Commission to institute a new fuel adjustment clause which recognized increases or

decreases in the average cost per kwh generated by all fossil fuels. The time lag for recoupment is about two months. The Company changed to deferred fuel cost accounting in May, 1974 retroactive to the first of the year.

With respect to obtaining the necessary oil for electric generation, Philadelphia Electric expects that its deliveries through at least June, 1975 will meet its projected requirements. At present, the Company's oil storage facilities have on hand about 15 days requirements. With respect to coal, the Company continues its attempts to increase its coal inventories. Currently on hand is around 600,000 tons which represents approximately a 95 day supply for the Philadelphia service area units currently burning coal.

In the gas department, the situation continues very tight and no new customers are being connected. The Company does not expect its supplies to improve appreciably in the immediate future nor is there any assurance that deliveries to it may not be further curtailed. The Company purchases natural gas from Texas Eastern Transmission Corporation and from Transcontinental Gas Pipeline Corporation. Because of the continued tight gas supply situation, it appears to us that the gas department will continue to be essentially a no-growth situation over the next several years.

CONSTRUCTION

The Company recently announced cutbacks in construction estimates of around 8% to $520 million for 1974 and 26% to $417 million for 1975. In addition, the Company now estimates that construction for the years 1975 through 1978 will amount to $1.7 billion representing a reduction of $430 million or around 20% from previous estimates.

As compared with the current construction estimates of $2,635 million in the five years ending 1978, gross property additions in the prior five years ended 1973 amounted to about $1,861 million. Whereas gross plant increased 88% or around 13.5% compounded annually in the five years ended 1973, we estimate gross plant increasing around 68% or around 11% compounded annually in the five years ending 1978, based on current estimates.

FINANCING AND CAPITALIZATION

The Company estimates that internally generated cash will provide about $133 million in 1974 or 25% of anticipated 1974 construction. For the entire five years ending 1978, total capital requirements are estimated at around $2,936 million consisting of construction expenditures and $300 million for sinking fund payment and bond maturities. The Company estimates that approximately 67%

of these capital requirements will be obtained externally and 33%
It currently appears that total capitalization in the five years endi
increase slightly less then 10% compounded annually. By comparison, the rate of increase was nearly 15-1/2% compounded annually in the prior five years ended 1973.

The depressed market price of the Company's Common stock has resulted in Philadelphia Electric deferring to a later date its $100 million Common stock sale previously scheduled for the fall, 1974. The market price of about 10 at present is only around 50% of book value. At the current depressed market price, such a $100 million offering would have necessitated about a 20% increase in shares outstanding. Current Company thinking is to perhaps sell additional Common after a decision in the pending rate case.

Actual and pro forma capitalizations as of July 31, 1974 are shown on the following page. Our pro forma adjustments include the proposed sale of Bonds, the retirement at maturity of a $65 million 2-3/4% bond issue, and a $60 million reduction in bank loans.

As computed by us, pro forma capitalization ratios would include 44.7% bonds and 8.3% other debt for a total debt ratio of 53.0%, 14.8% Preferred stock, and 32.2% Common stock equity. This would be below the Company's longer term objective of maintaining around a 37% Common stock equity ratio. Our calculations indicate that to have even a 35% Common equity at the end of 1978, some $500 million of outside Common stock equity would have to be raised. We expect sales of additional Common stock every year through 1978.

If coverages remain at or below present levels, the result may be greater use of unsecured debt or Common stock, or the further curtailment or rescheduling of a portion of the program if such unsecured debt or Common stock is not marketable on acceptable terms. To sell additional mortgage bonds, pre-tax earnings before IDC have to cover pro forma mortgage bond interest at least 2 times. On a pro forma basis, the coverage under the mortgage for the 12 months ended July 31, 1974 would be 2.01 times assuming the new Bonds at an average interest rate of 10-1/2%. To sell additional Preferred stock, the earnings test is 1.5 times as compared with an actual 1.47 times and based on this earnings coverage test, no Preferred stock may be issued at the present time.

VALUATION

Principal asset support for pro forma capitalization as of July 31, 1974 is shown on page 7. Carried at original cost, Philadelphia Electric had utility plant in service of $2,944 million at the balance sheet date. This was made

PHILADELPHIA ELECTRIC COMPANY

Capitalization - July 31, 1974

	Actual		Pro Forma	
	$ 1,000	%	$ 1,000	%
Debt:				
First & Refunding Mtg. Bonds				
23 Series - 2/3/4% - 9%				
due 1975 - 2004	1,350,200		1,350,200	
2-3/4% Series, due 1974	65,000		-	
—% Series, due 1980	-		50,000	
—% Series, due 1994	-		75,000	
Total Mortgage Bonds	1,415,200	42.9	1,475,200	44.7
Long-Term Notes due 1979	125,000	3.8	125,000	3.8
Pollution Control Note, 5.5%	40,000	1.2	40,000	1.2
4.85% S/F Debs., due 1986	29,387	0.9	29,387	0.9
Unamortized D. D. & Prem.	1,301*	-	1,301*	-
Subsidiary Debt	24,985	0.8	24,985	0.8
Total Long-Term Debt	1,633,271	49.6	1,693,271	51.4
Bank Loans	67,600	2.0	7,600	0.2
Commercial Paper	46,520	1.4	46,250	1.4
Total Debt	1,747,391	53.0	1,747,391	53.0
Preferred Stock - Cum., $100 Par				
11 Series, 3.8%-9.50%				
4,863,835 Shares	486,383	14.8	486,383	14.8
Total Debt & Preferred	2,233,774	67.8	2,233,774	67.8
Common Stock Equity:				
Common Stock - No Par				
52,804,226 Shares	777,641		777,641	
Other Paid-In Capital	1,305		1,305	
Retained Earnings	284,714		283,714	
Total Common Equity	1,062,660	32.2	1,062,660	32.2
Total Capitalization	3,296,434	100.0	3,296,434	100.0
Book Value Per Share - Preferred	$318.48			
- Common	20.12			

	$ 1,000
Utility Plant at Original Cost	2,944,233
Less: Depreciation Reserve	700,361
Net Plant in Service	2,243,872
Construction Work in Progress	1,013,750
Net Plant	3,257,622
Other Property and Investments	11,839
Pro Forma Net Working Capital	63,430
Total	3,332,891

up about 86% electric, 9% gas, and the small balance steam and common plant. The reserve for depreciation was equivalent to nearly 24% of plant in service. Despite the fact that the Peach Bottom No. 2 nuclear unit went in service early in July, 1974, construction work in progress at July 31, 1974 was substantial at $1,013.8 million. Overall, we arrive at total asset support of $3,332.9 million or some $36.5 million in excess of our pro forma capitalization. This primarily reflects nearly $61 million of deferred income taxes and unamortized investment credits which have been invested in plant, but are not included by us in capitalization, net of $26.6 million of deferred fuel expense carried as a deferred debit.

The pro forma mortgage bonds are equivalent to 45% of the aforementioned total net plant and 44.2% of the aforementioned asset support. In other words, there would be $2,259 of asset support for each $1,000 of pro forma mortgage bonds.

ACCOUNTING PRACTICES

Effective in 1971, PE started treating on a normalized basis the tax deferrals related to accelerated depreciation taken on property additions after December 31, 1969. Prior years acceleration is still being flowed through but as time goes on, the amount of flow-through will be reduced and the amount normalized will be increased, thereby contributing to cash flow. Tax deferrals from the use of ADR are normalized. Income tax reductions resulting from investment tax credits arising from new plant placed in service are being amortized over a five year period at the former 3% rate, and over the estimated useful life of utility plant and credit for the new 4% rate under the Revenue Act of 1971. For book purposes, the composite depreciation rate is 2.9%. Credit for interest charged to construction was taken at an 8% rate July 1, 1970 through September 30, 1973; effective October 1, 1973 the rate was reduced to 7-1/2% in conformance with an Order of the Pennsylvania Public Utility Commission which accepted the Company's request to allocate non-utility income, the income tax reductions arising from interest charges

associated with debt used to finance construction work in progress. We calculate the effective book income tax rate at 34% for 1973 and 32% in 1972.

Effective in April 1974 and retroactive to the first of the year, PE changed to deferred fuel cost accounting under which electric generation fuel expense (which is recoverable under the fuel adjustment clause) is not booked until it is recovered in fuel adjustment revenue. This accounting change indicates a less conservative approach than before. If the Company had not gone to deferred fuel cost accounting, the impact of sharply rising fuel costs on fuel cost lag would have cost the Company 24¢ per share. We regard the quality of reported earnings to be about average noting that the buildup in normalized accelerated depreciation tax deferrals will raise the quality over time. Only about 6¢ per share of earnings in 1974 will be from flow-through of accelerated depreciation tax deferrals.

EARNINGS AND COVERAGES

Detailed income statements covering the calendar years 1970 through 1973 and the 12 months ended July, 1974, are presented on the following page. At the bottom of the page we show the Company's returns earned on average capitalization and on average Common equity as well as our computation of the book effective income tax rate.

We show below coverages and margins of safety beginning with the year 1971. Our pro forma coverages are after annualizing all interest and Preferred stock dividends and assume a 10% interest rate on the new $50 million of six-year Bonds and an 11% interest rate on the new $75 million 20 year Bonds.

	Pro Forma	-Actual-				
	1974ϕ	1974ϕ	1973	1972	1971	1970
Times Earned Pre-Tax:						
Long-Term Debt Interest						
Excl. IDC	1.68	2.22	2.30	2.51	2.67	2.57
Incl. IDC	2.24	2.97	2.99	3.09	3.20	2.94
Total Debt Interest						
Excl. IDC	1.62	2.01	2.16	2.36	2.43	2.23
Incl. IDC	2.16	2.69	2.81	2.91	2.90	2.55
Times Earned After-Tax:						
Total Debt Interest						
Excl. IDC	1.38	1.60	1.71	1.84	1.92	1.86
Incl. IDC	1.92	2.28	2.36	2.39	2.39	2.18
Total Int. & Pfd. Divs.(a)	1.50	1.75	1.81	1.87	1.95	1.90
Margin of Safety:						
Total Debt Interest(a)	16.8%	19.6%	21.3%	21.7%	20.9%	17.8%

(a) - Includes IDC.

ϕ - 12 Months ended July 31, 1974.

PHILADELPHIA ELECTRIC COMPANY
Income Statements

	- In Thousands of Dollars -				
	1974ϕ	1973	1972	1971	1970
Operating Revenues:					
Electric	756,696	646,758	574,431	506,670	412,496
Gas	103,371	100,508	93,286	87,290	80,960
Steam	23,810	19,392	17,321	14,174	10,915
Total	883,877	766,658	685,038	608,134	504,371
Operating Expenses					
Operation	486,089	392,729	331,927	294,616	234,781
Maintenance	59,377	58,742	55,461	49,242	48,078
Depreciation	68,860	64,271	60,515	55,937	53,947
General Taxes	63,177	57,353	52,980	47,109	38,410
Total	677,503	573,095	500,883	446,904	375,216
Operating Income (Before Income Taxes)	206,374	193,563	184,155	161,230	129,155
Federal Income Taxes	33,327	24,335	23,541	21,695	17,834
State Income Taxes	9,593	7,608	7,890	7,457	5,330
Deferred Income Taxes	10,989	9,601	7,306	3,947	818
Investment Tax Credit - Net	6,869	3,596	1,870	569	836
Net Operating Income	145,596	148,423	143,548	127,562	107,645
Other Income					
IDC	69,826	58,743	42,450	31,691	18,513
Income Tax Credit on IDC	18,556	4,748	-	-	-
Taxes on Other Income	761	1,374	435	1,680	190
Other - Net	1,440	2,643	196	3,196	34
Income Before Interest	234,657	213,183	185,759	160,769	126,382
Interest Deductions					
Long-Term Debt	93,249	84,837	73,383	60,854	50,336
Short-Term Debt	9,848	5,479	4,402	6,291	7,670
Total	103,097	90,316	77,785	67,145	58,006
Net Income	131,560	122,867	107,974	93,624	68,376
Preferred Dividends	30,731	27,600	21,558	15,320	8,612
Balance for Common	100,829	95,267	86,416	78,304	59,764
Effective Tax Rate	35%	34%	32%	29%	25%
% Earned on Reported Average Capitalization	7.69	7.56	7.56	7.54	6.83
Common Equity	10.0	9.8	10.3	10.8	9.4

- Red figure.
ϕ - 12 months ended July 31, 1974.

Despite the 1971 and 1973 permanent rate increases, coverages in general have slowly declined, a reflection of the relatively slow electric and gas sales growth, higher operating expenses, and heavy outside financing. Actual and pro forma coverages for the 12 months ended July 31, 1974 reflect only about one-quarter of the $24 million rate increase effective April 1, 1974, subject to refund. This was the first part of a three-part filing seeking $136 million or 21%. We calculate that if the pro forma figures shown above were to be further adjusted for the annualization of this $24 million rate increase, the coverage for long-term debt interest pre-tax would be around 1.8 times excluding IDC and 2.4 times including IDC. We think coverages for the full year will be only slightly above those just cited. With satisfactory rate relief early in the year and satisfactory operation of the two Peach Botton nuclear units, we would visualize coverages in 1975 improving slightly.

Philadelphia Electric several years ago undertook a massive construction program geared largely to adding nuclear capacity. Substantial fuel savings are in prospect as nuclear generation increases as a percent of total and oil generation declines. In the current environment of unprecedented high capital costs, construction cutbacks have been made thus reducing somewhat the need for outside financing. Nevertheless, substantial outside financing is necessary. Following sale of these mortgage bonds and the near-term payment at maturity of the 2-3/4% Bonds, the Company will have the ability to issue $65 million of Bonds without regard to the earnings test. Sale of a substantial amount of additional Common stock is indicated for early 1975. The timing and amount granted of the pending rate relief will be a very important determinent of near-term coverages. Further rate increase applications appear to be required and we think management will continue to seek rate relief. We have considered Pennsylvania regulation as reasonable and constructive. However, as discussed earlier, the regulatory climate could change within the next nine months or so.

BOND INDENTURE PROVISIONS

Trustee: The Fidelity Bank is trustee under the mortgage.

Maturity: The $50 million six-year Bonds will be due on October 15, 1980 and the $75 million twenty-year Bonds will be due on October 15, 1994.

Security: No securities may be issued by the Company which will rank ahead of the Bonds as to security. Both of the new Bond series will be secured equally and proportionately with all outstanding series by a first mortgage lien on substantially all of the Company's fixed property, now owned or hereafter acquired with the usual minor exceptions. All the Common stock of Philadelphia Electric Power Company (a wholly-owned subsidiary) is pledged as additional security.

Additional Bonds: Additional bonds may be issued against 60% of net property additions, deposited cash, or for refunding. For this purpose, property additions are confined to those located in Pennsylvania or within 150 miles of Philadelphia. Property additions used exclusively in the steam business are not bondable until all bonds issued prior to September 1, 1957 are no longer outstanding. Except in the case of refunding, additional bonds may be issued only if net earnings computed before income taxes and IDC but after depreciation are equal to at least 2 times pro forma bond interest.

The new $125 million of Bonds are to be issued against available bondable property additions. Coverage under the earnings test of the mortgage for the 12 months ended July 31, 1974 would be 2.01 times giving effect to the payment of the 2-3/4% bonds at maturity on November 1, 1974 and the sale of $125 million aggregate principal amount of new Bonds at an assumed average interest rate of 10-1/2% per year. In order to meet the earnings test of the mortgage, the aggregate principal amount of new Bonds would have to be decreased by approximately $1 million for each increase of 1/8th of 1% in the actual interest rate of the new Bonds over such assumed average interest rate of 10-1/2%.

Upon the retirement of the $65 million 2-3/4% bonds due November 1, the Company will be entitled under the mortgage to issue an additional $65 million of mortgage bonds without regards to the earnings test.

Redemption Provisions: Prior to October 15, 1979, for the new $50 million six-year Bonds and prior to October 15, 1984 for the new $75 million twenty-year Bonds, the new Bonds may not be redeemable as a part of or in anticipation of any refunding operation involving the use of borrowed funds having an effective interest cost to the Company of less than ____% in the case of the new Bonds due 1980, or of less than ____% in the case of the new Bonds due 1994. In both cases, we think this percentage will be the effective interest cost to the Company of the respective series. Other than this, the exact redemption provisions are to be announced.

Sinking Fund: No sinking fund is provided for the new six-year Bonds due 1980. For the twenty-year Bonds, the sinking fund is $3,750,000 or 5% annually, commencing October 15, 1979. This may be met with cash or new Bonds, but not property additions. The sinking fund is designed to retire 75% of the new twenty-year Bonds prior to maturity. In addition, the Company has the non-cumulative option to increase any sinking fund payments by an amount not exceeding the required 5% payment.

Maintenance, Depreciation and Improvement Provisions: The Company has covenanted in the mortgage that it will maintain the mortgaged property in good repair, working order and condition, and that it will maintain in its accounts a reasonably adequate reserve for renewals and replacements or depreciation. Certain other, more specific maintenance, depreciation and improvement covenants contained in the mortgage will expire upon the retirement at maturity of the Company's 2-3/4% bonds due November 1, 1974.

Conclusion: Largely because of the absence of any control of depreciation cash after 1974, we consider the Indenture to be rather loose.

CERTAIN PENNSYLVANIA TAX MATTERS

Philadelphia Electric's new Bond issue is, in the opinion of Company Counsel, exempt from all existing personal property taxes in Pennsylvania. However, the Company is required by law to deduct the Pennsylvania Corporate Loans Tax from interest payments to individuals and partnerships resident in Pennsylvania and to certain fiduciaries.

RJS/mb

NEW
FINANCING
REPORT

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Puff and Phelps, Inc.

Utility investment
research service

September 27, 1977

PHILADELPHIA ELECTRIC COMPANY

COMMON STOCK OFFERING

On October 5, 1977, Philadelphia Electric Company proposes to sell 4.0 million shares of Common stock (no par value) at a negotiated price with underwriters headed by Drexel Burnham & Co. and The First Boston Corporation. The offering will represent a 5.7% increase in shares outstanding to 74.1 million. Proceeds of approximately $78 million will be used to retire short-term debt and for construction; such short-term debt is expected to be $42.3 million at August 31, 1977.

INVESTMENT OPINION

The Company provides electric, gas and steam service to Philadelphia and its environs. In the 12 months ended July 31, 1977 electric operations accounted for 84% of revenues and 88% of pre-tax income. Kwh sales are projected at 4%-5% annually. We rank Pennsylvania regulation as Group III in our I (highest) to VI (lowest) rating system.

Construction expenditures aggregate $2,392 million for 1977-1981. The Company estimates internal sources can provide 44% of the $448 million budgeted for 1977 and about 46% of 1978-1981 expenditures amounting to $1,944 million. Capitalization at July 31, 1977 on a pro forma basis consisted of 52.1% total debt, 13.2% Preferred stock and 34.7% Common equity. We project capitalization growth at 7% annually for the five years ended 1981 versus an 11% annual rate recorded in the prior five year period ended 1976.

Per share earnings for the 12 months ended July 31, 1977 were reported at $2.08 versus $1.84 for the similar prior period and $1.91 for calendar 1976. Earnings for the 12 months ended July 1977 benefited principally from an increase in AFC of $10 million since year-end 1976 and rate relief. A slowdown in financing cost increases was also a positive factor. However, as a result of commercial operation of the Salem nuclear unit at June 30, 1977, AFC will begin to decline $2 million monthly and depreciation will rise $900,000 monthly; other fixed charges relating to this generating addition will increase. Less rate relief will also be effective for the balance of 1977. A small offset will be the nuclear fuel savings. Overall, we expect some attrition in per share earnings for the balance of 1977 and until rate relief is received. Thus, we are maintaining our 1977 earnings estimate of $2.00 per share on 8% additional average outstanding shares which equates to a 10.3% return on average equity.

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Common Stock Data

	Earnings $	Avg. Shares Outstanding (1,000)	Dividend Rate $	Payout %
7/31/77	2.08	68,612	1.80	86.5
1976	1.91	65,606	1.64	85.9
1975	1.86	58,135	1.64	88.2
1974	1.81	52,717	1.64	90.6
1973	1.99	47,847	1.64	82.4
1972	2.08	41,505	1.64	78.8
% Gain 1971-1976				
Company	(9)	76	0	
D&P Average	15	52	19	
1971	2.10	37,323	1.64	78.1
1970	1.84	32,556	1.64	89.1
1969	1.97	29,644	1.64	83.2
1968	1.94	29,032	1.64	84.5
1967	2.13	27,880	1.64	77.0
% Gain 1966-1971				
Company	1	36	11	
D&P Average	19	13	19	

	Market				P/E Ratios		Yield	
Year	High $	Low $	Close $	To Book %	High	Low	Low %	High %
7/31/77ø	21.2	17.1	19.6	104	10.2	8.2	8.47	10.51
1976	18.0	14.7	17.7	93	9.4	7.8	9.11	11.03
1975	15.4	11.1	15.0	79	8.3	6.0	10.58	14.74
1974	19.4	9.3	10.7	54	10.8	5.2	8.41	17.49
1973	23.4	17.0	18.0	89	11.8	8.5	6.98	9.65
1972	25.0	21.2	22.6	114	12.0	10.2	6.56	7.72
1971	25.1	20.5	23.7	122	12.0	9.8	6.53	7.95
1970	24.7	19.0	22.4	119	13.5	10.3	6.59	8.63
1969	32.1	22.0	24.0	127	16.3	11.2	5.11	7.45
1968	32.4	27.2	31.1	171	16.8	14.0	5.05	6.02
1967	34.7	28.4	29.5	168	16.4	13.4	4.70	5.75

ø - Market range and close through September 19, 1977.

For 1978 our estimate is $2.05 per share. The decision of the Pennsylvania Commission on the Company's recent petition regarding proposed changes in the fuel clause and request for $119 million of annual rate relief--which has been suspended to April 1978--will be a primary determinent of the level of earnings for the year. Assuming reasonable treatment by the Commission, on 7% additional shares, our $2.05 estimate indicates a 10.6% return on average equity. Longer term, with capitalization growth slowing and financing pressures easing, we envision modest earnings progress, assuming rate relief is received on a timely basis.

We rate the Common D&P II. Trading at 19-3/4 (1977 market range: 21-1/4 - 17-1/8) and at a 4% premium to its book value, the shares sell at 9.8 times our 1977 estimate of $2.00 per share. Yield on the $1.80 dividend established March 1977 is 9.1% which compares with an 8.0% average yield for other utility issues on our II electric list. The current dividend is a 90% payout of our 1977 earnings estimate of $2.00. However, cash flow covers the dividend around 1.8-1.9 times. The Company estimates between 15% and 30% of the 1977 dividend will be considered a non-taxable return of capital. We regard the Common stock as a Better Value for its above average current income.

SYSTEM OPERATIONS

Philadelphia Electric Company is a combination electric, gas and steam utility serving southeast Pennsylvania including Philadelphia and the surrounding suburban areas. Electric revenues contributed 84% of total revenues for the 12 months ended July 31, 1977 and provided 88% of pre-tax operating income. The City of Philadelphia itself accounts for only 5% of total geographical service area but about 40% of electric revenues are derived therein. Overall, population and customer growth have been below average--characteristics of a mature service territory.

Philadelphia is the fourth largest U.S. metropolitan area and is a principal financial and commercial center. The economy is well diversified with many basic industries. A weakening economy together with voluntary conservation adversely affected kwh sales growth in 1974 and 1975. In 1976 kwh sales registered some improvement with a 4% gain being experienced; gas sales rebounded 13% due to the abnormally cold weather. Kwh sales showed a 3.4% increase in the initial seven months of 1977 while gas sales declined 4%. Company forecasts anticipate a 5% kwh growth rate over the next few years. This rate appears attainable with growth of electric space heating and use of electricity as an alternative energy source.

REGULATION

Previous rate decisions by the Pennsylvania Public Utilities Commission have been based on fair value, end-of-period historical rate bases and the adjusted book Common equity returns have been 14%-14-1/2%. Interim rate relief has been granted and normalization of accelerated depreciation tax deferrals on post-1969 property was allowed.

Two Pennsylvania statutes adopted in late 1976 and expected to be effective to filings dated October 1977 provide for several modifications to regulation. These include: 1) the establishment of a maximum seven month suspension period plus 60 days for the filed effective date of a general rate increase (nine months effectively vs. eleven previously), 2) authorization of a possible future test year (vs. historical previously), and 3) prohibition of potential rate retroactivity of multiple rate filings (pancaking) and interim rate relief other than for emergency purposes. Additionally, regulatory lag, filling vacancies and defining what constitutes a majority of the Commission was also addressed. There has been one vacancy on the five person Pennsylvania Commission since April 1977; the man nominated by the Governor has not yet been confirmed by the Senate.

An electric fuel adjustment clause which recognizes increases or decreases in the average cost per kwh generated by all fossil fuels and also covers external power purchases is applicable to virtually all sales. Nuclear is excluded from the fuel clause per se, but does enter into the picture inasmuch as the fuel adjustment is calculated by dividing total dollars of fossil fuel by total kwh sold. The lag for recoupment is two months. A May 1976 Commission Order requires advance notice of the fuel adjustment computation and provides for continuous review. Philadelphia Electric adopted deferred fuel cost accounting January 1974. A gas fuel adjustment clause recovers higher costs of all purchased gas and of alternate gas supplies.

In February 1977 the Pennsylvania Commission authorized an electric rate increase of $72 million in response to a $95 million request filed November 1975 in a two-part application. The Company requested the first part--$47 million--not be suspended. In January 1976 the Commission suspended both parts for up to six months but permitted an interim increase of $24.3 million to be effective subject to possible refund. In July 1976 the PUC authorized an additional interim increase of $22.7 million effective August 1976. The $25 million additionally granted in February 1977 was retroactive to October 1976. The February 1977 decision was based on a period-end, fair value rate base; the test year was the 12 months ended August 1975; and the overall return allowed incorporated about a 14.15% return on book Common equity. The decision allowed a slightly lower return on book Common equity than the prior March 1975 Order and took 15 months but the interims partially mitigated the delay.

An Order was received in late 1976 allowing $9.2 million of increased gas rates in two steps. The first part consisting of $6.4 million went into effect June 1975, subject to refund. The additional $2.8 million allowed was retroactive to March 1976. The decision took almost 20 months and was based on a calendar 1974 test period. We calculate the return allowed on Common equity at around 13.5%. The Company has appealed the Order based on an inadequate rate of return.

Philadelphia Electric made a two-part electric rate filing August 1977. The first part seeks to transfer the existing electric fuel adjustment charges into base rates, eliminate the electric fuel adjustment clause for residential and small commercial customers (30% of kwh sales) and to substitute a new energy adjustment clause for other customers (including nuclear). Part two calls for a $119 million increase (11.5%) in electric rates. Both parts have been suspended to April 1978.

We rank Pennsylvania regulation in Group III in our I (highest) to VI (lowest) rating system.

POWER, GAS AND FUEL SUPPLY

Net installed electric generating capacity totaled 8,202 mw at July 31, 1977 which included the June 1976 addition of the 400 mw oil-fired Eddystone unit and the commercial operation of the Salem nuclear unit June 30, 1977 to which the Company is entitled to 464 mw. Based on an estimated peak load of 6,000 mw, the generating reserve margin was 36%. However, outages relating to refueling and repair modifications on the nuclear units have effectively reduced capability and have held the actual reserve margin to around 23%. Assuming 5% peak load growth, full operation of existing units and present construction plans, the reserve margin will be above 20% through 1980. Additionally, the Company is a member of the Pennsylvania-New Jersey-Maryland interconnection (PJM) and the PJM reserve margin was approximately 37% for 1977.

Fuel system input for the 12 months ended July 1977 was coal 25%, oil 21%, nuclear 18%, hydro 4%, gas 3%, and purchased and net interchange 29%. Nuclear is expected to supply a growing proportion of the power generation with the addition of Salem No. 1 June 1977 and 474 mw from Salem No. 2 scheduled for commercial operation in 1979. Public Service Electric and Gas Company has the construction and operating authority for these two Salem units. An additional two nuclear units have been delayed until 1983 and 1985.

Most of the coal and oil requirements are contracted for annually or on a short-term one to five year basis. Commitments for the nuclear fuel supply cycle have been made for four units through 1981-1985 and the two Salem units through 1979. Unit fuel costs escalated sharply, particularly in 1974 to 1.46¢ per kwh, but cost increases have been modified with the growing use of nuclear generation and from economy interchange purchases. However, for the 12 months ended July 1977 fuel and interchange expense rose 10% to 1.57¢ per kwh sold.

Overall, we view the Company's power generation and fuel supply as satisfactory through the 1970's. The Company does not currently meet all the Federal, state and local pollution control regulations but is attempting to comply or is seeking variances. Equipment failures have resulted in cooling tower outages at the Peach Bottom Nuclear Station of which the Company has an 886 mw ownership interest.

Natural gas service is supplied to the surrounding suburban area of Philadelphia and contributed 12% of total revenues and 10% of pre-tax operating income in the 12 months ended July 31, 1977. The Company purchases about two-thirds of its gas from Transcontinental Gas Corporation under contracts expiring in 1990 and about one-quarter from Texas Eastern Transmission Corporation under contracts expiring in 1987. The Company's contracted supply of 79 billion cubic feet was curtailed 25% in 1975, 29% in 1976 and the 1977 curtailment is anticipated at 32%. Gas service was partially curtailed to large industrial customers January through April 1977. Gas storage contracts enable the Company to store 40% of heating season gas deliveries. Purchases of LPG and SNG together with small amounts of gas from its own drilling and exploration program are expected to supplement regular gas supplies. Based on normal winter weather conditions, the Company considers curtailments to non-interruptible customers during the 1977-1978 heating season as unlikely. However, the Company cannot increase the number of customers served and longer term growth prospects appear limited.

CONSTRUCTION

Construction expenditures including nuclear fuel are currently budgeted at $448 million for 1977, $434 million for 1978, $455 million for 1979, $511 million for 1980, and $544 million for 1981. This five year program is a reduction from prior estimates and aggregates $2,392 million. Gross plant will increase 7.8% annually which compares with the prior five year program of $2,112 million which resulted in a 10.7% annual increase in gross plant. Most of this budget will be spent on the electric department with two-thirds of the expenditures geared to the addition of new generating facilities. Also included is $88 million for environmental requirements.

FINANCING AND CAPITALIZATION

Financing

Capital requirements for 1977 are estimated at $486 million including $448 million for construction and $38 million for debt maturities and sinking funds. Internal sources are expected to provide 44% of 1977 construction funds. Financing in 1977 has consisted of $24 million of Pollution Control bonds in February, $75 million of First Mortgage bonds in March and again in July, and the current sale of 4.0 million shares of Common together with that issued through the Shareholder Dividend Reinvestment and Employee Plans.

For 1978-1981 the Company estimates about 46% of the construction program can be funded from internal sources, which appears reasonable to us. In addition, debt maturities total $333 million with $26 million of debt maturing in 1978, $51 million in 1979, $126 million in 1980 and $130 million in 1981. We expect debt and Common to be sold in each of the years 1978-1981 and Preferred to be sold in 1978, 1980 and 1981.

Capitalization

Pro forma capitalization at July 31, 1977 as shown on the following page, totaled $4.05 billion. It consisted of 44.5% mortgage debt, 52.1% total debt, 13.2% Preferred and 34.7% Common equity. Our calculations indicate total capitalization will increase about 7% annually in the five years ending 1981 as compared with an 11% compound annual rate experienced for the prior five years. At a market price of 19-3/4, the Common currently sells at a 4% premium to its book value of $18.99.

ASSET SUPPORT

Principal asset support for pro forma capitalization as of July 31, 1977 is presented in the table below capitalization. Carried at original cost, Philadelphia Electric had utility plant in service of $3,895 million at the balance sheet date, 88% of which applies to the electric plant. The $915 million total reserve for depreciation was equivalent to 24% of gross plant in service. Primarily reflecting work on new generating capacity, construction work in progress at the balance sheet date of $994 million represented one-quarter of total net plant. Total assets were about double total pro forma debt, similar to the ratio for the Duff and Phelps Electric Utility Average.

ACCOUNTING PRACTICES

Tax deferrals related to accelerated depreciation on property additions are normalized; prior to 1971 the resultant tax deferrals were flowed through to income. Tax deferrals from the use of ADR are normalized. Investment tax credits are amortized over the estimated useful life of the utility plant. Income tax credits applicable to non-operating activities (primarily interest relating to construction work in progress) are reported in other income with a corresponding increase in income taxes. For the 12 months ended July 31, 1977 the effective book Federal income tax rate (computed by us) was an above average 41%, similar to that of recent years.

Depreciation as a percent of average depreciable utility plant in service was 2.98% for the 12 months ended July 31, 1977. AFC was computed at a net after-tax rate of 8% on January 1, 1975, 8.25% on July 1, 1975, 8.20% on January 1, 1976, and 8.40% on July 1, 1976. A rate of 8.60% on January 1, 1977 and 8.70% beginning July 1, 1977 was adopted in accordance with the FPC method of accounting. We note net after-tax AFC has been a relatively high proportion of reported earnings in recent years and in 1977 will contribute over one-half of the Balance for Common. Beginning January 1974 deferred fuel cost accounting was adopted. At July 31, 1977 deferred fuel expense totaled $39 million, up from $20 million at year-end 1976. We consider the overall quality of reported earnings to be about average; both the quality of earnings and cash flow have improved in recent years.

PHILADELPHIA ELECTRIC COMPANY

Capitalization - July 31, 1977

	Actual		Pro Forma	
	$1,000	%	$1,000	%
Debt:				
First & Ref. Mortgage Bonds	1,804,345	45.1	1,804,345	44.5
Note Payable to Bank	125,000	3.1	125,000	3.1
Pollution Control Note	37,000	0.9	37,000	0.9
Debentures	150,148	3.7	150,148	3.7
Unamortized Debt Disc. & Prem.-Net	(6,142)	(0.1)	(6,142)	(0.1)
Total Long-Term Debt	2,110,351	52.7	2,110,351	52.1
Short-Term Debt	31,680	0.8	-	-
Total Debt	2,142,031	53.5	2,110,351	52.1
Cumulative Preferred Stock, $100 Par				
5,350,690 Shares	535,069	13.3	535,069	13.2
Total Debt & Preferred	2,677,100	66.8	2,645,420	65.3
Common Stock Equity:				
Common Stock - No Par				
70,102,536 Shares	1,018,096		-	
74,102,536 Shares	-		1,097,096	
Other Paid-In Capital	1,713		1,713	
Retained Earnings	308,172		308,172	
Total Common Equity	1,327,981	33.2	1,406,981	34.7
Total Capitalization	4,005,081	100.0	4,052,401	100.0
Book Value per Common Share	$ 13.94		$ 18.99	
Recent Market to Book Value	104%		104%	

Asset Support - July 31, 1977

	$1,000
Utility Plant at Original Cost	3,895,104
Less: Accumulated Depreciation	915,361
Net Plant in Service	2,979,743
Construction Work in Progress	994,284
Nuclear Fuel	80,976
Net Plant	4,055,003
Other Property and Investments	18,006
Pro Forma Net Working Capital	199,164
Total Assets	4,272,173
$ Per $1,000 First & Ref. Mortgage Bonds	
Net Plant	2,247
Total Assets	2,368
$ Per $1,000 Total Debt	
Net Plant	1,921
Total Assets	2,024

EARNINGS

Detailed income statements for the calendar years 1973 through 1976 and for the 12 months ended July 31, 1977 are presented on the following page. Also shown are the Company's effective book Federal income tax rates and returns earned on average capitalization and average Common equity which we compute at 8.80% and 11.1%, respectively, applying to the 12 months ended July 31, 1977.

	Pro Forma 7/31/77	7/31/77	December 31, 1976	1975	1974	1973
Times Earned Pre-Tax:						
Long-Term Debt Interest						
Excl. AFC	2.03	2.14	2.13	2.09	2.08	2.30
Incl. AFC	2.56	2.71	2.65	2.58	2.74	2.99
Total Debt Interest						
Excl. AFC	2.03	2.11	2.08	1.98	1.83	2.16
Incl. AFC	2.56	2.67	2.59	2.44	2.42	2.81
Times Earned After-Tax:						
Total Debt Interest						
Excl. AFC	1.56	1.61	1.58	1.53	1.48	1.71
Incl. AFC	2.09	2.16	2.09	2.00	2.07	2.36
Total Int. & Pfd. Divs.	1.68	1.72	1.66	1.60	1.62	1.81
Margin of Safety:						
Total Debt Interest-%[a]	19.3	19.8	19.6	18.3	16.9	21.3

a - Includes AFC.

Earnings Record

1) Earnings for the five years ended 1976 ranged from $2.08 per share in 1972 to a low of $1.81 in 1974. Earnings recovered to $1.91 per share with receipt of rate relief in 1976. Kwh growth of 12% compared with the D&P Average of 26% for the period, with all categories significantly underperforming the industry. Electric revenues rose 78% for the period; sales contributed only a small portion of this increase and realizations, including rate relief and pass-through of higher fuel costs, accounted for the larger portion. AFC rose substantially but only partially offset the rapid advance in interest charges and Preferred dividends. In comparison, revenues of the D&P Average rose 67%.

2) Capitalization growth at 11% annually was similar to that of the D&P Average. Internal cash generation was only slightly lower than the industry. However, Common shares outstanding rose 73% or 11-1/2% annually, reflecting sales in 1973, 1974, 1975 and 1976 being made below book value. The high payout ratio also resulted in a below average retention of earnings. Book value remained stationary during this five year period versus a 4% annual gain by the D&P Average.

PHILADELPHIA ELECTRIC COMPANY

Income Statements

In Thousands of Dollars

	7/31/77	December 31, 1976	1975	1974	1973
Operating Revenues:					
Electric	1,118,904	1,024,814	978,368	873,474	646,758
Gas	163,949	158,865	117,989	108,929	100,508
Steam	42,171	40,462	38,453	29,323	19,392
Total	1,325,024	1,224,141	1,134,810	1,011,726	766,658
Operating Expenses:					
Operation	718,666	656,464	620,287	584,646	392,729
Maintenance	86,871	75,030	62,313	61,971	58,742
Depreciation	102,344	97,980	91,221	77,802	64,271
General Taxes	87,037	82,644	77,567	67,143	57,353
Total	994,918	912,118	851,388	791,562	573,095
Operating Income:					
(Bef. Income Taxes)	330,106	312,023	283,422	220,164	193,563
Federal Income Taxes	(3,134)	6,147	42,161	10,986	24,335
State Income Taxes	19,207	18,336	15,868	12,340	9,643
Def. Income Taxes	37,912	23,447	19,955	23,140	7,366
Invest. Tax Cr. (Net)	51,480	52,668	8,353	20,691	3,596
Net Operating Income	224,641	211,425	197,085	153,007	148,423
Other Income:					
AFC	87,487	77,641	66,874	70,841	58,743
Inc. Tax Credit on AFC	26,322	24,701	22,520	25,135	4,748
Taxes on Other Income	(845)	(534)	(249)	306	(1,374)
Other - Net	3,097	2,548	2,087	271	2,643
Income Before Interest	340,702	315,781	288,317	249,560	213,183
Interest Deductions:					
Long-Term Debt	155,394	147,596	136,507	106,298	84,837
Short-Term Debt	2,149	3,567	7,885	14,165	5,479
Total	157,543	151,163	144,392	120,463	90,316
Net Income	183,159	164,618	143,925	129,097	122,867
Preferred Dividends	40,719	39,022	36,026	33,682	27,600
Balance for Common	142,440	125,596	107,899	95,415	95,267
Avg. Com. Shs. Outstg. (000's)	68,612	65,606	58,135	52,717	47,847
Earnings per Avg. Share	$ 2.08	$ 1.91	$ 1.86	$ 1.81	$ 1.99
Dividends per Avg. Share	1.68	1.64	1.64	1.64	1.64
Effective Tax Rate	41%E	42%	41%	37%	34%
% Earned on Reported Average					
Capitalization	8.80 E	8.43	8.14	7.75	7.56
Common Equity	11.1 E	9.9	9.4	8.9	9.8

3) Returns earned on average Common equity ranged between 10.3% in 1972 to 8.9% in 1974 and partially recovered to 9.9% in 1976. These returns averaged about 15% below the D&P Average.

We attribute Philadelphia Electric's below average five year record to: 1) sluggish sales growth, 2) high financing costs, and 3) lags in obtaining sufficient rate relief.

Current and Prospective Earnings

Earnings for the 12 months ended July 31, 1977 were reported at $2.08 per share versus $1.84 a year earlier on 8.2% additional average outstanding shares. Seven-month earnings of $1.23 per share compared with $1.06 for the similar 1976 period. Seven-month 1977 revenues of $810 million were up 14% from the similar 1976 period reflecting a modest 2% gain in kwh sales, a small decline in Mcf gas sales, pass-through of higher fuel charges, about $17 million higher AFC and electric rate relief.

As a result of commercial operation of the Salem nuclear unit June 30, 1977, pre-tax earnings will be reduced $900,000 monthly due to depreciation charges and AFC will decline $2 million monthly. A small offset will be the nuclear fuel savings, although most of the savings will accrue to customers under operation of the present fuel clause. For the balance of 1977, only about $10 million of rate relief is expected to be effective. We expect some attrition in per share earnings until rate relief is received. Thus, we are maintaining our 1977 earnings estimate of $2.00 per share on about an 8% gain in average outstanding shares. This estimate represents a 10.3% return on average Common equity.

For 1978 our estimate is $2.05 per share. A most important facet will be the Commission decision regarding proposed fuel clause changes and the related rate relief for inclusion of Salem No. 1 into rate base. As noted earlier, the Company's filing has been suspended until April 1978. Assuming reasonable treatment and rate relief is effective by mid-1978, our $2.05 estimate on 7% additional average outstanding shares equates to about a 10.6% return on equity. Longer term, with capitalization growth slowing and financing pressures easing, Philadelphia Electric has an opportunity to show modest earnings progress, assuming a moderate amount of rate relief is received on a timely basis.

DIVIDENDS

The $1.80 annual dividend was established March 1977, up from $1.64 which has been paid since 1967. The payout ratio of 90% on our $2.00 earnings estimate compares with a ten-year historical rate of 84%. The Company estimates 15% to 30% of the 1977 dividend will be considered a non-taxable return of capital. In view of the high payout and anticipation of annual sales of Common stock, we do not foresee another dividend increase near term. The dividend

coverage for 1977-1978 is estimated at around 1.8-1.9 times. This is below average but adequate. Yield based on the current market price of 19-3/4 is 9.1%. This above average yield compares with an 8.0% average for our D&P II list. The Company has a Shareholders' Reinvestment Plan and a voluntary Employee Stock Purchase Plan.

COMMON STOCK PROVISIONS

Shares Authorized

There are 100 million shares of Philadelphia Electric no par value Common stock authorized, of which 74,102,536 shares are expected to be outstanding following the proposed offering. The Common stock is fully paid and nonassessable. There are no outstanding convertible securities.

Voting Rights

Shareholders are entitled to one vote per share of Common stock held with cumulative voting permitted in the election of Directors. Preferred stockholders normally have no voting rights, but with respect to certain matters the consent of a majority of the Preferred stockholders is required. In the case of default in payment of four full quarterly dividends the holders of the Preferred stock would be entitled to elect a majority of the Board of Directors until all dividends in default have been paid or declared and set apart for payment.

Dividend Rights

Common stock dividends may be declared out of legally available earnings. The Company's Charter prohibits payment of any dividend on Common stock if after giving effect thereto the Common stock equity would be less than the involuntary liquidating value of the Preferred stock. In this respect, the Common stock equity is currently more than two times the liquidating value.

Preemptive Rights

No class of securities of the Company presently outstanding has any preemptive or conversion rights.

Other Provisions

The Company may not purchase or otherwise acquire for value, shares of its Common stock whenever it is in arrears on any dividends on its Preferred stock.

Conclusion

In our opinion, the provisions relating to Philadelphia Electric's Common stock are generally comparable to those of many other electric utility Common stocks.

Dorothy M. Jelinek, C.F.A.