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

DOCKET
FOLDER

DIRECT TESTIMONY OF
ROGER J. MATTSON

DOCKETED
DEC 23 1985

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

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.

I. 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 present
- International Energy Associates Limited, Washington, D.C.
- 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 6/84
- U.S. Nuclear Regulatory Commission
- 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 Care 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 satisfactory 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

		ISSUANCES		
FISCAL YEAR	STAFFING LEVEL	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 back-fitting 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

PECO STATEMENT NO. 1

PH 12-17-85
Hbg

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

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SECRETARY'S OFFICE
Public Utility Commission

DIRECT TESTIMONY OF
VINCENT S. BOYER

LIMERICK 1 AND COMMON PLANT
OVERVIEW AND DECISIONS
RESPECTING SCHEDULED COMPLETION

September 27, 1985

DOCKETED
DEC 23 1985

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TESTIMONY OF VINCENT S. BOYER

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

A. Vincent S. Boyer, 2301 Market Street, Philadelphia, Pennsylvania.

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

A. I am Senior Vice President, Nuclear Power, of Philadelphia Electric Company (PECO).

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Mechanical Engineering from Swarthmore College in 1939. I received a Master of Science Degree in Mechanical Engineering in 1944 from the University of Pennsylvania. I have also taken graduate courses in nuclear reactor engineering and nuclear instrumentation at the University of Pennsylvania and Drexel University.

Q. Please describe your experience prior to your present position.

A. In 1939, I joined PECO as Engineer of Plant Tests in the Electric Operations Department. Following service in the United States Navy from 1944 to 1946, I returned to PECO and served in various supervisory positions in power stations, where I had responsibility for the maintenance and operation of boiler plant equipment. In 1951, I was transferred to the Mechanical Engineering Division, where I was engaged in power station design. I was appointed Assistant Superintendent of the Company's Cromby Station in 1953 and I assisted in directing the operator's training program and in placing the two units of the Cromby Station in service. In 1956, I was appointed Superintendent of the Cromby Station. In 1960, I was designated Superintendent of the Company's Peach Bottom Atomic Power Station, and, in 1963, I was appointed Manager of Nuclear Power in the Electric Operations Department. In January 1965, I was designated Manager of the Electric

Operations Department. In October 1968, I was appointed to the position of Vice President, Engineering & Research. I was elected to my present position of Senior Vice President, Nuclear Power in January 1980.

Q. Are you active in any professional organizations?

A. I am a Fellow of the American Society of Mechanical Engineers and past Chairman of its Philadelphia Section. I am a Fellow of the American Nuclear Society, a past President and Director of the Society and have served as Chairman of its Reactor Operations Division. I have also served as President of the Philadelphia Post of the Society of American Military Engineers. I am a registered Professional Engineer and a member of the National Society of Professional Engineers.

Q. Have you served or do you presently serve on any industry committees?

A. Yes. For the Edison Electric Institute, I served as Chairman of the Utility Occupational Radiation Exposure Group and Chairman of the Nuclear Power Executive Advisory Committee. For the Atomic Industrial Forum, I serve as Chairman of the Committee on Three Mile Island Unit 2 Recovery and as a member of the Policy Committee on Nuclear Regulations. For the Gas-Cooled Reactor Associates, I serve as a Chairman of the Management Committee. I was also the American Nuclear Society representative to the Coordinating Committee on Energy of the Association for Cooperation in Engineering and Chairman of the Public Policy Committee, and am presently a member of the Honors and Awards Committee of the Reactor Operations Division. I am a member of the Steering Committee of the BWR Owners Group and a past member of the Mark II Owners Group, and was Chairman of the American Society of Mechanical Engineers Committee on Industry Relations.

Q. Have you previously testified in other proceedings?

A. I testified in every PECO electric rate proceeding conducted before the PUC between the years 1971 and 1977 (i.e. a total of 4 cases). In addition, I presented testimony in the 1980 Limerick Investigation and the current Limerick 2 Show Cause proceeding. My testimony in these proceedings addressed such subjects as the capacity need and economic advantage of completing additional generating capacity including Limerick, the processes employed by the Company to plan additional capacity, the reasons for and process for planning plant retirements, anticipated nuclear plant capacity factors and other similar subjects.

Q. What is the purpose of your testimony?

A. My testimony is divided into three sections:

First, I will (a) describe the main characteristics of the Limerick Generating Station, Unit No. 1 and Common Plant which is being included in PECO's rate base for the first time in this proceeding; and (b) summarize PECO's involvement and experience in nuclear power.

Second, I will briefly review the decision to build the Limerick Generating Station both at its inception and in the continued justification analyses performed through the 1970s and early 1980s. I will also explain, from a construction manager's viewpoint, the several scheduled completion dates adopted for the plant during this period.

Finally, I will support the Company's request that all of the Limerick Station Common Plant be included in rate base upon the commercial operation of Unit 1, and will explain the engineering and practical reasons why such plant is used and useful.

1. DESCRIPTION OF LIMERICK STATION AND PECO NUCLEAR EXPERIENCE

Q. What has been your involvement with the Limerick Generating Station?

A. I have been involved in the management decisions concerning the Limerick Generating Station since its inception.

This project, as well as all nuclear fueled electric generating stations, falls within my area of responsibility as Senior Vice President, Nuclear Power. Additionally, the Engineering & Research Department, which I headed from 1968 until January 1980, has cognizance over the design and construction of all new electric generating plants, whether fossil-fueled, nuclear-fueled or hydroelectric.

Q. Please describe briefly the Limerick Generating Station.

A. The Limerick Generating Station consists of two 1055 MW turbine generator units, each of which operates at 1800 rpm and is served by its own nuclear steam supply system - a single cycle, forced circulation, boiling water reactor system - capable of producing 14,156,000 pounds/hour of steam at 1000 psig and 550° F. Unit No. 1 is currently undergoing pre-commercial testing and is scheduled to be in commercial operation in the first quarter of 1986. The major features of the station include the main generating station building which houses the turbine generator units, the reactors and their associated equipment, and the administrative and maintenance areas; two cooling towers; a river water intake and pumping structure; and a circulating water pump structure. Adjacent to the generating facilities there are two electric substations, one of 500 kV and the other of 220 kV, each with conventional substation equipment such as circuit breakers, buses and supporting structures, switch gear, transformers, and control buildings.

Q. Mr. Boyer, please describe the water supply system which will be used at Limerick.

A. The main condenser cooling water system for the Limerick Generating Station is a recirculating, closed system with cooling towers. Makeup rates to replenish cooling tower water lost due to evaporation at the cooling towers must be supplied from an adequate source on a continuous basis during plant operations. The primary source of this makeup water will be the Schuylkill River. However, the Delaware River Basin Commission ("DRBC") has imposed restrictions that limit withdrawal of water from the Schuylkill River during periods of low flow and high river water temperature. Therefore, a supplemental supply is needed to augment water taken from the Schuylkill River to meet these restrictions. This additional water is to be diverted from the Delaware River to the Perkiomen Creek, and then pumped to the Limerick Generating Station through the Perkiomen Pumphouse and Pipeline.

Construction of the water diversion facilities began in January 1983. These facilities were initially scheduled for completion by late July 1984. However, construction has been delayed by litigation. On January 3, 1985, the Court of Common Pleas of Bucks County - Civil ruled that the Company's existing contract rights are enforceable and, therefore, Bucks County is contractually obligated to "operate and maintain the Point Pleasant Pumping Station and combined transmission main." On February 27, 1985 in its Opinion Sur Exception, the Court denied the County's exception to the decision. The Court's decision enables the Company to proceed with the construction of the facilities. The County and other defendants have filed appeals to the appellate court.

The Company has aggressively sought to enforce its contractual rights and expedite completion of the Point Pleasant facilities. While this litigation continues, PECO is actively pursuing short-term solutions to assure water availability. The Company on March 15, 1985 submitted an application to the DRBC for approval of the temporary substitution of in-stream monitoring of dissolved oxygen levels in the Schuylkill River in place of the 15°C temperature constraint on withdrawals. This request was approved on May 29, 1985.

In addition, on May 30, 1985, PECO filed with the DRBC an application for the consumptive use of water allocations of Metropolitan Edison's Titus Station Units No. 1, 2 & 3, and PECO's Cromby Station Unit No. 2. This request was approved on August 9, 1985.

On July 3, 1985, the Company filed with the DRBC an application for temporary withdrawal of water released under a variance from the Beechwood Pit, owned by the Reading Anthracite Company. The water supply from this source alone equals approximately 2.2 billion gallons, and would be a sufficient quantity to meet Limerick's consumptive needs through early commercial operation when the Schuylkill River is otherwise unavailable. On September 20, 1985, the Company filed a letter with the DRBC modifying this request. This request has not yet been acted upon by the DRBC. Finally, also on September 20, 1985, the Company filed an application with the DRBC requesting a modification of the flow restrictions imposed on Schuylkill water use from 530 cfs to 415 cfs. This request has also not yet been acted upon. Additional sources of interim water supply are available and requests for their use can be presented to the DRBC as required. Moreover, the various approvals described above, which are presently limited to 1985 operations, can be extended.

The Company believes that, based upon these and other on-going efforts, an adequate supply of water to permit full commercial operation of Limerick is or will be available.

Q. What background and experience does PECO have in the use of nuclear energy for the generation of electricity?

A. PECO has been active in the development of atomic energy generation for over thirty years. In 1952, PECO became a charter member of the Dow Chemical - Detroit Edison Nuclear Power Development Project, which subsequently became Atomic Power Development Association, Incorporated (APDA).

This organization designed and developed a fast breeder power reactor for the Atomic Energy Commission's ("AEC's") Power Demonstration Program. The Company also participated in the formation of Power Reactor Development Company, which was organized to finance, construct, own and operate the fast breeder reactor designed by APDA for the Enrico Fermi Atomic Power Station. The Company's engineers have participated at various times on a full-time basis in many phases of nuclear projects undertaken by the electric utility industry in the 1950s and 1960s, including the development and implementation of plant design and operation.

In 1958, in response to invitations from the Federal government for the industry to participate in the development of nuclear energy for the generation of electricity, PECO, supported by 52 other electric utilities, submitted a proposal for the construction and operation of the world's first high-temperature, helium-cooled reactor. Following approval of the proposal by the AEC, the plant, now known as Peach Bottom No. 1, was constructed and successfully operated for a period of seven years, during which time 1.2 million net electrical MWh were produced for the PECO grid over a lifetime of 1349 equivalent full-power days. Peach Bottom No. 1 was retired in 1975, having very successfully fulfilled its role as a prototype reactor.

In 1974, following the appropriate regulatory approvals, we placed in operation Units 2 and 3 at Peach Bottom, each with a design electrical rating of 1065 MW electric. These units, owned jointly with Public Service Electric and Gas Company, Delmarva Power and Light Company, and Atlantic Electric Company, use boiling water reactors and have been providing reliable, low-cost energy for our customers. Together with the three other utilities just mentioned, we are also joint owners of Salem Units 1 and 2. These units, which employ pressurized water reactors and are similar in size to the Peach Bottom Units, are located in Salem County, New Jersey, were placed in service in 1977 and 1981, and are operated by Public Service Electric and Gas Company.

2. INITIAL DECISIONS TO CONSTRUCT, CONTINUED JUSTIFICATION ANALYSES AND SCHEDULED COMPLETION DATES

a. Initial Decisions to Construct

Q. What was the basis for the Company's initial decision to build additional nuclear capacity and to locate such generation at the Limerick site?

A. I responded to that question in detail in the first Limerick Investigation at Docket No. I-80100341. Instead of repeating my answer here, I have attached the pertinent portion of my testimony in that proceeding as Appendix A.

As explained in Appendix A, the load/capacity forecasts, the PJM reserve obligations, and the social and regulatory pressures of the late 1960s prompted the initiation of the Limerick Generating Station. Because the Company had sufficient generation for cycling and peaking service, it was clear that the new facility should be for base-load operation. After careful and repeated analyses of various fuel sources, it was concluded that nuclear generation was the most economic alternative. The Limerick site was chosen after a thorough investigation by PECO and outside consultants of alternatives compared on the basis of economic, environmental and social factors. Selection of the Limerick site curtailed the use of Pennsylvania land resources, avoided adverse environmental impacts, and minimized the capital investment in the project while enhancing overall system reliability and service to the Company's customers.

The PUC, in the first Limerick Investigation, expressly approved the Company's initial determination that additional capacity was needed, its selection of the nuclear alternative and its choice of the Limerick site. The Commission found that "PECO's decision to build a nuclear station at Limerick was reasonable at the time it was made, and was a valid exercise of managerial discretion." Further, the PUC stated: "We agree with the finding of the Nuclear Regulatory Commission that the site chosen was the best available." Finally, the Commission noted its prior granting in 1971 of an application for a finding of necessity for certain site construction activities.

After the decision was made to construct a nuclear plant, the Company requested and evaluated bids from NSSS suppliers and Architect-Engineer firms to supply the equipment and assist in the engineering and construction of the plant. General Electric was selected as the NSSS supplier based upon cost considerations and our preference for BWR technology. Bechtel Corporation was selected as the A/E because its bid was cost competitive, it was the most experienced firm in the nuclear area and it agreed to transfer experienced engineers from the Peach Bottom Project to the Limerick Project. In addition, as both General Electric and Bechtel had participated in the construction of Peach Bottom, we believed that substantial cost savings would be realized by replication of this prior effort.

Q. When was the formal capital authorization for the Limerick plant approved by Company management?

A. The Limerick project was developed and approved in concept by Corporate Management in the 1968 Construction Budget. Meetings were then held with the AEC, the Pennsylvania PUC and Department of Forests and Waters, the DRBC and various vendor and Architect-Engineer firms leading to a definition of the project with more complete cost estimates. With the award of the design-construction contract to Bechtel, the Preliminary Safety Analysis Report was prepared and submitted to the AEC in February 1970. In June 1970, a request for an Environmental Report was received from the AEC in conformance with the National Environmental Policy Act ("NEPA") of 1969. The formal capital authorization for Limerick's construction was approved by Corporate Management in January 1971.

Q. Was the Construction Permit issued within the time frame originally anticipated by PECO?

A. No. The issuance of the Construction Permit was substantially delayed because of new environmental evaluations which the AEC was required to make under NEPA and because of an extended hearing process. Consideration of the application was suspended for some time to comply with these requirements which were not considered applicable at the time of its filing. The Construction Permit was not issued until June 1974.

b. <u>Continued Justification Analyses</u>

Q. Please describe the analyses which PECO conducted during Limerick's construction to assure that its continuation was justified.

A. The Company, throughout the 1970's, continuously analyzed the need for the additional generating capacity represented by Limerick through its annual capacity planning process. This process begins with the forecast of future annual sales and peak demands. At least once a year, the sales and peak demands are estimated for up to twenty years into the future. In addition, the reserves necessary to reliably supply these forecasted demands are calculated. The amount of generation reserves required depends on the desired reliability of the system. The PJM Interconnection reliability criterion, which is widely used by many other electric utilities, is that customers will not experience a curtailment in electric service more often than one day every ten years because of an inadequate supply of generation. For Philadelphia Electric Company and other members of the PJM Interconnection, the required reserve generating capacity has been recently calculated to be approximately 25% of the estimated annual peak demand.

The combination of the Company's peak load demand plus reserve requirements yields the total future generation required. This generation requirement is compared to the installed generation, which is calculated by deducting scheduled retirements and adding in commitments to new capacity. When the total forecasted generation requirement exceeds the projected supply, additional capacity is planned. This process is described in greater detail by Mr. Rush.

Table 1 illustrates the results of these annual capacity planning analyses. As shown, in the early 1970s, projected reserves even with the Limerick Units were at or below the target reserve margin required to assure service reliability. Required reserve levels were obtained only by planning and initiating construction of additional major stations, including the Fulton and Summit nuclear stations. As projected load levels declined, these stations as well as proposed coal and oil plants, all of which were substantially less progressed than Limerick, were cancelled. In the later years, the numbers above the line in the Limerick service years indicate what the reserves would have been without the proposed Limerick Units. These reserves are all at or below the current 25% reserve criteria, thus indicating continuing need for both Limerick Units.

The Company also continuously examined the economics of nuclear generation against other types of capacity. Both oil and coal-fired generation were compared to nuclear. These analyses, more fully described by Mr. Rush, indicated that nuclear capacity was substantially more economic than fossil for our service territory. In fact, between 1974 and 1978 the average total cost of coal and oil-fired generation exceeded nuclear capacity by 36% and 46% respectively. I should note that these analyses do not reflect the substantial advantage of continuing with the Limerick Project in light of the substantial investment already made in the Project at the time of analysis. The combination of these analyses (i.e. of comparative generation plant economics) and our studies described above showing the need for additional capacity demonstrated to us throughout the late 1970s and early 1980s that continued construction of Limerick was both necessary and desirable.

In addition to these Company studies, the superiority of nuclear generation was consistently confirmed by independent sources. In 1976, for example, Mr. Leonard Reichle, Senior Vice President of Ebasco Services, Inc., presented a paper on "The Economics of Nuclear Power" in which he compared nuclear and coal-fired generation at a hypothetical 2-unit 2400 MW station in the Central Atlantic region with service dates of 1987 and 1989, and concluded that nuclear power was 27%

cheaper than the coal alternative. Another comparative generation study was performed by the National Academy of Sciences in 1979 ("Energy in Transition 1985-2010"). This analysis concluded:

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

In addition, the Company performed two separate computer analyses in 1979 and 1980 which further confirmed the continuing need for and economic desirability of the Limerick capacity. Our 1979 study was performed in response to an analysis presented by the Pennsylvania Consumer Advocate in our 1979 rate case and was itself presented to the Commission in that case. Even employing assumptions suggested by the Advocate, it demonstrated the desirability of continued Limerick construction.

The 1980 study was entitled "Comparison of the Limerick Nuclear Station With Other Alternatives Updated to September 1980", and consisted of a computer based analysis of Limerick's economics under a number of alternative assumptions, including such unfavorable assumptions as

- zero PECO load growth;
- reduction of Limerick capacity factor from 70% to 60%;
- reduction in fossil fuel cost escalation rates from 12% to 8%; and
- an increase of Limerick nuclear capacity costs of $1 billion over the then current estimate.

The 1980 analysis concluded as follows:

> "The Limerick nuclear project should be completed as fast as possible because it is in the national and PECO customers' interest. It will reduce the consumption of oil and will result in lower PECO revenue requirements from its customers than any other alternative available to PECO. The abandonment of the Limerick project will not only leave a large debt to be amortized, but also lose the benefits of oil conservation and lower revenue requirements. Detailed economic analyses have brought out that under reasonable assumptions and unfavorable departures from them, the Limerick nuclear plant will result in lower annual PECO revenue requirements than the following situations:
>
> 1. PECO had not started Limerick or any other alternative generation plant.
>
> 2. PECO had not started Limerick and started at the end of 1980 to install an alternative coal generation plant.
>
> 3. PECO had started at the end of 1980 to convert the Limerick nuclear plant to coal fired operation.
>
> 4. PECO abandons at the end of 1980 the Limerick nuclear project."

Thus, the Company has conducted a number of analyses throughout the 1970s and early 1980s, all of which have confirmed the continued need for and economic superiority of the Limerick plant.

Q. Did the PUC review the continuing need for the Limerick Generating Station during its construction?

A. Yes. In both the Company's 1979 Rate Case at RID 865 and the first Limerick Investigation at Docket No. I-80100341, the Commission was presented with extensive data indicating that there was a continuing economic justification for the Limerick plant. In the 1980 Limerick Investigation, the ALJ concluded that

> "(T)here can be no doubt as to the economics of and need for the completion of both Limerick units. There has been no analysis presented which, using plausible assumptions, has shown Limerick to be uneconomic. Rather, all reasonable analyses have shown that Limerick will produce economic benefits to ratepayers over any proposed alternative."

Although the Commission ultimately determined that immediate construction of Limerick Unit 2 should not be continued for financial reasons, it found that "customer savings associated with the completion of the units still do exist" and "encourage[d] the Company to complete [Unit 1] as rapidly as possible consistent with the public safety . . . to retain for ratepayers the lower future revenue requirements and customer savings." Requests by opposing parties in each proceeding that the Company be directed to cancel the units were rejected.

c. Scheduled Completion Dates

Q. Mr. Boyer, the Company announced deferrals in the completion of Limerick 1 and Common in 1974, 1976 and 1978. What was the effect of these announcements upon the Limerick Project as perceived by the construction organization which you headed at the time?

A. As construction managers, the role of the E&R Department was to develop construction schedules and programs which would implement management's funding and completion date directives. In performing this function, consistent with management's objectives, we sought: (1) to minimize funding requirements in the early years of construction as required by financial constraints; and (2) to retain the option of accelerated completion of the project as compared to the announced completion dates in the event additional funding became available and such completion were to appear desirable. Of course, we also sought to construct the plant as efficiently and promptly as possible.

In performing our function, we developed construction schedules. These schedules are shown on Table 2 along with the associated announced completion schedules. As there shown, our construction target completion date was almost always earlier than the announced schedule. This reflected two objectives of ours and of Senior Management. First, throughout this period, i.e. the mid and late 1970s, we sought to employ the available cash to achieve the greatest overall schedule progress. Further, we developed our construction schedules on the assumption that additional funds would be available in later years to permit the plant's completion as planned. Through this process, we preserved for as long as possible the option of earlier than announced plant completion.

Second, we maintained early construction target completion dates in order to place maximum pressure upon our contractors and their craft laborers to progress construction efficiently and rapidly. Throughout this period, the projected completion date as shown in the construction schedule was only deferred after every attempt had been made to meet the earlier target date. As I explain below, cash unavailability, recognition of additional work scope due principally to new NRC requirements, labor unavailability and reduced labor effectiveness were the principal causes of these schedule extensions.

Q. Please describe in greater detail the effects upon the construction schedule of the 1974 public announcement?

A. As shown in Table 2, we started 1974 with a projected Limerick 1 fuel load date of January 1979. By mid-year, delay in the receipt of the Construction Permit made it apparent that fuel load would probably not occur before June 1979, though no public announcement of this date was made. In September 1974, as described by Mr. Paquette, the cash budgeted for Limerick in future years was reduced and the publicly announced fuel load date for Limerick was postponed until October 1980. Pursuant to the objectives which I have described above, the construction target fuel load schedule was retained as June 1979. However, by May 1975, lack of sufficient funds and early recognition of the possible effects of changing NRC regulatory requirements necessitated a construction target fuel load postponement to August 1980.

Q. What were the effects upon the construction schedule of the 1976 public announcement?

A. Throughout 1975 to May 1976, we continually reviewed the need for and financial implications of keeping Limerick 1 on a 1980 fuel load schedule. Due to the Company's poor financial condition, the 1975 budgeted cash for Limerick direct costs was reduced from $179 million to $113 million. Maintaining the 1980-81 fuel load dates, it was recognized, would require $186 million in 1976 and $251 million in 1977. By mid-1975, consideration was being given to reducing Limerick expenditures still further. Contingency plans were thus developed with Bechtel to hold Limerick direct costs at $125 million per year.

In April 1976, revised PECO forecast plans held 1976 Limerick expenditures to about $150 million, and overall PECO annual total construction expenditures to about $400 million. As shown on Table 2, in May of 1976, the Company announced a two-year delay in the Limerick fuel load date, i.e. from October 1980 to October 1982. However, again pursuant to the objectives described above, the construction target fuel load date was extended only from August 1980 until October 1981, a period of 14 months.

Q. Please now describe the effects upon the construction schedule of the 1978 deferral announcement?

A. The 1977 cash budget for Limerick included sufficient funds, i.e. $155 million, to maintain the then construction target fuel load date, i.e. October 1981. However, our analysis (i.e. in Spring 1977) showed that this fuel load date would require significant increased revenues in the immediate years following the placement of the plant in service (i.e. a net of capital charges and fuel savings of $187 million), which increase would not be offset by savings of advanced plant completion for eight years. Our calculation of net lifetime ratepayer savings of this completion advancement was only $159 million. A further study made in the fall of 1977 produced similar results, i.e. a $159 million initial net cost penalty of advancement, with a break even point from plant cost savings of 6 years and a total net lifetime ratepayer savings of about $123 million. Yet a further study, described by Mr. Paquette, was conducted early in 1978 with similar results.

During January 1978, it became apparent that increased funding to meet an October 1981 construction target fuel load date would not be forthcoming, and the target date was slipped to March 1982. In April 1978, a preliminary construction forecast for the years 1978 through 1982 was prepared, on the basis of holding to a construction target fuel load of October 1982. In view of anticipated depressed earnings, a revised forecast with Limerick postponed two years to 1984-1986 fuel load and with a reduction in financing needs of $139 million in 1979 to 1981 was also prepared. Following extensive analysis, the revised forecast (i.e. 1984-86 fuel load dates) was adopted. This plan minimized the financing requirements in the 1978 through 1982 period, and had minimum revenue requirements through the 1983-87 period. Thus, in May 1978, PECO publicly announced the stretched out fuel load date of 1984. In conjunction with this announcement, and in recognition of the effects of increased work scope due principally to changed NRC requirements as described below, the construction target fuel load schedule for Limerick 1 was slipped to October 1982.

Q. Please continue with your discussion of events as they unfolded in 1978 through 1980.

A. By mid-1978, we were following a construction cash forecast based on 1984-86 Limerick fuel load dates, but with sufficient cash in 1978 to permit a two-year advancement if additional funding were available beginning in 1979. In October, 1978, a draft five-year construction forecast was prepared with the Limerick fuel load dates of 1984-86. A back-up forecast was also prepared with 1982-84 fuel load dates.

The PECO 1979 cash construction budget was approved in January 1979. This provided for $118 million for Limerick in 1979. In March 1979, special approval from the Board of Directors was sought and obtained for an additional $18 million so as to be able to maintain the possibility of 1982-84 Limerick fuel load dates. Indeed, throughout the 1978 to 1980 period, this target was the completion date to which we were working. This schedule was viewed as achievable throughout most of this period. However, a number of factors combined such that in 1980 we realized that this schedule could not be achieved. It became clear at that time that manpower availability and labor effectiveness in the installation of bulk commodities such as conduit and pipe were not meeting the target values. The manhours to install the seismic design of pipe hangers and restraints proved greater than estimated, and interferences introduced by these hangers to duct work and cable trays also required additional manhours to resolve. As the NRC action items resulting from Three Mile Island were issued and as additional NRC required design changes were recognized, significant additional manhours of job effort were added such that a lengthened project schedule became necessary. In June 1980, the construction target fuel load date was delayed from October 1982 to October 1983 due to the recognition of additional work scope associated with new NRC requirements, the TMI accident and a shortage of pipefitters.

In view of this revision in the field construction schedule and an associated cost increase, a meeting was held in Philadelphia with Bechtel Power Corporation at which the background and basis for the revisions were presented and discussed. This meeting was held on July 15, 1980, and in attendance were the Vice Presidents of the Bechtel Power Group, Project Management and Construction as well as their staff representatives. Philadelphia Electric Company was represented by the Senior Vice President, Nuclear Power, the Vice President of Engineering & Research, the Project Manager, and appropriate Construction and Engineering personnel. Immediately following this meeting, a presentation and summary were presented to our President, Mr. Everett.

In October 1980, Forecast 5 was developed and presented to PE by Bechtel. This forecast recommended a fuel load date of October 1984, based on an evaluation of bulk commodity installation rates, required manual staffing levels and the impact of project scope increases caused by regulatory changes. The recommendation for a construction target fuel load date of October 1984 was adopted.

Following the issuance of this Forecast, a complete review of the Limerick costs and schedules was presented by Bechtel and the E&R Department to the Company President and Executive Vice President on December 19, 1980. The meeting was attended by the appropriate PECO Vice Presidents and Project Managers, as well as the Bechtel Project Manager and scheduling personnel. Reasons for the schedule extension and projected plant cost increase were the subject of detailed inquiry.

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

Q. Mr. Boyer, at several places in your testimony, you have stated that funding levels were requested to permit earlier than publicly announced Limerick completion (i.e. 1976-1980). In retrospect, with the knowledge that you have gained by completing the construction of the plant, were these funding levels sufficient to permit plant completion upon the proposed dates?

A. No, they were not. Our judgments respecting the cash required for plant completion were based upon our understanding of the Project scope in those years. As I have explained above, and as is explained in greater detail by Mr. Kemper and Mr. Clarey, the Project's scope as we understood it in 1976 to 1980 turned out to be greatly underestimated. Because of new and changed NRC design requirements, the Mark II containment new loads problem, reduced labor effectiveness as compared to our estimates due principally to increased congestion and enhanced QA/QC requirements attributable to new or revised NRC requirements, labor unavailability and other factors, the funding levels provided would not have permitted Project completion by the earlier target dates. Indeed, even as late as 1980, we did not fully appreciate the scope of work required on the Project. Substantially greater work has been performed in the last four years of Project construction than we anticipated would be the case in 1980 when the October 1984 fuel load schedule was adopted.

Q. Why was the Company unaware in the 1976 to 1980 period of the full scope of work which was ultimately required to complete Limerick 1 and Common Plant's construction?

A. We were unaware of the full scope of work because the plant which we have constructed is not the plant which we had designed or planned to construct during that period. As described in PECO Exhibit 2, which Exhibit will be discussed in detail by others, substantial additional commodities, engineering and craft manhours, additional testing and equipment installation were required principally by changing NRC requirements for the design of a licensable plant. We did not and could not forsee that these requirements would be imposed.

Q. Mr. Boyer, could the Company have completed Limerick 1 and Common Plant any earlier than it did?

A. Obviously, that is a very hypothetical question. My answer is that no, given the circumstances that we faced and the resources that we had available, we could not have completed the plant earlier than we in fact did. As explained by Mr. Paquette, during the early years of the Project the amount of money which we could spend had to be restricted. Moreover, the amount of money which we needed grew substantially because of the NRC-imposed changes in the plant, further exacerbating our cash constraint problems. As described in PECO Exhibit 2, a number of those changes were imposed very late in the Project, in 1980 to as late as 1983. For instance, new NRC requirements resulting from the TMI accident in March of 1979 were issued through May of 1983. Compliance with these requirements delayed engineering completion until mid-1983. Consequently, related construction activities could not be completed until mid-1984. Another example of these late-imposed regulatory changes is the NRC's fire protection requirements. Although some of these requirements were imposed in 1975-1976 following the Brown's Ferry fire, the major fire protection regulations such as Appendix R were not issued until 1981. Engineering for these regulatory changes was not completed until mid-1984, while construction of additions and modifications could not be completed until September 1984.

Because of these and other late additions to work scope as a result of NRC requirements, substantial rescheduling had to be done and inefficiencies were generated in startup and system completion activities. In light of all of these factors, many of which are more thoroughly described in other testimony, and including the licensing delay I describe below, I do not believe that we could have significantly shortened the Project's duration.

Q. Please discuss the delays in the Limerick licensing process and its impact on the project's duration?

A. A further cause of delay in Limerick 1's commercial operation has been the protracted NRC licensing process. PECO submitted its application for an Operating License for Limerick on March 17, 1981. From July 1981 to mid-1983, PECO responded to more than 1200 questions concerning the environmental and safety aspects of the plant. Hearings on the application commenced in October 1982, and were subject to extensive intervention. The hearings were not concluded until July 1985.

A major cause of the licensing delay was the development of the Radiological Emergency Response Plans (RERP's) for the counties, municipalities and school districts surrounding Limerick, which was not within the control of the

Company. The Company did, however, engage the services of Energy Consultants to assist the responsible governmental units in developing their RERP's. However, the development of these plans was substantially delayed by a number of factors.

First, the state agency responsible for emergency planning — the Pennsylvania Emergency Management Agency ("PEMA") — changed its RERP policy which resulted in plan revisions and resultant delays. For example, PEMA was initially undecided regarding acceptable plan formats. In addition, PEMA realized after considerable delay that it was having difficulty fulfilling some of its commitments to RERP development. Energy Consultants and PECO then provided assistance in satisfying the requirements. Moreover, the implementation of new state and federal RERP program guidance increased the scope of the work involved and necessitated plan revisions. For instance, the Commonwealth policy to plan for day care centers necessitated consultant involvement and resulted in significant additional planning requirements. At the federal level, the criteria for developing the RERP's was repeatedly revised by the Federal Emergency Management Agency ("FEMA") during the 1982 to 1984 period. For example, FEMA-43 issued in September of 1983 resulted in substantial additional requirements for offsite emergency planning. Furthermore, disagreements in RERP policy between PEMA and FEMA resulted in additional plan changes. Also, PEMA and FEMA reviews were protracted due to inadequate agency staffing levels.

Thus, the development and finalization of the RERP's was substantially delayed by procedural problems at both PEMA and FEMA. It was not until January of 1984 that the Atomic Safety and Licensing Board ("ASLB") issued an order setting a schedule for submittal of Offsite Emergency Planning contentions, and the hearings on the contentions could not commence until November of 1984. These hearings lasted until the end of January 1985. It was May of 1985 before all of the contentions regarding the RERP's — excluding the Graterford contentions discussed below — were resolved.

The NRC issuance of a Commercial Operating License for Limerick Unit 1 has been further delayed by the specific contentions as to the RERP for the State Correctional Institution of Graterford ("Graterford"). On June 1, 1982, the ASLB admitted the Graterford inmates as a party to the NRC licensing proceeding. On April 20, 1984, the ASLB granted the inmates 20 days after receipt of their RERP to submit specific contentions. Development of the Graterford plan, which was the responsibility of PEMA and the Pennsylvania Bureau of Corrections, was significantly delayed. It was not until December 13, 1984 that the Commonwealth sent counsel for the inmates an expurgated copy of the Graterford RERP. On December 19, 1984, the Graterford inmates moved for an order requiring full disclosure by Pennsylvania of the Graterford Plan. On January 29, 1985, the Board denied this motion and gave the inmates 20 days in which to submit specific contentions.

Recognizing that the Graterford issues would be the only remaining obstacle to full commercial operation of Limerick 1 and that litigation of these issues could significantly delay such commercial operation, we moved on February 7, 1985 for an exemption from NRC emergency planning regulations to permit issuance of the full power license prior to the litigation of the Graterford issues. This motion was granted by the ASLB on May 24, 1985. However, on June 11, 1985, the NRC ordered the Atomic Safety and Licensing Appeal Board (ASLAB) to expeditiously consider the inmate's appeal of the ASLB's exemption, and on June 17, 1985, the ASLAB vacated the ASLB's May 24 Order.

On June 24, 1985, we filed a second request for exemption with the ASLB. At the same time, we filed a Petition with the NRC requesting that they either reverse the Appeal Board's June 17 Order and reinstate the earlier exemption or assume jurisdiction and expeditiously grant the requested exemption. The ASLB hearings were held on July 15 - July 17, 1985. On July 22, the ASLB issued its Fourth Partial Initial Decision authorizing the NRC to issue an Operating License to PECO. On August 8, 1985, the NRC issued the Limerick full power Operating License. All of these delays in receipt of our operating license were due to factors which were not within our control.

Q. What role did you play in the preparation of PECO Exhibit 2?

A. I was responsible for providing information on the project impact of the Mark II phenomenon. This included a description of the development of NRC requirements associated with Mark II, the substantial increase in the design and construction effort resulting from these new requirements, and the impact of these changes on project cost.

3. RATE BASE INCLUSION OF COMMON PLANT

Q. Has the Company included all Limerick "Common Plant" in its rate base claim for Limerick 1?

A. Yes, the Company has included all of Limerick "Common Plant" in rate base for the following reasons: (1) the use of Common Plant at Limerick was a prudent and reasonable decision designed to produce substantial cost savings to ratepayers; (2) the construction and completion of Common Plant was required either for the actual operation of Limerick 1 or for the efficient and cost effective completion of the plant; and (3) the inclusion of all Common Plant in rate base will reduce the total cost of Limerick.

Q. Why was the Company's decision to employ Common Plant in the construction of Limerick prudent and cost effective?

A. As set forth above in Section 2 of my testimony, the Company requires the capacity of Limerick Units 1 and 2 to meet its future demand for electricity reliably and economically. Once it is determined that two units are required, the use of Common Plant allowed the Company to avoid duplicate construction of numerous facilities, buildings and systems that could be "shared" between the two units. Indeed, as shown in the examples discussed below, a principal advantage of a dual-unit power plant such as Limerick is that the sharing of certain facilities, buildings and systems permits efficiencies which produce a lower cost per unit than would be possible for two single-unit power plants. Various studies and experience have shown that the use of Common Plant is cost effective and can be expected to produce cost savings on the order of 10% in the total cost of a multiple unit plant.

Q. Please explain why the Common Plant included in the Company's claim is required either for the actual operation of Limerick 1 or for efficient construction of the project.

A. In this context, Common Plant can be classified into four categories:

First, certain items of the Common Plant will be employed in operating both Limerick Units 1 and 2, but would have been required in the same size, design and cost even if Limerick 1 had been constructed from the start as a single unit plant. These facilities and systems include the Administration Building (including the security facilities), Emergency Public Notification Facility, Sewage Treatment Plant, Exclusion Area, Technical Support Facilities, Clarified Water System, Domestic Water System, and the Generator H2 and CO2 System.

Second, certain items of Common Plant would have been required to operate a single-unit plant, but could have been designed somewhat smaller and constructed at a somewhat lower cost as part of a single unit facility. However, each of these items will be required to operate Limerick 1, and as set forth above, the use of Common Plant will produce substantial cost savings for PECO's ratepayers. These facilities and systems include the Off-Gas Facility, Circulating Water Pumphouse, Spray Pond Pumphouse, Control Room, RHR Service Water System, Yard Piping, Emergency Service Water System, Cable Spreading Room, Emergency Switchgear and Batteries, and the Liquid and Solid Radioactive Waste Storage Systems.

Third, a portion of Common Plant will be used solely for the operation of Limerick 1. These facilities and systems include the Unit 1 portion of the Circulating Water System, Off-Gas System and Service Water System.

Fourth, a portion of Common Plant will be used solely for operation of Limerick 2, but installation and completion of these facilities during Limerick 1 construction was required to construct and complete the Limerick plant efficiently and cost effectively. These facilities and systems include the Unit 2 Circulating Water System, Off-Gas System, and Service Water System.

The use of the first three types of Common Plant set forth above is necessary for the actual operation of Limerick 1. Completion of the fourth category during Limerick 1 construction was required for the cost effective construction of Limerick for the benefit of ratepayers. Therefore, in my opinion, all of the Company's Common Plant investment is used and useful and should be included in rates.

Q. Have you assessed the costs associated with your second and fourth types of common plant?

A. Yes. We have reviewed facility drawings and piping and instrumentation drawings to identify those portions of the plant which should be considered in these categories and have developed estimates of their cost. The results indicate that only \$15.3 million, or approximately 2% of Common Plant is solely for the operation of Unit 2 and that only \$47 million, or approximately 6% of Common Plant cost is attributable to larger sizing due to construction of Unit 2. Added to these direct costs should be AFUDC, overheads, and taxes in the amounts of \$8.8 and \$26.9 million, respectively.

Q. How will the inclusion of Common Plant in rate base reduce the cost of Limerick?

A. If one-half of Common Plant is excluded from rate base, the Company will continue to accrue AFUDC on this excluded amount until 1990, when Limerick 2 goes into service. These additional AFUDC accruals would add \$330.4 million to the total cost of the Limerick plant. By including all of Common Plant in rate base with Unit 1, this increase in capital cost is avoided, although current rates are increased.

Q. Mr. Boyer, does this conclude your testimony?

A. Yes, it does.

APPENDIX A

EXCERPT FROM THE TESTIMONY OF VINCENT S. BOYER IN DOCKET NO. I-80100341

Q. When did PECO initially project the need for the capacity additions which were subsequently to be provided by the Limerick Generating Station?

A. In 1967.

Q. Please describe in general terms the climate of the electric utility industry during the 1960's and early 1970's.

A. The 1960's and early 1970's were characterized by electrical demand exceeding forecasts, inadequate reserve margins, brownouts and blackouts, expressions of regulatory concern about adequate and reliable electric power systems and power plant siting delays. Electric utilities were and are mandated by statute to provide reliable service and thus to overcome any electric power shortage by installing facilities which will be necessary to meet anticipated customer demand. The Limerick Generating Station was initiated to fulfill PECO's statutory obligation. The load/capacity forecasts, the PJM reserve obligations, and the social and regulatory pressures of the late 1960's prompted the initiation of the Limerick Generating Station.

In the decade 1960-1970, the number of residential customers served by PECO grew some 17 percent from about 913,000 to 1,070,000. Average annual kilowatt-hour consumption per residential customer in the 1960-1970 decade rose by over 77 percent from 3,373 kilowatt-hours per residential customer to 5,990 kilowatt-hours, and total residential consumption grew by over 108 percent. Commercial and industrial use of electricity in the area served by PECO rose 79 percent in the 1960-1970 decade. As described more fully by Mr. Hoch and Mr. Kasum, we anticipated substantial further growth in the 1970-1980 decade.

In the early and mid 1960's, 12 to 15 percent of the estimated annual peak was considered an adequate generation reserve. As a result of the northeast blackout on November 9, 1965, the Pennsylvania Public Utility Commission and the Federal Power Commission stimulated the electric utilities to increase their generation capacity to meet anticipated load growth and future demands. On March 31, 1966, the utilities were told that immediate preparations should be made to increase installed capacity until a reserve of 20% above forecasted annual peak loads was reached. The utilities agreed to accept the Commissions' proposals and institute construction programs that would meet the stated goal. A few of the expressions of concern during this period by the Federal Power Commission and the Pennsylvania Public Utility Commission are set forth in Exhibit VCB-1, Section A. In 1972, the regulatory concern over the continually increasing load growth and the lack of sufficient reliable capacity culminated in the entry of an order by the Pennsylvania Public Utility Commission on March 12, 1972 initiating an investigation to determine the need for additional electric generating and transmission facilities during the next decade.

Q. What was the basis for the Company's decision that Limerick was needed to provide new capacity?

A. The Company's decision to build Limerick rested on its determination made in 1967 and 1968 that additional generating capacity would be required beginning in 1975 to meet its customers' needs. The planning process which led to this decision was much the same in 1967 as it is today. Although Mr. Kasum will testify in detail regarding the Company's capacity planning, an overview of the process and the factors influencing the Company's decision in 1968 may be helpful at this juncture.

Generation planning begins with the forecast of future annual sales and peak demands. At least once a year the sales and peak demands are estimated for up to twenty years into the future. In addition, the reserves necessary to reliably supply these forecasted demands are calculated. The total generation required—peak load demand plus reserve requirements—is compared to the installed generation, which is calculated by deducting scheduled retirements and adding in commitments to new capacity. When the total forecasted generation requirement exceeds the projected supply, additional capacity is planned.

From 1961 through 1969, the Company had witnessed a 5.9% increase per year compounded in residential consumption of electricity, and a 6% increase in commercial and industrial use of electricity. The demand for electricity in fact outstripped available capacity during 1967, 1968, and 1969 which necessitated the voltage reductions and voluntary customer load curtailments experienced during those years.

Thus, when the Company prepared its 1967 and 1968 forecasts of future capacity requirements, it confronted pressures to add capacity both to meet its projected load growth plus the increased reserve target of 20%. Although the Company had planned new generating capacity to come into service between 1971 and 1974, the May 1968 forecast revealed that this new capacity would not be enough to meet the targeted 20% reserve margin beginning in 1975. As is more fully explained by Mr. Kasum, the reserve requirement would have been 11.5% in 1975, 6.0% in 1976, and 0.9% in 1977 unless additional capacity was added in these years.

The alternatives to adding new capacity in 1975 and 1977 were to plan for voltage reductions and/or service curtailments to customers, or to purchase power from other sources. The former option was unacceptable given the Company's obligation to its customers as a public utility and the pressures then being exerted by regulatory authorities. The purchase of power from other PJM companies similarly was unacceptable because those companies were facing increased demands on their own systems, possible delays in construction of new capacity to meet those demands, and current voltage reductions and load curtailments similar to those being experienced by the Company. Thus, Philadelphia Electric could not reasonably rely on the availability of excess power among PJM members to purchase electricity rather than add its own new capacity.

Q. What were the alternatives to nuclear generation considered by the Company and why were these alternatives not selected?

A. Once the need for additional capacity in 1975 had been determined, the Company decided that the new facility should be for base-load operation because the PECO system already had sufficient generation for cycling and peaking service. Peaking capacity of 260 megawatts recently had been added at Conowingo in 1964, an additional 880 megawatts was under construction at Muddy Run in 1969, and an additional 500 megawatts of combustion turbine capacity was also in the process of construction.

Once it was determined that base load generation was required, the selection was limited to nuclear, oil or coal-fired plants (i.e., mine-mouth or local area). Hydroelectric generation was not an available alternative because the only locations capable of significant generation had been or were being fully developed, while natural gas did not present a prudent alternative for economic reasons and due to the then-emerging uncertainties associated with future supply.

Of the fossil fuels, coal was preferred to oil generation in the mid 1960's for several reasons. First, throughout the 20th century coal rather than oil had been the dominant fuel used by utilities. This historic emphasis on coal produced a highly-refined and efficient coal technology which perpetuated coal as the principal alternative. Furthermore, oil prices in the mid-1960's were slightly higher per million BTUs than coal prices, which made the oil-fired plants more costly to operate even though the capital costs of the plants were comparable. The Company predicted that the disparity in prices between coal and oil would continue, in part because the demand for residential use of oil was increasing and in part because the transport of coal, which constituted nearly half of its price, was becoming cheaper with the introduction of the unit train method of shipment. As a result of these factors, oil was the least preferred alternative for base load generation.

With respect to coal-fired generation, the Company explored the possibility of mine-mouth sites, but rejected this alternative because sites near large coal reserves within reasonable proximity to the Company's service territory were already being developed. Moreover, transmission limitations necessitated the construction of extensive additional transmission facilities to bring the power to the Company's service territory. More distant locations would have necessitated the construction of hundreds of miles of transmission lines with the concomitant costs and environmental problems incurred in obtaining rights-of-way. Accordingly, this alternative also was viewed as being uneconomic.

Given the inappropriateness of these various alternatives, we focused principally on the choice between nuclear and coal generation (i.e., with the latter located in the Company's service territory). A series of studies were performed in the 1965 to 1970 period which established that nuclear represented the more economic alternative. The most detailed of these was conducted jointly in 1965 by Philadelphia Electric and the Public Service Electric and Gas Company prior to the commitment decisions for the Peach Bottom and Salem units. The specific purpose of this study was to recommend the type, location, and basis of ownership for new generating capacity to be installed jointly by the companies beginning in 1971. Coal and nuclear units of 900 MW net output were compared from the stand-point of reliability and system-wide production cost calculations. The fossil unit did not include the costs of coal and ash handling facilities or stack heights which vary with the location of the plant. Moreover, the extensive environmental equipment which after 1970 began to be required on local generating facilities was, of course, also not considered.

As stated in the report, portions of which are attached as Exhibit VSB-1, Section B, a two-unit 1800 MW nuclear station would provide electricity at a total cost, excluding transmission, of 3.63 mills per kilowatt hour levelized over the 1971 - 1990 period. A fossil fuel plant would provide power at a cost of 4.71 mills per kilowatt hour over the same period. The capital costs of the nuclear units ranged from $206 to $230 million, depending upon the location of the facility, while the coal plant capital costs ranged from $176 to $205 million. The initially higher capital costs of the nuclear plant would be recaptured within three years because of the operating savings derived from the lower cost of nuclear fuel compared to coal. Over its life, the nuclear plant would produce a levelized annual revenue savings to the ratepayers of $6,500,000 over the coal alternative.

In further analyzing the nuclear and fossil alternatives during the late 1960's, the Company updated the 1965 analysis to reflect known changes in construction and fuel costs affecting a choice between nuclear and fossil fuel generation. By the end of the decade, as the Company noted in its first Environmental Report submitted in support of its application for the Limerick Construction Permit, the analyses indicated that oil generation was the preferred fossil fuel alternative to nuclear power because no appropriate sulfur dioxide removal process was available to meet the emerging pollution requirements for coal generation. However, both fossil fuel options reflected higher fuel costs than the nuclear alternative, which continued to make nuclear generation the most economic of the three options.

Q. Please explain the basis for the Company's selection of the Limerick site.

A. The preliminary objective of the site selection process was to locate new generating capacity near the area to be served, thereby minimizing transmission costs and improving overall system reliability by placing generating units close to the load center. In the late 1960's, 48% of the Company's generating capacity was outside or on the periphery of the service area. Moreover, this capacity represented the newer base load generation of the Company. To achieve more balance, the first criterion of the selection process was to locate additional capacity inside the service area.

Within the service territory, nuclear units were planned in the south for capacity additions in 1972 and 1973. The northern portion thus represented the logical location for capacity additions to be provided in 1975 and 1977, especially given the expanding populations in Montgomery and Bucks counties. About nineteen sites were originally considered, but these were quickly reduced to five sites in the desired northern service area: Sanatoga Crossing (Limerick Township), Washington Crossing (Bucks County), Buckingham (Bucks County), Tohican Creek (Bucks County) and Pine Forge (Berks County). (See Exhibit VCB-1, Section C.)

In 1969 Philadelphia Electric hired Gilbert Associates to perform a systematic appraisal of ten alternatives based on these five sites. The Gilbert analysis was supplemented by Company analyses of the same and additional factors affecting the desirability of these alternatives. These analyses were designed to compare site alternatives on the basis of costs and methods for the development of each site. Factors considered in the detailed evaluation included: topography, access to road and rail facilities, availability of water supply, land procurement costs, general geology and seismology, population density and proximity, meteorology, costs of transmission rights-of-way and facilities, and improvements to roads and bridges necessary for the transport of the reactor vessel and other super-heavy components to the site.

Among the principal advantages of the Limerick site was the existence of a 500 KV transmission line crossing the site. Because additional new transmission rights-of-way would not have to be purchased, the site presented the most economical of the five alternatives from this standpoint. Furthermore, the availability of the transmission line avoided the adverse environmental effects associated with the construction of lines over new rights-of-way which the other sites would have imposed. In the same manner, access to the Limerick site from existing roads and railroad spurs was via significantly shorter routes than most of the other sites considered, which produced corresponding cost savings and environmental benefits favoring the Limerick site. Land procurement cost comparisons were also favorable to selection of the Limerick site.

The issue of the availability of water also was considered by the Company in the 1969 study of possible sites. The analysis of the Sanatoga site in Limerick Township recognized that the water from the Schuylkill River would not supply the total requirements of the generating station. The study considered the possibility that a reliable water supply would depend upon fulfillment of plans by the Delaware River Basin Commission to build dams on the Schuylkill upriver from the plant. To avoid reliance on the DRBC plans, the study also considered an alternative design which included the costs of an impounding reservoir. Even taking into account the costs of a reservoir, the Limerick site remained the most economical of acceptable sites according to total site costs because of the low transmission costs.

After the preliminary desirability of the Limerick site was determined, Philadelphia Electric again engaged Gilbert Associates to conduct a detailed evaluation of the site and plant design, the summary section of which is attached as Exhibit VCB-1, Section D. This second 1969 study encompassed a more detailed review of the hydrology, water supply facilities, geology, meteorology, land use and recreational activities in the area, population patterns, and manufacturing and commercial uses of the surrounding area. The study found, among other conclusions, that the Limerick topography was ideal, that the geology was favorable to this type of facility, that no major residential, commercial, or manufacturing complexes were closer than 1.5 miles to the site, that the site was removed from heavily traveled highways, and that population density was not a bar to the site's employment.

In short, the Company reached its decision to locate the generating station at Limerick only after thorough investigation of alternatives compared on the basis of economic, environmental, and social factors. The final selection of the Limerick site curtailed the use of Pennsylvania land resources, avoided adverse environmental impacts associated with other sites, and minimized the capital investment in the project while enhancing overall system reliability and service to the Company's customers.

TABLE 1

PHILADELPHIA ELECTRIC COMPANY

PERCENT RESERVE PLANNED 1970-1990

Year Est. Prepared	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
1970	8.2	8.5	10.1	18.2	11.1																
1971		10.7	2.9	-1.4	9.2	20.4	10.6	15.9	19.8	12.4	15.6										
1972			4.6	3.7	4.9	11.3	15.7	20.9	11.3	17.1	11.1	15.2									
1973				6.5	14.3	23.7	14.1	11.3	11.2	15.0	18.8	23.1	17.0								
1974					20.1	15.1	13.2	11.6	11.9	17.7	12.1	17.5	21.6	17.2							
1975						19.6	18.2	17.4	10.2	10.0	4.5	12.5	16.6	11.1	17.0						
1976							34.0	30.8	24.1	24.5	18.3	[12.3] 25.9	[5.3] 18.2	[0.4] 25.0	[-5.6] 17.9	[2.1] 24.6					
1977								37.0	30.0	32.0	26.0	20.0	15.0	[9.6] 23.0	[5.5] 19.0	[0.3] 25.0	[-3.2] 21.0				
1978									36.0	40.0	36.0	31.0	24.0	23.0	19.0	[12.6] 27.0	[9.6] 24.0	[6.7] 35.0			
1979										36.0	40.0	36.0	31.0	27.0	24.0	[18.4] 34.0	[14.9] 30.0	[11.6] 42.0	[8.5] 38.0		
1980											33.0	36.0	33.0	31.0	29.0	[23.9] 41.0	[21.9] 38.0	[7.7] 40.0	[6.1] 38.0	[4.5] 36.0	

NOTE

20.4 Indicates Limerick 1 in service.

15.9 Indicates Limerick 2 in service.

[ ] Reserve w/o both units.

TABLE 2

Limerick No. 1 Fuel Load

Date	Construction Target Date	Publicly Announced Date
1/74	1/79	1/79
9/74	6/79	10/80
5/75	8/80	10/80
5/76	10/81	10/82
1/78	3/82	10/82
5/78	10/82	10/84
6/80	10/83	10/84
10/80	10/84	10/84

R-85-015-2

Q.DR-Staff-LIM-8. Refer to PECo Statement 1. Provide a list of referenced "additional sources of interim water supply", their owners and their capability to meet needs.

A.DR-Staff-LIM-8. The additional sources of short-term, interim supplemental cooling water, should water from primary sources not be available, and assuming necessary governmental approvals and owner consents are obtained, include:

1. Temporary Use of Reservoir Water. Water could be released upon PECo's request from certain reservoirs and would flow naturally into the Schuylkill River, to then be used at Limerick.

2. Mines. There are several abandoned mines that contain water within the Schuylkill basin. Such water could be piped into the Schuylkill River upstream of Limerick or directly to Limerick, with treatment, if required, to improve its quality.

3. On-Site Storage. The Company has 7 million gallons of water in the Limerick Unit 2 cooling tower basin that could be used for full operation of Limerick Unit 1 for part of one day, should water not be available from primary sources on a given day.

These sources could be used individually or in various combinations along with primary sources to meet Limerick cooling water needs for the short-term. In addition, the restrictions imposed on Schuylkill water use could be modified on a temporary basis. A discussion of specific sources would be premature prior to the filing of appropriate applications with the DRBC.

Responsible Witness: V.S. Boyer, Sr. Vice President - Nuclear Power

RM 12-17-85
Pkg
R-850152

Q. DR-Staff-LIM-23. What is the present status of acquiring an assured water supply for the operation of Limerick 1?

a. How much water is available for the operation of Limerick 1 from approved existing sources? (List all sources and amounts of water available.)

b. How much water is being assumed to come from unapproved sources? (List all sources and amounts of water assumed available.)

c. Based on approved existing sources, what yearly capacity factor could be detained for the operation of Limerick 1?

A. DR-Staff-LIM-23.

a. Approved existing sources of water include the Schuylkill River, the Perkiomen Creek, and the Delaware River. These sources are capable of meeting 100% of the water needs for Limerick 1 upon the completion of the Point Pleasant project and the Merrill Creek reservoir.

b. PECo is not assuming that any water will come from unapproved sources, but rather that such water will come only from sources that have received appropriate approvals. For a description of interim water sources that could be used, if necessary, subject to appropriate approvals, pending the completion of the Point Pleasant project and the Merrill Creek reservoir, see response to DR-Staff-LIM-8.

c. PECo expects to obtain a yearly capacity factor for Limerick 1 of at least 65% over the life of the plant's operation. Based on approved existing sources of water, PECo does not anticipate that the availability of water would significantly affect its ability to achieve this capacity factor.

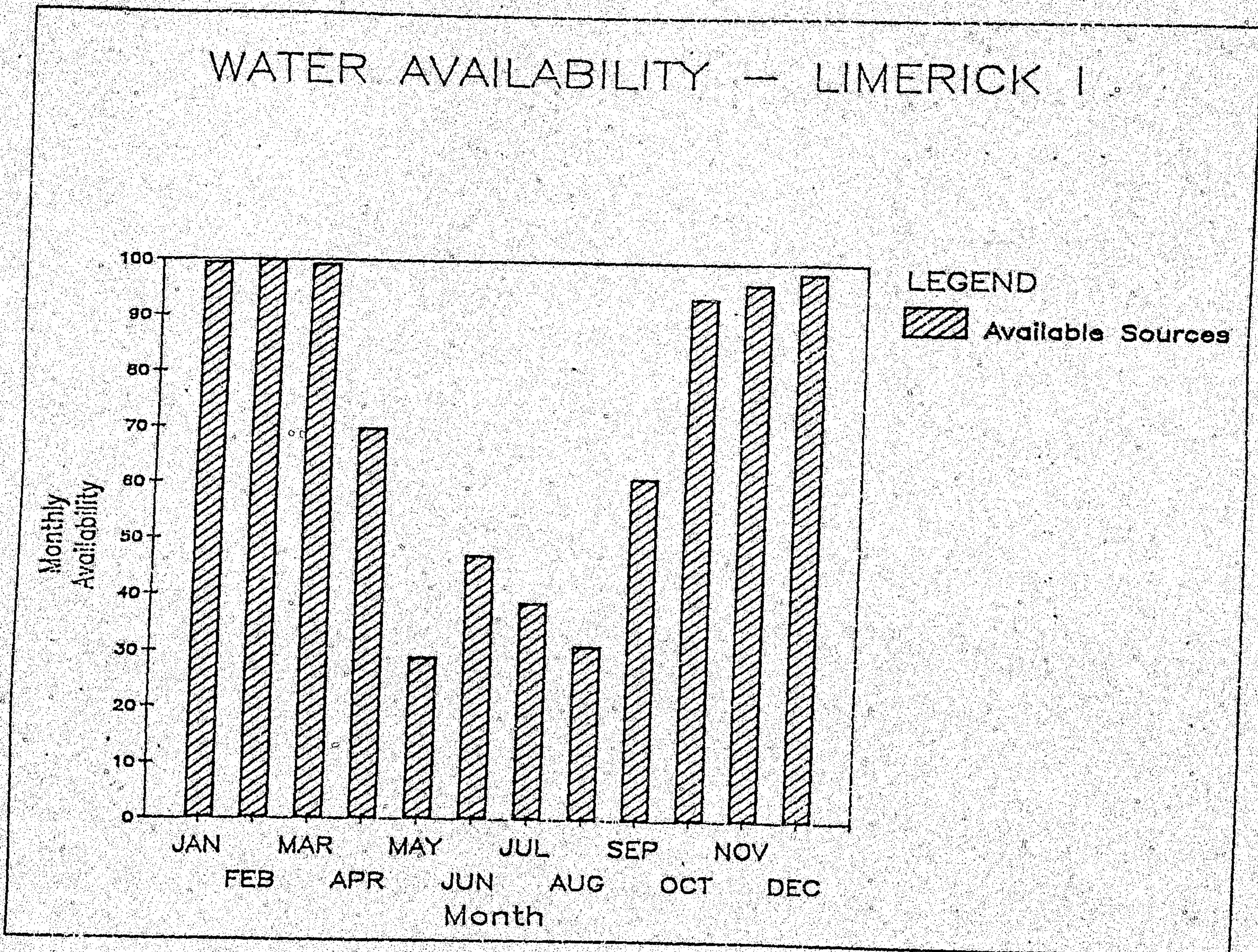
Responsible Witness: V. S. Boyer, Senior Vice President, Nuclear Power

Hbg
R-850152

Q. IR-Staff-LIM-3. Provide a schedule and graph showing when, during the average flow year, Limerick 1 will be able to operate with the water supply as it presently exists.

A. IR-Staff-LIM-3. See attached graph, which reflects only those sources, allocations and standards that are approved and in use currently. This graph does not reflect any planned maintenance outages that may occur during times of water unavailability nor does it take into account any modification of the current standards, nor any additional sources such as those set forth in response to DR-Staff-Lim-8.

Responsible Witness: V. S. Boyer, Senior Vice President, Nuclear Power



WATER AVAILABILITY — LIMERICK I
Monthly Availability
100
90
80
70
60
50
40
30
20
10
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Month
LEGEND
Available Sources

12-17-85

DR-Staff-LIM-11

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Q.DR-Staff-LIM-11. Refer to page 18 of PECo Statement 1. Provide the Spring-1977 analysis and its assumptions for net lifetime ratepayer savings of completion advancement of $159 million.

A.DR-Staff-LIM-11. The Spring-1977 analysis is contained in Attachment DR-Staff-LIM-11(a). The assumptions used in this analysis are contained in Attachment DR-Staff-LIM-11(b).

Please note that this analysis is for both units.

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Responsible Witnesses: V.S.Boyer,Sr.Vice President - Nuclear Power

C.H.Rush,Chief Engr.,Research & Planning Div.

LIMERICK ADVANCEMENT

The annual cash requirements for Limerick as included in the 1977-86 Budget-Forecast are shown in the first column of Table I. These cash expenditures are based on unit service dates of 1983 and 1985, though the 1977 expenditure of 155 million dollars is sufficient to allow both units to be advanced one year to meet 1982 and 1984 service dates provided such a decision is made by next Fall. The forecasted service dates for the transmission associated with Limerick are consistent with the 1983 and 1985 unit service dates, though they also can be advanced as necessary.

Advancing the Limerick service dates to 1982-84 would result in the cash flows shown in the second column of Table I, with the third column indicating cost differentials resulting from this advancement. The one year advancement would mean higher expenditures during the 1978-1981 period, but would result in a reduction of 49 million dollars in direct costs, together with 108 million dollars in IDC, taxes, and overhead for a total savings of 157 million dollars.

The annual revenue requirements for the two schedules for Limerick are compared in Table II. The first column tabulates the difference in capital carrying charges resulting from the advancement, while the second column shows the savings in production costs in 1982 and 1984 due to the earlier availability of the nuclear units. The carrying charges and energy savings are combined in the third column to show the net differential in revenue requirements that result from advancing Limerick to 1982-84. After the first year, which would require additional revenues of 204 million dollars, the 1982-84 schedule results in savings in revenue requirements each year. The present worth in 1982 dollars of these annual differentials are tabulated in the fourth column and are accumulated in the fifth and last columns. This comparison indicates that advancement of Limerick to 1982-84 would breakeven in the 1988-89 time period.

A comparison of the total present worth for the lifetime of the plant (35 years) shows savings in production costs of 248 million dollars resulting from advancing the units to 1982-84. Since this advancement would cost an additional 89 million dollars in present worth of carrying charges, the net savings would be 159 million dollars.

Should the decision not to advance Limerick service dates be made now rather than this Fall, a reduction in the 155 million dollars budgeted for 1977 might be possible.

AFT:tms 3/9/77
System Planning Division

TABLE I

COMPARISON OF LIMERICK CASH FLOWS

(PROD. PLANT COSTS ONLY)

Year	Annual Direct Costs - $\$x10^6$ Forecast Plan SD: 83-85	SD: 82-84	Differential
Prior 1976	499	499	-
1977	155*	155*	-
1978	147	191	44
1979	165	219	54
1980	184	202	18
1981	165	172	7
1982	155	134	-21
1983	146	85	-61
1984	89	29	-60
1985	30	-	-30
Total Direct Costs	1735	1686	-49
IDC and Overhead	796	688	-108
Total	2531	2374	-157

* Sufficient 1977 Dollars to allow a 1982-84 service date to be met.

TABLE II

ECONOMIC COMPARISON OF LIMERICK ADVANCEMENT

(1982 DOLLARS - TRANSMISSION & PUMPING STATION COSTS INCLUDED)

Present Worth of Annual Revenue Requirement Differentials - $\$x10^6$

	Differential of Capital C.C.	Energy Savings	Net Differential From Advancement	P.W. of Annual Differential	Cumulative P.W. of Diff.
1982	342	-138	204	187	187
1983	-50	-	-50	-42	145
1984	145	-159	-14	-11	134
1985	-61	-	-61	-43	91
1986	-51	-	-51	-33	58
1987	-48	-	-48	-28	30
1988	-44	-	-44	-24	6

Total Present Worth Comparison for Lifetime of Plant

	$\$ \times 10^6$
Present Worth Limerick SD 1982-84	3834
Present Worth Limerick SD 1983-85	3745
Differential Present Worth of Capital	89
Present Worth of Energy Svgs. due to Advancement	-248
Present Worth of Net Savings due to Advancement	-159

Assumptions Used in March 1977 Limerick Analysis

① Limerick Capital Cost

1983/85 Service Dates	#1 & Common	$1739 million
	#2	917 million
1982/84 Service Dates	#1 & Common	1627 million
	#2	862 million

② Levelized Carrying Charge Rate - 15.8% (33 yr life)

③ Discount Rate = 9 1/4 %

④ Limerick Capacity Factor - 70%

⑤ 1982 Net Replacement Energy Cost - $21.4/Mwh

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PECO STATEMENT No. 1D

LIMERICK NUCLEAR GENERATING STATION INVESTIGATION

Pa. PUC I-80100341

SURREBUTTAL TESTIMONY OF

VINCENT S. BOYER

PHILADELPHIA ELECTRIC COMPANY

AUGUST 14, 1981

by a comparison of direct construction dollars expended versus anticipated total direct construction costs. I have stated the following percentage completions on the basis of Limerick 1 and 50% of common and Limerick 2 and 50% of common in order to permit an accurate assessment of the completion status of each separate economic unit.

Employing field man-hours, Limerick 2 and common was 67% complete at July 31, 1981 and is anticipated to be 79% complete by April 30, 1982. On this same basis, Limerick 2 and common is 37% complete at July 31, 1981 and is anticipated to be 42% complete by April 30, 1982.

The following table provides the actual and estimated direct construction expenditures (i.e., exclusive of PECO overhead and AFUDC) of Limerick 1 and 50% of common and Limerick 2 and 50% of common at July 31, 1981 and April 30, 1982. The total cost expended is taken from our expenditure records, while the anticipatedtotal and April 30, 1982 expended costs are developed from Forecast 5 and trend reports through July 1981.

(Millions of Dollars)

	Dir. Con. $ Expended 7/31/81	Dir. Con. $ Expended 4/30/82	Anticipated Total Direct Con. $
Limerick 1 & common	$ 763	$ 868	$ 1,136
Limerick 2 & common	503	567	1,326
Total	$ 1,266	$ 1,435	$ 2,462

As shown in the Table, on a direct construction dollar basis, Limerick 1 and common are 67% complete at July 31, 1981 and 76% at April 30, 1982. Limerick 2 and common is 38% and 43% complete at the same dates. I have employed April 30, 1982 as a reasonable approximation of when the Commission will enter its Order in this investigation. Additional cancellation costs would be incurred if either unit were terminated.

Q. Mr. Boyer, in your rebuttal testimony, you provided an analysis of the cost forecast and construction schedule of the Limerick Plant through April 1981. Can you provide a further update of the project's status at this time?

A. Yes, I can. The total project cost of Limerick continues to be $4.2 billion as I stated in my testimony in April. The project remains on schedule for an October 1984 fuel load of Unit 1. The installation of most of the major material categories is either ahead of or on schedule, and we anticipate that major facilities progress will meet the Forecast 5 schedule requirements.

Q. Has the problem experienced in the construction of the Limerick Unit II cooling tower affected the project schedule or cost?

A. No, it has not. As I have previously explained, a problem was discovered in the construction of the Limerick Unit II cooling tower on July 8, 1981. That problem consisted of the fact that the radius of the tower at a particular elevation was discovered to be up to 5.5 inches at variance with the designed radius of 160 feet. Upon analysis, however,

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LIMERICK NUCLEAR GENERATING STATION INVESTIGATION

Pa. P.U.C. I-80100341

SUR-SURREBUTTAL TESTIMONY OF

VINCENT S. BOYER

PHILADELPHIA ELECTRIC COMPANY

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October 7, 1981

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currently-estimated service dates. Dr. Rosen's corresponding total Limerick direct cost (i.e., exclusive of AFUDC) is given in his Table 1 as $4.1 billion. Although the cash flow and details of how he obtained this estimate are not given in Dr. Rosen's testimony, the annual dollar expenditures are included in Schedules F and I of Mr. Czahar's surrebuttal testimony. For 1982, 1983, and 1984, cash expenditures of $713, $543, and $491 million are given, with a total direct expenditure of $2.7 billion from 1982 to the end of construction.

This $2.7 billion represents $1.5 billion more than PECO estimates for direct expenditures in 1982 and beyond. In 1982 alone, Dr. Rosen forecasts an expenditure of more than three times the estimate of Forecast 5 and in 1983 and 1984 considerably more than twice our estimated expenditures. These early massive expenditure assumptions, it should be noted, increase Dr. Rosen's AFUDC accruals in later years, thereby increasing his assumed Limerick capital cost.

In my opinion, Dr. Rosen's $6.6 billion capital cost estimate is implausible in that it assumes unrealistically high expenditures for labor and materials during his assumed remaining construction period.

Q. In what way is Dr. Rosen's cost estimate implausible?

A. Assuming the same percentage split of Dr. Rosen's remaining $2.7 billion direct cost estimate as currently experienced and as developed in Forecast 5 between material and subcontract, non-manual, manual and other construction costs, Dr. Rosen's estimate would call for an expenditure to the end of the job of $890 million for Bechtel manual labor compared to the Forecast 5 estimate of $383 million. Dr. Rosen's estimate is equivalent to some 35-40 million remaining craft manhours, a number that is greater than Forecast 5 projects for such labor for the entire project. At least 4,700 Bechtel craftsmen would be required to obtain this manhour level, even employing the Rosen/Czahar economic assumptions.

This peak craft manning level exceeds by a factor greater than 2 the Forecast 5 projected peak craftsmen of 2,150 and the Wass best estimate projection of 1,800. A work force of this size (i.e., 4,700 craftsmen + 600 subcontractor employees, a total of 5,300) would be greater than has been experienced on any two-unit nuclear plant in this country. For purposes of comparison, the peak construction work forces at Susquehanna and Sequoya (the latter's operating license for unit 1 received by TVA in February, 1980) equalled but 3,400 and 3,300, respectively.

Use of the Forecast 5 construction element breakdown in evaluating the realism of the Rosen/Czahar Limerick plant cost and annual cash flow can be supported on the basis that Dr. Rosen employed Forecast 5 to develop his Limerick 1, Limerick 2 and common plant component costs. However, it is not a reasonable assumption since there is no basis for assuming that other construction costs, such as engineering and project oversight and support activities, or material costs, much of

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OCA Exhibit No. 67

Pennsylvania Public Utility Commission

ELECTRIC UTILITY
FORECAST ACCURACY
COMPARISON
1972-1983

Bureau of

Conservation, Economics & Energy Planning

November 1984

TABLE OF CONTENTS

PREFACE

This report is a supplement to the Commission's "Electric Power Supply & Demand" report released in September 1984, and updates our comparative summary issued October 1982.

The report includes a statistical analysis of the utilities' forecasts of actual peak loads and energy demands.

The terms "year forecast filed" and "forecast year" refer to the year in which the forecast was filed with the Commission. The utilities' Annual Capacity Planning Reports are submitted by May 1 of each year; however, some of the forecasts may have been prepared during the previous year.

This report explains the accuracy of electric utilities' capacity and energy forecasts from 1972 through 1983. The report also presents the predictions of those same utilities for future growth through 1990.

In order to properly evaluate the variance between utility forecasts and experienced loads, it is important for the reader to understand that load forecasting is an imprecise science affected by many unpredictable factors. Some predominant factors include economic conditions, population, price and availability of alternate fuels, and weather.

Unpredicted changes to several of these factors can cause forecasts to deviate significantly from eventual sales experience. For example, the recent recession, the stagnation of population growth in Pennsylvania, and widespread conservation practices spurred by the Arab Oil Embargo could not have been foreseen when current utility construction projects were in the planning stage. These compound fluctuations in the principal factors are primarily responsible for the significant forecasting errors presented in this analysis.

SECTION A. FORECAST ACCURACY SUMMARY

PEAK LOAD FORECAST ACCURACY

This figure compares the historical accuracy of the peak load forecasts of each company.

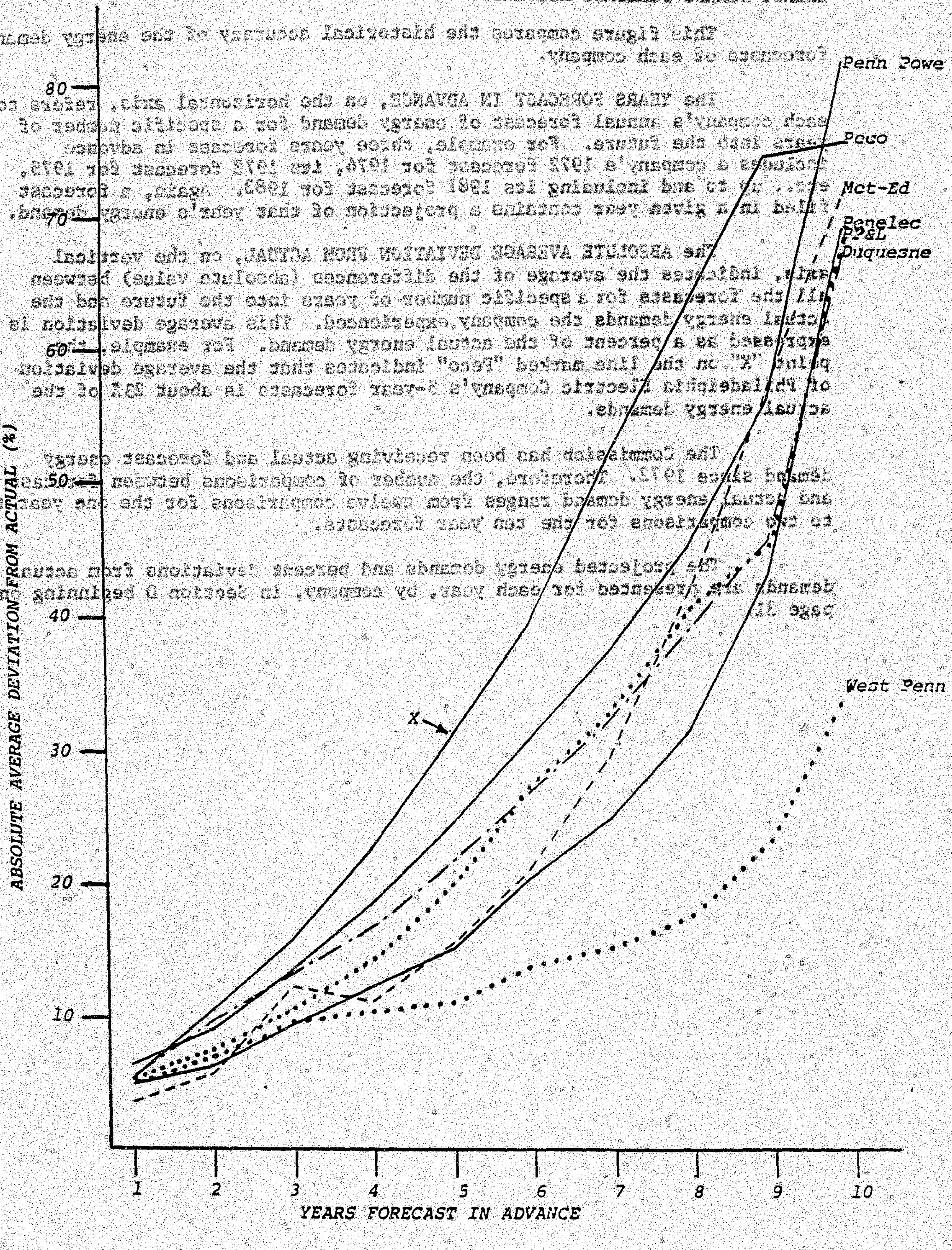
The YEARS FORECAST IN ADVANCE, on the horizontal axis, refers to each company's annual forecasts of peak load for a specific number of years into the future. For example, three years forecast in advance includes a company's 1972 forecast for 1974, its 1973 forecast for 1975, etc., up to and including its 1981 forecast for 1983. Again, a forecast filed in a given year contains a projection of that year's peak load.

The ABSOLUTE AVERAGE DEVIATION FROM ACTUAL, on the vertical axis, indicates the average of the differences (absolute value) between all the forecasts for a specific number of years into the future and the actual peak loads the company experienced. This average deviation is expressed as a percent of the actual peak load. For example, the point "X" on the line marked "Peco" indicates that the average deviation of Philadelphia Electric Company's 5-year forecasts is about 31% of the actual peak loads.

The Commission has been receiving actual and forecast peak load information since 1972. Therefore, the number of comparisons between forecast and actual peak load ranges from twelve comparisons for the one year forecasts to two comparisons for the ten year forecasts.

The projected peak loads and percent deviations from actual loads are presented for each year, by company, in Section C beginning on page 15.

PEAK LOAD FORECAST ACCURACY



ENERGY DEMAND FORECAST ACCURACY

This figure compares the historical accuracy of the energy demand forecasts of each company.

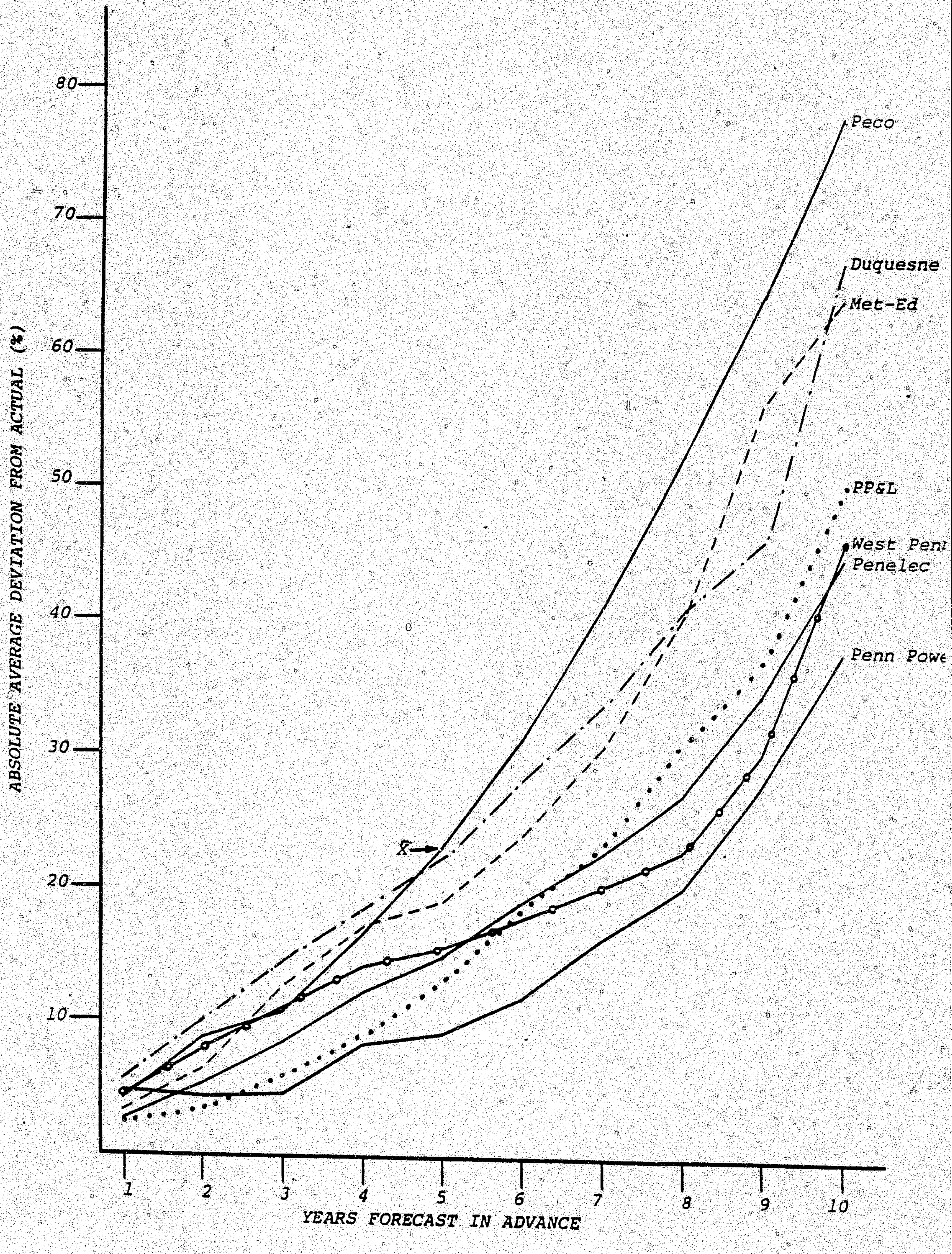
The YEARS FORECAST IN ADVANCE, on the horizontal axis, refers to each company's annual forecast of energy demand for a specific number of years into the future. For example, three years forecast in advance includes a company's 1972 forecast for 1974, its 1973 forecast for 1975, etc., up to and including its 1981 forecast for 1983. Again, a forecast filed in a given year contains a projection of that year's energy demand.

The ABSOLUTE AVERAGE DEVIATION FROM ACTUAL, on the vertical axis, indicates the average of the differences (absolute value) between all the forecasts for a specific number of years into the future and the actual energy demands the company experienced. This average deviation is expressed as a percent of the actual energy demand. For example, the point "X" on the line marked "Peco" indicates that the average deviation of Philadelphia Electric Company's 5-year forecasts is about 23% of the actual energy demands.

The Commission has been receiving actual and forecast energy demand since 1972. Therefore, the number of comparisons between forecast and actual energy demand ranges from twelve comparisons for the one year forecasts to two comparisons for the ten year forecasts.

The projected energy demands and percent deviations from actual demands are presented for each year, by company, in Section D beginning on page 31.

ENERGY DEMAND FORECAST ACCURACY



SECTION B. ANNUAL GROWTH RATES

PEAK LOAD GROWTH RATES

This table presents average annual growth rates of the companies' 10-year peak load forecasts filed between 1972 and 1983. For example, Pennsylvania Power Company's 1973 10-year forecast projected that peak load would increase at an average rate of 6.9% annually.

These figures were developed by computing nominal levelized (average) growth rates from the 10-year projections using the following formula:

$$g = \left(\sqrt[n]{Fn/A} - 1 \right) \times 100\%$$

where "g" is the levelized projected annual growth rate,
"n" is the number of years in the forecast period,
"A" is the actual peak load for the year preceding the forecast year, and
"Fn" is the forecast peak load for the nth year.

PEAK LOAD

PROJECTED NOMINAL ANNUAL GROWTH RATE (%) (1)

	Forecast Year												Actual (2)
	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	72-83
Duquesne	4.8	5.1	4.7	5.4	4.6	4.0	3.9	2.4	3.0	1.9	1.7	3.4	0.5
Met-Ed	8.2	6.6	4.9	5.2	4.5	3.6	2.9	3.2	2.1	2.2	2.0	2.7	0.4
Penelec	6.9	6.9	6.8	4.6	3.9	4.5	4.3	4.4	2.8	2.4	2.7	3.8	1.7
PP&L	6.9	7.8	8.6	7.6	7.8	5.5	5.5	3.4	3.1	3.8	1.8	3.0	2.8
Penn Power	7.2	6.9	5.9	4.7	5.3	5.2	5.2	3.9	2.0	2.3	2.4	2.7	0.6
PECO	8.6	7.2	6.0	6.7	5.4	5.0	2.5	2.4	1.7	1.1	1.9	0.5	0.9
West Penn	5.8	5.1	5.2	5.1	4.7	5.7	5.4	4.1	3.9	3.4	2.6	3.5	2.4

(1) The growth rates are based upon 10-year forecasts with the exception of 1972 which is based upon 9 year forecasts.

(2) These figures represent the nominal levelized (average) annual growth rates of peak loads.

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ENERGY DEMAND GROWTH RATES

This table presents average annual growth rates of the companies' 10-year energy demand forecasts filed between 1972 and 1983. For example, West Penn Power Company's 1973 10-year forecast projected that energy demand would increase at an average rate of 4.8% annually.

These figures were developed by computing nominal levelized (average) growth rates from the 10-year projections using the following formula:

$$g = \left(\sqrt[n]{Fn/A} - 1\right) \times 100\%$$

where "g" is the levelized projected annual growth rate,
"n" is the number of years in the forecast period,
"A" is the actual energy demand for the year preceding the forecast year, and
"Fn" is the forecast energy demand for the nth year.

ENERGY DEMAND

PROJECTED NOMINAL ANNUAL GROWTH RATE (%) (1)

	Forecast Year												Actual(2)
	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	72-83
Duquesne	5.1	4.5	4.4	4.3	4.4	3.8	3.7	2.6	2.6	2.3	2.0	3.3	-0.4
Met-Ed	8.1	6.1	4.5	5.0	4.6	4.3	3.6	3.0	3.2	2.9	2.1	1.8	0.7
Penelec	6.9	5.7	5.5	5.0	5.0	5.1	4.8	3.3	2.8	2.5	1.6	1.3	1.7
PP&L	6.0	7.2	7.1	6.7	7.2	4.9	5.0	2.9	2.8	3.0	2.4	2.5	3.1
Penn Power	5.3	4.2	4.1	2.9	4.2	4.1	2.9	3.6	1.9	1.7	2.0	2.3	1.4
PECO	6.8	7.7	6.8	6.7	6.2	5.1	3.5	2.5	2.2	1.8	2.4	1.2	1.4
West Penn	5.9	4.8	4.8	4.5	5.3	5.7	5.0	3.8	3.6	3.1	2.9	3.0	1.2

(1) The growth rates are based upon 10-year forecasts with the exception of 1972 which is based upon 9 year forecasts.

(2) These figures represent the nominal levelized (average) annual growth rates of peak loads.

SECTION C. PEAK LOAD FORECAST PROFILES

This section compares each company's projected peak loads with the actual peak loads experienced from 1972 to 1983. These comparisons are presented statistically on two tables and graphically on one figure for each company.

The first table, entitled PROJECTED PEAK LOAD BY FORECAST YEAR, displays the company's forecasts for 1972 through 1983, by the year in which they were filed, and the actual peak loads experienced. For example, on page 16 Duquesne Light Company's 1973 forecast of peak load for 1979 is 2,975 megawatts, compared to the actual 1979 peak load of 2,296 megawatts.

The second table, entitled DEVIATION FROM ACTUAL BY FORECAST YEAR, presents a summary of forecast error between actual peak load and forecast peak load, by the year in which the forecasts were filed. These deviations are presented as a percentage of actual peak load. For example, on page 16 Duquesne Light Company's 1974 forecast of the 1977 peak load overestimated the actual peak load by 16.2%.

The figure entitled PROJECTED VS ACTUAL PEAK LOAD graphically compares each 10-year forecast with actual peak load data.

DUQUESNE LIGHT COMPANY

PROJECTED PEAK LOAD BY FORECAST YEAR (MW)

(Year Forecast Filed)

	ACTUAL PEAK LOAD	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	2075	2075	-	-	-	-	-	-	-	-	-	-	-
1973	2296	2200	2230	-	-	-	-	-	-	-	-	-	-
1974	2158	2325	2355	2375	-	-	-	-	-	-	-	-	-
1975	2230	2450	2470	2480	2375	-	-	-	-	-	-	-	-
1976	2260	2560	2585	2625	2480	2350	-	-	-	-	-	-	-
1977	2371	2680	2705	2755	2625	2460	2375	-	-	-	-	-	-
1978	2379	2800	2835	2895	2755	2585	2455	2455	-	-	-	-	-
1979	2296	2930	2975	3030	2895	2700	2660	2660	2385	-	-	-	-
1980	2474	3060	3115	3175	3030	2830	2745	2745	2545	2395	-	-	-
1981	2522	-	3255	3320	3175	2950	2845	2845	2645	2485	2435	-	-
1982	2031	-	3410	3480	3320	3080	2945	2945	2700	2525	2600	2600	-
1983	2184	-	-	3640	3480	3210	3040	3040	2755	2610	2675	2620	2260

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	0.00	-	-	-	-	-	-	-	-	-	-	-
1973	- 4.18	- 2.87	-	-	-	-	-	-	-	-	-	-
1974	7.74	9.13	10.06	-	-	-	-	-	-	-	-	-
1975	9.87	10.76	11.21	6.50	-	-	-	-	-	-	-	-
1976	13.27	14.38	16.15	9.73	3.98	-	-	-	-	-	-	-
1977	13.03	14.09	16.20	10.71	3.75	0.17	-	-	-	-	-	-
1978	17.70	19.17	21.69	15.80	8.66	3.19	3.19	-	-	-	-	-
1979	27.61	29.57	31.97	26.09	17.60	15.85	15.85	3.88	-	-	-	-
1980	23.69	25.91	28.33	22.47	14.39	10.95	10.95	2.87	-3.19	-	-	-
1981	-	29.06	31.64	25.89	16.97	12.81	12.81	4.88	-1.47	3.45	-	-
1982	-	67.90	71.34	63.47	51.65	45.00	45.00	32.94	24.32	28.02	28.02	-
1983	-	-	66.67	59.34	46.98	39.19	39.19	26.14	19.51	22.48	19.96	3.48

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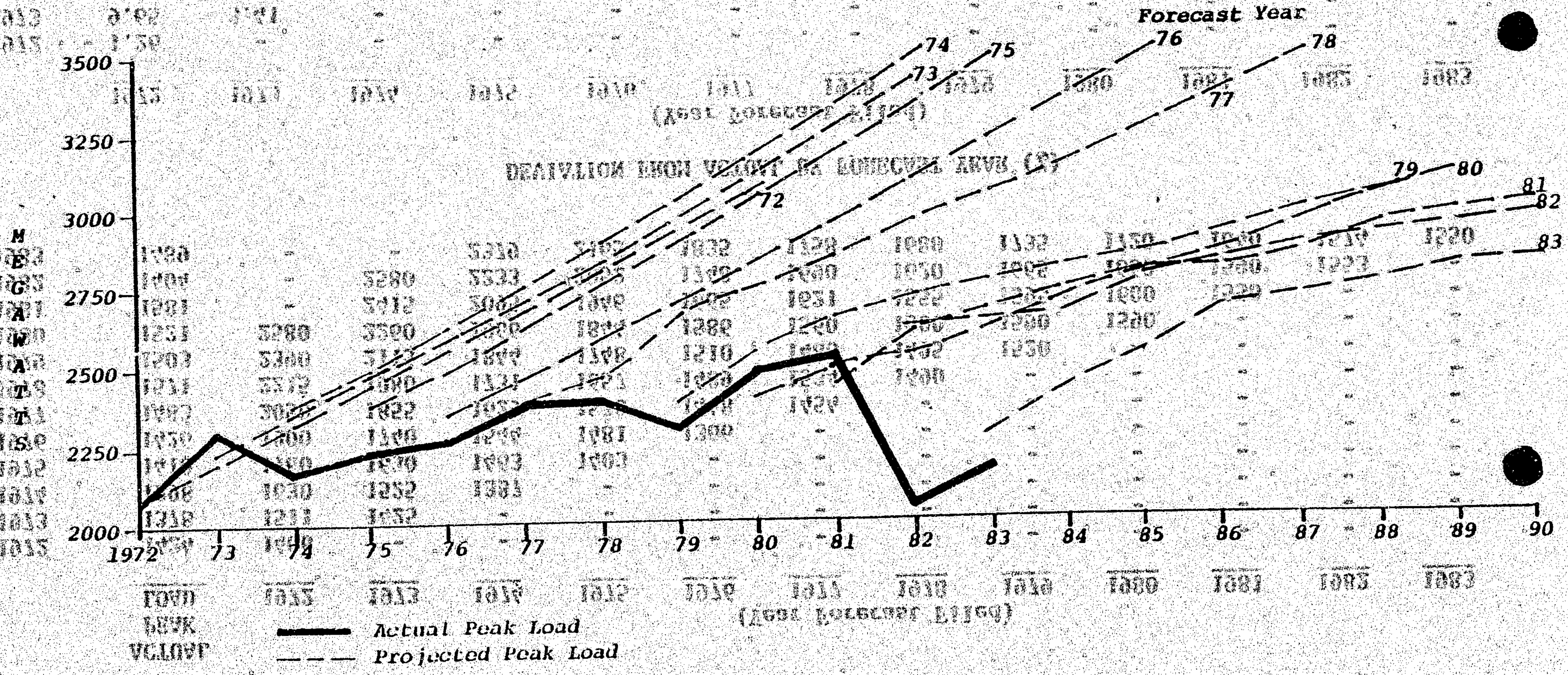
DUQUESNE LIGHT COMPANY

PROJECTED VS ACTUAL PEAK LOAD



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METROPOLITAN EDISON COMPANY

PROJECTED PEAK LOAD BY FORECAST YEAR (MW)

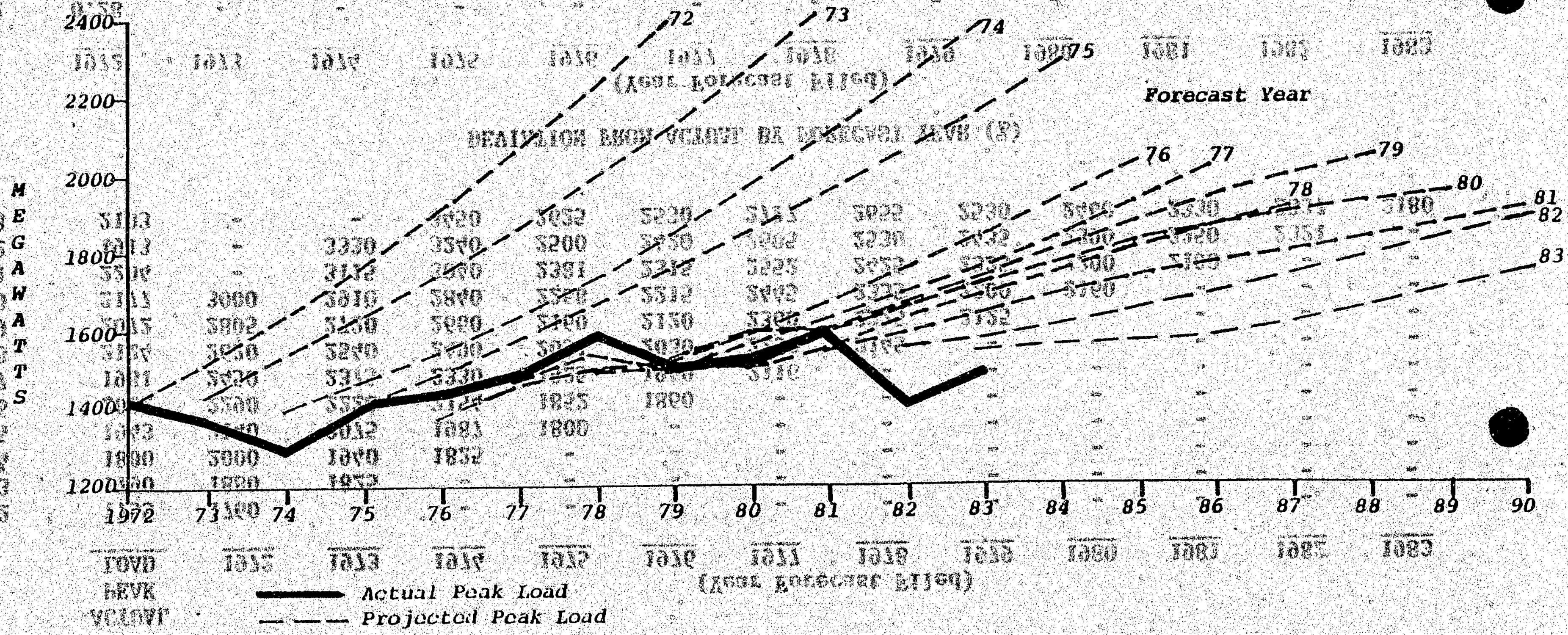
	ACTUAL PEAK LOAD	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	1424	1406	-	-	-	-	-	-	-	-	-	-	-
1973	1378	1511	1425	-	-	-	-	-	-	-	-	-	-
1974	1298	1630	1525	1387	-	-	-	-	-	-	-	-	-
1975	1410	1760	1630	1463	1403	-	-	-	-	-	-	-	-
1976	1426	1900	1740	1544	1481	1366	-	-	-	-	-	-	-
1977	1483	2050	1855	1629	1570	1448	1454	-	-	-	-	-	-
1978	1571	2215	1980	1731	1657	1489	1534	1490	-	-	-	-	-
1979	1503	2390	2115	1844	1748	1510	1488	1495	1520	-	-	-	-
1980	1521	2580	2260	1966	1844	1586	1560	1500	1590	1590	-	-	-
1981	1581	-	2415	2095	1946	1665	1621	1555	1595	1600	1550	-	-
1982	1404	-	2580	2233	2052	1748	1690	1620	1665	1660	1590	1553	-
1983	1489	-	-	2379	2165	1835	1758	1680	1735	1720	1640	1574	1550

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	- 1.26	-	-	-	-	-	-	-	-	-	-	-
1973	9.65	3.41	-	-	-	-	-	-	-	-	-	-
1974	25.58	17.49	6.86	-	-	-	-	-	-	-	-	-
1975	24.82	15.60	3.76	-0.50	-	-	-	-	-	-	-	-
1976	33.24	22.02	8.27	3.86	- 4.21	-	-	-	-	-	-	-
1977	38.23	25.08	9.84	5.87	- 2.36	- 1.96	-	-	-	-	-	-
1978	40.99	26.03	10.18	5.47	- 5.22	- 2.36	- 5.16	-	-	-	-	-
1979	59.02	40.72	22.69	16.30	0.47	- 1.00	- 0.53	1.13	-	-	-	-
1980	69.63	48.59	29.26	21.24	4.27	2.56	- 1.38	4.54	4.54	-	-	-
1981	-	52.75	32.51	23.09	5.31	2.53	- 1.64	0.89	1.20	- 1.96	-	-
1982	-	83.76	59.05	46.15	24.50	20.37	15.38	18.59	18.23	13.25	10.61	-
1983	-	-	59.77	45.40	23.24	18.07	12.83	16.52	15.51	10.14	5.71	4.10

METROPOLITAN EDISON COMPANY

PROJECTED VS ACTUAL PEAK LOAD



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PENNSYLVANIA ELECTRIC COMPANY

PROJECTED PEAK LOAD BY FORECAST YEAR (MW)

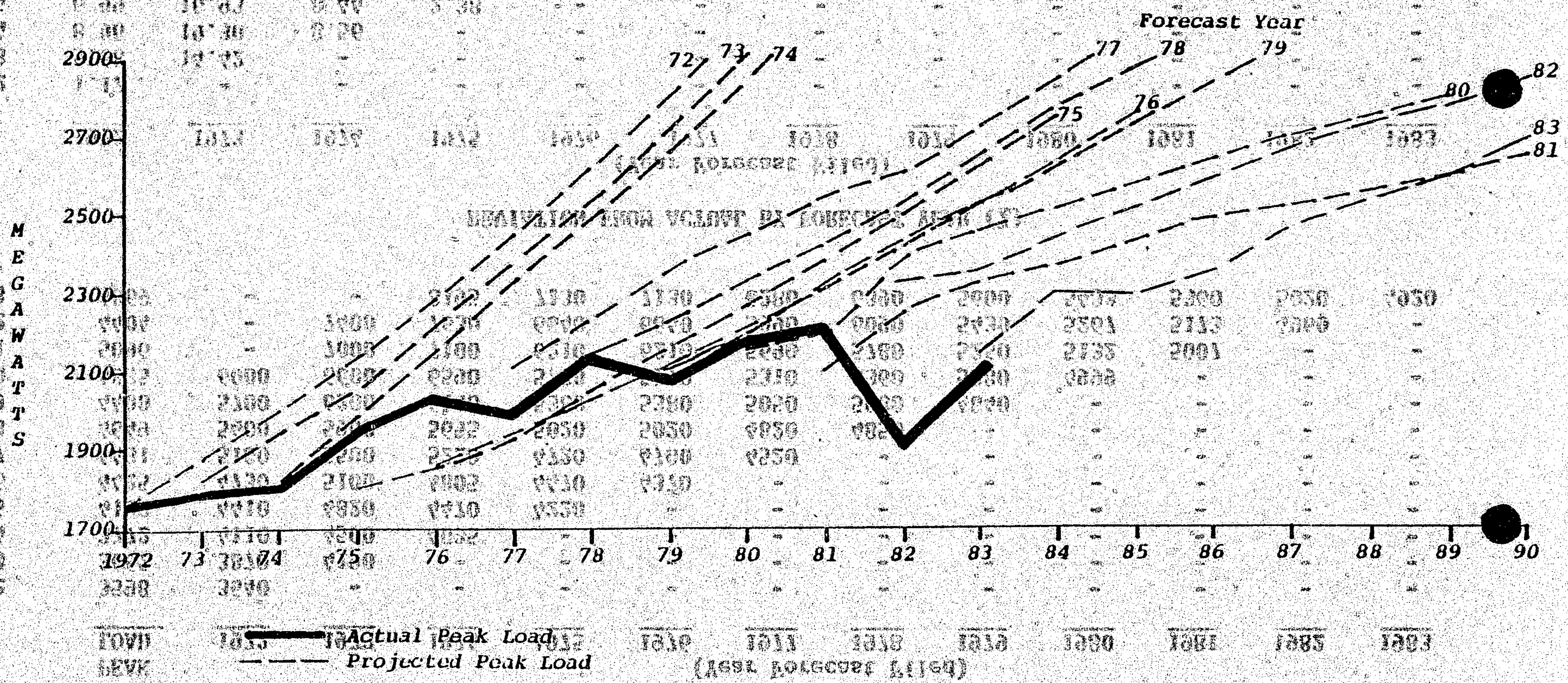
	ACTUAL PEAK LOAD	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
		(Year Forecast Filed)											
1972	1755	1760	-	-	-	-	-	-	-	-	-	-	-
1973	1790	1880	1825	-	-	-	-	-	-	-	-	-	-
1974	1800	2000	1940	1825	-	-	-	-	-	-	-	-	-
1975	1943	2140	2075	1987	1800	-	-	-	-	-	-	-	-
1976	2022	2290	2220	2154	1852	1860	-	-	-	-	-	-	-
1977	1981	2450	2375	2330	1925	1940	2110	-	-	-	-	-	-
1978	2124	2620	2540	2490	2051	2030	2230	2145	-	-	-	-	-
1979	2072	2805	2720	2660	2160	2120	2360	2225	2125	-	-	-	-
1980	2177	3000	2910	2840	2268	2215	2445	2335	2200	2160	-	-	-
1981	2204	-	3115	3040	2381	2315	2552	2425	2325	2200	2100	-	-
1982	1913	-	3330	3240	2500	2420	2605	2530	2435	2390	2250	2321	-
1983	2103	-	-	3450	2625	2530	2727	2655	2530	2460	2330	2337	2180

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
	(Year Forecast Filed)											
1972	0.28	-	-	-	-	-	-	-	-	-	-	-
1973	5.03	1.96	-	-	-	-	-	-	-	-	-	-
1974	11.11	7.78	1.39	-	-	-	-	-	-	-	-	-
1975	10.14	6.79	2.26	- 7.36	-	-	-	-	-	-	-	-
1976	13.25	9.79	6.53	- 8.41	- 8.01	-	-	-	-	-	-	-
1977	23.67	19.89	17.62	- 2.83	- 2.07	6.51	-	-	-	-	-	-
1978	23.35	19.59	17.23	- 3.44	- 4.43	4.99	0.99	-	-	-	-	-
1979	35.38	31.27	28.38	4.25	2.32	13.90	7.38	2.56	-	-	-	-
1980	37.80	33.67	30.45	4.18	1.75	12.31	7.26	1.06	- 0.78	-	-	-
1981	-	41.33	37.93	8.03	5.04	15.79	10.03	5.49	- 0.18	- 4.72	-	-
1982	-	74.07	69.37	30.68	26.50	36.17	32.25	27.29	24.93	17.62	21.33	-
1983	-	-	64.05	24.82	20.30	29.67	26.25	20.30	16.98	10.79	11.13	3.66

PENNSYLVANIA ELECTRIC COMPANY

PROJECTED VS ACTUAL PEAK LOAD



PENNSYLVANIA POWER & LIGHT COMPANY

PROJECTED PEAK LOAD BY FORECAST YEAR (MW)

(Year Forecast Filed)

	ACTUAL PEAK LOAD	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	3598	3640	-	-	-	-	-	-	-	-	-	-	-
1973	3662	3870	4190	-	-	-	-	-	-	-	-	-	-
1974	3772	4110	4500	4095	-	-	-	-	-	-	-	-	-
1975	4122	4410	4820	4470	4220	-	-	-	-	-	-	-	-
1976	4425	4730	5100	4805	4470	4370	-	-	-	-	-	-	-
1977	4431	5100	5500	5220	4720	4700	4520	-	-	-	-	-	-
1978	4649	5400	5900	5655	5020	5020	4820	4850	-	-	-	-	-
1979	4400	5700	6200	6140	5380	5380	5050	5080	4840	-	-	-	-
1980	4835	6000	6600	6590	5770	5770	5310	5360	5080	4999	-	-	-
1981	5096	-	7000	7100	6210	6210	5690	5780	5250	5132	5007	-	-
1982	4404	-	7400	7630	6640	6640	5990	6090	5430	5267	5173	4960	-
1983	4869	-	-	8195	7130	7130	6280	6390	5600	5433	5360	5020	4920

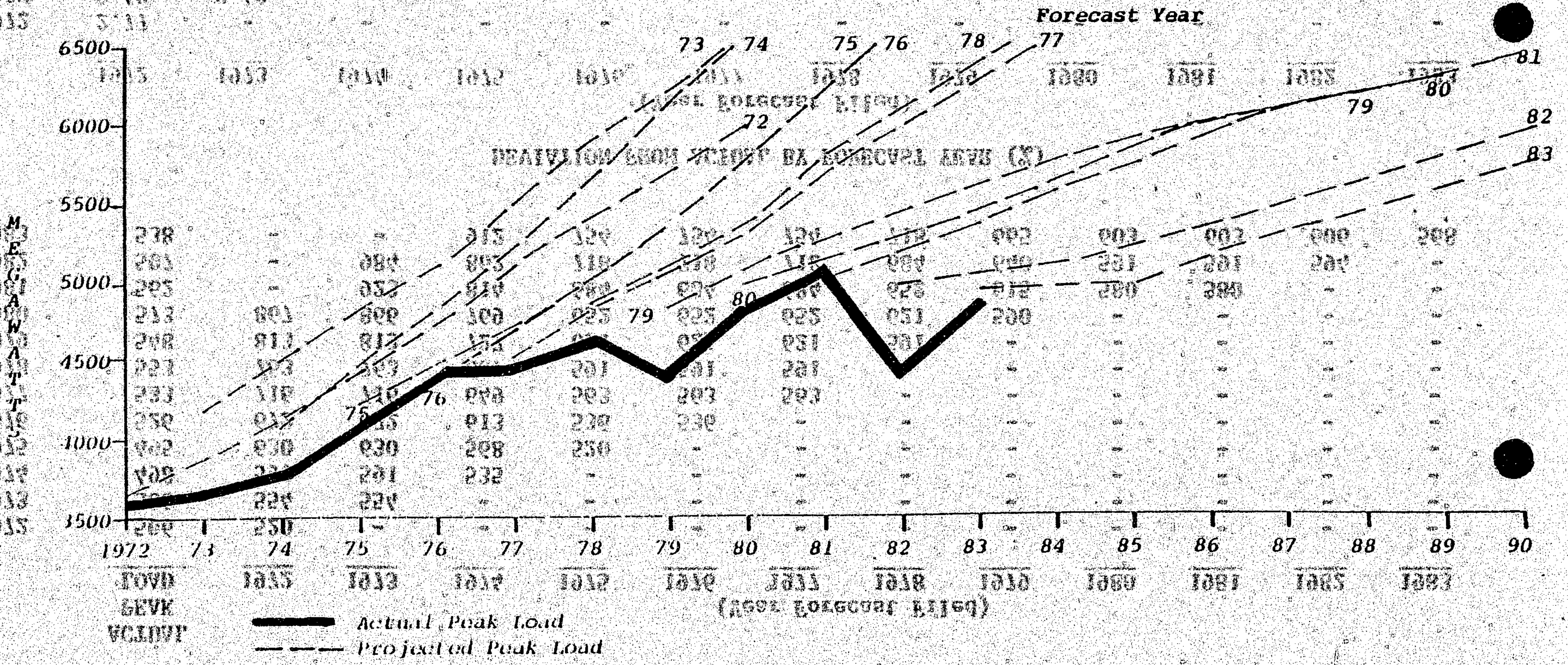
DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	1.17	-	-	-	-	-	-	-	-	-	-	-
1973	5.68	14.42	-	-	-	-	-	-	-	-	-	-
1974	8.96	19.30	8.56	-	-	-	-	-	-	-	-	-
1975	6.99	16.93	8.44	2.38	-	-	-	-	-	-	-	-
1976	6.89	15.25	8.59	1.02	- 1.24	-	-	-	-	-	-	-
1977	15.10	24.13	17.81	6.52	6.07	2.01	-	-	-	-	-	-
1978	16.15	26.91	21.64	7.98	7.98	3.68	4.32	-	-	-	-	-
1979	29.55	40.91	39.55	22.27	22.27	14.77	15.45	10.00	-	-	-	-
1980	24.10	36.50	36.30	19.34	19.34	9.82	10.86	5.07	3.39	-	-	-
1981	-	37.36	39.32	21.86	21.86	11.66	13.42	3.02	0.71	- 1.75	-	-
1982	-	68.03	73.25	50.77	50.77	36.01	38.28	23.30	19.60	17.46	12.62	-
1983	-	-	68.31	46.44	46.44	28.98	31.24	15.01	11.58	10.08	3.10	1.05

PENNSYLVANIA POWER & LIGHT COMPANY

PROJECTED VS ACTUAL PEAK LOAD



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PENNSYLVANIA POWER COMPANY

PROJECTED PEAK LOAD BY FORECAST YEAR (MW)

(Year Forecast Filed)

	ACTUAL PEAK LOAD	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	506	520	-	-	-	-	-	-	-	-	-	-	-
1973	506	554	554	-	-	-	-	-	-	-	-	-	-
1974	498	591	591	535	-	-	-	-	-	-	-	-	-
1975	495	630	630	568	520	-	-	-	-	-	-	-	-
1976	526	672	672	613	536	536	-	-	-	-	-	-	-
1977	533	716	716	649	563	563	563	-	-	-	-	-	-
1978	553	763	763	687	591	591	591	-	-	-	-	-	-
1979	548	813	813	727	621	621	621	591	-	-	-	-	-
1980	573	867	866	769	652	652	652	621	590	-	-	-	-
1981	562	-	923	814	684	684	684	652	615	580	580	-	-
1982	507	-	984	862	718	718	718	684	640	591	591	594	-
1983	538	-	-	912	754	754	754	718	665	603	603	606	568

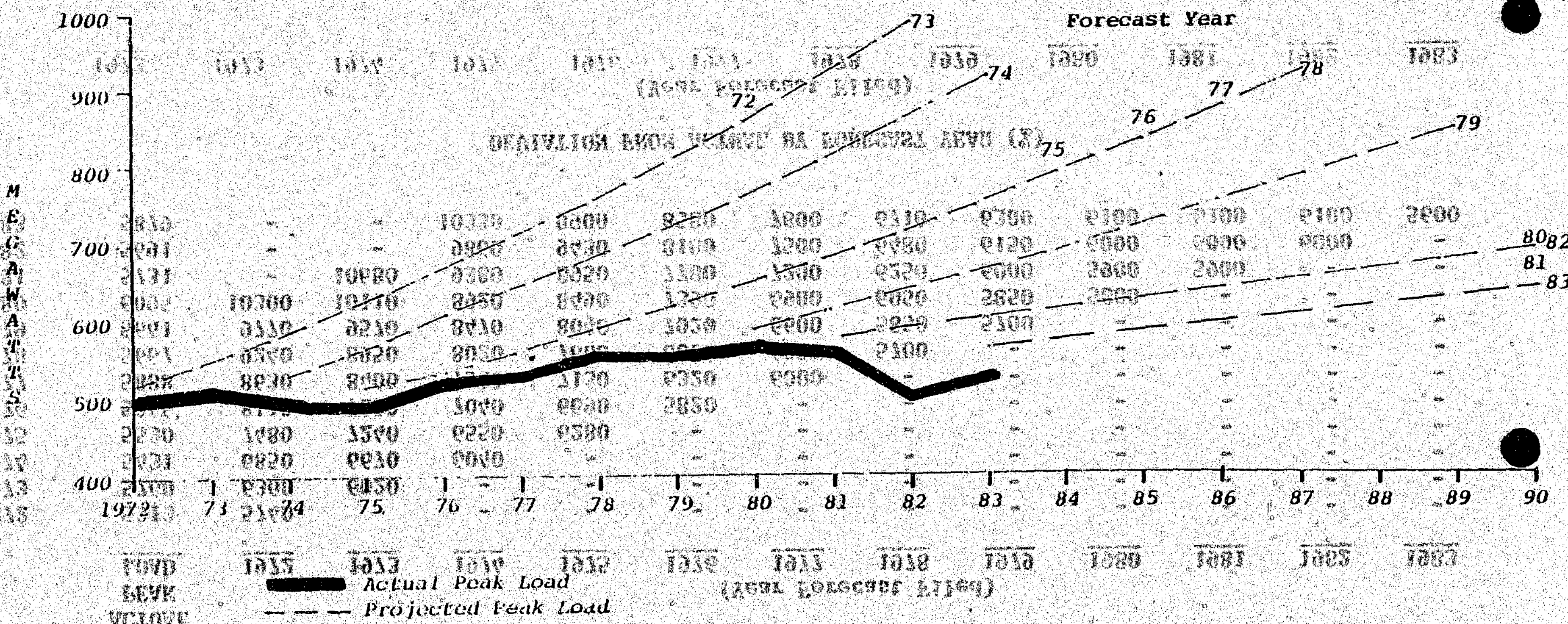
DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	2.77	-	-	-	-	-	-	-	-	-	-	-
1973	9.49	9.49	-	-	-	-	-	-	-	-	-	-
1974	18.67	18.67	7.43	-	-	-	-	-	-	-	-	-
1975	27.27	27.27	14.75	5.05	-	-	-	-	-	-	-	-
1976	27.76	27.76	16.54	1.90	1.90	-	-	-	-	-	-	-
1977	34.33	34.33	21.76	5.63	5.63	5.63	-	-	-	-	-	-
1978	38.22	38.22	24.46	7.07	7.07	7.07	7.07	-	-	-	-	-
1979	48.36	48.36	32.66	13.32	13.32	13.32	7.85	-	-	-	-	-
1980	51.31	51.13	34.21	13.79	13.79	13.79	8.38	2.97	-	-	-	-
1981	-	64.23	44.84	21.71	21.71	21.71	16.01	9.43	3.20	3.20	-	-
1982	-	94.08	70.02	41.62	41.62	41.62	34.91	26.23	16.57	16.57	17.16	-
1983	-	-	69.52	40.15	40.15	40.15	33.46	23.61	12.08	12.08	12.64	5.58

PENNSYLVANIA POWER COMPANY

PROJECTED VS ACTUAL PEAK LOAD



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PHILADELPHIA ELECTRIC COMPANY

PROJECTED PEAK LOAD BY FORECAST YEAR (MW)

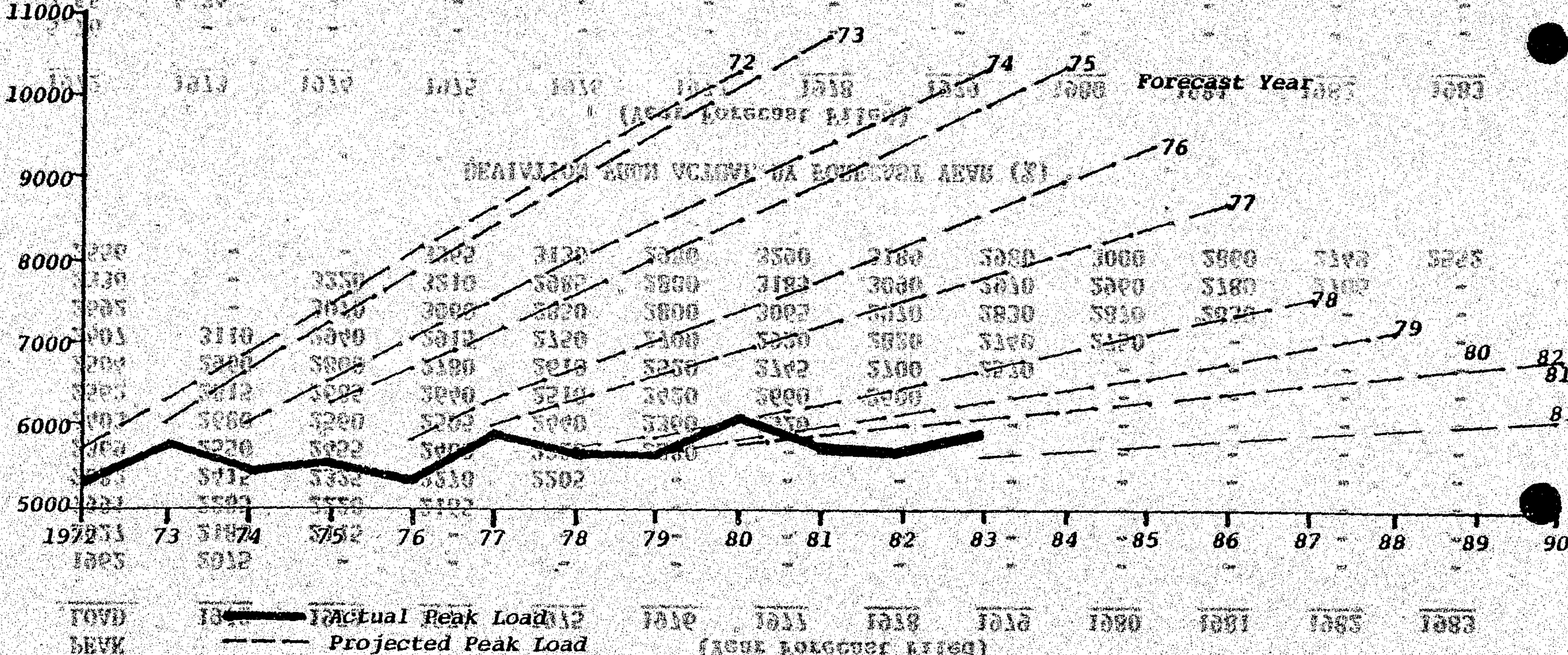
	ACTUAL PEAK LOAD	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
		(Year Forecast Filed)											
1972	5313	5740	-	-	-	-	-	-	-	-	-	-	-
1973	5760	6300	6020	-	-	-	-	-	-	-	-	-	-
1974	5431	6850	6670	6040	-	-	-	-	-	-	-	-	-
1975	5530	7480	7240	6550	6280	-	-	-	-	-	-	-	-
1976	5346	8110	7850	7040	6690	5820	-	-	-	-	-	-	-
1977	5888	8630	8400	7540	7130	6320	6000	-	-	-	-	-	-
1978	5667	9240	8950	8020	7600	6660	6300	5700	-	-	-	-	-
1979	5641	9770	9570	8470	8040	7020	6600	5850	5700	-	-	-	-
1980	6095	10300	10110	8920	8490	7390	6900	6050	5850	5800	-	-	-
1981	5731	-	10680	9380	8950	7780	7200	6250	6000	5900	5900	-	-
1982	5691	-	-	9860	9430	8180	7500	6480	6150	6000	6000	6000	-
1983	5879	-	-	10330	9900	8580	7800	6710	6300	6100	6100	6100	5600

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
	(Year Forecast Filed)											
1972	8.04	-	-	-	-	-	-	-	-	-	-	-
1973	9.38	4.51	-	-	-	-	-	-	-	-	-	-
1974	26.13	22.81	11.21	-	-	-	-	-	-	-	-	-
1975	35.26	30.92	18.44	13.56	-	-	-	-	-	-	-	-
1976	51.70	46.84	31.69	25.14	8.87	-	-	-	-	-	-	-
1977	46.57	42.66	28.06	21.09	7.34	1.90	-	-	-	-	-	-
1978	63.05	57.93	41.52	34.11	17.52	11.17	0.58	-	-	-	-	-
1979	73.20	69.65	50.15	42.53	24.45	17.00	3.71	1.05	-	-	-	-
1980	68.99	65.87	46.35	39.29	21.25	13.21	- 0.74	- 4.02	- 4.84	-	-	-
1981	-	86.35	63.67	56.17	35.75	25.63	9.06	4.69	2.95	2.95	-	-
1982	-	-	73.26	65.70	43.74	31.79	13.86	8.07	5.43	5.43	5.43	-
1983	-	-	75.71	68.40	45.94	32.68	14.14	7.16	3.76	3.76	3.76	- 4.75

PHILADELPHIA ELECTRIC COMPANY

PROJECTED VS ACTUAL PEAK LOAD



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WEST PENN POWER COMPANY

PROJECTED PEAK LOAD BY FORECAST YEAR (MW)

(Year Forecast Filed)

	ACTUAL PEAK LOAD	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	1962	2075	-	-	-	-	-	-	-	-	-	-	-
1973	2027	2180	2115	-	-	-	-	-	-	-	-	-	-
1974	1991	2285	2220	2165	-	-	-	-	-	-	-	-	-
1975	2082	2415	2325	2270	2205	-	-	-	-	-	-	-	-
1976	2369	2550	2455	2400	2320	2280	-	-	-	-	-	-	-
1977	2403	2680	2560	2505	2440	2360	2520	-	-	-	-	-	-
1978	2562	2815	2685	2640	2510	2420	2660	2600	-	-	-	-	-
1979	2504	2960	2800	2780	2610	2520	2745	2700	2570	-	-	-	-
1980	2607	3110	2940	2915	2750	2700	2920	2820	2740	2750	-	-	-
1981	2692	-	3070	3060	2850	2800	3065	2970	2830	2870	2630	-	-
1982	2336	-	3220	3210	2985	2880	3185	3090	2970	2960	2780	2706	-
1983	2556	-	-	3365	3130	2980	3290	3180	2980	3000	2860	2748	2552

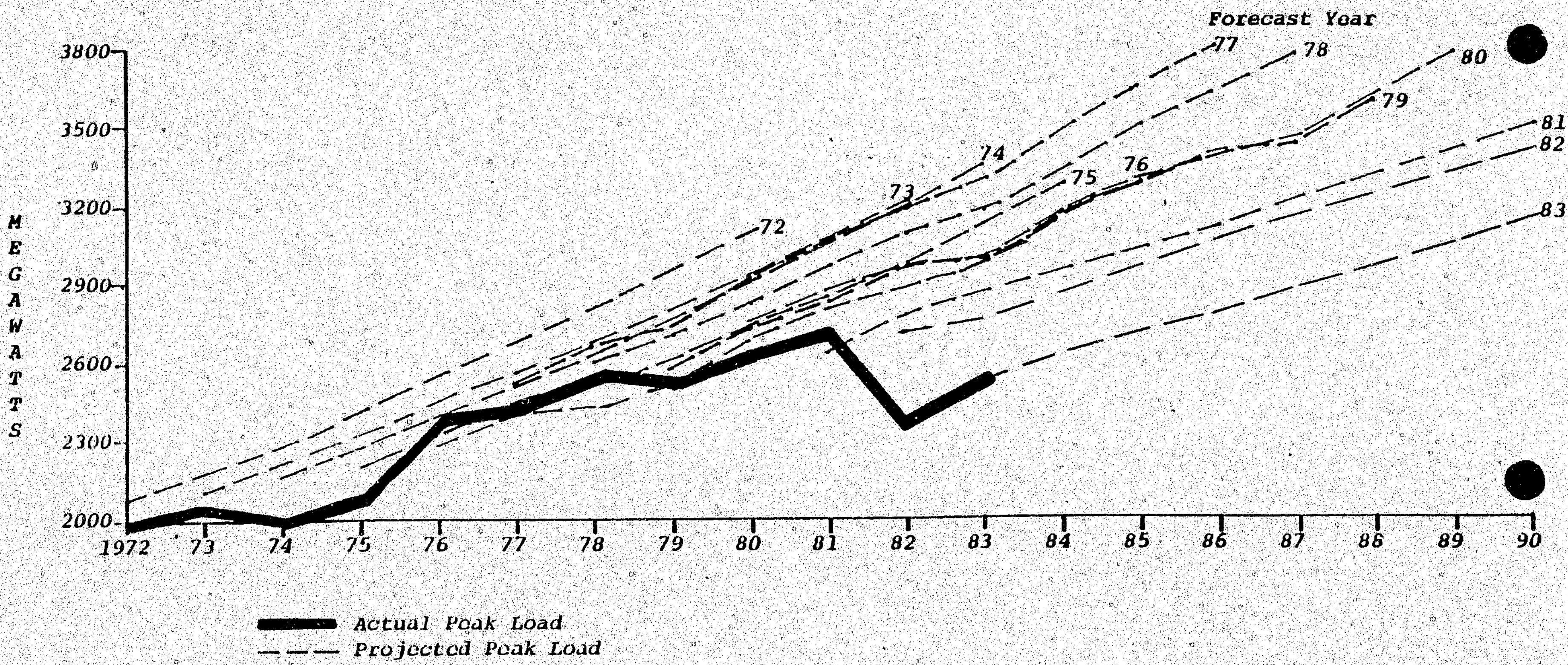
DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	5.76	-	-	-	-	-	-	-	-	-	-	-
1973	7.55	4.34	-	-	-	-	-	-	-	-	-	-
1974	14.77	11.50	8.74	-	-	-	-	-	-	-	-	-
1975	15.99	11.67	9.03	5.91	-	-	-	-	-	-	-	-
1976	7.64	3.63	1.31	- 2.07	3.76	-	-	-	-	-	-	-
1977	11.53	6.53	4.24	1.54	- 1.79	4.87	-	-	-	-	-	-
1978	9.88	4.80	3.04	- 2.03	- 5.54	3.83	1.48	-	-	-	-	-
1979	18.21	11.82	11.02	4.23	0.64	9.62	7.83	2.64	-	-	-	-
1980	19.29	12.77	11.81	5.49	3.57	12.01	8.17	5.10	5.49	-	-	-
1981	-	14.04	13.67	5.87	4.01	13.86	10.33	5.13	6.61	- 2.30	-	-
1982	-	37.84	37.41	27.78	23.29	36.34	32.28	27.14	26.71	19.01	15.84	-
1983	-	-	31.65	22.46	16.59	28.72	24.41	16.59	17.37	11.89	7.51	- 0.16

WEST PENN POWER COMPANY

PROJECTED VS ACTUAL PEAK LOAD



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SECTION D. ENERGY DEMAND FORECAST PROFILES

This section compares each company's projected energy demands with the actual energy demands experienced from 1972 to 1983. These comparisons are presented on two tables.

The first table, entitled PROJECTED ENERGY DEMAND BY FORECAST YEAR, displays the company's forecasts for 1972 through 1983, by the year in which they were filed, and the actual energy demands experienced. For example, on page 32 Duquesne Light Company's 1973 forecast of energy demand for 1979 is 15,720 gigawatthours, compared to the actual 1979 energy demand of 13,575 gigawatthours.

The second table, entitled DEVIATION FROM ACTUAL BY FORECAST YEAR, presents a summary of forecast error between actual energy demand and forecast energy demand, by the year in which the forecasts were filed. These deviations are presented as a percentage of actual energy demand. For example, on page 32 Duquesne Light Company's 1974 forecast of the 1977 energy demand overestimated the actual energy demand by 14.82%.

DUQUESNE LIGHT COMPANY

PROJECTED ENERGY DEMAND BY FORECAST YEAR (GWH)

	ACTUAL ENERGY DEMAND	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	11485	11688	-	-	-	-	-	-	-	-	-	-	-
1973	12547	12340	12170	-	-	-	-	-	-	-	-	-	-
1974	12602	12980	12740	13080	-	-	-	-	-	-	-	-	-
1975	12168	13620	13270	13600	13080	-	-	-	-	-	-	-	-
1976	12520	14210	13820	14330	13600	12840	-	-	-	-	-	-	-
1977	13038	14840	14410	14970	14330	13530	13135	-	-	-	-	-	-
1978	12649	15500	15050	15670	14970	14270	13565	13565	-	-	-	-	-
1979	13575	16150	15720	16340	15670	14820	14815	14535	13665	-	-	-	-
1980	13301	16660	16410	17040	16340	15480	15265	15265	14085	13580	-	-	-
1981	13634	-	17100	17740	17040	16090	15725	15725	14705	14010	13350	-	-
1982	11038	-	17690	18480	17740	16730	16215	16215	15095	14310	14280	14300	-
1983	10990	-	-	19230	18480	17370	16705	16705	15285	14770	14920	14590	11900

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	1.77	-	-	-	-	-	-	-	-	-	-	-
1973	- 1.65	- 3.00	-	-	-	-	-	-	-	-	-	-
1974	3.00	1.10	3.79	-	-	-	-	-	-	-	-	-
1975	11.93	9.06	11.77	7.50	-	-	-	-	-	-	-	-
1976	13.50	10.38	14.46	8.63	2.56	-	-	-	-	-	-	-
1977	13.82	10.52	14.82	9.91	3.77	0.74	-	-	-	-	-	-
1978	22.54	18.98	23.88	18.35	12.82	7.24	7.24	-	-	-	-	-
1979	18.97	15.80	20.37	15.43	9.17	9.13	7.07	0.66	-	-	-	-
1980	25.25	23.37	28.11	22.85	16.38	14.77	14.77	5.89	2.10	-	-	-
1981	-	25.42	30.12	24.98	18.01	15.34	15.34	7.86	2.76	2.08	-	-
1982	-	60.26	67.42	74.98	60.72	51.57	46.90	36.75	29.64	29.37	29.55	-
1983	-	-	74.98	68.15	58.05	52.00	52.00	39.08	34.39	35.76	32.76	8.28

METROPOLITAN EDISON COMPANY

PROJECTED ENERGY DEMAND BY FORECAST YEAR (GWH)

(Year Forecast Filed)

	ACTUAL ENERGY DEMAND	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	7114	7160	-	-	-	-	-	-	-	-	-	-	-
1973	7740	7791	7502	-	-	-	-	-	-	-	-	-	-
1974	7208	8550	7970	7390	-	-	-	-	-	-	-	-	-
1975	6604	9433	8448	7433	7341	-	-	-	-	-	-	-	-
1976	7089	10148	8965	7985	7779	7022	-	-	-	-	-	-	-
1977	7411	10906	9514	8409	8307	7447	7583	-	-	-	-	-	-
1978	7917	11723	10095	8916	8737	7488	7997	7765	-	-	-	-	-
1979	8084	12604	10720	9479	9126	7789	8072	8111	8134	-	-	-	-
1980	7813	13550	11385	10047	9602	8161	8451	8178	8263	8246	-	-	-
1981	7759	-	12098	10654	10103	8556	8789	8524	8511	8567	8317	-	-
1982	7426	-	12862	11301	10621	8975	9152	8878	8831	8951	8609	7987	-
1983	7683	-	-	11979	11174	9417	9543	9230	9185	9278	8899	8170	7593

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	0.65	-	-	-	-	-	-	-	-	-	-	-
1973	0.66	- 3.07	-	-	-	-	-	-	-	-	-	-
1974	18.62	10.57	2.52	-	-	-	-	-	-	-	-	-
1975	42.84	27.92	12.55	11.16	-	-	-	-	-	-	-	-
1976	43.15	26.46	12.64	9.73	0.95	-	-	-	-	-	-	-
1977	47.16	28.38	13.47	12.09	0.49	2.32	-	-	-	-	-	-
1978	48.07	27.51	12.62	10.36	- 5.42	1.01	- 1.92	-	-	-	-	-
1979	55.91	32.61	17.26	12.89	- 3.65	- 0.15	0.33	0.62	-	-	-	-
1980	73.43	45.72	28.59	22.90	4.45	8.17	4.67	5.76	5.54	-	-	-
1981	-	55.92	37.31	30.21	10.27	13.27	9.86	9.69	10.41	7.19	-	-
1982	-	73.20	52.18	43.02	20.86	23.24	19.55	18.92	20.54	15.93	7.55	-
1983	-	-	55.92	45.44	22.57	24.21	20.14	19.55	20.76	15.83	6.34	- 1.17

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PENNSYLVANIA ELECTRIC COMPANY

PROJECTED ENERGY DEMAND BY FORECAST YEAR (GWH)

(Year Forecast Filed)

	ACTUAL ENERGY DEMAND	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	8815	8787	-	-	-	-	-	-	-	-	-	-	-
1973	9387	9389	9149	-	-	-	-	-	-	-	-	-	-
1974	9533	10033	9693	9377	-	-	-	-	-	-	-	-	-
1975	9588	10723	10254	9943	10080	-	-	-	-	-	-	-	-
1976	10062	11506	10842	10694	10545	10262	-	-	-	-	-	-	-
1977	10457	12276	11469	11453	11035	10785	10840	-	-	-	-	-	-
1978	10914	13128	12129	12270	11639	11366	11598	11194	-	-	-	-	-
1979	11140	14055	12833	12931	12182	11927	12365	11809	11391	-	-	-	-
1980	11118	15073	13588	13633	12776	12461	13143	12394	11809	11617	-	-	-
1981	11328	-	14396	14387	13402	13027	13506	12929	12009	11957	11392	-	-
1982	10941	-	15271	15185	14054	13624	13945	13450	12492	12648	12034	11974	-
1983	10608	-	-	16039	14754	14256	14457	14056	12838	12751	12056	12228	10789

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	- 0.32	-	-	-	-	-	-	-	-	-	-	-
1973	0.02	- 2.54	-	-	-	-	-	-	-	-	-	-
1974	5.24	1.68	- 1.64	-	-	-	-	-	-	-	-	-
1975	11.84	6.95	3.70	5.13	-	-	-	-	-	-	-	-
1976	14.35	7.75	6.28	4.80	1.99	-	-	-	-	-	-	-
1977	17.40	9.68	9.52	5.53	3.14	3.66	-	-	-	-	-	-
1978	20.29	11.13	12.42	6.64	4.14	6.27	2.57	-	-	-	-	-
1979	26.17	15.20	16.08	9.35	7.06	11.00	6.01	2.25	-	-	-	-
1980	35.57	22.22	22.62	14.91	12.08	18.21	11.48	6.22	4.49	-	-	-
1981		27.08	27.00	18.31	15.00	19.23	14.13	6.01	5.55	0.56	-	-
1982	-	39.58	38.79	28.45	24.52	27.46	22.93	14.18	15.60	9.99	9.44	-
1983	-	-	51.20	39.08	34.39	36.28	32.50	21.02	20.20	13.65	15.27	1.71

PENNSYLVANIA POWER & LIGHT COMPANY

PROJECTED ENERGY DEMAND BY FORECAST YEAR (GWH)

(Year Forecast Filed)

	ACTUAL ENERGY DEMAND	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	16376	15841	-	-	-	-	-	-	-	-	-	-	-
1973	17486	16814	17946	-	-	-	-	-	-	-	-	-	-
1974	17939	17798	19446	18534	-	-	-	-	-	-	-	-	-
1975	18413	19208	20933	20286	18944	-	-	-	-	-	-	-	-
1976	19621	20653	22318	21807	20053	20175	-	-	-	-	-	-	-
1977	20179	22080	23980	23614	21140	21250	20593	-	-	-	-	-	-
1978	21808	23627	25543	25581	22555	22533	21346	20992	-	-	-	-	-
1979	22513	24910	27265	27665	24106	24106	23713	22713	21856	-	-	-	-
1980	22451	26492	28919	29694	25859	25869	23822	23822	22597	22078	-	-	-
1981	22645	-	30960	31936	27182	27812	25627	25627	23445	22854	22018	-	-
1982	21990	-	32825	34299	29751	29751	26916	26916	24320	23704	23003	22924	[illegible]
1983	22848	-	[illegible]	34780	32034	32034	28137	28137	25157	24458	23779	23424	22745

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	-3.27	-	-	-	-	-	-	-	-	-	-	-
1973	-3.84	2.63	-	-	-	-	-	-	-	-	-	-
1974	-0.79	8.40	3.32	-	-	-	-	-	-	-	-	-
1975	4.32	13.69	10.17	2.88	-	-	-	-	-	-	-	-
1976	5.26	13.75	11.14	2.20	2.82	-	-	-	-	-	-	-
1977	9.42	18.84	17.02	4.76	5.31	2.05	-	-	-	-	-	-
1978	8.34	17.13	17.30	3.43	3.32	-2.12	-3.74	-	-	-	-	-
1979	10.65	21.11	22.88	7.08	7.08	5.33	0.89	-2.92	-	-	-	-
1980	18.00	28.81	32.26	15.18	15.22	6.11	6.11	0.65	-1.66	-	-	-
1981	-	36.72	41.03	20.04	22.82	13.17	13.17	3.53	0.92	-2.77	-	-
1982	-	49.27	55.98	35.29	35.29	22.40	22.40	10.60	7.79	4.61	4.25	-
1983	[illegible]	[illegible]	52.22	40.20	40.20	23.15	23.15	10.11	7.05	4.07	2.52	-0.45

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PENNSYLVANIA POWER COMPANY

PROJECTED ENERGY DEMAND BY FORECAST YEAR (GWH)

	ACTUAL ENERGY DEMAND	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	2907	2767	-	-	-	-	-	-	-	-	-	-	-
1973	3083	2924	2900	-	-	-	-	-	-	-	-	-	-
1974	3051	3092	3035	3101	-	-	-	-	-	-	-	-	-
1975	2806	3269	3184	3212	2694	-	-	-	-	-	-	-	-
1976	3035	3459	3339	3358	2980	2980	-	-	-	-	-	-	-
1977	3124	3660	3500	3510	3074	3074	3148	-	-	-	-	-	-
1978	3251	3874	3664	3669	3189	3189	3263	-	-	-	-	-	-
1979	3345	4103	3830	3836	3296	3296	3382	3129	-	-	-	-	-
1980	3251	4346	4005	4011	3448	3448	3531	3232	3324	-	-	-	-
1981	3477	-	4188	4193	3595	3595	3682	3332	3462	3426	3188	-	-
1982	3057	-	4380	4385	3748	3748	3836	3434	3604	3504	3260	3393	-
1983	3396	-	-	4585	3893	3893	3984	3539	3742	3582	3333	3634	3155

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	-4.82	-	-	-	-	-	-	-	-	-	-	-
1973	-5.16	-5.94	-	-	-	-	-	-	-	-	-	-
1974	1.34	-0.52	1.64	-	-	-	-	-	-	-	-	-
1975	16.50	13.47	14.47	-3.99	-	-	-	-	-	-	-	-
1976	13.97	10.02	10.64	-11.81	-11.81	-	-	-	-	-	-	-
1977	17.16	12.04	12.36	-1.60	-1.60	0.77	-	-	-	-	-	-
1978	19.16	12.70	12.86	-1.91	-1.91	0.37	-	-	-	-	-	-
1979	22.66	14.50	14.68	-1.46	-1.46	1.11	-6.46	-	-	-	-	-
1980	33.68	23.19	23.38	6.06	6.06	8.61	-0.58	2.25	-	-	-	-
1981	-	20.45	20.59	3.39	3.39	5.90	-4.17	-0.43	-1.47	-8.31	-	-
1982	-	43.28	43.44	22.60	22.60	25.48	12.33	17.89	14.62	6.64	10.99	-
1983	-	-	35.01	14.63	14.63	17.31	4.21	10.19	5.48	-1.86	7.01	-7.10

PHILADELPHIA ELECTRIC COMPANY

PROJECTED ENERGY DEMAND BY FORECAST YEAR (GWH)

(Year Forecast Filed)

	ACTUAL ENERGY DEMAND	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	23370	22372	-	-	-	-	-	-	-	-	-	-	-
1973	25109	24670	24841	-	-	-	-	-	-	-	-	-	-
1974	24339	26846	27999	26059	-	-	-	-	-	-	-	-	-
1975	24108	29037	30455	29123	26767	-	-	-	-	-	-	-	-
1976	25001	31664	32785	31346	28932	25340	-	-	-	-	-	-	-
1977	25848	34012	35153	33901	31244	27942	26040	-	-	-	-	-	-
1978	27394	36768	37578	36470	33464	29591	27396	25810	-	-	-	-	-
1979	27601	39551	40089	38781	35509	31318	28968	26764	26280	-	-	-	-
1980	27621	42290	42788	41146	37536	33187	30558	27751	27120	26697	-	-	-
1981	27050	-	45546	43570	39714	35134	32217	28824	27900	27280	26337	-	-
1982	26210	-	-	46081	41961	37196	33902	30035	28760	27961	27277	28268	-
1983	27232	-	-	48570	44319	39379	35630	31324	29680	28749	27988	28440	26866

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

(Year Forecast Filed)

	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	-4.27	-	-	-	-	-	-	-	-	-	-	-
1973	-1.75	-1.07	-	-	-	-	-	-	-	-	-	-
1974	10.30	15.04	7.07	-	-	-	-	-	-	-	-	-
1975	20.45	26.33	20.80	11.03	-	-	-	-	-	-	-	-
1976	26.65	31.13	25.38	15.72	1.36	-	-	-	-	-	-	-
1977	31.58	36.00	31.16	20.88	8.10	0.74	-	-	-	-	-	-
1978	34.22	37.18	33.13	22.16	8.02	0.01	-5.78	-	-	-	-	-
1979	43.30	45.24	40.51	28.65	13.47	4.95	-3.03	-4.79	-	-	-	-
1980	53.11	54.91	48.97	35.90	20.15	10.63	0.47	-1.81	-3.35	-	-	-
1981	-	68.34	61.07	46.82	29.89	19.10	6.56	3.14	0.85	-2.64	-	-
1982			75.81	60.10	41.92	29.35	14.59	9.73	6.68	4.07	7.85	-
1983	-	-	78.36	62.75	44.61	30.84	15.03	8.99	5.57	2.78	4.44	-1.34

WEST PENN POWER COMPANY

PROJECTED ENERGY DEMAND BY FORECAST YEAR (GWH)

	ACTUAL ENERGY DEMAND	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	11844	12089	-	-	-	-	-	-	-	-	-	-	-
1973	12653	12684	12388	-	-	-	-	-	-	-	-	-	-
1974	12645	13418	12998	13018	-	-	-	-	-	-	-	-	-
1975	11985	14186	13596	13592	12682	-	-	-	-	-	-	-	-
1976	12809	15079	14412	14373	13782	13547	-	-	-	-	-	-	-
1977	14220	15729	14997	15092	14451	14326	14078	-	-	-	-	-	-
1978	14626	16522	15688	15843	15033	14895	15543	15267	-	-	-	-	-
1979	15375	17373	16341	16627	15541	15402	16074	15772	15046	-	-	-	-
1980	15165	18303	17205	17446	16424	16297	17096	16687	15895	15632	-	-	-
1981	15436	-	17947	18301	17044	17124	17968	17482	16712	16623	15443	-	-
1982	13206	-	18870	19193	17862	17722	18688	18163	17323	17138	16220	15837	-
1983	13461	-	-	20124	18719	18258	19320	18764	17871	17648	16751	16255	14060

DEVIATION FROM ACTUAL BY FORECAST YEAR (%)

	(Year Forecast Filed) 1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
1972	2.07	-	-	-	-	-	-	-	-	-	-	-
1973	0.25	-2.09	-	-	-	-	-	-	-	-	-	-
1974	6.11	2.79	2.95	-	-	-	-	-	-	-	-	-
1975	18.36	13.44	13.41	5.82	-	-	-	-	-	-	-	-
1976	17.72	12.51	12.21	7.60	5.76	-	-	-	-	-	-	-
1977	10.61	5.46	6.13	1.62	0.75	-1.00	-	-	-	-	-	-
1978	12.96	7.26	8.32	2.78	1.84	6.27	4.38	-	-	-	-	-
1979	13.00	6.28	8.14	1.73	0.18	4.55	2.58	-2.14	-	-	-	-
1980	20.69	13.45	15.04	8.30	7.46	12.73	10.04	4.81	3.08	-	-	-
1981	-	16.27	18.56	10.42	10.94	16.40	13.25	8.27	7.69	0.05	-	-
1982	-	42.89	45.34	35.26	34.20	41.51	37.54	31.18	29.77	22.82	19.92	-
1983	-	-	49.50	39.06	35.64	43.53	39.40	32.76	31.10	24.44	20.76	4.45

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OCA EXHIBIT NO. 57

DOCKET NO. R-850152

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Q. IR-OCA-2-67.

Regarding PECO Statement 12, Testimony of L.A. Guth, please list "other forecasts at much lower growth rates" for electric sales or peak demand issued during the 1978-1980 period, for either the PECO service area, the PJM/MAAC territory, or the nation, of which the witness or PECO had knowledge, indicating forecast growth rates and authors. Please indicate whether the witness or PECO believed these forecasts to be "informed", either then or now.

A. IR-OCA-2-67.

I was not referring directly to any specific forecasts. I was, instead, acknowledging the existence of forecasts of lower growth rates. The following forecasts are among those that predicted average annual growth rates of less than 5 percent:

- "Regional Analysis of Electricity Demand Growth", by Wen S. Chern and Richard E. Just. This forecast predicted national average annual growth rates from 1974-1990 of 4.3 percent under the base case, 4.8 percent under the low-price case and 3.6 percent under the high-price case.

- "Specification, Estimation and Forecasts of Industrial Demand and Price of Electricity", by Hui S. Chang and Wen S. Chern. This study forecasts national industrial demand for electricity to grow at an average annual rate of 3.53 percent from 1976 to 1990 in the base case and 2.39 percent in the high-price case.

- "Philadelphia Electric Company System Forecast, Vol. I: The State Base Case Forecast", by Paul D. Raskin, John K. Stutz and David R. McAnulty. This study forecasted average annual growth rates for the PECO Service area from 1977 to 2000 of 1.1 percent for the base case, 1.7 percent for the high case and 0.4 percent for the low case.

I did not mean to imply that these forecasts were not "informed" but rather that compared with other forecasts (i.e., MAAC and NERC) they tended to predict growth rates that were on average lower. The existence of these forecasts does not, in my view, render PECO's higher forecasts unreasonable. As noted in my testimony, many forecasters, including both respected independent, industry groups and government forecasters, were forecasting growth rates equal to or higher than PECO. Indeed, PECO's forecast was about average for the period.

Responsible Witness: Louis A. Guth,
NERA