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DECOMMISSIONING COST ESTIMATES FOR
LIMERICK GENERATING STATION, UNITS 1 AND 2
PEACH BOTTOM ATOMIC POWER STATION, UNITS 2 AND 3
SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2

Prepared for
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1.0 INTRODUCTION

When a nuclear electric generation facility reaches the end of its useful life, it must be placed in a condition such that future risk from the facility to public health and safety is negligible. The activities and processes involved in achieving such a condition are referred to as "decommissioning" of the nuclear facility. The costs of decommissioning are a part of the total cost of generating electricity.

This report presents the results of a detailed site-specific decommissioning cost estimate performed for the Philadelphia Electric Company (PECo). The generating facilities for which a decommissioning cost estimate was performed, and the corresponding percentage of PECo ownership in those facilities are as follows:

Station	Percentage Ownership
o Peach Bottom Atomic Power Station, Units 2 and 3	42.49%
o Salem Nuclear Generating Station, Units 1 and 2	42.59%
o Limerick Generating Station, Units 1 and 2	100%

The other owners of the Peach Bottom and Salem stations are Public Service Electric and Gas Company, Atlantic Electric Company and Delmarva Power and Light Company.

1.1 Station Descriptions

1.1.1 Peach Bottom Atomic Power Station

The Peach Bottom site is approximately 620 acres on the Conowingo Reservoir, about 38 miles north-northwest of Baltimore, Maryland. The Peach Bottom Station is comprised of two operating power generating units each using a General Electric boiling water reactor (BWR) steam supply system. Each unit is rated at 1065 MWe net. Also located at the Peach Bottom Station is a "mothballed" 40 MWe high temperature gas cooled (HTGR) generating unit. The decommissioning cost estimate for complete removal of the HTGR unit has been estimated separately from the remainder of the Peach Bottom Station costs.

Major structures associated with Peach Bottom Units 2 and 3 include reactor buildings, turbine building, radwaste building, recombiner building, circulating water pump and screen structures, five banks of mechanical draft cooling towers, safety-related cooling tower and an on-site low-level radwaste storage facility. In addition, the cooling water system includes piers, walls and dikes extending into the Conowingo Reservoir. Other auxiliary structures/buildings are also located on-site.

1.1.2 Salem Nuclear Generating Station

The Salem Station covers an area of approximately 400 acres of a 700 acre site on the Delaware River, about 8 miles southwest of Salem, New Jersey. The Salem Station is comprised of two power generating units each using a Westinghouse pressurized water reactor (PWR) steam supply system. Salem Unit 1 is rated at 1090 MWe net and Unit 2 at 1115 MWe net.

Major structures include the containments, fuel handling buildings, circulating water and service water intake structures, auxiliary building and turbine building. Other auxiliary structures/buildings are also located on-site.

1.1.3 Limerick Generating Station

The Limerick site is approximately 595 acres on the Schuylkill River, about 21 miles northwest of Philadelphia. The Limerick Station is comprised of two power generating units each using a General Electric BWR steam supply system. Each unit is rated at 1055 MWe net.

Major structures include reactor building, turbine building, radwaste and off-gas building, diesel generator buildings, a circulating water pump house and two hyperbolic natural draft cooling towers. Other auxiliary structures/buildings are also located on-site.

1.2 Contents of Report

The remainder of this report contains the following major sections:

- Section 2.0 SUMMARY AND CONCLUSIONS - This section provides an executive summary of the report including the total costs of decommissioning each of the three stations, the nuclear-related costs of decommissioning and the basis for possible future updating of the early-1984 dollar costs to correspond to then-current dollar costs in recognition of possible future cost inflation.

- Section 3.0 GENERAL DESCRIPTION OF DECOMMISSIONING - This section summarizes the basic features of boiling and pressurized water reactor and power plant systems, the sources of the radioactivity, and the sequence of activities and processes by which all equipment is removed, all structures demolished, and all equipment and materials appropriately disposed of by either burial at radioactive waste disposal sites (radioactive materials), conventional disposal (non-radioactive materials) or salvage (non-radioactive equipment or material with scrap or used-equipment value).

- Section 4.0 DECOMMISSIONING COSTS AND SCHEDULES - This section describes the method for estimating decommissioning costs, the various activities and corresponding cost categories, and the detailed costs for each station by FERC account and by activity. Total and nuclear-related costs are included, as well as the basis for possible future cost adjustments to account for possible future inflation. The activity schedule and corresponding expenditure schedule during decommissioning are provided for each station, and a summary of physical quantities of concrete, steel, pipe and cable, etc. is provided.

2.0 SUMMARY AND CONCLUSIONS

This report summarizes the activities and processes necessary to decommission a nuclear power unit at the end of its useful life, and provides the estimated cost of decommissioning the seven nuclear units at the three nuclear generation stations in which Philadelpha Electric Company has an ownership interest.

The estimates of total decommissioning cost are based on the complete removal of all equipment, material and structures to three feet below grade, and the grading and restoration of the site to original or equivalent contour. The cost estimates are based on the assumption of prompt removal following final station shutdown, as distinguished from interim mothballing or entombment for an extended period followed by delayed removal. The prompt removal option was selected because 1) the decommissioning costs are equivalent or cheaper for prompt removal and 2) the Nuclear Regulatory Commission (NRC) has indicated a strong preference for prompt removal on the basis of overall public health and safety. Decommissioning cost estimates do not include the costs of removal and disposal of spent fuel because those costs are funded currently as a part of nuclear fuel costs.

The actual process of decommissioning begins about three years prior to final shutdown, and consists of developing a detailed plan for decommissioning and submitting this plan to the NRC as part of the basis for amending the operating license once the plant is shut down. Other important activities prior to shutdown include selection of general and specialty contractors, development of detailed work plans and procedures, training of staff, and the selection and procurement of special equipment. The actual decommissioning activities begin with the decontamination by chemical or physical cleaning of all accessible systems and surfaces that contain radioactivity, or physical removal of contaminated surfaces. This removes the majority of the radioactivity and markedly reduces personnel radiation exposure during subsequent operations. Next, all radioactive systems and equipment are removed, cut up and packaged, and all the previously inaccessible contaminated surfaces and materials are removed. All radioactive material is appropriately packaged and shipped by truck to licensed low level radwaste burial facilities for final disposal. At this point all radioactivity above safe levels has been removed and conventional demolition and disposal practices are employed thereafter. All other equipment and salvagable materials are removed and sold as used equipment or scrap. The remaining structures are then demolished and the resulting materials are disposed of in nearby landfills or in the case of Salem, disposed of at a sea dump site. The site is then graded and restored to original or acceptable equivalent contour.

2.1 Total Cost of Decommissioning

The estimated costs of decommissioning the three nuclear power generating stations, broken down into removal, disposal and salvage components, plus the total costs are:

Station	Total Decommissioning Cost in March 1984 Million Dollars			
	Removal	Disposal	Salvage	Total
Peach Bottom 2 & 3*	219.1	62.1	(7.7)	273.5
Salem 1 & 2	171.8	46.3	(6.5)	211.6
Limerick 1 & 2**	216.6	62.0	(6.0)	272.6

Table 2-1 shows a breakdown of the total decommissioning cost of each station in accordance with Federal Energy Regulatory Commission (FERC) accounts.

A comparison of the estimated costs among the three stations exhibits both similarities and differences. A basic similarity is expected because each station consists of two large units, each of which is in the 1055 Mwe to 1115 Mwe capacity range. The differences between stations arise because of reactor type differences, differences in sites, and differences between earlier and later designs of the same reactor type. The Salem reactors are Pressurized Water Reactor (PWR) types whereas both the Peach Bottom and Limerick stations use Boiling Water Reactors (BWR). By its nature, the PWR tends to be built more into the ground than the BWR, and therefore less of it must be physically removed to meet the "three feet below grade" removal criterion. Thus removal of a PWR tends to be inherently less costly then removal of a BWR. In the particular case of Salem, foundation conditions required the establishment of a large and relatively deep foundation pad. As a result, Salem is even more below grade than is typical of PWRs, and its removal costs are even lower than is typical of PWRs relative to BWRs.

* Does not include an additional cost of $19,072,000 for the removal of Peach Bottom Unit 1, the entombed nuclear facility located on same site.

** Costs for Limerick Station are presented in Appendix C on a per unit and common equipment basis.

TABLE 2-1
Summary of Total Decommissioning
Cost by FERC Account
March 1984
$1,000's

FERC Account		Total Cost		
Number	Title	Peach Bottom 2 & 3	Salem 1 & 2	Limerick 1 & 2
321	Nuclear Production - Structures and Improvements	$ 74,360	$ 36,642	$ 52,135
322	Nuclear Production - Reactor Equipment	80,840	70,474	83,848
323	Nuclear Production - Turbogenerator Units	23,872	7,764	21,898
324	Nuclear Production - Accessory Electric Equipment	10,690	11,363	10,844
352	Transmission Plant - Structures and Improvements	--	111	189
524	Nuclear Power - Miscellaneous Nuclear Power Expenses	7,595	7,495	7,594
920	Administration and General Expenses - Salaries	23,052	21,919	28,427
923	Administration and General Expenses - Outside Services	51,668	54,381	66,569
924	Administration and General Expenses - Property Ins.	1,476	1,465	1,117
	TOTAL	$273,553	$211,614	$272,621

The similarity in decommissioning costs between the older Peach Bottom station and the newer Limerick station, both of which use BWR's of almost identical capacity, masks very real offsetting differences, which by coincidence almost cancel. At the older Peach Bottom station, the lower costs of removing the smaller quantities of equipment and materials used in the older plants is offset by the added cost, unique to Peach Bottom, of removing the cooling water canals and dikes built into Conowingo Reservoir, in order to restore state-owned land to its original condition.

2.2 Nuclear-Related Cost of Decommissioning

In addition to the total cost of decommissioning, the nuclear-related cost of decommissioning has also been estimated. This is the portion of total decommissioning cost which has been established as allowable for ratemaking purposes, consistent with prior regulatory practice in the Commonwealth of Pennsylvania. The original precedent was set by the Pennsylvania Public Utility Commission ruling on the allowable portion of decommissioning costs in 1978 (Pennsylvania Electric Company, 51 Pa P.U.C. at 669), and confirmed in subsequent ratemaking proceedings in connection with the decommissioning costs of Peach Bottom 2 and 3 and Salem 1. In the original Pennsylvania Electric ruling, the Commission did not allow those decommissioning costs that were for the dismantling of non-nuclear structures such as cooling towers, river water pump houses, and miscellaneous structures which by their nature, pose no special concern in regard to health and safety.

Consistent with the above, the nuclear-related portions of the decommissioning costs of the three nuclear power generating stations are:

Station	Nuclear-Related Decommissioning Cost in March 1984 Million Dollars			
	Removal	Disposal	Salvage	Total
Peach Bottom 2 & 3*	133.5	58.5	(0.5)	191.6
Salem 1 & 2	115.7	44.6	(0.1)	160.2
Limerick 1 & 2**	154.8	59.5	(1.1)	213.2

* Does not include an additional nuclear-related cost of $13,581,000 for the removal of Peach Bottom Unit 1, the entombed nuclear facility located on the same site.

** Cost for Limerick Station are presented in Appendix C on a per unit and common equipment basis.

TABLE 2-2
Summary of Nuclear-Related Decommissioning
Cost by FERC Account
March 1984
$1,000's

FERC Account Number	FERC Account Title	Total Cost: Peach Bottom 2 & 3	Total Cost: Salem 1 & 2	Total Cost: Limerick 1 & 2
321	Nuclear Production - Structures and Improvements	$ 34,218	$ 24,806	$ 36,681
322	Nuclear Production - Reactor Equipment	70,894	66,703	73,956
323	Nuclear Production - Turbogenerator Units	17,502	--	17,726
324	Nuclear Production - Accessory Electric Equipment	1,193	791	1,299
352	Transmission Plant - Structures and Improvements	--	--	--
524	Nuclear Power - Miscellaneous Nuclear Power Expenses	6,020	6,145	6,469
920	Administration and General Expenses - Salaries	18,762	17,208	22,682
923	Administration and General Expenses - Outside Services	41,615	43,171	53,369
924	Administration and General Expenses - Property Ins.	1,400	1,400	1,050
	TOTAL	$191,604	$160,224	$213,232

Table 2-2 shows a breakdown of the nuclear-related decommissioning cost of each station in accordance with FERC accounts.

2.3 Escalation of Base-Year Decommissioning Costs

Prior Commission rulings have adopted the sound practice of maintaining the current purchasing power of funds being accumulated to pay for future decommissioning. Central to this concept is an estimate of current decommissioning costs. This has been done by using a cost estimate in base-year dollars and escalating this base-year cost to a current-year cost by use of appropriate inflation indices. These indices are accepted measures of the degree of inflation in each of the various components (i.e., labor, materials, disposal, etc.) which make up the total cost. The bases for adjustments of March 1984 costs to reflect future increases in decommissioning costs is described in subsection 4.4.2.

3.0 GENERAL DESCRIPTION OF DECOMMISSIONING

Once a nuclear facility has reached the end of its operating life, it must be placed in a condition such that the public health and safety is ensured from any residual radioactivity or other hazards present in the facility. The various activities and processes involved in achieving such a condition are generally referred to as the "decommissioning" of the nuclear facility.

A description of the decommissioning of nuclear power plants is presented in this section emphasizing how dismantling, shipping and ultimate disposal of residual radioactive material is accomplished without meaningful risk to the public.

3.1 Summary of Nuclear Plant Features

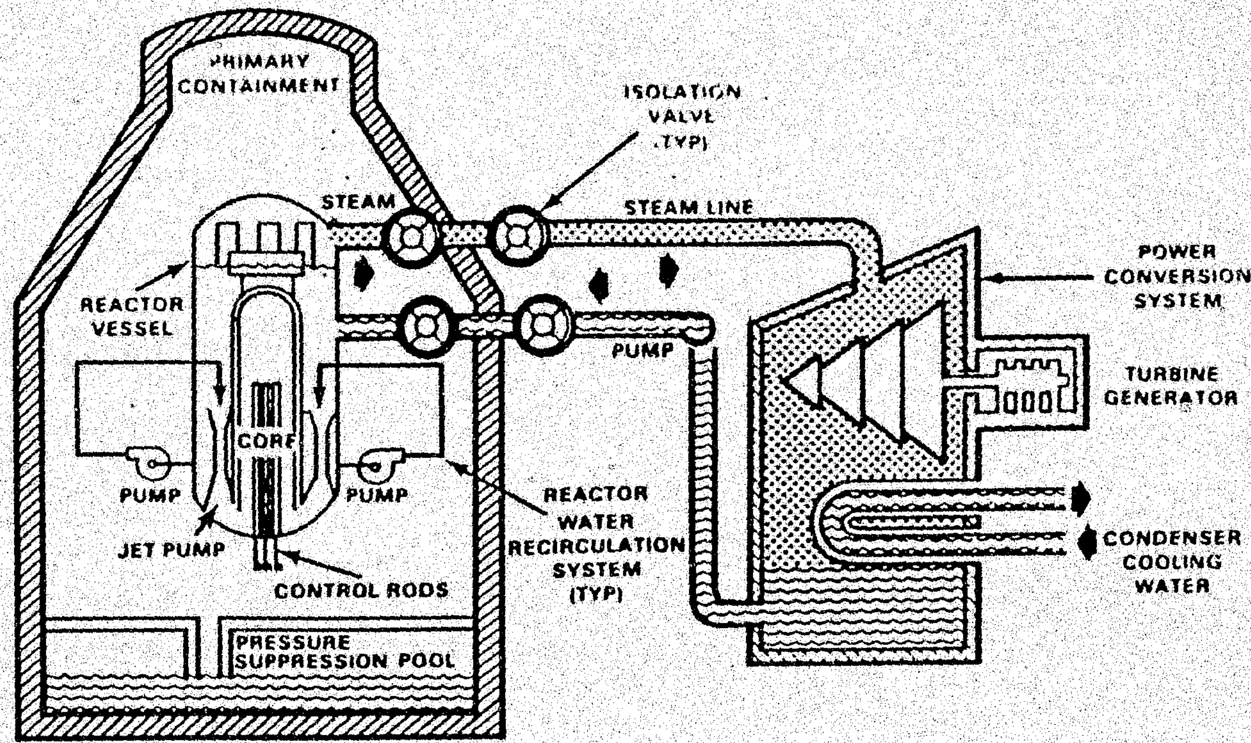
The decommissioning of nuclear power plants is still considered a relatively new experience by the nuclear industry of today. It will become quite a common experience in 30 to 40 years as an increasing number of nuclear power plants reach the end of their operating lives.

To describe decommissioning of the nuclear power plant in general terms, it is useful to begin with the structure and function of a typical nuclear power plant. Since the Philadelphia Electric generating stations include both boiling water reactor (BWR) and pressurized water reactor (PWR) nuclear steam supply systems, a brief description of both types of facilities is provided.

3.1.1 Typical BWR Plant

The Peach Bottom Units 2 and 3 and the Limerick Units 1 and 2 are BWR systems. The general configuration of a typical BWR plant system similar to Limerick Unit 1 or Unit 2 is illustrated in Figure 3-1. Peach Bottom Units 2 and 3 differ in containment configuration and have a torus for a suppression chamber. The basic operation is the same. The principal components and systems of interest are the reactor vessel containing the core and steam generating equipment, the reactor water recirculation system, and the power conversion system.

FIGURE 3–1
GENERAL CONFIGURATION OF
A TYPICAL BOILING WATER REACTOR PLANT



The reactor vessel is a right circular cylinder with a permanently attached hemispheric bottom and a removable hemispheric top. The major reactor internal components are the core (fuel, flow channels, control rods, and instrumentation), the core support structure (including the core shroud, top fuel guide, and core support plate), the shroud head and steam separator assembly, the steam dryer assembly, the jet pumps, the feedwater spargers, and the core spray lines.

The reactor water recirculation system has two loops external to the reactor vessel but inside the primary containment. Each loop contains a pump and two motor-operated isolation valves. Each loop supplies water to jet pumps located inside the reactor vessel in the annular region between the core shroud and the vessel wall.

The power conversion system converts the usable energy from the steam produced in the reactor vessel to electricity, condenses the steam, and heats the condensate and pumps it back to the reactor as feedwater. The system consists of a large steam turbine and generator, moisture separator-reheaters, a single-pass condenser, motor-driven condensate and a full-flow condensate polishing system, turbine-driven feed-water pumps, and several stages of feedwater heating. At Peach Bottom, the condensers are normally cooled by water drawn from and returned to Conowingo Reservoir via mechanical draft cooling towers. At Limerick, the condensers are cooled by water which is cooled in the two large hyperbolic natural draft cooling towers.

Immediately adjacent to the reactor vessel is the biological shield which stops the neutron and gamma radiation from the reactor and the primary containment which provides the ultimate barrier and the energy absorption capability in the event of a rupture of the primary system. The secondary containment structure surrounds the primary containment and houses auxiliary equipment and the spent fuel pool. Outside the secondary containment building, additional other equipment and facilities exist which can be seen at typical fossil power plants; switchyard, intake and discharge structures, cooling tower, turbine building, office and other buildings.

3.1.2 Typical PWR Plant

The Salem Units 1 and 2 are PWR systems. The general configuration of various equipment and systems for a typical PWR plant is illustrated in Figure 3-2. The pressurized water reactor operates on an indirect cycle; the heat generated by the fission of nuclear fuel in the reactor core is removed by high-pressure water (primary coolant) that is circulated through the reactor core. The primary coolant piping system connects the reactor core in series with steam generators and reactor coolant pumps. The primary coolant system transfers the heat through the steam generators to the secondary system in which steam is produced to drive the turbine-generator and generate electricity. The secondary system is isolated from the primary system and does not come into contact with the reactor, and therefore is not radioactive.

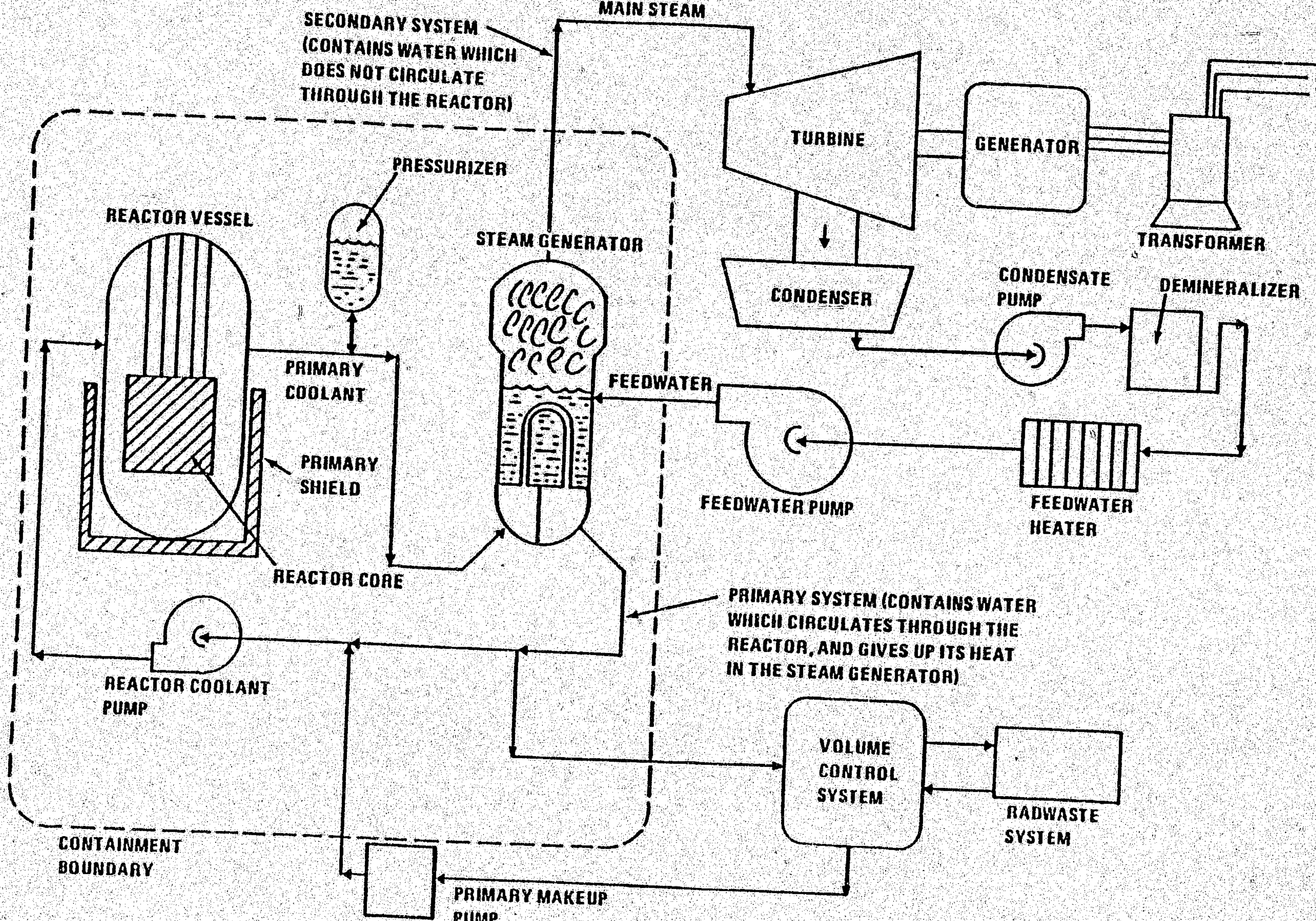
The primary coolant system boundary provides a barrier against the release of radioactivity from the reactor, and is designed to ensure a high degree of integrity throughout the life of the PWR plant. It is housed within what is typically called a containment building shown by the dotted boundary in Figure 3-2.

The containment building is made of 3 to 4 feet thick steel-reinforced concrete, and contains the reactor vessel, steam generators, the pressurizer, reactor coolant pumps, and interconnecting piping system.

The reactor vessel is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The reactor vessel contains the fuel core, core support structures, control rods and other parts directly associated with the core. Immediately adjacent to the reactor vessel is the primary shield which reduces the neutron and gamma radiation from the reactor.

Outside the containment building, various other equipment and facilities exist which can be seen at typical fossil power plants; turbine-generator, condenser, feedwater pumps, switchyard, intake and discharge structures, office buildings, etc.

FIGURE 3–2
GENERAL LAYOUT OF A TYPICAL PWR PLANT



3.1.3 Sources of Radioactive Materials

The primary source of radioactive materials in all nuclear power plants is the nuclear fuel located in the reactor core; when the nuclear fuel fissions, it produces not only the heat but also radioactive materials called "fission products." By far the majority of radioactivity generated in a power reactor is from the fission products generated in the fuel. The fuel is deliberately designed to retain all of the fission products within the fuel rods. The spent fuel is discharged from the reactor, stored in the spent fuel pool, and ultimately shipped away in specially designed casks. Thus, by far the majority of radioactivity in a power reactor stays with, and goes away with the fuel. Although the last fuel discharged from the reactor may be shipped away during the decommissioning period, spent fuel shipment is a separate activity from decommissioning. Decommissioning does not include spent fuel shipment, but is concerned with the amount of radioactivity that remains in the reactor system after the spent fuel is removed.

Sources of radioactive materials at the time of final reactor shutdown, after the fuel is removed, are basically of two types; neutron-activated components in and surrounding the reactor core and surface contamination from fission products and activated corrosion products deposited inside certain piping and equipment systems, and on some structural surfaces.

Neutron-Activated Components

Radioactive material is produced in the structural components in and around the reactor vessel because of interactions with neutrons produced in the reactor fuel during operation. Three basic types of materials are used in and around the reactor vessel: stainless steel (types 304 and 316), carbon steel (type SA 553), and reinforced concrete. The time dependence of radioactivity concentrations and dose rates of selected radionuclides produced in the structural components indicate that the decay rate of cobalt-60 (Co^{60}) generally controls the reduction of the radiation dose rate for the first 70 years. After that time, the dose rate is increasingly dominated by niobium-94 (Nb^{94}).

Surface Contamination

Both activated corrosion products (from structural materials in contact with the reactor water) and fission products (from leaking fuel) contribute to the radionuclide mixtures and levels of surface contamination.

Specific alloys used in the structural components of the reactor coolant system play a major role in the composition of the internal surface contamination. The activated corrosion product cobalt-60 is dominant because of the abundance of its parent in structural materials, its large-formation cross section, its energetic decay, and its 5.3 year half-life. Cobalt-58 is only a minor source of radiation in a BWR, while in a PWR it can be a significant contributor to the shutdown radiation levels. Depending on the type of condenser tubes and condensate polishing system used, zinc-65 could be an isotope of concern in BWR's.

Mobile fission products from leaking reactor fuel also contribute to the internal surface contamination. Their concentrations are directly related to the number of leaking fuel elements in the reactor core and thus will change during plant operation.

During decommissioning of the nuclear power plant, it will be necessary to remove the primary source of radioactive materials and to decontaminate the equipment, piping systems and structural materials in such a way that the radiation exposure to workers is kept within acceptable limits. Procedures and activities involved in decommissioning are described below.

3.2 Summary of the Decommissioning Process

3.2.1 Pre-Shutdown Activities

The physical decommissioning of a large nuclear power generating facility is a complex undertaking, and its success depends greatly on good planning and completion of preparatory work before final reactor shutdown. The regulatory requirements that must be met are summarized in Appendix A. Planning and preparation work need to be started, in general, about three years prior to final reactor shutdown, and include:

- satisfying regulatory requirements

- developing work plans and procedures
- designing, procuring and testing special equipment
- training staff
- selecting specialty contractors (environmental monitoring, explosives, hauling, etc.)
- removing accumulated spent fuel
- selecting disposal method
- selecting disposal location

The activities for immediate dismantlement of a nuclear facility include decontamination, equipment disassembly, packaging, shipping and disposal of radioactive waste, quality assurance, contamination control, and environmental surveillance.

3.2.2 Decontamination

At final reactor shutdown, significant radioactive contamination is present on the surfaces of process systems and equipment. Decontamination is necessary to remove the bulk of this radioactive contamination from selected systems and components to minimize personnel exposure during disassembly, and to clean as much material as possible to unrestricted levels, thereby permitting salvage of valuable material and reducing the quantities of material that must be packaged and shipped to a disposal site.

Three basic methods can be used to remove radioactive materials from contaminated surfaces:

- dissolution of the surface film containing the radionuclides
- physical cleaning of the surface
- physical removal of the contaminated structural material

Two methods can be used to dissolve surface films containing radionuclide contamination; chemical and electrochemical. The chemical method is generally used to decontaminate the internal and, in some cases, external surfaces of in-place piping and equipment. The electrochemical method can sometimes be used in-place for internal decontamination, but it is more commonly applied to disassembled or segmented piping and equipment.

Removal of smearable radioactive contamination from surfaces such as walls, floors, and tank exteriors can be accomplished using a variety of physical cleaning techniques. For small quantities of loose contamination on floors, vacuuming or simple sweeping is often effective. For more tenacious contaminants, various cleansing compounds are utilized in combination with handwiping and scrubbing techniques. Several proprietary decontamination solutions are available. Ordinary household detergents are quite effective but produce sizable quantities of waste water that may require special processing. Aerosol-type foaming cleaners are effective and can eliminate the wastewater problem.

During facility decontamination, removal of both metal and concrete surfaces may be required. However, the techniques for metal-surface removal are the same as those for equipment disassembly. Some concrete in nuclear facilities is contaminated below the surface and cannot be decontaminated to release levels by physical surface cleaning alone. In addition, some of the concrete and structural steel in the sacrificial shield surrounding the reactor vessel is activated as a result of neutron bombardment. In both instances, the structural materials must be physically removed and disposed of offsite to sufficiently decontaminate the facility.

Decontaminated materials will be treated as non-radioactive if the remaining surface contamination meets the guidelines presented in Table 1 of Regulatory Guide 1.86. This study assumed that a nominal 5 to 10% of the structural and miscellaneous steel, conduit, and cable trays in contaminated areas had to be disposed of as radwaste. Also, the non-activated portion of the nuclear steam supply system (NSSS) was assumed to have radioactive contamination levels in excess of allowable levels following decontamination.

3.2.3 Equipment Removal

Decommissioning requires the disassembly and removal of various contaminated equipment systems. The equipment must be segmented into pieces small enough to facilitate packaging for offsite shipment and disposal.

Any of a number of methods can be used to disassemble and remove a particular piece of equipment. However, equipment-related parameters (e.g., size, location, design, and radioactive contamination and/or activation) and manpower/cost efficiencies of the various methods dictate the appropriate method for any given situation. In some cases, the required tools are available as part of the facility's normal operating-equipment complement; in others, the tools are readily available commercially (e.g., boltcutters, pipe saws, tubing cutters, and impact wrenches). However, some methods require the use of unique specialized tools and equipment.

The exact component removal sequence within a given system or locality is dictated by the component's accessibility and the anticipated personnel exposures during removal. When possible, items that contribute significantly to the general level of exposure in the work area are either removed first or are temporarily shielded while the work goes on. Systems are cut into manageable sections, using an appropriate cutting device (plasma-arc torch, arc saw, oxyacetylene torch, or power hack saw). Piping is cut into lengths compatible with standard shipping boxes. Similarly, tanks are cut into plate segments appropriately sized.

The reactor vessel internals are removed from the reactor vessel with the vessel and the reactor well filled with water. Components welded in place in the reactor vessel are cut loose using an underwater plasma-arc torch. These components are moved under water from the vessel to the dryer and separator storage pool in the case of a BWR and to the refueling canal in the case of a PWR. There they are cut (with a plasma-arc torch or an arc saw) into pieces that fit into DOT-approved shipping containers for transport to the disposal site. The plasma-arc torch that is used to cut the core shroud into packageable segments is guided by a remotely controlled manipulator installed in the reactor vessel.

The reactor vessel is also remotely cut into packageable sections. The vessel is cut in place in an air environment with an appropriate cutting device guided by the remotely controlled manipulator. The exact cutting sequence will differ between a BWR vessel and PWR vessel because of the way in which they are supported. However, the segmenting approach is similar for both types of vessels.

The reactor vessel and its internals are packaged in 120 cubic foot liners. These liners are assumed to be shipped in casks equivalent to the CNS-8-120 cask which can accept waste with radiation levels up to 250 R per hour. In some cases, it was considered necessary to add concrete to the liner to reduce radiation levels.

Small contaminated equipment is removed and packed in standard shipping containers. Large contaminated equipment having no external smearable contamination is sealed by welding steel plates over all openings. Such equipment is then shipped to a burial site, using the outer shell as the packaging. Contaminated equipment that is too large to be shipped as a unit is cut up either into segments that will fit into standard shipping containers or into segments that can be sealed with welded steel plates.

Contaminated concrete is removed using a concrete scabbler, which removes the surface layer. The rubble is packaged in standard shipping containers for disposal.

Packaging of radioactive materials for disposal is accomplished in accordance with DOT regulations published in 49CFR Parts 173 through 178, and with NRC regulations published in 10CFR Part 71 and Regulatory Guide 7.1. Containers are lined with shielding material when necessary to reduce surface dose rates to acceptable levels. Some items such as heat exchangers will have openings welded shut and shipped using the outer shell of the exchanger as the container.

3.2.4 Site Restoration

In addition, all remaining plant equipment and structures including switchyard, fences, roadways and parking facilities are removed. Generally, the following guidelines are observed:

- Removal of all above ground structures to at least three feet below grade.
- Removal of the intake discharge structure and collapsing the conduits to the turbine building.
- Collapsing and/or filling all subterranean voids more than three feet below grade.
- Verifying residual radiation levels equal to or less than Regulatory Guide 1.86.

After removal of all equipment and structures, the site is restored by filling all remaining holes; essential grading, backfilling, planting, and replacement of rock and soil as required to return the site to essentially preconstruction condition. A final survey of radiation is performed to ensure that the activity level is within the specified limits.

4.0 DECOMMISSIONING COSTS AND SCHEDULES

4.1 Approach to Decommissioning Costing

4.1.1 Approach and Assumptions

In developing the decommissioning cost estimates, three basic criteria were used. The first criteria was that all decommissioning activities would be performed using only established technology.

The second criteria required that before general demolition of structures and components could take place, all radioactively contaminated materials and components would be removed from the various structures. The reasons for this constraint are:

- to prevent the uncontrolled release of radioactive material during demolition

- to prevent the inleakage of rain and ground water into areas of the plant still containing contaminated materials (Should inleakage occur, significant demands could be imposed on the waste processing equipment, which may not be totally intact, as well as presenting a real potential for recontamination of clean areas.)

This criteria, therefore, requires that the basic structure remain intact while radioactive material is removed. As a result there can be a significant impact on normal demolition practices and labor productivity rates. The reason for this is that in many portions of various buildings:

- there exists little or no installed material handling equipment

- the work areas will be extremely confined

- many of the accesses to work areas through which removal equipment must be transferred are of a labyrinth design

It should also be noted that reduced productivity rates will be experienced when the work area is a radiation area and/or has spreadable contamination.

The third criterion is that decommissioning is to be performed under a contracted site decommissioning manager, with technical and management oversight being provided by the utility. It is assumed that the decommissioning effort will be a succession of sub-contracted specific efforts such as:

- Decontamination
- Mobile solidification
- General demolition and site reclaimation
- Health physics service
- Guard services

Bases for Cost Estimates

The development of a decommissioning cost estimate involves characterizing structures, components and systems in terms of basic units of volume, weight and lengths. To these units, cost factors are applied which represent labor, disposal, salvage and difficulty/constraints associated with labor productivity. This is a standard practice for the estimation of demolition costs. For this project every effort was made to use site specific data in the development of the decommissioning quantities. Information on plant designs, and actual construction quantities, were provided by PECo. This information was supplemented by a thorough review of each of the three stations to identify structural items, mechanical components, and electrical components. The review was made by examining station drawings, equipment lists, safety analysis reports and by visiting each station. In addition, station final safety analysis reports, generic documents such as BWR and PWR plant decommissioning studies, Westinghouse and General Electric technical documents and similar data sources were reviewed and as necessary used as sources for data/information.

The decommissioning cost estimate reflects immediate dismantlement to three feet below grade following removal of the spent nuclear fuel from the site. Dismantlement of all structures and switchyards to the tie-off of the transmission system was to be assumed except at Peach Bottom where the switchyard is an integral part of the PECo systemwide transmission system.

The decommissioning costs were generated in March 1984 dollars. Values of labor and removal cost factors were obtained as follows:

A. Labor rates were based on union wages in the area of the sites.

B. Structural, mechanical and electrical demolition cost factors and salvage values were developed by NUS with input from demolition specialists and/or standard industry cost estimating reference documents.

The labor rates were fully burdened. That is the labor rates were adjusted to include:

- fringes
- equipment
- overhead - indirect labor
- overhead - travel and living for key personnel
- workmen's compensation
- overhead - home office
- general liability
- contractor's fee
- bonding

Guidance on fully burdening the labor rates was provided by demolition specialists.

Cost data in transportation and disposal of radioactive wastes were taken from current rate sheets supplied by waste shippers and radwaste burial site operators. March 1984 dollars were used as the basis since they were the latest figures available at the time this report was compiled.

Major Assumptions

The major assumptions used to develop this cost estimate are:

- Decommissioning costs are to reflect immediate dismantlement following removal of all spent fuel from the site.

- Demolition is to be performed to a depth of three feet below grade. All radioactive material below this depth would be removed.

- Large yard buried pipe (36 inches and larger) would be collapsed and backfilled.
- Small yard pipe and conduit would be abandoned in place.
- At Peach Bottom, areas of the site claimed from the Conowingo Reservoir would be returned to the reservoir.
- At Limerick and Peach Bottom, non-radioactive debris would be disposed of at an on-site landfill. Non-radioactive debris from Salem would be disposed of at sea, approximately 50 miles from the Salem site.
- Radioactive waste from all three stations would be disposed of at the Barnwell, South Carolina low-level radwaste disposal facility.
- Secondary side components at the Salem station would not be treated as radioactive waste.
- At all three stations, the NSSS and other radioactive systems would be decontaminated prior to dismantling.
- At all three stations, the large NSSS components would be sectioned to facilitate removal, packaging and transportation.
- Structural demolition of a given facility would not be performed until all radioactive materials have been removed from the facility.
- Sites would be restored to a natural condition, that is graded and landscaped.
- The utility will provide oversight of the decommissioning effort, with a prime decommissioning contractor managing the project.

4.1.2 Major Cost Centers

Following the criteria given above, the total decommissioning cost is developed. This cost being an aggregate of numerous subcosts which can be grouped into major cost centers. It is along the lines of these cost centers that the subcosts associated with decommissioning were developed. The major cost centers are:

- o Utility planning and oversight of the decommissioning effort
- o General contractor project management and sub-contractor services
- o Structural demolition
- o Mechanical/electrical demolition
- o Waste disposal
- o Miscellaneous (consumables, insurance, etc.)

How costs were developed for these major cost centers is discussed in the following subsections.

4.1.2.1 Cost Development for Utility Planning and Control, General Contractor Management and Subcontractors

The costs for utility planning and control, general contractor management and subcontractors were developed based on the site-specific decommissioning schedule. Prior to the start of physical decommissioning, the principal activities are planning, licensing, contractor selection, and training. Once decommissioning begins, labor requirements for these activities are a function of craft labor on site requiring management, planning/scheduling and subcontractor support. The craft labor on site as a function of time was determined by man loading the decommissioning schedule. Once the craft labor force was established, these indirect labor requirements were determined.

4.1.2.2 Cost Development for Structural, Mechanical and Electrical Demolition

The development of decommissioning costs related to structural, mechanical and electrical demolition necessitated converting structures, components and systems to quantities of volume, weight, and length. The base quantities were further subdivided into demolition categories or groups. All items in a given demolition category have the same base removal cost which is representative of the demolition technique employed.

4.1.2.3 Structural Demolition

For structural decommissioning, the categories are based on the thickness and degree of reinforcement of the concrete components as well as whether or not it is a wall or slab. Basically the structural demolition efforts used can be grouped into three generic categories which are:

<u>Light to Medium Structures</u>

These structures are demolished by use of wrecking balls, track loaders and pneumatic breakers. Cutting torches are used throughout the demolition process to sever steel elements. Debris is handled and removed by front end loader equipment.

<u>Medium to Heavy Structures</u>

These structures are demolished as follows:

A. Superstructures and light walls and slabs are demolished by use of a combination of wrecking balls, pneumatic breakers, and track loader equipment to collapse the components and break them into manageable pieces for disposal.

B. Massive walls and slabs are broken out using explosive demolition methods.

Cutting torches are used throughout the demolition process to sever steel elements. Debris is handled and removed by a combination of crane mounted clam bucket and front end loader equipment.

<u>Heavy to Very Heavy Structures</u>

These structures are demolished as follows:

A. Superstructures and light walls and slabs are demolished by use of a combination of heavy wrecking balls, pneumatic breakers, and track loader equipment to collapse the components and break them into manageable pieces for disposal.

B. Massive walls and slabs are broken out by the very extensive use of explosive demolition methods along with heavy wrecking ball equipment and pneumatic and hydraulic breakers.

Cutting torches are used throughout the demolition process to sever steel elements. Debris is handled by front end loaders and removed by hydraulic backhoes and crane mounted clam buckets.

In addition, at each of the sites under evaluation there were site specific structural demolition activities which could not be addressed generically, these are as follows:

Peach Bottom

A. Off Gas Stack and Associated Piping

The stack is razed using "controlled collapse" explosive demolition methods. Secondary breaking of the razed stack is performed with large track loaders. Throughout the concrete breaking operations, exposed reinforcing bars are severed with cutting torches. Debris is trucked to an on-site disposal area.

Off gas piping is excavated, cut into 20 ft. long sections and transported to a central area where it is decontaminated. The pipe is then trucked to an on-site disposal area.

B. Cooling Towers, Basins, Dredged Fill and Rock Dikes

The five mechanical cooling towers with their basins are demolished with wrecking balls and track loaders similar to method 1 above. Debris is trucked to on-site disposal areas.

The dredged fill and rock dikes are excavated with crawler cranes with drag line, backhoe and clamshell buckets, as is appropriate. Excavated material is trucked to an on-site stockpile area where it is used to grade the site after demolition.

C. Circulating Water Screen Structure

The structure consists of concrete slabs, piers and walls partially submerged in the Susquehanna River with the two ends of the structure built into the rock dike system. Demolition would be by a combination of wrecking ball and explosive demolition methods with the underwater portions demolished using bulk explosive charges. Debris is handled and removed with a crane mounted clam bucket and trucked to an on-site disposal area.

D. Circulating Water Canal Sheet Piling Barrier

Barrier consists of sheet piling placed horizontally in panels between soldier piles. The soldier piles are embedded in the bedrock.

To demolish the barrier a barge mounted crane is floated into the canal through an opening in the screen structure and the sheet piling panels are lifted out. The soldier piles are cut at the underlying bedrock line by divers.

<u>Salem</u>

A. Circulating Water Pipe

All pipe is post-tensioned concrete cylinder water pipe. Pipe in the area of the turbine building is encased in reinforced concrete and the discharge pipe is extended approximately 500 ft. offshore into the river.

Demolition is accomplished as follows:

- o Open ends of concrete-encased pipe are plugged with lean concrete.
- o Buried on-shore pipe is line drilled, and the top demolished with explosive charges to allow placement of backfill materials.
- o Off-shore pipe is abandoned in place.

Limerick

A. Cooling Towers

The hyperbolic natural draft cooling towers are constructed with precast concrete panels at the base, reinforced concrete footings and basin and cast-in-place shells.

The shells are demolished to grade using "controlled collapse" explosive demolition methods. Secondary breaking of the felled concrete shell is performed by large track loaders. The foundations and basin are demolished using wrecking balls, large track loaders and explosive demolition.

B. Schuylkill River and Perkiomen Make-Up Water Intake Structures.

Demolition methods are similar to those used at the Peach Bottom Circulating Water Screen Structure.

C. Circulating Water Pipe

Demolition methods are similar to those used at the Salem Circulating Water Pipe.

4.1.2.4 Mechanical Demolition

Mechanical demolition can be divided into two categories: (1) removal of equipment from inside the contaminated buildings and (2) removal of equipment from the general site bildings where contamination is not present.

Removal of equipment from contaminated buildings include both contaminated and non-contaminated components. The building contamination control envelope must be maintained until all contamination is removed. Additional building HVAC systems, lighting, and basic air and water service systems must be maintained and operated during the equipment removal process.

This results in difficult access problems for some components and requires that the equipment removal be planned and sequenced in order to minimize the impact on building service systems and to achieve the most efficient removal.

Removal of equipment from non-contaminated buildings is accomplished by standard demolition practice. Walls are removed and equipment extracted in the most rapid manner. Building services and contamination control are not required.

Large and highly contaminated or activated components require special techniques and handling to facilitate their removal. At each station, the reactor vessel, which is highly activated, must be segmented prior to removal into packageable size pieces. Cutting on the reactor vessel must be done with remotely operated tooling such as a plasma arc torch. Each of these pieces must be removed and placed in a 6' diameter by 6' high liner which is then inserted into a shipping cask. Cutting on the vessel creates substantial airborne particulate and require that a HEPA filter HVAC control environment be put in place to allow concurrent work in other areas.

At Limerick and Peach Bottom, the turbines, condensers, and entire feedwater system are contaminated. Turbine covers and condenser shells must be cut to shipment size and wrapped for shipment. Turbine blades are removed and packed in crates. Turbine shafts are broken at the couplings and wrapped for shipment. Condenser tubes are extracted and placed in mechanical shredder to reduce volume for burial. Feedwater heaters are removed and covers welded over each opening prior to shipment.

At Salem, the steam generators, pressurizers, and NSSS piping are contaminated. The turbine, condensers, and feedwater system are considered clean or easily decontaminateable. Steam generators, because of size and weight, must be segmented. Tubes are reduced in volume by mechanical shredder. The pressurizer is segmented into several sections and covers are welded on segments and over openings. Pressurizer segments are used as burial containers for contaminated scrap such as insulation or instrument tubing.

The remaining components at each station were evaluated on the basis of size, location, contamination, and accessibility. Major components were individually tabulated into a data base for cost development. In general, the list consisted of:

- o tanks with volumes greater than 1,500 gallons
- o pumps with motors having a horsepower rating of greater than 50 horsepower
- o heat exchangers with inlet nozzles greater than 8 inches

Items smaller than those listed above were identified and an aggregate weight was used in developing a demolition cost. Typical process piping was classified as large or small bore pipe and an aggregate weight was developed. Large piping, such as reactor coolant and main steam piping was addressed separately when developing its decommissioning cost.

4.1.2.5 Electrical Demolition

Electrical demolition cost estimating followed standard estimating efforts for electrical equipment and components. Equipment classifications used in developing the electrical demolition cost included:

- o Cable (control and instrumentation, power 480V and 5 kV)
- o Conduit
- o Cable trays
- o Transformers
- o Motor control centers
- o Switchgear
- o Diesel driven generators
- o Main generators

Although the sizes of some of the electrical components addressed in this cost estimate may be larger than those typically encountered in demolition, unique efforts such as NSSS removal or containment demolition were not identified under electrical demolition.

4.1.2.6 Development of Demolition Costs

Having developed quantities for each of the demolition classifications, the decommissioning cost is obtained by applying a demolition cost factor to each of the demolition classification quantities. Demolition cost factors were developed by NUS with input from demolition specialists and standard industry references. These costs factors represented standard industrial demolition practices and when appropriate, required adjustments to reflect particular constraints under which this work is to be performed. Adjustments to the demolition cost factors were made wherever necessary to reflect conditions or practices unique to demolition of a nuclear facility. Adjustments which were made to the base demolition cost factors included:

- o work in a radiation area
- o confined working area
- o work required to provide special packing of contaminated materials

4.1.2.7 Waste Disposal Cost Development

Both radioactive and non-radioactive waste/debris will be produced during the decommissioning of a nuclear power facility. The cost to dispose of the two waste types was developed using the following cost areas and assumptions.

<u>Non-Radioactive Debris</u>

A. Cost Areas

- o labor to load transport vehicles (including loading equipment)
- o transportation of waste
- o disposal fees

B. Assumptions

- o Waste quantities were based on the demolition quantities developed for each site.

- At the Limerick and Peach Bottom stations, debris would be disposed of at an on-site landfill.

- At Salem, the debris will be dumped at sea at approximately fifty miles off-shore.

- When appropriate, debris will be used to fill below-grade areas of the structure from which it was removed as well as below-grade areas of adjacent structures.

- Off-the-road hauling equipment will be used to transport debris from the demolition site to the on-site landfill or to the barge docking site.

- Barges will be of 2,500 ton capacity with a 15 ton capacity crane mounted on the barge to load/unload debris.

- Burial sites at Limerick and Peach Bottom are on land owned by PECo and do not require any dumping fee. However, the costs to open, operate and close the burial sites have been included.

Radioactive Waste Disposal

A. Cost Areas

- disposal containers
- labor to load disposal containers
- labor to load transport vehicle (including loading equipment)
- radiation surveys of waste
- transportation of waste
- cask rental
- disposal fees

NOTE: Cost associated with sectioning of radioactive materials, special preparation for packaging or special tools and equipment for these activities are accounted for under demolition costs.

B. Assumptions

- o Waste quantities were based on the removed radioactive quantities developed for each site which were, in turn, based on removal of all radioactivity down to the unrestricted release limits of Regulatory Guide 1.86, which is attached as Appendix B.

- o Radioactive waste from all three sites would be sent to the low-level waste disposal facility in Barnwell, South Carolina.

- o The transportation routes selected were the most direct, but did not go through cities.

With respect to the disposal of radwaste, the disposal fee includes:

- o base disposal fee
- o radiation surcharge
- o weight surcharge
- o curie surcharge
- o special handling surcharge
- o cask handling fee
- o perpetuity escrow fund charges
- o low-level radioactive waste disposal tax
- o license tax

Not all surcharges were applied to each radwaste shipment. Each waste form was addressed separately and the appropriate surcharges applied.

Using the cost areas and assumptions slated above, the disposal costs for radwaste and non-radwaste debris were developed based on information and data provided by:

- o demolition specialists
- o companies engaged in sea disposal of waste
- o published transportation rates for radioactive material
- o published disposal rates for the Barnwell low-level radwaste disposal facility

4.1.2.8 Miscellaneous Costs

The miscellaneous cost center contains those costs that cannot be attributed specifically to one of the other cost centers. Items included in this category include:

- o health physics supplies
- o rental of a mobile solidification service
- o insurance

Costs for these items were based on nuclear power plant experience, supplied by vendors or by PECo.

4.2 Total Decommissioning Cost Base

The total decommissioning cost estimates for the three nuclear generating stations addressed in this cost analysis are:

Station	Total Decommissioning Cost in Milllions of March 1984 Dollars
Peach Bottom 2 & 3*	273.5
Salem 1 & 2	211.6
Limerick 1 & 2	272.6

These total costs can be subdivided and grouped in at least two different ways: by the major cost centers decribed above which are based on functional decommissioning activities; and by FERC account which is related to the physical parts of the stations being decommissioned. These two particular subdivisions are described below.

4.2.1 Costs Subdivided by Activity

Table 4-1 summarizes the total decommissioning cost estimate grouped by the cost center activities which were described in Section 4.1 Some cost differences are evident in the table: Limerick general contractor costs are somewhat higher than for the other two stations because Unit 2 shuts down 5 years after Unit 1, extending the

* Does not include an additional cost of $19,072,000 for the removal of Peach Bottom Unit 1, the entombed nuclear facility located on the same site.

TABLE 4-1
Total Decommissioning Cost
Grouped by Major Cost Centers

Cost Center	Total Cost, Million $, March 1984		
	Peach Bottom 2 & 3	Salem 1 & 2	Limerick 1 & 2
Utility Planning and Control	23.0	21.9	28.4
General Contractor and Subcontractor	51.7	54.4	66.5
Mechanical/Electrical Demolition	65.9	55.8	66.4
Structural Demolition	69.4	30.7	46.5
Waste Disposal	62.1	46.3	62.1
Miscellaneous (consumables, insurance)	9.1	9.0	8.8
Salvageable Components and Materials	(7.7)	(6.5)	(6.1)
TOTAL	273.5	211.6	272.6

decommissioning period by about 5 years. The mechanical/electrical demolition, structural demolition, and waste disposal are lower at Salem because it is a PWR and its turbine and condenser are not radioactive. The structural demolition at Peach Bottom is high because of over $20 million dollars of costs to remove the cooling water dikes and canals built into Conowingo Pond. The Peach Bottom and Limerick costs are similar because some large differences between these plants have offsetting costs which by coincidence nearly cancel.

4.2.2 Cost by FERC Account

The total cost in 1984 dollars for the demolition of the Peach Bottom Units 2 and 3, Salem Units 1 and 2, and Limerick Units 1 and 2 stations are shown in Tables 4-2, 4-3, and 4-4 respectively. A breakdown of the total estimated decommissioning cost is provided by Federal Energy Regulatory Commission (FERC) account as well as being subdivided into removal, disposal, and salvage categories. The FERC accounts used are as follows:

- 321 Nuclear Production - Structures and Improvements
- 322 Nuclear Production - Reactor Plant Equipment
- 323 Nuclear Production - Turbogenerated Units
- 324 Nuclear Production - Accessory Electrical Equipment
- 352 Transmission Plant - Structure and Improvements
- 524 Nuclear Power - Miscellaneous Nuclear Power Expenses
- 920 Administration and General Expenses - Administrative and General Salaries
- 923 Administration and General Expenses - Outside Services Employed
- 924 Administration and General Expenses - Property Insurance

The major cost areas for which subtotals are provided are:

<u>Removal Cost</u>

This subtotal includes costs incurred except for disposal costs, that is, equipment, prime and subcontractors, service contractors, fees, insurance and consumables. Basically <u>any</u> cost incurred during and in preparation/support of the demolition/ripout phase of the decommissioning effort is called removal. Also included are site restoration costs.

TABLE 4-2
Decommissioning Cost Summary for the
Peach Bottom Atomic Power Station, Units 2 and 3
(in thousands of March 1984 dollars)
Total Cost

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 69,387	$ 8,358	$(3,384)	$ 74,361
322	Reactor Equipment	36,094	45,082	(337)	80,839
323	Turbogenerator	15,977	8,188	(293)	23,872
324	Accessory Electrical	13,923	481	(3,714)	10,690
524	Miscellaneous Nuclear Expense	7,595	0	0	7,595
920	Utility A&G	23,052	0	0	23,052
923	Outside Services	51,668	0	0	51,668
924	Insurance	1,476	0	0	1,476
	TOTAL	$219,171	$62,109	$(7,728)	$273,553

TABLE 4-3
Decommissioning Cost Summary for the
Salem Nuclear Generating Station, Units 1 and 2
(in thousands of March 1984 dollars)
Total

FERC Account	Name	Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 30,573	$ 6,599	$ (530)	$ 36,642
322	Reactor Equipment	31,772	39,223	(471)	70,474
323	Turbogenerator	9,559	144	(1,939)	7,764
324	Accessory Electrical	14,540	301	(3,478)	11,363
352	Transmission Plant	179	20	(88)	111
524	Miscellaneous Nuclear Expense	7,495	0	0	7,495
920	Utility A&G	21,919	0	0	21,919
923	Outside Services	54,381	0	0	54,381
924	Insurance	1,465	0	0	1,465
	TOTAL	$171,833	$46,287	$(6,506)	$211,614

TABLE 4-4
Decommissioning Cost Summary for the
Limerick Generating Station, Units 1 and 2
(in thousands of March 1984 dollars)
Total

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 46,463	$ 6,890	$(1,218)	$ 52,135
322	Reactor Equipment	37,991	46,719	(862)	83,848
323	Turbogenerator	14,088	7,963	(153)	21,898
324	Accessory Electrical	14,132	438	(3,726)	10,844
352	Transmission Plant	241	36	(90)	187
524	Miscellaneous Nuclear Expense	7,594	0	0	7,594
920	Utility A&G	28,427	0	0	28,427
923	Outside Services	66,569	0	0	66,569
924	Insurance	1,117	0	0	1,117
	TOTAL	$216,622	$62,046	$(6,049)	$272,619

Disposal Cost

This subtotal presents the cost to dispose of both the radioactive and non-radioactive debris/waste produced as a result of the decommissioning effort. Cost items included in this subtotal are containers, labor, transportation and disposal fee.

Salvage Value

This subtotal presents the projected income received from the sale of materials that have a recycle/reuse value as measured in the scrap and used equipment market.

Total Cost

The total cost for each FERC account is the sum of the removal cost and the disposal cost less the salvage value.

4.3 Nuclear-Related Decommissioning Cost Base

Prior regulatory precedent and related ratemaking practice in the Commonwealth of Pennsylvania have established that only the nuclear-related portion of total nuclear station decomissioning costs are allowable for ratemaking purposes. The definition of what is non-nuclear-related is found in the Commission order in connection with the original precedent-setting decommissioning ratemaking in 1978 (Pennslyvania Electric Company, 51 Pa P.U.C. at 669) for the dismantling of non-nuclear structures such as cooling towers, river water pump houses, and miscellaneous structures which by their nature, pose no special concern in regard to health and safety.

Wholly consistent with the above, the nuclear-related portions of total decommissioning costs have been estimated. This has been done by excluding from the estimate all parts of the conventional plant which are not radioactive, including the cooling system and cooling towers, turbine generator, administration buildings, and miscellaneous structures. In addition, parts of the nuclear plant safety system such as the diesel generators and spray ponds are also excluded because these components and their structures are not radioactive. The turbine generator and condenser systems in the BWR units (Peach Bottom and Limerick) are radioactive, and the radioactive portions and related shielding are included in the nuclear-related portion of the decommissioning cost estimate. The indirect costs of utility control and general contractor management which are not specifically nuclear-related are allocated on the basis of the split between nuclear-related and other costs. The resulting nuclear-related decommissioning cost estimates for the three nuclear generating stations are:

Station	Nuclear-Related Decommissioning Cost in Millions of March 1984 Dollars
Peach Bottom 2 & 3	191.6
Salem 1 & 2	160.2
Limerick 1 & 2	213.2

The corresponding cost breakdowns by activity and by FERC accounts are described below.

4.3.1 Nuclear-Related Costs by Activity

Table 4-5 summarizes the nuclear-related decommissioning cost estimate, grouped by the cost center activities that are described in Section 4.1. A comparison of the nuclear-related costs in Table 4-5 with the total costs in Table 4-1 shows the following differences: the utility planning and control costs drop somewhat, but because most of the planning and licensing is NRC-mandated, most of this cost group is nuclear-related ;similarly, in the general contractor and subcontractor category, almost all of the subcontractor costs are nuclear-related, including decontamination, health physics, and plant security; the mechanical/electrical and the structural demolition costs drop significantly in the nuclear-related case because of the significant part of the physical plant which is not nuclear-related; the waste disposal cost drops very little because almost all of this cost is for radioactive waste disposal; and the salvage credit almost disappears in the nuclear-related case because radioactive equipment is generally not

* Does not include an additional nuclear-related cost of $13,581,000 for the removal of Peach Bottom Unit 1, the entombed nuclear facility located on the same site.

TABLE 4-5
Nuclear-Related Decommissioning Cost
Grouped by Major Cost Centers

Cost Center	Nuclear-Related Cost, Million $, March 1984		
	Peach Bottom 2 & 3	Salem 1 & 2	Limerick 1 & 2
Utility Planning and Control	18.8	17.2	22.7
General Contractor and Subcontractor	41.6	43.2	53.4
Mechanical/Electrical Demolition	37.7	28.1	39.2
Structural Demolition	27.1	19.7	32.0
Waste Disposal	58.5	44.6	59.5
Miscellaneous (consumables, insurance)	7.4	7.5	7.5
Salvageable Components and Materials	(0.5)	(0.1)	(1.1)
TOTAL	190.6	160.2	213.2

salvagable. The overall nuclear-related costs are significantly below the total costs, with the Peach Bottom nuclear-related cost dropping the most because of the $20 million (non-nuclear) cost of removing the dikes and canals that extend onto state-owned land in Conowingo Reservoir.

4.3.2 Nuclear-Related Costs for FERC Account

The nuclear-related costs of decommissioning the Peach Bottom, Salem, and Limerick stations are shown in Tables 4-6, 4-7, and 4-8 respectively, by FERC Account. The largest decreases in cost occur in: Account 321, Structures and Improvements, which contains many non-nuclear structures; Account 324, Accessory Electrical, which is essentially non-nuclear; and Account 352, Transmission Plant, which is wholly non-nuclear.

4.4 Escalation of Base-Year Decommissioning Costs

Prior rulings of the Commission have established the sound practice of requiring the collection of revenues for decommissioning, based on current decommissioning costs. In parallel, the purchasing power of the funds being accumulated is also maintained at current levels. Both of these practices require periodic estimates of then-current decommissioning costs. This is done by escalating each of the components of the base cost by an appropriate inflation index and obtaining an updated (current) decommissioning cost. The purpose of this section is to identify the specific cost indices to be used and to describe the subdivision of total and nuclear-related decommissioning costs into components that are appropriate for escalation. The cost breakdowns and a one-year projection of the indices using past one-year actual rates are used to estimate March 1985 decommissioning costs.

4.4.1 Selection of Cost Indices for Escallation

The costs in decommissioning are incurred for craft labor, professional labor, equipment and materials, nuclear waste disposal, and a number of "other" costs, including energy, less credits for salvaged equipment and materials. The federal government regularly publishes indices which represent average costs in most of these categories. In addition, a number of private organizations develop indices of costs for special categories not covered by government publications. In the latter category, the

TABLE 4-6
Decommissioning Cost Summary for the
Peach Bottom Atomic Power Station, Units 2 and 3
(in thousands of March 1984 dollars)
Nuclear-Related

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 28,173	$ 6,521	$ (476)	$ 34,218
322	Reactor Equipment	26,080	44,814	0	70,894
323	Turbogenerator	10,634	6,868	0	17,502
324	Accessory Electrical	849	344	0	1,193
524	Miscellaneous Nuclear Expense	6,020	0	0	6,020
920	Utility A&G	18,762	0	0	18,762
923	Outside Services	41,615	0	0	41,615
924	Insurance	1,400	0	0	1,400
	TOTAL	$133,533	$58,547	$ (476)	$191,604

TABLE 4-7
Decommissioning Cost Summary for the
Salem Nuclear Generating Station, Units 1 and 2
(in thousands of March 1984 dollars)
Nuclear-Related

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 19,736	$ 5,122	$ (52)	$ 24,806
322	Reactor Equipment	27,492	39,223	(11)	66,704
323	Turbogenerator	0	0	0	0
324	Accessory Electrical	571	220	0	791
352	Transmission Plant	0	0	0	0
524	Miscellaneous Nuclear Expense	6,145	0	0	6,145
920	Utility A&G	17,208	0	0	17,208
923	Outside Services	43,171	0	0	43,171
924	Insurance	1,400	0	0	1,400
	TOTAL	$115,723	$44,565	$ (63)	$160,225

TABLE 4-8
Decommissioning Cost Summary for the
Limerick Generating Station, Units 1 and 2
(in thousands of March 1984 dollars)
Nuclear-Related

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 32,040	$ 5,694	$(1,053)	$ 36,681
322	Reactor Equipment	27,531	46,432	(7)	73,956
323	Turbogenerator	10,755	6,974	(3)	17,726
324	Accessory Electrical	924	375	0	1,299
352	Transmission Plant	0	0	0	0
524	Miscellaneous Nuclear Expense	6,469	0	0	6,469
920	Utility A&G	22,682	0	0	22,682
923	Outside Services	53,369	0	0	53,369
924	Insurance	1,050	0	0	1,050
	TOTAL	$154,820	$59,475	$(1,063)	$213,232

government does not publish appropriate regional cost indices for construction craft labor. Because the large statistically-oriented McGraw Hill organization, in its Engineering News Record, publishes cost indices for skilled and common construction labor in the Philadelphia area, these two indices were selected for craft labor. With the exception of nuclear waste burial, appropriate Department of Labor indices have been selected for the other cost component. Nuclear waste burial costs are based on the price lists for current commercial services. Table 4-9 identifies the specific indices that have been selected and the base values for March 1984, which is the base date for the costs in this report.

4.4.2 Cost Components for Escalation

This section summarizes the bases for establishing the costs in each of the cost categories that will be used for escalation. The removal and non-nuclear disposal portions of Account 321, 322, 323, 324, and 352 include craft labor and related burdens plus equipment cost. The latter averages 25.9% of the total cost, the remainder being allocated as craft labor. Craft labor costs are judged to be 35% common and 65% skilled. All of Account 524, except energy, is equipment cost. All of Account 920 plus the A/E, health physics, and corresponding portions of HP training in Account 923, are professional/technical labor costs, and the remainder are craft labor. The nuclear waste disposal cost is allocated 3.7% to craft labor, 17.0% to equipment, 11.8% (transportation) to energy and other, and 67.5% to burial fees. The salvage credits are allocated between the iron and steel scrap and the copper scrap categories. All remaining costs are included in the energy and other category.

Tables 4-10 and 4-11 summarize the actual cost breakdowns for the three stations for the total and nuclear-related decommissioning costs, respectively. The one characteristic shown in these tables that has not been identified previously is the relatively large component for professional/technical labor, compared to what is typical for construction jobs. Part of the reason is that $8 to 11 million of health physics costs are included in this category. The principal reason is the comparatively large amount of planning, licensing, training, and control required for a major decommissioning.

TABLE 4-9
Cost Categories, Cost Indices, and Base Values for Future Inflation Adjustments

Cost Category	Index	Base Value of Index March 1984
Craft Labor, Skilled	Engineering News Record, "Construction Wage Indexes" for Philadelphia Area	353.6
Craft Labor, Common	Engineering News Record, "Construction Wage Indexes" for Philadelphia Area	420.0
Professional Labor	BLS, Monthly Labor Review, Table 34 "Professional and Technical Workers"	122.2
Equipment	BLS, Producer Prices and Price Indexes, Table 6, Code 112, "Construction Machinery and Equipment"	355.8
Low-Level Waste Burial	Chem-Nuclear Barnwell Price List Effective January 1, 1984 ($14.50/$ft^3$ base + $2.50/$ft^3$ escrow, + $4.00/$ft^3$ S.C. tax + 2.4% county tax)	21.57
Salvage:		
Iron and Steel Scrap	BLS, Producer Prices and Price Indexes, Table 6, Code 1012, "Iron and Steel Scrap	311.8
Copper Scrap	Code 1023.01 "Copper Base Scrap"	149.6
Energy and Other	BLS, Producer Prices and Price Indexes, Table 1, "Materials and Components for Construction"	309.6

TABLE 4-10
Total Decommissioning Cost
by Cost Escalation Category
(thousands of March 1984 dollars)

Cost Category	Cost by Station		
	Peach Bottom 2 & 3	Salem 1 & 2	Limerick 1 & 2
Craft Labor, Skilled	83,902	62,655	78,569
Craft Labor, Common	38,085	26,266	32,128
Professional/Technical Labor	60,765	61,603	74,154
Equipment	37,127	25,494	31,100
Low-Level Waste Burial	37,568	23,687	38,786
Salvage:			
Iron and Steel	(4,361)	(3,420)	(2,644)
Copper Scrap	(3,367)	(3,080)	(3,405)
Energy and Other	23,833	18,409	23,933
TOTAL	273,552	211,614	272,621

TABLE 4-11
Nuclear-Related Decommissioning Costs
by Cost Escalation Category
(thousands of March 1984 dollars)

	Cost by Station		
Cost Category	Peach Bottom 2 & 3	Salem 1 & 2	Limerick 1 & 2
Craft Labor, Skilled	43,086	37,848	49,901
Craft Labor, Common	24,783	16,141	21,064
Professional/Technical Labor	50,635	50,239	61,758
Equipment	18,826	15,370	20,039
Low-Level Waste Burial	37,568	23,687	38,786
Salvage:			
Iron and Steel	(476)	(64)	(1,063)
Copper Scrap	0	0	0
Energy and Other	17,182	17,003	22,747
TOTAL	191,604	160,224	213,232

4.5 Decommissioning Schedules

At the Salem and Peach Bottom stations, it is planned that the decommissioning of both units at each station be performed simultaneously. At these two stations, both units are currently scheduled to terminate operation in the same year. At the Limerick station, Unit 1 is planned to terminate operation five (5) years before Unit 2. Again, it is planned that the decommissioning occur simultaneously at Limerick. However, to eliminate the cost associated with a short-term "mothballing" of Unit 1, it is planned to proceed with a low-level decommissioning effort. This low-level decommissioning effort would preclude demolition/ripout activities, but would address radiation surveys, cleanup and decontamination efforts. Presented in Figures 4-1, 4-2, and 4-3 are the site specific decommissioning schedules for Peach Bottom Units 2 and 3, Salem Units 1 and 2 and Limerick Units 1 and 2, respectively. These schedules were used to develop PECo prime decommissioning contractor and subcontractor manpower requirements and other cost information relating to the duration of the decommissioning effort.

4.6 Similarities and Differences Among Stations

Two nuclear power stations with the same type of NSSS and same general configuration located at two different sites could be expected to incur decommissioning costs that have both simularities and differences. Some of the reasons why decommissioning costs could differ are:

A. Differences due to local site conditions, including method of cooling

B. Differences due to evolution of plant design - earlier vs. later plant designs

C. The relative amounts of structure that are more than 3 feet below grade

D. The extent to which decontamination is used

E. Differences in the transportation distance to a low-level radwaste disposal site

Provided in Table 4-12 are similarities and differences among the three sites under evaluation. The similarities will tend to draw the cost estimates together while

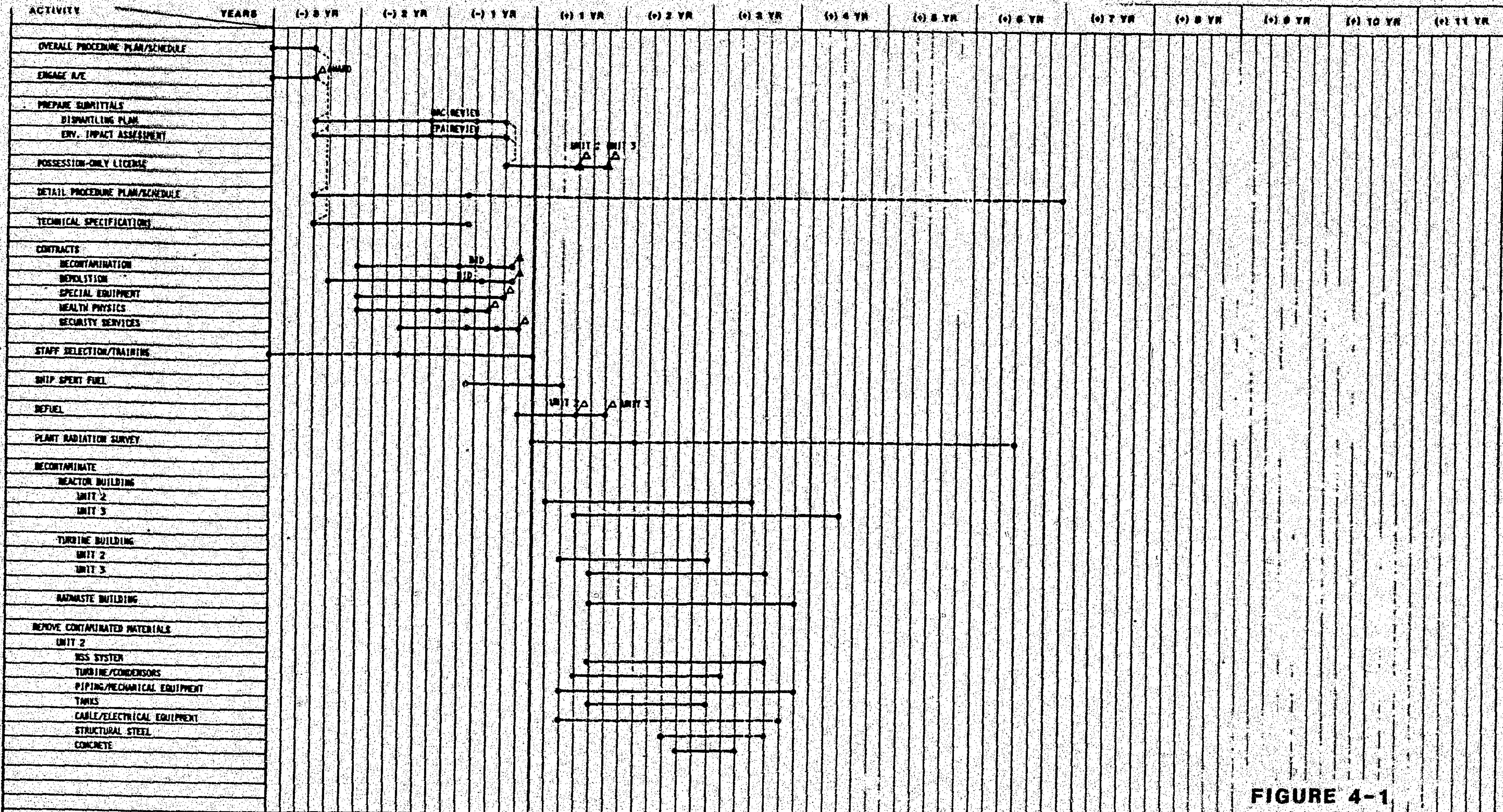


FIGURE 4-1

LEGEND:
o BEGIN OR END TASK
——— CONTINUOUS ACTION
- - - - - SPORADIC ACTION
Δ MILESTONE

NUS CORPORATION

PHILADELPHIA ELECTRIC COMPANY
PEACH BOTTOM ATOMIC POWER STATION
DECOMMISSIONING SCHEDULE
SHEET 1 of 4

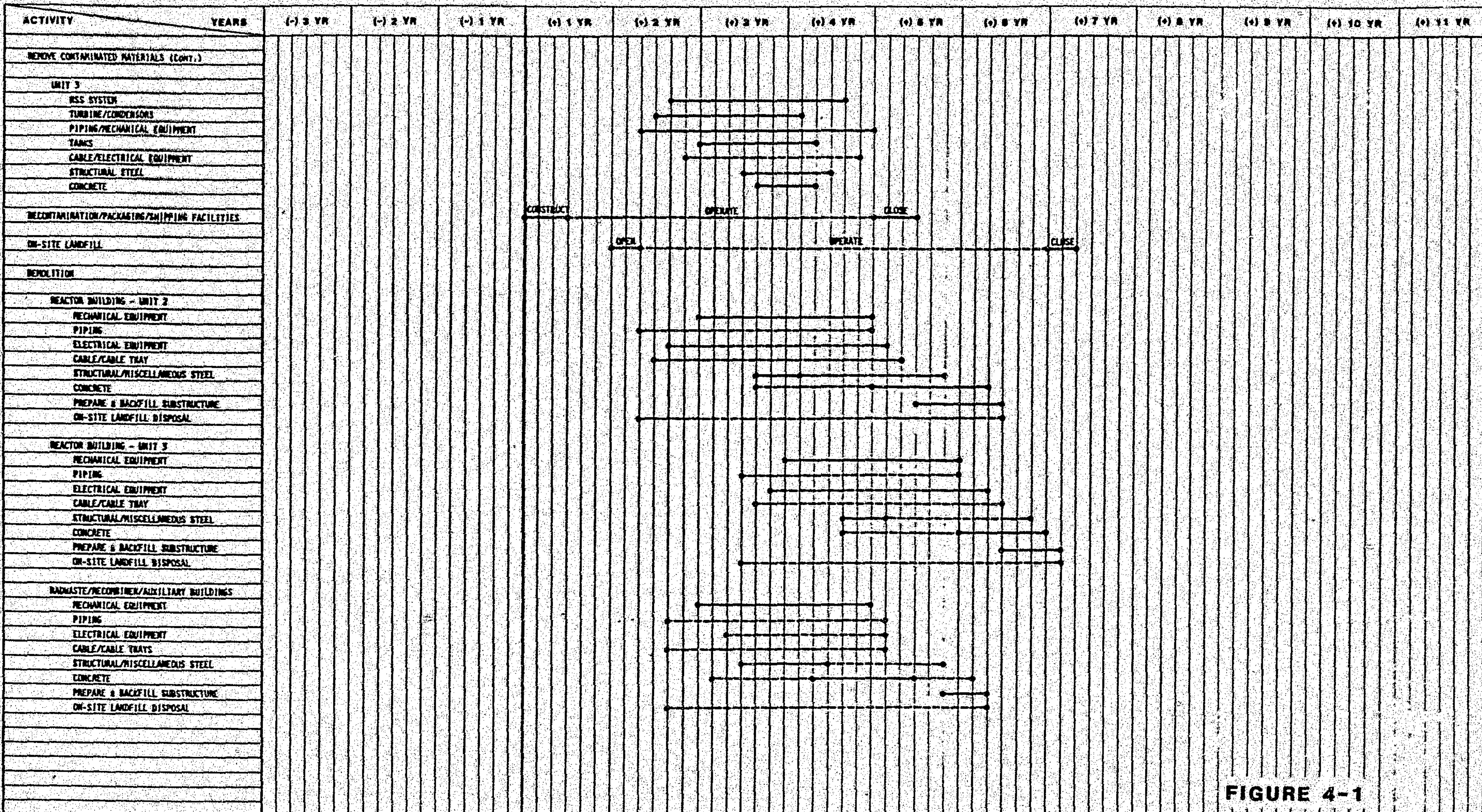
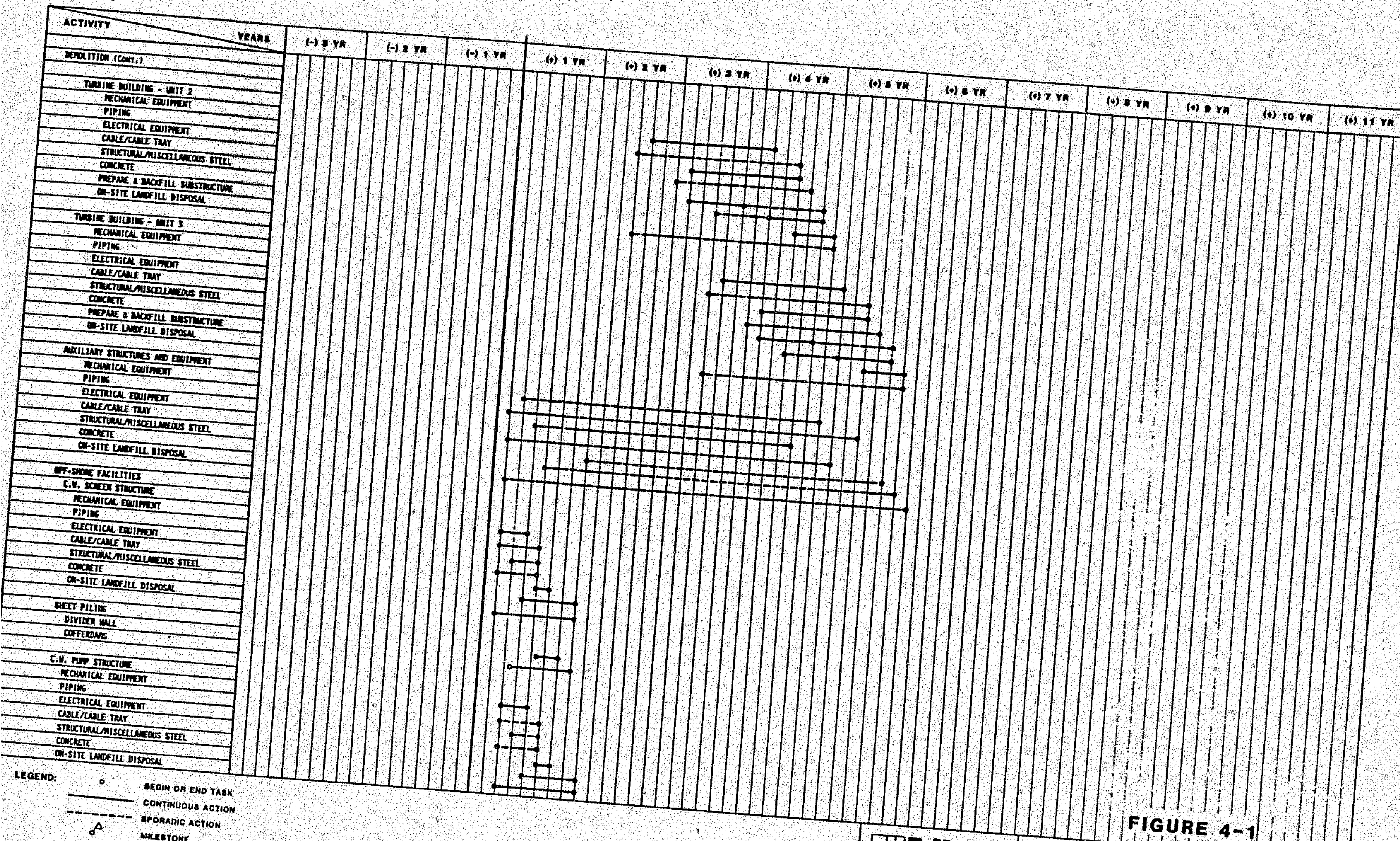


FIGURE 4-1

LEGEND:
o BEGIN OR END TASK
——— CONTINUOUS ACTION
- - - - - SPORADIC ACTION
MILESTONE

NUS CORPORATION

PHILADELPHIA ELECTRIC COMPANY
PEACH BOTTOM ATOMIC POWER STATION
DECOMMISSIONING SCHEDULE
SHEET 2 of 4



NUS CORPORATION

FIGURE 4-1

PHILADELPHIA ELECTRIC COMPANY
PEACH BOTTOM ATOMIC POWER STATION
DECOMMISSIONING SCHEDULE
SHEET 3 of 4

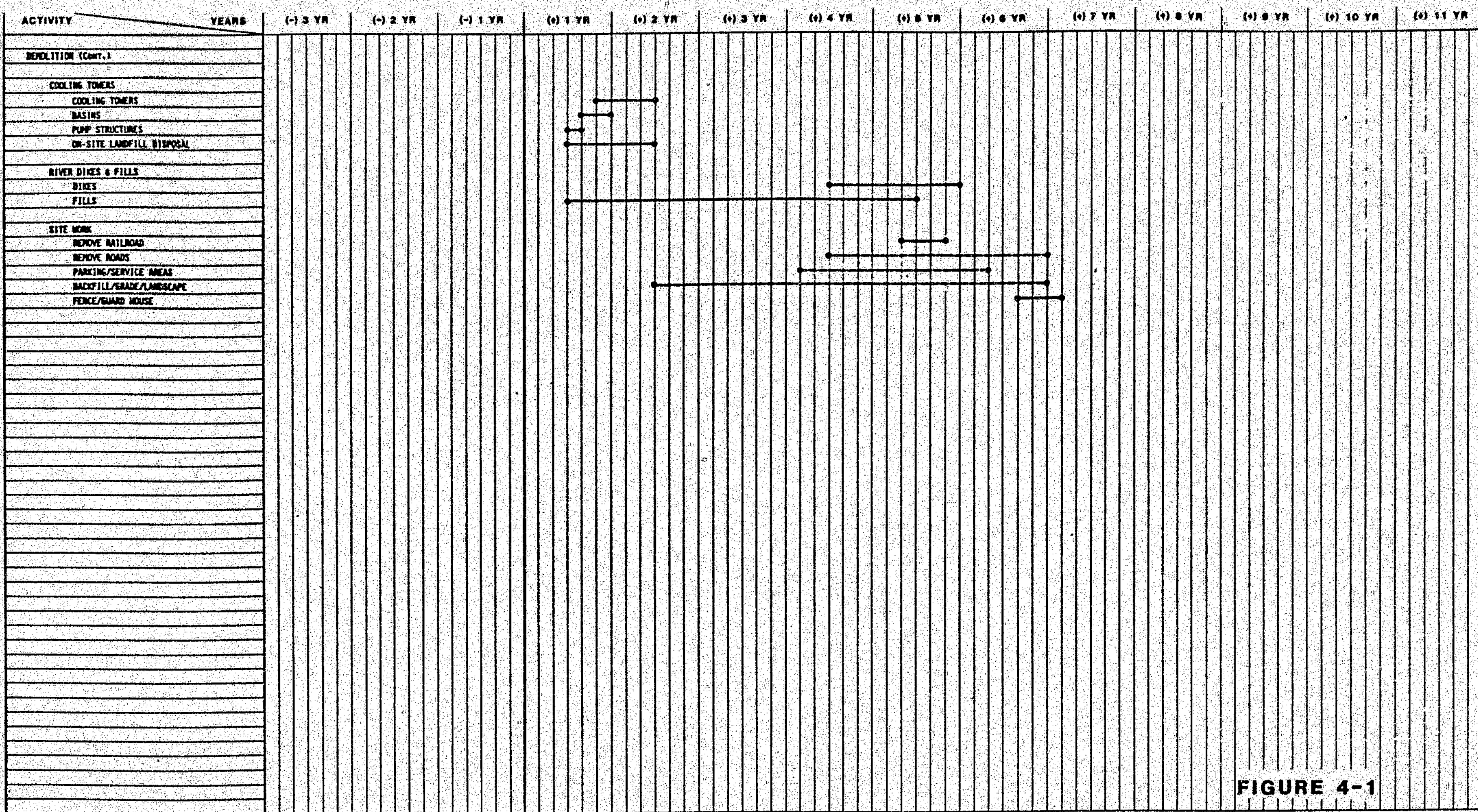


FIGURE 4-1

LEGEND:
o BEGIN OR END TASK
CONTINUOUS ACTION
SPORADIC ACTION
MILESTONE

NUS CORPORATION

PHILADELPHIA ELECTRIC COMPANY
PEACH BOTTOM ATOMIC POWER STATION
DECOMMISSIONING SCHEDULE
SHEET 4 of 4

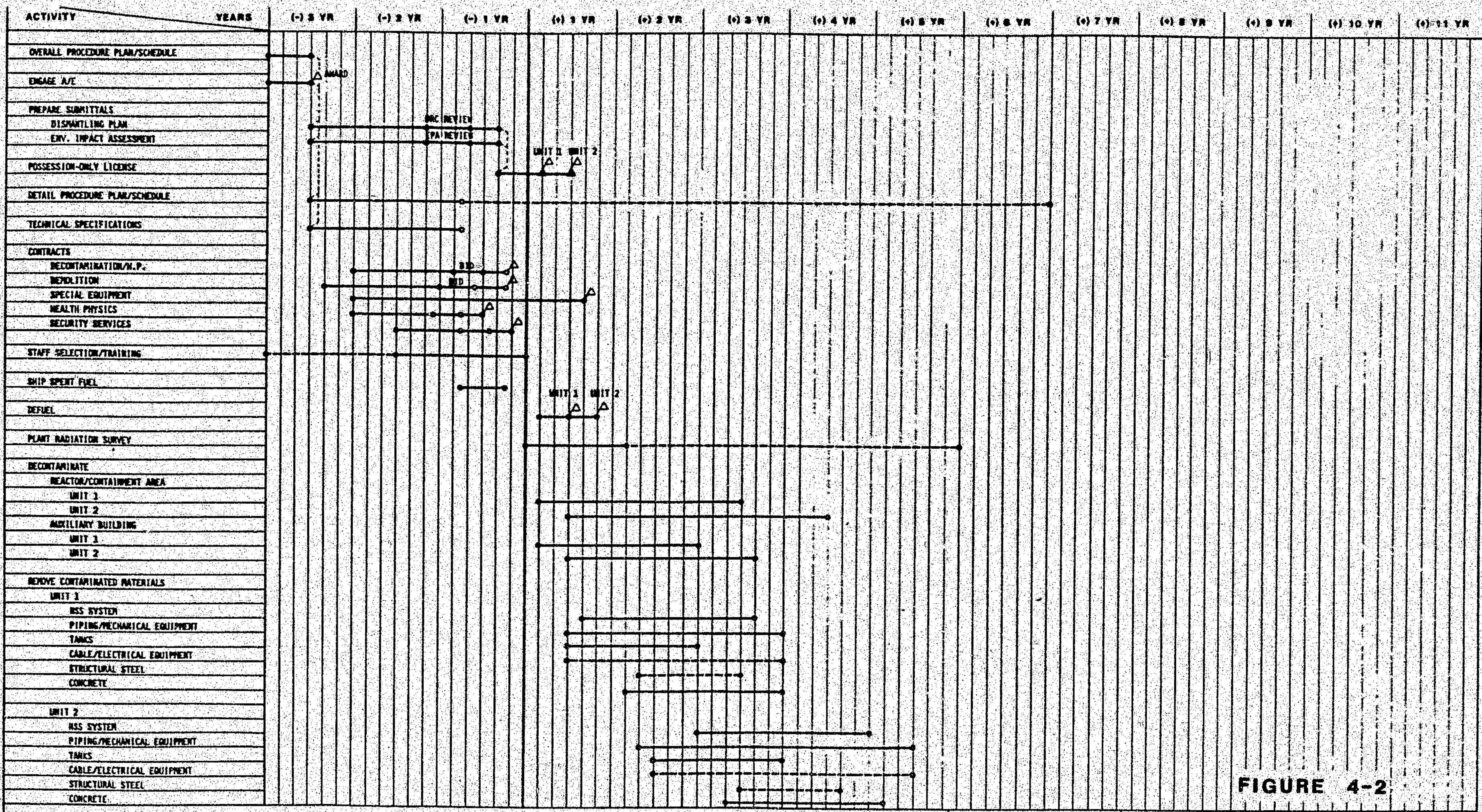
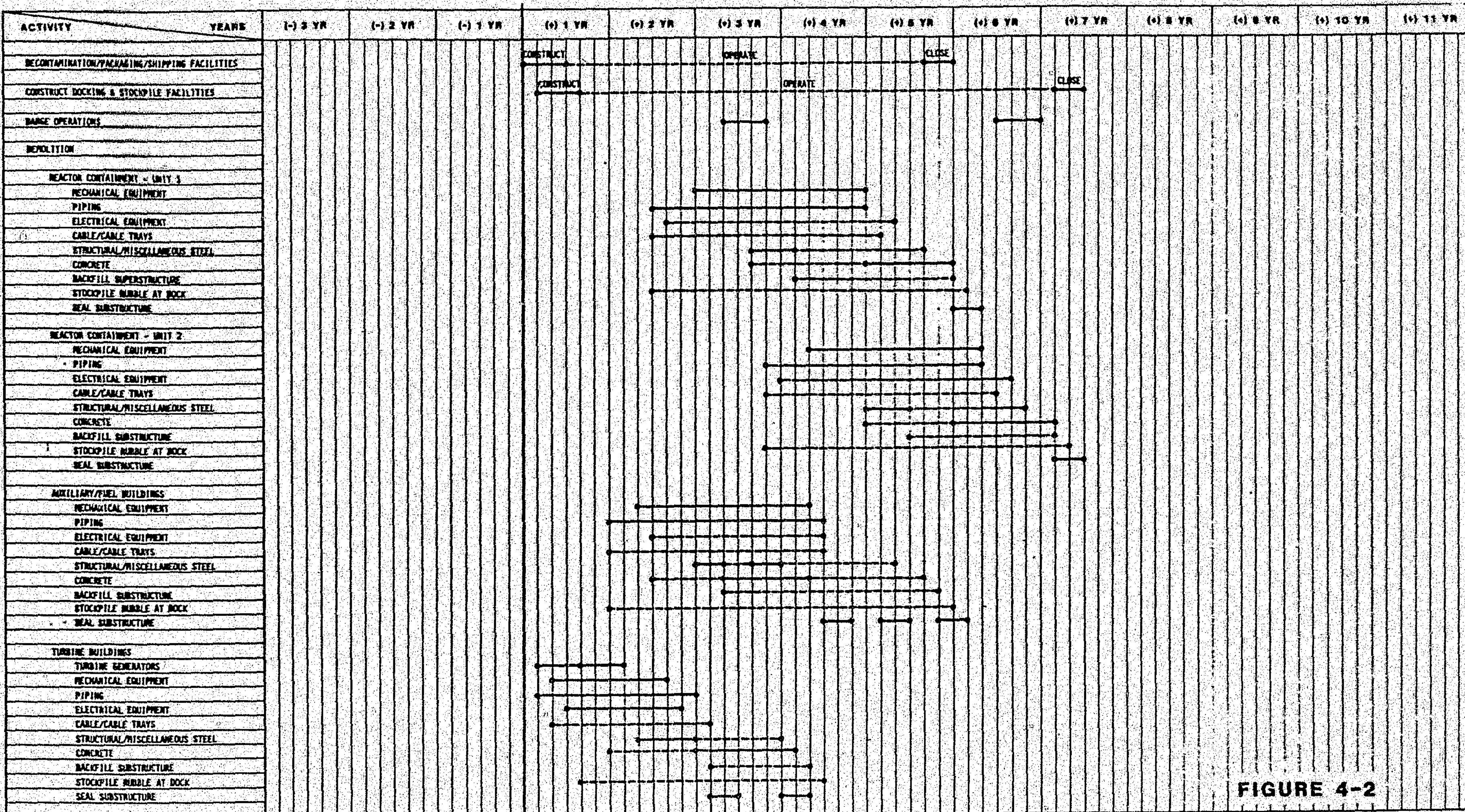


FIGURE 4-2

NUS CORPORATION

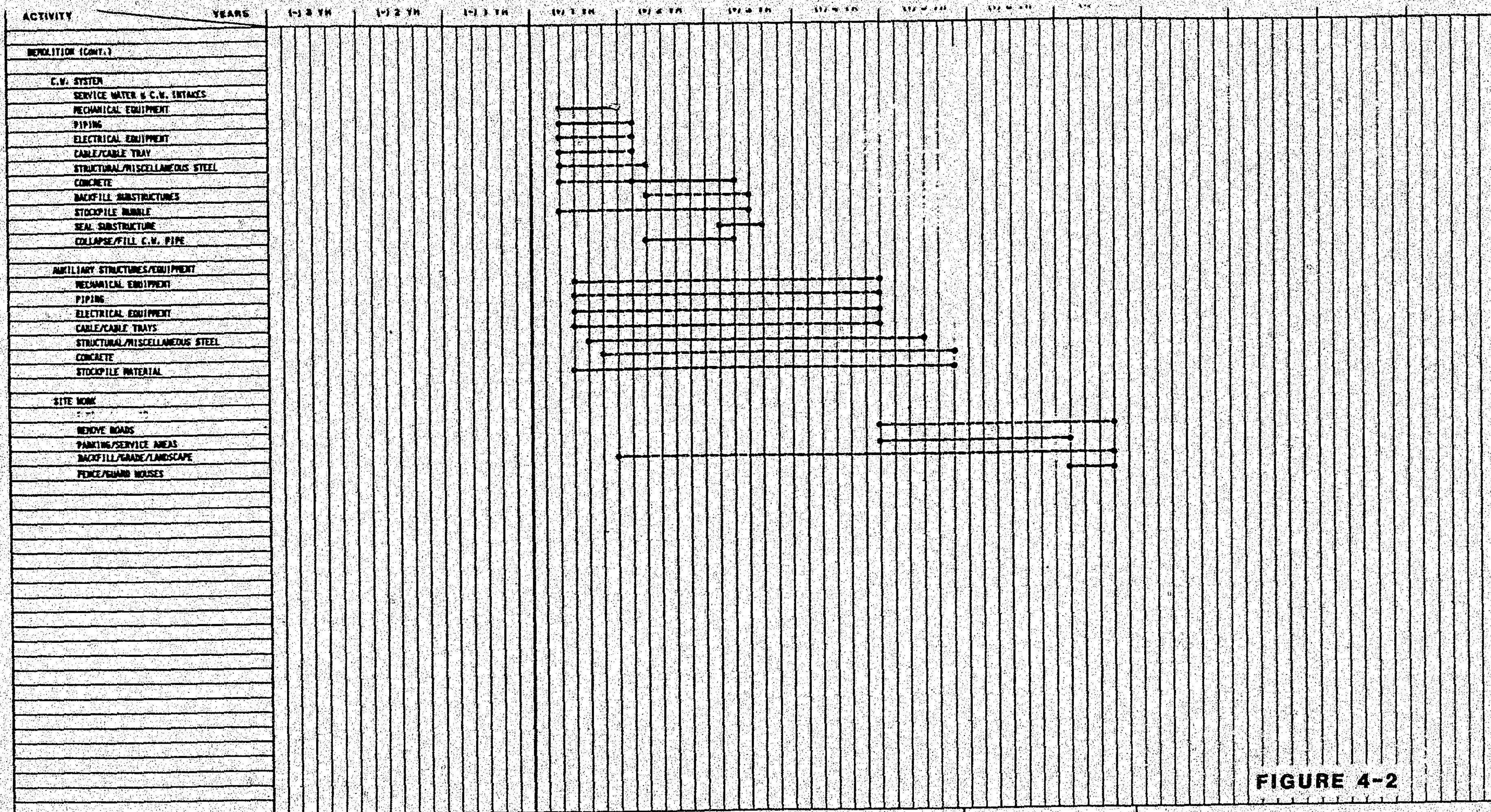
PHILADELPHIA ELECTRIC COMPANY
SALEM NUCLEAR GENERATING STATION
DECOMMISSIONING SCHEDULE
SHEET 1 of 3



NUS CORPORATION

FIGURE 4-2

PHILADELPHIA ELECTRIC COMPANY
SALEM NUCLEAR GENERATING STATION
DECOMMISSIONING SCHEDULE
SHEET 2 of 3



LEGEND:
- o BEGIN OR END TASK
- ——— CONTINUOUS ACTION
- - - - - SPORADIC ACTION
- MILESTONE

NUS CORPORATION

FIGURE 4-2

PHILADELPHIA ELECTRIC COMPANY
SALEM NUCLEAR GENERATING STATION
DECOMMISSIONING SCHEDULE
SHEET 3 of 3

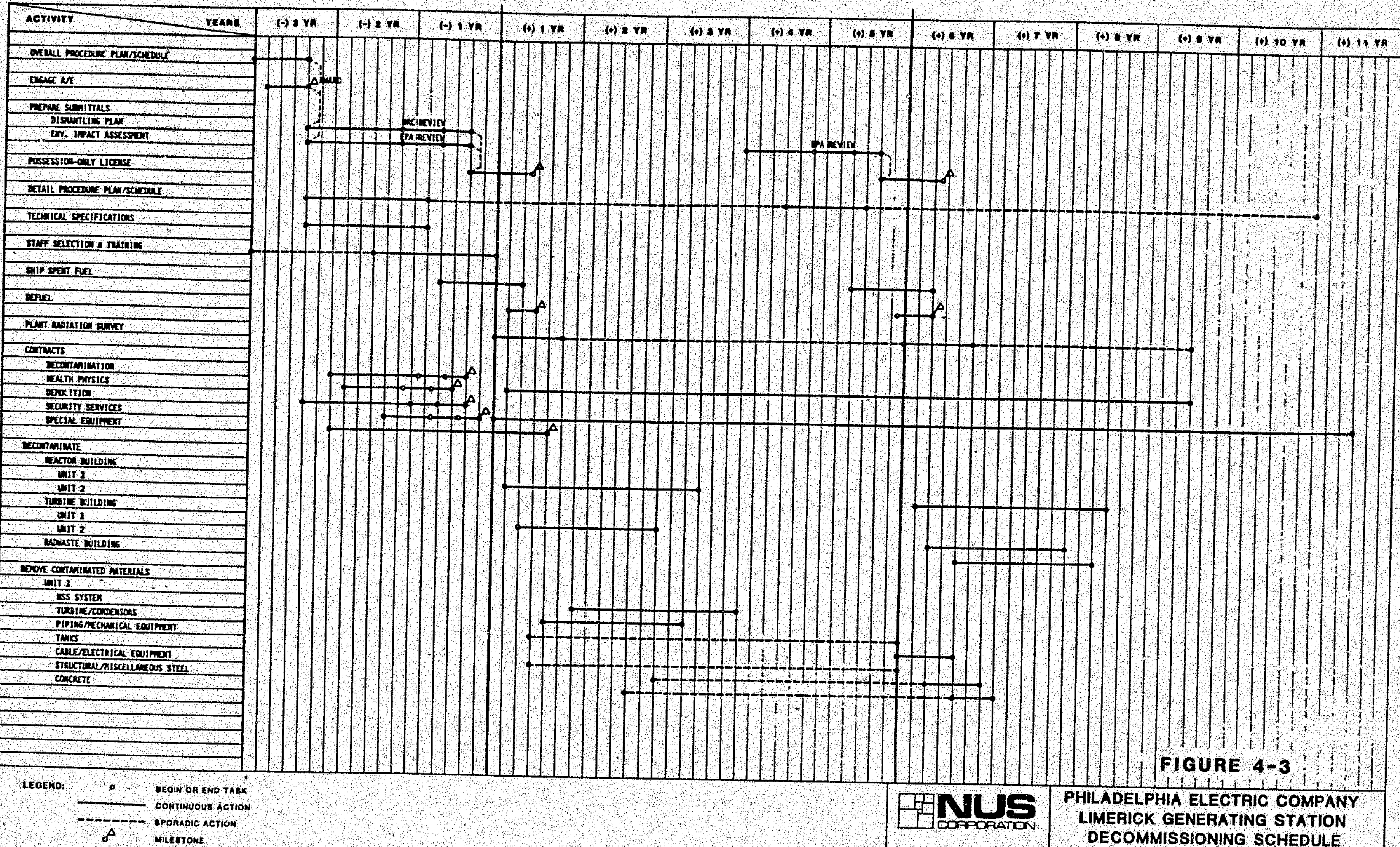


FIGURE 4-3

NUS CORPORATION

PHILADELPHIA ELECTRIC COMPANY
LIMERICK GENERATING STATION
DECOMMISSIONING SCHEDULE

SHEET 1 of 4

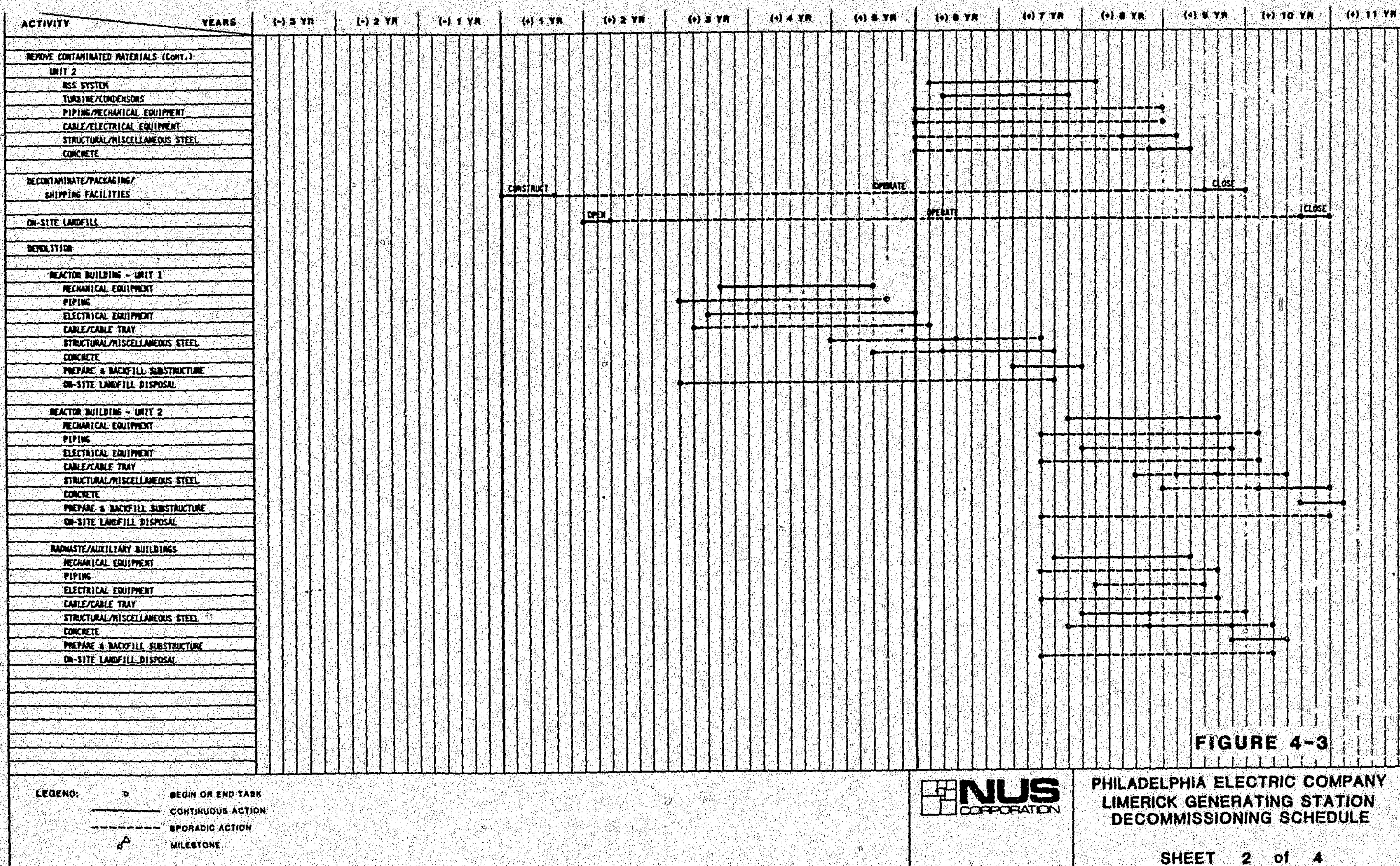


FIGURE 4-3

PHILADELPHIA ELECTRIC COMPANY
LIMERICK GENERATING STATION
DECOMMISSIONING SCHEDULE

SHEET 2 of 4

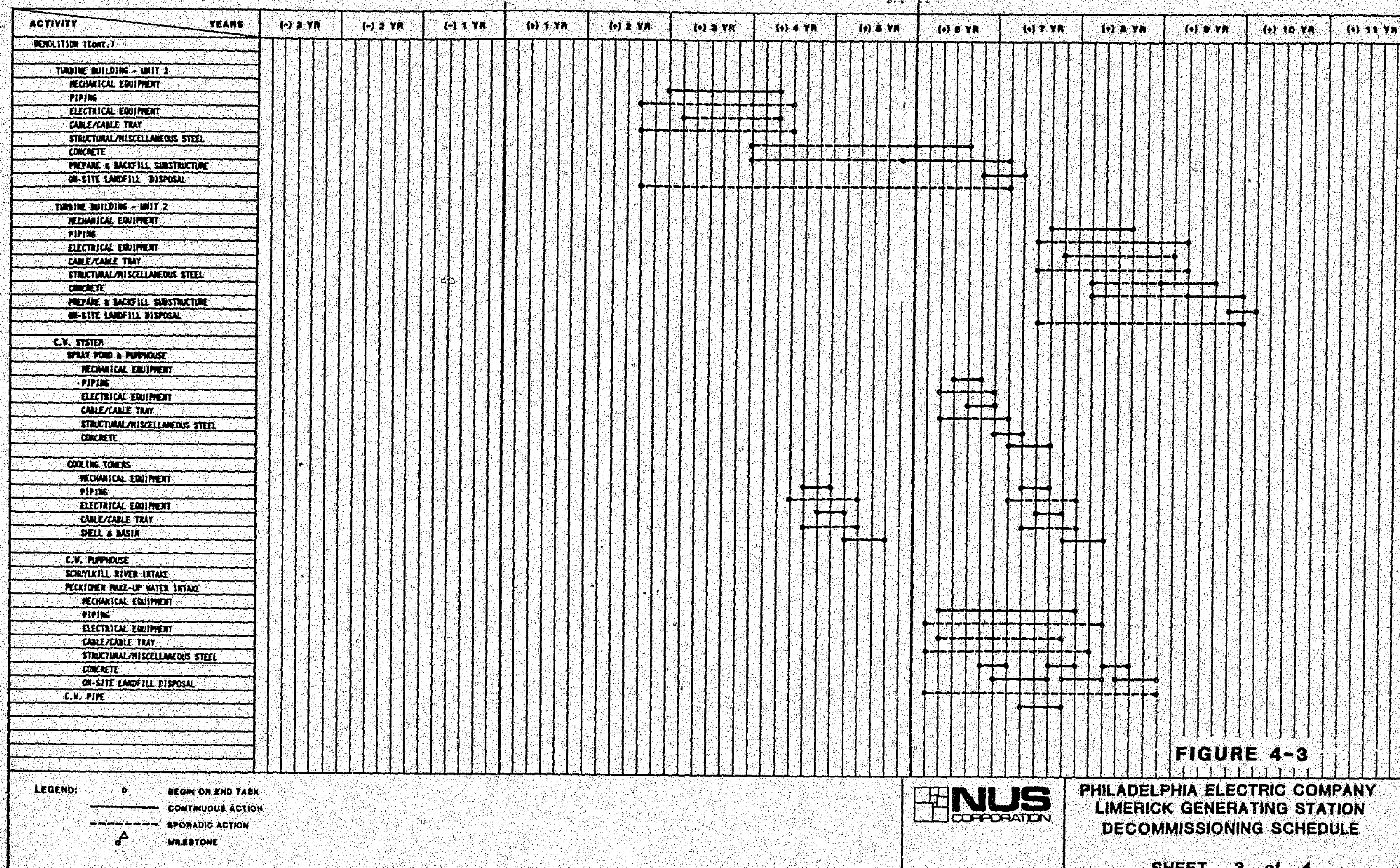


FIGURE 4-3

NUS CORPORATION

PHILADELPHIA ELECTRIC COMPANY
LIMERICK GENERATING STATION
DECOMMISSIONING SCHEDULE

SHEET 3 of 4

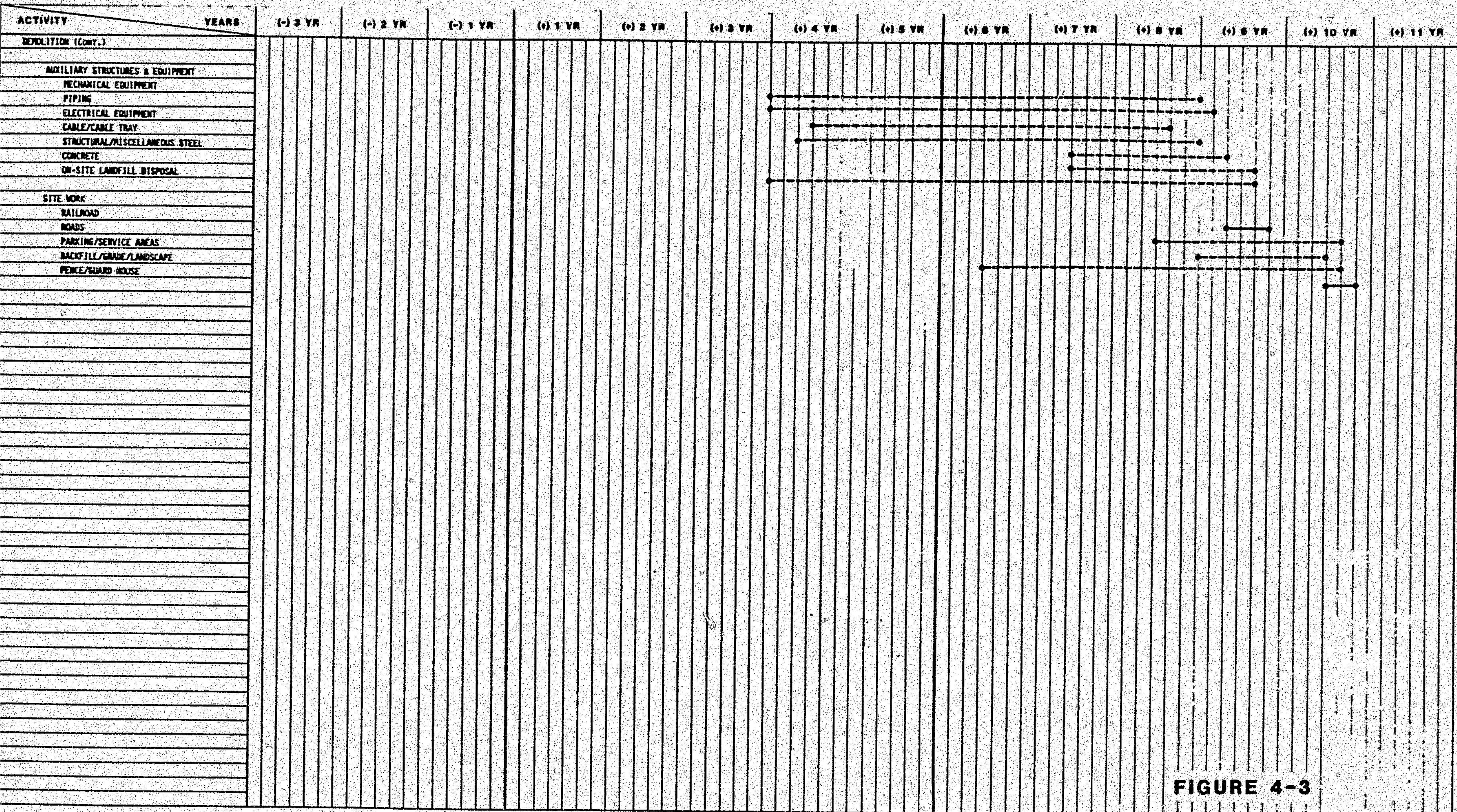


FIGURE 4-3

LEGEND:
- o BEGIN OR END TASK
- ——— CONTINUOUS ACTION
- - - - - SPORADIC ACTION
- MILESTONE

NUS CORPORATION

PHILADELPHIA ELECTRIC COMPANY
LIMERICK GENERATING STATION
DECOMMISSIONING SCHEDULE

SHEET 4 of 4

conversely the differences will tend to spread out the cost estimates. It should be noted that similarities and differences other than those listed in Table 4-12 exist. The items listed are the more obvious and meaningfully affect the cost estimates.

TABLE 4-12

MAJOR SIMILARITIES AND DIFFERENCES AMONG THE LIMERICK, PEACH BOTTOM AND SALEM GENERATING STATIONS THAT WOULD INFLUENCE THEIR ESTIMATED TOTAL COST OF DECOMMISSIONING

SIMILARITIES

ITEM	DISCUSSION
1. Transportation distance from sites to a a low-level waste disposal facility	The subject transporation distance is almost identical for all three sites. There is only a 35 mile difference between the shortest and longest transportation distance.
2. All nuclear steam supply systems and associated systems (i.e., reactor water cleanup system and chemical and volume control systems) will be chemically decontaminated prior to dismantling.	This ensures conformance in the decommissioning approach and cost estimating.
3. Both the Limerick and Peach Bottom Stations use large BWR's.	Removal and disposal of the NSSS is a major cost item. This similarity will tend to draw the cost estimates for these two stations together.
4. The decommissioning cost estimate for Limerick and Peach Bottom assumes all non-radioactive debris/non-salvagable material will be disposed of on-site.	Waste disposal, both radioactive and non-radioactive is costly. This assumption for the two BWR's will tend to keep the cost estimate similar.

TABLE 4-12

MAJOR SIMILARITIES AND DIFFERENCES AMONG THE LIMERICK, PEACH BOTTOM AND SALEM GENERATING STATIONS THAT WOULD INFLUENCE THEIR ESTIMATED TOTAL COST OF DECOMMISSIONING

DIFFERENCES

ITEM	DISCUSSION
1. This decommissioning cost study includes two BWR stations and one PWR station.	The differences in NSSS has a significant impact on the decommissioning cost. The PWR has large components not found in a BWR. These components include (in Salem's case) four steam generators, a pressurizer and safety injection tanks. However, in the case of the BWR's, more of the station systems handle radioactive fluids. In particular, the entire secondary side of a BWR must be treated as radioactively contaminated. This will <u>more</u> than offset any potential saving realized with respect to NSSS removal and disposal.
2. Extent of demolition.	Guidelines established for this cost study provided for demolition of structures to three feet below grade. However, the degree of below grade construction varies significantly with Salem having the most below grade construction and Peach Bottom the least.
3. Cooling towers.	The circulating water system is different at all three sites. At Limerick the circulating water system is a closed cycle using massive concrete natural draft hyperbolic cooling towers. At Peach Bottom the circulating water system is an open cycle, however, prior to discharge to the Conowingo Reservoir the circulating water system discharge is passed through large mechanical draft cooling towers of a wood frame construction. At Salem, no cooling of the circulating water system discharge is performed prior to its entering the Delaware River.

TABLE 4-12
MAJOR SIMILARITIES AND DIFFERENCES AMONG THE LIMERICK, PEACH BOTTOM AND SALEM GENERATING STATIONS THAT WOULD INFLUENCE THEIR ESTIMATED TOTAL COST OF DECOMMISSIONING

DIFFERENCES (Continued)

ITEM	DISCUSSION
4. Demolition of the turbine buildings.	Because the steam in a BWR plant contains a radioactivity inventory, extensive shielding is required in the turbine building. This will add to the demolition cost of a BWR turbine building. This is not the case for PWR's. In fact, at Salem the turbine deck is open.
5. Reactor building demolition.	The reactor building/containment is a very massive structure designed to withstand both natural phenomena (e.g., earthquakes and tornados) as well as design basis accidents. Such structures will be costly to take down regardless of their design. However, each site uses a different design for this structure. Salem uses the standard PWR cyclindrical containment structure. Peach Bottom uses the Mark I reactor containment with a common refueling area in the reactor building. Limerick uses a Mark II reactor containment and separate refueling areas.
6. Disposal of non-radioactive waste.	At Peach Bottom and Limerick it was assumed that the disposal of the non-radioactive demolition debris would be performed on-site. Due to the high ground water level at Salem this is not possible and barged sea disposal was assumed.
7. Site restoration.	Part of the Peach Bottom site was claimed from the Conowingo Reservoir by backfilling along the site shoreline. At the time of site decommissioning, this area will be given back to the Conowingo Reservoir by dredging the backfilled area.

APPENDIX A
SUMMARY OF REGULATORY REQUIREMENTS

The Nuclear Regulatory Commission has licensing jurisdiction over both operating units and decommissioning activities. Current decommissioning regulations are contained in 10CFR Part 40 and in Section 50-33(f), Section 50.82, Appendix C and Appendix F of 10CFR Part 50. General guidance is provided in NRC Regulatory Guide 1.86 appended hereto as Appendix B and in NRC staff guidelines. These cover the requirements and criteria for decommissioning of nuclear facilities. The Nuclear Regulatory Commission is presently developing a more explicit overall policy for decommissioning of commercial nuclear facilities and amending its regulations in Title 10 to the Code of Federal Regulations to include more specific decommissioning guidance for production and utilization facility licensees and byproduct, source and special nuclear material licensees.*

While the general policy and revised rules for decommissioning of light water reactors are not available, the NRC's internal thinking with respect to the mode of decommissioning had been reflected in the past. In the Federal Register dated February 10, 1982 (46FR 11666-11668), the NRC recommended for example "30 years" as the maximum delay for reactor decommissioning, wherein the principal contaminant is radioactive cobalt, because there would be little dose reduction due to delay after a delay of 30 years. This effectively appears to rule out the entombment option as one of decommissioning alternatives as is currently provided in Regulatory Guide 1.86.

A brief summary of current regulations and guidelines is presented below for each decommissioning phase.

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* NUREG-0436, "Plan for Reevaluation of NRC Policy on Decommissioning of Nuclear Facilities," March 1981.

During Planning and Preparation

Prior to terminating operation of a facility, the electric utility (licensee) must decide on a plan for the final disposition of the facility and obtain the approval of the NRC. Termination of the operating license is regulated by the requirements of 10CFR 50, Section 50.82. Regulatory Guide 1.86 describes methods acceptable to the NRC for satisfying the requirements of Section 50.82.

The NRC may issue either a possession-only license appropriate to the selected decommissioning option, or a modified operating license.

Sections 50.59 and 50.90 of 10CFR50 and 10CFR33 provide the rules by which a licensee may amend its license. The NRC approval must be obtained in order to amend requirements in technical specifications applicable to normal operation.

As part of the amended license, the licensee must have authorization for byproduct material (10CFR30), source material (10CFR40), and special nuclear material (10CFR70) until the radioactive material and any sources of special nuclear material are removed from the facility.

An environmental impact statement or appraisal must be prepared describing the probable effects of the proposed decommissioning actions in accordance with 10CFR51. These requirements are defined in Section 51, Subpart A. Section 51.5.b(7) which states that license amendments may or may not require an impact statement, depending upon the circumstances. In determining whether an environmental impact statement should or should not be prepared for such action, the commission shall be guided by the Council on Environmental Quality Guidelines, 40CFR1500.

In addition to Regulatory Guides, the NRC has internal guidance for its staff for evaluating safety analysis reports and environmental impact statements. These guides are found in NUREG-75/087 and NUREG-0158. Decommissioning is also addressed in NUREG-0158.

No current regulation specifically requires a detailed decommissioning plan, but Regulatory Guide 1.86 implies that one is needed. It states that the NRC will impose requirements depending on the decommissioning alternative selected by the licensee.

Such a plan should be included as part of the application for a license amendment and should cover the decommissioning objectives for the facility/site, safety analysis, procedures, safeguard plans, contingency plans for postulated events, and a time schedule.

The decommissioning plan should address quality assurance (QA) for the prevention or mitigation of the consequences of accidents that could cause undue risk to the health and safety of the public (10CFR50, Appendix B). Guidance is also found for nuclear facilities in the NRC's Standard Review Plans (SRP) 17.1 and 17.2. The principles and objectives of such guidance should be applied to all aspects of decommissioning.

Of significant concern are the amounts of the annual license fee and facility insurance premiums required to satisfy regulations during the active decommissioning and continuing care periods.

These costs are dictated by the type and quantity of radioactive and/or special nuclear materials, the type of activities being conducted and the type of license regulating the activities. Licensing fees are addressed in 10CFR170. The requirements for financial protection and indemnity agreements are provided in 10CFR40. The level of protection required for decommissioning is not specifically defined.

<u>During Decommissioning</u>

During the planned shutdown period, and until quantities of radioactive materials and/or special nuclear materials are removed from the facilities, safeguards and security precautions must be continued. Regulations defining required precautions are found in 10CFR70 and 10CFR73.

During decommissioning, radioactive waste will be accumulated, packaged, stored, and transported to one or more disposal sites. Regulations defining the requirements to assure the safety of the public and the protection of occupational workers during such waste-related activities are found in 10CFR20, 10CFR50, and 10CFR70. Means for compliance with these regulations, including safeguards and security precautions, and the procedures for disposal of radioactive materials should be clearly defined in the specifications and plans of the amended license at the start of decommissioning.

Radioactive effluents from waste processing operations or other decommissioning activities must comply with Environmental Protection Agency (EPA) regulations as well as 10CFR20. Specific EPA regulations for radiation limits for decommissioning are now being developed. It is anticipated that the radiation dose limits from waste management operations will be similar to those presented in 40CFR190, and will include decommissioning.

The NRC is presently developing comprehensive waste management regulations that will include wastes from decommissioning.

Regulatory authority for decommissioned facilities in Agreement States (10CFR150)* is relinquished to the States. Since Section 274(b) of the Atomic Energy Act of 1954, as amended, requires Agreement State programs to be compatible with NRC regulations, the NRC will require that these programs reflect the NRC's lead in the area of decommissioning.

Requirements for packaging of radioactive material are defined by transportation regulations. Packaging of the decommissioning wastes will also be affected by their storage and/or ultimate disposal mode. Regulations have been established to prevent the loss or dispersal of radioactive materials during shipment and to assure the safety of the public and transportation workers. Some overlapping responsibilities exist for regulating the safe transport of radioactive materials. Primary responsibility lies with the Department of Transportation (DOT), Material Transportation Bureau, and secondary responsibility lies with the NRC.

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* Agreement States are those states which have developed sufficient capability to assume regulatory authority over radioisotopes, source materials, and special nuclear materials in quantities not sufficient to form a critical mass.

The DOT is responsible for promulgating and enforcing safety standards governing packaging and shipping containers and for the labeling, classification, and marking of all packages under 49CFR173. The DOT also implements safety standards for the mechanical condition of carrier equipment and qualifications of carrier personnel. The NRC develops performance standards for package designs, and reviews package designs for Type B, Fissile, and large quantity packages, under 10CFR71. The Federal Aviation Administration (FAA), the Interstate Commerce Commission (ICC), and the U.S. Coast Guard also exercise some regulatory authority over the shipment of radioactive materials.

The transportation or packaging for transport of radioactive materials is subject to issuance of appropriate licenses. The application must describe proposed controls and precautions to be used in loading, unloading, handling, and transport of radioactive materials and the procedures to be followed in the event of an accident or delay in shipment. Inspection and accountability procedures must also be described.

State governments exercise some control of these shipments. State Highway Departments regulate gross vehicle weights, vehicle dimensions, and other parameters for radioactive shipments. Currently, about half of the states have adopted the U.S. DOT Hazardous Materials Regulations to cover interstate shipments. Several states have adopted additional regulations concerning radioactive materials. The variation of regulations between adjacent states can often require special considerations for interstate shipments.

Because of the anticipated high radiation sources and contaminated work locations, occupational safety is of major importance during decommissioning. Radiation protection to workers is regulated by 10CFR20. Section 20.101 defines exposure limits. These limits have recently been changed to reflect the operating philosophy of As Low As is Reasonably Achievable (ALARA), described in Regulatory Guides 8.8 and 8.10. Although not specifically applicable to decommissioning activity, these guides definitely apply. Additional information on compliance with the ALARA concept can be found in SRP Section 12.1.

In order to release the facility and/or site for unrestricted use, the residual radioactive contamination must be at an acceptably low level. Guidance on permissible levels can be found in Regulatory Guide 1.86.

During decommissioning activities, normal industrial (nonradiation related) safety regulations governing occupational work conditions are provided by Title 29 Code of Federal Regulations, Parts 1900 to end (Occupational Safety and Health Administration (OSHA), Department of Labor).

APPENDIX B

REGULATORY GUIDE 1.86

TERMINATION OF OPERATING LICENSES

FOR NUCLEAR REACTORS

U.S. ATOMIC ENERGY COMMISSION

June 1974

REGULATORY GUIDE

DIRECTORATE OF REGULATORY STANDARDS

REGULATORY GUIDE 1.86

TERMINATION OF OPERATING LICENSES FOR NUCLEAR REACTORS

A. INTRODUCTION

Section 50.51, "Duration of license, renewal," of 10 CFR Part 50, "Licensing of Production and Utilization Facilities," requires that each license to operate a production and utilization facility be issued for a specified duration. Upon expiration of the specified period, the license may be either renewed or terminated by the Commission. Section 50.82, "Applications for termination of licenses," specifies the requirements that must be satisfied to terminate an operating license, including the requirement that the dismantlement of the facility and disposal of the component parts not be inimical to the common defense and security or to the health and safety of the public. This guide describes methods and procedures considered acceptable by the Regulatory staff for the termination of operating licenses for nuclear reactors. The Advisory Committee on Reactor Safeguards has been consulted concerning this guide and has concurred in the regulatory position.

B. DISCUSSION

When a licensee decides to terminate his nuclear reactor operating license, he may, as a first step in the process, request that his operating license be amended to restrict him to possess but not operate the facility. The advantage to the licensee of converting to such a possession-only license is reduced surveillance requirements in that periodic surveillance of equipment important to the safety of reactor operation is no longer required. Once this possession-only license is issued, reactor operation is not permitted. Other activities related to cessation of operations such as unloading fuel from the reactor and placing it in storage (either onsite of offsite) may be continued.

A licensee having a possession-only license must retain, with the Part 50 license, authorization for special nuclear material (10 CFR Part 70, "Special Nuclear Material"), byproduct material (10 CFR Part 30, "Rules of General Applicability to Licensing of Byproduct Material"), and source material (10 CFR Part 40, "Licensing of Source Material"), until the fuel, radioactive components, and sources are removed from the facility. Appropriate administrative controls and facility requirements are imposed by the Part 50 license and the technical specifications to assure that proper surveillance is performed and that the reactor facility is maintained in a safe condition and not operated.

A possession-only license permits various options and procedures for decommissioning, such as mothballing, entombment, or dismantling. The requirements imposed depend on the option selected.

Section 50.82 provides that the licensee may dismantle and dispose of the component parts of a nuclear reactor in accordance with existing regulations. For research reactors and critical facilities, this has usually meant the disassembly of a reactor and its shipment offsite, sometimes to another appropriately licensed organization for further use. The site from which a reactor has been removed must be decontaminated, as necessary, and inspected by the Commission to determine whether unrestricted access can be approved. In the case of nuclear power reactors, dismantling has usually been accomplished by shipping fuel offsite, making the reactor inoperable, and disposing of some of the radioactive components.

Radioactive components may be either shipped offsite for burial at an authorized burial ground or secured on the site. Those radioactive materials remaining on the site must be isolated from the public by physical barriers or other means to prevent public access to hazardous levels of radiation. Surveillance is necessary to assure the long term integrity of the barriers. The amount of surveillance required depends upon (1) the potential hazard to the health and safety of the public from radioactive material remaining on the site and (2) the integrity of the physical barriers. Before areas may be released for unrestricted use, they must have been decontaminated or the radioactivity must have decayed to less than prescribed limits (Table I).

The hazard associated with the retired facility is evaluated by considering the amount and type of remaining contamination, the degree of confinement of the remaining radioactive materials, the physical security provided by the confinement, the susceptibility to release of radiation as a result of natural phenomena, and the duration of required surveillance.

C. REGULATORY POSITION

1. APPLICATION FOR A LICENSE TO POSSESS BUT NOT OPERATE (POSSESSION-ONLY LICENSE)

A request to amend an operating license to a possession-only license should be made to the Director of Licensing, U.S. Atomic Energy Commission, Washington, D.C. 20545. The request should include the following information:

a. A description of the current status of the facility.

b. A description of measures that will be taken to prevent criticality or reactivity changes and to minimize releases of radioactivity from the facility.

c. Any proposed changes to the technical specifications that reflect the possession-only facility status and the necessary disassembly/retirement activities to be performed.

d. A safety analysis of both the activities to be accomplished and the proposed changes to the technical specifications.

e. An inventory of activated materials and their location in the facility.

2. ALTERNATIVES FOR REACTOR RETIREMENT

Four alternatives for retirement of nuclear reactor facilities are considered acceptable by the Regulatory staff. These are:

a. **Mothballing.** Mothballing of a nuclear reactor facility consists of putting the facility in a state of protective storage. In general, the facility may be left intact except that all fuel assemblies and the radioactive fluids and waste should be removed from the site. Adequate radiation monitoring, environmental surveillance, and appropriate security procedures should be established under a possession-only license to ensure that the health and safety of the public is not endangered.

b. **In-Place Entombment.** In-place entombment consists of sealing all the remaining highly radioactive or contaminated components (e.g., the pressure vessel and reactor internals) within a structure integral with the biological shield after having all fuel assemblies, radioactive fluids and wastes, and certain selected components shipped offsite. The structure should provide integrity over the period of time in which significant quantities (greater than Table I levels) of radioactivity remain with the material in the entombment. An appropriate and continuing surveillance program should be established under a possession-only license.

c. **Removal of Radioactive Components and Dismantling.** All fuel assemblies, radioactive fluids and waste, and other materials having activities above accepted unrestricted activity levels (Table I) should be removed from the site. The facility owner may then have unrestricted use of the site with no requirement for a license. If the facility owner so desires, the remainder of the reactor facility may be dismantled and all vestiges removed and disposed of.

d. **Conversion to a New Nuclear System or a Fossil Fuel System.** This alternative, which applies only to nuclear power plants, utilizes the existing turbine system with a new steam supply system. The original nuclear steam supply system should be separated from the electric generating system and disposed of in accordance with one of the previous three retirement alternatives.

3. SURVEILLANCE AND SECURITY FOR THE RETIREMENT ALTERNATIVES WHOSE FINAL STATUS REQUIRES A POSSESSION-ONLY LICENSE

A facility which has been licensed under a possession-only license may contain a significant amount of radioactivity in the form of activated and contaminated hardware and structural materials. Surveillance and commensurate security should be provided to assure that the public health and safety are not endangered.

a. Physical security to prevent inadvertent exposure of personnel should be provided by multiple locked barriers. The presence of these barriers should make it extremely difficult for an unauthorized person to gain access to areas where radiation or contamination levels exceed those specified in Regulatory Position C.4. To prevent inadvertent exposure, radiation areas above 5 mR/hr, such as near the activated primary system of a power plant, should be appropriately marked and should not be accessible except by cutting of welded closures or the disassembly and removal of substantial structures and/or shielding material. Means such as a remote-readout intrusion alarm system should be provided to indicate to designated personnel when a physical barrier is penetrated. Security personnel that provide access control to the facility may be used instead of the physical barriers and the intrusion alarm systems.

b. The physical barriers to unauthorized entrance into the facility, e.g., fences, buildings, welded doors, and access openings, should be inspected at least quarterly to assure that these barriers have not deteriorated and that locks and locking apparatus are intact.

c. A facility radiation survey should be performed at least quarterly to verify that no radioactive material is escaping or being transported through the containment barriers in the facility. Sampling should be done along the most probable path by which radioactive material such as that stored in the inner containment regions could be transported to the outer regions of the facility and ultimately to the environs.

d. An environmental radiation survey should be performed at least semiannually to verify that no signficant amounts of radiation have been released to the environment from the facility. Samples such as soil, vegetation, and water should be taken at locations for which statistical data has been established during reactor operations.

e. A site representative should be designated to be responsible for controlling authorized access into and movement within the facility.

f. Administrative procedures should be established for the notification and reporting of abnormal occurrences such as (1) the entrance of an unauthorized person or persons into the facility and (2) a significant change in the radiation or contamination levels in the facility or the offsite environment.

g. The following reports should be made:

(1) An annual report to the Director of Licensing, U.S. Atomic Energy Commission, Washington, D.C. 20545, describing the results of the environmental and facility radiation surveys, the status of the facility, and an evaluation of the performance of security and surveillance measures.

(2) An abnormal occurrence report to the Regulatory Operations Regional Office by telephone within 24 hours of discovery of an abnormal occurrence. The abnormal occurrence will also be reported in the annual report described in the preceding item.

h. Records or logs relative to the following items should be kept and retained until the license is terminated, after which they may be stored with other plant records:

(1) Environmental surveys,

(2) Facility radiation surveys,

(3) Inspections of the physical barriers, and

(4) Abnormal occurrences.

4. DECONTAMINATION FOR RELEASE FOR UNRESTRICTED USE

If it is desired to terminate a license and to eliminate any further surveillance requirements, the facility should be sufficiently decontaminated to prevent risk to the public health and safety. After the decontamination is satisfactorily accomplished and the site inspected by the Commission, the Commission may authorize the license to be terminated and the facility abandoned or released for unrestricted use. The licensee should perform the decontamination using the following guidelines:

a. The licensee should make a reasonable effort to eliminate residual contamination.

b. No covering should be applied to radioactive surfaces of equipment or structures by paint, plating, or other covering material until it is known that contamination levels (determined by a survey and documented) are below the limits specified in Table I. In addition, a reasonable effort should be made (and documented) to further minimize contamination prior to any such covering.

c. The radioactivity of the interior surfaces of pipes, drain lines, or ductwork should be determined by making measurements at all traps and other appropriate access points, provided contamination at these locations is likely to be representative of contamination on the interior of the pipes, drain lines, or ductwork. Surfaces of premises, equipment, or scrap which are likely to be contaminated but are of such size, construction, or location as to make the surface inaccessible for purposes of measurement should be assumed to be contaminated in excess of the permissable radiation limits.

d. Upon request, the Commission may authorize a licensee to relinquish possession or control of premises, equipment, or scrap having surfaces contaminated in excess of the limits specified. This may include, but is not limited to, special circumstances such as the transfer of premises to another licensed organization that will continue to work with radioactive materials. Requests for such authorization should provide:

(1) Detailed, specific information describing the premises, equipment, scrap, and radioactive contaminants and the nature, extent, and degree of residual surface contamination.

(2) A detailed health and safety analysis indicating that the residual amounts of materials on surface areas, together with other considerations such as the prospective use of the premises, equipment, or scrap, are unlikely to result in an unreasonable risk to the health and safety of the public.

e. Prior to release of the premises for unrestricted use, the licensee should make a comprehensive radiation survey establishing that contamination is within the limits specified in Table I. A survey report should be filed with the Director of Licensing, U.S. Atomic Energy Commission, Washington, D.C. 20545, with a copy to the Director of the Regulatory Operations Regional Office having jurisdiction. The report should be filed at least 30 days prior to the planned date of abandonment. The survey report should:

(1) Identify the premises;

(2) Show that reasonable effort has been made to reduce residual contamination to as low as practicable levels;

(3) Describe the scope of the survey and the general procedures followed; and

(4) State the finding of the survey in units specified in Table I.

After review of the report, the Commission may inspect the facilities to confirm the survey prior to granting approval for abandonment.

5. REACTOR RETIREMENT PROCEDURES

As indicated in Regulatory Position C.2, several alternatives are acceptable for reactor facility retirement. If minor disassembly or "mothballing" is planned, this could be done by the existing operating and maintenance procedures under the license in effect. Any planned actions involving an unreviewed safety question or a change in the technical specifications should be reviewed and approved in accordance with the requirements of 10 CFR §50.59.

If major structural changes to radioactive components of the facility are planned, such as removal of the pressure vessel or major components of the primary system, a dismantlement plan including the information required by §50.82 should be submitted to the Commission. A dismantlement plan should be submitted for all the alternatives of Regulatory Position C.2 except mothballing. However, minor disassembly activities may still be performed in the absence of such a plan, provided they are permitted by existing operating and maintenance procedures. A dismantlement plan should include the following:

a. A description of the ultimate status of the facility

b. A description of the dismantling activities and the precautions to be taken.

c. A safety analysis of the dismantling activities including any effluents which may be released.

d. A safety analysis of the facility in its ultimate status.

Upon satisfactory review and approval of the dismantling plan, a dismantling order is issued by the Commission in accordance with §50.82. When dismantling is completed and the Commission has been notified by letter, the appropriate Regulatory Operations Regional Office inspects the facility and verifies completion in accordance with the dismantlement plan. If residual radiation levels do not exceed the values in Table I, the Commission may terminate the license. If these levels are exceeded, the licensee retains the possession-only license under which the dismantling activities have been conducted or, as an alternative, may make application to the State (if an Agreement State) for a byproduct materials license.

TABLE I

ACCEPTABLE SURFACE CONTAMINATION LEVELS

NUCLIDE[a]	AVERAGE[b c]	MAXIMUM[b d]	REMOVABLE[b e]
U-nat, U-235, U-238, and associated decay products	5,000 dpm α/100 cm^2	15,000 dpm α/100 cm^2	1,000 dpm α/100 cm^2
Transuranics, Ra-226, Ra-228, Th-230, Th-228, Pa-231, Ac-227, I-125, I-129	100 dpm/100 cm^2	300 dpm/100 cm^2	20 dpm/100 cm^2
Th-nat, Th-232, Sr-90, Ra-223, Ra-224, U-232, I-126, I-131, I-133	1000 dpm/100 cm^2	3000 dpm/100 cm^2	200 dpm/100 cm^2
Beta-gamma emitters (nuclides with decay modes other than alpha emission or spontaneous fission) except Sr-90 and others noted above.	5000 dpm β-γ/100 cm^2	15,000 dpm β-γ/100 cm^2	1000 dpm β-γ/100 cm^2

[a]Where surface contamination by both alpha- and beta-gamma-emitting nuclides exists, the limits established for alpha- and beta-gamma-emitting nuclides should apply independently.

[b]As used in this table, dpm (disintegrations per minute) means the rate of emission by radioactive material as determined by correcting the counts per minute observed by an appropriate detector for background, efficiency, and geometric factors associated with the instrumentation.

[c]Measurements of average contaminant should not be averaged over more than 1 square meter. For objects of less surface area, the average should be derived for each such object.

[d]The maximum contamination level applies to an area of not more than 100 cm^2.

[e]The amount of removable radioactive material per 100 cm^2 of surface area should be determined by wiping that area with dry filter or soft absorbent paper, applying moderate pressure, and assessing the amount of radioactive material on the wipe with an appropriate instrument of known efficiency. When removable contamination on objects of less surface area is determined, the pertinent levels should be reduced proportionally and the entire surface should be wiped.

APPENDIX C
LIMERICK STATION COST ON A PER UNIT BASIS

Limerick Station, Unit 1 is scheduled to begin operation 5 years prior to Limerick Station, Unit 2. In order to facilitate the inclusion of decommissioning cost attributable to Unit 1 into the rate base, this appendix has separated the Limerick Station decommissioning cost into Unit 1, Unit 2, and common equipment cost.

Total Cost of Decommissioning Per Unit

The following table shows the total decommissioning cost for Limerick Station as developed on Page 2-2, separated into a per unit basis.

Limerick Station	Total Decommissioning Cost in March 1984 Million Dollars			
	Removal	Disposal	Salvage	Total
Unit 1	101.2	30.0	(3.1)	128.1
Unit 2	99.3	29.8	(2.7)	126.4
Common	16.1	2.2	(0.2)	18.1
Station Total	216.6	62.0	(6.0)	272.6

Table C-1 shows a breakdown of the total decommissioning cost of each unit and common equipment in accordance with Federal Energy Regulatory Commission (FERC) Accounts.

Nuclear-Related Cost of Decommissioning

In accordance with the definition of nuclear-related cost presented on Page 2-4, the following table shows Limerick Station nuclear-related cost on a per unit and common equipment basis.

Limerick Station	Total Decommissioning Cost in March 1984 Million Dollars			
	Removal	Disposal	Salvage	Total
Unit 1	75.2	29.3	(0.5)	104.0
Unit 2	75.9	29.2	(0.5)	103.6
Common	4.7	1.0	(0.1)	5.6
Station Total	154.8	59.5	(1.1)	213.2

TABLE C-1
Limerick Station
Summary of Total Decommissioning by Unit
Cost by FERC Account
March 1984
$1,000's

FERC Account		Total Cost		
Number	Title	Limerick Unit 1	Limerick Unit 2	Limerick Common
321	Nuclear Production - Structures and Improvements	$ 19,561	$ 19,555	$ 13,019
322	Nuclear Production - Reactor Equipment	41,625	41,622	601
323	Nuclear Production - Turbogenerator Units	10,744	10,741	413
324	Nuclear Production - Accessory Electric Equipment	6,119	4,725	0
352	Transmission Plant - Structures and Improvements	13	13	163
524	Nuclear Power - Miscellaneous Nuclear Power Expenses	3,675	3,653	266
920	Administration and General Expenses - Salaries	13,720	13,626	1,081
923	Administration and General Expenses - Outside Services	32,134	31,917	2,518
924	Administration and General Expenses - Property Ins.	543	540	33
	TOTAL	$128,134	$126,392	$ 18,094

Table C-2 shows a breakdown of nuclear-related cost of each unit in accordance with FERC accounts.

Total Decommissioning Cost Base by Activity

Table C-3 presents total decommissioning cost grouped by cost center activities which were described in Section 4.1.

Cost by FERC Account

Consistant with Section 4.2.2, Table C-4, C-5, and C-6 present total cost of Limerick Station decommissioning for each unit and the common equipment by FERC account classification.

Nuclear-Related Decommissioning Cost Base by Activity

Nuclear-related decommissioning cost by activity as discussed in Section 4.3.1 for Limerick Station are displayed in Table C-7.

Nuclear-Related Costs for FERC Account

Tables C-8, C-9, and C-10 present the nuclear-related decommissioning cost for Limerick Station for each unit and common equipment. See Section 4.3.2 for a discussion of nuclear-related costs.

Cost Components for Escalation

As discussed in Section 4.4.2, Tables C-11 and C-12 present Limerick Station total and nuclear-related cost by cost escalation category. These costs can be used with changes in the cost indices (Table 4-9) to evaluate escalated cost in future years.

TABLE C-2
Limerick Station
Summary of Nuclear-Related Decommissioning by Unit
Cost by FERC Account
March 1984
$1,000's

FERC Account		Total Cost		
Number	Title	Limerick Unit 1	Limerick Unit 2	Limerick Common
321	Nuclear Production - Structures and Improvements	$ 16,911	$ 16,911	$ 2,859
322	Nuclear Production - Reactor Equipment	36,679	36,676	601
323	Nuclear Production - Turbogenerator Units	8,863	8,863	0
324	Nuclear Production - Accessory Electric Equipment	783	517	0
352	Transmission Plant - Structures and Improvements	0	0	0
524	Nuclear Power - Miscellaneous Nuclear Power Expenses	3,155	3,142	172
920	Administration and General Expenses - Salaries	11,062	11,016	603
923	Administration and General Expenses - Outside Services	26,028	25,921	1,420
924	Administration and General Expenses - Property Ins.	512	510	28
	TOTAL	$103,992	$103,556	$ 5,683

TABLE C-3
Total Decommissioning Cost
Grouped by Major Cost Centers

Cost Center	Total Cost, Million $, March 1984 Limerick Station Unit 1	Unit 2	Common
Utility Planning and Control	13.7	13.6	1.0
General Contractor and Subcontractor	32.1	31.9	2.5
Mechanical/Electrical Demolition	33.7	31.9	0.8
Structural Demolition	17.5	17.5	11.5
Waste Disposal	29.9	29.9	2.2
Miscellaneous (consumables, insurance)	4.3	4.3	0.4
Salvageable Components and Materials	(3.1)	(2.7)	(0.3)
TOTAL	128.1	126.4	18.1

TABLE C-4
Decommissioning Cost Summary
Limerick Generating Station, Unit 1
(in thousands of March 1984 dollars)
Total

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 17,498	$ 2,566	$ (504)	$ 19,561
322	Reactor Equipment	18,892	23,163	(430)	41,625
323	Turbogenerator	6,820	3,982	(58)	10,744
324	Accessory Electrical	7,929	264	(2,073)	6,119
352	Transmission Plant	57	0	(44)	13
524	Miscellaneous Nuclear Expense	3,675	0	0	3,675
920	Utility A&G	13,720	0	0	13,720
923	Outside Services	32,134	0	0	32,134
924	Insurance	543	0	0	543
	TOTAL	$101,268	$29,975	$(3,109)	$128,134

TABLE C-5
Decommissioning Cost Summary
Limerick Generating Station, Unit 2
(in thousands of March 1984 dollars)
Total

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 17,494	$ 2,565	$ (504)	$ 19,555
322	Reactor Equipment	18,891	23,161	(430)	41,622
323	Turbogenerator	6,818	3,981	(58)	10,741
324	Accessory Electrical	6,204	174	(1,653)	4,725
352	Transmission Plant	57	0	(44)	13
524	Miscellaneous Nuclear Expense	3,653	0	0	3,653
920	Utility A&G	13,626	0	0	13,626
923	Outside Services	31,917	0	0	31,917
924	Insurance	540	0	0	540
	TOTAL	$ 99,200	$29,881	$(2,689)	$126,392

TABLE C-6
Decommissioning Cost Summary
Limerick Generating Station, Common
(in thousands of March 1984 dollars)
Total

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 11,472	$ 1,758	$ (211)	$ 13,019
322	Reactor Equipment	208	395	(2)	601
323	Turbogenerator	451	0	(38)	413
324	Accessory Electrical	0	0	0	0
352	Transmission Plant	128	36	(1)	163
524	Miscellaneous Nuclear Expense	266	0	0	266
920	Utility A&G	1,081	0	0	1,081
923	Outside Services	2,518	0	0	2,518
924	Insurance	33	0	0	33
	TOTAL	$ 16,157	$ 2,189	$ (252)	$ 18,094

TABLE C-7
Nuclear-Related Decommissioning Cost
Grouped by Major Cost Centers

Cost Center	Nuclear-Related Cost, Million $, March 1984 Limerick Station		
	Unit 1	Unit 2	Common
Utility Planning and Control	11.0	11.0	0.6
General Contractor and Subcontractor	26.0	25.9	1.4
Mechanical/Electrical Demolition	19.6	19.4	0.2
Structural Demolition	14.9	14.9	2.2
Waste Disposal	29.2	29.2	1.0
Miscellaneous (consumables, insurance)	3.8	3.7	0.3
Salvageable Components and Materials	(0.5)	(0.5)	(0.1)
TOTAL	104.0	103.6	5.6

TABLE C-8
Decommissioning Cost Summary
Limerick Generating Station, Unit 1
(in thousands of March 1984 dollars)
Nuclear-Related

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 14,900	$ 2,507	$ (496)	$ 16,911
322	Reactor Equipment	13,662	23,019	(3)	36,678
323	Turbogenerator	5,377	3,487	(1)	8,863
324	Accessory Electrical	556	227	0	783
352	Transmission Plant	0	0	0	0
524	Miscellaneous Nuclear Expense	3,155	0	0	3,155
920	Utility A&G	11,062	0	0	11,062
923	Outside Services	26,028	0	0	26,028
924	Insurance	512	0	0	512
	TOTAL	$ 75,252	$29,240	$ (500)	$103,992

TABLE C-9
Decommissioning Cost Summary
Limerick Generating Station, Unit 2
(in thousands of March 1984 dollars)
Nuclear-Related

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 14,900	2,507	$ (496)	$ 16,911
322	Reactor Equipment	13,661	23,018	(3)	36,676
323	Turbogenerator	5,377	3,487	(1)	8,863
324	Accessory Electrical	369	148	0	517
352	Transmission Plant	0	0	0	0
524	Miscellaneous Nuclear Expense	3,142	0	0	3,142
920	Utility A&G	11,016	0	0	11,016
923	Outside Services	25,921	0	0	25,921
924	Insurance	510	0	0	510
	TOTAL	$ 74,896	$29,160	$ (500)	$103,556

TABLE C-10
Decommissioning Cost Summary
Limerick Generating Station, Common
(in thousands of March 1984 dollars)
Nuclear-Related

FERC Account/Name		Removal Cost	Disposal Cost	Salvage Gain	Total Cost
321	Structures and Improvements	$ 2,240	$ 680	$ (61)	$ 2,859
322	Reactor Equipment	208	395	(2)	601
323	Turbogenerator	0	0	0	0
324	Accessory Electrical	0	0	0	0
352	Transmission Plant	0	0	0	0
524	Miscellaneous Nuclear Expense	172	0	0	172
920	Utility A&G	603	0	0	603
923	Outside Services	1,420	0	0	1,420
924	Insurance	28	0	0	28
	TOTAL	$ 4,671	$ 1,075	$ (63)	$ 5,683

TABLE C-11
Total Decommissioning Cost
by Cost Escalation Category
(thousands of March 1984 dollars)

Cost Category	Cost by Unit Limerick Station		
	Unit 1	Unit 2	Common
Craft Labor, Skilled	35,942	34,988	7,639
Craft Labor, Common	14,573	14,132	3,423
Professional/Technical Labor	35,854	35,627	2,673
Equipment	14,070	13,631	3,398
Low-Level Waste Burial	19,093	19,039	654
Salvage:			
Iron and Steel	(1,215)	(1,178)	(251)
Copper Scrap	(1,894)	(1,511)	(0)
Energy and Other	11,711	11,664	558
TOTAL	128,134	126,392	18,094

TABLE C-12
Nuclear-Related Cost
by Cost Escalation Category
(thousands of March 1984 dollars)

Cost Category	Cost by Unit Limerick Station		
	Unit 1	Unit 2	Common
Craft Labor, Skilled	24,196	24,074	1,631
Craft Labor, Common	10,214	10,162	688
Professional/Technical Labor	30,120	29,996	1,642
Equipment	9,711	9,661	667
Low-Level Waste Burial	19,093	19,039	654
Salvage:			
Iron and Steel	(500)	(500)	(63)
Copper Scrap	0	0	0
Energy and Other	11,158	11,124	464
TOTAL	103,992	103,556	5,683

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Public Utility Commission

PHILADELPHIA ELECTRIC COMPANY
(Electric Operations)

Exhibit to Accompany
the Direct Testimony

of

Joseph F. Brennan, President
Associated Utility Services, Inc.

DOCKETED
SEP 27 1985

Philadelphia Electric Company

Index to the Financial Supporting Schedules of Joseph F. Brennan

Philadelphia Electric Company
Cost of Capital and Fair Rate of Return
Estimated At June 30, 1986

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.7%	10.84%	5.50%
Preferred Stock	10.8	10.54	1.14
Common Equity	38.5	16.9-17.4	6.51-6.70
Overall Cost of Capital	100.0%		13.15%-13.34%

Indicated level of coverage related to the debt part of the rate base to be achieved if the Company actually experienced (after attrition) a 13.15% overall fair rate of return relative to an original cost rate base.

Before-income tax interest coverage (1)	3.8x
After-income tax interest coverage (13.15% ÷ 5.50%)	2.4x
Overall coverage of interest and preferred stock dividends (13.15% ÷ 6.64% (5.50% + 1.14%))	2.0x

Notes:

(1) Based upon the assumption that the Company actually achieved an overall rate of return relative to an original cost rate base of 13.15% and the Company experienced an assumed 49.6% effective income tax rate prospectively, the before-income tax overall rate of return would be 20.68% (13.15% - 5.50% = 7.65% ÷ 50.4% (100.0% - 49.6% = 50.4%) = 15.18% + 5.50%). Thus, the indicated before-income tax coverage of rate base related interest expense, based on these assumptions, would be 3.8x (20.68% ÷ 5.50%).

Philadelphia Electric Company
Cost of Capital and Fair Rate of Return
Actual at June 30, 1985

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	51.5%	10.74%	5.53%
Preferred Stock	11.0	10.42	1.15
Common Equity	37.5	16.9-17.4	6.34-6.53%
Overall Cost of Capital	100.0%		13.02%-13.21%

Indicated level of coverage related to the debt part of the rate base to be achieved if the Company actually experienced (after attrition) a 13.02% overall fair rate of return relative to an original cost rate base.

Before-income tax interest coverage (1)	3.7x
After-income tax interest coverage (13.02% ÷ 5.53%)	2.4x
Overall coverage of interest and preferred stock dividends (13.02% ÷ 6.68% (5.53% + 1.15%))	1.9x

Notes:

(1) Based upon the assumption that the Company actually achieved an overall rate of return relative to an original cost rate base of 13.02% after attrition and the Company experienced an assumed 49.6% effective income tax rate prospectively, the before-income tax overall rate of return would be 20.39% (13.02% - 5.53% = 7.49% ÷ 50.4% (100.0% - 49.6% = 50.4%) = 14.86% + 5.53%). Thus, the indicated before-income tax coverage of rate base related interest expense, based upon these assumptions, would be 3.7 times (20.39% ÷ 5.53%).

Philadelphia Electric Company
Summary of Basis for Cost Rate for Common Equity

		Philadelphia Electric Company	Barometer Group of Four Electric Companies With Bonds Rated Baa (1
I.	Traditional Discounted Cash Flow Employing Historic and Forecasted Growth Rates		
	(A) Dividend Yield (2)	15.0%	12.1%
	(B) Growth in Value (3)	1.7	2.9
	(C) DCF Cost Rate (sum of average yield and growth)	16.7%	15.0%
II.	Risk Spread Analysis		
	(A) Forecasted Bond Yield (4)	12.5%	12.5%
	(B) Risk Spread	4.5 (5)	4.0 (6)
	(C) Risk Spread Cost Rate	17.0%	16.5%
III.	Average of DCF (I) and Risk Spread Cost Rate (II) before recognition of any market pressure, selling and issuance expenses	16.9%	15.8%
IV.	Recommendation After Recognition of Issuance and Selling Expenses (16.9% x 1.03%) and (15.8% x 1.03%)	17.4%	16.3%

See page 2 for Notes

Philadelphia Electric Company
Summary of Cost of Capital and Fair Rate of Return

Notes:

(1) The dividend yield and growth rate for the barometer group is the arithmetic average of the achieved results for each individual company.

(2) The dividend yields, which includes an adjustment for one-half the next period dividend growth, are developed on Schedule 14, page 1.

(3) For the development and support of growth rates used in calculating growth in value, see Schedule 15, page 1.

(4) Forecasted A rated long-term debt yield for 1985 is 12.0% (see Schedule 6, page 3). The spread between A rated and Baa rated long-tem debt is more than 0.5% which can be derived from the information shown on page 1, Schedule 6 for the five years ended 1984. Thus, a forecasted Baa rated long-term debt yield for 1985 of 12.5% for both Philadelphia Electric Company and the Barometer Group of Baa Rated Electric Companies is indicated when A rated long-term debt is expected to yield 12.0%.

(5) On average, for the years 1983-1984, Philadelphia Electric Company's long-term debt cost rate was 13.7% with a corresponding risk spread of 3.7% (see Schedule 16, page 1). Generally, as interest rates fall, risk spreads widen. For this reason, I believe 4.5% is an appropriate risk spread at the 12.5% interest rate level (interest rates down 1.2% and risk spread up 0.8% as a minimum).

(6) On average for the years 1983-1984, the long-term debt cost rate for the Barometer Group of Four Electric Companies with bonds rated Baa was 13.6% with a corresponding risk spread of 2.7% (see Schedule 16, page 1). Generally, as interest rates fall, risk spreads widen. If the prospective interest rate level is 12.5%, or 1.1% lower than the 13.6%, the risk spread would be not less than 3.5%, which is 0.8% higher than the 2.7% risk spread. For the larger eighty-two group of electric companies, whose average bond rating is probably A, at the 13.1% average interest rate level for the years 1983-1984, the risk spread was 3.2%. Thus, if for companies whose bonds are A rated, the prospective long-term interest rate is 12% (Note 4, above) the spread would be at least 4.0% (interest rate down 1.1%, risk spread up 0.8%). Based on all of the foregoing, I believe a risk spread for the four barometer group companies should be 4.0%, particularly in light of the PECO risk spread of 4.5%.

Philadelphia Electric Company (Company Alone)
Capitalization and Capital Structure Ratios Based Upon Investor-Provided Capital
Actual at June 30, 1985 and Estimated at June 30, 1986

	June 30, 1985 (Actual)			June 30, 1986 (Estimated)		
		Ratios			Ratios	
	Amount Outstanding ($000's)	Excl. S-T Debt	Incl. S-T Debt	Amount Outstanding ($000's)	Excl. S-T Debt	Incl. S-T Debt
Long-Term Debt: (1)						
First Mortgage Bonds	$2,538,190			$2,738,190 (3)		
Debentures	320,800			320,800		
Pollution Control Notes	518,185			518,185		
Term Bank Loans	775,000			775,000		
Serial Notes	20,000			20,000		
Other Long-Term Debt	1,866			326 (4)		
Total Long-Term Debt	4,174,041	51.5%	51.5%	4,372,501	50.7%	50.4%
Preferred Stock	890,881	11.0	11.0	926,182 (5)	10.8	10.7
Common Equity:						
Common Stock	2,469,098			2,641,663 (6)		
Other Paid-in Capital	6,091			6,091		
Retained Earnings (2)	566,018			672,285 (7)		
Total Common Equity	3,041,207	37.5	37.5	3,320,039	38.5	38.3
Total Permanent Capital	8,106,129	100.0%	100.0	8,618,722	100.0%	99.4
Short-Term Debt	-0-		0.0	56,335 (8)		0.6
Total Capital Employed	$8,106,129		100.0%	$8,675,057		100.0%

Comment: The Company's construction expenditures for 1985 are expected to be $962.0 million.

If the investment in subsidiary companies at June 30, 1985 of $129.743 million were removed from common equity, the capital structure ratios would be as follows:

	1985 Excl. S-T Debt	1985 Incl. S-T Debt	1986 Excl. S-T Debt	1986 Incl. S-T Debt
Long-Term Debt	52.3%	52.3%	51.5%	51.2%
Preferred Stock	11.2	11.2	10.9	10.8
Common Equity	36.5	36.5	37.6	37.3
Total	100.0%	100.0	100.0%	99.3
Short-Term Debt		0.0		0.7
Total		100.0%		100.0%

See following page for Notes.

Philadelphia Electric Company (Company Alone)
Capitalization and Capital Structure Ratios Based Upon Investor Provided Capital
Actual at June 30, 1985 and Estimated at June 30, 1986

Notes:

(1) Includes current portion of long-term debt and excludes unamortized debt premium, discount or expense.

(2) Includes unappropriated undistributed subsidiary earnings.

(3) Reflects the proposed issuance of $100 million of First Mortgage Bonds in November 1985 and the proposed issuance of $100 million of First Mortgage Bonds in May 1986.

(4) Reflects the retirement of the Conrail Note on January 1, 1986 of $1,540 million.

(5) Reflects the proposed issuance of $50.0 million of preferred stock in May 1986 and sinking fund requirements, $3.330 million on the 8.75% Series, $3.0 million on the 7.325% Series, $1.469 million on the 9.52% Series, $4.4 million on the 10.0% Series, and $2.5 million on the 15.25% Series Cumulative Preferred Stock.

(6) Reflects the estimated proceeds of $118.925 million from participating Company's Dividend Reinvestment plan, $11.465 million from the Employee Stock Purchase Plan and $42.175 million from continuous offerings of common stock.

(7) Company provided estimate of retained earnings at June 30, 1986.

(8) Company provided estimate of short-term debt at June 30, 1986.

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt at June 30, 1985 (Actual)

	Amount Outstanding ($ 000's)	Percent to Total	Effective Interest Rate (1)	Weighted Interest Rate
First Mortgage Bonds:				
4 3/8% Series, due 1986	$ 50,000	1.75%	4.43%	0.08%
4 5/8% Series, due 1987	40,000	1.40	4.69	0.07
3 3/4% Series, due 1988	40,000	1.40	3.82	0.05
5 % Series, due 1989	50,000	1.75	5.00	0.09
6 1/2% Series, due 1993	60,000	2.10	6.57	0.14
4 1/2% Series, due 1994	50,000	1.75	4.50	0.08
9 % Series, due 1995	59,452	2.08	8.49 (2a)	0.18
8 1/4% Series, due 1996	80,000	2.80	8.31	0.23
6 1/8% Series, due 1997	75,000	2.62	6.16	0.16
7 1/2% Series, due 1998	100,000	3.50	7.51	0.26
7 1/2% Series, due 1999	100,000	3.50	7.54	0.26
7 3/4% Series, due 2000	60,800	2.12	7.43 (2b)	0.16
7 3/8% Series, due 2001	80,000	2.80	7.38	0.21
8 1/2% Series, due 2004	125,000	4.37	8.51	0.37
11 5/8% Series, due 2000	65,000	2.27	11.73	0.27
11 % Series, due 2000	55,938	1.95	10.72 (2c)	0.21
9 1/8% Series, due 2006	100,000	3.50	9.23	0.32
9 5/8% Series, due 2002	100,000	3.50	9.74	0.34
6 % Series, due 2007	23,500	0.82	6.21	0.05
8 5/8% Series, due 2007	75,000	2.62	8.72	0.23
8 5/8% Series, due 2003	75,000	2.62	8.70	0.23
9 1/8% Series, due 2008	100,000	3.50	9.13	0.32
12 1/2% Series, due 2005	100,000	3.50	12.64	0.44
13 3/4% Series, due 1992	125,000	4.37	13.90	0.61
15 1/4% Series, due 1996	52,500	1.84	15.40	0.28
15 % Series, due 1996	21,000	0.73	15.17	0.11
17 5/8% Series, due 2011	125,000	4.37	18.01	0.79
18 3/4% Series, due 2009	125,000	4.37	18.96	0.83
18 % Series, due 2012	100,000	3.50	18.39	0.65
15 3/8% Series, due 2010	100,000	3.50	15.53	0.54
13 3/8% Series, due 2013	125,000	4.37	13.67	0.60
13.05 % Series, due 1994	20,000	0.70	13.19	0.09
14 % Series, due 1994	80,000	2.80	14.10	0.40
Debentures:				
14 1/8% Series, due 1990	50,000	1.75	14.28	0.25
14 3/4% Series, due 2005	100,000	3.50	14.89	0.52
Sinking Fund Debentures:				
4.85 % Series, due 1986	20,800	0.73	3.38 (2d)	0.02
14 1/2% Series, due 2009	150,000	5.25	14.73	0.77
Total Bonds	$2,858,990	100.00%		11.21%
Pollution Control Notes:				
5.50 %, due 1997	$ 24,485	4.72%	5.02%(2e)	0.24%
13 %, due 2010	71,500	13.80	13.38	1.85
11 1/2%, due 2011	18,500	3.57	13.16	0.47
Floating Rate, 1982 Series A	60,000	11.58	5.87 (8a)	0.68
Floating Rate, 1982 Series B	40,000	7.72	5.68 (8b)	0.44
Floating Rate, 1983 Series A	50,000	9.65	5.69 (8c)	0.55
Floating Rate, 1984 Series A (York)	4,500	0.87	5.38 (8d)	0.05
Floating Rate, 1984 Series A (Salem)	4,200	0.81	5.38 (8d)	0.04
10 1/2%, Series, due 2015	245,000	47.28	10.79	5.10
Total Pollution Control Notes	$ 518,185	100.00%		9.42%
Term Bank Loans				
Citibank N.A.	$ 75,000	9.68%	9.50% (3)	0.92%
Chase Manhattan N.A.	75,000	9.68	10.00 (4)	0.97
Morgan Guaranty Trust Co.	25,000	3.22	9.98 (5)	0.32
Chemical Bank	50,000	6.45	9.98 (6)	0.64
Limerick Revolving Credit Line	550,000	70.97	9.75 (7)	6.92
Total Term Bank Loans	$ 775,000	100.00%		9.77%
Other Long-Term Debt:				
Conrail Note	$ 1,540	82.53%	0.00%	0.00%
Land Purchase Notes	326	17.47	8.97 (9)	1.57
Total Other Long-Term Debt	$ 1,866	100.00%		1.57%
Total Long-Term Debt:				
Bonds	$2,858,990	68.50%	11.21%	7.68%
Pollution Control Notes	518,185	12.41	9.42	1.17
Term Bank Loans	775,000	18.57	9.77	1.81
Serial Notes	20,000	0.48	17.06	0.08
Other Long-Term Debt	1,866	0.04	1.57	0.00
	$4,174,041	100.00%		10.74%

See following pages for Notes.

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt
at June 30, 1985 (Actual)

Notes:

(1) Effective interest rate for each Series as developed on pages 9 and 10.

(2) The effective interest rates for these series were adjusted to recognize previous years' gains on reacquired debt. These rates were computed by multiplying the amount outstanding by the unadjusted effective interest rate, subtracting the amortization during the twelve months ended June 30, 1985, of net gains from repurchase and dividing the resulting interest cost by the amount outstanding.

(a) \$59,452,000 x 8.87% = \$5,273,392 - \$226,383 = \$5,047,009 ÷ \$59,452,000 = 8.49%

(b) \$60,800,000 x 7.85% = \$4,772,800 - \$258,185 = \$4,514,615 ÷ \$60,800,000 = 7.43%

(c) \$55,938,000 x 11.15% = \$6,237,087 - \$239,102 = \$5,997,985 ÷ \$55,938,000 = 10.72%

(d) \$20,800,000 x 4.89% = \$1,017,120 - \$314,687 = \$702,433 ÷ \$20,800,000 = 3.38%

(e) \$24,485,000 x 5.65% = \$1,383,403 - \$154,125 = \$1,229,278 ÷ \$24,485,000 = 5.02%

(3) Effective interest rate is equal to the actual prime rate charged by Citibank at June 30, 1985, of 9.50%.

(4) Effective interest rate calculated as the prime rate charged by Chase Manhattan Bank plus 1/2 of 1%. At June 30, 1985, the effective cost rate is 10.00% based upon an actual prime rate of 9.50% (9.50% + 0.50% = 10.00%).

(5) Effective interest rate calculated as the prime rate charged by Morgan Guaranty Trust Company times 105%. At June 30, 1985, the effective cost rate is 9.98% based upon an actual prime rate of 9.50% (9.50% x 105% = 9.98%).

(6) Effective interest rate calculated as the prime rate charged by Chemical Bank times 105% (during the period 5-28-84 through 5-28-87). At June 30, 1985, the effective cost rate is 9.98% based upon an actual prime rate of 9.50% (9.50% x 105% = 9.98%).

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt
at June 30, 1985 (Actual)

Notes (continued):

(7) The effective interest rate on the Limerick Revolving Credit Line is calculated as the prime rate charged by Citibank plus 1/4 of 1%. At June 30, 1985, the effective cost rate is 9.75% based upon a prime rate of 9.50% (9.50% + 0.25% = 9.75%).

(8) The Floating Rate Monthly Demand Pollution Control Revenue Bonds bear an interest rates payable monthly which will vary monthly based upon separate Interest Indexes for each series computed as a 30-day average yield at par of short-term securities which are exempt from federal income taxation.

(a) The effective interest rate for 1982 Series A of 5.87% is computed as the actual Interest Index for the period 7-1-85 to 7-31-85 of 4.50% ÷ net proceeds ratio (based upon $924,000 discount and issuance expenses) x principal amount outstanding added to 1.25% Letter of Credit Commission and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding (4.50% ÷ 98.46% = 4.57% x $60,000,000 = $2,742,000) + (1.25% x $62,196,986 = $777,462) = $3,519,462 ÷ $60,000,000 = 5.87%).

(b) The effective interest rate for 1982 Series B of 5.68% is computed as the actual Interest Index for the period 7-1-85 to 7-31-85 of 4.70% ÷ net proceeds ratio (based upon $616,000 discount and issuance expenses) x principal amount outstanding added to 0.875% Letter of Credit Commission, and Fee and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding (4.70% ÷ 98.46% = 4.77% x $40,000,000 = $1,908,000) + (0.875% x $41,464,657 = $362,816) = $2,270,816 ÷ $40,000,000 = 5.68%).

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt
at June 30, 1985 (Actual)

Notes (continued):

(8)

(c) The effective interest rate for 1983 Series A of 5.69% is computed as the actual Interest Index for the period 7-1-85 to 7-31-85 of 4.70% ÷ net proceeds ratio (based upon $802,000 discount and issuance expenses) x principal amount outstanding added to 0.875% Letter of Credit Commission, and Fee and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding (4.70% ÷ 98.40% = 4.78% x $50,000,000 = $2,390,000) + (0.875 x $51,830,022 = $453,513) = $2,843,513 ÷ $50,000,000 = 5.69%.

(d) The effective interest rate for 1984 Series A (York and Salem Counties) of 5.38% is computed as the actual Interest Index for the period 7-1-85 to 7-31-85 of 4.60% ÷ net proceeds ratio (based upon $250,511 discount and issuance expenses) x principal amount outstanding added to 0.625% Letter of Credit Commission, and Fee and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding (4.60% ÷ 97.12% = 4.74% x $8,700,000 = $412,380) + (0.625% x $9,018,563 = $56,366) = $468,746 ÷ $8,700,000 = 5.38%.

(9) Composite of Company provided interest rates on other long-term debt.

Source of Information: Company provided data

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt
at June 30, 1986 (Estimated)

	Amount Outstanding ($ 000's)	Percent to Total	Effective Interest Rate (1)	Weighted Interest Rate
First Mortgage Bonds:				
4 3/8% Series, due 1986	$ 50,000	1.63%	4.43%	0.07%
4 5/8% Series, due 1987	40,000	1.31	4.69	0.06
3 3/4% Series, due 1988	40,000	1.31	3.82	0.05
5 % Series, due 1989	50,000	1.63	5.00	0.08
6 1/2% Series, due 1993	60,000	1.96	6.57	0.13
4 1/2% Series, due 1994	50,000	1.63	4.50	0.07
9 % Series, due 1995	59,452	1.94	8.49 (2a)	0.16
8 1/4% Series, due 1996	80,000	2.62	8.31	0.22
6 1/8% Series, due 1997	75,000	2.45	6.16	0.15
7 1/2% Series, due 1998	100,000	3.27	7.51	0.25
7 1/2% Series, due 1999	100,000	3.27	7.54	0.25
7 3/4% Series, due 2000	60,800	1.99	7.43 (2b)	0.15
7 3/8% Series, due 2001	80,000	2.62	7.38	0.19
8 1/2% Series, due 2004	125,000	4.09	8.51	0.35
11 5/8% Series, due 2000	65,000	2.12	11.73	0.25
11 % Series, due 2000	55,938	1.82	10.72 (2c)	0.20
9 1/8% Series, due 2006	100,000	3.27	9.23	0.30
9 5/8% Series, due 2002	100,000	3.27	9.74	0.32
6 % Series, due 2007	23,500	0.77	6.21	0.05
8 5/8% Series, due 2007	75,000	2.45	8.72	0.21
8 5/8% Series, due 2003	75,000	2.45	8.70	0.21
9 1/8% Series, due 2008	100,000	3.27	9.13	0.30
12 1/2% Series, due 2005	100,000	3.27	12.64	0.41
13 3/4% Series, due 1992	125,000	4.09	13.90	0.57
15 1/4% Series, due 1996	52,500	1.72	15.40	0.26
15 % Series, due 1996	21,000	0.68	15.17	0.10
17 5/8% Series, due 2011	125,000	4.09	18.01	0.74
18 3/4% Series, due 2009	125,000	4.09	18.96	0.78
18 % Series, due 2012	100,000	3.27	18.39	0.60
15 3/8% Series, due 2010	100,000	3.27	15.53	0.51
13 3/8% Series, due 2013	125,000	4.09	13.67	0.56
13.05 % Series, due 1994	20,000	0.65	13.19	0.09
14 % Series, due 1994	80,000	2.62	14.10	0.37
12 1/2% Proposed Series	100,000	3.27	12.63	0.41
12 1/2% Proposed Series	100,000	3.27	12.63	0.41
Debentures:				
14 1/8% Series, due 1990	50,000	1.63	14.28	0.23
14 3/4% Series, due 2005	100,000	3.27	14.89	0.49
Sinking Fund Debentures:				
4.85 % Series, due 1986	20,800	0.68	3.38 (2d)	0.02
14 1/2% Series, due 2009	150,000	4.90	14.73	0.72
Total Bonds	$3,058,990	100.00%		11.29%
Pollution Control Notes:				
5.50 %, due 1997	$ 24,485	4.72%	5.02%(2e)	0.25%
13 %, due 2010	71,500	13.80	13.38	1.85
11 1/2%, due 2011	18,500	3.57	13.16	0.47
Floating Rate, 1982 Series A	60,000	11.58	6.26 (8a)	0.72
Floating Rate, 1982 Series B	40,000	7.72	5.87 (8b)	0.45
Floating Rate, 1983 Series A	50,000	9.65	5.87 (8c)	0.57
Floating Rate, 1984 Series A (York)	4,500	0.87	5.67 (8d)	0.05
Floating Rate, 1984 Series A (Salem)	4,200	0.81	5.67 (8d)	0.05
10 1/2% Series due 2015	245,000	47.28	10.79	5.10
Total Pollution Control Notes	$ 518,185	100.00%		9.51%
Term Bank Loans				
Citibank N.A.	$ 75,000	9.68%	9.50% (3)	0.92%
Chase Manhattan N.A.	75,000	9.68	10.00 (4)	0.97
Morgan Guaranty Trust Co.	25,000	3.22	9.98 (5)	0.32
Chemical Bank	50,000	6.45	9.98 (6)	0.64
Limerick Revolving Credit Line	550,000	70.97	9.75 (7)	6.92
Total Term Bank Loans	$ 775,000	100.00%		9.77%
Total Long-Term Debt:				
Bonds	$3,058,990	69.96%	11.29%	7.90%
Pollution Control Notes	518,185	11.85	9.51	1.13
Term Bank Loans	775,000	17.72	9.77	1.73
Serial Notes	20,000	0.46	17.06	0.08
Other Long-Term Debt	326	0.01	8.97 (9)	0.00
	$4,372,501	100.00%		10.84%

See following pages for Notes.

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt at June 30, 1986 (Estimated)

Notes:

(1) Effective interest rate for each Series as developed on pages 9 and 10.

(2) The effective interest rates for these series were adjusted to recognize previous years' gains on reacquired debt. These rates were computed by multiplying the amount outstanding by the unadjusted effective interest rate, subtracting the amortization during the twelve months ended June 30, 1985, of net gains from repurchase and dividing the resulting interest cost by the amount outstanding.

(a) $59,452,000 x 8.87% = $5,273,392 - $226,383 = $5,047,009 ÷ $59,452,000 = 8.49%

(b) $60,800,000 x 7.85% = $4,772,800 - $258,185 = $4,514,615 ÷ $60,800,000 = 7.43%

(c) $55,938,000 x 11.15% = $6,237,087 - $239,102 = $5,997,985 ÷ $55,938,000 = 10.72%

(d) $20,800,000 x 4.89% = $1,017,120 - $314,687 = $702,433 ÷ $20,800,000 = 3.38%

(e) $24,485,000 x 5.65% = $1,383,403 - $154,125 = $1,299,278 ÷ $24,485,000 = 5.02%

(3) Effective interest rate is equal to the estimated prime rate charged by Citibank at June 30, 1986, of 9.50%.

(4) Effective interest rate calculated as the prime rate charged by Chase Manhattan Bank plus 1/2 of 1%. Estimated at June 30, 1986, the effective cost rate is 10.00% based upon an estimated prime rate of 9.50% (9.50% + 0.50% = 10.00%).

(5) Effective interest rate calculated as the prime rate charged by Morgan Guaranty Trust Company times 105%. Estimated at June 30, 1986, the effective cost rate is 9.98% based upon an estimated prime rate of 9.50% (9.50% x 105% = 9.98%).

(6) Effective interest rate calculated as the prime rate charged by Chemical Bank times 105% (during the period 5-28-84 through 5-28-87). Estimated at June 30, 1986, the effective cost rate is 9.98% based upon an estimated prime rate of 9.50% (9.50% x 105% = 9.98%).

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt
at June 30, 1986 (Estimated)

Notes (continued):

(7) The effective interest rate on the Limerick Revolving Credit Line is calculated as the estimated prime rate charged by Citibank plus 1/4 of 1%. Estimated at June 30, 1986, the effective cost rate is 9.75% based upon an estimated prime rate of 9.50% (9.50% + 0.25% = 9.75%).

(8) Company provided weighted interest rate.

The Floating Rate Monthly Demand Pollution Control Revenue Bonds bear an interest rates payable monthly which will vary monthly based upon separate Interest Indexes for each series computed as a 30-day average of yields at par of short-term securities which are exempt from federal income taxation. In the event the Interest Index for any month cannot be computed, the interest rate for the Bonds during that month will be equal to 60% of the yield applicable to the 13-week United States Treasury bills sold at the most recent Treasury auction held within 30 days prior to the date on which the calculation is to be made. This alternative method is employed to estimate the monthly interest rates for June 1986. The settled yield on Treasury Bill Future Contracts with a settlement date of June 1986 of 8.13% will be employed for this purpose.

(a) The estimated effective interest rate for 1982 Series A of 6.26% is computed as 60% of the August 9, 1985, settled yield on Treasury Bill Future Contracts with a settlement date of June 1986 ÷ net proceeds ratio (based upon $924,000 discount and issuance expenses) x principal amount outstanding added to 1.25% Letter of Credit Commission and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding ((60% x 8.13% = 4.88% ÷ 98.46% = 4.96% x $60,000,000 = $2,976,000) + (1.25% x $62,196,986 = $777,462) = $3,753,462 ÷ $60,000,000 = 6.26%).

(b) The estimated effective interest rate for 1982 Series B of 5.87% is computed as 60% of the August 9, 1985, settled yield on Treasury Bill Future Contracts with a settlement date of June 1986 ÷ net proceeds ratio (based upon $616,000 discount and issuance expenses) x principal amount outstanding added to 0.875% Letter of Credit Commission, and Fee and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding ((60% x 8.13% = 4.88% ÷ 98.46% = 4.96% x $40,000,000 = $1,984,000) + (0.875% x $41,464,657 = $362,816) = $2,346,816 ÷ $40,000,000 = 5.87%).

Philadelphia Electric Company (Company Only)
Composite Interest Rate of Long-Term Debt
at June 30, 1986 (Estimated)

Notes (continued):

(8)

(c) The estimated effective interest rate for 1983 Series A of 5.87% is computed as 60% of the August 9, 1985, settled yield on Treasury Bill Future Contracts with a settlement date of June 1986 ÷ net proceeds ratio (based upon $802,000 discount and issuance expenses) x principal amount outstanding added to 0.875% Letter of Credit Commission, and Fee and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding ((60% x 8.13% = 4.88% ÷ 98.40% = 4.96% x $50,000,000 = $2,480,000) + (0.875% x $51,830,822 = $453,520) = $2,933,520 ÷ $50,000,000 = 5.87%).

(d) The estimated effective interest rate for 1984 Series A (York and Salem Counties) of 5.67% is computed as 60% of the August 9, 1985, settled yield on Treasury Bill Future contracts with a settlement date of June 1986 ÷ net proceeds ratio (based upon $250,511 discount and issuance expenses) x principal amount outstanding added to 0.625% Letter of Credit Commission, and Administrative Costs x the aggregate amount of the Letter of Credit ÷ the principal amount outstanding ((60% x 8.13% = 4.88% ÷ 97.12% = 5.02% x $8,700,000 = $437,150) + (0.625% x $9,018,563 = $56,366) = $493,516 ÷ $8,700,000 = 5.67%).

(9) Composite of company-provided interest rates on other long-term debt.

Source of Information: Company provided data

Philadelphia Electric Company

Calculation of the Effective Interest Rate of First and Refunding Mortgage Bonds

Series	Date of Issue	Date of Maturity	Average Term in Years (1)	Original Amount Issued	Total Expenses, Premium or (Discount)	Net Proceeds on Principal Amount Issued	Net Proceeds Ratio	Effective Interest Rate (2)
First Mortgage Bonds:								
4 3/8% Series, due 1986	12- 1-58	12- 1-86	28	$ 50,000	$ (463,097)	$ 49,536,903	99.07%	4.43%
4 5/8% Series, due 1987	9- 1-57	9- 1-87	30	40,000	(415,004)	39,584,996	98.96	4.69
3 3/4% Series, due 1988	5- 1-58	5- 1-88	30	40,000	(482,646)	39,517,354	98.79	3.82
5 % Series, due 1989	10- 1-59	10 -1-89	30	50,000	18,437	50,018,437	100.04	5.00
6 1/2% Series, due 1993	3- 1-68	3- 1-93	25	60,000	(480,686)	59,519,314	99.20	6.57
4 1/2% Series, due 1994	5- 1-64	5- 1-94	30	50,000	25,238	50,025,238	100.05	4.50
9 % Series, due 1995	2- 1-70	2- 1-95	20.8	80,000	960,024	80,960,024	101.20	8.87
8 1/4% Series, due 1996	8- 1-71	8- 1-96	25	80,000	(495,210)	79,504,790	99.38	8.31
6 1/8% Series, due 1997	10- 1-67	10- 1-97	30	75,000	(384,944)	74,615,056	99.49	6.16
7 1/2% Series, due 1998	6-15-72	6-15-98	26	100,000	(156,059)	99,843,941	99.84	7.51
7 1/2% Series, due 1999	1-22-73	1-22-99	26	100,000	(499,981)	99,500,019	99.50	7.54
7 3/4% Series, due 2000	12-15-70	12-15-00	23.5	80,000	(879,028)	79,120,972	98.90	7.85
7 3/8% Series, due 2001	12-15-71	12-15-01	30	80,000	(83,239)	79,916,761	99.90	7.38
8 1/2% Series, due 2004	1-16-74	1-16-04	30	125,000	(111,634)	124,888,366	99.91	8.51
11 5/8% Series, due 2000	4-15-75	4-15-00	25	65,000	(526,075)	64,473,925	99.19	11.73
11 % Series, due 2000	11- 1-75	8- 6-00	15.5	80,000	(876,944)	79,123,056	98.90	11.15
9 1/8% Series, due 2006	3- 1-76	3- 1-06	30	100,000	(1,034,220)	98,965,780	98.97	9.23
9 5/8% Series, due 2002	8- 1-76	8- 1-02	26	100,000	(1,043,108)	98,956,892	98.96	9.74
6 % Series, due 2007	2- 1-77	2- 1-07	28	23,500	(639,048)	22,860,952	97.28	6.21
8 5/8% Series, due 2007	3-15-77	3-15-07	30	75,000	(788,291)	74,211,709	98.95	8.72
8 5/8% Series, due 2003	7-15-77	7-15-03	26	75,000	(570,154)	74,429,846	99.24	8.70
9 1/8% Series, due 2008	3-15-78	3-15-08	30	100,000	(41,614)	99,958,386	99.96	9.13
12 1/2% Series, due 2005	10-15-79	10-15-05	26	100,000	(1,057,750)	98,942,250	98.94	12.64
13 3/4% Series, due 1992	10-15-80	10-15-92	12	125,000	(1,072,443)	123,927,557	99.14	13.90
15 1/4% Series, due 1996	4-28-81	4-28-96	10.5	52,500	(410,978)	52,089,022	99.22	15.40
15 % Series, due 1996	4-28-81	4-28-96	10.5	21,000	(183,965)	20,816,035	99.12	15.17
17 5/8% Series, due 2011	7- 1-81	7- 1-11	30	125,000	(2,634,392)	122,365,608	97.89	18.01
18 3/4% Series, due 2009	9-15-81	9-15-09	30	125,000	(1,377,265)	123,622,735	98.90	18.96
18 % Series, due 2012	4- 1-82	4- 1-12	30	100,000	(2,091,008)	97,908,992	97.91	18.39
15 3/8% Series, due 2010	10 -1-82	10- 1-10	28	100,000	(1,005,722)	98,994,278	99.01	15.53
13 3/8% Series, due 2013	6-15-83	6-15-13	30	125,000	(2,649,000)	122,351,000	97.88	13.67
13.05 % Series, due 1994	11-26-84	11-26-94	10	20,000	(148,322)	19,851,678	99.26	13.19
14 % Series, due 1988-94	12 -1-84	12 -1-94	6.9	80,000	(369,080)	79,630,920	99.54	14.10
12 1/2% Proposed Series (3)	11- 1-85	11- 1-15	30	100,000	-	-	99.00	12.63
12 1/2% Proposed Series (3)	5- 1-86	5- 1-16	30	100,000	-	-	99.00	12.63

See page 10 for notes.

Philadelphia Electric Company

Calculation of the Effective Interest Rate of Debentures, Sinking Fund Debentures and Pollution Control Notes

Series	Date of Issue	Date of Maturity	Average Term in Years (1)	Original Amount Issued (000's)	Total Expenses, Premium or (Discount)	Net Proceeds on Principal Amount Issued	Net Proceeds Ratio	Effective Interest Rate (2)
Debentures:								
14 1/8% Series, due 1990	4-15-80	4-15-90	10	$ 50,000	$ (411,981)	$ 49,588,019	99.18%	14.28%
14 3/4% Series, due 2005	4-15-80	4-15-05	25	100,000	(894,198)	99,105,802	99.11	14.89
Sinking Fund Debentures:								
4.85 % Series, due 1986	10- 1-61	10- 1-86	18	40,000	(188,855)	39,811,145	99.53	4.89
14 1/2% Series, due 2009	2-15-84	2-15-09	18.	150,000	(2,185,784)	147,814,216	98.54	14.73
Pollution Control Notes:								
5.50 % due 1997	11-22-72	11-22-97	18.8	30,000	(580,818)	32,419,182	98.24	5.65
13 % Series B, due 2010	6- 1-81	6- 1-10	28.5	71,500	(1,982,849)	69,517,151	97.23	13.38
11 1/2% Series B, due 2011	6- 1-81	6- 1-11	30	18,500	(2,285,721)	16,214,279	87.64	13.16
10 1/2% Series, due 2015	5-15-85	5-15-15	30	245,000	(6,360,000)	238,640,000	97.40	10.79
Serial Notes:								
17 % Series, due 1986-87	6-29-82	6-29-87	4.5	20,000	(35,961)	19,964,039	99.82	17.06

Notes: (1) Determined by taking into account the effect of annual sinking fund requirements which are met by the retirement of bonds which reduce the average term of each series for those issues which have sinking fund requirements.

(2) Effective cost rate is the cost rate to maturity using as inputs the average term of each series, the stated interest rate and net proceeds ratio.

(3) For the two proposed new series of first mortgage bonds planned to be issued in November 1985 and May 1986, respectively, the stated coupon rate is estimated to be 12-1/2%, the average term of issue is assumed to be 30 years, and the net proceeds ratio is estimated to be 99.00%.

Source of Information: Data provided by the Company upon request
Annual Report to the Federal Energy Regulation Commission (Form 1)

Philadelphia Electric Company
Composite Cost Rate of Preferred Stock
Actual at June 30, 1985

	Amount Outstanding ($000's)	Percent to Total	Effective Cost Rate (1)	Composite Cost Rate
Cumulative Preferred Stock:				
14.15 % Series	$ 50,000	5.61%	14.84%	0.83%
14.625% Series	50,000	5.61	14.89	0.83
13.35 % Series	75,000	8.42	13.98	1.18
12.8 % Series	75,000	8.42	13.42	1.13
17.125% Series	30,000	3.37	17.62	0.59
15.25 % Series	50,000	5.61	15.72	0.88
10.00 % Series	22,000	2.50	10.07	0.25
8.75 % Series	43,340	4.86	8.81	0.43
9.52 % Series	39,469	4.43	9.83	0.44
9.50 % Series	75,000	8.42	9.64	0.81
8.75 % Series	65,000	7.29	8.89	0.65
7.85 % Series	50,000	5.61	7.98	0.45
7.80 % Series	75,000	8.42	7.92	0.67
7.75 % Series	20,000	2.24	7.91	0.18
7.325% Series	54,000	6.06	7.40	0.45
7.00 % Series	29,600	3.32	7.21	0.24
4.68 % Series	15,000	1.68	4.76	0.08
4.40 % Series	27,472	3.08	4.33	0.13
4.30 % Series	15,000	1.68	4.44	0.07
3.80 % Series	30,000	3.37	3.80	0.13
Total Cumulative Preferred Stock Outstanding	$890,881	100.0%		10.42%

Note: (1) Effective cost rate for each issue as taken from calculations on page 3.

Source of Information: Company provided data

Philadelphia Electric Company
Composite Cost Rate of Preferred Stock
Estimated at June 30, 1986

	Amount Outstanding ($000's)	Percent to Total	Effective Cost Rate (1)	Composite Cost Rate
Cumulative Preferred Stock:				
12.50 % Proposed Series	$50,000	5.40%	12.63%	0.68%
14.15 % Series	50,000	5.40	14.84	0.80
14.625% Series	50,000	5.40	14.89	0.80
13.35 % Series	75,000	8.10	13.98	1.13
12.80 % Series	75,000	8.10	13.42	1.09
17.125% Series	30,000	3.24	17.62	0.57
15.25 % Series	47,500	5.13	15.72	0.81
10.00 % Series	17,600	1.90	10.07	0.19
8.75 % Series	40,010	4.32	8.81	0.38
9.52 % Series	38,000	4.10	9.83	0.40
9.50 % Series	75,000	8.10	9.64	0.78
8.75 % Series	65,000	7.01	8.89	0.63
7.85 % Series	50,000	5.40	7.98	0.43
7.80 % Series	75,000	8.10	7.92	0.64
7.75 % Series	20,000	2.16	7.91	0.17
7.325% Series	51,000	5.50	7.40	0.41
7.00 % Series	29,600	3.20	7.21	0.23
4.68% Series	15,000	1.62	4.76	0.08
4.40 % Series	27,472	2.96	4.33	0.13
4.30 % Series	15,000	1.62	4.44	0.07
3.80 % Series	30,000	3.24	3.80	0.12
Total Cumulative Preferred Stock Outstanding	$926,182	100.00%		10.54%

Note: (1) Effective cost rate for each issue as taken from calculations on page 3.

Source of Information: Company provided data.

Philadelphia Electric Company
Calculation of Preferred Stock Effective Cost Rate

	Series	Date of Issue	Original Amount Issued	Premium or (Discount) At Issuance Net of Expenses	Net Proceeds on Principal Amount Issued	Net Proceeds Ratio	Effective Cost Rate
Cumulative Preferred Stock:							
	12.50%(8)	5- 1-86	$50,000,000	-	-	99.00%	12.63%
	14.15	12-11-84	50,000,000	$(2,323,000)	$47,677,000	95.35	14.84
	14.625	3-28-84	50,000,000	(888,000)	49,112,000	98.22	14.89
	13.35	11-15-83	75,000,000	(3,384,000)	71,616,000	95.49	13.98
	12.80	2- 9-83	75,000,000	(3,443,000)	71,557,000	95.41	13.42
	17.125	2-18-82	30,000,000	(525,484)	29,474,516	97.17 (1)	17.62
	15.25	3-18-80	50,000,000	(925,000)	49,075,000	97.02 (2)	15.72
	10.00	3-18-80	22,000,000	(131,000)	21,869,000	99.26 (3)	10.07
	8.75	5- 1-78	50,000,000	(225,000)	49,775,000	99.31 (4)	8.81
	9.52	5- 4-76	50,000,000	(920,369)	49,079,631	96.86 (5)	9.83
	9.50	4-18-74	75,000,000	(1,093,088)	73,906,912	98.54	9.64
	8.75	7-22-70	65,000,000	(1,040,129)	63,959,871	98.40	8.89
	7.85	3-10-71	50,000,000	(801,475)	49,198,525	98.40	7.98
	7.80	4-20-72	75,000,000	(1,105,544)	73,894,456	98.53	7.92
	7.75	11-16-71	20,000,000	(399,174)	19,600,826	98.00	7.91
	7.325	4- 2-73	75,000,000	(441,533)	74,558,467	99.02 (6)	7.40
	7.00	2- 4-69	40,000,000	(646,306)	39,353,694	97.04 (7)	7.21
	4.68	5-14-53	15,000,000	(243,769)	14,756,231	98.37	4.76
	4.40	2- 1-42	27,472,000	448,876	27,920,876	101.63	4.33
	4.30	2- 5-48	15,000,000	(468,342)	14,531,658	96.88	4.44
	3.80	12- 4-46	30,000,000	(30,218)	29,969,782	99.90	3.80

See Notes on following page.

Philadelphia Electric Company
Calculation of Preferred Stock Effective Cost Rate

Notes:

(1) Net proceeds ratio calculation based upon the average principal amount outstanding in recognition of annual sinking fund requirements to arrive at an effective cost rate. Average principal amount outstanding of $18,600,000 less $525,484 (discount and issuance expenses) equals $18,074,516 (net proceeds on average amount outstanding) $18,074,516 ÷ 18,600,000 = 97.17%.

(2) Net proceeds ratio calculation based upon the average principal amount outstanding. Average principal amount outstanding of $31,000,000 less $925,000 (discount and issuance expenses) equals $30,075,000 (net proceeds on average amount outstanding) $30,075,000 ÷ $31,000,000 = 97.02%.

(3) Net proceeds ratio calculation based upon the average principal amount outstanding. Average principal amount outstanding of $17,600,000 less $131,000 (discount and issuance expenses) equals $17,469,000 (net proceeds on average amount outstanding) $17,469,000 ÷ $17,600,000 = 99.26%.

(4) Net proceeds ratio calculation based upon the average principal amount outstanding. Average principal amount outstanding of $32,517,500 less $225,000 (discount and issuance expenses) equals $32,292,500 (net proceeds on average amount outstanding) $32,292,500 ÷ $32,517,500 = 99.31%.

(5) Net proceeds ratio calculation based upon the average principal amount outstanding. Average principal amount outstanding of $29,310,345 less $920,369 (discount and issuance expense) equals $28,389,976 (net proceeds on average amount outstanding) $28,389,976 ÷ $29,310,345 = 96.86%.

(6) Net proceeds ratio calculation based upon the average principal amount outstanding. Average principal amount outstanding of $45,000,000 less $441,533 (discount and issuance expenses) equals $44,558,467 (net proceeds on average amount outstanding $44,558,467 ÷ $45,000,000 = 99.02%

(7) Net proceeds ratio calculation based upon the average principal amount outstanding. Average prinicpal amount of $21,851,852 less $646,306 (discount and issuance expenses) equals $21,205,546 (net proceeds on average amount outstanding) $21,205,546 ÷ $21,851,852 = 97.04%.

(8) For the proposed new series of $50 million Preferred Stock planned to be issued in October 1985, the stated dividend rate is estimated to be 12.5% and the net proceeds ratio is estimated to be 99.00%.

Source of Information: Company provided data

Comparison of Interest Rate Trends for Investor-Owned Public Utility and Industrial Companies Years 1955, 1975-1984 and 1985 (1)

Years	Aaa Rated Public Utilities	Aaa Rated Industrials	Aaa Rated Spread	Aa Rated Public Utilities	Aa Rated Industrials	Aa Rated Spread	A Rated Public Utilities	A Rated Industrials	A Rated Spread	Baa Rated Public Utilities	Baa Rated Industrials	Baa Rated Spread
1955	3.09	3.00	.09	3.13	3.11	.02	3.22	3.16	.06	3.43	3.47	(.04)
1975	9.03	8.61	.42	9.44	8.90	.54	10.09	9.21	.88			
1976	8.63	8.23	.40	8.92	8.59	.33	9.29	8.88	.41	10.96	10.26	.70
1977	8.19	7.86	.33	8.43	8.04	.39	8.61	8.36	.25	9.82	9.67	.15
1978	8.87	8.58	.29	9.10	8.74	.36	9.29	8.94	.35	9.06	8.87	.19
1979	9.86	9.39	.47	10.22	9.65	.57	10.49	9.91	.58	9.62	9.35	.27
1980	12.30	11.57	.73	13.00	11.99	1.01	13.34	12.44	.90	10.96	10.42	.54
1981	14.64	13.70	.94	15.30	14.19	1.11	15.95	14.62	1.33	13.95	13.39	.56
1982	14.22	13.35	.87	14.79	14.03	.76	15.87	15.00	.86	16.60	15.48	1.12
1983	12.52	11.56	.96	12.83	12.00	.83	13.66	12.53	1.13	16.45	15.77	.69
										14.20	12.90	1.30
Jan.1984	12.85(2)	12.01	.84	13.02	12.39	.63	13.39	12.85	.54			
Feb.1984	N/A	12.08	N/A	13.04	12.37	.67	13.41	12.81	.60	14.05	13.24	.81
Mar.1984	N/A	12.57	N/A	13.66	12.78	.88	13.87	13.21	.66	14.05	13.13	.92
Apr.1984	N/A	12.81	N/A	13.93	13.02	.91	14.16	13.38	.78	14.56	13.42	1.14
May 1984	N/A	13.28	N/A	14.66	13.54	1.12	14.90	13.84	1.06	14.82	13.78	1.04
Jun.1984	N/A	13.55	N/A	14.90	13.76	1.14	15.09	14.22	.87	15.28	14.21	1.07
Jul.1984	N/A	13.44	N/A	14.42	13.80	.62	14.82	14.30	.52	15.50	14.60	.90
Aug.1984	N/A	12.87	N/A	13.67	13.26	.41	14.43	13.82	.61	15.50	14.79	.71
Sep.1984	N/A	12.66	N/A	13.43	13.12	.31	14.17	13.70	.47	14.79	14.48	.31
Oct.1984	13.00(3)	12.42	.58	13.38	12.85	.53	13.80	13.42	.38	14.51	14.19	.32
Nov.1984	12.66	11.92	.74	13.00	12.32	.68	13.23	12.94	.29	14.17	13.71	.46
Dec.1984	12.51	11.76	.75	12.76	12.23	.53	13.11	12.72	.39	13.72	13.24	.48
Avg.1984	12.76(4)	12.61	.73(4)	13.65	12.95	.70	14.03	13.43	.60	13.46	13.34	.12
										14.53	13.84	.69
Jan.1985	12.47	11.67	.80	12.68	12.18	.50	12.99	12.61	.38	13.36	13.15	.21
Feb.1985	12.61	11.64	.97	12.87	12.10	.77	13.08	12.51	.57	13.44	13.00	.44
Mar.1985	13.08	12.04	1.04	13.50	12.32	1.18	13.87	12.84	1.03	14.19	13.18	1.01
Apr.1985	12.77	11.67	1.10	13.17	12.22	.95	13.61	12.71	.90	14.11	12.90	1.21
May 1985	12.18	11.26	.92	12.65	11.95	.70	13.12	12.28	.84	13.62	12.68	.94
Jun.1985	11.17	10.71	.46	11.68	11.24	.44	12.13	11.83	.30	12.66	12.14	.52
Jul.1985	11.18	10.74	.44	11.55	11.29	.26	12.07	11.77	.30	12.70	12.17	.53
Aug.1985	11.23	10.87	.36	11.65	11.29	.36	12.13	11.87	.26	12.73	12.27	.46

Notes: (1) All yields are distributed yields.
(2) Average through January 16. On January 17 the Aaa public utility bond yield average was suspended because of the lack of appropriate issues.
(3) Average of the last 14 days of October. The Aaa public utility bond yield average was reinstated on October 12.
(4) Average for the months January, October, November and December, 1984.

Source of Information: Moody's Investor Services, Inc. (Public Utility Manuals and Bond Surveys)

Comparison of Interest Rate Trends for Investor-Owned Public Utility and Industrial Companies Years 1955, 1975-1984 and 1985 (1)

Years	Yield Spread Aa vs. Aaa		Yield Spread A vs. Aaa		Yield Spread Baa vs. Aaa	
	Public Utilities	Industrials	Public Utilities	Industrials	Public Utilities	Industria
1955	.04	.11	.13	.16	.34	.47
1975	.41	.29	1.06	.60	1.93	1.65
1976	.29	.36	.66	.65	1.19	1.44
1977	.24	.18	.42	.50	.87	1.01
1978	.23	.16	.42	.36	.75	.77
1979	.36	.26	.63	.52	1.10	1.03
1980	.70	.42	1.04	.87	1.65	1.82
1981	.66	.49	1.31	.92	1.96	1.78
1982	.57	.68	1.65	1.65	2.23	2.42
1983	.31	.44	1.14	.97	1.68	1.34
Jan.1984	.17(2)	.38	.54(2)	.84	1.20(2)	1.23
Feb.1984	N/A	.29	N/A	.73	N/A	1.05
Mar.1984	N/A	.21	N/A	.64	N/A	.85
Apr.1984	N/A	.21	N/A	.57	N/A	.97
May 1984	N/A	.26	N/A	.56	N/A	.93
Jun.1984	N/A	.21	N/A	.67	N/A	1.05
Jul.1984	N/A	.36	N/A	.86	N/A	1.35
Aug.1984	N/A	.39	N/A	.95	N/A	1.61
Sep.1984	N/A	.46	N/A	1.04	N/A	1.53
Oct.1984	.38(3)	.43	.80(3)	1.00	1.17(3)	1.29
Nov.1984	.34	.40	.57	1.02	1.06	1.32
Dec.1984	.25	.47	.60	.96	.95	1.58
Avg.1984	.29(4)	.34	.63(4)	.82	1.10(4)	1.23
Jan.1985	.21	.51	.52	.94	.89	1.48
Feb.1985	.26	.46	.47	.87	.83	1.36
Mar.1985	.42	.28	.79	.80	1.11	1.14
Apr.1985	.40	.55	.84	1.04	1.34	1.23
May 1985	.47	.69	.94	1.02	1.44	1.42
Jun.1985	.51	.56	.96	1.12	1.49	1.43
Jul.1985	.37	.55	.89	1.03	1.52	1.43
Aug.1985	.42	.42	.90	1.00	1.50	1.40

Notes: (1) All yields are distributed yields.
(2) Computed on the basis of data reported through Jan. 16, 1984 for Aaa rated Public Utility Issues. Reported rate was 12.85%.
(3) Computed on the basis of data reported from October 12, 1984 to month-end for Aaa rated Public Utility Issues. Reported rate was 13.00%.
(4) Average for the months January, October, November and December, 1984.

Source of Information: Moody's Investor Services, Inc. (Public Utility Manuals and Bond Surveys)

Estimates of the Consumer Price Index
GNP Implicit Price Deflator (1) and Interest Rates for 1985

	Estimated Year-End 1985					
	Consumer Price Index(2)	GNP Implicit Price Deflator (3)	Prime Rate(4)	Public Utility Bonds(7)	Treasury Bonds(8)	Treasury Bills (9)
The Value Line Investment Survey	3.8%	4.1%	9.5%	11.8%(5)	N/A	N/A
Standard & Poor's Corporation	3.6	3.5	9.5	N/A	N/A	7.2%
Blue Chip Economic Indicators	3.8	3.7	N/A	N/A	N/A	7.3
Blue Chip Financial Forecasts	3.9	N/A	9.6	11.7(6)	10.5%	7.3

Notes:

(1) Based upon an annual rate of increase or percent change.
(2) For the year 1985, the CPI is estimated to be 3.5% by the Value Line Investment Survey, 3.6% by Standard & Poor's Corporation, 3.6% by Blue Chip Economic Indicators and 4.0% by Blue Chip Financial Forecasts, for the four-quarter period ending June 30, 1986.
(3) For the year 1985, the GNP Implicit Price Deflator is estimated to be 3.8% by the Value Line Investment Survey, 3.7% by Standard & Poor's Corporation and 3.7% by Blue Chip Economic Indicators.
(4) For the year 1985, the prime rate is estimated to be 9.9% by the Value Line Investment Survey, 9.9% by Standard & Poor's Corporation and 9.7% by Blue Chip Financial Forecasts, for the four-quarter period ending June 30, 1986.
(5) Estimate for Aa Public Utility Bonds.
(6) Estimate for A Public Utility Bonds.
(7) For the year 1985 Aa rated public utility bonds are estimated to yield 12.1% by Value Line Investment Survey. The A rated public utility bond are estimated by Blue Chip Financial Forecasts to yield 11.7% for the four-quarter period, ending June 30, 1986. Given the aforesaid, I believe a 12.0% A rated public utility bond yield, and a 12.5% Baa rated Public utility bond yield are reasonable estimates for the end of 1985. As can be derived from the information shown on page 1, Schedule 6, the spread in yield for public utility bonds rated A and Baa for the five years ended 1984 is slightly more than 1/2 of 1%.
(8) For the year 1985, Treasury Bonds are estimated to yield 10.6% by Blue Chip Financial Forecasts, for the four-quarter period ending June 30, 1986.
(9) For the year 1985, Treasury Bills are estimated to yield 7.5% by the Standard & Poor's Corporation, 7.5% by Blue Chip Economic Indicators and 7.4% by Blue Chip Financial Forecasts, for the four-quarter period ending June 30, 1986.

Source of Information: Value Line Investment Survey - Selection & Opinion, August 9, 1985; Standard & Poor's Trends & Projections, July 18, 1985; Blue Chip Economic Indicators, September 10, 1985; Blue Chip Financial Forecasts, September 1, 1985

Treasury Bill and Treasury Bond Futures Contracts as Traded on International Monetary Market at Chicago Mercantile Exchange and the Chicago Board of Trade, respectively, on September 19, 1985

Contract Data	T-Bill Settled Yields	T-Bond Settled Yields
September	7.00%	10.936%
December	7.38	11.156
March 1986	7.75	11.326
June	8.09	11.490
September	8.40	11.692
December	8.69	11.787
March 1987	-	11.923
June	-	12.045
September	-	12.157
Average	7.89%	11.607%

Moody's Ten-Year Treasury Index on September 9, 1985 10.42%

Source of Information: The Wall Street Journal - September 20, 1985.
Moody's Bond Survey - September 16, 1985.

Rate of Return on Average Book Common Equity (1)
Historic Comparison of Philadelphia Electric Company and
Barometer Group of Four Electric Companies with Bonds Rated Baa
Years 1975-1984, Inclusive, and Spot 1985

Year	Philadelphia Electric Company	Barometer Group of Four Electric Companies with Bonds Rated Baa (2)
1985 Spot (3)	15.1%	14.8%
1984	15.1	14.6
1983	13.4	13.6
1982	13.1	12.2
1981	12.1	12.3
1980	10.6	10.5
1979	9.8	11.0
1978	9.7	9.1
1977	9.6	10.7
1976	9.9	11.1
1975	9.4	11.2
5 Year Average 1980-1984	12.9%	12.6%
5 Year Average 1975-1979	9.7%	10.6%
Common Equity Ratio (4)	36.8%	34.7%

Notes: (1) Rate of return on average book common equity = income available for common equity ÷ average beginning and ending year's balance of book common equity.
(2) Arithmetic average of achieved results for all individual companies in the group.
(3) Spot 1985 rate of return on average book common equity = latest 12 months reported earnings per share ÷ 1984 year-end book value.
(4) Average common equity ratio based upon permanent capital for the years 1980-1984, inclusive.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Interactive Data Corporation

Exhibit
Schedule 8

Market/Book Ratio (1)
Historic Comparison of Philadelphia Electric Company and Barometer Group of Four Electric Companies with Bonds Rated Baa for the Years 1975-1984, Inclusive, and Spot 1985

Year	Philadelphia Electric Company: Average Book Value	Philadelphia Electric Company: Market/ Book Value	Barometer Group of Four Electric Companies with Bonds Rated Baa(2)
1985 Spot (3)	$17.80 (4)	82.2%	95.0%
1984	17.90	69.9	80.8
1983	17.95	88.4	91.3
1982	18.00	84.7	81.5
1981	18.39	69.3	72.0
1980	18.88	75.1	73.2
1979	19.16	81.2	82.8
1978	19.25	90.2	90.7
1977	19.18	100.1	104.0
1976	19.07	86.2	97.6
1975	19.61	67.9	77.0
5 Year Average 1980-1984		77.5%	79.8%
5 Year Average 1975-1979		85.1%	90.4%

Notes: (1) Market/Book Ratio = average of yearly high/low market price ÷ average beginning and ending year's book value per share.
(2) Arithmetic average of achieved results for all individual companies in the group.
(3) Spot 1985 Market/Book Ratio = 9-19-85 market price ÷ 1984 year-end book value.
(4) 1984 year-end book value per share. Philadelphia Electric Company's market price was $14.625 on 9-19-85.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Interactive Data Corporation

Exhibit
Schedule 9

Market Price and Book Value Index (1974=100)
Historic Comparison of Philadelphia Electric Company, Barometer Group of Four Electric Companies with Bonds Rated Baa, and Dow Jones Industrial and Utility Averages for the Years 1974-1984, Inclusive, and Spot 1985

	Philadelphia Electric Company		Barometer Group of Four Electric Companies with Bonds Rated Baa		DJI		DJU	
(1974=100)	Market Price Index(2)	Book Value Index	Market Price Index(3)	Book Value Index(4)	Market Price Index(2)	Book Value Index	Market Price Index(2)	Book Value Index
1985 Spot	101.3%	88.2%	116.8%	99.7	171.7%	145.7%	198.5%	126.6%
1984	86.6	88.7	97.7	98.8	161.5	145.5	177.9	124.3
1983	110.0	88.9	109.0	97.5	157.1	145.9	170.1	119.6
1982	105.6	89.2	97.3	98.0	125.7	152.8	147.7	121.3
1981	88.3	91.1	86.9	99.2	125.8	155.7	143.2	123.1
1980	98.3	93.5	89.7	100.7	119.7	147.9	139.4	119.9
1979	107.8	94.9	102.3	101.6	115.3	137.7	135.9	117.3
1978	120.4	95.3	112.6	102.0	112.3	127.7	135.5	114.3
1977	132.9	95.0	128.1	101.4	122.6	120.8	146.2	110.2
1976	113.9	94.5	117.6	99.6	127.5	113.9	126.1	105.4
1975	92.2	97.1	92.4	99.8	103.0	107.0	97.4	102.5
1974	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Price								
1985 Spot (1)	$14.625	$17.80	$17.44	$18.20	$1,261.38	$36.10	$151.91	$24.64
1984	12.50	17.90	14.59	18.04	1,186.61	36.06	136.09	24.18
1983	15.88	17.95	16.28	17.80	1,157.12	36.15	130.11	23.28
1982	15.25	18.00	14.53	17.89	923.74	37.86	113.03	23.60
1981	12.75	18.39	12.97	18.12	924.03	38.59	109.55	23.96
1980	14.19	18.88	13.39	18.39	879.65	36.64	106.69	23.34
1979	15.56	19.16	15.27	18.56	847.14	34.12	103.99	22.83
1978	17.38	19.25	16.81	18.63	824.93	31.65	103.67	22.24
1977	19.19	19.18	19.13	18.52	900.30	29.94	111.82	21.44
1976	16.44	19.07	17.56	18.19	936.75	28.23	96.45	20.52
1975	13.31	19.61	13.79	18.22	756.93	26.52	74.55	19.94
1974	14.44	20.19	14.93	18.26	734.63	24.78	76.51	19.46

Notes: (1) Based upon the spot market price on 9-19-85 and 1984 year-end book value. The spot market price for the Barometer Group is the arithmetic average of the individual market prices for each company in the group.
(2) Market price is the computed average of yearly high-low market price.
(3) Arithmetic average of individually computed average of yearly high-low prices.
(4) Arithmetic average of individually computed average book values.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Interactive Data Corporation
The Wall Street Journal

Exhibit
Schedule 10

Earnings/Price Ratio (1)
Historic Comparion of Philadelphia Electric Company, and Barometer Group of Four Electric Companies With Bonds Rated Baa for the Years 1975-1984, Inclusive, and Spot 1985

Year	Philadelphia Electric Company Earnings Per Share	Philadelphia Electric Company Earnings/ Price Ratio	Barometer Group of Four Baa Rated Electric Companies With Bonds Rated Baa(2)
1985 Spot (3)	$2.68 (6-30-85)	18.3%	15.6%
1984	2.70	21.6	18.1
1983	2.40	15.1	14.9
1982	2.39	15.7	12.2
1981	2.25	17.7	17.5
1980	2.00	14.1	14.4
1979	1.86	12.0	13.4
1978	1.87	10.8	10.3
1977	1.86	9.7	10.4
1976	1.91	11.6	11.5
1975	1.86	14.0	14.4
5 Year Average 1980-1984		16.8%	15.4%
5 Year Average 1975-1979		11.6%	12.0%

Notes: (1) Earnings/Price Ratio = reported earnings per share ÷ average yearly high/low market price.
(2) Arithmetic average of achieved results for all individual companies in the group.
(3) Spot 1985 earnings price ratio = latest reported earnings per share ÷ 9-19-85 market price. Philadelphia Electric Company's market price was $14.625 on 9-19-85.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Interactive Data Corporation

Common Dividend Yield (1) and Dividend Payout Ratio (2)
Historic Comparison of Philadelphia Electric Company, and Barometer Group of Four Electric Companies With Bonds Rated Baa for the Years 1975-1984, Inclusive, and Spot 1985

	Philadelphia Electric Company			Barometer Group of Four Electric Companies With Bonds Rated Baa (3)	
Year	Dividends Per Share	Dividend Payout Ratio (2)	Dividend Yield (1)	Dividend Payout Ratio (2)	Dividend Yield(1)
1985 Spot	$2.20	82.1%	15.0%	76.7%	12.0%
1984	2.20	81.6	17.6	77.0(4)	13.8
1983	2.12	88.2	13.4	81.0	12.0
1982	2.06	86.2	13.5	87.9	12.9
1981	1.90	84.7	14.9	80.4	13.8
1980	1.80	90.0	12.7	94.1	13.1
1979	1.80	96.9	11.6	87.3	11.2
1978	1.80	96.0	10.4	105.0	9.9
1977	1.76	94.1	9.2	82.3	8.5
1976	1.64	85.7	10.0	80.6	9.2
1975	1.64	88.5	12.3	80.2	11.5
5 Year Average 1980-1984		86.1%	14.4%	84.1%	13.1%
5 Year Average 1975-1979		92.2%	10.7%	87.1%	10.1%

Notes: (1) Dividend Yield = yearly dividends per share ÷ average yearly high-low market price. The 1985 spot dividend yield was computed by dividing the current dividend per share by the spot market price on 9-19-85.

(2) Dividend payout ratio = reported dividends ÷ income available for common equity. Spot 1985 dividend payout ratio = current annualized dividends per share ÷ latest reported earnings per share.

(3) Arithmetic average of achieved results for all individual companies in the group.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Interactive Data Corporation

Exhibit
Schedule 12
Page 1 of 4

CAPITALIZATION AND FINANCIAL STATISTICS
1980 - 1984, INCLUSIVE

	1984	1983	1982	1981	1980	PERCENT INCREASE 1984 OVER 1980
	(THOUSANDS OF DOLLARS)					
OUNT OF CAPITAL EMPLOYED						
OTAL PERMANENT CAPITAL	$7,970,130	$6,758,460	$5,969,000	$5,384,710	$4,883,690	
HORT-TERM DEBT	260,000	267,500	64,700	54,220	52,590	
TOTAL CAPITAL EMPLOYED	$8,230,130	$7,025,960	$6,033,700	$5,438,930	$4,936,280	66.7%
	=========	=========	=========	=========	=========	
DICATED AVERAGE CAPITAL COST RATES (1)						
ONG TERM DEBT	10.6%	10.3%	10.5%	10.1%	9.2%	15.2%
REFERRED STOCK	9.7	9.1	8.8	8.4	8.5	14.1
						5 YEAR AVERAGE
PITAL STRUCTURE RATIOS						
ASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	52.4%	50.0%	51.1%	51.7%	51.2%	51.3%
PREFERRED STOCK	11.3	12.0	11.2	11.9	13.3	11.9
COMMON EQUITY	36.3	38.0	37.7	36.4	35.5	36.8
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	======	======	======	======	======	======
ASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	54.0%	51.9%	51.6%	52.1%	51.8%	52.3%
PREFERRED STOCK	10.9	11.5	11.0	11.8	13.1	11.7
COMMON EQUITY	35.1	36.6	37.4	36.1	35.1	36.0
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	======	======	======	======	======	======
ERAGES-INCLUDING ALL AFC (2)						
EFORE INCOME TAXES: ALL INTEREST CHARGES	2.4x	2.4x	2.4x	2.1x	2.1x	2.3x
FTER INCOME TAXES: ALL INTEREST CHARGES	2.1	2.1	2.0	1.9	2.0	2.0
VERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.8	1.7	1.7	1.6	1.6	1.7
ERAGES-EXCLUDING ALL AFC (3)						
EFORE INCOME TAXES: ALL INTEREST CHARGES	1.6x	1.6x	1.7x	1.5x	1.5x	1.6x
FTER INCOME TAXES: ALL INTEREST CHARGES	1.3	1.3	1.4	1.3	1.3	1.3
VERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.1	1.1	1.2	1.1	1.1	1.1
LITY OF EARNINGS						
THER INC./PRE-TAX GROSS INC. INCL. AFC (4)	33.6%	31.5%	26.3%	29.7%	29.6%	30.1%
FC/INCOME AVAILABLE FOR COMMON EQUITY	86.6	85.8	76.5	84.4	84.3	83.5
FFECTIVE INCOME TAX RATE	20.9	22.4	28.2	19.3	16.4	21.4
NTERNAL CASH GENERATION/GROSS CONSTR. (5)	5.2	8.9	11.5	2.8	3.6	6.4
OMMON DIVIDEND COVERAGE (6)	1.1x	1.2x	1.3x	1.1x	1.1x	1.2x

PAGE 2 FOR NOTES.

Philadelphia Electric Company and Subsidiary Companies
Capitalization and Financial Statistics
1980-1984, Inclusive

Notes:

(1) Computed by relating actual long-term debt interest or preferred stock dividends booked to average of beginning and ending long-term debt or preferred stock reported to be outstanding.

(2) Coverages - including all AFC - represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety included as income, cover fixed charges.

(3) Coverages - excluding all AFC - represent the number of times available earnings, excluding all AFC, cover fixed charges.

(4) Other income/pre-income tax gross income including AFC is non-operating income (net of expenses and non-income taxes) including all AFC as reported in its entirety, as a percentage of income available for fixed charges, including all AFC, before income taxes.

(5) Internal cash generation/gross construction is the percentage of gross construction expenditures, excluding all AFC, provided by internally generated funds from operations, excluding all AFC, and after payment of all cash dividends.

(6) Common dividend coverage is the relationship of internally generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

	August 1985 Bond and Preferred Stock Ratings			
	Bonds		Preferred Stock	
	Moody's	S&P	Moody's	S&P
Philadelphia Electric Company	Baa3	BBB-	"bal"	BB

Source of Information: Associated Utility Services, Inc. Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Moody's Bond Survey
Standard & Poor's Bond Guide

Philadelphia Electric Company
Analysis of Public Offerings of Common Stock
1980 to Date

ate of Prospectus	4-4-85	11-1-84(6)	10-4-84	8-14-84(3)	4-12-84	10-5-83	3-29-83	10-6-82	4-6-82	9-30-81	4-2-81	7-10-80
umber of Shares Offered	4,000,000	1,000,000	4,000,000	1,000,000	6,000,000	5,000,000	6,000,000	6,000,000	6,000,000	7,800,000	5,000,000	7,000,000
ollar Amount of Offering ($Million)	$62,500	$14,813	$52,000	$11,937	$77,250	$86,875	$104,400	$96,000	$84,900	$99,450	$61,875	$105,000
rice to Public	$15.625	$14.813	$13.000	$11.937	$12.875	$17.375	$17.40	$16.00	$14.15	$12.750	$12.375	$15.00
nderwriter Discounts Per Share	.16	.056	.530	.060	.59	.48	.47	.39	.49	.505	.520	.52
ross Proceeds Per Share	15.465	14.757	12.470	11.877	12.285	16.895	16.93	15.61	13.66	12.245	11.855	14.48
ompany Expenses Per Share	.041	.100	.056	.100	0.046	0.055	.04	.04	.04	.031	.040	.02
et Proceeds Per Share	$15.424	$14.657	$12.414	$11.777	$12.239	$16.84	$16.89	$15.57	$13.62	$12.214	$11.815	$14.46
atest Available EPS as Revealed in ach Prospectus (Before New Issue) or 12 Months Ended	$2.70 (12-31-84)	$2.65(5) (8-31-84)	$2.65 (8-31-84)	$2.65 (6-30-84)	$2.46 (2-29-84)	$2.41 (8-31-83)	$2.39 (12-31-82)	$2.33 (8-31-82)	$2.35 (2-28-82)	$2.20 (8-31-81)	$2.12 (2-28-81)	$1.76 (5-30-80)
atest Annualized Reported Dividend t Time of Offering	$2.20	$2.20(5)	$2.20	$2.20	$2.20	$2.12	$2.12	$2.12	$2.00	$2.00	$1.80	$1.80
ook Value Per Common Share as alculated from Each Prospectus efore New Issue) at	$17.81 (12-31-84)	$17.77(5) (8-31-84)	$17.77 (8-31-84)	$17.95 (6-30-84)	$17.94 (2-29-84)	$17.85 (8-31-83)	$17.82 (12-31-83)	$17.82 (8-31-82)	$18.07 (2-28-82)	$18.39 (8-31-81)	$18.70 (12-31-81)	$18.77 (5-31-80)
rnings/Net Proceeds Ratio	17.5%	18.1%	21.3%	22.5%	20.1%	14.3%	14.2%	15.0%	17.3%	18.0%	17.9%	12.2%
vidend Yield on Offering Price	14.1	14.9	16.9	18.4	17.1	12.2	12.2	13.3	14.1	15.7	14.5	12.0
t Proceeds/Book Ratio	86.6	82.5	69.9	65.6	68.2%	94.3	95.5	87.4	75.4	66.4	63.2	77.0
o Forma Capital Structure Based on Total rmanent Capital (After New Financing)												
Long-Term Debt	49.8%	50.5%(5)	50.5%(4)	50.7%	50.2%	49.1%	49.7%	51.5%(2)	51.8%(1)	53.0%	54.4%	52.0%
Preferred Stock	11.8	11.5	11.5	11.7	12.2	11.6	12.1	11.3	11.9	12.0	12.9	13.5
Common Equity	38.4	38.0	38.0	37.6	37.6	39.3	38.2	37.2	36.3	35.0	35.7	34.5
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

tes: (1) Reflects utilization in 1982 of a proposed $125 million of Pollution Control Notes, the proposed issuance of $20.0 million of Unsecured Notes, the issuance of $100.0 million of new First Mortgage Bonds.
(2) Reflects estimated net proceeds from the sale of common stock, the proceeds from the issuance of $100 million of new bonds on 10-1-82, the utilization of $69.0 million of a proposed new issuance of $100 million of Pollution Control Notes in 1982 and the repayment of $100.0 million of revolving credit notes.
(3) Continuously offered from August 14, 1984 to September 11, 1984.
(4) Reflects the sale of $8.7 million of Floating Rate Pollution Control Notes and the sale of 482,400 shares of common stock pursuant to a continuous offering program.
(5) Taken from the final Offering Prospectus issued in regard to the October 4, 1984 public offering of common stock.
(6) Continuously offered from November 1, 1984 to January 17, 1985.

urce of Information: Prospectus for each offering, Company provided data

Philadelphia Electric Company
Issuance and Selling Expense Study for
Public Offerings of Common Stock 1980 to Date

Date of Offering Prospectus	4-4-85	11-1-84	10-4-84	8-14-84	4-12-84	10-5-83	3-29-83	10-6-82	4-6-82	9-30-81	4-2-81	7-10-80	Average
Underwriters' Discount as a Percent of Offering Price	1.02%	0.38%	4.08%	0.50%	4.58%	2.76%	2.70%	2.44%	3.46%	3.96%	4.20%	3.46%	2.80%
Company Issuance Expenses as a Percent of Offering Price	0.26	0.68	0.43	0.84	0.36	0.32	0.23	0.25	0.28	0.24	0.32	0.13	0.36%
Total Issuance and Selling Expenses	1.28%	1.06%	4.51%	1.34%	4.94%	3.08%	2.93%	2.69%	3.74%	4.20%	4.52%	3.59%	3.16%

Source of Information: Prospectus for each offering

Exhibit
Schedule 12

BAROMETER GROUP OF FOUR ELECTRIC COMPANIES WITH BONDS RATED Baa
CAPITALIZATION AND FINANCIAL STATISTICS (1)
1980 - 1984, INCLUSIVE

(THOUSANDS OF DOLLARS)

	1984	1983	1982	1981	1980	PERCENT INCREASE 1984 OVER 1980
AMOUNT OF CAPITAL EMPLOYED						
TOTAL PERMANENT CAPITAL	$4,824,050	$4,297,090	$3,843,340	$3,283,480	$2,974,350	
SHORT-TERM DEBT	15,520	24,440	82,650	83,970	37,590	
TOTAL CAPITAL EMPLOYED	$4,839,570	$4,321,530	$3,925,990	$3,367,450	$3,011,940	60.7%
INDICATED AVERAGE CAPITAL COST RATES (2)						
LONG TERM DEBT	10.5%	10.3%	10.6%	9.7%	8.4%	25.0%
PREFERRED STOCK	9.5	9.4	8.8	8.3	8.1	17.3

	1984	1983	1982	1981	1980	5 YEAR AVERAGE
CAPITAL STRUCTURE RATIOS						
BASED ON TOTAL PERMANENT CAPITAL:						
LONG-TERM DEBT	54.5%	52.5%	53.4%	53.0%	53.1%	53.3%
PREFERRED STOCK	10.5	11.7	11.9	12.7	13.1	12.0
COMMON EQUITY	35.0	35.8	34.7	34.3	33.8	34.7
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
BASED ON TOTAL CAPITAL:						
TOTAL DEBT, INCLUDING SHORT TERM	54.8%	53.0%	54.3%	53.9%	53.6%	53.9%
PREFERRED STOCK	10.4	11.6	11.7	12.4	13.0	11.8
COMMON EQUITY	34.8	35.4	34.0	33.7	33.4	34.3
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
COVERAGES-INCLUDING ALL AFC (3)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	2.4x	2.4x	2.2x	2.3x	2.3x	2.3x
AFTER INCOME TAXES: ALL INTEREST CHARGES	2.1	2.0	1.9	2.0	2.0	2.0
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.7	1.7	1.6	1.6	1.6	1.6
COVERAGES-EXCLUDING ALL AFC (4)						
BEFORE INCOME TAXES: ALL INTEREST CHARGES	1.8x	1.8x	1.7x	1.8x	1.8x	1.8x
AFTER INCOME TAXES: ALL INTEREST CHARGES	1.4	1.4	1.4	1.5	1.5	1.4
OVERALL COVERAGE: ALL INTEREST + PFD. DIV.	1.2	1.2	1.2	1.3	1.2	1.2
QUALITY OF EARNINGS						
OTHER INC./PRE-TAX GROSS INC. INCL. AFC (5)	29.8%	28.2%	26.9%	21.4%	22.3%	25.7%
AFC/INCOME AVAILABLE FOR COMMON EQUITY	74.6	80.0	82.6	65.4	67.3	74.0
EFFECTIVE INCOME TAX RATE	22.7	26.1	24.0	22.9	19.5	23.0
INTERNAL CASH GENERATION/GROSS CONSTR. (6)	17.9	14.8	9.2	20.3	19.7	16.4
COMMON DIVIDEND COVERAGE (7)	1.5x	1.4x	1.4x	1.7x	1.6x	1.5x

SEE PAGE 2 FOR NOTES.

Barometer Group of Four Electric Companies With Bonds Rated Baa
Capitalization and Financial Statistics (1)
1980-1984, Inclusive

Notes:

(1) All capitalization and financial statistics for Barometer Group of Four Electric Companies with Bonds Rated Baa are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements originally reported in each year.

(2) Computed by relating actual long-term debt interest or preferred stock dividends booked to average of beginning and ending long-term debt or preferred stock reported to be outstanding.

(3) Coverages - including all AFC - represent the number of times available earnings, including AFC (allowance for funds used during construction) as reported in its entirety included as income, cover fixed charges.

(4) Coverages - excluding all AFC - represent the number of times available earnings, excluding all AFC, cover fixed charges.

(5) Other income/before-income tax gross income including AFC is non-operating income (net of expenses and non-income taxes) including all AFC as reported in generated funds from operations, excluding all AFC, and after payment of all cash dividends.

(6) Internal cash generation/gross construction is the percentage of gross construction expenditures, excluding all AFC, provided by internally generated funds from operations, excluding all AFC, and after payment of all cash dividends.

(7) Common dividend coverage is the relationship of internally generated funds from operations, excluding all AFC, and after payment of preferred stock dividends to common dividends paid.

Basis of Selection:

The criteria used in the selection of this barometer group of operating electric companies were to include those companies which operate in the eastern part of the United States, have a current (August 1985) bond rating of Baa by Moody's Investor Service, Inc., have common stock which is actively traded, have permanent capitalization of at least $2.5 billion at year-end 1984, and have at least 75% of their 1984 operating revenues derived from electric sales.

The names of the companies and their Bond and Preferred Stock Ratings are:

	August 1985 Bond and Preferred Stock Ratings			
	Bond		Preferred Stock	
	Moody's	S&P	Moody's	S&P
Detroit Edison Company	Baa1	BBB	"baa2"	BBB-
Duquesne Light Company	Baa1	BBB+	"baa1"	BBB
New York State Electric & Gas Corp.	Baa2	BBB+	"baa2"	BBB
Ohio Edison Company	Baa3	BBB-	"baa3"	BB

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Moody's Bond Survey
Standard & Poor's Bond Guide

Barometer Group of Four Electric Companies With Bonds Rated Baa
Capitalization and Financial Statistics
1980-1984, Inclusive

Basis of Selection (continued):

Further items of comparison between the Barometer Group and Philadelphia Electric Company are shown below:

		Average for Four Barometer Group Companies	Philadelphia Electric Company
1984 Operating Revenues ($ Million)		$1,531.5	$2,981.0
1984 Operating Revenues Derived from:	-Electric	94.8%	81.7%
	-Gas	4.6	15.5
	-Other	0.6	2.8
		100.0%	100.0%

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat, Inc., Utility Compustat II

Philadelphia Electric Company
Comparison of Statistical Data Pertaining for the Barometer Group of
Four Electric Companies with Bonds Rated Baa
for the Year Ended December 31, 1984

	Philadelphia Electric Company	Barometer Group of 4 Elec. Cos. with Bonds Rated Baa	Detroit Edison Company	Duquesne Light Company	New York State Electric & Gas Corp.	Ohio Edison Company
A) 1984 Permanent capitalization (in thousands)	$ 7,970.135	$ 4,824,046	$ 7,264,674	$ 2,916,091	$ 3,203,228	$ 5,912,190
B) 1984 Total operating revenues (in thousands)	2,981.016	1,531,538	2,498,205	861,775	1,129,066	1,637,104
C) 1984 Percent of total operating revenues derived from electric sales	81.7%	94.8%	97.7%	100.0%	81.6%	100.0%
D) 1984 Total electric sales (in MMKWH)	29,395.007	22,164.629	35,886.910	11,562.800	14,444.800	26,764.007
E) 1984 Average total customers-electric	1,358.410	999,071	1,768,864	559,088	689,667	978,664
F) 1984 Common equity ratio based upon permanent capital	36.3%	35.0%	32.4%	36.1%	38.5%	32.9%

ource of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II

Philadelphia Electric Company
Comparison of Statistical Data for the Barometer Group of Four
Electric Companies with Bonds Rated Baa for the Year Ended December 31, 1984

Electric Statistics	Philadelphia Electric Company	Barometer Group of 4 Elec. Cos. with Bonds Rated Baa	Detroit Edison Company	Duquesne Light Company	New York State Electric & Gas Corp.	Ohio Edison Company
Revenue Mix ($)						
Residential	35.1%	34.6%	31.1%	32.6%	39.7%	34.9%
Commercial	14.8	26.2	23.4	36.4	20.7	24.4
Industrial	41.4	28.0	37.7	28.4	17.0	28.7
Other (1)	3.9	6.1	2.6	1.6	9.4	10.7
Sales for Resale	2.8	3.7	3.3	0.1	11.6	0.0
Other (Non-Ultimate)(2)	2.0	1.4	1.9	0.9	1.6	1.3
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Sales Mix (MMKWH)						
Residential	29.0%	27.7%	28.3%	25.2%	31.7%	25.5%
Commercial	12.0	23.6	19.1	38.0	18.1	19.1
Industrial	50.6	33.8	45.5	35.9	19.6	34.2
Other (1)	3.6	8.3	2.4	0.8	8.8	21.2
Sales for Resale	4.8	6.6	4.7	0.1	21.8	0.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Customers Mix						
Residential	90.6%	90.5%	91.8%	90.4%	89.3%	90.4%
Commercial	8.9	8.8	8.0	8.9	9.0	9.3
Industrial	0.4	0.2	0.1	0.4	0.2	0.2
Other (1)	0.1	0.5	0.1	0.3	1.5	0.1
Sales for Resale	0.0	0.0	0.0	0.0	0.0	0.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Notes: (1) Represents the percent of total electric revenues, MMKWH or customers not classified as commercial, industrial or residential. It includes such items as electric service supplied to public street and highway lighting, other sales to public authorities (not for resale) and sales to railroads and railways.

(2) Represents percent of electric operating revenue from sources other than actual sales of electricity, such as forfeited discounts, miscellaneous service revenues, rent from electric property and inter-departmental rents.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II

Philadelphia Electric Company
Comparison of Reserve Margin and Nuclear Capability to the Barometer Group of Four Electric Companies with Bonds Rated Baa for the Year Ended December 31, 1984

RESERVE MARGIN
(Based on Total Supply Capability (1))

Utility	1984
Philadelphia Electric Company	23.1%
Detroit Edison Company	21.2%
Duquesne Light Company	42.4
New York State Electric & Gas Corp.	38.7
Ohio Edison Company	33.2

NUCLEAR CAPABILITY
(Percent of Total Supply Capability)

Utility	1984
Philadelphia Electric Company	24.9%
Detroit Edison Company	0.0%
Duquesne Light Company	12.5
New York State Electric & Gas Corp.	0.0
Ohio Edison Company	6.2

(1) Total Supply Capability = Generating Capability + Purchase Obligations - Sales Obligations. PECO total supply capability excludes the sale obligations of the 471MW output of Salem 2 to JCP&L.

Source of Information: Annual Report to Shareholders
Uniform Statistical Report
Form 10-K

Philadelphia Electric Company
Volatilaty of Revenues
For 1980 to 1984, Inclusive

	Philadelphia Electric Company	Detroit Edison Company	Duquesne Light Company	New York State Electric and Gas Corp.	Ohio Edison Company
			(Thousands of Dollars)		
1980	$2,123,394	$1,812,513	$689,465	$645,314	$1,080,869
1981	2,433,424	2,054,056	796,847	767,539	1,279,649
1982	2,644,752	2,123,253	746,462	889,223	1,429,626
1983	2,596,050	2,309,657	800,345	993,589	1,515,852
1984	2,981,016	2,498,205	861,775	1,129,066	1,637,104
Average 1980-1984	$2,555,727	$2,159,537	$778,979	$884,946	$1,388,620
Standard Deviation	313,166	259,856	64,616	188,828	215,754
Coefficient of Variation	0.1225	0.1203	0.0829	0.2134	0.1554

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II

Philadelphia Electric Company
Volatilaty of Net Income Available for Common Equity
For 1980 to 1984, Inclusive

	Philadelphia Electric Company	Detroit Edison Company	Duquesne Light Company	New York State Electric and Gas Corp.	Ohio Edison Company
			(Thousands of Dollars)		
1980	$174,950	$137,529	$69,609	$73,637	$101,403
1981	223,761	176,787	85,895	98,265	149,850
1982	278,623	181,456	94,496	122,485	161,338
1983	321,705	266,008	122,815	133,214	227,843
1984	409,707	297,778	134,839	184,006	290,694
Average 1980-1984	$281,749	$211,912	$101,531	$120,721	$186,226
Standard Deviation	90,482	67,070	26,811	42,745	73,796
Coefficient of Variation	0.3211	0.3165	0.2641	0.3541	0.3963

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II

Development of Dividend Yield for Use in Discounted Cash Flow (DCF) Analysis for Philadelphia Electric Company, and Barometer Group of Four Electric Companies with Bonds Rated Baa

	1 Current Dividend Yield(1)	2 Next Period Dividend Growth Rate (2)	3 Current Dividend Yield Reflecting Growth (3)	4 12-Month Average Dividend Yield (1)	5 Next Period Dividend Growth Rate (2)	6 12-Month Yield Reflecting Growth (3)	7 Average Yield (Average of Col. 1,3,4,&6)(4)
Philadelphia Electric Company	15.0%	2.4%	15.4%	14.6%	2.4%	15.0%	15.0%
Barometer Group of Four Electric Companies with Bonds Rated Baa							
Detroit Edison Company	11.0%	3.0%	11.3%	10.5%	3.0%	10.8%	10.9%
Duquesne Light Company	13.5	2.7	13.9	13.2	2.7	13.6	13.6
New York State Electric and Gas Corporation	10.4	5.0	10.9	10.4	5.0	10.9	10.7
Ohio Edison Company	12.9	1.4	13.1	13.0	1.4	13.2	13.1
	12.0%	3.0%	12.4%	11.8%	3.0%	12.1%	12.1%

Notes: (1) As developed on Schedule 14, page 2.

(2) Average of Merrill Lynch and Value Line projected dividend growth rates and the historic dividend growth rate as shown on Schedule 15, page 1 (columns 2, 5, and 7).

(3) Dividend yields reflecting next period growth in dividends are computed by increasing the yields by the next period dividend growth rate. The next period dividend growth rate is the average of historic and projected dividend growth rates.

(4) Average of current and 12-month average yields and current yield reflecting next period growth in dividends and 12-month average yields reflecting next period growth in dividends. The price of common stock may be reflective of the next period dividend which is a requirement of the DCF model when the dividend is paid discretely or periodically rather than continuously. However, there are no empirical studies which prove that investors in fact always expect the next period dividend and reflect that estimate in the current price of stock. Thus, it is possible that the present price of stock is reflective of the current annualized dividend. Moreover, sometimes the current dividend yield, which of course is the product of a stock price of a particular day, could be distorted because the price that day may be abnormally high or low or not representative of the future. Thus, judgments about the future should be the product of a recent period, such as the last twelve months' average dividend yield, as well as reflecting the value of the next period dividends expected by investors.

Calculation of Current and Average Dividend Yield for Philadelphia Electric Company, and the Barompeter Group of Four Electric Companies with Bonds Rated Baa

	Current Dividend Per Share	Current Market Price (9-19-85)	Current Dividend Yield	12-Month Average Dividend	12-Month Average Closing Price	12-Month Average Closing Yield(1)
Philadelphia Electric Company	$2.20	$14.625	15.0%	$2.20	$15.10	14.6%
Barometer Group of Four Electric Companies with Bonds Rated Baa :						
Detroit Edison Company	$1.68	$15.25	11.0%	$1.68	$15.95	10.5%
Duquesne Light Company	2.06	15.25	13.5	2.06	15.65	13.2
New York State Electric & Gas Corp.	2.56	24.625	10.4	2.46	23.65	10.4
Ohio Edison Company	1.88	14.625	12.9	1.87	14.33	13.0
Average			12.0%			11.8%

Note: (1) The average dividend yield was computed by relating the indicated annualized dividend rate and closing market price on the last trading day of each month for the twelve months ended August 30, 1985.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Interactive Data Corporation
Standard & Poor's Compustat Service, Inc., Utility Compustat II

Development of the Growth in Value Component of Discounted Cash Flow (DCF) Analysis
for Philadelphia Electric Company, and Barometer Group of Four Electric Companies With Bonds Rated Baa
Projected Earnings Per Share, Dividends Per Share and Five Year Historic Dividend Per Share Growth

	1	2	3	4	5	6	7	8
	Merrill Lynch Projected Growth			Value Line Projected Growth				
	Earnings Per Share	Dividends Per Share	Average Projected Growth	Earnings Per Share	Dividends Per Share	Average Projected Growth	Historic Five-Year Dividends Per Share Growth	Average of Merrill Lynch and Value Line Projected Growth and Historic Growth (1)
Philadelphia Electric Company	(2.3%)	1.8%	(0.3%)	2.0%	2.0%	2.0%	3.5%	1.7%
Barometer Group of Four Electric Companies With Bonds Rated Baa								
Detroit Edison Company	2.7%	2.4%	2.6%	4.5%	4.5%	4.5%	2.0%	3.0%
Duquesne Light Company	4.0	2.5	3.3	3.5	2.5	3.0	3.0	3.1
New York State Electric and Gas Corp.	3.5	4.0	3.8	4.0	5.0	4.5	6.0	4.8
Ohio Edison Company	(2.0)	1.8	(0.1)	2.0	2.0	2.0	0.5	0.8
	2.1%	2.6%	2.6%	3.5%	3.5%	3.5%	2.9%	2.9%

Notes: (1) Average of Columns 3, 6, and 7.

Source of Information: Value Line Investment Survey Edition 1, June 28, 1985 and Edition 5, July 26, 1985, Merrill Lynch Quantitative Analysis July 1985, May-June 1984, and September-October 1983

Common Stock Turnover Rates and Current Institutional Holdings for Philadelphia Electric Company and Barometer Group of Four Electric Companies with Bonds Rated Baa for 1980 to 1984, Inclusive

	Common Stock Turnover Rates in Years						Current
	1984	1983	1982	1981	1980	Five Year Average	Percentage of Institutional Holdings(1)
Philadelphia Electric Company	2.4	3.0	3.6	5.0	6.5	4.1	16.0%
Barometer Group of Four Electric Companies with Bonds Rated Baa							
Detroit Edison Company	2.7	3.1	3.2	6.2	5.9	4.2	24.0%
Duquesne Light Company	2.9	3.2	3.5	5.7	4.7	4.0	14.3
New York State Electric & Gas Corp.	1.8	2.1	2.7	6.2	5.6	3.7	30.6
Ohio Edison Company	2.1	3.0	3.0	4.0	4.5	3.3	14.6
Average	2.4	2.9	3.1	5.5	5.2	3.8	20.9%

Comment: Common stock turnover rates are calculated by dividing average common shares outstanding by common shares traded. The current percentage of institutional holding is calculated by dividing the number of shares held by institutions by the number of shares outstanding.

Note: (1) Current institutional holdings as of August 1985.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Interactive Data Corporation
Standard & Poor's Stock Guide, September 1985

Growth Rate Test
for Philadelphia Electric Company and the Barometer Group of
Four Electric Companies with Bonds Rated Baa for June 1981 to June 1985

		Value Line Five Year Growth Rates (2)						Merrill Lynch Growth Rates (2)	
	Stock Price Growth(1)	Projected Earnings Per Share	Historic Earnings Per Share	Projected Dividends Per Share	Historic Dividends Per Share	Projected Book Value Per Share	Historic Book Value Per Share	Projected Earnings Per Share	Projected Dividends Per Share
Philadelphia Electric Co.	4.7%	5.0%	(1.0)%	2.5%	1.5%	1.0%	(0.5)%	2.0%	(0.1)%
Barometer Group of Four Electric Companies with Bonds Rated Baa									
Detroit Edison Company	10.0%	3.5%	1.0%	3.5%	1.5%	0.5%	(1.5)%	2.0%	2.4%
Duquesne Light Company	6.9	5.5	(5.5)	0.5	0.5	N/A	1.5	3.0	1.7
New York State Gas & Electric	14.1	4.5	3.5	5.0	3.0	4.0	1.0	3.0	4.4
Ohio Edison Company	4.5	5.0	(3.0)	2.0	2.0	2.0	1.5	2.0	(0.1)

Notes: (1) Stock price growth as measured as the average annual growth rate in stock prices from the second quarter of 1981 to the second quarter of 1985. Stock prices used are the average of the monthly highs, lows and closing prices for the three months of the quarter.

(2) Value Line and Merrill Lynch growth rates are those from the first quarter of 1981.

Source of Information: Associated Utility Services, Inc., Computerized Data Base
Standard & Poor's Compustat Services, Inc., Utility Compustat II
Value Line Investment Survey, Edition 1, January, 1981
Merrill Lynch Quantitative Analysis, Common Stock Valuation, January, 1981

Comparison of Cost of Long-Term Debt and Cost Rate Spread in Long-Term Debt and Common Equity for Eighty-two Electric Companies, Barometer Group of Four Electric Companies with Bonds Rated Baa, and Philadelphia Electric Company Using Merrill Lynch and Value Line Projected Growth Rates and Historic Dividend Growth For 1981-1984, Inclusive

Year	Average Company-Specific Long-Term Debt Cost Rate	Average Spread in Market-Determined Debt Cost Rate and DCF Calculated Common Equity Cost Rate (1)
1. Eighty-two Electric Companies		
1981-1982	15.0%	2.3%
1983-1984	13.1	3.2
2. Barometer Group of Four Electric Companies with Bonds Rated Baa (2)		
1981-1982	15.5%	1.4%
1983-1984	13.6	2.7
3. Philadelphia Electric Company		
1981-1982	15.6%	1.3%
1983-1984	13.7	3.7

See page 2 for Notes.

Comparison of Cost of Long-Term Debt and Cost Rate Spread in Long-Term Debt and Common Equity for Eighty-two Electric Companies, Barometer Group of Four Electric Companies with Bonds Rated Baa, and Philadelphia Electric Company Using Merrill Lynch and Value Line Projected Growth Rates and Historic Dividend Growth 1981-1984, Inclusive

Notes:

(1) Represents the difference between the Discounted Cash Flow (DCF) computed cost rate of common equity and the yield on long-term debt for each company computed monthly. The DCF cost rate of common equity computed for each month of the study period employed the most recent quarterly dividend payment annualized, divided by the average high, low and closing monthly price per share, adjusted for the prospective dividend per share by applying one half of the average Merrill Lynch and Value Line projected earnings and dividend per share growth rate and historic dividend per share growth rate to the computed dividend yield and recognizing as the growth component the average of Merrill Lynch and Value Line projected earnings and dividends per share growth rates, and historic dividends per share growth rate. For each company, an arithmetic average of the twelve month differences between debt and common equity cost rates was used to develop the yearly average in each rating group. The yearly average for all companies is the product of an arithmetic average for all companies contained in that rating group in that year.

(2) Arithmetic average of three companies because Merrill Lynch discontinued publishing growth rates for Duquesne Light Company in September-October 1983.

Source of Information: Standard & Poor's Monthly Bond Guide
Standard & Poor's Utility Compustat II for monthly average stock prices and dividends per share
The Value Line Investment Survey for historic dividend growth rates and projected growth rates in earnings and dividends per share
The Merrill Lynch Quantitative Analysis for projected growth rates in earnings and dividends per share

Representative Bond Issuer and Names
of Eighty-two Electric Power Utilities

Name of Company	Issuer (If not Company Listed on Left)
Allegheny Power System, Inc.	(Potomac Edison Co.)
American Electric Power Co., Inc.	(Indiana & Michigan Elec. Co.)
Arizona Public Service Co.	
Atlantic City Electric Co.	
Baltimore Gas & Electric Co.	
Boston Edison Co.	
Carolina Power & Light Co.	
Central & South West Corp.	(Public Service Co. of Oklahoma)
Central Illinois Public Service Co.	
Cincinnati Gas & Electric Co.	
Cleveland Electric Illuminating Co.	
Commonwealth Edison Co.	
Consolidated Edison of New York, Inc.	
Consumers Power Co.	
Dayton Power & Light Co.	
Delmarva Power & Light Co.	
Detroit Edison Co.	
Dominion Resources Inc.	(Virginia Electric Power Co.)
Duke Power Co.	
El Paso Electric Co.	
Florida Power & Light Co.	
Florida Progress Corp.	(Florida Power Corp.)
Gulf States Utilities Co.	
Hawaiian Electric Industries, Inc.	(Hawaiian Electric Co.)
Houston Industries, Inc.	(Houston Power & Light Co.)
Idaho Power Co.	
Illinois Power Co.	
Iowa Electric Light & Power Co.	
Iowa-Illinois Gas & Electric Co.	
Iowa Resources, Inc.	(Iowa Power & Light Co.)
Ipalco Enterprises, Inc.	(Indianapolis Power & Light Co.)
Kansas City Power & Light Co.	
Kansas Gas & Electric Co.	
Kansas Power & Light Co.	
Kentucky Utilities Co.	
Long Island Lighting Co.	
Louisville Gas & Electric Co.	
Middle South Utilities, Inc.	(Arkansas Power & Light Co.)
Midwest Energy Company	(Iowa Public Service Co.)
Minnesota Power & Light Co.	
Montana-Dakota Utilities Co.	
Montana Power Co.	

Representative Bond Issuer and Names of Eighty-two Electric Power Utilities

Name of Company	Issuer (If not Company Listed on Left)
Nevada Power Co.	
New England Electric System	(Naragansett Electric Co.)
New York State Electric & Gas Corp.	
Niagara Mohawk Power Corp.	
Northeast Utilities	(Connecticut Light & Power Co.)
Northern Indiana Public Service Co.	
Northern States Power Co.	
Ohio Edison Co.	
Oklahoma Gas & Electric Co.	
Orange & Rockland Utilities	
Pacificorp	(Pacific Power & Light Co.)
Pacific Gas & Electric Co.	
Pennsylvania Power & Light Co.	
Philadelphia Electric Co.	
Portland General Electric Co.	
Potomac Electric Power Co.	
Public Service Co. of Colorado	
Public Service Co. of Indiana	
Public Service Co. of New Hampshire	
Public Service Co. of New Mexico	
Public Service Electric & Gas Co.	
Puget Sound Power & Light Co.	
St. Joseph Light & Power Co.	
San Diego Gas & Electric Co.	
Sierra Pacific Resources	(Sierra Pacific Power Co.)
South Carolina Electric & Gas Co.	
Southern California Edison Co.	
Southern Company	(Alabama Power Co.)
Southern Indiana Gas & Electric Co.	
Southwestern Public Service Co.	
TECO Energy, Inc.	(Tampa Electric Co.)
Texas Utilities Co.	(Dallas Power & Light Co.)
Toledo Edison Co.	
Tucson Electric Power Co.	
Union Electric Co.	
Utah Power & Light Co.	
Washington Water Power Co.	
Wisconsin Electric Power Co.	
Wisconsin Power & Light Co.	
Wisconsin Public Service Corp.	

Philadelphia Electric Company
Indicated Results of Pennsylvania Jurisdictional Electric Operations, Pro Forma Present Rates and Pro Forma Proposed Rates, if the Rate Base is Financed in Harmony with the Rate of Return Opinion for Twelve Months Ended June 30, 1986

Line No.	Description	Pro Forma Present Rates	Proposed Rates
1.	Before-income tax overall rate of return	7.22% (1)	19.79% (3)
2.	Federal income tax	0.83 (2)	7.09 (4)
3.	After income tax overall rate of return (line 1 less line 2)	6.39	12.70
4.	Less: Long-term debt component (50.7% long-term debt ratio x 10.84% long-term debt cost rate)	5.50	5.50
5.	Component available for preferred stock and common equity	0.89	7.20
6.	Less: Preferred stock component (10.8% preferred stock ratio x 10.54% preferred stock cost rate)	1.14	1.14
7.	Component available for common equity	(0.25)%	6.06%
	Financial Ratios		
	Interest coverage:		
	Before Income tax (line 1 ÷ line 4)	1.3x	3.6x
	After income tax (line 3 ÷ line 4)	1.2x	2.3x
	Overall coverage of interest and preferred dividends (Line 3 ÷ sum of lines 4 and 6)	1.0x	1.9x
	Return rate for common equity component of the rate base (component available for common equity ÷ 38.5% common equity ratio)	(0.6)%	15.75%
	Effective income tax rate (line 2 ÷ (line 2 + line 5))	48.3%	49.6%

Philadelphia Electric Company
Indicated Results of Pennsylvania Jurisdictional Electric Operations,
Pro Forma Present Rates and Pro Forma Proposed Rates,
if the Rate Base is Financed in Harmony with the Rate of Return Opinion
for Twelve Months Ended June 30, 1986

Notes:

(1) Sum of Operating Income Available for Return pro forma at present rates of \$444.781 million and related Federal Income Taxes and equivalents of \$58.036 million or \$502.817 million of before-income tax net operating income related to per books adjusted original cost rate base of \$6,963.532 million.

(2) Federal Income Taxes and Equivalents pro forma at present rates of \$58.036 million related to per books adjusted original cost rate base of \$6,963.532 million.

(3) Sum of Operating Income Available for Return pro forma at proposed rates of \$884.369 million and related Federal Income Taxes and equivalents of \$493.563 million or \$1,377.932 million of before income tax net operating income related to claimed original cost rate base of \$6,963.532 million.

(4) Federal Income Taxes and Equivalents pro forma at proposed rates of \$493.563 million related to claimed original cost rate base of \$6,963.532 million.

Source of Information: Exhibit TPH-2, Schedule A-1 n/e/r/a

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
CONSULTING ECONOMISTS

PECO STATEMENT NO. 29

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

RECEIVED

SEP 27 1985

SECRETARY'S OFFICE
Public Utility Commission

DIRECT TESTIMONY OF
DR. JOHN H. WILE

LIMERICK 1 AND COMMON PLANT INDEPENDENT ASSESSMENT OF LIMERICK COST AND SCHEDULE AND PRUDENCY OF PAST DECISIONS

September 27, 1985

Q. Please state your name and business address.

A. My name is John H. Wile and my business address is 123 Main Street, White Plains, New York.

Q. Who is your employer?

A. I work at National Economic Research Associates, Inc. (NERA), which was established in 1961 to offer economic consulting services with particular emphasis on regulated industries and their problems. NERA specializes in the economics of energy, the environment, antitrust and labor.

Q. Dr. Wile, what is your position at NERA?

A. I am a Senior Consultant.

Q. Would you briefly describe your educational and employment background prior to your association with NERA.

A. I received my B.A. degree in economics from California State University at Northridge in 1966 and my Ph.D. in economics from Brown University in 1971. From 1970 to 1973 I taught economics at Rensselaer Polytechnic Institute. Between 1973 and 1976, when I joined NERA, I taught economics at the State University of New York at Stony Brook.

Q. Please describe your work at NERA.

A. Since joining NERA I have directed and consulted on a variety of long-range planning, energy, environmental and transportation projects. These include analyses of the comparative economics of coal and nuclear generating plants, of the economic, energy and environmental impacts of nuclear curtailment, of the impacts of deregulating export coal rail rates and of regional coal markets.

In addition, I have done a number of studies on the impacts of environmental legislation including the 1977 Clean Air Act Amendments. The results of my work have been presented as testimony before the Interstate Commerce Commission, the Florida Department of Environmental Regulation, the Maine Public Utilities Commission, the Pennsylvania Public Utility Commission and the Arkansas Public Service Commission. Also, I have given speeches before a number of professional groups including the National Council for Environmental Balance, the Mid-Continent Area Planning Pool, the Control Data Corporation Electric Utility Executive Seminar and the Pennsylvania Electric Association. A copy of my resume listing testimonies, publications and speeches is attached.

Q. Have any of your writings been published?

A. Yes. I have written papers that have been published in <u>The Analysis of Regional Structure: Essays in Honour of August Losch</u>, <u>Journal of Urban Economics</u>, <u>Economic Inquiry</u> and <u>Urban and Social Economics in Market and Planned Economies: Policies, Planning and Development</u>.

Q. Please list the professional organizations in which you are a member.

A. I am a member of the American Economic Association, the International Association of Energy Economists and the Association of Environmental and Resource Economists.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the linear programming model and the key assumptions NERA used to determine whether the Limerick system and Limerick 1 were part of the least cost expansion plan for PJM.

Q. Would you please give an overview of how NERA evaluated Limerick?

A. We evaluated the Limerick system and Limerick 1 in the context of the PJM system plans as of 1973, 1976, 1978 and 1980. For each of these years, we focused on capacity needs as of the commercial operation dates for the Limerick system and Limerick 1.

Evaluating capacity needs involves comparing electricity demand with the various sources of electricity available to meet the demand. On the demand side, there are the expected peak and energy demands. On the supply side, there are several sources of electricity that can be combined to meet the demand--existing generating units, planned units and additional new capacity (generic plants). Because we were focusing only on the issue of whether Limerick is economic, we assumed that other units planned as of 1973, 1976, 1978 and 1980 would enter service as expected. Consequently, whether Limerick is part of the most economic mix for PJM depends on the operating cost and availability of the existing and the planned units, and on the capital costs, operating costs and availability of Limerick and generic capacity.

To determine whether the Limerick system and Limerick 1 were part of the least cost PJM expansion plan, we used the NERA Utility System Planning Model. This is a linear programming model that determines the mix of generating capacity that meets electricity demand at lowest cost. In projecting this mix of capacity, the model takes into account:

1. Electricity demand--by season and load period.
2. Existing and planned generating units--their operating costs and characteristics.
3. The Limerick system and Limerick 1--their operating costs, operating characteristics and capital costs.
4. Generic capacity--its operating cost, operating characteristics and capital costs.

Q. Would you describe the basis of the demand forecasts you used in your analysis?

A. There were several steps in deriving the demand projections. First, we evaluated Limerick as of its expected commercial operation dates for each year of analysis. For the Limerick system we assumed the in-service dates to be the average dates for Units 1 and 2. The expected commercial operation dates are described in Schedule 1.

Second, to take account of transmission constraints among PJM members, we aggregated companies into four regions. These are described in Schedule 2.

Third, we developed two sets of demand projections for each expected commercial operation date. The first set of forecasts are the Expected Growth cases. These are based on the company demand forecasts for each year of analysis aggregated according to our regional definitions. The company peaks were adjusted when aggregating them into the regional peaks to reflect non-coincidence of peak demands. The regional demand forecasts by year of analysis and expected in-service date are summarized in Schedule 3.

The other set of forecasts are the Zero Growth cases. These assumed no growth in demand beyond each year of analysis. These forecasts were used to evaluate the sensitivity of the economic benefits of Limerick to demand growth. The Zero Growth regional demands are also summarized in Schedule 3.

Q. How did you develop the demands by seasons and by load periods?

A. The first step was to define the seasons. These were derived from hourly load data for 1983. The peak demands for each month were identified. Then months with similar peak demands were grouped into seasons. Based on this analysis we defined the four seasons given in Schedule 4.

Second, we defined the load periods. This was done by grouping hourly demands within each season by the intensity of demand, from highest to lowest. This process yielded seven load periods for the peak season and from three to five load periods for the other seasons. The loads for each season and load period were then expressed as a percent of the annual peak demand. The hours in each load period are given in Schedule 5.

The third step was to determine the level of electricity demand for each load period and season for each growth case and in-service date. The shape of the load curves developed in the first two steps reflect the peak and energy demands, and therefore the load factors, prevailing in 1983. These load curves are adjusted for the demand characteristics--peak, energy and load factor--of the forecasts for each year of analysis. When these demands reflect a load factor higher than what prevailed in 1983, the load for each period is increased relative to the peak demand. Those load periods with the lowest level of demand increase the most. If the forecasted load factor for a year of analysis is less than in 1983, the level of demand for each load period is lowered. The projected demands by season and load period for the Expected Growth cases are given in Schedule 6, and those for the Zero Growth cases are given in Schedule 7.

Q. How did you take into account the limits on transmission among PJM companies?

A. Based on data from Philadelphia Electric Company and discussions with Philadelphia Electric engineers, we grouped the companies into the four regions described in Schedule 2. The limits on transmission among regions were provided by Philadelphia Electric and are given in Schedule 8. From the point of view of transmission, Philadelphia Electric is part of the eastern region. Consequently, we assumed there were no limits on transmission between Philadelphia Electric and the East region.

Q. What are the key characteristics that determine whether Limerick should be part of the PJM least cost capacity expansion plan?

A. The key factors for Limerick are capital costs, capital additions, fuel costs, non-fuel operating and maintenance (O&M)

expenses, and maximum capacity factor. In evaluating Limerick, however, we must also consider these same factors for generic capacity as well as the operating costs of the existing and planned units on the PJM system.

Q. Would you please describe the basis for the Limerick capital costs used in your analysis?

A. We evaluated Limerick on an incremental cost basis. The incremental costs are the capital expenditures that remain to be spent after the year of analysis. Limerick's total costs, sunk costs (what had been spent through each year of analysis) and incremental costs are described in Schedule 9 of Dr. Perl's testimony.

The direct incremental capital costs were then booked using the NERA utility financial model. It is described in Dr. Perl's testimony along with the underlying accounting and financial assumptions.

Using these booked capital costs we then estimated levelized annual capital charges for the Limerick system, Limerick 1 and generic coal units. These charges include all revenues needed to amortize the plants, pay a return to investors, interest on debt and taxes. For nuclear plants, decommissioning costs are also included. In addition, they include allowances for continuing capital expenses which are associated with coal and nuclear plants.

In order to estimate the levelized annual capital charge, the NERA utility financial model was used to calculate capital-related revenue requirements for each year of plant life. We then solve for a constant annual charge which, after adjusting for inflation, yields revenues with the same discounted present value. For convenience, we have expressed the levelized annual capital charge as a percentage of initial capital costs. This is referred to as the levelized real fixed charge rate. The fixed charge rates, along with other key characteristics for Limerick in each year of analysis are summarized in Schedule 9.

As indicated above, the estimates of levelized annual capital charges include allowances for post-commercial nuclear additions. For nuclear plants, these capital additions were estimated using a regression equation which relates capital additions to plant characteristics and to time. The regression results are given in Schedule 12 of Dr. Perl's testimony.

Q. How did you derive the O&M for Limerick?

A. For Limerick units we estimated the non-fuel O&M using a regression relating O&M expenses to unit characteristics. The fixed O&M costs as of each analysis year were based on the predictions of the regression equation as of that year. For example, the 1978 forecast was based upon prevailing O&M costs in 1978. The regression results are described in Schedule 13 of Dr. Perl's testimony.

Q. What is the basis for the availability rates used in your analysis?

A. For Limerick the expected maximum capacity factor we used declined over the course of the analysis. For the 1973 analysis, we assumed Limerick would achieve a 70 percent capacity factor.

This was based on data for small nuclear units which had achieved these capacity factors. However, during the seventies larger nuclear units came on-line and did not realize these output levels, and, consequently, expected capacity factors have declined. We have reflected these declining expectations by reducing the maximum capacity factor. From the 70 percent for the 1973 year of analysis, it declines by 1 percentage point per year so that for the 1976 year of analysis, it is 67 percent, 65 percent for 1978 and 63 percent for 1980.

Q. Did you consider any other units besides Limerick?

A. Yes, in order to determine whether Limerick was the least cost alternative we allowed the option of adding new coal (generic coal units) capacity beyond the existing planned units.

Q. What was the basis for the costs and characteristics of the generic coal units?

A. These units were assumed to consist of two 400 MW subcritical units burning a medium sulfur, 2.7 percent, bituminous coal and having a flue gas desulfurization system (scrubbers). For the 1973 and 1976 analyses we assumed the scrubbers were designed to remove about 70 percent of the sulfur to achieve an emissions rate of 1.2 pounds of sulfur dioxide per million Btu, as mandated under the 1970 Clean Air Act for new sources. Their particulate standard was assumed to be 0.10 pounds per million Btu.

For the 1978 and 1980 analyses we assumed the generic coal units would meet the 1977 Clean Air Act Amendments by removing about 90 percent of the sulfur and having a particulate system to comply with the 0.03 pounds per million Btu standard. The costs and key characteristics for the generic coal units are summarized in Schedule 10.

The basis for the capital costs, non-fuel O&M expenses, availability factors and heat rates are described in Schedules 10, 14, 15, 16 and 19, respectively, of Dr. Perl's testimony.

Q. How did you estimate fuel costs for Limerick and generic coal units?

A. For generic coal units we developed estimates of delivered prices in two steps. First, using FERC data on the cost and quality of fuels we determined for coal with a sulfur content of at least 1.5 percent the delivered prices to eastern PJM for each year of analysis. Second, we estimated the real coal price escalation rate, 1 percent per year, using the NERA Coal Model. The 1 percent is the real escalation rate projected by the model for medium sulfur coal delivered to Pennsylvania. This model specifies supplies for 24 different coal types from 21 regions and coal demands for 21 regions of the country. It determines the prices for coals that will balance regional demands and supplies for different coal types. The coal prices and the annual real escalation rates as of each year of analysis are given in Schedule 11.

For the Limerick fuel prices we developed estimates based on the NERA Nuclear Fuel Model. The derivation of Limerick's fuel prices is described in Dr. Perl's testimony and in his Schedule 17.

Q. What did you assume about fuel prices for the existing units in PJM?

A. Philadelphia Electric provided us with unit specific data fuel costs as of the beginning of 1983. For the nuclear fuel we developed estimates for U.S. average prices as of each year of analysis and as of the beginning of 1983. We then scaled the 1983 unit specific prices to the levels prevailing in each year of analysis. This was done by multiplying the 1983 unit prices by the ratio of the average price prevailing in a year of analysis to the average 1983 price.

For coal prices we followed a similar approach. In this case, we used historical delivered prices of medium sulfur coal to eastern PJM to develop the ratios to scale the unit specific fuel price data for beginning 1983. For oil prices we also used this approach, based on historical delivered prices to Pennsylvania, to develop these ratios.

Q. What was the basis for your assumptions about other characteristics for existing units?

A. With respect to the availability and capability of these units, we relied on the information provided by Philadelphia Electric. The key characteristics for the units are capacity, forced outage rates, maintenance requirements and heat rates.

Q. Dr. Wile, does this conclude your testimony?

A. Yes, it does.

PROJECTED COMMERCIAL OPERATION DATE FOR LIMERICK SYSTEM AND LIMERICK 1 BY YEAR OF ANALYSIS

Year of Analysis	Projected Commercial Operation Date: Limerick System[1,2] (1)	Projected Commercial Operation Date: Limerick 1[2] (2)
1973	1980.5	1980
1976	1984	1983
1978	1986	1985
1980	1986.5	1985

Sources and Notes

[1]Limerick system commercial operation date is an average of the commercial operation dates of Limerick 1 and 2.

[2]Commercial operation date estimates were provided by PECO.

DEFINITION OF REGIONS

Region	Companies
PECO	Philadelphia Electric
East	Atlantic Electric Delmarva Power and Light Jersey Central Public Service Electric and Gas
West	Metropolitan Edison Pennsylvania Power and Light Luzerne (UGI) Pennsylvania Electric
South	Baltimore Gas and Electric Potomac Electric Power

THE 1973 DEMAND FORECAST FOR 1980 BY REGION

Region and Case	Projected Demand: Peak (MW) (1)	Projected Demand: Generation (GWH) (2)
Expected Growth:[1]		
PECO	8,332	41,600
East	17,872	82,451
West	10,874	61,144
South	10,776	48,555
PJM	47,854	233,750
Zero Growth:[2]		
PECO	5,702	27,681
East	11,827	56,088
West	6,805	40,414
South	7,111	31,833
PJM	31,445	156,016

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1974.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1976 DEMAND FORECAST FOR 1983
BY REGION

Region and Case	Projected Demand Peak (MW) (1)	Projected Demand Generation (GWH) (2)
Expected Growth:[1]		
PECO	8,120	41,344
East	16,495	78,758
West	10,930	62,387
South	10,346	47,822
PJM	45,891	230,311
Zero Growth:[2]		
PECO	5,607	28,433
East	11,987	56,833
West	7,485	41,748
South	7,232	32,703
PJM	32,311	159,717

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1976.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

**THE 1976 DEMAND FORECAST FOR 1984
BY REGION**

Region and Case	Demand Forecast: Peak (MW) (1)	Demand Forecast: Generation (GWH) (2)
Expected Growth:[1]		
PECO	8,514	43,688
East	17,313	82,869
West	11,579	65,880
South	10,760	50,043
PJM	48,166	242,480
Zero Growth:[2]		
PECO	5,607	28,433
East	11,987	56,833
West	7,485	41,748
South	7,232	32,703
PJM	32,311	159,717

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1976.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1978 DEMAND FORECAST FOR 1985 BY REGION

Region and Case	Projected Demand: Peak (MW) (1)	Projected Demand: Generation (GWH) (2)
Expected Growth:[1]		
PECO	7,035	38,035
East	16,294	80,014
West	10,402	59,389
South	9,652	45,959
PJM	43,383	223,397
Zero Growth:[2]		
PECO	5,606	29,197
East	12,460	60,239
West	7,973	44,824
South	7,543	34,933
PJM	33,582	169,193

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1978.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1978 DEMAND FORECAST FOR 1986 BY REGION

Region and Case	Demand Forecast: Peak (MW) (1)	Demand Forecast: Generation (GWH) (2)
Expected Growth:[1]		
PECO	7,231	39,479
East	16,901	83,084
West	10,719	61,427
South	9,946	47,516
PJM	44,797	231,506
Zero Growth:[2]		
PECO	5,606	29,197
East	12,460	60,239
West	7,973	44,824
South	7,543	34,933
PJM	33,582	169,193

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1978.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1980 DEMAND FORECAST FOR 1985 BY REGION

Region and Case	Projected Demand Peak (MW) (1)	Projected Demand Generation (GWH) (2)
Expected Growth:[1]		
PECO	6,209	34,153
East	14,616	73,495
West	9,700	56,246
South	8,959	42,571
PJM	39,484	206,465
Zero Growth:[2]		
PECO	5,992	29,975
East	12,468	62,611
West	8,020	46,273
South	7,727	36,334
PJM	34,207	175,193

Sources and Notes

[1]The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1980.

[2]The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

THE 1980 DEMAND FORECAST FOR 1986 BY REGION

Region and Case	Demand Forecast: Peak (MW) (1)	Demand Forecast: Generation (GWH) (2)
Expected Growth:[1]		
PECO	6,308	35,129
East	14,991	76,017
West	10,012	58,137
South	9,205	43,842
PJM	40,516	213,125
Zero Growth:[2]		
PECO	5,992	29,975
East	12,468	62,611
West	8,020	46,273
South	7,727	36,334
PJM	34,207	175,193

Sources and Notes

[1] The expected growth peak and generation values were derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast for June 1, 1980.

[2] The peak and energy demands for the zero growth case are derived from the forecast of the analysis year in the source cited above.

DEFINITION OF SEASONS

Season	Months
1	July, August, September
2	June
3	December, January, February
4	March, April, May, October, November

HOURS BY LOAD PERIOD AND SEASON[1]

Load Period	Season (1)	(2)	(3)	(4)
1	22	53	115	897
2	45	74	822	1,587
3	247	170	882	1,188
4	436	261	341	
5	458	162		
6	723			
7	277			
Total Hours	2,208	720	2,160	2,672

Sources and Notes

[1]Derived from the 1983 hourly load data.

THE 1973 PROJECTED ELECTRICITY DEMAND FOR 1980 (EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region: PECO	East	West	South
		---(Megawatts)---			
		(1)	(2)	(3)	(4)
1	1	8,107	17,341	9,488	10,631
	2	7,704	16,390	9,224	10,276
	3	7,052	14,851	8,743	9,315
	4	6,264	12,989	7,984	8,094
	5	5,455	11,079	7,110	6,774
	6	4,476	8,769	5,760	5,346
	7	3,508	6,482	4,695	3,885
2	1	7,034	14,806	8,923	9,188
	2	6,295	13,064	8,326	8,009
	3	5,441	11,047	7,617	6,694
	4	4,486	8,792	6,118	5,381
	5	3,452	6,350	4,831	3,872
3	1	6,090	12,759	10,061	7,388
	2	5,482	11,143	8,883	6,407
	3	4,465	8,742	7,152	5,153
	4	3,653	6,825	5,755	4,046
4	1	5,319	10,757	8,340	6,030
	2	4,498	8,821	6,914	5,010
	3	3,452	6,352	5,218	3,650

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1974) and the hourly load data for 1983.

1976 ELECTRICITY DEMAND FOR 1983
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	7,906	16,024	9,574	10,211
	2	7,524	15,180	9,316	9,879
	3	6,906	13,815	8,846	8,982
	4	6,157	12,163	8,104	7,841
	5	5,390	10,470	7,249	6,609
	6	4,461	8,420	5,929	5,276
	7	3,542	6,391	4,888	3,911
2	1	6,888	13,776	9,022	8,863
	2	6,187	12,230	8,438	7,762
	3	5,377	10,441	7,745	6,534
	4	4,470	8,441	6,279	5,308
	5	3,489	6,274	5,020	3,899
3	1	5,992	11,799	10,135	7,182
	2	5,415	10,526	8,983	6,266
	3	4,450	8,396	7,290	5,095
	4	3,680	6,696	5,923	4,061
4	1	5,260	10,184	8,452	5,914
	2	4,482	8,466	7,058	4,962
	3	3,489	6,276	5,399	3,692

Sources and Notes

[1]The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1976) and the hourly load data for 1983.

1976 ELECTRICITY DEMAND FOR 1984
(EXPECTED GROWTH)

		Electricity Demand by Region			
Season	Load Period	PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)[1]
1	1	8,293	16,820	10,134	10,620
	2	7,896	15,937	9,859	10,278
	3	7,254	14,508	9,358	9,351
	4	6,478	12,780	8,567	8,173
	5	5,682	11,008	7,656	6,901
	6	4,719	8,863	6,249	5,523
	7	3,766	6,740	5,140	4,114
2	1	7,236	14,467	9,546	9,229
	2	6,509	12,850	8,923	8,091
	3	5,669	10,977	8,184	6,823
	4	4,729	8,884	6,622	5,557
	5	3,710	6,617	5,281	4,101
3	1	6,307	12,399	10,732	7,492
	2	5,708	11,066	9,504	6,546
	3	4,708	8,838	7,700	5,336
	4	3,909	7,058	6,243	4,269
4	1	5,548	10,709	8,938	6,182
	2	4,741	8,911	7,452	5,199
	3	3,711	6,619	5,685	3,887

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, (June 1, 1976) and the hourly load data for 1983.

1978 ELECTRICITY DEMAND FOR 1985
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region: PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	6,866	15,845	9,112	9,530
	2	6,563	15,040	8,867	9,231
	3	6,073	13,737	8,419	8,422
	4	5,480	12,161	7,714	7,394
	5	4,873	10,545	6,901	6,283
	6	4,137	8,590	5,645	5,081
	7	3,409	6,654	4,654	3,851
2	1	6,059	13,699	8,587	8,315
	2	5,504	12,224	8,032	7,323
	3	4,862	10,518	7,372	6,216
	4	4,144	8,609	5,978	5,111
	5	3,367	6,542	4,781	3,840
3	1	5,350	11,814	9,646	6,800
	2	4,893	10,599	8,550	5,974
	3	4,129	8,567	6,939	4,918
	4	3,518	6,944	5,640	3,986
4	1	4,770	10,272	8,045	5,656
	2	4,154	8,634	6,718	4,798
	3	3,368	6,544	5,141	3,653

Sources and Notes

[1] The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1978) and the hourly load data for 1983.

1978 ELECTRICITY DEMAND FOR 1986
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region: PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	7,060	16,435	9,399	9,821
	2	6,754	15,602	9,148	9,514
	3	6,258	14,252	8,690	8,694
	4	5,658	12,620	7,968	7,629
	5	5,044	10,946	7,136	6,488
	6	4,300	8,921	5,851	5,254
	7	3,563	6,916	4,838	3,992
2	1	6,244	14,213	8,862	8,574
	2	5,683	12,686	8,293	7,555
	3	5,033	10,918	7,618	6,419
	4	4,307	8,941	6,192	5,285
	5	3,520	6,800	4,967	3,980
3	1	5,526	12,260	9,945	7,018
	2	5,064	11,002	8,823	6,171
	3	4,291	8,897	7,176	5,087
	4	3,674	7,216	5,846	4,131
4	1	4,940	10,664	8,307	5,845
	2	4,316	8,966	6,950	4,964
	3	3,521	6,801	5,335	3,789

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1978) and the hourly load data for 1983.

1980 ELECTRICITY DEMAND FOR 1985
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	6,064	14,225	8,533	8,846
	2	5,804	13,525	8,310	8,567
	3	5,384	12,392	7,905	7,814
	4	4,875	11,022	7,267	6,858
	5	4,354	9,617	6,530	5,825
	6	3,723	7,917	5,393	4,706
	7	3,098	6,233	4,497	3,561
2	1	5,372	12,360	8,057	7,715
	2	4,896	11,077	7,554	6,792
	3	4,345	9,593	6,957	5,762
	4	3,729	7,934	5,695	4,733
	5	3,062	6,136	4,611	3,551
3	1	4,763	10,720	9,015	6,305
	2	4,371	9,663	8,023	5,536
	3	3,716	7,897	6,565	4,554
	4	3,192	6,486	5,389	3,687
4	1	4,266	9,380	7,566	5,241
	2	3,737	7,955	6,366	4,442
	3	3,063	6,137	4,937	3,377

Sources and Notes

[1]The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1980) and the hourly load data for 1983.

1980 ELECTRICITY DEMAND FOR 1986
(EXPECTED GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	6,164	14,595	8,810	9,089
	2	5,905	13,885	8,582	8,804
	3	5,487	12,736	8,165	8,032
	4	4,982	11,347	7,507	7,052
	5	4,463	9,922	6,750	5,993
	6	3,835	8,198	5,579	4,847
	7	3,214	6,491	4,656	3,675
2	1	5,475	12,703	8,321	7,931
	2	5,002	11,403	7,803	6,984
	3	4,454	9,898	7,189	5,929
	4	3,842	8,215	5,889	4,875
	5	3,178	6,392	4,774	3,664
3	1	4,870	11,041	9,307	6,486
	2	4,480	9,969	8,286	5,698
	3	3,828	8,178	6,786	4,692
	4	3,307	6,747	5,574	3,803
4	1	4,375	9,682	7,816	5,396
	2	3,850	8,237	6,580	4,577
	3	3,179	6,394	5,110	3,486

Sources and Notes

[1]The electricity demand in megawatts is derived from the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1980) and the hourly load data for 1983.

1973 ELECTRICITY DEMAND FOR 1980
(NO GROWTH)

Season	Load Period	Electricity Demand by Region PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,542	11,486	6,025	7,015
	2	5,257	10,877	5,876	6,779
	3	4,794	9,890	5,605	6,140
	4	4,235	8,696	5,179	5,329
	5	3,661	7,472	4,687	4,452
	6	2,967	5,990	3,927	3,503
	7	2,279	4,524	3,328	2,533
2	1	4,781	9,861	5,707	6,056
	2	4,257	8,744	5,371	5,273
	3	3,651	7,451	4,972	4,399
	4	2,974	6,005	4,128	3,527
	5	2,240	4,439	3,404	2,524
3	1	4,111	8,433	6,347	4,860
	2	3,680	7,512	5,684	4,208
	3	2,959	5,973	4,710	3,375
	4	2,383	4,744	3,924	2,639
4	1	3,564	7,265	5,379	3,958
	2	2,982	6,025	4,577	3,280
	3	2,240	4,440	3,622	2,376

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, for June 1, 1974, and the hourly load data for 1983.

1976 ELECTRICITY DEMAND FOR 1983 AND 1984
(NO GROWTH)

Season	Load Period	PECO	East	West	South
		Electricity Demand by Region			
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,459	11,642	6,517	7,135
	2	5,193	11,024	6,333	6,898
	3	4,764	10,023	5,997	6,255
	4	4,244	8,813	5,467	5,439
	5	3,711	7,572	4,857	4,557
	6	3,066	6,070	3,914	3,602
	7	2,428	4,583	3,170	2,625
2	1	4,751	9,994	6,123	6,170
	2	4,265	8,861	5,706	5,382
	3	3,702	7,550	5,210	4,503
	4	3,073	6,085	4,164	3,625
	5	2,391	4,497	3,265	2,616
3	1	4,130	8,546	6,917	4,967
	2	3,729	7,613	6,094	4,311
	3	3,059	6,052	4,886	3,472
	4	2,524	4,806	3,910	2,733
4	1	3,621	7,362	5,715	4,059
	2	3,081	6,103	4,720	3,377
	3	2,391	4,498	3,536	2,467

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, for June 1, 1976, and the hourly load data for 1983.

1978 ELECTRICITY DEMAND FOR 1985 AND 1986
(NO GROWTH)

Season	Load Period	Electricity Demand by Region			
		PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,463	12,110	6,956	7,445
	2	5,208	11,482	6,763	7,203
	3	4,794	10,466	6,410	6,550
	4	4,294	9,237	5,854	5,721
	5	3,781	7,977	5,212	4,825
	6	3,160	6,452	4,222	3,854
	7	2,546	4,943	3,441	2,862
2	1	4,782	10,437	6,542	6,464
	2	4,314	9,287	6,104	5,663
	3	3,772	7,955	5,584	4,770
	4	3,166	6,467	4,485	3,878
	5	2,510	4,855	3,541	2,853
3	1	4,184	8,966	7,377	5,241
	2	3,798	8,019	6,512	4,575
	3	3,153	6,435	5,243	3,723
	4	2,638	5,169	4,218	2,971
4	1	3,694	7,764	6,114	4,139
	2	3,174	6,486	5,069	3,626
	3	2,511	4,857	3,825	2,702

Sources and Notes

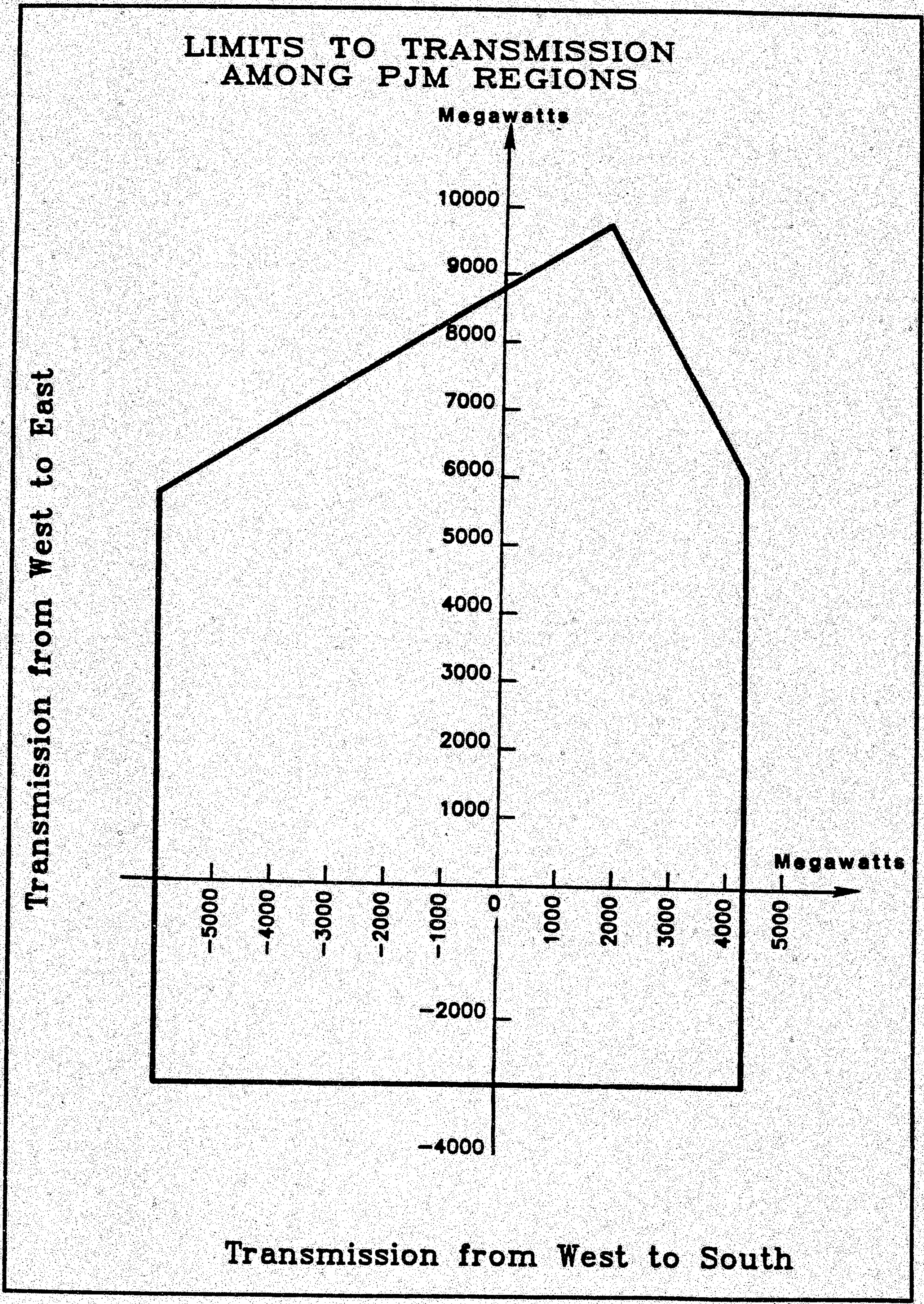
[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland Interconnection Load and Capacity Forecast, (June 1, 1978) and the hourly load data for 1983.

1980 ELECTRICITY DEMAND FOR 1985 AND 1986
(NO GROWTH)

Season	Load Period	Electricity Demand by Region: PECO	East	West	South
		(Megawatts)			
		(1)	(2)	(3)	(4)
1	1	5,831	12,134	7,045	7,628
	2	5,542	11,536	6,860	7,385
	3	5,074	10,568	6,522	6,728
	4	4,508	9,397	5,988	5,893
	5	3,928	8,196	5,374	4,990
	6	3,226	6,743	4,425	4,013
	7	2,532	5,304	3,676	3,014
2	1	5,061	10,540	6,648	6,641
	2	4,531	9,444	6,228	5,835
	3	3,918	8,175	5,730	4,935
	4	3,233	6,757	4,676	4,037
	5	2,491	5,221	3,772	3,005
3	1	4,385	9,139	7,448	5,410
	2	3,948	8,236	6,620	4,739
	3	3,218	6,726	5,403	3,881
	4	2,636	5,520	4,421	3,124
4	1	3,820	7,993	6,238	4,481
	2	3,242	6,776	5,236	3,783
	3	2,492	5,222	4,044	2,853

Sources and Notes

[1]The electricity demand in megawatts is derived from the analysis year forecast in the Pennsylvania - New Jersey - Maryland interconnection Load and Capacity Forecast, for June 1, 1980, and the hourly load data for 1983.


LIMITS TO TRANSMISSION AMONG PJM REGIONS
Megawatts
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
-2000
-4000
Megawatts
-5000
-4000
-3000
-2000
-1000
0
1000
2000
3000
4000
5000
Transmission from West to East
Transmission from West to South

EXPECTED CHARACTERISTICS OF LIMERICK SYSTEM AND LIMERICK 1

	Limerick 1				Limerick System			
	1973 (1)	1976 (2)	1978 (3)	1980 (4)	1973 (5)	1976 (6)	1978 (7)	1980 (8)
Capital Cost (Mid-84 $/kW)[1]	603	640	542	397	555	705	606	623
Real Levelized Fixed Charge Rate (Percent)[2]	6.4	5.8	5.9	6.5	6.4	5.9	6.0	6.7
Levelized Fixed O&M (Mid-84 $/kW)[3]	13.91	21.36	26.99	37.01	10.43	16.01	20.23	27.75
Levelized Capital Additions (Mid-84 $/kW)[4]	2.59	5.31	8.82	18.31	1.98	4.05	6.72	13.95
Equivalent Forced Outage Rate (Percent)[5]	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Hours of Maintenance Per Year (Hours)[6]	582	932	1,165	1,398	582	932	1,165	1,398
Maximum Capacity Factor (Percent)[7]	70	67	65	63	70	67	65	63
First Year Fuel Cost (Mid-84 $/MMBTU)[8]	0.683	1.302	1.335	1.119	0.684	1.316	1.348	1.130

Sources and Notes

[1]The booked cost per kilowatt of Limerick 1 and Limerick system as of the projected on-line date. This estimate includes all construction costs through commercial operation plus capitalized property taxes and allowance for funds used during construction (AFDC). The estimate of AFDC assumes that construction work in progress is excluded from the rate base. The rates used to estimate AFDC in each year are described in Schedule 11 of Dr. Perl's testimony. For the derivation of construction costs see Schedule 9 of Dr. Perl's testimony. To estimate booked costs in 1984 dollars, costs as of the date of commercial operation were brought back to year of analysis dollars by removing expected inflation and brought forward to 1984 dollars using actual inflation rates. The GNP implicit deflator was used to measure price changes and is given in Schedule 11 of Dr. Perl's testimony. Expected inflation is also shown in Schedule 11.
The projected commercial operation dates by year of analysis for Limerick 1 and Limerick plant can be found in Schedule 1.

EXPECTED CHARACTERISTICS OF LIMERICK SYSTEM AND LIMERICK 1

Sources and Notes

[2]The real levelized fixed charge rate is the annual fraction which, when applied to the initial plant investment, will yield sufficient revenues over the life of the project to cover all capital-related expenses—depreciation, interest expense, return on invested capital and taxes. It is equal to the annual capital cost, found in Schedule 8 of Dr. Perl's testimony, divided by the booked cost.

[3]The levelized annual non-fuel operation and maintenance cost in mid-1984 dollars per kilowatt. The derivation is described in Schedule 13 of Dr. Perl's testimony.

[4]The levelized annal cost of capital additions occurring over the plant's operating lifetime, in mid-1984 dollars per kilowatt. The derivation is described in Schedule 12 of Dr. Perl's testimony.

[5]The equivalent forced outage rate represents the probability the plant will not operate during the time it is not undergoing maintenance. Based on NERA assumptions.

[6]The hours of maintenance per year is one minus the capacity factor divided by the utilization rate, multiplied by the number of hours in the year (8760). The utilization rate represents the probability the plant will operate during the time it is not undergoing maintenance and is based on NERA assumptions.

[7]The projected levelized capacity factor of Limerick 1 and Limerick system. The estimate was derived, as discussed in the text, from a combination of engineering and statistical data.

[8]The levelized annual cost of fuel for Limerick in dollars per million Btu. The prices assumed for each nuclear fuel cycle component as of each analysis year are reported in Schedule 17 of Dr. Perl's testimony.

EXPECTED CHARACTERISTICS OF GENERIC COAL PLANTS[1]

	1973 (1)	1976 (2)	1978 (3)	1980 (4)
Capital Cost (Mid-84 $/kW)[2]	840	1,097	1,198	1,405
Real Levelized Fixed Charge Rate (Percent)[3]	6.9	6.3	6.4	7.3
Levelized Fixed O&M (Mid-84 $/kW)[4]	13.88	15.31	16.19	16.84
Equivalent Forced Outage Rate (Percent)[5]	19.00	19.00	19.00	19.00
Hours of Maintenance Per Year (Hours)[6]	1,203	1,774	1,772	1,744
Maximum Capacity Factor (Percent)[7]	70	65	65	65
First Year Fuel Cost (Mid-84 $/MMBtu)[8]	1.794	1.906	1.900	1.997

Sources and Notes

[1]The costs and characteristics are for a coal plant with two 400 MW units.

[2]The booked cost per kilowatt of the coal alternative as of the projected on-line date. This estimate includes all construction costs through commercial operation plus capitalized property taxes and allowance for funds used during construction (AFDC). The estimate of AFDC assumes that construction work in progress is excluded from the rate base. The rates used to estimate AFDC in each year are described in Schedule 11 of Dr. Perl's testimony and construction costs are derived in Schedule 10. To estimate booked costs in 1984 dollars, costs as of the date of commercial operation were brought back to year of analysis dollars by removing expected inflation and brought forward to 1984 dollars using actual inflation rates. The GNP implicit deflator was used to measure price changes and is given in Schedule 11 of Dr. Perl's testimony. Expected inflation is also shown in Schedule 11.
The projected commercial operation dates for the coal alternative to Limerick system by year of analysis can be found in Schedule 1.

EXPECTED CHARACTERISTICS OF GENERIC COAL PLANTS[1]

Sources and Notes

[3]The real levelized fixed charge rate is the annual fraction which, when applied to the initial plant investment, will yield sufficient revenues over the life of the plant to cover all capital-related expenses -- depreciation, interest expense, return on invested capital and taxes. It is equal to the annual cost, found on page 5 of Schedule 8 of Dr. Perl's testimony, divided by the booked cost.

[4]The levelized annual revenue requirements associated with fixed non-fuel operating and maintenance costs, expressed in mid-1984 dollars per kilowatt. The derivation of O&M cost is described in Schedule 14 of Dr. Perl's testimony.

[5]The equivalent forced outage rate represents the probability the plant will not operate during the time it is not undergoing maintenance. Based on NERA assumptions.

[6]The hours of maintenance per year is one minus the capacity factor divided by the utilization rate, multiplied by the number of hours in the year (8,760). The utilization rate represents the probability the plant will operate during the time it is not undergoing maintenance and is based on NERA assumptions.

[7]The levelized capacity factor is 93 percent of the projected equivalent availability. This derivation is described in Schedule 16 of Dr. Perl's testimony. The forecast for each analysis year was based only on units operating in that year.

[8]Coal price data reflect the average cost of coal with a sulfur content greater than 2.7 percent delivered to the Eastern PJM region in each year. Cost data are taken from FERC Form 423.

HISTORIC COAL AND OIL PRICES BY YEAR OF ANALYSIS

Year of Analysis	Oil Price[1] (Mid-84 \$/MMBTU) (1)	Coal Price[2] (Mid-84 \$/MMBTU) (2)
1973	2.925	1.272
1976	3.498	1.765
1978	3.877	1.819
1980	6.015	1.879

Sources and Notes

[1]Nominal prices for the Mid-Atlantic region were taken from FERC Form 423. The prices were then brought forward to 1984 dollars using actual inflation rates.

[2]Nominal prices for the Mid-Atlantic region were taken from the Statistical Year Book of the Electric Utility Industry. The coal price was converted to dollars per million Btu using heat contents of 11851, 11923, 11931 and 12076 Btu/lb. for the years 1973, 1976, 1978 and 1980 respectively. The prices were then brought forward to 1984 dollars using actual inflation rates.

REAL ESCALATION RATES FOR OIL AND COAL PRICES BY YEAR OF ANALYSIS[1]

Year of Analysis	Oil Price (Percent) (1)	Coal Price (Percent) (2)
1973	1.0	1.0
1976	1.0	1.0
1978	1.0	1.0
1980	2.0	1.0

[1] Based on NERA assumptions.

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BROWN UNIVERSITY
Ph.D., Economics, 1971
Dissertation Title: "The Effect of Technical Change on the Location Distribution of an Industry with Application to the Fertilizer Industry"

CALIFORNIA STATE UNIVERSITY
B.A., Economics, 1966

PROFESSIONAL EXPERIENCE:

6/1976-Present

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC. (NERA)
As a Senior Consultant, Dr. Wile has directed and consulted on a variety of long range planning, energy, environmental and transportation projects. Most recently he participated in a study for the Public Service Commission of Indiana which compared the economic and financial impacts of completing the Marble Hill nuclear plant with those for various alternatives. In response to the Three Mile Island accident, Dr. Wile conducted the first study on the economic, energy and environmental effects of curtailing nuclear power. The impacts of deregulating export coal rail rates on world coal prices and shipments were the subject of another study, the results of which appeared in a New York Times editorial. He has directed many studies on the economic and energy implicatons of environmental regulations and proposals including provisions of the Clean Air and Clean Water Acts. Other studies involve the effects on the electric utility industry of deregulating natural gas.

Dr. Wile designed models used in these studies including the NERA World Coal Model and the NERA Electric Utility System Planning Model. These models and results from them have also been used in analyses conducted by others at NERA.

In addition, Dr. Wile developed the NERA Regional Electricity Price Forecasting Model.

As an expert witness, Dr. Wile has testified before regulatory agencies such as the Interstate Commerce Commission and the Maine Public Utilities Commission. He has also addressed professional groups including the National Council for Environmental Balance, Mid-Continent Area Planning Pool and the Control Data Corporation Electric Utility Executive Seminar. Attached is a list of his publications, reports and testimonies.

1973-1976 STATE UNIVERSITY OF NEW YORK AT STONY BROOK—New York
Assistant Professor
Taught graduate and undergraduate courses in urban economics and mathematics for economists in the Department of Economics and W. Averill Harriman College of Urban and Policy Sciences.

1970-1973 RENSSELAER POLYTECHNIC INSTITUTE—Troy, New York
Assistant Professor
Taught industrial organization, mathematical economics and economic theory.

PUBLICATIONS:

"Prospects for International Trade in Coal," n/e/r/a Topics, 1982.

"The Impact of Demand and Cost Changes on the Spatial Dispersion of a Market-Oriented Industry," in The Analysis of Regional Structure: Essays in Honour of August Losch 1978.

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"On the Interaction Between Local Government and Urban Location"

"Pure Local Public Goods, City Size and Taxation Revisited"

November 1, 1985

R-850152

David B. MacGregor, Esquire
Philadelphia Electric Company
Morgan, Lewis & Bockius
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PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PHILADELPHIA ELECTRIC COMPANY

Dear Sir:

The Commission in a public meeting on October 31, 1985, instituted an inquiry and investigation at the above docket to determine the fairness, reasonableness and justness of rates named in Supplement No. 15 to Tariff Electric-PA PUC No. 26 filed to become effective November 27, 1985. Under authority of Title 66 PA C.S. ss 1308 (d), application of the proposed rates is suspended, by statute, for a period of up to seven months or to June 27, 1986.

Under the Public Utility Code, a supplement must be filed with the Commission and posted at the offices of the company to announce that the aforementioned Supplement is suspended until the date stated in the Commission's order.

Attached is a sample copy of a seven months suspension supplement which must be filed in triplicate with the Commission as soon as possible.

Copies of the formal order adopted by the Commission will be forwarded to you within the near future.

Very truly yours,

DOCKETED
NOV 4 - 1985

Jerry Rich
Secretary

Attachment
CERTIFIED MAIL
RETURN RECEIPT REQUESTED

DOCUMENT FOLDER